Creating Markets for Wind Electricity in China: Case Studies in Energy Policy and Regulation

by

Michael R. Davidson

B.S., Mathematics and Physics, Case Western Reserve University (2008)
B.A., Japanese Studies, Case Western Reserve University (2008)
S.M., Technology and Policy, Massachusetts Institute of Technology (2014)

Submitted to the Institute for Data, Systems, and Society
in partial fulfillment of the requirements for the degree of

Doctor of Philosophy in Engineering Systems

at the

MASSACHUSETTS INSTITUTE OF TECHNOLOGY

June 2018

Author . . . .
Institute for Data, Systems, and Society
April 6, 2018

Certified by . . . .
Prof. J. Ignacio Pérez-Arriaga
Visiting Professor, MIT Sloan School of Management; Professor, School of Engineering and Director of the BP Chair on Energy & Sustainability, Comillas University, Madrid, Spain
Thesis Supervisor

Certified by . . . .
Prof. Valerie J. Karplus
Class of 1943 Career Development Assistant Professor, Global Economics and Managament Group, MIT Sloan School of Management
Thesis Supervisor

Certified by . . . .
Prof. Margaret M. Pearson
Professor, Department of Government and Politics, University of Maryland, College Park

Accepted by . . . .
Prof. Stephen C. Graves
Professor, Mechanical Engineering and Engineering Systems, MIT; Abraham J. Siegel Professor, Management Science, MIT; and Graduate Officer, Institute for Data, Systems, and Society

Creating Markets for Wind Electricity in China: Case Studies in Energy Policy and Regulation

by

Michael R. Davidson

Submitted to the Institute for Data, Systems, and Society
in partial fulfillment of the requirements for the degree of
Doctor of Philosophy in Engineering Systems

Abstract

China's rapid economic growth—largely industrial, energy-intensive, and reliant on coal—has generated environmental, public health, and governance challenges. While China now leads the world in renewable energy deployment, curtailment (waste) of wind and solar is high and increasing, generating much discussion on the relative contributions of technical inflexibilities and incomplete institutional reforms on integration outcomes. These integration challenges directly affect China's ability to meet long-term environmental and economic objectives. A second, related challenge emerges from how wind integration interacts with China's reinvigoration in 2015 of a three-decade-old process to establish competitive electricity markets. A "standard liberalization prescription" for electricity markets exists internationally, though Chinese policy-makers ignore or underemphasize many of its elements in current reforms, and some scholars question its general viability in emerging economies. This dissertation examines these interrelated phenomena by analyzing the contributions of diverse causes of wind curtailment, assessing whether current experiments will lead to efficient and politically viable electricity markets, and offering prescriptions on when and how to use markets to address renewable energy integration challenges.

To examine fundamentals of the technical system and the impacts of institutional incentives on system outcomes, this dissertation develops a multi-method approach that iterates between engineering models and qualitative case studies of the system operation decision-making process (Chapter 2). These are necessary to capture, respectively, production functions inclusive of physical constraints and costs, and incentive structures of formally specified as well as *de facto* institutions. Interviews conducted over 2013-2016 with key stakeholders in four case provinces/regions with significant wind development inform tracing of the processes of grid and market operations (Chapter 3). A mixed-integer unit commitment and economic dispatch optimization is formulated and, based on the case studies, further tailored by adding several institutions of China's partially-liberalized system (Chapter 4). The model generates a reference picture of three of the systems as well as quantitative contributions of relevant institutions (Chapter 5). Insights from qualitative and quantitative approaches are combined iteratively for more parsimonious findings (Chapter 6).

This dissertation disentangles the causes of curtailment, focusing on the directional and relative contributions of institutions, technical issues, and potential interactive effects. Wind curtailment is found to be closely tied to engineering constraints, such as must-run combined heat and power (CHP) in northern winters. However, institutional causes—inflexibilities in both scheduling and inter-provincial trading—have a larger impact on curtailment rates. Technical parameters that are currently set administratively at the provincial level (e.g., coal generator minimum outputs) are a third and important leading cause under certain conditions.

To assess the impact of China's broader reform of the electricity system on wind curtailment, this dissertation examines in detail "marketizing" experiments. In principle, spot markets for electricity naturally prioritize wind, with near zero marginal cost, thereby contributing to low

curtailment. However, China has not yet created a spot market and this dissertation finds that its implementation of other electricity markets in practice operates far from ideal. Market designs follow a similar pattern of relying on dual-track prices and out-of-market parameters, which, in the case of electricity, leave several key institutional causes of inefficiency and curtailment untouched. Compared to other sectors with successful marketization occurring when markets "grow out of the plan," all of the major electricity experiments examined show deficiencies in their ability to transition to an efficient market and to cost-effectively integrate wind energy.

Although China's setting is institutionally very different, results support implementation of many elements of standard electricity market prescriptions: prioritize regional (inter-provincial) markets, eliminate conflicts of interest in dispatch, and create a consistent central policy on "transition costs" of reducing central planning. Important for China, though overlooked in standard prescriptions: markets are enhanced by clarifying the connection between dispatch and exchange settlement. As is well established, power system efficiency is expected to achieve greatest gains with a short-term merit order dispatch and primarily financial market instruments, though some workable near-term deviations for the Chinese context are proposed. Ambiguous property rights related to generation plans have helped accelerate reforms, but also delay more effective markets from evolving. China shares similarities with the large class of emerging economies undergoing electricity market restructuring, for which this suggests research efforts should disaggregate planning from scheduling institutions, analyze the range of legacy sub-national trade barriers, and prioritize finding "second-best" liberalization options fit to country context in the form and order of institutional reforms.

J. Ignacio Pérez-Arriaga
Committee Chair, Thesis Supervisor
Visiting Professor, Sloan School of Management, Massachusetts Institute of Technology
Professor, School of Engineering; Director of the BP Chair on Energy & Sustainability, Comillas University, Madrid, Spain

Valerie J. Karplus
Thesis Supervisor
Class of 1943 Career Development Assistant Professor, Global Economics and Managament Group, Sloan School of Management, Massachusetts Institute of Technology

Margaret M. Pearson
Professor, Department of Government and Politics, University of Maryland, College Park

Acknowledgements

Any insights I developed over the course of this work derive from the patient and generous advising by my committee: Ignacio Pérez-Arriaga, Valerie Karplus, and Margaret Pearson. Ignacio has guided me through all aspects of the electricity system, giving me the benefit of his decades of knowledge in systems around the world. He is the most approachable world expert in any domain I have met. Valerie has been a fantastic advisor and mentor, to whom I am grateful for bringing me into the unique collaboration with Tsinghua University she carefully built up. She has been generous with her time and experience and, important to a young scholar, always has the bigger picture in mind—whether advising on research or career goals. Margaret has been a consistent source of research ideas and practical advice in trying to understand the politics of regulation in China. I will always be grateful to her for introducing me to a larger community of scholars in these topics, with whom I have had the opportunity to further extend my academic impact. An interdisciplinary thesis requires a special kind of committee, and no amount of three-legged chair metaphors would be sufficient to convey how uniquely served these three have been to advise on this topic.

I was fortunate to receive support from a range of organizations during my time at MIT. I would like to thank ICF International, the other founding sponsors of the Tsinghua-MIT China Energy and Climate Project—Eni S.p.A., Shell International Limited, and the French Development Agency (AFD)—and the U.S. Energy Information Administration for their support through a cooperative agreement. The folks at ICF not only generously supported a good fraction of my time at MIT, but also provided many stimulating conversations in Cambridge, Beijing and Fairfax. In particular, I am grateful to Phil Mihlmester, David Hathaway, Steve Fine, and Joel Bluestein. I would like to thank the Martin Family for inviting me into their community of sustainability fellows, and the MIT Energy Initiative for providing a range of research and academic support. MIT International Science and Technology Initiatives (MISTI) supported much of my travel to China, and the MIT Center for International Studies supported a trip to India, sparking the next stage of work following my dissertation.

The Engineering Systems Division / Institute for Data, Systems, and Society is a unique community of scholars, a source of constant stimulation from my student peers, and the only academic home I could have imagined accomplishing this work. The Technology and Policy Program was my first stop at MIT, and I am grateful to everyone at TPP that helped get me here. The Joint Program on the Science and Policy of Global Change is a truly interdisciplinary group of scientists, with whom I have learned more than anywhere else how to pragmatically combine different methods to answer hard questions. Through the lively and curious JP student community, hailing from multiple schools on campus, I gained familiarity with a range of climate change topics that helped round out my education. The Electricity Students Research Group, which I had the pleasure to help lead, provided a home for electricity systems research on campus.

My second academic home in China was graciously provided by Prof. Xiliang Zhang and the Institute of Energy, Environment, and Economy at Tsinghua University. The group of faculty and students in China have been with me on this project since the beginning, providing valuable directions for research as well as to the best *biang-biang mian* shop. I would also like to thank the research and fieldwork assistance of Haotian Zhao, Chiao-Ting Li, Valerie Karplus, Yixin Dai, Alix de Monts, and Weiming Xiong.

My friends (of whom I count all of the above) have been a constant source of encouragement. My family—Mom, Betty and Travis—have supported me throughout this journey, even during long winters of writing. And this thesis would have gotten nowhere without the love of Yiting, my life partner in a shared quest to help clean up China and the world's environment.

Contents

Chapter 1

Introduction

1.1 China's Climate and Environmental Challenges

China's rapid economic growth, over the last fifteen years in particular, has generated unprecedented gains in human welfare through income and standards of living, bringing 500-800 million people out of poverty and helping China to meet all of the global community's Millennium Development Goals by 2015 (The World Bank and DRC, 2013; The World Bank, 2017). The economic growth, built on largely industrial and energy-intensive activities, has also resulted in a range of environmental public health challenges. Air, water and soil pollution are severe and have been increasing across much of China. Total costs of air pollution alone are above 5% of national welfare, compared to GDP growth rates of 7-10% over this period (Matus et al., 2012).

China's growth has also raised its contribution to global climate change, becoming the largest emitter of greenhouse gas (GHG) emissions in the world starting from approximately 2005-2007 (Grubb et al., 2015; Olivier et al., 2017). China's GHG emissions grew by 2.5 times from 2000 to 2014, rising from 15% of the global total to now above 25% (Grubb et al., 2015). In fact, over the 1990s and 2000s carbon dioxide (CO_2) emissions per energy use grew, as this energy-intensive growth was dependent on coal as a cheap and abundant fuel and feedstock. Approximately 80% of energy-related CO_2 emissions[1] in China are from coal, second in share only to South Africa, and

[1] Energy-related CO_2 emissions from the combustion of fossil fuels are 87% of China's total, with the remainder primarily coming from industrial processes that directly emit CO_2. Non-CO_2 GHGs such as methane are also important for China's overall climate change contribution, for which energy and agriculture are both roughly half of the total (Olivier et al., 2017).

half of all emissions are associated with electricity generation (Olivier et al., 2017). Coal represents virtually all of the direct GHG emissions from electricity generation, and 65% of total generation in 2016 (CEC, 2017b).

Coal combustion—for power generation, district heating, and cogeneration of the two—is also a major contributor to air pollution in large cities. Possibly one-quarter of particulate matter (PM), the most hazardous pollutant to human health, comes from coal during high PM episodes in northern China (Sun et al., 2013). There is some uncertainty with the precise contribution: other approaches have pegged the contribution of coal-burning in the power sector at 6% of $PM_{2.5}$ (the smallest PM, with diameters of less than 2.5 microns) in Beijing (Zhang et al., 2015). Studies show there is strong regional transport of PM and its precursors, meaning that power generation separated by large distances can still harm human health (Zhao et al., 2009; Zhang et al., 2015).

China's central government has adopted a variety of policies to reduce air pollution, focusing on three regions surrounding the major cities of Beijing, Shanghai and Guangzhou, as well as several additional problem spots. National average $PM_{2.5}$ is supposed to be reduced by 10% by 2017 compared to 2012 levels, and by 15-25% in the three regions (State Council, 2013). The energy sector is naturally a key target of control efforts (NEA, 2014a): 1) stopping growth and promoting coal retirements in key regions; 2) replacing coal district heating with cleaner heating sources (natural gas or electric); 3) improving environmental controls on existing facilities; and 4) encouraging adoption of non-coal cooking options in rural areas. By far the largest transition called for in this action plan is to massively build up electricity bases away from the control areas, first building coal bases in regions with plentiful coal deposits, water, "environmental capacity and ecological loading capability" (*huanjing rongliang he shengtai chengzaili* | 环境容量和生态承载力) (NEA, 2014a, p. 9). A second prong is to build and deliver electricity from low-carbon sources such as renewable energy and nuclear energy.

In terms of international commitments, China pledged at Copenhagen, by 2020, to reduce CO_2 emissions per unit GDP (carbon intensity) by 40-45% relative to 2005 levels and increase the share of non-fossil fuels in primary energy consumption to 15% (NDRC, 2010). Under the Paris Agreement on Climate Change China further pledged, by 2030, to: peak its carbon emissions, reduce carbon intensity by 60-65% relative to 2005, and increase the share of non-fossil fuels to 20% (NDRC, 2015a). These represent significant departures from China's unwillingness prior to 2009 to make globalized emissions reduction commitments.

Recent declines in coal as a fraction of GHG growth point to partial success of these policies as well as increasing demand for fossil fuels in transportation, a trend that will likely continue in the medium-term (Olivier et al., 2017). Nevertheless, power generation will remain a dominant source of China's climate change and environmental impacts. In the long-term, the trend of electrification of transport, driven by energy security as well as local air pollution concerns, could stabilize or increase power sector's share of the problem.

1.2 Rise and Challenges of Renewable Energy

Even prior to major public and diplomatic pressures to move away from coal combustion for electricity generation, China's leaders pursued renewable energy as a conventional form of cheap electricity (hydropower) and as industrial policy to establish high-tech industries (solar and wind). Following a variety of local experiments in the 1990s, China passed the 2006 Renewable Energy Law (amended in 2009), which established a framework for subsidizing wind and solar and included various beneficial supporting policies such as mandatory dispatch requirements (NPC, 2009). Feed-in-tariffs (FITs) providing direct subsidies per generation were established for wind first in 2009, and are currently in the range of 0.47 - 0.60 yuan / kWh (7.1 - 9.1 US cents / kWh) for new builds (NDRC, 2015c) (NDRC, 2009). Other policies have targeted aspects across the sector, from R&D to manufacturing, helping to create rapidly growing industries in wind and solar equipment manufacturing (Dai and Xue, 2015; Nahm and Steinfeld, 2014).

Wind energy has grown faster than virtually every government target and prediction. It is the second largest renewable energy and non-fossil energy in terms of electricity generation with 43% annual capacity growth over the last decade (CEC, 2017b). In 2007, the central government established a target to build 5 gigawatts (GW) of wind by 2010 and 30 GW by 2020 (NDRC, 2007). By 2010, it achieved 30 GW (six times the initial target), and is now on track to meeting its current target of 205 GW by 2020 (NEA, 2016a; CEC, 2017b).

The primary constraint on continued rapid growth of wind energy has been the rising levels of curtailed energy, a situation in which an essentially free resource (the marginal cost of wind production is near-zero) is not accepted onto the grid to its full availability. In practice, the wind generator is instructed by the grid company to lower its output (by changing the shape of blades and/or locking the turbine axis), and the typical reasons for doing so in high wind systems around the world are grid security-related concerns, such as transmission lines reaching their safe loading limits, and economic curtailment caused by inflexible conventional generators willing to accept large negative prices instead of costly changes in output (Wiser and Bolinger, 2017). I will refer to these collectively as technical contributions to curtailment. However, China's curtailment rates are unusually high: reaching 40% in some regions, compared to single digits for other large wind regions in North America and Europe (Bird et al., 2014; Fink et al., 2009; NEA, 2017b). Curtailment is responsible for roughly a third (grid connection and turbine quality being the other major contributors) of the difference between China's and US wind capacity factors[2], which helped cause China to generate 28% less electricity from wind in 2012 despite having 25% more capacity (Lu et al., 2016).

China's divergence from other large wind systems motivates examining to what extent technical factors are to blame for high curtailment, or if there are aspects of its electricity system governance that lead to higher-than-normal curtailment—a primary topic of this thesis. Assessing the technical contributions to curtailment typically requires detailed models of power systems operation. Curtailment can arise from characteristics of wind energy, which is not perfectly controllable and has unpredictability in output over typical power system scheduling timeframes (hours to days) (Xie et al., 2011; Apt and Jaramillo, 2014). Due to the need to instantaneously balance supply and demand of electricity within small tolerances, these characteristics could threaten grid security. Transmission lines have rated limits, and additional wind generation could threaten to push some lines above their limits. Other shorter-term phenomena related to voltage and power stability can also present issues. All of these events can be mitigated by the grid operator through curtailment.

The above interact with characteristics of other generators on the system, namely, conventional power plant operational inflexibilities, to create additional wind integration difficulties. Most conventional power plants have a variety of engineering constraints on production (Bozzuto, 2009). Some power plants are also cogeneration plants, in which electricity is a secondary output determined by the primary output such as district heating in urban areas.

[2]Capacity factor is the percentage of actual output relative to the theoretical potential assuming constant generation at the rated power.

Engineering interventions to improve renewable energy integration typically adjust the flexibility of system operation practices: how frequent are scheduling decisions for conventional units; how much in advance of real-time are decisions on individual outputs of generators determined; and what types and how much fast response "reserve" (backup) generation are necessary in case of large forecast errors and diverse contingencies (Xie et al., 2011; Holttinen et al., 2011). Increasing trade between neighboring regions also has well-recognized implications for addressing integration issues of renewable energy by managing variability, accessing cheaper generators, and sharing reserves (GE, 2010).

Wind integration challenges are not purely technical, however. They can also be caused by the structures of institutions—the rules that govern decision-making in the planning, operation, and regulation of the electricity system—as well as persistent political economies that favor certain energy types over others. Renewable energy can affect this large and important sector through: transfers of economic rents from politically-connected incumbents to new entrants; increased coordination demands on complicated and entrenched governing bureaucracies; and cost allocation questions related to renewable energy subsidies, additional grid investments, and system balancing (Davidson et al., 2017). Many of these have been identified in China, which result from legacy protections for incumbent coal, local governments engaging in protectionist practices, and difficult-to-change planning institutions (Zhao et al., 2013; Kahrl et al., 2013). Crucially, because of the wide range of possible causes of wind curtailment, there is a need to study both technical and institutional factors simultaneously.

Addressing wind and other renewable energy integration issues is now an urgent task occupying many levels of China's government. Mandatory dispatch policies—requiring the grid company to integrate all possible renewable energy except in cases of grid security—have been in place since 2006, and subsequently revised several times, though with little observable impact on curtailment, most recently in 2015 (NDRC and NEA, 2015a). Minimum capacity factor requirements for wind and solar have been put in place at the provincial level (NDRC, 2016b). New developments in high-curtailment provinces have been frozen (NEA, 2017a). Still, curtailment rates remain persistently high, which represent not only wasted investment but could also undermine China's energy sector's contribution to long-term economic and environmental goals. Appropriately attributing causes of current challenges is important for appropriate policy design.

1.3 Electricity Sector Restructuring and Broader Market Reforms

China's electricity sector is also in its third decade of a protracted transition toward competitive markets in this historically state-run sector. Originally, vertically-integrated utilities (VIUs) were established in electricity systems in every major country—in some cases, after an initial phase of lightly-regulated private enterprise—wherein the entire supply chain from generation to customer retail was within a single organization that may be publicly-owned or a private firm operating under an exclusive government franchise. Beginning in the 1980s and accelerated most recently in 2015, China has joined many other countries in restructuring these utilities by introducing competition in some of the segments of the supply chain through diversification of actors and market-based pricing (a process also known as "deregulation" or "liberalization"). China's stated electricity sector reform goals are to enhance efficiency through market-based generation and retail pricing, establish trading platforms and fair network access, and address burgeoning renewable energy integration challenges (State Council, 2015; NDRC and NEA, 2015a). This round of reforms and multiple supporting documents with goals of markets follow broad central directives to allow markets to play a "decisive role" in resource allocation in the economy (CPCCC, 2013).

Initial reforms, precipitated by massive energy shortages that the central ministry was unable to address, opened up investment in the generation sector to private, foreign, and local government-owned firms, cementing the role of local governments in management of the sector (State Council, 1985). Local grids—later subsidiaries of larger state-owned grid companies—were financially separated from each other by formalizing their interactions through various settlement-based mechanisms, and giving provincial governments more autonomy over production decisions (State Council, 1988). Decentralization of authority such as this, combined with refined incentives within the bureaucracy, has been attributed by many as the dominant cause of China's rapid market development in many other sectors over a similar time period[3]. The key conditions for such markets to be effective appear to be an institutional structure of "market-preserving federalism" in which the central government grants certain authorities to local governments while retaining the ability to police the common market; and a package of reforms that establishes dual-track pricing facilitating a gradual "growing out of the plan" (Montinola et al., 1995; Weingast, 1995; Naughton, 1995). These theories

[3] Ang (2016)'s Introduction provides a helpful summary of the various theories of China's growth.

are supported by other analyses of China's policy-making that focus primarily on the relationship between central and local (provincial and sub-provincial) governments (Lieberthal and Oksenberg, 1988).

However, even before the first electricity investment decentralization reforms were initiated, Chinese government leaders recognized the need to interconnect provincial grids and unify system operation across the country, seeing decentralization efforts as expedient but temporary solutions to address undersupply challenges (Kong, 2010). Nevertheless, the province-centric nature of operations, regulation, and reforms to both, has persisted and been enhanced over the intervening decades either through policies explicitly granting authorities to sub-national governments or ambiguous policies allowing *de facto* local variation. Today, much of the market design and implementation is left to pilots mostly by provincial governments, which can be strongly motivated by specific and/or short-term interests. Indeed, China's provinces offer a diversity of market designs, in line with the observation that, globally, electricity markets (in particular, emerging economies) vary by objectives, regulatory institutions, and other related economic drivers (Jamasb, 2006).

It is an open question whether China's decentralized institutional development strategy will result in sustained and efficient electricity markets. Standard electricity market designs in the literature are necessarily more complicated than liberalizations of many other sectors due to numerous engineering and institutional requirements (Joskow, 2008). Well-functioning electricity markets share a common institutional feature of an independent regulator, which is famously difficult to create and give sufficient authority in China (Pearson, 2007). "Textbook" models call for significant privatization and inherently assume Western conceptions of secure and distinct public and private property rights, whereas China experiments with a variety of rights and ownership forms (Oi and Walder, 1999). System operators—grid companies—should also be free of conflicts of interest in market transactions, while China's grid companies are active "policy entrepreneurs" shaping central policy and technology choices throughout the sector (Xu, 2016).

Finally, assuming China surmounts these difficulties, there is debate about the ability of current electricity markets (focused predominantly on U.S. and EU systems) to integrate large quantities of intermittent renewable energy (Ahlstrom et al., 2015; Pollitt and Anaya, 2016; Neuhoff et al., 2016). A well-designed short-term electricity market ("spot" market) can accommodate renewable energy by incentivizing flexible solutions to the above characteristics of renewable energy. However, many markets contain imperfections such as price caps and floors, which lead some regulators, in lieu of fixing the underlying market failures, to create or enhance other affiliated markets and compensation schemes such as reserve, capacity, and/or various flexibility products (MITEI, 2016). China's electricity market designs, as this dissertation reveals, often contain such layering concepts, though with a substantially wider variation than explored in current literature focusing on industrialized countries. This work attempts to fill gaps in the electricity markets literature by examining how a variety of partially-restructured institutions—inherent in China's approach of "growing out of the plan"—impact renewable energy outcomes.

1.4 China and Global Climate Goals

As the world's largest GHG emitter, China plays a critical role in determining whether emissions are kept within levels that prevent catastrophic temperature rise and other impacts, both within China and globally. The current global architecture for climate change action, established in Paris, rests on commitments by virtually all countries, established according to their own national circumstances. This encourages broad participation, but requires substantial transparency by countries and work by the international community to track progress toward collective goals (Jacoby et al., 2017).

China's commitment—in particular, the peaking and non-fossil targets—has generated a range of commentary and analyses on how difficult it is to meet the policies, or relatedly, how different is it from baseline outcomes in the absence of the pledge. Some argue that it will require substantial additional work (e.g., Grubb et al., 2015), while others that it is relatively unambitious (Economy, 2017). Much of this looks to historical trends of decarbonization within China and elsewhere as indications of future trends.

However, China's electricity sector is at a unique stage in terms of broad market reforms upsetting established institutions, fundamentally different energy sources that run up against a range of political economies, and shifting national and global economic drivers. The future ability for China to integrate wind electricity and other renewable sources is thus a key uncertainty to the success of the Paris regime that requires further study.

1.5 Goals of Thesis

This dissertation seeks to understand current governance practices and evolving market mechanisms in electricity system operations in China and their impacts on wind energy, using a hybrid approach of multiple qualitative case studies and an engineering-economic model. Four provincial/regional cases of China, together with a diversity of electricity market experiments, are chosen to explore these questions. A foundational contribution will be to assess the causes of wind curtailment among a relatively large set of engineering-related constraints and costs as well as political economies embedded in China's protracted reform process. Using this, I will establish which institutions are most important to tinker with, and which likely have little impact on wind integration. The second contribution, primarily qualitative, will place the design and operation of a set of electricity market experiments in the context of dominant political economy theories of China's market reforms in order to speculate whether these experiments will likely lead to sustained reforms on the path toward an efficient electricity market, or face obstacles leading to a relatively static incomplete state. Finally, combining these two, I will identify which institutional changes are influential and feasible for enhancing wind integration as well achieving efficient system outcomes, and I will make policy recommendations fit to context.

1.6 Organization of Thesis

Chapter 2 provides the analytical framework for the entire dissertation, identifying the two traditions of institutional analysis and engineering-economic tools, and literature on appropriately combining qualitative and quantitative methods. The research design includes process tracing within the cases, a cross-case analysis, quantitative modeling inclusive of identified institutional realities, and an integrative analysis combining these.

Chapter 3 introduces the literature on electricity sector restructuring, its impacts on renewable energy, and China's three decades of reforms. It then introduces the method and results of the four case studies of the dissertation, including within-case process-tracing and a cross-case thematic analysis. A summary of findings at the end of the chapter is useful for those interested in the highlights before going into the details.

Chapter 4 introduces the various decision-support and research tools in electricity systems, highlighting the essential role of optimization techniques. The engineering-economic model developed for this dissertation—a unit commitment and economic dispatch optimization with clustering—is formulated along with additions to incorporate institutional features of China's system. The second half of the chapter describes each of the data inputs necessary for this model—and some of the challenges of working with Chinese data.

Chapter 5 presents quantitative results for the three modeled case regions. The results are structured within each case by reference results (absent any idiosyncratic institutions), combinations of key legacy institutions, and extensive parameter sensitivities along both technical and institutional dimensions. I then summarize cross-case findings as well as high-level case-specific findings.

Chapter 6 integrates the two sets of results—qualitative case study and quantitative grid model—through simple triangulation and more integrative analysis. I describe a number of important interactive elements that would be difficult or impossible to capture in typical multi-method techniques using statistical analyses.

Chapter 7 concludes with methodological contributions to the literatures on multi-method research and electricity modeling, substantive contributions to the political economy of emerging economy electricity market reforms and China's market transitions, and policy implications and recommendations for China's electricity sector reform agenda.

Chapter 2

Analytical Framework

This dissertation uses a methodological approach that iterates between engineering models and qualitative case studies, in order to examine basic electricity system functioning as well as the impacts of various reform measures in China's electricity system. The research questions, all with respect to China, are three-fold:

1. What causes wind curtailment?
2. Will current marketization approaches lead to efficient and sustained markets that support renewable energy?
3. What institutional arrangements are necessary and feasible to address wind integration challenges?

These draw separately from quantitative techniques in the engineering and market analysis of electricity systems, and qualitative techniques in institutional analysis of bureaucracies, generally, and China, specifically. The integration of these two broad approaches is informed by the methodological literature on multi-method research. This chapter lays out the relevant analytical frameworks, before describing in detail their specific integration in this dissertation.

In short, the method proceeds as follows: case studies (Chapter 3) generate qualitative data on grid operations institutions that can trace various stages of decision-making from the relevant universe of political factors to outcomes. Based on this process tracing, a subset of political factors with potentially important impact on outcomes are chosen to be modeled using an engineering-economic model (Chapter 4) fit to purpose, capturing the interaction of these with relevant technical constraints. Results from the model (Chapters 5 and 6) are analyzed in the context of the above case studies and based on cross-case comparison of underlying processes. Finally, quantitative exploration informs and focuses data collection in subsequent interviews.

2.1 Review of Relevant Analytical Traditions

In explaining electricity sector outcomes, I draw broadly on two traditions: 1) an engineering-economic tradition of quantitative models including a bottom-up representation of production functions inclusive of physical constraints and costs (Momoh, 2009); and 2) an institutional rational choice tradition that examines the interests and coupled decision-making structures within a range of private and public organizations (North, 1990; Kiser and Ostrom, 1982). The former tends to assume welfare maximization of one or more rational actors in order to evaluate system optima or equilibria. The latter is also a branch of rational choice theory, but with less strict requirements on specifying welfare functions, acknowledging that the range of observed institutional arrangements are more complex than neoclassical economic models, and for which analytical models may be insufficient to predict behavior (Kiser and Ostrom, 1982).

2.1.1 Engineering-Economic Tools

Electricity systems are complex engineered systems encompassing a large number of interconnected components, covering significant geographic areas, and with decision-making timeframes from decades down to seconds. Electricity delivery broadly encompasses its generation, transmission/distribution, and consumption, each of which consists of number of physical constraints and decision variables. Due to its size and complexity, electricity systems rely on a centralized system operator that has significant authority over multiple aspects in order to maintain reliability of the grid. System operators have also long used mathematical models—originally, heuristic solutions, and later, optimization techniques—to find least-cost methods of matching supply and demand (Momoh, 2009).

An optimization model specifies a set of variables, constraints, and objective function, and seeks to maximize or minimize the objective (Bertsimas and Tsitsiklis, 1997). The objective in electricity systems models is typically related to social welfare: for example, the total cost of meeting a fixed demand. A central planner seeking to maximize social welfare minimizes total social costs. Researchers have similarly adopted these centralized optimization tools to analyze future trajectories in power systems given changing technologies (MITEI, 2016). The integration of renewable energy sources, given their different technology characteristics such as intermittency, are also the focus of numerous centralized optimization studies, of which a major outcome is the rate of curtailment under different generation or market settings (Dowds et al., 2015).

As many electricity systems have developed into markets, multiple decentralized decision-makers replace the single central operator, each presumably seeking to maximize their own welfare. These decisions can be formulated mathematically in an equilibrium model that captures some of the constraints of the system, and if certain conditions hold, this formulation is equivalent to an optimization problem. Optimization models have also been adopted as the underlying market mechanism in most organized electricity markets, determining prices and quantities for various actors in the system as a function of their bidding (e.g., Rothleder, 2010).

There is thus a natural place for optimization techniques in electricity systems research, from the perspective of generating internally valid results of the system as well as policy prescriptions, as they represent societally optimal outcomes.

2.1.2 Institutional Analysis

Since market restructuring began to accelerate around the world in the 1990s, there has also been a strong thread of case study work examining the roles of various institutions (e.g., Sioshansi and Pfaffenberger, 2006; Sioshansi, 2013). These qualitative case studies—often supported with quantitative indicators—have been valuable in identifying causal mechanisms from institutional design and implementation to outcome. Some are historical analyses of how actors responded to different incentives, and help to inform prescriptions such as "textbook" models of restructuring (Joskow, 2008). These are typically supported by theoretical models of rational actors facing different profit-making situations (e.g., Joskow, 2014; Hunt, 2002).

Broadly speaking, most institutional analyses of the electricity sector fall in the institutional rational choice tradition, where actors at multiple levels make decisions within the "game" of established institutions as well as to change the rules of the game to advance their individual interests (Kiser and Ostrom, 1982). For this and future purposes in the dissertation, I adopt this framework together with Northian institutions—“humanly-devised constraints” on how actors (possibly, organizations) behave (North, 1990).

With the increasing deployment of renewable energy technologies, which have different physical and economic characteristics than conventional generating technologies, a growing body of work analyzes the institutional requirements to achieve cost-effective renewable energy utilization. In practice, the normative goal is to reduce costs and curtailment. For example, some question the sufficiency of current market institutions to properly incentivize system flexibility, examining and proposing different types of arrangements (Pollitt and Anaya, 2016). Others explore the differences across countries and, based on theoretical expectations of market functioning, propose (politically-feasible) changes to current practice (Neuhoff et al., 2016). Fundamental assumptions throughout these explorations are that curtailment and inefficiencies are largely caused by either engineering constraints or market failures.

A separate, growing body of literature examines the various political economy aspects of the transition occuring in many countries toward renewable energy. Taking broader views of the range of political and economic institutions that affect and are affected by changing technologies in the energy sector, an historically slow-moving industry, this body of research highlights key drivers and obstacles (Arent et al., 2017). Conventional technologies, primarily using fossil fuels, have advantages in terms of political incumbency, and external shocks such as energy crises in the 1970s have historically been one way of upsetting this advantage (Aklin and Urpelainen, 2018).

One lens through which to view the “game” of decision-making within institutions—relevant for the case of the Chinese bureaucracy in future chapters—is the Allisonian description of “bureaucratic politics”: using this framework, the outcomes are seen as the result of overlapping bargaining games among political actors with varying strengths (Allison, 1969). In this manner, rules and outcomes can “deviate” from a social welfare perspective through individual rational behaviors. Similarly, “formal” rules may deviate and/or suffer incomplete implementation because of weak institutional strength relative to individual power holders (Levitsky and Murillo, 2009).

Weak institutions are frequently cited in literature on electricity market restructuring in developing countries, encompassing regulatory institutions (e.g., market regulators), political institutions (e.g., cycles and stability), and economic institutions (e.g., financial systems) (Jamasb, 2006). In these contexts, the benefits of markets and efficient societal outcomes are under-achieved. In addition to a large body of qualitative research on the importance of various institutions, some panel regression analysis data also support the notion of the importance of specific institutions such as the regulator to sector outcomes (Zhang et al., 2008; Sen et al., 2018).

2.1.3 Multi-Method Integration

Bringing together quantitative and qualitative data within a single study—"mixed methods" or "multi-method" research—is recognized for its ability to complement biases in respective methods, leading to convergent validation of results (Creswell, 2009). This "pragmatic" approach that examines the same set of questions from multiple vantage points can take various formats, including comparing the results of separate analyses, integrating them sequentially where outputs of one become inputs of the other, testing respective assumptions, or helping identify subsequent questions or cases to study (Tashakkori and Teddlie, 1998; Seawright, 2016).

A classic example is to combine a small number of qualitative case studies with a large-N statistical analysis, applied in fields from econometrics to political science (Ichniowski and Shaw, 2003; Seawright, 2016). Case studies have strong internal validity by focusing in detail on the processes that occurred between independent variables and dependent outcomes (George and Bennett, 2005). Process tracing (PT) is one formalization of this method, which looks within a case at intermediate variables to make stronger causal inferences (Bennett and Checkel, 2015a). By contrast, quantitative models allow for generalizable insights assuming underlying causal mechanisms remain constant across systems. These two techniques can be integrated more closely in a "nested analysis", which iterates between model-building and testing until there is convergence between results (Lieberman, 2005).

This prototypical combination—statistical analysis and small-N case study—forms the basis for an epistemological debate over whether qualitative and quantitative methods are, in fact, fundamentally distinct ways of learning (Goertz and Mahoney, 2012; Paine, 2015). In the argument in favor of distinction, statistical models measure average treatment effects, which do not say anything about any specific case, while qualitative models look for configurations of causes, such as necessary and/or sufficient conditions which are presumed more universal (Goertz and Mahoney, 2012). Others have downplayed this distinction (Paine, 2015). Nevertheless, the debate has been narrowly focused on this particular example of large-N statistical analysis together with small-N case studies.

In the engineering systems literature, some have argued that qualitative methods are increasingly important when the bounds of the research extend beyond the technical components: when phenomena are poorly understood or must be studied empirically, qualitative data can help inform hypothesis creation and modeling assumptions, or test the real-world application of new decision-support tools (Szajnfarber and Gralla, 2017).

Moving beyond the conventional statistical analysis and case study combination, other work attempts to create an analytical framework for combining PT with formal models—quantitative representations of a data generating process that precisely specifies assumptions and that is solved (Morton, 2009). Formal models bear more similarities to PT than statistical techniques, because of the need to specify in the model what and when information was available to actors, and how they reacted (Lorentzen et al., 2015). Benefits of integrating these two methods include 1) evaluating mechanisms, including model assumptions; 2) gathering additional evidence; and 3) selecting cases based on model assumptions (Lorentzen et al., 2015). The model in this dissertation is more similar in function to this as opposed to a statistical analysis, and thus leads to a natural combination with process tracing.

2.2 Research Design

I implement a mixed methods framework combining a multiple case study analysis with a quantitative grid model. The case studies address the formulation and implementation of selected electricity regulations targeting grid operations in different provincial contexts. They help identify outcomes caused by possible "institutional causes", deviating from standard social welfare objectives. The quantitative model evaluates the outcomes of the system under a reference case, identifying technical constraints of a hypothetical efficiently-run system. Finally, a "mixed" approach combines the quantitative model with various real-world and counter-factual institutions, identifying which institutions or configurations of institutions are most influential. Outcomes of both approaches are compared using a traditional triangulation mindset as well as an integrative approach of model-building and validation (see Figure 2.1).

In drawing the system boundary around both the technologies and the institutions that shape

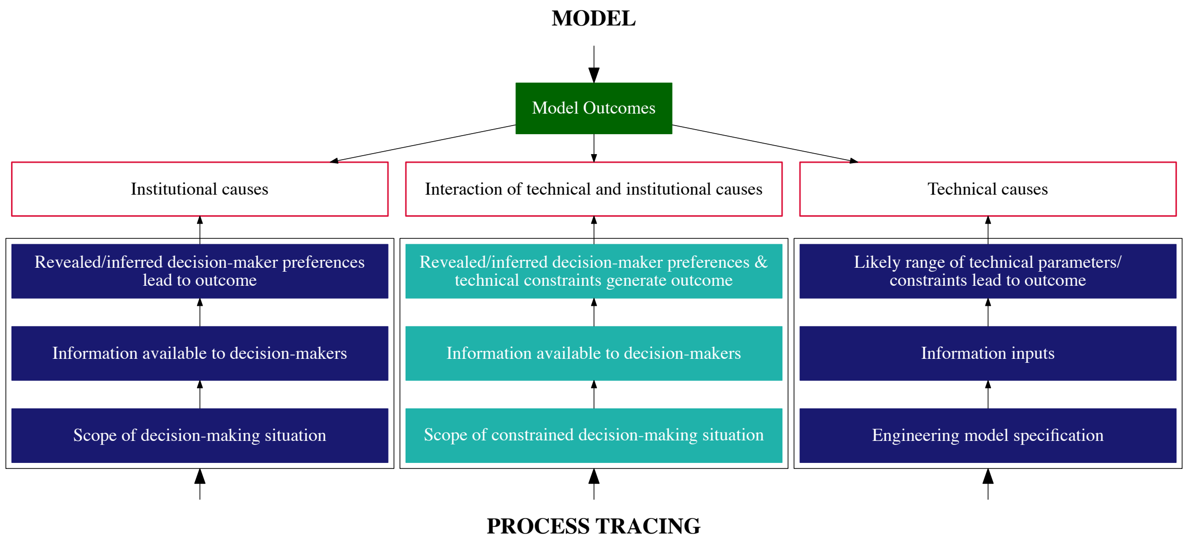


Figure 2.1: Integration of quantitative model and causal mechanism process-tracing analysis in this dissertation. Central light-colored tier comprises the interaction of primarily qualitative case study data (left) with the quantitative model (right).

the operation of these technologies, I argue that the mutual interactions are essential to understanding the implications of electricity market design and renewable energy outcomes. Actors are driven by incentives from institutions, which are likely a combination of formal specifications and *de facto* processes, thus requiring more detailed tracing of the entire decision-making process. Engineering-economic models can more realistically specify technical constraints on decision-making structures —critically important for electricity systems—given a common objective of welfare maximization.

The quantitative model is a constrained rational choice model, similar to the idea of a bureaucratic politics "game", though with a large number of constraints derived not from institutions but from the built infrastructure and the physics of electricity production and delivery. The basic tenets of using PT in a rational choice framework—the basis for Figure 2.1—are instructive (Bennett and Checkel, 2015a):

1. Decision-making structure—do actors have the ability to make these decisions and effectuate them?

2. Revealed / inferred preferences—what do decision-makers want?

3. Information—do actors have sufficient information to make rational choice decisions?

These are preconditions for rational choice causal mechanisms to occur.

This approach takes full advantage of both methods, generating insights at multiple levels of analysis ranging from specific technology characteristics to dispatch practices to the institutional environment. The case studies are designed to help determine how and when to use quantitative models, with a focus on process tracing in order to specify the constellation of (potentially competing) interests and overlapping decision-making structures that can occur. Specifically, I identify four validity assumptions for the quantitative model, which have similar themes of actors' objectives, information, and decision-making autonomy from the PT literature. The in-depth qualitative analysis also stands on its own in analyzing institutions that cannot easily be put into the specific quantitative framework. The next chapter organizes the qualitative data and analytical methods to achieve this.

Chapter 3

Cases of Local Electricity Markets and Wind Integration

After an initial teething phase of private ownership, open competition and scarce or no regulation, electricity systems in every major country context were established as vertically-integrated utilities (VIUs), wherein the entire supply chain from generation to customer retail is within a single organization that may be publicly-owned or privately-owned by a firm operating under an exclusive government franchise. Increasingly, over the last three decades, some countries have restructured these utilities, introducing competition in some of the segments of the supply chain through diversification of actors and market-based pricing. Goals of these reforms vary based on level of development, typically encompassing aims to optimize efficiency, provide greater choice to market participants, and attract private capital (Williams and Ghanadan, 2006). Considering the complex physical nature of electricity systems, a "standard liberalization prescription" has been developed to serve as recommendations to countries, though designs frequently diverge from these prescriptions and poor outcomes may arise due to a wide range of contextual factors such as existing political and economic institutions, history of other market reforms, and resource endowments, particularly in developing countries (Joskow, 2008; Jamasb, 2006).[1]

In 2015, China began undertaking its most comprehensive set of electricity reforms in over

[1]For a review of the effects of electricity sector reforms in developing countries see Zhang et al. (2008), Jamasb et al. (2017); for a review of the current status in U.S. states see Brooks (2015); and for a review of EU member countries see Teixeira et al. (2014).

a decade, with goals of improving efficiency and increasing the use of renewable energy, among other central priorities (State Council, 2015). These are in part responding to a rapid expansion in China's electric generation capacity that has outstripped demand (building roughly an entire United Kingdom grid each year over 2005-2016) and revealed significant gaps in institutional incentives for performance efficiency. The reforms are also happening at a time when wind energy, a key component of China's proposed transformation toward a low-carbon grid, is being wasted (curtailed) by more than 40% in some regions, compared to single digits for other large wind regions in North America and Europe (Bird et al., 2014; Fink et al., 2009). Administrative (i.e. non-market) measures such as strengthening the mandatory renewable energy dispatch policy or establishing minimum renewable generation quotas have been commonplace policies to address curtailment (NDRC and NEA, 2015a, 2016). Increasingly, however, central government agencies have encouraged market-oriented methods to address renewable energy integration issues. Stopping short of specifying a nation-wide strategy for using markets, these documents encourage sub-national entities (typically, provinces, though there have been limited regional cooperation) to create pilots, which have a dizzying array of market designs and implementation details. These market and administrative measures co-exist and, in many cases, are designed to be mutually exclusive, such as NEA's minimum capacity factor requirements for renewable energy that explicitly forbid meeting the threshold though price competition or extra payments (NDRC and NEA, 2016). Through the cases in this chapter, it is apparent that this strict separation is not maintained, creating an important interaction between wind integration and market development efforts.

This chapter introduces and evaluates the primary cases of the dissertation—four different high wind development areas of China, their system operation and wind integration status, and 1-2 market experiments in each—including case selection, data collection, within-case process-tracing, and cross-case analysis. This dissertation examines almost all regions with reasonably high wind penetrations ($> 5\%$ share of generation), selecting province(s) within each seeking diversity on curtailment pressures, institutions and market experiments, as well as other exogenous variables. Given that there are no examples of provinces with high penetrations of wind power and low curtailment, these cases are also high on one of the key dependent variables, wind curtailment.

Key stakeholders in these processes are governments, grid companies, and generation companies. Motivations and influence of these will depend on the location and the particular decision-making process, and thus qualitative data collection discussed in this chapter was primarily focused on elucidating these. Researchers affiliated with these three in addition to university academics form the fourth type of actor, with roles of observer and policy advisor.

Each case provides a lens, from different regional and energy contexts in China, into why and how markets are formed, how they interact with existing planning institutions, and what outcomes with respect to wind integration have been achieved/can be expected. I also introduce elements of the quantitative engineering-economic model of the dissertation (described in greater detail in Chapter 4) that will draw on the qualitative case studies, including an explicit evaluation of the assumptions necessary for model realism.

Throughout the chapter, I use "market" or "exchange" in a very general sense to refer to any process by which buyers or sellers of electricity nominally compete with each other outside of the traditional planning process. This encompasses many processes that would not satisfy a regulator's conception of a market (and I highlight the deviations in exhaustive detail), but it is a shorthand to ease reading and bypass having to make a threshold argument about which (if any) qualifies as a "market". This definition also aligns with how Chinese official documents themselves refer to these experiments.

Each case begins with baseline data on the history of the region and specific procedures of system operation, before going into detail on the selected market experiments. These are aggregated into a handful of themes in a cross-case analysis. To help guide the reader, the main highlights from these cases will be:

1. Local governments and grids have the incentive and ability to contravene commitments to wind deployment, creating non-technical contributors to curtailment.

2. Markets have been primarily used as supplements to administrative measures, with narrow purposes and varied impacts on supply-side dispatch.

3. "Benchmark" product markets—whose value is defined relative to administrative reference parameters—are popular but do not reflect the underlying value of electricity and are thus inefficient.

4. Local governments retain levers over markets of various complexities, which are used to guide

outcomes toward desired (possibly, narrowly-defined) goals.

5. Markets can improve flexibility of the system to cope with wind variability, but at varied costs, and hampered by their ambiguous relationship to mandatory dispatch planning.

6. Grid companies are implementing agents of plans and markets, but are not impartial.

3.1 Literature Review

3.1.1 Electricity Sector Restructuring

Diversity of regulatory systems

Since the 1980s, numerous countries have reformed historically government-run electric utilities or private monopoly franchises into various forms of "restructured" markets. There are multiple segments of the electricity supply chain, and similar to other infrastructure industries, some are natural monopolies in which it is not societally beneficial to encourage direct competition (Newberry, 2002). The generation segment, which consists of multiple interconnected electric power plants that supply electricity to the grid, is a key activity that has been recognized to lack a justification for a natural monopoly and hence could be open to competition (Joskow and Schmalensee, 1983). Similarly, the retail segment of the much larger number of consumers could be given choice in terms of who they purchase from (distinct from the natural monopoly of the grid infrastructure), leading to competition between retail companies on tariff structures including more efficient time-varying prices (Hunt, 2002).

The basic goal of this and other market creation initiatives is to improve system performance on metrics of efficiency, productivity and total output. However, the details of this market differ and are significantly more complex than most other commodities: it should consider underlying physics recognizing, e.g., that electricity cannot easily be stored (inventory-less); it travels instantaneously on a path that cannot easily be directed; and it involves complex network interactions among suppliers and consumers (Hunt, 2002). Since supply and demand must be balanced instantaneously within a small margin, this leads to a marginal price for power evaluated on hourly or shorter time scales, and creates the strong need for a system operator to ensure proper functioning (Schweppe et al., 1988; Hunt, 2002; Joskow, 2008).

Beyond seeking efficiency improvements, why individual countries choose to restructure can vary substantially. Broadly speaking, countries with well-developed electricity systems may wish to promote competition to enhance consumer choice and reduce government intervention as an end in itself. Countries with systems still under development may seek to attract more private finance to supplement overburdened public finances in addressing electricity shortages. It has been noted that exogenous macroeconomic events such as financial crises as well as "structural adjustments" encouraged by international development organizations may also precipitate electricity sector reforms (Williams and Ghanadan, 2006).

Based on the first two decades of international experiences, a blueprint or "textbook model" of restructuring has been discussed in the regulatory economics literature, which includes how and which markets to create as well as relevant institutions to oversee their functioning (Hunt, 2002; Joskow, 2008). In reality, the complex nature and ordering of creating these institutions ensure that there is still substantial diversity across countries, and even once a reform path is agreed upon, there may still be significant divergences due to vested interests and weak economic and regulatory institutions. For example, in government-planned electricity systems, industries frequently cross-subsidize households to keep electricity tariffs low for consumers. Under restructuring, commercial and industrial customers are typically the first to benefit from competitive wholesale markets, with households seeing price hikes or much slower price declines (Jamasb, 2006). This has led to extended government intervention in the form of price controls in many contexts, including those with well-developed generation markets such as the U.S. where these regulatory efforts to control prices for smaller consumers has led to uneven implementation of competitive retail (Morey and Kirsch, 2016). Countries without a strong tradition of independent regulatory agencies or robust financial systems may also face challenges carrying out the standard prescription (Williams and Ghanadan, 2006; Jamasb, 2006).

Contracts for electricity can be physical or financial (also referred to as "inflexible" or "flexible" , respectively), according to how they are linked to system operation decisions, referred to as dispatch. Physical contracts are considered by the system operator during dispatch, while financial contracts are settlement mechanisms cleared separately after dispatch. In the latter, the system operator is unconstrained by these contracts and able to find an efficient dispatch from a system-level perspective. By contrast, physical contracts made well in advance of knowledge of accurate system conditions may lead to generation that is inefficient from a system-level perspective. If there is congestion (i.e., a transmission line has reached its maximum safe level), physical contracts must then be rejected, requiring additional mechanisms to adjust dispatch to solve the congestion. Bilateral physical contracts, even those cleared frequently, will never be as efficient as an integrated real-time market and dispatch (Hogan, 2003).

If the drawbacks of physical contracts relate to treatment of distances over the network, then the sizes of bidding zones are another facet of this challenge. Chinese, European, and many other markets aggregate large areas into “zonal markets”, within which all generators and consumers are treated the same—i.e., transmission constraints and congestion within zones are not considered in market transactions—and frequently require additional congestion management mechanisms (Neuhoff et al., 2016). Between countries, zonal designs tend to create larger grid imbalances (e.g., as a result of unpredictable flows caused by renewable energy), and ineffectively-designed imbalance penalties can lead to an over-reliance on intraday trading and cause additional congestion in a neighbor's network (Sauvage and Bahar, 2013).

Increasing trade between neighboring markets has well-recognized theoretical implications for reducing costs and addressing integration issues of renewable energy, including by accessing cheaper generators, sharing back-up generators (reserves) to deal with unexpected deviations, and reducing market power (GE, 2010; Borenstein et al., 2002). Enhancing trading through cross-jurisdictional markets, however, is notoriously difficult as seen in the long road to establish a common electricity market in Europe (Teixeira et al., 2014). Several models exist depending on the degree of coupling and size of the market: the integrated markets, such as Independent System Operators (ISOs) in the US and in a handful of other countries, operate “organized markets” that cross multiple sub-national (state) boundaries and fundamentally ignore these borders when determining transactions and dispatch. Another is “market coupling”, such as between ISOs as well as in the EU Internal Electricity Market model linking nation-states (some of which have internal integrated markets): neighboring jurisdictions can choose to couple markets without relinquishing system operation to a centralized body. In the EU model, there is a multi-step process where cross-state transactions are considered separately from within-state transactions, and the respective transactions include different details in the network representation, all of which can affect the market outcomes and renewable energy integration (Neuhoff et al., 2016). Protectionism, institutional and market design differences, as well as insufficient regulatory oversight all affect the particular model choice and implementation details.

Attribution analyses

Research into electricity regulatory interventions and related political economies at the country level often take the form of single case studies, sometimes supported by quantitative indicators (e.g., Sioshansi and Pfaffenberger, 2006; Sioshansi, 2013). Cross-country studies are reviewed in Zhang et al. (2008) and Jamasb et al. (2017), which are dominated by panel regressions with institution dummies (e.g., Steiner, 2000), but also include other methods such as data envelopment analysis, a linear program that measures efficiencies relative to an efficient frontier (Yunos and Hawdon, 1997). Some analyses point to interaction effects among different institutional components: for example, using three metrics of restructuring in a panel regression study—privatization, independent regulation, and competition—significant effects of privatization were only found when coupled with establishing independent regulators (Zhang et al., 2008). Estimating the ex-post impacts of privatization, in particular, on sector outcomes draws from a larger body of literature in industrial organizations on the empirics of privatization (Megginson and Netter, 2001). Scoring institutional development toward the international model in Asia in terms of dummy variables, Sen et al. (2018) found some technical and economic gains, but also that weak institutions led to incomplete savings pass-through to consumers. This coarse method of evaluating the effects of institutions—e.g., China is coded as having an independent regulator in Sen et al. (2018), despite its poor track record of independence and formal closure in 2013—does not capture many of their important aspects.

Attributing the role of specific institutions to sector outcomes is also fundamentally complicated by the technical complexities in electricity systems, absent in most political analyses. For example, Zhang et al. (2008) uses a single country-wide number derived from market concentration of top firms to represent how competitive a country's electricity system is. Market power, wherein some actors are able to unilaterally alter the price through strategic bidding, is a key concern, but its effect is highly dependent on locational (i.e., network) configurations and constraints over short time periods (Borenstein et al., 2002), impossible to capture with units of analysis of country-year. Furthermore, market design and inter-regional trading arrangements potentially have much bigger impacts on efficiency. For example, expanding centralized bidding into a service territory previously using bilateral contracting mechanisms led to an estimated greater than $160 million annual savings in a portion of the eastern U.S. (Mansur and White, 2012). Looking across the various markets introduced in the U.S. between 1999-2012, out-of-merit costs fell by 20%, saving $3 billion per year (Cicala, 2017).

Quantitative simulations incorporating greater technical detail can address many of these complexities. Frequently, the models may be similar to those used in practice by power system operators, sufficiently simplified to aid analysis, which fundamentally assume a cost-minimization paradigm (Stoft, 2002). These approaches have been applied to comparing fundamental market design choices such as the detail with which networks should be considered in evaluating prices (Aravena and Papavasiliou, 2017; Weijde and Hobbs, 2011). However, the impacts on system performance of a greater variety of institutions arising in contexts without satisfactorily competitive conditions have been under-explored. These relationships—and their interactions—go to the heart of which institutions matter more when restructuring electricity sectors and why.

Political economy of wind integration

One of the most significant changes impacting electricity systems operation and regulation today is the increasing introduction of renewable energy technologies, often supported by policies to address the environmental impacts of conventional power generation (Pérez-Arriaga, 2013). In terms of technical operation, the variability and unpredictability of renewable energy (solar and wind daily, and hydropower seasonally) interact with inflexibilities of fossil-fuel generators, demand, and network constraints. Hence, new operational practices are often required.

There is also a landscape of political economy challenges in wind energy integration, including conventional energy's incumbency advantages, degrees of federalism, subsidization and cost structures, relative independence of regulatory bodies, and industry structure (Davidson et al., 2016a). Early work on political impediments to renewable energy adoption often focused on public acceptance rather than institutional design (Haggett, 2008). Acknowledging increasing public desire for renewable energy policies and the political importance of renewable energy coalitions, the specific processes leading to continued support of policies have also been examined (Stokes, 2013; Aklin and Urpelainen, 2018). Renewable energy policy processes can be complex interactions of economic, political and technical criteria and reasoning[2].

While the focus of this dissertation is on wind power, the other two dominant renewable energies—hydropower and solar—face some related challenges with respect to grid integration and, in some contexts, political economy. Solar is highly variable on shorter timescales (seconds to minutes) as a result of changing cloud-cover, and over timescales similar to wind (hours to days), causing similar challenges with the technical operation of balancing the system (Apt and Jaramillo, 2014, p. 128-140). Over the time periods of main interest to this dissertation, solar can have higher predictability than wind (i.e., changes in output can be predicted with greater accuracy) because of its highly regular daily variation and, particularly in high resource regions, reduced cloud-cover. Political economy challenges such as disadvantages relative to incumbent energies, federalist structures causing difficulties coordinating across jurisdictions, and subsidy and cost allocation politics, are comparable to wind.

Hydropower is a seasonal resource with much higher availability during rainy seasons, varying by geography. On daily timescales, it is more predictable and controllable. Additionally, for most newer and larger installations, a good-sized reservoir provides storage to enhance its controllability up to weeks and months, even years, making hydropower a valuable flexibility resource to accommodate wind and solar variations (EPRI, 2013). Run-of-river hydropower (i.e., without a reservoir), common in southern China, is significantly less flexible. Hydropower is not a new energy source in many countries; hence, the political economy issues of incumbency are different from solar and wind. Impacts on the local environment are, on the other hand, typically larger, making siting more contentious (Trussart et al., 2002).

There is debate about the ability of current electricity markets (focused predominantly on U.S. and EU systems) to accommodate large quantities of intermittent renewable energy (Ahlstrom et al., 2015; Pollitt and Anaya, 2016; Neuhoff et al., 2016). The first group argues that a spot market can accommodate renewable energy by addressing many of the above system flexibility issues. Renewable energy sources have close to zero marginal cost because of the lack of fuel costs and the bulk of costs, such as capital expenditures, being constant regardless of production. While

[2] Various country and regional-level examinations provide useful documentary evidence of the range of challenges: U.S. states (Fischlein et al., 2010); European member countries (Lehmann et al., 2012); India (Krishna et al., 2015); and China (Kahrl and Wang, 2014). Aklin and Urpelainen (2018) is a multiple case study across several developed renewable energy markets.

most electricity market designs were thought of in terms of fuel-consuming (i.e., non-zero marginal cost) generators, renewable energy can be integrated into a well-designed spot market if it includes such conditions as no overly restrictive price caps and floors, prices determined at granular levels in time (e.g., intra-hourly) and space (over small geographic distances), co-optimized transmission capacity allocation and reserves, and balancing mechanisms that incentivize accurate forecasting (Ahlstrom et al., 2015; Neuhoff et al., 2016; MITEI, 2016). Renewable energy will generally be infra-marginal—i.e., dispatched in most cases, ahead of the marginal generator that is typically conventional fuel-burning. Exceptions to this that result in renewable energy curtailment arise with security concerns such as transmission limitations and network stability, or economic concerns such as costly conventional generator ramping or cycling. Additionally, variability in prices such as sudden drop-offs in renewable energy leading to price spikes provide monetary incentives to build and operate flexible resources to balance the system.

On the other hand, some argue that markets are not well-adapted to renewable energy, hence why many systems are adjusting designs in response to renewable energy (Pollitt and Anaya, 2016). First, most markets contain restrictions such as price caps or price floors, and other imperfections such as long settlement periods, which in turn lead to inadequate compensation for flexibility. Thus, in lieu of fixing the underlying constraints on the market, some systems have proposed implementing additional products valuing "flexibility" (MITEI, 2016). Second, relatedly, as low marginal cost generators take up a larger part of the system, overall revenues from constrained energy markets (i.e., disallowing high price hours that help cover costs of peaking generators) tend to decline. In this situation, reserve markets and/or capacity markets (i.e., paying generators for available capacity, typically on yearly or longer horizons) would need to fill in to cover conventional generators' lost revenues (Ahlstrom et al., 2015). Third, issues of transmission allocation across market borders might be enhanced with more variable flows from renewable energy (Neuhoff et al., 2016). Fourth, distributed renewable energy generation (i.e., connected on low-voltage networks typically beyond the visibility of current price formation) will present a new set of challenges (MITEI, 2016). A limited number of analyses have attempted to quantify the impact of market design on renewable energy outcomes (e.g., Aravena and Papavasiliou, 2017), though none to the author's knowledge has focused on the detailed aspects of a partially-restructured system such as China's.

3.1.2 Political Economy of China's Market Reforms

China's essentially state-run economy began its marketization process in 1978 under the new leadership of Deng Xiaoping. Over the four decades since, China has undergone massive economic and political reorganizations, together with unprecedented economic growth. The political economy of this growth story—that is, how political institutions influenced economic activities and vice versa, and whether this process is unique to China or generalizable—has been the subject of much scholarship. Due to the complexity of an economy as vast and a political and social landscape as multi-faceted as China's, explanations offered are unsurprisingly myriad and often predicated on exceptions more than rules. Within this literature, changes to government decision-making structures during the 1980s and 1990s are frequently used as explanatory variables, drawing on the more descriptive literature of the functioning of bureaucracies, both generally and specifically to China. This section summarizes some of the relevant literature that will be important background to the story of the electricity sector that follows.

Prior to market reforms in the late 1970s, economic and political activity was carefully planned through a network of ministries and coordinating committees or agencies. This early system was adopted substantially in the 1956 Communist Party Congress and based on communist organizational principles of Lenin. Accelerated during the decentralization efforts of the Great Leap Forward, production and planning decisions were localized to spur rapid industrialization and promote protective regions of self-sufficiency throughout the country (Schurmann, 1968; Yeh and Lewis, 2004). An important organizational element became the distinction between "vertical rule" (*tiao* | 条) within a single functional hierarchy typical of production ministries, and "horizontal rule" (*kuai* | 块) composed of a regional (local) collection of diverse functional organizations. "Dual rule" organizations with two or more superordinate agencies, such as planning commissions, proliferated and generated characteristic ambiguity of authorities that persists to this day. The strategic decision to invest significant power in sub-national governments without close supervision by the center was balanced by a selection process of local Party leaders to be united by shared ideology (Schurmann, 1968).

Numerous changes to the political economic context occurred in the 1980s and 1990s which have been cited as causes for growth, including loosened restrictions on labor and capital mobilization, changes in bureaucratic incentives such as promotion prospects and revenue sharing, increase autonomy to lower level governments, and "transitional" plan/market hybridizations within sectors (Ang, 2016). These changes are frequently compared and contrasted with standard (typically, Anglo-American) ideals of "strong" institutions deemed necessary to promote and preserve markets: an impartial bureaucracy, independent regulation, and secure property rights.

In short, these "strong" institutions include, first, a Weberian bureaucracy based on technical competence (i.e., specialization) and impartiality as the ideal, most efficient form of organization, and necessary for modern societies (Weber, 1947). Second, market regulators should be independent of both the regulated entities as well as political bodies that may interfere in an ad-hoc manner with proper market functioning (Pearson, 2005). Third, secure property rights are a necessary condition for markets and seen as essential to Western economic development (Hayek, 1948; Weingast, 1995).

Reality is far from ideal, even in Western contexts: for example, in public bureaucracies, goals can never be as explicitly articulated as a profit-maximizing private firm, and bureaucrats may desire other goals besides metrics of efficiency, such as autonomy (Crozier, 1964). In any system with a large number of bureaucracies it is also impossible to create alignment along simple goals, and classic bureaucratic politics games result, driven by various lines of authority and the bargaining power of key actors (Allison, 1969). This is particularly complex in China, due to "dual rule" and overlapping organizational bureaucracies, and a form of "fragmented authoritarianism" has been observed which is bypassed through informal consensus-building measures at various levels (Lieberthal and Oksenberg, 1988). Key determinants of the pace of a policy process in this framework are the interests and status of central officials; the interests and ability of lower-level bureaucrats to place the issue on the agenda; and external circumstances or emerging critical issues (Lieberthal and Oksenberg, 1988).

There are many examples of the central government giving additional autonomy to localities to pursue "policy experimentation" during the reform period, essentially smoothing the process of policy innovation and implementation and bypassing the above constraints on bureaucratic decision-making. In this model, localities are given circumscribed discretion (e.g., identifying a single sector, such as agriculture, or type of reform, such as out-of-plan market pricing) and allowed to experiment with different strategies (Heilmann, 2008). The classic example is agricultural decollectivization in the 1980s, with the transfer of some property rights from villages to farmer households (Oi, 1999).

Frequently cited sectors also include special economic zones with preferential access to foreign capital, rural industries, and stock markets (Oi, 1992; Heilmann, 2008).

This flexibility to choose from a variety of policy options ("means") was coupled with changes in bureaucratic incentives ("ends") during the reform period, most notably: promoting local leaders according to a narrow set of metrics such as economic growth, and allowing local governments to retain revenues from their commercial activities, primarily township and village enterprises (TVEs), and reinvest in what has been called "local state corporatism" (Landry, 2008; Oi, 1999). By 1991, as a result of enhanced local autonomy and incentives, rural industry accounted for 50% of total industrial output (Oi, 1992).

A less restrictive condition than "strong" Anglo-American institutions seeks to find common ground among various historical growth episodes, focusing on a particular set of conditions on central-local relations known as "market-preserving federalism" (Montinola et al., 1995; Weingast, 1995). Under this framework, a federalist system "preserves" markets if subnational governments have primary economic authority in their jurisdictions, the central government can police the common market, governments face borrowing limits, and there is durability in the arrangements (Weingast, 1995). This has been applied as the "political basis for economic success" in China, addressing how autonomy at various levels of China's government bureaucracy and healthy competition between jurisdictions were sufficient to kickstart markets in the absence of "strong" institutions such as property rights or formal institutional durability, such as constitutional federalism, which restricts higher levels of government from unilaterally renegging on agreed divisions of powers (Montinola et al., 1995).

With the additional autonomy granted to provincial officials and bureaucrats during the 1980s, they developed certain expectations, and the inability of central leadership under Premier Li Peng to re-centralize following 1989 events was taken as evidence of the "institutional durability" of the new central-local balance (Montinola et al., 1995). A contrasting view suggests that as Li was eventually successful and leaders of the "provincial rebellion" expelled, provincial power was much less effective than thought (Cai and Treisman, 2006). This view, centered on the "elite politics" of which provincial leaders were with which central faction, rejects much of the incentive-based theories, favoring instead the notion that promotions were "clientelistic" and less linked to provincial economic performance (Nathan, 1973; Li and Zhou, 2005; Shih et al., 2012).

As to the specifics of how localities were able to change established norms and institutions built up during central planning, the classic argument is one of “growing out of the plan”, particularly referring to the waves of corporatization and privatization in the 1990s (Naughton, 1995). In lieu of eliminating price controls, governments gradually raised the share of market exchanges on the “margin”, and as state-owned enterprises (SOEs) became more sensitive to competitive pressures they made efficiency improvements, in turn creating a positive feedback loop where firms demanded further reforms (Rawski, 1995).

A dynamic view into this process in various Chinese localities raises the possibility that different types of institutions may be best-suited depending on the level of market and institutional development (Ang, 2016). For example, at least three stages were identified wherein weak institutions are first harnessed to *build* markets; these markets *stimulate* the growth of strong institutions; and strong institutions *preserve* markets. The key elements of success all relate to the adaptability to different sets of conditions, in particular, localities are allowed to improvise (under some central restrictions); bureaucratic success is well-defined and rewarded; and there are exchanges between regions at diverse levels of development (Ang, 2016).

In the above literature, the use of the word “market” becomes increasingly muddied, and can be synonymous with “growth” in many cases. For example, in each of Ang (2016)’s “successful” transition cases, the resulting “strong” institutions that preserve markets resembled elements of the East Asian developmental state model (discussed below), where leaders specify investment priorities, pick winning sectors, and establish specialized bureaucrats to oversee them. Government has thus become more selective in what it supports but not less interventionist in the “market”.

This ambiguity could be traced to how the Chinese government (as well as scholars of China) view the purpose and logic of markets. There are at least two economic camps (Steinfeld, 2004): the first, “market as salvation” to help ailing incumbent firms become more efficient; and the second, a selection process encouraging new entrants to force exit of underperforming incumbents. “Growing out of the plan” centers around the former. High-priority sectors for the central government—which some scholars refer to as the “top tier” of the economy—likely have markets and interventions designed to protect and encourage incumbents, while “bottom tier” sectors which make up the majority of the number of businesses have a lighter government hand and limited barriers to entry (Pearson, 2015). The “success” of China’s reforms thus varies depending on the metric used for “market”.

The second pillar of “strong” institutions is market regulation. The extent to which the political bureaucracy intervenes in the regulation and outcomes of markets has been put on a spectrum, with the extremes of “independent regulation” and “developmental state” on either end. The independent regulator model, fashioned on the ideal Anglo-American system, separates the regulator from both the businesses that it regulates as well as political bodies, designed to create a “level playing field” for firms (Pearson, 2005). The developmental state model, beginning with the classic study of Japan’s post-war economic rise, identified large government intervention in markets favoring specific firms with the intention of creating internationally-competitive “national champions”, and a specialized central bureaucracy carrying a strong role in sector selection and management (Johnson, 1982). There is diversity, as well, in western industrialized countries such as France with a long history of strong state-corporate ties and managed competition (Zysman, 1994).

China’s economic management in the reform era shares some similarities with both models. It has created a large number of protected (predominantly, state-owned) oligopolies to engage in “orderly competition” in various sectors—such as electricity, telecommunications, and finance—where marketization has proceeded further than privatization (Pearson, 2015). At the same time, beginning in the 1990s, many new regulatory bodies designed to be separate from the existing bureaucracy were created, and discourse in favor of independent regulation has historically been strong (Pearson, 2005).

However, China’s efforts toward independent regulation have been fraught, with regulators lacking sufficient authority. The causes are familiar: strong supra-regulatory bodies (e.g., planning commissions) that dominate overall economic policy, fragmented decision-making within overlapping bureaucracies, and ambiguous regulatory authority in part because of the lower official rank of its regulators (Pearson, 2007). Major reforms inaugurated under Premier Zhu Rongji (1998-2003) have been stagnant under subsequent leadership due to political intertia and comfortability with the status quo of SOEs (Naughton and Tsai, 2015).

China also differs in many aspects from the developmental state model. While Japanese and Korean bureaucracies had “modern” Weberian characteristics of specialization and impersonality, China’s official hierarchies have demonstrated strong tendencies to enlist all of its members in various missions and to utilize rather than eschew personal connections (Ang, 2016). China’s commitment to private property rights is uneven and its interventions were not similarly "market-conforming" in the sense of aiming to "get prices right" (Hsueh, 2011, p. 17).

Property rights have been seen as fundamental to modern societies and markets (Hayek, 1948; North, 1990)—a "clear, necessary condition for a successful market system" (Montinola et al., 1995, p. 51). These entail a strong government to enforce contracts while simultaneously limiting its own confiscation of private property (Weingast, 1995). The central challenge for China thus has been to maintain credibility of its property rights protections in the context of high public ownership and substantial ambiguity in bureaucratic and policy directions outlined above.

First among these deficiencies, during the reforms China did not have established private property and commercial rights laws (Montinola et al., 1995). Nevertheless, because much of the growth occurred first in local government-owned firms, a key achieved condition was inherent to its federalist structure: limiting the central government's ability to confiscate property of lower level governments (Weingast, 1995; Oi, 1992). Furthermore, rather than viewing ownership in terms of the binary public or private, China experimented with a variety of forms, for which familial ties and other local bonds help bridge the lack of formal protections (Oi and Walder, 1999). Hybrid or partial rights split up various constituents of property rights systems, which include control of the asset, rights to income derived from it, and ability to transfer/sell it (Ang, 2016). For example, extra-budgetary revenues from TVEs were retained by the local government (Oi, 1999).

Another line of inquiry downplays the importance of ownership in establishing efficient markets. For example, a sole focus on privatization ignores the institutionalization of rights, which apply for public, private, and combined ownership (Steinfeld, 1998). More broadly, given the range of ownership structures and ambiguity of authorities in China's official bureaucracies, it is helpful to separate state ownership—in terms of capital or shareholders—from state control, defined as "authority systems that are designed to make the myriad decisions" in the economy (Pearson, 2015, p. 28). The latter is more fundamental to the distinction between planning and markets, and thus potentially more relevant in analyzing market outcomes.

In implementing the wide range of reforms outlined in this section, despite the relatively rapid ascent of China's economy, government policy change is famously gradualist and incremental. Dual-track pricing and slowly raising market shares inherent to "growing out of the plan" is a clear example. Re-allocating various components of the property rights bundle individually instead of all at once is another. This is one case of a broader phenomenon recognizing that endogenous pressures are more frequently responsible for institutional change than large exogenous shocks (Mahoney and Thelen, 2010). Incremental changes thus "layer" on top of rather than replace existing institutions (Van der Heijden, 2011). China's approach has also been positively contrasted with unsuccessful "big bang" or "shock therapy" reforms of many former USSR states (Roland, 2002).

3.1.3 China's Evolving Electricity Sector Institutions

Initial Opening of the Sector (1980s-1997)

In the electricity sector, the central priority of self-sufficiency lasted through the 1970s as localities were encouraged to "split up, stand against mountains, and take cover" ("分散，靠山，隐蔽"), resulting in building sometimes unnecessary infrastructure in costly places, such as a transformer deep inside a mountain northeast of Guangzhou (Guangzhou Committee, 2001). The grid was directed by the central ministry and its provincial bureaus, with many overlapping responsibilities such as government officials also holding positions at power plants (Zhang and Heller, 2007).

Energy shortages in the 1980s revealed limitations to this rigid reliance on central direction and investment. China's electricity sector restructuring thus began in the mid-1980s with encouragement of investment by entities other than the central electricity ministry and its affiliates (State Council, 1985). Soon after, Li Peng—former Minister of Power, and Premier (1988-1998)—announced policy directions that were adopted in 1988 by the State Council: separating government and grid, strengthening the province as economic and authority unit, and interconnecting the grid and unifying dispatch (State Council, 1988). The settlement-based system established between provincial grids—as if between two companies—became a defining feature of the electricity system. The national goal of interconnection and unifying dispatch (i.e., centralization) contradicted with the strong localization pressures, which Premier Li recognized at the time, but was necessary, he argued, to deal with electricity shortages (Kong, 2010).

The contradiction and ambiguity of competing goals and decentralized authority mirror the discussion of fragmented authoritarianism observed throughout China's bureaucracies. In the case of electricity: vertical, functional relationships (*tiao*) extended from local and provincial bureaus to central ministries, such as the provincial bureaus of electric power under the former Ministry of Electric Power. Horizontal, regional relationships (*kuai*) organized by geography connected the provincial production bureaus of coal and electric power, as well as the various provincial planning commissions (Lieberthal and Oksenberg, 1988). Ambiguous central energy policies resulted, partially because of the wide range of political demands on this critical sector, but also due to the lack of detailed information available to decision-makers (Fingar, 1987). Local governments became the locus of conflict in many aspects of the sector.

Much work has focused on how investment authorities varied over the reform period (and continues to evolve, most recently in 2015), and how this reflects the changing power of central vs. local officials (e.g., Lieberthal and Oksenberg, 1988). In electricity, this balance has been adjusted most directly by setting the threshold for plant sizes that may be approved directly by provincial and lower governments, with numerous implications. For example, early decentralization reforms resulted in a proliferation of very small, inefficient plants (<50 MW) (Wirtshafter and Shih, 1990).

Of additional importance—and the focus of this dissertation—is the production planning process, which specifies who generates and how much. Production planning prior to grid-government separation was subject to multiple agencies: the State Power Commission, the Capital Construction Commission, various ministries, banks and local planning offices (Fingar, 1987). As provinces were given the ability to invest in their own generation plants, and with more exchange-based settlements between provinces, the province also naturally led the process of setting annual generation and consumption plans (Ma and He, 2008).

For a little over a decade, multiple generation owners competed with assets of the central state-run VIU under ambiguous criteria for allocating plan amounts, including the lack of price-based competition. While different tariffs were assigned to plants, and even to different portions of electricity from the same plant, this system predated "dual-track pricing" and markets on the "margin"—characteristic of China's market reforms—which were still over a decade away. This lack of clarity led to claims that the VIU discriminated against locally-owned plants, such as the Ertan hydropower station (二滩水电站) in Sichuan which some claimed was underutilized relative to coal plants owned by the VIU (Ma and He, 2008; Xu, 2016). Local government ownership of generators also created conditions for "reverse" discrimination against VIU-owned plants through the local government's authority over production planning (Xu and Chen, 2006; Bai and Qian, 2010).

Partial Restructuring of Electricity (1998~2014)

Over 1998-2002, China's highest policy-making body, the State Council announced its plans to create an "open, competitive and orderly electricity market", allocating the functions of the former state-run electricity ministry to newly-created state-owned grid companies, new regulatory and policy bodies as well as additional responsibilities for existing government agencies, and five new large state-owned generation companies accounting for roughly half of the market (State Council, 1998, 2002). This was the result of an intense period of negotiation among many parties, in particular, Li Peng and his family embedded in the electricity industry lobbying to maintain the integrity of the grid company, and Premier Zhu pushing to break up the sector as a key policy priority at the end of his tenure (Chen, 2010b).

As observed throughout the market reforms discussion, governments (both local and central) did not give up their significant role in the sector following unbundling. Central governments retained primary price-setting authority and provincial governments retained plan-setting authority as well as other discretion in the sector. Provincial governments have been noted to use this power to promote forms of contracting that reduce electricity prices for local industries (as demonstrated in several of this chapter's cases, and, e.g., SCEO, 2015). These authorities are the primary motivation for selecting the province as the geographic unit of analysis in this dissertation's cases.

Following unbundling, a centrally-determined "benchmark electricity tariff" for each province was established for thermal generators, reflecting unpublished cost and return expectations as well as affordability based on the economic development of the province (Ma, 2011). This structure, sometimes referred to as a yardstick tariff, was only intended as a temporary measure before competitive wholesale regional markets were fully implemented (Ma, 2011; Ma and He, 2008; Kahrl and Wang, 2014). The initial rounds of pilot markets in the early 2000s to replace this system all failed, due to opposition or co-option by protectionist local governments, generation firms seeking to maintain high rents, and grid companies whose revenues became threatened, and due to insufficient oversight by regulatory bodies (Andrews-Speed, 2013). The benchmark tariffs became the *de facto* long-term solution, which have been adjusted downward on an ad-hoc basis in response to changing coal prices since 2011, with a small increase in 2018 possible for the first time this decade (Li, 2017). Provincial governments continue to have financial incentives to give preference to coal plants whose tax revenues are larger and distributed at various government levels (Zhao et al., 2013).

In the absence of differentiated cost signals, either through internal cost accounting or market-clearing bids, other criteria are used to determine the dispatch order. First, an overriding priority across operation of China's electricity sector is the concept of fairness (or, "equitable dispatch", "equal shares dispatch"), typically referred to in Chinese by the broad principles of "transparency, equity and fairness" (*gongkai gongping gongzheng* | 公开，公平，公正), abbreviated *sangong* (三公). Established after unbundling to maintain the rights of generators, under *sangong*, benefits (and costs) of supplying electricity should be shared equitably among generators (SERC, 2003b).

Actual costs may differ from the benchmark tariff and there is no consistently applied method to adjust the tariff to respond to these changes. As a result, minimum generation quotas (in principle equal for similar types according to *sangong*) are allocated to generators on an annual basis to guarantee sufficient revenues (Kahrl et al., 2013). In other countries, stranded assets and insufficient compensation as a result of a transition to wholesale power markets are sometimes handled by side-payments from the regulator (Ventosa et al., 2013). However, no comprehensive system of transition payments was created in China, the absence of which creates political pressure to maintain production from inefficient generators.

Second, a dominant criteria for dispatch since 2007, areas of the country have implemented various forms of an additional grid management priority called "energy-efficient dispatch" (*jieneng diaodu* | 节能调度), which prioritizes first renewables and nuclear, and continues with coal units in decreasing order of efficiency (NDRC et al., 2007). This was instituted in response to some provinces dispatching lower-efficiency coal units more than new high-efficiency units, thereby degrading the benefits of central energy conservation policies (SERC, 2011a). This is tied to mandatory renewable dispatch policies, on the books since 2007 and reiterated several times over the last decade (SERC, 2007; NDRC and NEA, 2016). Several evaluations have noted that energy-efficient dispatch implementation is uneven, attributed to preferential treatment by provincial governments for government-invested plants, conflicts with government-mediated bilateral contracts between suppliers and large consumers, and lack of incentives for grid companies to comply (Tong et al., 2011; Ding and Yang, 2013; Kahrl and Wang, 2014; Zhong et al., 2015).

Over the same time period as "energy-efficient dispatch" became a priority, the central government began encouraging massive centralization and consolidation in the sector. Minimum size restrictions on new builds and mandatory closure of small plants (*shanda yaxiao* | 上大压小) designed to raise the efficiency of the sector and reduce air pollution also gave central SOEs a dominant position in the resulting construction boom (Schreifels et al., 2012; Zhang and Gao, 2016). Local governments, wary of employment and financial strain from small power plant closures, were unable to hold off this trend as they had done previously (Williams and Kahrl, 2008). Over 2002-2010, the proportion of capacity controlled by the State-owned Assets Super- vision and Administration Commission (SASAC)—the owner of the largest central SOEs—rose from 46% to 60% (Wang and Chen, 2012). Vertical integration between coal mining—which underwent its own consolidation drive around this time—and power generation activities also dramatically increased (Zhang and Chen, 2011).

In contrast to the dominant central-local theory, which views inter-governmental exchanges as the primary driver of industrial policy in China, new theories with a plurality of actors are emerging, many of which implicate energy. Lobbying by both state-owned and private firms has been shown to be pervasive: from a survey of 131 companies in 2007, virtually all firms had lobbied local governments and roughly half lobbied the central government (Deng and Kennedy, 2010). Some have posited centrally-owned SOEs exert considerable sway particularly in the electricity sector with local governments which are eager to "collude" with SOEs in contravention of central orders (Tsai, 2011). Wind manufacturers have developed close relationships with local governments home to good wind resources (Dai, 2015). Policy-making is also increasingly pluralized outside established state and SOE hierarchies, with non-governmental organizations (NGOs) as well as officials in unrelated areas exercising influence (Mertha, 2009).

In the electricity sector, grid companies play crucial roles in both designing and implementing policy due to their authority on technical matters and distinct information asymmetries over government agencies. Internationally, the political strength of electricity VIUs and other network industries that are subject to price regulation is a major motivation for restructuring (Newberry, 2002). In China, leaders in the State Power Corporation of China (SPCC), the corporatized version established in the 1990s from the former ministry, engaged in active lobbying as well as co-option of reform language to slow and limit its break-up as well as delay introduction of markets (Chen, 2010b; Xu, 2005).

Following the 2002 State Council decision, China established two large multi-provincial state-owned grid companies—State Grid Corporation of China (SGCC) and China Southern Grid (CSG), broken off of SPCC—and retained a limited number of independent provincial grid companies. As early as 2004, the SGCC head Liu Zhenya became an active "policy entrepreneur", shaping rather than responding to central directives: it was at this time that the vision of interconnecting its various provincial and regional grids through ultra-high voltage (UHV) lines was introduced, and soon after became official government policy (Xu, 2016, 2017). With respect to electricity systems operation—the focus of this dissertation—others have noted that a three-party bargaining game now exists between the center, the province, and the grid for control (Dai, 2015; Lema and Ruby, 2007).

Wind energy, still only 5% of electricity nationwide, grew in the post-2002 reform period under a different set of conditions than the dominant coal and hydropower energy sources. Wind is primarily supported by a central feed-in-tariff (FIT), established first in 2009 (NDRC, 2009). Prior to this, wind farms received tariffs determined on a project-basis or through concessions determined by competitive auction. Under the FIT, the country is divided into four different tariff levels depending on resource quality, construction costs, and other considerations. Parts of northern China are in tiers 1-3, with tariffs for new builds in 2017 set at 0.47-0.54 yuan / kWh, and the rest of country is in tier 4 at 0.60 yuan/kWh (see Figure 3.1). Specifically, the central government subsidizes the difference between the FIT and the provincial benchmark coal tariff using funds collected on electricity sales across the country (NPC, 2009). When wind developers enter into market-based contracts, they still receive this central subsidy, though typically the market prices do not include it. Hence, wind market contract prices should be compared to local benchmark coal prices to understand the reduction in revenues for wind developers, not to the FIT directly. In addition to the FIT, wind projects receive other benefits such as reduced tax rates (Kang et al., 2012).

Northern regions were preferred by developers to other regions with lower quality resources but greater integration capability such as in the south and east, even with the slightly lower tariffs. Concentrated development in a handful of areas followed. Central government attempts to control this expansion included a period when all wind farms greater than 50 MW should also be approved by central agencies. Developers and localities responded by building many 49.5 MW wind farms, including breaking up larger farms into several stages, in order to expedite approval (Luo et al.,

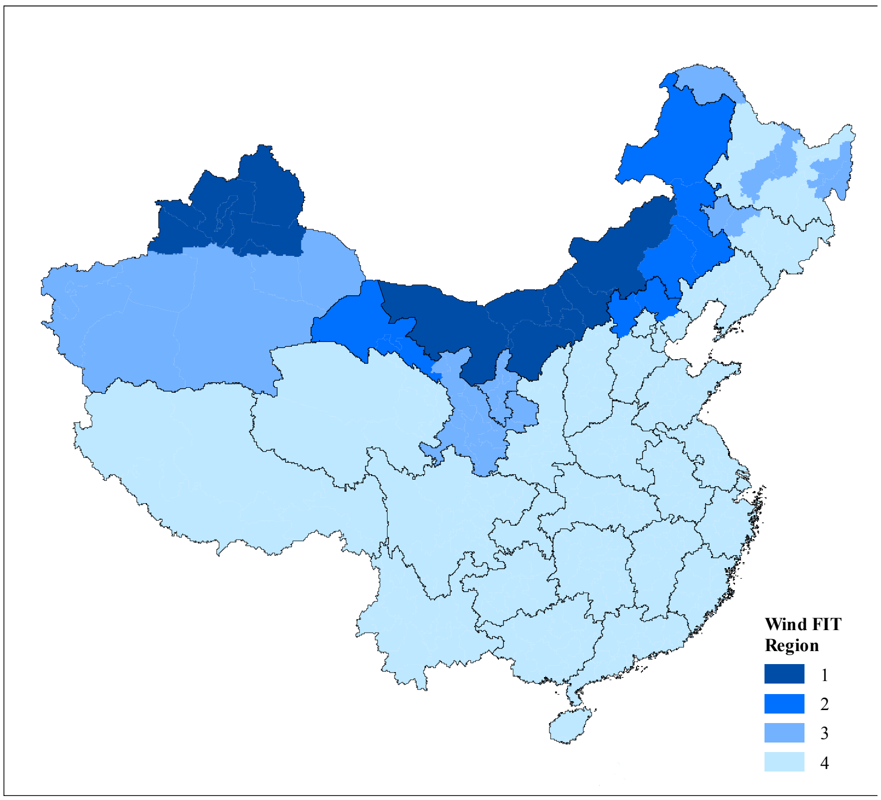


Figure 3.1: Wind feed-in-tariff (FIT) regions of China. New builds in 2017 in tiers 1-4 received 0.47, 0.50, 0.54 and 0.60 yuan / kWh, respectively. Source: (NDRC, 2015c)

2012).

While local governments in high quality regions eagerly accepted these developments, incentives for wind energy development rarely exceeded those for new coal plants. Because of the shared tax system, the tax holidays and other benefits for renewable energy put in place by the central government also affect local government revenues. According to one analysis, when adjusting to similar levels of investment, average taxation per year of a wind farm over its lifetime can be half that of a coal plant (Zhao et al., 2013). Employment concerns of existing coal plants, as noted above, are also important drivers of local government policy.

Since the FITs were put in place, annual outlays have increased dramatically, prompting increases in the electricity surcharge to make up for the shortfall in available funds. By the end of 2017, the deficit has reached 100 bn yuan ($16 bn), which is one of the primary drivers for the expected announcement of a mandatory renewable energy certificate (REC) program, which would force either grid companies or other generators to purchase credits up to a certain percentage of total consumption or generation (Li, 2018). The certificates, which are only purchased on a voluntary basis as of this writing, substitute for the central subsidy and as a result fetch rather high prices close to the subsidy amount, between 0.14-0.24 yuan / kWh ($0.02 - $0.03 / kWh) (Ng, 2017).

Current Reform Period (2015~)

In 2015, China embarked on a new round of electricity sector reforms, nominally designed to achieve objectives of efficiency as well as encourage the integration of renewable energy. The specific objectives of the reform plan at a high-level are to create market-based prices for generation and retail; marketize non-essential planned generation; establish electricity exchanges; expand inter-regional transmission; enhance government regulation; and strengthen comprehensive planning in the sector (State Council, 2015).

The current reform pathway focuses heavily on gradually reducing the amount of planned electricity sales by moving all commercial and industrial electricity demand to medium-term contracts (monthly to annually) directly with generators by 2020 (NEA, 2016c). These are the majority of market experiments in the sector, and the focus of most of the cases in this dissertation. Notably, the original reform document explicitly excluded certain types of “public interest” generation from marketization requirements, such as load balancing and frequency management to ensure residential, agricultural and public interest electricity demand as well as renewable energy integration (State Council, 2015). One case in this chapter—the Northeast peaking ancillary services market—extends market mechanisms into this domain. The reforms also call for prioritizing hydropower, solar and wind, and increasing inter-provincial trade in annual planning processes (NDRC and NEA, 2015a). As a sign of the continued power of SGCC in policy-making, it lobbied effectively to maintain ownership (full or majority) as well as control of the newly created electricity exchanges, which would only be "relatively independent" (*xiangdui duli* | 相对独立) from the grid (State Council, 2015).

The reforms were concurrent with broader decentralization and government reduction drives (e.g., *jianzheng fangquan* | 简政放权), which led to the cancellation of a number of central authorities. Chief among these was the responsibility to permit new power plants, which falling to the provincial governments in 2015 immediately resulted in the largest coal capacity expansion in over a decade despite chronic nationwide over-surplus (NDRC and NEA, 2015b; CEC, 2017c).

China's preferred approach to market reforms clashes with lessons from other electricity sector restructuring experiences, raising questions about its ultimate effectiveness. For example, while stated reforms goals are to encourage medium-term bilateral contracts, international reform experiences[3] emphasize the importance of the more physically accurate shorter-term markets (e.g., daily or hourly) to trade these and to incentivize supply to address imbalances (Joskow, 2008). These spot markets are seen as merely "supplementary" in Chinese documents (NEA, 2016c). Two cases illustrate Chinese variants of short-term market pilots, which still diverge from a standard design and implementation.

Short-term, or "spot", markets are essential to create appropriate economic signals for long-run sector efficiency: a well-functioning operational scheme that reflects scarcity at granular levels of time and location (whether via markets or regulated electric utilities) provides accurate signals for long-term investment decisions (Pérez-Arriaga and Meseguer, 1997). Bilateral contracting is a key feature of the UK market, which is facing increasing challenges with its model that differs from that predominant in US and many other regions that relies more on centralized exchanges (Sioshansi et al., 2008b). However, the UK's short-term imbalance market is crucial to overall

[3]Pollitt et al. (2017) grades China's institutions according to 14 elements of international best practices, touching on a wider variety of shortcomings.

efficient operation. Additionally, variable energy sources such as wind power cannot participate effectively in UK's other long-term markets, and hence has implemented financial auctions at guaranteed prices, which are ignored during dispatch, as described above (DECC, 2015).

China's recent reform documents related to generation markets also do not mention explicitly a move to delink with the physical delivery of electricity (NDRC, 2015b; NDRC and NEA, 2015a; NEA, 2016c). As noted above, physical contracts—especially those contracted far in advance—can lead to large inefficiencies if system conditions change. Financial contracts—which are used for settlement only and do not enter dispatch—are more efficient when there is a short-term merit order dispatch. In several of the market pilots explored in this dissertation, contracts may contain some financial elements, though with potentially ambiguous definitions. Furthermore, China's price zones—for both the predominant government-set prices and ongoing market pilots—are at the provincial level, which can create a need for complex congestion management systems in concert with market development. Short-term (i.e., spot) markets could help alleviate congestion without relying on administrative measures.

More recent markets for wind and solar energy also nominally aim to link to physical delivery, as a means to increase integration and reduce curtailment. Central regulations prescribing minimum utilization hours (related to capacity factors) specifically preclude using markets to achieve them, requiring that all electricity up to the threshold be paid at full benchmark price and "any excess amount should be integrated using market exchanges" (NDRC and NEA, 2016). It also explicitly forbids "adopting any method below the minimum purchase threshold where renewable energy pays coal or other power sources for generation rights" (NDRC and NEA, 2016). These minimum purchase requirements for wind were not met in most major wind provinces in China in 2016 (see Figure 3.2). However, even for the provinces that have been claimed to meet the requirement—Liaoning, Hebei and Shanxi—the evaluation report does not discuss or tabulate what percentage was sold at below-benchmark tariffs (NEA, 2017b).

Similar to cross-national studies on the benefits of restructuring, missing in much of the academic literature on China's grid policies—though not all[4]—is more detailed consideration of the technical constraints on grid operations as well as the details of market designs. Technical constraints limit

[4] Xu (2016) is a highly instructive example of the interaction of technical and political debates unfolding in SGCC's decision to promote UHV technology.

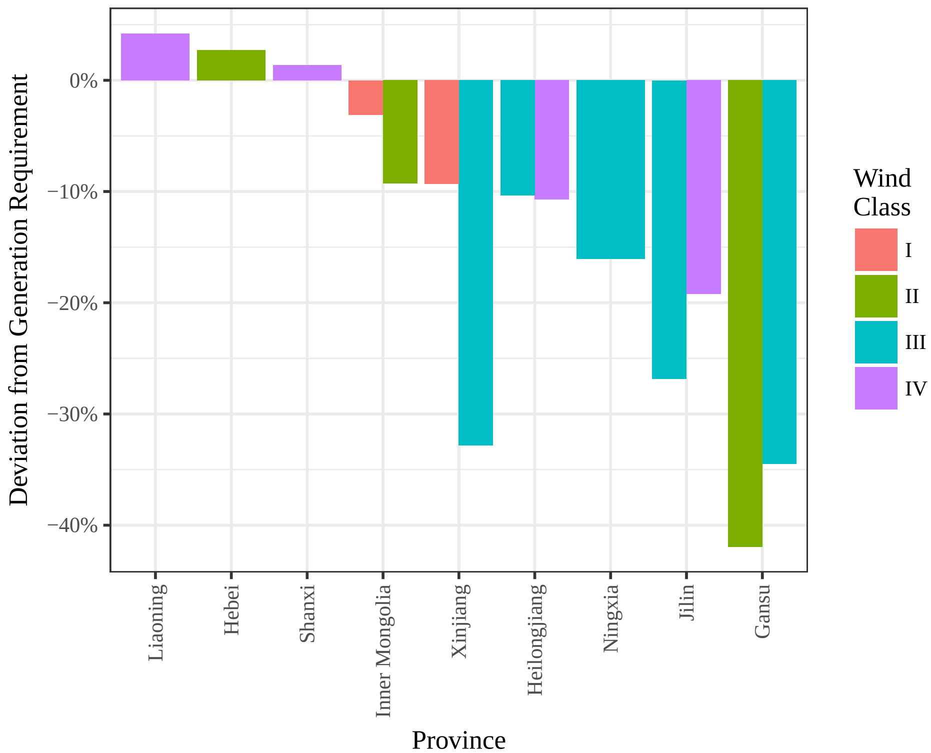


Figure 3.2: Wind generation deviations with respect to minimum capacity factor requirements by province and wind class (I–highest, IV–lowest), 2016. As discussed in the text, these do not consider the tariff paid to wind generators, such as what share is paid through below-benchmark market mechanisms. Source: (NEA, 2017b).

the ability of actors to control the bureaucratic “game” and pursue their own interests and market designs offer a variety of additional levers for government control of the sector beyond simply a binary state-market indicator. Considering these additional elements—engineering realities of system operation and specifics of market construction—can serve multiple purposes: providing insights into why and how certain reforms are chosen; explaining why desired outcomes are not achieved; and generating more contingent prescriptions for future reforms.

Two types of combinations of these elements recur throughout the dissertation: resolving some technical issues may require institutional changes that are overlooked because they appear to be less significant. For example, sharing reserve generation across provincial borders is only recently highlighted in reform documents compared to the typical energy markets and transactions. Second, even with well-aligned interests, desired goals may not be achieved because of ignored or under-appreciated technical challenges. For example, there is interest alignment in reducing planned electricity allocations from both central and local governments—in the former, to enhance efficiency and increase space for renewable energy; in the latter, to reduce the price of electricity for local industries. However, as noted above, medium-term bilateral contracts alone may be ineffective at incentivizing wind and solar energy in the absence of other financial instruments, on which current reform documents are silent. Aligning interests in terms of promoting inter-provincial trade through annual plans may also not capture all benefits of electricity trading in the absence of other less visible institutions, such as allowing reserve generator sharing.

In fitting with the purpose of determining how and to what extent technical and institutional factors interact in market reforms and wind integration outcomes, the focus of this research is on operations (*yunxing* | 运行) and (short-term) planning (*jihua* | 计划) , which I define as decisions made annually or on shorter timescales, to distinguish from long-term planning (*guihua* | 规划) such as generation or network investment decisions. This aligns with regular production planning processes in the Chinese government hierarchy, for which the year is an important time horizon. Investment decisions, the greater focus of China’s electricity reform efforts prior to 2015, do carry important implications for system outcomes, particularly in terms of contractual or quasi-contractual requirements to use a particular generator or transmission line. However, this study considers the set of assets as mostly exogenous in order to focus on current reforms in shorter-term generation markets and particular challenges with renewable energy integration.

3.1.4 Expectations for System Operations

To summarize the above discussion, the political economy of China's provinces, resting on a greater amount of autonomy from central management, can have a large impact on electricity systems functioning. Planning, operations and markets are all potentially under the jurisdiction of provincial governments, which gives an opportunity and, in some cases, a strong incentive to put in place industrial policies in favor of politically favored sectors and protectionist policies that restrict imports from neighboring provinces and other grid regions. In addition, due to the partial restructuring, annual generation planning has been maintained and similar long time-frame physical contracts for electricity markets have been encouraged. Both of these aspects—inflexible nature of contracts, and differences in trading rules—can have a larger impact on renewable energy integration relative to conventional coal or hydropower, and are thus potential institutional causes of wind curtailment. In Table 3.1, I summarize the most important expectations integrating the above discussions with regard to political economy and engineering aspects. I will return to these in the modeling chapter and, in Chapter 6, give an integrated answer on the extent to which I find evidence for each and my assessment of Chinese reform efforts to date to improve them.

Technical causes of curtailment—which I define as outcomes that would occur under an efficiently-run system according to standard objectives—are also manifold in China: insufficient demand when wind is available, inadequate transmission infrastructure, district heating cogeneration constraints, conventional generator limitations, and limited export potential. These are referred to as engineering expectations in Table 3.1.

3.2 Case Study Selection and Design

3.2.1 Case Variables and Selection Criteria

This dissertation examines cases of sub-national electricity market experiments, either at the regional or provincial level, selected on various criteria including implications for wind energy integration. Each is nested within the larger national discussion at the central government level about market designs and methods to address wind curtailment. The sub-national unit of analysis is necessary because of the distinct pilots that are ongoing at the provincial and, in a limited way,

Political Economy Expectations	**Engineering Expectations**
Physical Contracts: Long-term physical contracts restrict short-term balancing, increasing curtailment.	***Poor Demand Correlation***: Low demand during hours of high wind penetrations result in excess wind curtailed.
Provincial Authority: Provincial governments give preference to (within-province) conventional energy through its planning, operations and market authority.	***Must-Run Generation***: Combined heat and power (CHP) plants, classified as must-run, reduce integration space for wind.
Inter-Provincial Trading Rules: Different trading rules across provinces and regions inhibit short-term trading, restricting renewable exports and increasing curtailment.	***Conventional Plant Inflexibility***: Technical criteria of conventional plants (e.g., minimum outputs, start-up times, etc.) limit the system's ability to manage wind's variability.
	Grid Inflexibility: Transmission network or reliability constraints limit integration potential.
	Export Potential: Inter-regional export capacity and receiving region demand determine wind integration.

Table 3.1: Political economy and engineering expectations of China's wind integration outcomes based on prior literature

regional levels. National policies provide some guidance and constraints on local government actions, though, as discussed above, there is considerable autonomy granted to local governments to implement and, in most cases, design policy approaches.

Dependent variables of interest include metrics of electricity production including efficiency, distributional equity and wind integration outcomes. Given the engineering and institutional complexity of operating power systems, exogenous factors influencing outcomes are numerous. Besides the institutional features of the partially-restructured power system and the set of electricity system assets, which are the independent variables of this research, there are exogenous factors such as local resource endowments, economic structure, policy shocks and others. It is infeasible to sufficiently control for all of these in a large-N sense, hence the main focus of this chapter will be on describing the causal pathways inclusive of exogenous factors as well as intermediate variables such as market functioning.

	Endowments	Economy	Institutions	Macro shocks
	Natural resources, Geography	GDP, Industrial structure, Population	Pre-reform history	Policy or economic shocks, Fuel disruptions, Corruption inquiries, etc.
Independent variables of dissertation:	Electricity system assets (generation mix, network, etc.)		System operation and management bureaucracies, Inter-governmental relations, Market pilots	

Table 3.2: Exogenous factors of electricity systems

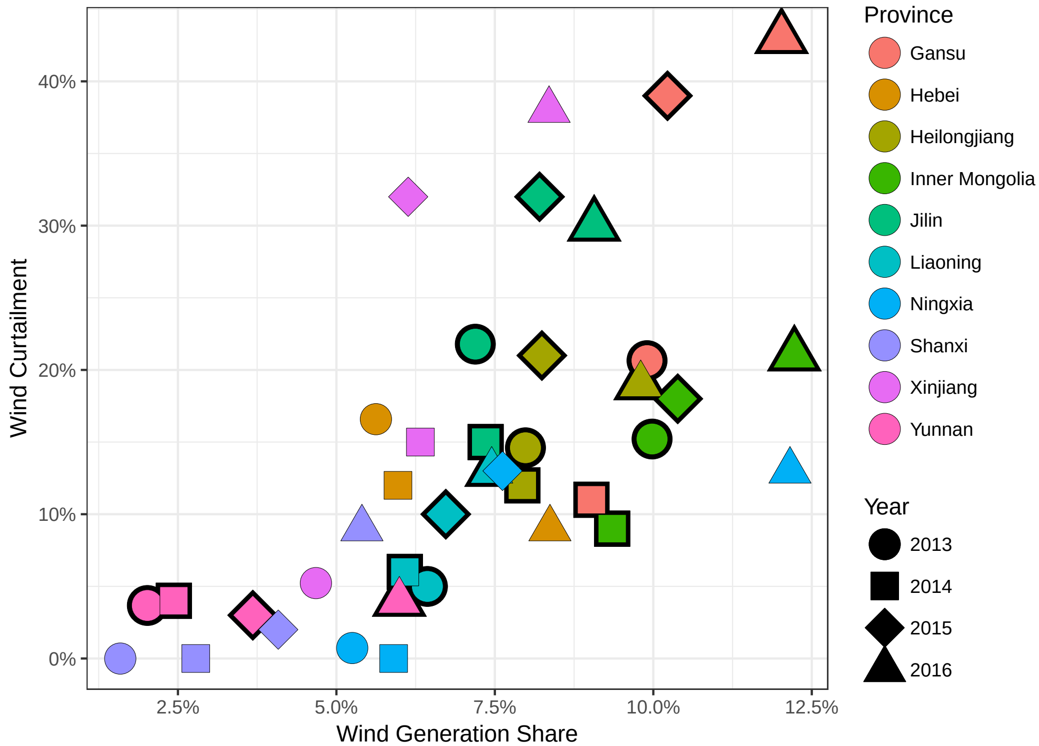
Wind utilization
Cost (efficiency) of production
Utilization of conventional units
Import/export totals

Table 3.3: Dependent variables

Virtually every province in China is experimenting with electricity markets, several of which began prior to the 2015 State Council reform documents. Shares of electricity transacted through markets as opposed to plan-based allocation vary widely by province and energy source: from 20% up to 68% in 2017 (CEC, 2018). Relevant cases for this dissertation are thus regions or provinces with ongoing electricity market experiments that could impact wind integration, with a focus on those provinces with large existing wind deployments (see top of Figure 3.3). Broadly, of China's seven major grid regions, these ten provinces are concentrated in the Northeast Grid, Northwest Grid, North Grid, and Western Inner Mongolia, as well as Yunnan province in Southern Grid (see bottom of Figure 3.3).

Selecting cases for in-depth study can serve a variety of goals, leading to a wide range of case selection techniques in the literature. Broadly, these goals can be segmented according to whether the purpose of the larger study is to make statements on "average" treatment effects, to make stronger statements on the necessity and/or sufficiency of certain conditions for outcomes to occur, or to generate insights or new hypotheses (Goertz and Mahoney, 2012). In particular, if the case study is combined with a large-N statistical analysis (e.g., regression), then the additional value of in-depth qualitative data of specific cases may be to examine (a) typical cases that fit the regression well, looking for evidence of hypothesized causal mechanisms; (b) deviant cases that do not fit the regression well, looking for potential omitted variable bias; or (c) extreme cases where case variables differ greatly from the population mean, looking for potential measurement error (Seawright, 2016). The multi-method approach in this thesis does not follow this traditional process (as outlined in Chapter 2), though the concepts of typical, extreme, and adjacent cases are nevertheless useful for similar reasons.

This dissertation examines almost all regions with reasonably high wind penetrations ($> 5\%$ share of generation), selecting province(s) within each seeking diversity on curtailment pressures, independent variables in Table 3.2 such as institutions and market experiments, as well as other exogenous variables. Selecting cases in part on the dependent variable (in this case, high wind curtailment) is sometimes criticized as biasing the analysis by giving too much weight to chosen explanatory variables without examining counter-cases where the explanatory conditions existed but that did not result in the same outcome (Geddes, 1990). However, given that there are no examples of provinces with high penetrations of wind power and low curtailment (i.e., lower right



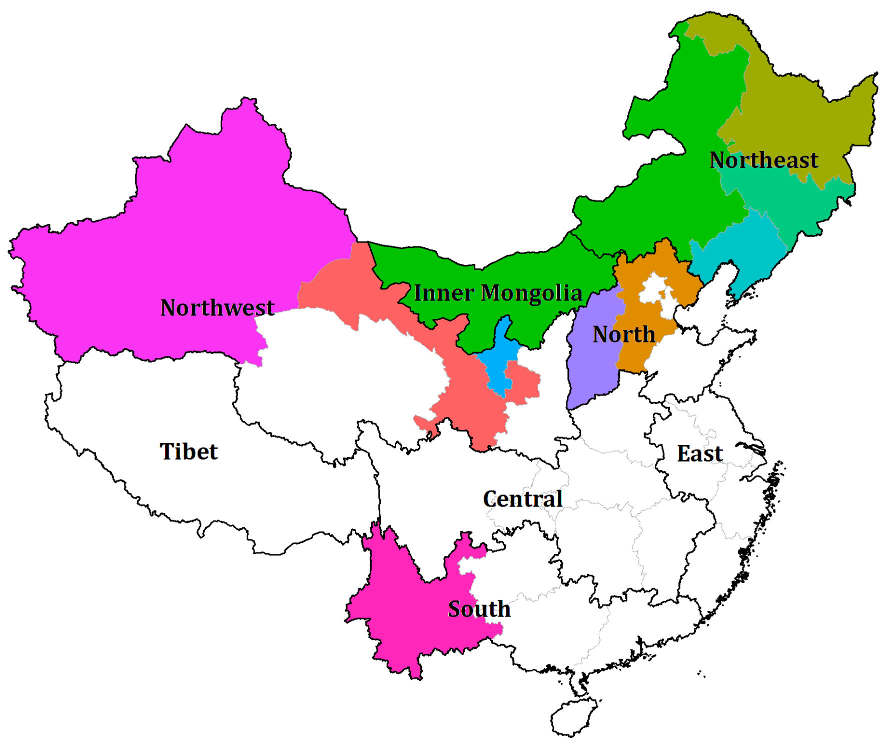


Figure 3.3: Wind curtailment in major wind provinces of China (wind share of generation> 5% in 2016) and cases explored in this dissertation (black borders), 2013-2016 (*top*). Source: NEA. Grid regions and provinces of China (same colors) (*bottom*). Inner Mongolia is split between the Inner Mongolia Grid Company and the Northeast Grid—the border drawn here is approximate. Light grey lines are provincial borders. Source: Author's illustration.

corner of Figure 3.3), the counter-cases envisioned in Geddes (1990) simply do not exist. Furthermore, I am also using case studies to generate insights such as new hypotheses or more detail on processes, as opposed to strictly testing hypotheses (George and Bennett, 2005). For this purpose —e.g., understanding the variety of reasons why wind curtailment might be high across a diversity of Chinese regions—selecting on the dependent variable may be justified.

Four cases were chosen for this study: Northeast Grid, Gansu province in the Northwest Grid, Inner Mongolia Grid, and Yunnan in the Southern Grid (see Figure 3.4). These represent a range of market developments in terms of history, as well as types and quantity of transactions currently through out-of-plan market mechanisms: for example, the lowest (Liaoning) had 13% of wind transacted through markets in 2017H1, while the highest (Yunnan) had 48% (CEC, 2017a).

For each province / region, 1-2 market experiments were chosen as cases to examine in depth (see Table 3.4). Here, there is sufficient coverage of common cases such as bilateral contracts which are the dominant form of exchange throughout China, as well as more unique experiments such as the "peaking ancillary services market" in the Northeast, specific to that region up until recently and a very clear departure from other market approaches both within China and internationally. Yunnan in Southern Grid has predominantly a hydropower system, though with wind and solar deployments increasing and some early curtailment. Some of the mechanisms to address the seasonality of hydropower and cross-provincial trade, such as excess hydropower exchanges and day-ahead transactions, are very relevant for wind markets as well. Finally, two adjacent cases in the same province and with similar wind resources but in different grid companies—Western Inner Mongolia in the Inner Mongolia Grid and Eastern Inner Mongolia in Northeast Grid—are examined for variation across system operation, market functioning, and wind outcomes.

3.2.2 Archival Materials

This study relies on numerous primary and secondary archival materials: first, government work reports, policies and statistics provide official descriptions of many exogenous parameters in Table 3.2, in addition to providing useful insight into the problem-identification process in Chinese government agencies. Second, grid yearbooks and historical annals include a wealth of information on the development of both infrastructures and institutions of provincial grids. Third, (Chinese-language) news articles provide various contemporaneous accounts, sometimes written by government offi-

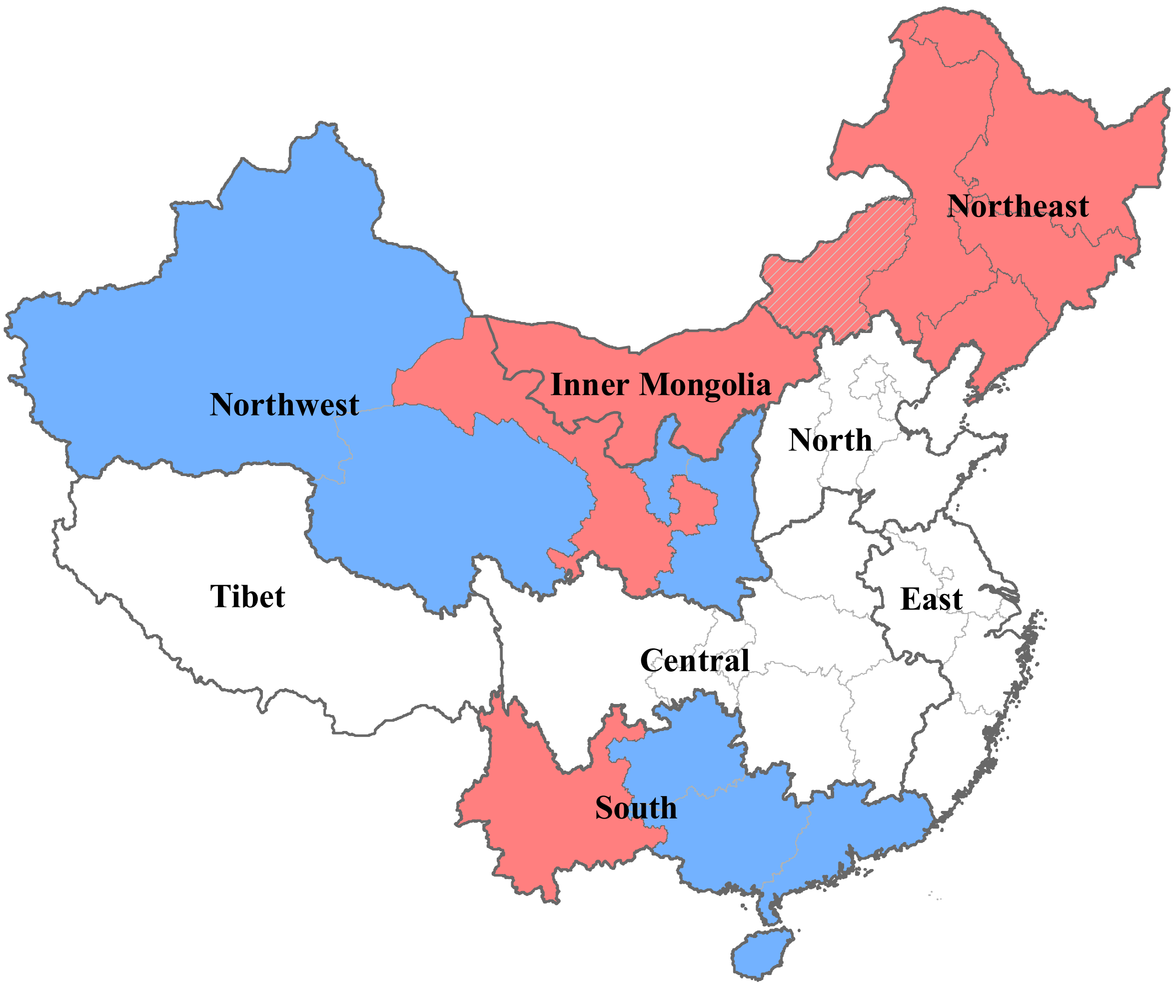


Figure 3.4: Case study provinces (red) and broader grid regions of which they are part (blue, thick outline). Shaded Xilingol prefecture has plants in both Inner Mongolia Grid and Northeast Grid.

Case	Abbrev.	Region Characteristics	Electricity Market Development (Approx.*)
Heilongjiang, Jilin, Liaoning, E. Inner Mongolia (**Northeast Grid**): Excess wind exchanges Peaking ancillary services market	NE	Relatively isolated grid, pronounced coal overcapacity	Wind: 20% (HL), 13% (JL), 13% (LN) in market
Gansu (**Northwest Grid**): Wind bilateral contracts	NW	Centrally-designated energy exporting region	Coal: 83% in market Wind: 38% in market
Western Inner Mongolia Excess wind exchanges	W. IM	Provincial grid company, early exporter to North China	Coal: 40% in market Wind: 15% in market (entire IM province)
Yunnan (**Southern Grid**): Excess hydropower exchanges Day-ahead exchange	SoG	Hydropower-rich, exporter, persistent seasonal balancing issues	Hydro: 80% in market (48% of which inter-provincial) Wind: 48% in market

Table 3.4: Cases of regional electricity market pilots with region characteristics.
*Market development figures are only for the 10 largest generation groups. Source: (CEC, 2017a).

cials or including quotes from them. Fourth, academic publications (primarily in Chinese-language journals) by electrical engineers and policy and management scholars examining issues related to renewable energy integration provide additional context for how the system operates.

3.2.3 Semi-Structured Interviews

Semi-structured interviews were conducted in Chinese over multiple visits spanning six months in 2015-2016 with respondents from grid companies, local and central governments, research organizations, and the electricity industry (see Table 3.5 and Figure 3.5). Scoping interviews conducted during three visits in 2013-2014 helped frame later study design but are not included in the table. Approximately half were conducted with other researchers present. Hand-written notes were taken during interviews, and augmented as best as possible following each interview with a roughly hour-long debrief with other researchers (if present) and exercise to reconstruct missing gaps. A small

Region	# Respondents
Beijing (Center)	17
Northeast	12
Northwest	21
W. Inner Mongolia	7
South	9

Organization	# Respondents
Government	8
Grid Company	15
Industry	29
Research	14
Total	*66*

Table 3.5: Interviews conducted and included in this dissertation (2015-2016)—not including scoping interviews during 2013-2014 visits. Group interviews with multiple respondents are considered as one in these tables. Respondents are classified as "grid company" if they have an operational role in the grid company (e.g., dispatch, planning, etc.), while "research" includes academics, consultants, and grid company-affiliated researchers.

number of respondents consented to recording, but the vast majority preferred not be recorded.

Within grid companies, respondents were from the dispatch control centers (the department primary responsible for systems operations), planning offices (responsible for converting annual government plans to monthly schedules), exchange centers (responsible for market operation), and affiliated research institutes. Local government respondents were from provincial planning agencies (e.g., Development and Reform Commissions (DRC) and Economic and Information Commissions (EICs or IICs)) and energy regulators (National Energy Administration (NEA) regional or provincial branches). Central government respondents were from the NEA, which has a separate bureaucracy from but is formally under the jurisdiction of the NDRC. Generation company respondents were from central or provincial offices, wind farms and coal-fired power plants. Throughout, interviewees are noted in superscript (e.g., [16A1]), anonymized using an interview code to preserve confidentiality.

3.2.4 Within-Case Process Tracing

For each case, qualitative data is analyzed within a process tracing lens, examining causal processes along the chain (e.g., system operation and market experiments) from independent to dependent variables. Throughout, attention is paid to consider diverse sets of sources, alternative hypotheses, potential biases during data collection, and both inductive and deductive reasoning (Bennett and Checkel, 2015b). Specifically, this part of the dissertation uses a process tracing framework to:

1. Disaggregate the rule-making and implementation process of system and market operations;

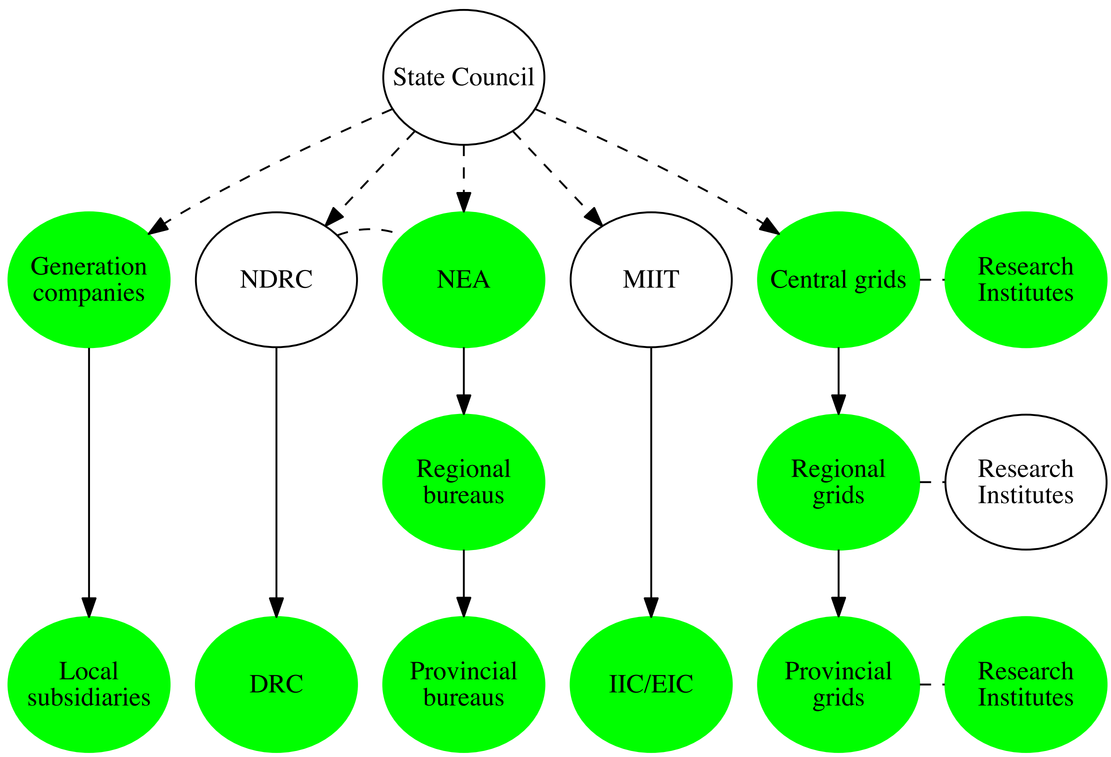


Figure 3.5: Hierarchies of various grid-related government and state-owned institutions. Respondents are from shaded institutions. Dashed lines represent authority relationships between different organizations, while solid lines are within-organization. NEA is distinct from NDRC though under its purview. Not shown: academic and consultant respondents.

2. Explore intermediate variables such as functioning of markets with respect to stated goals and economic theory (e.g., degrees of government intervention); and

3. Test assumptions necessary for validity of the quantitative model.

Rule-making and implementation

The baseline common to all cases is system operation, which was explored through examining various decision-making steps by timescales—from multi-annual to hourly—and function—rule-making, implementation and oversight. Market experiments entailed more diversity, though these steps were nevertheless helpful as a structuring tool. Question guides and subsequent analysis were designed to evaluate the relevance of each step for outcomes of interest, and to facilitate comparability across cases. These stages are described in Appendix B.

Market functioning as intermediate variables

Details of market functioning are properly seen as elements of the causal chain from inputs to outcome, rather than an end in themselves. Chinese economic policy has embraced a diversity of economic reforms since the 1980s, most of which nominally attempt to reduce the role of governments in making economic production and consumption decisions or to delegate decision-making authorities closer to the point of production. As noted above, there is wide heterogeneity in how these reforms are embraced, often mediated by government reticence to relinquish control of legacy economic planning authorities. There are also complex interactions among different markets, with some designed in reference to others or to certain planning institutions.

Beyond the details of market design, process tracing is useful to understand the extent to which these markets achieve the competitiveness nominally sought by policy, and the extent of continued government interference beyond what is desired according to standard economic theories of electricity market design and regulation. Competitiveness is a relative term, as there does not exist a perfect market. In particular, a "comparative governance approach" should clearly compare what the alternative institutions are (in this case, pre-reform planning methods), and recognize that "textbook" institutions, particularly of markets, never operate as planned (Joskow, 2008; Williamson, 1985).

Test assumptions necessary for quantitative model validity

Similar to the role of case studies in testing identification assumptions of a regression analysis in a more traditional multi-methods study, this dissertation's case studies can assess the validity of assumptions necessary for validity of the quantitative engineering-economic model. The model, together with these assumptions to be tested, are explained below.

3.3 Cross-Case Thematic Analysis

From the within-case analysis, a generalized cross-case narrative of system operation is constructed. Four additional themes are examined, based on *a priori* knowledge of Chinese economic reforms as well as inductively through the analysis: the roles and motivations of grid companies; the changing engineering context; the nature of government interventions into electricity markets; and the range of barriers to trading wind electricity.

3.3.1 Qualitative Data Analysis Procedure

Each interview produced several pages of hand-written notes, which were analyzed together with other interviews from each case following the trips. The majority of the analysis presented here was conducted by myself—in the interviews with multiple researchers present, consistency was sought in the post-interview debrief. Thus, I adopted a more flexible coding and analysis procedure.

I developed a routine inputting markdown language[5] into Atom, a customizable text editor, and coded python scripts for searching and aggregating, producing formatted markdown as a result. The basic unit is an observation, a line and any subsequent description or formatting (e.g., table, picture of hand-drawn diagram, etc.). All observations can be tagged with metadata of categories and respondent code(s). Each case is contained in a single file, which is primarily organized around a set of categories. An observation/note can be tagged in multiple categories. Multiple files can be combined via intersection or union of all tags.

A case analysis begins with a list of categories—many of which are common to all cases, a sample of which is shown in Appendix B. Of these, I choose a subset of around five and go through each

[5]Markdown is a streamlined plaintext language that can easily generate a range of formatted text (e.g., bullets, tables, graphics, etc.), commonly used for web development.

interview's notes chronologically, entering observations as I see them. Some additional categories may also be added to the list at this time. I then move onto the next set of roughly five categories. Generally, the first pass focuses on case descriptions and rule processes, and subsequent passes focuses on the individual case study institutions.

By adding notes to each set of categories at a time—as opposed to creating a transcript, which is then coded—there are additional opportunities to find common observations across respondents. These observations are not strictly transcripts, hence, data from multiple respondents can be combined into a single, more confident generalized observation (maintaining nuance from each respondent in the description). This avoids much of the need for secondary post-coding analysis identifying similar observations under a single, more general code.

3.3.2 Validity of Quantitative Grid Model

Among operational time scales (annual or shorter), the unit commitment and economic dispatch optimization (UC) is essential for determining system performance on metrics of cost and wind integration (Xie et al., 2011). In most systems, this is conducted on a daily basis to determine the schedule of generator start-up and shut-down decisions (known as "commitments") and predicted generator outputs for the next day or several days based on forecasts of demand and supply availability (Padhy, 2004). The UC model used in the dissertation is fully described in Chapter 4, and is introduced here to motivate how case studies can address questions of model validity given the complexities of actual operation. Schematically, the model minimizes production costs to meet a given demand by choosing appropriate values of production variables subject to (s.t.) various constraints:

$$
\begin{aligned}
Z = \min \quad & \sum_{\substack{\text{Generators}\\ \text{Time}}} (\text{Production Cost} + \text{Commitment Cost}) && (3.1)\\
\text{s.t.} \quad & \text{Supply} + \text{transmission} = \text{demand}\ (\forall\, \text{node})\\
& \text{Network losses}\\
& \text{Generator minimum/maximum outputs}\\
& \text{Generator ramp limits}\\
& \text{Generator minimum up/down times}\\
& \text{District heating requirements}\\
& \text{Hydropower storage}\\
& \text{Reserve requirements}
\end{aligned}
$$

The optimization simulates the decision-making situation faced by a central planner such as a vertically-integrated utility, but it equivalently represents the optimal set of market transactions from the perspective of an independent market operator under perfectly competitive conditions in a bid-based central auction, i.e., no strategic use of market power (Pérez-Arriaga and Meseguer, 1997). Under this assumption, the bidding behavior of individual firms may be ignored, simplifying greatly the modeling burden. A list of the key assumptions of this model and application to China are described in Table 3.6.

Using this modeling framework, the effects of different institutional combinations can be measured with respect to the reference scenario of a central optimization. Because of the complexities in actual system operation, which include operator discretion, opaque bargaining processes, and insufficient quantifiable data on various smaller decisions (as elaborated in the cases below), it is difficult to calibrate and validate the model against actual historical practice. Instead, the *relative* changes under different institutions (treatments) are used to build up contributions toward efficiency losses and other societal outcomes, with the remaining unexplained portions left for fur-

Assumption	*Description*	*Application to China*
Welfare maximization subject to constraints	Objective is to minimize cost of supplying a given demand (i.e., non-price-responsive demand over time frame) subject to various constraints, exclusive of investment decisions.	Holds if objective function consists only of costs or prices, and all other considerations (e.g., legacy planning institutions) are constraints that cut off part of decision-space.
Single optimizing agent	Under perfectly competitive conditions (no strategic exercise of market power) in a bid-based central auction, individual bidding behavior can be ignored.	While no bidding is done in China through, e.g., short-term centralized energy auctions, this assumption holds if dispatch decisions incorporate marginal costs of generators in the objective function.
Perfect information	Projected demand and supply availabilities (i.e., wind resource) are known perfectly at beginning of time period.	Strictly not true. Holds to the extent that knowledge of demand and supply forecast errors would not change scheduling decisions (i.e., commitments).
Zonal demand and supply	Demand and supply zones are aggregated to the provincial level.	Holds if intra-provincial network constraints are never binding (resulting in congestion), and intra-provincial network losses are negligible.

Table 3.6: Quantitative reference model assumptions

ther qualitative analysis and/or modeling improvements. Given this structure, the key modeling assumptions are laid out in Table 3.6. Some assumptions may not strictly hold, and in these cases it is useful to examine whether *the extent to which they do not hold* depends on the individual treatments. Thus, some assumptions may not strictly hold, but the reasons may also be unrelated to the independent variables. This is discussed in Section 3.8.6.

Models are further run as sensitivities across a wide range of parameters, which can help strengthen the plausibility of certain mechanisms as causes of wind curtailment and/or efficiency losses. For example, if a large sensitivity of a parameter or parameters representing an institution does not result in large changes in outcomes, the model can effectively rule out this cause. By contrast, a strong sensitivity of outcomes over likely ranges of the parameters provides greater evidence of plausibility. Another strong indicator is when outcomes change under interaction of multiple mechanisms as opposed to each individually.

Figure 3.6: Northwest grid region

3.4 Gansu (Northwest Grid)

3.4.1 Resource Exporter and Late Industrial Developer

Located in northwestern China, Gansu is far from eastern urban centers where most early industrialization took place. Per capita GDP is chronically below that of the more industrialized regions. Early economic development targeted Gansu's rich natural resources, which include a wealth of minerals including coal, as well as hydropower potential along the Yellow River. It is bordered on the west by the now large industrial province Xinjiang and on the east by the more developed Shaanxi province (see Figure 3.6).

Prior to 1990, Gansu predominantly exported electricity. In the 1990s, with targeted efforts from the central government through the "Develop the West" campaign (*xibu dakaifa* | 西部大开发) and rapid growth of energy-intensive industry, the local economy began to pick up, leading to electricity shortages and increased focus on improving efficiency of the sector by sticking closely to annual plans and energy-saving measures. With the Asian Financial Crisis in 1998-9, demand plummeted, and government efforts instead shifted to supporting industry with firm-specific incentives, known as “one firm, one measure” (*yichangyice* | 一厂一策)[6].

When the Gansu grid was unbundled in 2002—power plants split off from the grid company into several generation companies—challenges for the new system, according to government documents, included: over-dependence on hydropower, proliferation of small coal-fired power plants, and lagging grid development leading to bottlenecks in peak hours (CEAEC, 2010). Since then, wind power development has provided another driver of industrial development in the province, gaining national prominence after northern Gansu was designated as the first large-scale wind power base in 2009. While wind energy has still been a smaller portion of the electricity sector than coal in both economic output and employment, certain cities have benefitted greatly. In Jiuquan, the site of the wind power base, the local government has actively courted deployment and local revenues from wind power are large, in contrast to smaller impacts at the provincial level (Dai, 2015).

Following the 2008-9 financial crisis, incentives for industry such as reducing electricity prices have intensified. It is frequently thought that Gansu’s industry cannot survive without subsidies, that a goal of the electricity sector is to “nurture consumers” (*yang yonghu* | 养用户)[16G2, 16G5]. This has motivated a range of methods to adjust electricity tariffs despite the fact that the central National Development and Reform Commission (NDRC) still retains official control over benchmark tariff-setting. To provide flexibility to provinces in economic recovery, the central government permitted localities to pursue bilateral contracts between energy-intensive industry and large electricity generators (SCEO, 2015). Prices determined by these out-of-plan transactions are always lower than the government tariffs, because of oversupply of generation capacity, and in some cases, explicit price caps set at the benchmark tariff (e.g., the wind-hydro exchange, discussed below).

Renewable energy integration challenges are compounded by overcapacity: Gansu’s electricity generating capacity is over twice its peak load of around 20 GW[16G4]. In 2016, Gansu faced the highest renewable curtailment rates in the country: 43% of wind power and 30% of solar power were curtailed (NEA, 2017b). It also failed to meet central goals for utilization of its wind and solar installations by the largest margin of any province: roughly 40% and 30%, respectively (NEA, 2017b). As a result, Gansu was designated a “renewable energy local integration pilot”, which set forward the province’s plans to address persistent curtailment, which include better planning,

[6]For example, discounts of 0.01 - 0.05 yuan / kWh were given to industries for electricity consumption above historical amounts (CEAEC, 2010).

improving renewable energy market mechanisms such as bilateral contracts discussed below, and stimulating local demand through heavy industry and electrification (Gansu DRC, 2016).

3.4.2 System Operation

On an annual basis, the Gansu Industry and Information Commission (IIC) organizes discussions to create a generation and consumption plan for the following year. These plans specify expected energy totals for each dispatchable generator (not including wind and solar), which are priced according to the "plan" benchmark price (*biaogan dianjia* | 标杆电价). The totals are largely based on the previous year, adjusting for any changes such as maintenance or new generation capacity[16G1]. These totals are transferred to the grid company, whose planning office (*jihuachu* | 计划处) allocates to months—possibly with suggested allocations from the government plan—considering other medium-term considerations such as hydropower availability, irrigation requirements and maintenance scheduling[16G1].

The primary goal and evaluated criterion of the grid company with respect to dispatch is how closely the plan is followed at the end of the year. This follows from the *sangong* principles: the goal is to meet all plans to approximately the same degree—and if adjustments are required during the year, they should be done equitably to all generators. There are additional reporting requirements at monthly and quarterly periods known as "generator-grid joint meetings" (*changwang lianxi huiyi* | 厂网联席会议) which will also track how closely the grid company's plan is followed (see, e.g., notes from one of these meetings: Northwest Grid (2015)). The expectation is that monthly plans are kept within roughly 4%, but the grid has discretion to "roll over" (*gundong* | 滚动) unmet or exceeded plans to the next month[16G4]. Monthly plans are the first conversion of energy contracts to power profiles, specifying *when* power generators will turn on (commitment) and produce.

Non-dispatchable generation sources (i.e., their availability and output cannot be prescribed well in advance) must be accommodated in a different fashion, and each region has its own procedure. The approach adopted in Gansu since 2010 and implemented in the grid management and optimization software D-5000[7]: the total annual energy allocated to wind and solar installations is spread evenly over all 8760 hours. If, in a given hour there is less wind than the allocation, the

[7] 16G3. D-5000, maintained by the State Grid subsidiary Nanrui, is a customizable platform in which virtually all systematic changes to dispatch procedures must be implemented.

plant's share is raised evenly for the rest of the year. In this design, all wind farms are treated equivalently based on capacity regardless of location or wind speed at their location. Hence, if there is curtailment, all wind farms are turned down such that their outputs are equivalent. This naturally hurts farms with better resources[16G3]. An additional approach is being tested that would allocate curtailment and generation space based on the ability to output[16G4]. With increasing solar deployment in the Northwest, particularly in areas co-located with wind, coincident generation during curtailment periods is increasing. As solar and wind have essentially the same marginal costs and official dispatch requirements, the grid operator has some discretion over which resource to curtail. Respondents noted that solar is given priority[15B1, 16D4].

The primary economic unit in electricity planning is the province. Import and export totals between provinces in the Northwest Grid are thus planned on the annual timeframe, negotiated between governments on the basis of supply and demand conditions. Because of stagnant demand growth over the last 5+ years, and oversupply of generation capacity throughout the region, this is an extended negotiation process. While Gansu used to have an advantage in being able to export its wind to other provinces, its neighbors have since developed their own renewable energy infrastructure, limiting the appetite and urgency to accommodate Gansu's excess supply[15B1, 16G3]. Similar to other regions, a secondary evaluative criterion for the grid company is verifying that electricity exchanged between provinces matches these plans (*lianluoxian kaohe* | 联络线考核)[16G3].

In contrast to the annual provincial plans in which generators, grid companies and regulators became separate parties, the official procedures for importing/exporting appear to be relatively unchanged since pre- and post-unbundling (2002). For reference, official documentation shows that the provincial exchange verification process began as early as 1995 (CEAEC, 2010).

On a daily basis, cross-provincial flows are determined by these contracts and sets of prescribed profiles, largely driven by demand in the receiving province. There is some flexibility in these profiles —e.g., ±10%—which Gansu has used successfully to integrate more wind. To make adjustments for the next day's or current day's schedule, the provincial grid dispatch operator must phone the regional grid, who will be an intermediary with the neighboring provincial grid company. This type of exchange can occur 10-15 times a day[16G3].

Cross-regional electricity trade is coordinated by the national dispatch center through primarily annual contracts. These are largely driven by demand, as opposed to supply, because of the current nationwide overcapacity situation[16G1]. Negotiation processes for these are significantly more complex—involving local government offices, governors, all relevant local grids, the national grid and some central agencies—and thus considerably less flexible[16G2]. For example, Northwest and Central grids share the *DeBao* (德宝线) high-voltage line that has northern flow during wet summer months and switches southward during the dry season. In 2014, due to greater than predicted rainfall the Sichuan government had to petition the central government to extend the northern transfer an additional three weeks[15C1]. A similar situation on a line to nearby Hubei in Central Grid was unable to be resolved, resulting in some early season curtailment of hydropower[16A13]. These kinds of cross-regional adjustments would be substantially more complicated for non-dispatchable renewable energies like wind and solar, whose variability is over the course of hours and days, and have never happened in China to the author's knowledge in response to wind and solar availability. The institutions governing cross-regional trade are only partially flexible for hydropower whose variability is over months.

3.4.3 Wind Bilateral Contracts

Facing large generator overcapacity and struggling local energy-intensive industry, Gansu has for several years organized exchange markets that allow coal-fired electricity to be sold at below-benchmark rates. Since 2015, renewable energy also began to participate. These are organized primarily on an annual or semi-annual basis. In 2015, they were centralized auctions, with all generators competing on a single platform on price. Organized into a multiple-bid round format, generators were given the opportunity to revise bids based on those of others', and the result was that price collapsed as generators were desperate to get any quantity[16G5, 16G8]. There were also undesirable outcomes in terms of certain plants or power groups (parent companies that own multiple generators) getting more than the average; in these cases, the government could rearrange post-hoc by taking away some amount for an additional exchange and preventing that group from participating[16G8].

This was transitioned to a bilateral format in 2016. Based on a typical announcement published by the Gansu Electricity Exchange Center—a subsidiary of the provincial grid company established to facilitate various non-plan transactions—the procedure consists of (Gansu Electricity Exchange, 2016a):

1. Total amounts of electricity to exchange by fuel type (coal and renewable energy) are determined (by the provincial government in concert with the grid). In some cases, these are determined by a calculation for specific consumers (e.g., company A gets to purchase a certain amount).

2. Generators and consumers agree bilaterally on contract price and quantity.

3. Renewable energy bilateral contracts come with the additional requirement that consumers must commit to purchase four times or more as much extra electricity from traditional coal-fired sources, in order to stimulate demand.

4. Contracts are reported to the exchange center and verified by the grid company for network-related issues.

Wind companies have been mixed in embracing the bilateral contract system. Ideally, it would represent an additional revenue stream for otherwise curtailed generation. Additionally, some wind company managers prefer to negotiate with counterparts 1-on-1 as opposed to more centralized mechanisms, because it leads to relationship building and can reduce price competition with other wind companies[16G7]. Rather than spend time calling up potential counter-parties, both sides may prefer to stay with their original partners[16G7]. This is, in fact, a transaction cost of the bilateral method, which could be associated with inefficiency (Williamson, 1985).

However, for many, there is concern that the exchange does not lead to an equivalent amount of additional generation[16G5]. For example, if a wind farm predicting that it will be curtailed 40%, contracts 40% of its expected generation bilaterally, it may end up still being curtailed. In this case, the grid company will preferentially settle the lower-priced bilateral contracts *first*, thereby reducing the amount of generation the wind farm receives at the full benchmark tariff compared to the counter-factual in which it contracts 0%. The perverse incentive against contracting centers on the lack of a consistent amount of generation guaranteed at the higher benchmark tariff, a responsibility of the provincial IIC[16G4]. Generators were told that in 2016 around 500 hours[8] (or as little as 1/4 of available wind power) was guaranteed, but there is no official document[16G2]. In

[8]Chinese generation statistics are frequently written in terms of “utilization hours” (*liyongxiaoshi* | 利用小时), the equivalent amount of the plant generating at full capacity for that time. Divide by 8760 to convert to the international convention of capacity factors.

a rare public display of local-central tensions, the Gansu government in fact published this number but was rebuked within weeks by the NEA, because the number directly violated the earlier central mandate of minimum full purchase of 1800 hours, causing Gansu to retract (Xiao, 2016). By the end of 2016, wind generators in fact generated only 1088 hours (NEA, 2017b). One member of the industry estimated that 60% of all renewable energy was settled through bilateral exchanges[16G5], which would bear out that the guaranteed "plan" amount was indeed around 500 hours.

The effectiveness of these markets and incentive to participate derive from how precisely exchange amounts are incorporated into dispatch. Given differences in wind speeds and network conditions throughout the province there is no way to ensure that wind farms generate precisely a certain amount greater than others in proportion to their exchanged amounts. The system in place since late 2015 proceeds by subtracting exchange amounts from real-time space and allocating this "plan" amount equally[16G3, 16G5]. This approach codifies the concerns that wind farms have about exchanges taking precedence over a minimum guaranteed amount at the higher benchmark price. A simple example helps illustrate:

1. Wind farms A, B, C of same capacity contract for totals of 1, 2, 3
2. Total integration space for these wind farms at a given day and hour: e.g., 15.
3. Subtracting the total exchanged (6) from total space (15), leaves 9 for the "plan".
4. Plan is divided equally (3) and added to all farms. (Scaled to capacity of farm)
5. Thus, totals for A, B, C are 4, 5, 6.

An important motivation of these exchanges is to ensure that profits are equitably distributed not only among wind farms, but also between different energy sources in terms of a "balanced development" (*junheng fazhan* | 均衡发展)[16G1]. Because wind and solar faced high persistent curtailment rates while hydropower—another renewable energy source—faced relatively little impact, the government set aside a certain amount of planned hydropower curtailment for wind and solar to contract bilaterally, with the price capped at the respective benchmark tariffs (Gansu Electricity Exchange, 2016b). In fact, in an unusual circumstance, this space was undersubscribed: only a third was actually contracted by wind and solar. It was a low hydropower year, and announcing the exchange in July already into the rainy season, the government was seen by generators as trying to extract further wind and solar power at reduced cost, and the grid company was suspected by generators of protecting one of its own hydropower facilities which it had not divested following unbundling[16G8, 16G5].

3.5 Northeast Grid

3.5.1 Early Industrial Base and Failed Market Experiments

The Northeast, consisting of Liaoning, Jilin, Heilongjiang and eastern Inner Mongolia provinces (see Figure 3.7), was a site of very early industrialization in China going back to the 1950s. These were aided by local energy and mineral resources—including coal and oil deposits—as well as close proximity to the former USSR, a source for technology sharing. Despite these resource advantages, the Northeast lost ground during the reform era of the 1980s and 1990s as central and southern coastal provinces attracted more capital, and the Northeast faced higher percentages of unemployment as some large, traditional industries in the state-owned sector were shaken up by privatization. In 2002, a central program called "Revive the Northeast" (*zhenxing dongbei* | 振兴东北) was initiated to reorient the industrial structure and enhance managerial efficiency of state-owned enterprises (Chung et al., 2009).

Due to its plentiful coal deposits, the Northeast's electricity sector was predominantly coal-based throughout this period. Some limited hydropower resources exist, declining from 15% of capacity in the 1990s to below 10% currently (CEC, 2014b). The Northeast was also selected as one of the earliest market reform experiments, as a pilot simulation in 1999 prior to unbundling and later as a larger pilot in 2004-2006 (Zhang and Heller, 2007; Varley, 2006). Conditions were seen to be right, given closer integration of Northeastern provinces in terms of electricity dispatch, planning, management and grid infrastructure (Dai, 2013).

The 2004-6 pilot entailed clearing 20% of total electricity on an exchange at monthly, day-ahead or real-time increments. One of the pilot's near-term goals was also to open up the market to trading the planned quota allocations as generation rights (SERC, 2003a). However, it failed and was discontinued, the proximate cause of which was a rise in coal prices that increased generation costs in northern provinces while retail prices in the larger, southern province of Liaoning remained fixed. The grid company, which collected only the difference between retail and wholesale tariffs,

Figure 3.7: Northeast grid region. Shaded Xilingol prefecture also has plants in Inner Mongolia Grid.

lost 3.2 billion yuan in 16 days (~$400 million in US$2006) (Dai, 2013). The SERC official tasked with pilot design has noted firms selected to participate (which excluded cogeneration facilities and units smaller than 100 MW) were heavily concentrated at a provincial level raising questions of possible market power if the pilot was allowed to continue (Dai, 2013)[9].

Inner Mongolia—including the eastern portions in Northeast Grid—has the best wind resources in the country, and was the site of early expansion of the wind sector following passage of policy supports in 2006 (Davidson et al., 2016b). The entire Northeast grid accounts for roughly a quarter of wind installations nationwide, and has faced the highest early curtailment of wind energy, exceeding 20% in two provinces as early as 2011 (Li et al., 2012; NECG, 2015a). Wind capacity expanded unabated until 2016 when new permitting authority for its provinces was revoked by the central government (NEA, 2017a).

With large population centers and cold winters, the Northeast has the highest percentage of coal-fired combined heat and power (CHP) units in the country (also known as cogeneration), producing district residential heating as well as electricity. Even in the absence of variable wind power, CHP presents difficulties for system operation, due to their must-run minimum electricity outputs determined by heating demands, which could exceed actual demand of electricity in some areas. Without changes to coal-fired power plant operation, these require additional exports in the coldest winter months of January and February, and drive some of the annual transmission planning from Jilin where this is most problematic[16B3].

Combined with wind's variability, the Northeast faces significant balancing issues, which has sparked much attention on broader power sector reform. Jilin's renewable energy integration plan prioritizes optimizing dispatch, exporting more electricity to North Grid, expanding renewable energy market transactions and electrifying the heating sector (Jilin DRC, 2016). The region has experimented with each type of observed market mechanism around the country—bilateral contracts, generation rights trading, grid-grid excess wind exchanges, coal-wind substitution—as well as some novel mechanisms, such as the "peaking ancillary services market" described below.

[9] An analysis conducted on mid-2000s calculated that the Hirschman-Herfindahl Index (HHI) of generating capacity was above 1,800 (typical threshold indicating high market concentration) in three of the four provinces, and in all four provinces for the subset of plants selected to participate in the 2005-2006 pilot (Zhang and Parsons, 2008).

3.5.2 System Operation

In the Northeast, annual generation plans are completed by the provincial Industrial and Information Commissions (IICs) (*gongyehe xinxihua weiyuanhui* | 工业和信息化委员会) or Industrial and Information Offices (*gongyehe xinxihuating* | 工业和信息化厅), local branches affiliated with the Ministry of Industry, Information and Technology (MIIT) (*gongyehe xinxihuabu* | 工业和信息化部). The process consists of estimating load for the coming year, splitting this up to different generators (like "splitting a cake"), and allocating to the month[16B3]. Adjustments can occur at the monthly level, but they are relatively small at the weekly or daily scale[16B3].

In some cases, the official annual plan may not be completed prior to the start of the calendar year: it may be delayed until the provincial government decides on its investment plan for the year at meetings of the People's Congress[16B2]. Prior to this, the government (together with the grid company) may complete an *expected* contract. The grid companies play a major role in completing the plan, given short-staffing and lack of detailed data available to the IIC[16B2].

Dispatch decisions in the winter time—when wind curtailment is most severe—are governed firstly by the needs of CHP units with the principle "using heat to set electricity" (*yiredingdian* | 以热定电). CHP units provide heat to local heating grids (frequently a separate company) based on annual contracts specifying heating load and area. Local heating companies, typically with the option to get heat from CHP plants as well as their own (non-CHP) peaking boilers, prefer to get as much of the low-cost heat from CHP[16B4]. Contracts divide the winter into three periods for calculating the expected heating load from the CHP plant, with the middle, coldest period having higher demands. CHP plants convert heating demands to a "minimum operational mode" (*zuixiao yunxing fangshi* | 最小运行方式) for electricity supply, which is given to the grid company, typically on an annual basis. Lowering these values—which are currently self-submitted by the plants—is the subject of ongoing engineering work as well as official calls in electricity reform documents for greater verification of these numbers (NDRC and NEA, 2015a). The aggregate minimum modes determine the available space left to meet demand from other generation sources, and there are periods when there is no space left for wind integration. Due to the impact on wind curtailment, some provincial governments recently began organizing a CHP report that looks at heating demand and minimum modes closely[16D4]. The regulator can check the minimum modes as well using last year's total receipts and the return temperature of the water—if it is too high, this is one indication that the plant is not at its minimum mode[16B2].

Cross-provincial transmission is included in the annual planning process, and as with the expected contracts, the opinions of the grid companies are most important[16B2]. For example, preparations need to be made for the Chinese New Year in late January/early February, during which electricity demand falls off and managing minimum modes of CHP plants is most problematic[16B3]. By contrast, cross-regional transmission to North Grid (which includes Beijing and surrounding provinces) is determined mostly by the national dispatch center and North Grid: the daily export profile is fixed based on the load, and total amounts on an annual basis are decided by North Grid[16B2]. One particular mechanism for allocating this export space to wind—"excess wind exchanges"—is described below in more detail.

From an overall perspective of Northeast Grid management, intra-regional trading has been falling (see Figure 3.8), which would seem to indicate that the inter-provincial ties are being more restricted. This is happening at the same time as exports to North China are increasing, hence the focus of negotiations are shifting more toward the center. However, this measure is imperfect, because it does not distinguish between the time period of the exchanges (i.e., determined annually or shorter) and if specific generation types are targeted (i.e., excess wind exchanges).

In fact, internally, the Northeast Grid has been increasingly centralizing operation to address renewable energy integration. Solving this problem appears to be the most important function of the local NEA branch currently. As one example, it has implemented the only regionally-cleared market mechanism designed to address wind integration in the country: a so-called "peaking ancillary services market" (*tiaofeng fuzhu fuwu shichang* | 调峰辅助服务市场), begun in pilot form in 2014 and now in full operation (Zhang and Song, 2016). Under this mechanism, coal plants across the entire region can bid the amount and required compensation for reducing *below* their administratively-set minimum output during curtailment conditions, which is paid for from all renewable energy generators and by conventional plants in proportion to output above their minimum outputs (where the minimum output of renewable energy is considered 0) (NEA, 2014b).

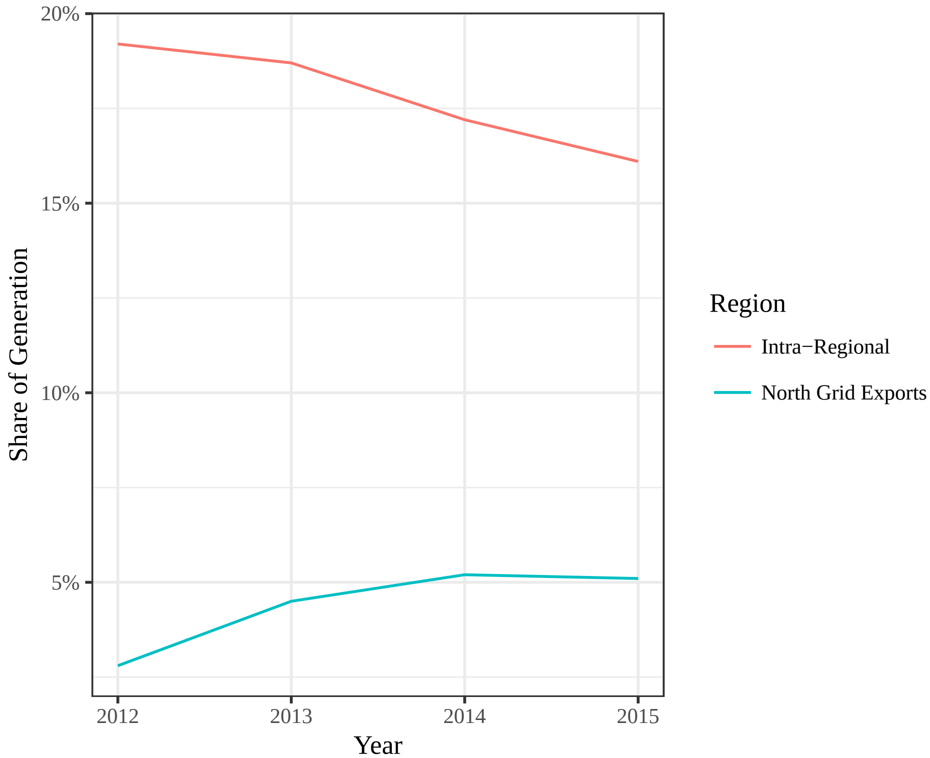


Figure 3.8: North Grid and intra-regional exports in Northeast Grid, 2012-2015. Source: author's calculations based on State Grid exchange reports.

3.5.3 Excess Wind Exchanges

Recognizing that it cannot integrate all of its wind electricity, beginning in 2013 the Northeast Grid has collaborated with North Grid to send its "excess wind" (*fuyu fengdian* | 富余风电) through structured exchanges to the Beijing/Tianjin/Hebei area. This followed on the adoption of a similar mechanism from Western Inner Mongolia to North Grid in 2011, primarily targeting high curtailment hours for increased transmission interconnection, and one of the cases examined in that region below (IM SASAC, 2011). The amount of the Northeast exchanges is the largest portion of total exports (i.e., much larger than traditionally planned amounts) (see Figure 3.9).

At the beginning of the exchange period, typically conducted semi-annually, the Northeast exchange center will publish a notice with a specified quantity to be traded, determined at the monthly level by North Grid (e.g., 400 mn kWh) (Northeast Electricity Exchange, 2016). This is conducted concurrently with an exchange for coal power, which is usually 2-3 times larger (e.g., Northeast ERO, 2015). Approved wind farms can bid an amount of generation and capacity, while prices are fixed according to central government guidelines for the standard inter-regional tariff plus the unadjusted central government subsidy for wind. This results in a roughly 0.07 yuan/kWh (~8%) reduction in revenue for wind farms in Heilongjiang, Jilin and Liaoning, and essentially no reduction for E. Inner Mongolia farms[10] . The Northeast Grid is the purchasing entity, and grid companies are responsible for allocating to provinces within the region—the respective governments do not specify[16B2]. The network is not considered in the bidding process—with the exception of a few locations with particular issues such as in the low-voltage network[16B2].

Faced with high curtailment, wind farms have piled on in large numbers to these types of exchanges. When it is over-subscribed, regulations dictate that amounts should be split according to the bid capacity, and not according to location (Northeast SERC, 2013). Nevertheless, we know that curtailment and actual generation vary widely across the region, according to resource differences and local grid conditions. This points to the primary reason why wind farms may

[10]The central government subsidy is defined as the difference between the feed-in-tariff (0.49-0.61 yuan/kWh, depending on the location, lowering to 0.40-0.57 yuan/kWh in 2018) and the provincial benchmark thermal generation tariff (0.38 yuan/kWh in northeastern provinces since April 2015, except for E. Inner Mongolia where it has been 0.31 yuan/kWh). The standard inter-regional tariff from Northeast to North is 0.31 yuan / kWh, last changed in April 2015 . Sources: (NDRC, 2014, 2015c, 2016a). Nationally, coal electricity benchmark tariffs are expected to rise in 2018 for the first time since 2011, which would tend to further reduce wind farm revenues unless paired with an equal rise in inter-regional tariffs (Li, 2017).

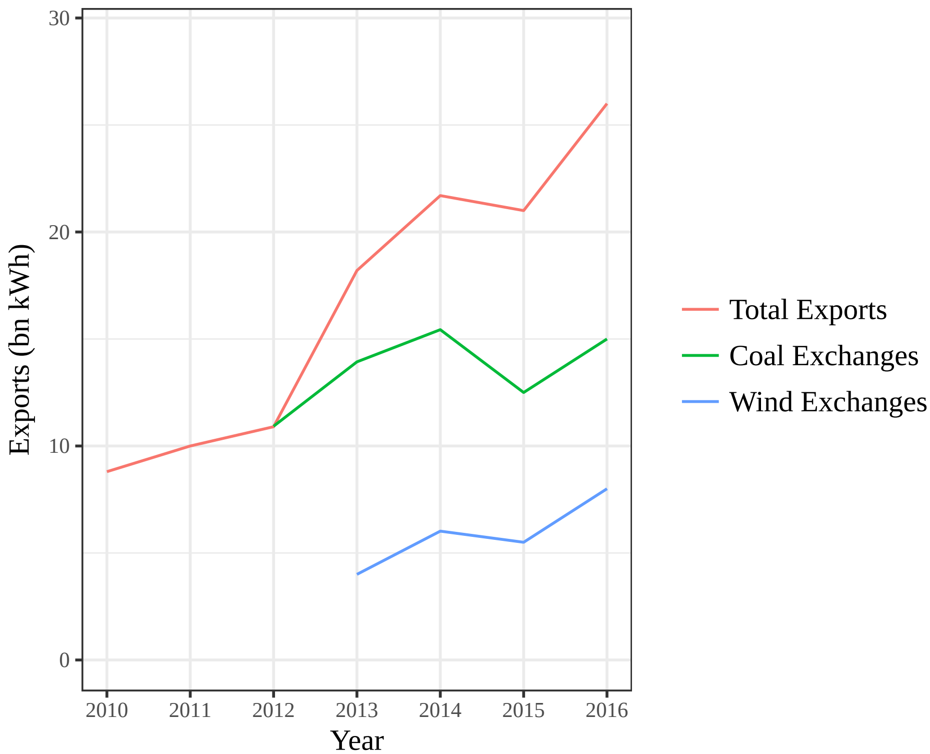


Figure 3.9: Northeast exports and listed exchanges to North Grid, 2010-2016. Sources: State Grid exchange reports, excess wind and coal exchange announcements.

not want to enthusiastically participate: they perceive an unclear link between participation in the exchange and more dispatched electricity. It is, in fact, not trivial for grid companies to separate dispatch from participating and non-participating farms based on exchanged amounts. With nearly 360 wind farms participating[11], spread across four different dispatch zones and local network conditions to also consider, it is very unlikely that this method could be used to distribute additionally precisely the exchange amounts.

Decisions that affect how much wind and where it is integrated basically amount to (a) what is the total space available after other minimum modes of conventional plants are considered—the focus of the "peaking ancillary services market" (discussed below) and ongoing engineering work—and (b) how to determine how much individual farms are curtailed when there are grid restrictions. The second procedure is relatively opaque, but in addition to considering the network, possibly considers some kind of ranking such that a certain group of farms are curtailed first at the same rate (according to *sangong*) before going on to the next group of farms[16B3].

Based on the results of auctions in 2015 and 2016, nearly all farms participate (though the bid totals vary considerably), and Heilongjiang and eastern Inner Mongolia are frequently over-subscribed, indicating the greatest curtailment pressure and desire to find new external markets for electricity. Transactions from over-subscribed firms were capped at roughly 8% of capacity during the peak winter months. Over the peak winter heating period of January-March 2015, 2.2 bn kWh was sold to North Grid at reduced price through this program, 31% of all wind electricity generation (NECG, 2015a). In 2016, 6 bn kWh was sold. Over the first half of 2016, I estimate that the reduction in total revenues for wind farms was 179 million yuan ($27 million), compared to if all the electricity was sold at the centrally-mandated feed-in-tariff[12].

While Northeast wind farms may have accepted the prospect of a third of their generation being sold at below-FIT levels, some in the central government have opposed this. New regulations spear-headed by the NEA in 2016 mandating "full purchase" (*quan'e shougou* | 全额收购) conflict directly with efforts to sell "excess" wind below the central tariff. These regulations prescribe minimum utilization hours of 1800-2000 in the Northeast (20% $\sim$ 23% capacity factor), only above which can

[11] According to the results from the 2016H2 exchange.

[12] 2.55 bn kWh transacted through the exchanges in Heilongjiang, Jilin and Liaoning, with a reduction in per unit revenue to wind farms of 0.07 kWh, the difference between the Northeast-North inter-regional transmission tariff and the benchmark tariff in the provinces. E. Inner Mongolia revenue reductions should be lower, because the inter-regional tariff is comparable to the benchmark tariff.

renewable energy be sold through market exchanges (NDRC and NEA, 2016). Respondents in the Northeast did voice concerns about this central policy, noting that previous years' integration was based to some extent on these exchanges, and that it would hurt overall integration prospects by stopping exchanges[16D4].

3.5.4 Peaking Ancillary Services Market

Beginning in 2014, the Northeast Grid piloted an innovative scheme to create more integration space for renewable energy: a market-based compensation scheme for coal power plants to go below administratively-set minimum outputs when there is renewable energy curtailment. While there existed forms of administrative compensation for plants that participated in "peaking ancillary services" (*tiaofeng fuzhu fuwu* | 调峰辅助服务) (which has also been translated as "load following ancillary services"), these were widely seen as unpopular and did not result in as much participation as desired[16B2, 16B3, 16E1]. The market-based version has resulted in 1 - 1.5 GW of additional space for wind energy in the Northeast[16B2], moved beyond a pilot designation, and is now being proposed and adopted in several additional locations, including Xinjiang, Gansu and Shanxi[13].

Under the scheme, coal plants are assigned a minimum output according to the season and whether they are cogeneration. Plants may bid into a day-ahead market their required price for *reducing output* below that level when the grid calls on them. The most recent guidelines specify two levels of minimum outputs, from roughly 50% down to 40% of generator capacity, and another below 40% of capacity. These ranges have different price floors and ceilings (see Table 3.7). Payments to these generators are then made by all the other generators operating *above* their minimum output. According to these regulations, wind's minimum output is zero (i.e., all generation will require some payments into this scheme), and nuclear's minimum output is 77% (i.e., any generation above 77% will require payments) (see Figure 3.10). There are similarly tiers in burden-sharing, so that generators at higher output pay a larger proportional share (Northeast ERO, 2016). Finally, the regulations also include upper limits on the amount of money that plants will need to transfer, which are differentiated by resource type: coal and nuclear are capped at 25%, and wind is capped at 80% of the provincial coal benchmark tariff. Payments are settled monthly[16E1]. The program is

[13]Some regions also refer to it as an "electricity ancillary services market" (电力辅助服务市场) and combine with other more traditional forms of ancillary services such as reserves.

	Non-Heating Season Outputs		Heating Season Outputs	
	Tier 1	Tier 2	Tier 1	Tier 2
Electricity-only plant	$40\% \sim 50\%$	$\leq 40\%$	$40\% \sim 48\%$	$\leq 40\%$
CHP	$40\% \sim 48\%$	$\leq 40\%$	$40\% \sim 50\%$	$\leq 40\%$
Price floor	≥ 0	≥ 0.4	≥ 0	≥ 0.4
Price ceiling	≤ 0.4	≤ 1	≤ 0.4	≤ 1

Table 3.7: Northeast peaking ancillary services market bidding output tiers and limits for coal plants. Source: (Northeast ERO, 2016).

seen locally to be widely successful because it is frequently oversubscribed (i.e., cleared bids are at the price caps)[16B2], though researchers and professionals outside the region are frequently unaware or have a skeptical view because of its unusual market structure.

This augments and modifies the administratively-compensated ancillary services scheme that includes a number of rewards and penalties for power plant performance: reactive power support, forced outages, wind forecast errors, frequency support, and peaking support, among others[14]. Under the administrative system, the total rewards or penalties for plant performance are shared among all the generators in a line-by-line fashion, proportional to *total generation* (NECG, 2014). For example, a coal plant will get a bonus for providing extra peaking, but proportional to its own generation it also has to pay into the pot of money; thus, the net receipts of the plant may be substantially less. Wind also pays into this system, but at a lower rate than coal plants. The new peaking market changes the distribution of payments, such that a large portion of coal plant generation does not need to cover the shared costs, shifting the weight more to renewable energy. The previous administrative payments for peaking are removed, though leaving intact all the other administrative measures.

Comparing the cost of this system for wind farms is possible for plants directly dispatched by the Northeast region, which are primarily located in E. Inner Mongolia and Liaoning, for which more complete and explicit data are available. According to their summary reports on the first quarters of 2014 and 2015[15], wind's share of the payments for peaking support rose from 8% to 28%. If the clearing price was at the cap of 0.4 yuan/kWh, then this translates into an effective reduction

[14]The earliest versions of ancillary services separated ancillary services into "basic" and "compensated" components and did not provide compensation for peaking (Kahrl and Wang, 2014; SERC, 2006). Currently, grids compensate (or levy fees) for all of these performance aspects (NECG, 2014).

[15]Calculated using payments from major coal plants and wind totals (NECG, 2014, 2015a).

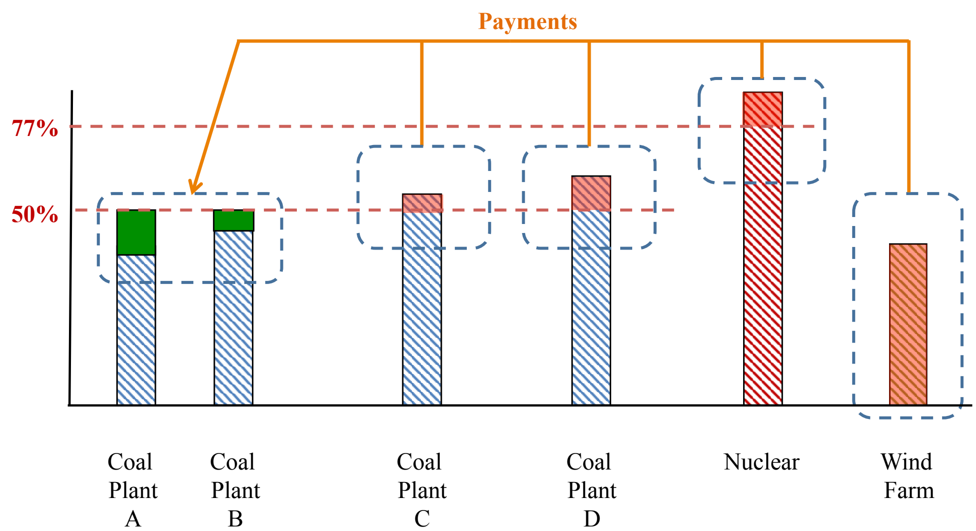


Figure 3.10: Northeast peaking ancillary services market system of payment transfers. Coal plants A and B are generating below their minimum output, and thus will receive payments from coal plants C and D, the nuclear plant and the wind farm. These payments will scale with the amount these generators' outputs exceed their minimum outputs which varies by type. The precise coal plant thresholds (here, 50%) vary by season, see Table 3.7. Source: (NEA, 2014b; Northeast ERO, 2016).

in the wind tariff of 0.113 yuan/kWh, or roughly 20%. On the other side of the transaction, one coal plant, the 3600-MW *Suizhong* plant (绥中电厂), went from receiving 0.49 to 19.6 million yuan. Assuming revenues from generation at the benchmark tariff and including other ancillary services payments, the share of total revenues deriving from peaking support for this plant rose from 0.05% to 2.5%.

As there is no comparable scheme outside China, it is useful to take a step back to compare how this relates to a more traditional spot market. A traditional spot market for energy collects offers for supply and demand, which under competitive conditions would equal the marginal cost of production and value of consuming electricity, respectively. The clearing price for each location in the network is set by the marginal generator, i.e., the highest bid offer of the dispatched generators, which is determined considering all the constraints of the system, including transmission network congestion (Schweppe et al., 1988). Hence, the market reflects the physics of the underlying commodity: electricity. In the Northeast peaking market, only "supply" offers to reduce minimum output exist ("demand" participation—i.e., paying for extra peaking space—is mandatory and based on output above their respective minimum outputs). Further, the offers to supply peaking power can be equated to two distinct economic concepts: the increase in marginal cost associated with lower efficiencies during deep peaking, and the opportunity cost of foregone generation. The former could be equated to an increase in the bid of the plant in a traditional spot market, and result, on the higher end, in a 10-20% increase in the cost of production (Zhong et al., 2015).

The opportunity cost, on the other hand, does not have a parallel in a spot market, and depends on the relationship of the peaking market to the parallel generation planning processes. If plants were guaranteed that the generation they lost while reducing output would be returned during normal hours and/or in other months of the year, the opportunity cost should be zero. If, on the other hand, plants feared that they would simply lose that portion of their planned generation, then the opportunity cost should be equal to their marginal profit while generating. People knowledgeable of the program claim that it is simply an additional revenue stream and there was no instance of reduced planned generation as of 2016 as a result[16E1, 16D4]. To facilitate trading generation rights over longer periods, later versions of the rules required provisions for monthly planned decommitments during off-peak hours when wind integration space is needed (Northeast ERO, 2016).

Despite the obvious differences with traditional electricity markets, proponents told me that the peaking market's success demonstrates its usefulness, and that markets are designed to solve a problem, which may not precisely be the same as increasing efficiency[16B2]. The first problem to solve in this case is there is no price incentive for coal plants to respond to renewable energy availability and reduce output. Previous administrative measures were not effective at this. Second, making coal plants more flexible may require various types of investment, which were not adequately compensated before. The scheme encourages cogeneration units to install heat storage facilities or electric boilers which would allow them to create more integration space for renewable energy when needed, and for traditional coal plants to engage in flexibility retrofits[16B2, 16D4]. Others noted that the market, by replacing the old administrative system where every plant had its own minimum output, was putting everyone on equal footing through "hard-and-fast rules" (*yidaoqie* | 一刀切)[16E1]. Reducing the ability for political favoritism to influence technical parameters will enhance efficiency, but this approach of setting one reference level for a large variety of generators does not adequately consider technological differences across plants. The setting of this reference level furthermore has a large impact on the total cost of the scheme to renewable energy.

Market Design and Functioning in a Legacy System

Equity concerns and the relationship to previous (administrative) systems play a large role in the market design and ongoing adjustment process[16B2, 16E1]. Among the many details of the market, the setting of the standard minimum outputs in Table 3.7 is the most contentious and most influential in terms of redistribution. Additionally, a basic consideration from the beginning was that the size of the market would not exceed too much the amount given through previous administrative measures[16B2]. Modeling studies were conducted to assess the impact of the proposed designs on each plant and on the total amount of payments. Initial studies looked at coal minimum outputs in the 50-55% range, before the value was set at 52% with three tiers (as opposed to the current two) in the first period in 2014. Some of these indicated that payments may double if the minimum was changed by just one percentage point[16B2]. Over the subsequent years, there were proposed adjustments, ranging from 48%-54% depending on the generator, before settling on the current values laid out in Table 3.7.

The second critical component to the functioning of this market is the bid cap, set at 0.4 and 1 yuan for the first and second tiers, respectively. Price caps are used in most international electricity markets, out of concerns of price spikes, and it is well-known that they adversely affect market operation: most notably, in terms of reducing the amount of compensation for certain generators that operate only part of the time, a phenomenon known as the “missing money problem”[16]. The Northeast peaking market price caps do not lead to the same phenomenon, because of the different nature of what is being bid on, but nevertheless affect market functioning.

Specifically, early rounds of the market resulted in average clearing prices nearly at the first cap, indicating that most all plants were bidding at the maximum of 0.4[16B2]. With on-grid tariffs of around 0.4, this is more consistent with the view that plants were bidding their opportunity costs in addition to any cost increases due to inefficiencies. If, as several respondents claimed, plans were still being entirely fulfilled, this could indicate that firms did not believe the government and grid company would follow through on that promise, or that there were, in fact, very few plants technically capable of reaching below 52% output. The latter seems unlikely given that the standard off-season minimum output has been lowered over the two years since to 48%.

Additivity of Relative “Benchmark” Approaches to Markets

The peaking market, remarkably, integrates relatively seamlessly with the existing dispatch and pricing institutions in the Northeast. Particularly if planning quotas are entirely met by the grid company by transferring to different times of the month or year, the entire process can be conducted within the dispatch center, and settled on a monthly basis along with the planned tariffs and any exchange amounts. Importantly, the regional dispatch center does not alter any centrally-determined tariffs; it simply *adds* components, already an accepted practice under the previous administrative system.

It achieves this by adopting a relative “benchmark” approach to markets, which assigns value to an activity only in a relative sense with respect to some thresholds determined out of the market. In this case, the 48-50% thresholds are administratively-determined benchmarks, which are equated with having zero value (neither receiving nor paying money). Furthermore, this level is explicitly determined with the eventual size of the market and distributional benefits in mind. It allows for

[16]For an explanation of how the “missing money” in short-run markets affects long-term investments, see Hogan (2013).

layering multiple institutions together without explicitly contradicting (particularly, higher-level) directives. This market, in fact, does alter the price received by different generators, though it does not replace the centrality of the NDRC pricing authority. China's carbon cap-and-trade pilots do something similar with the use of benchmark permits in the electricity sector (Goulder and Morgenstern, 2018).

By contrast, an electricity spot market would completely replace the central price-setting scheme and lay bare inefficient pricing and trading mechanisms of the older system, as was simulated in 2005-6 in the Northeast (Dai, 2013). Similarly, the limited electricity market pilots operated on short time-scales (e.g., daily hydropower exchanges between Yunnan and Guangdong, discussed in Section 3.7) manage very small amounts of electricity, deemed "excess" or "supplementary", in a way that does not assert pricing authority in a larger sense.

3.6 Western Inner Mongolia Grid

3.6.1 Guaranteeing the Capitol's Electricity

Inner Mongolia has plentiful coal deposits, which were tapped to help build out the provincial government's grid company. Following the acceleration of local investment in the 1990s, there emerged a natural regionalization of the Inner Mongolia Grid Company and the centrally-owned State Power Corporation (SPC), with the former controlling dispatch and investing in generation in the western portions of the province, and the latter in the eastern. While a handful of other provinces had large generation companies, Inner Mongolia's provincial holdings were particularly large, outnumbering SPC's in the province and growing at a faster rate over the 1990s (CEAEC, 2013). From 1991 to 2003, the share of electricity in the province delivered in IM Grid's areas had grown from 69% to 85%, and SPC had built only one 1200-MW plant in IM Grid's territory, the rest confined in the smaller eastern region (CEAEC, 2013).

Due to IM Grid's success in developing its electricity infrastructure, the central government relied on the region to maintain electricity supply to the Beijing region, which was facing shortages along with other parts of the country in the 1980s and early 1990s. A 1993 State Council decision expanded export lines, going into operation in 1996 (CEAEC, 2013). Similar central energy planning assigned the eastern region under the SPC to supply the old industrial bases of the Northeast.

Inner Mongolia went from having the lowest generating capacity among its neighbors in 1996, to the highest by 2006, and the highest in the country by 2014, by which point it was the country's largest electricity exporting province for nearly 10 years (CEC, 2014b; CPNN.com.cn, 2017).

Wind resources are plentiful in the province, with the highest average onshore wind speeds in the country (Davidson et al., 2016b). Inner Mongolia built its first major wind farm in 1989 at Zhurihe (朱日和), and began assigning on-grid wind tariffs in 1996, before much of the rest of the country. The province has the largest wind capacity by far of any province, 26 GW at the end of 2016 (NEA, 2017b).

Perhaps no other province had as large a swing from energy shortage to surplus as Inner Mongolia, which was reflected in its approach to pricing and planning in the sector. In the early 1990s, when shortages were common, dispatch was assigned according to the size of the generator, with large generators mostly operating at their maximum, and smaller and medium generators varying over the day to meet load—based on these records, during this shortage period, there appeared to be less emphasis on *sangong* equity principles between coal generator types. There was tight control over consumption, with factories assigned quotas, scheduled days for shutting off electricity, and penalties for over-consumption. Prices during this period were set by the government to reflect firms' existing production needs, not necessarily expansion (CEAEC, 2013). Thus, to ration consumption, prices may have been kept higher than efficient.

As conditions changed to surplus in the mid-1990s, the government expanded its set of inputs in price-setting to include cost changes of production and the new needs of production expansion such as interest repayment on loans, which would become the benchmark tariff approach still existing today (CEAEC, 2013; Ma and He, 2008). By the late 1990s, nationwide policies subsidized certain heavy industry such as aluminum, a differential which still exists in Inner Mongolia's tariffs.

Following the unprecedented growth in industrial electricity demand nationwide in 2003-4, the country returned to scarcity conditions struggling to keep up. Inner Mongolia was poised to rapidly scale up in response, more than tripling its generating capacity from 2003-2006, and attracting heavy industry to the province with the promise of low tariffs[15D8]. This position of high and over-capacity has continued to this day.

Due to the substantial size of its provincial-owned utility, Inner Mongolia's two primary service territories were kept separate during the 2002 unbundling reforms, with the Eastern region becoming part of the new State Grid Corporation of China's Northeast Grid, and the Western region forming its own provincial grid company with the same name as the former utility. Wind resources are strong across the province, in particular around the borders of the western and eastern areas in Xilingol (锡林郭勒) (Davidson et al., 2016b). Yet, Western Inner Mongolia (hereafter W. IM) and Eastern Inner Mongolia (E. IM) had very different wind capacity factor trends over the period 2012-2016, with W. IM substantially better prior to 2015, after which the two regions became comparable (see Figure 3.11). Using curtailment rates directly as a dependent variable is not possible, because the two regions were not broken out in statistics for recent years. Large inter-annual changes attributed to wind resource quality (which peaked in 2013 over the period) and broad macro-economic drivers such as slowing demand growth nationally are shared across the two regions. The remaining gaps must therefore be explained primarily by grid conditions, such as generator and grid technical flexibility, grid management, local demand, and exports. The two adjacent cases form an interesting comparison in isolating to what extent each of these affects wind integration outcomes.

The adjacent case comparison begins with qualitative evidence in support of or ruling out certain causes, and continues with a quantitative analysis in subsequent chapters. It is structured primarily around two types of curtailment causes:

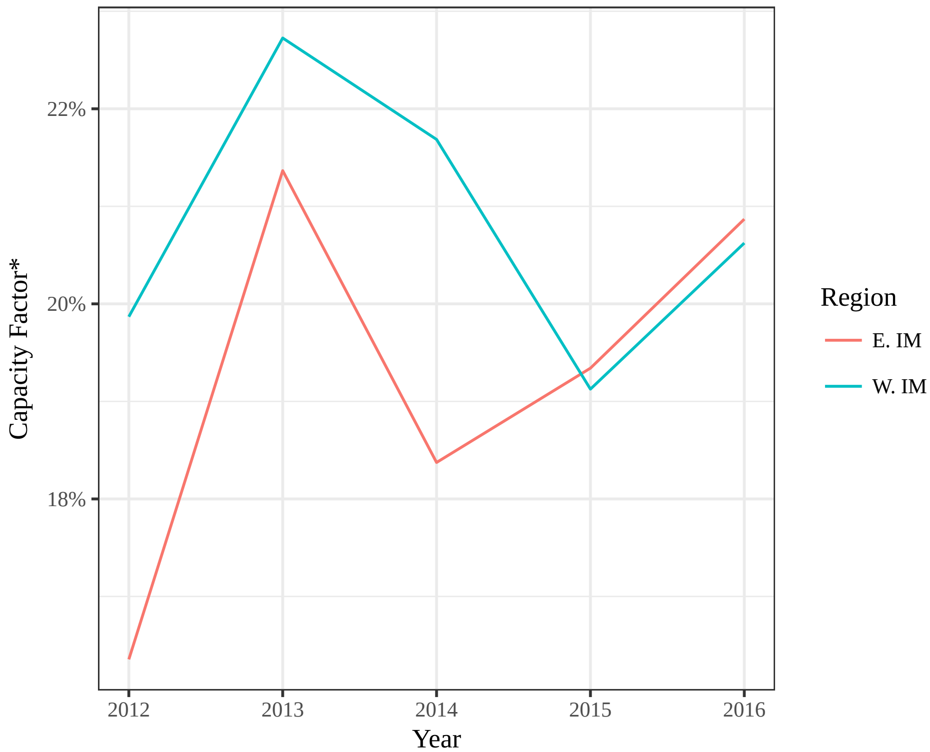
1. Curtailment is technical—the outcome of an efficiently-run system—hence, changes to technical parameters will affect integration.

2. Curtailment is institutional—hence, institutions changing over time explain integration.

I will advance an argument that the observations of provincially-managed W. IM Grid's latent flexibility, more consistent management of exchanges, and more export capacity coupled with more effective export negotiations led to better integration. These conditions were more equalized across the two regions from around 2015, leading to more comparable outcomes.

3.6.2 System Operation

Similar to other provinces, Inner Mongolia's electricity sector is primarily overseen by two different government agencies: the Development and Reform Commissions (at both provincial and city / local levels), which primarily handle permitting requests for new construction; and the Economic and



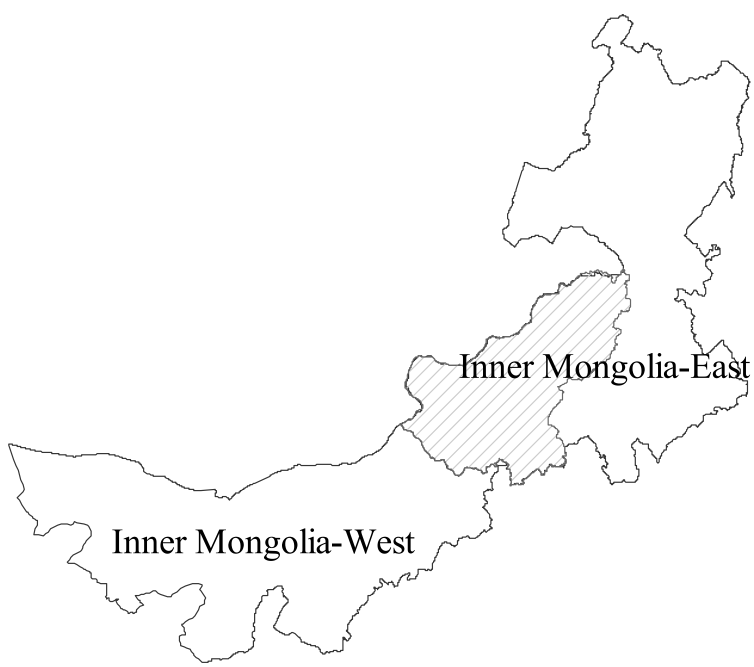


Figure 3.11: Wind capacity factors* for Western and Eastern Inner Mongolia, 2012-2016 (*top*). Map of regions of Inner Mongolia (*bottom*). Shaded Xilingol prefecture has plants in both E. and W. IM. Source: author's calculations based on NEA, W. IM Grid and State Grid exchange reports. *Because these are derived using year-end values for capacity, capacity factors would tend to be underestimates compared to an availability-based measure.

Information Commissions (EIC), which conduct activities related to after permitting[15D3]. The IM EIC organizes the annual planning process, approves market announcements, and adjusts parameters related to annual and sub-annual exchanges (see next section). The grid company's exchange center organizes the exchanges, which then converts plans and exchanges to monthly quantities. The grid dispatch, distinct from State Grid subsidiaries in the above cases, explicitly must meet only the annual quotas not monthly totals (monthly exchanges must still be met or carried over). In July or August, the grid company will do some verification and adjust as necessary the remaining year's plans to meet totals[15D1].

The grid company organizes "information disclosure" (*xinxi pilu* | 信息披露) meetings monthly and seasonally directly with generators to discuss achievement of these contracts—the equivalent of the "generator-grid joint meetings" (*changwang lianxi huiyi* | 厂网联席会议) in State Grid. Plant managers will learn about their plant's performance relative to others in their area, which is disaggregated to at least five different regions for the case of wind power[15D6].

Distinct from State Grid provincial companies, Inner Mongolia Grid does not organize a complete monthly plan (*yuedu jihua* | 月度计划): except for CHP, which generally plans for the entire winter heating season, commitment plans are made on roughly a weekly basis. Five to seven days were cited as the minimum up time for coal plants[15D1], compared to 7-10 days or longer for State Grid regions. On the 5-7 day scheduling period, the planning office (*jihua chu* | 计划处) allocates dispatchable generators (predominantly, coal) to meet peak demand, assuming the lowest wind availability. In practice, even up to day-ahead, wind may be assumed to be zero for the purposes of determining commitments[15D1]. In the day-ahead scheduling phase, peak and lowest demand for at least the next two days is considered. The largest exports (up to 4 GW) are to the North Grid, which are negotiated for the most part annually and separated into "normal" (7am-10am) and "valley" hours (10pm-7am), within which profiles are typically flat (discussed further, below).

Of course, improving forecasts of the "minimum wind", particularly at the day-ahead stage, could increase the amount of space reliably allocated to wind power. As of late 2015, wind power forecasts produced at each individual farm were mandatory but seldom used by the grid company because of large errors[15D1]. Instead, wind farms get a common set of meteorological data from the China Meteorological Administration (CMA), which is then sent directly to the grid dispatch center. One farm paid over 100,000 yuan for the data to be sent, while noting that central regulations explicitly forbid charging wind farms for these data[15D6].

In real-time, similar to State Grid, coal output is reduced to accommodate renewable energy (wind and solar), until hitting the minimum generation level of the plants. When curtailment occurs it is spread equally to farms in the area. Current flexibility of coal plants is seen as insufficient, and besides various exchanges to encourage trading of generation quotas, the grid company has asked the government for more regulations requiring plants to performing peaking functions[15D1].

Due to its heavy industry build-out, Inner Mongolia also has a relatively large number of "self-generation" plants (*zibei dianchang* | 自备电厂), which are power plants built and operated by an industrial facility with its own internal load. The plants typically have very high annual capacity factors relative to pure generators, also exporting to the grid to serve more than their own demand—e.g., in the 6000+ hours range (70%+) compared to 5000 hours (55%) for pure generators in 2015[15D1]. However, self-generation plants operate under different rules, in particular, not subject to the same rules regarding reducing to minimum outputs when the grid requires. This is a well-recognized issue, even before wind integration difficulties arose, though it has raised in prominence because of the issue of high coal generator minimum outputs when wind is plentiful (IM Government, 2016).

3.6.3 Bilateral to Multilateral Exchanges

The Inner Mongolia Grid Company was among the earliest grids to organize direct generator-consumer contracts for out-of-plan electricity, beginning a "multi-lateral exchange market" (*duobian jiaoyi shichang* | 多边交易市场) in 2010. It is discussed as a model for other provinces, having been lauded by the State Council in 2017 as one of 22 "model local experiences" (Xinhua, 2017). Under the system, the provincial government determines an amount of electricity to be allowed to be exchanged (initially set at 20%, it has risen over time, reaching 75% in 2016), minimum thresholds for participation (most recently lowered to consumers $\geq$ 10 GWh annual consumption), and allowable bid ranges defined with respect to market participants' benchmark prices ($\pm 20\% - 25\%$) (North China ERO, 2016a,b; SERC, 2010). Within these boundaries, the grid company organizes a variety of different exchanges with periods from annual down to monthly, described in more detail below. Intra-regional exchanges (within Western Inner Mongolia) and inter-regional exchanges (to North Grid) are conducted at the same time, though market operation differs with respect to quantity and price formation.

Exchange transactions have been primarily used as a means of selling out-of-plan electricity at reduced prices to a selected subset of industry. In welcoming the new exchanges, the provincial government of Inner Mongolia noted "promoting industry restructuring" ("促进产业结构调整") as a key motivation, which was to focus on large consumers with high levels of technology and environmental standards (IM Government, 2009). Initially setting high consumer participation thresholds of 200 GWh annual consumption and grid connections at $\geq$ 35kV ensured that only large, energy-intensive firms could participate (North China SERC, 2010). In fact, this preferential treatment extends to individual industries: the allowable price bands in the exchanges for aluminum and steel (which determine the price floor) are lower compared to other industries, allowing those industries to get greater savings (IM EIC, 2016). The preferential price floor-setting is in line with the government's benchmark electricity tariffs for planned electricity amounts: the most recent tariffs for a subset of heavy industry including aluminum was 0.4118 yuan/kWh, 10% less than general heavy industry, and 35% less than normal commercial and industrial customers (IM DRC, 2016).

The Inner Mongolia experience showcases another successful implementation of a relative "benchmark" market, though in a different manner than the Northeast peaking market. Most of the exchanges take bids of "price difference" with respect to the benchmark tariff, instead of an absolute price (North China ERO, 2016b). The difference-based approach allows lower government tariffs to specific industries to be passed through the exchange. For example, firms from two different sectors—e.g., aluminum and cement—have different government tariffs but can still compete on a shared market of "price differences". This ensures that local government price-setting authority is not completely contested. Recall the use of coal benchmark tariffs in setting the Northeast to North excess wind exchange price, which operates on a similar principle, though the exchanges were still operated completely separately, with coal-renewable ratios fixed in advance.

The government-controlled price bands have also been noted as a key reason for the market's success, as it limits the exposure of the grid company, an issue that other regions including the Northeast had faced during the early pilots of the 2000s (Dai, 2013). According to SERC guidelines, the contracted amounts are subtracted from generators' electricity quotas, rather than being additional generation, and should be dispatched first (SERC, 2009). This has led some generators (in particular, independent power producers) to claim they were pressured to enter into contracts by local governments (Zhang, 2015). Price bands limiting the reduction—particularly in an over-capacity situation—may have also helped eased these complaints. On the consumer side, the price bands are made with reference to the participant's *benchmark tariff* as described above, not an absolute floor, thereby allowing industries with preferential tariffs to maintain that advantage.

Inner Mongolia Grid's electricity exchanges have grown to encompass most products offered elsewhere in China, generating a complex system of sequential exchanges. On time periods of a year, a season, and a month, there is a wide range of opportunities to engage in out-of-plan contracts. The number and type have evidently been successful in raising the share of transactions, to roughly 70% over the months January-August 2017 for electricity sold inside the grid's service territory (excluding North Grid exports) (Inner Mongolia Electricity News, 2017c). The different market designs require different types of government interventions in structuring the market, and result in a wide range of price differences, with average price *differences* cleared through the market in August 2017 of 0.056 - 0.227 yuan/kWh, or 18% - 75% *reductions* relative to the benchmark tariff. I will describe the three main types of markets, including variations seen elsewhere in China, and show that the provincial government uses these primarily to advantage consumers as opposed to suppliers.

1. **Bilateral negotiations (*shuangfang xieshang* | 双方协商)**

The vast majority, over 90% for exchanges conducted in January-August 2017 or else planned for those months at the beginning of the year, come from bilaterally-negotiated contracts between consumers and generators. These contracts are finalized between the parties and reported to the exchange at specified intervals in advance of any other centralized markets, described next (North China ERO, 2016b). There is more flexibility in terms of the price-setting, provided that it stays within the allowable price bands of both sides of the transaction. It also results in a smaller price reduction compared to the centralized methods, as explained in the Northwest case that buying bilaterally helps develop long-term relationships and results in less fierce price competition[16D7].

2. **Listed auction (*guapai* | 挂牌)**

This single-sided auction begins with one-side (typically, consumers) submitting quantities, possibly with a pre-specified price-level. The other side (typically, generators) sees these quantities and bids for them. The Northeast to North Grid wind exchange is the simplest version of this, where the grid company is a single buyer, setting the quantity and the price. In this case, with a fixed price, multiple bids exceeding the amount of the auction are allocated according to capacity. The Inner Mongolia Grid to North Grid exchange is also one-sided (with the quantity fixed by the governments), while generators can compete on price. In this exchange, when prices are tied, the larger generator gets preference (North China ERO, 2016b). In listed auctions with multiple buyers, the government typically specifies a total amount to be traded, or else a proportion of the consumers' electricity that can be met through the exchange. Inner Mongolia held its first listed auction *without* price limits in July 2017. That auction resulted in a dramatic price reduction of 0.1584 yuan / kWh (or 53% of benchmark) for coal generators, and an astonishing 0.227 yuan / kWh reduction (75% of coal benchmark, or 48% of the most recent wind FIT) for participating wind farms (IM EIC, 2017).

3. **Centralized (dual-sided) auction (*jizhong jingjia* | 集中竞价)**

This third version involves both consumers and generators bidding in simultaneously, though it is not as common nationally in China (e.g., it is not listed in 2017 exchange transactions in Inner Mongolia). Nevertheless, it is important to examine because a traditional electricity spot market requires centralized (dual-sided) auctions, and all Chinese provinces engaged in electricity markets have procedures for it (Qianzhan, 2017). In this setup, both sides submit quantities and prices to a centralized system, and an algorithm determines amounts (typically, up to a pre-specified threshold) and prices (also with bands to control volatility) for each participant. I illustrate these with a simple example of a set of consumer and generator bids (Figure 3.12). There are basically three different algorithms, all of which are in use and mentioned in various market reform documents in China. The three are shown in Figure 3.13 and described below:

- **Single market clearing price** (*tongyi chuqing* | 统一出清). The traditional spot market approach, which determines a system marginal price (SMP) according to where supply offer curves (increasing price) and demand offer curves (decreasing price) intersect. Any generator with a bid at or below SMP will produce its bid amount or up to the remaining demand if it is the highest bidder. Any consumer with a bid at or above SMP will get electricity in a similar fashion. Notably, this is the closest pricing mechanism reflecting the underlying

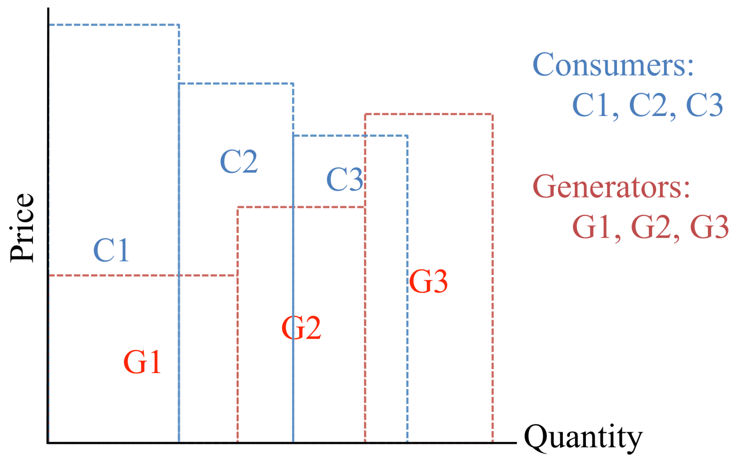


Figure 3.12: Example set of consumer and generator bids in dual-sided centralized auction

system conditions, and recall this is also the basis for various mathematical theorems on how spot prices lead to efficient long-term investment in electricity markets (e.g., Pérez-Arriaga and Meseguer, 1997). In order to create a consistent investment signal, the SMP also should not distinguish between "existing" and "additional" consumption, as recurs throughout many Chinese market designs.

- **Matched pairing** (*cuohe chengjiao* | 撮合成交). This market takes inspiration from securities or foreign exchange trading, which is a centralized way to match buyers and sellers without a centralized clearinghouse. It has no analogue that I am aware of in electricity systems outside of China. In the Chinese implementation, supply and demand curves are constructed per the SMP approach, and these are then used to individually match buyers and sellers, each at *different prices*. The lowest supply bidder and the highest demand bidder are matched, with the transaction quantity equal to the smallest of the two bids and the transaction price equal to their average, or in other cases leaving a gap between what both parties pay, recovered by the market operator (BJX.com.cn, 2015; YN IIC, 2017). These quantities are removed from the two curves, and the process continues. If one of the matched bids was for a higher quantity, the remaining portion continues into the next process looking for a match. Thus, while there is a market operator, the goal is to mimic as closely as possible decentralized trading between parties. Matched pairing—as well as "pay-as-bid" below—is a type of "discriminatory pricing", so-called because market participants have different prices for the same good.

- **Pay-as-bid** (*baojia jiage* | 报价价格). As the name suggests, in this market, the price is equal to the bid price, rather than a single clearing price. Variants of this have been used in some electricity markets, such as the imbalance market in England and Wales where producers and consumers submitted bids to manage short-term changes in system conditions and would pay/get paid according to averages of the largest respective bids. This was replaced with a single price, closer to the marginal unit, by recommendation of the regulator because the previous arrangement was not cost-reflective and did not provide incentives for parties to balance appropriately (Ofgem, 2014). China has adopted "pay-as-bid" for two-sided transactions, and it is essentially a variant on the matched pairing method above. In the Inner Mongolia rules, there are two versions: either (a) consumers bid quantity and only a maximum-allowed price, with the final price determined by matching individual generator bids, or (b) consumers bid both quantity and price, and the average of the matched pair is used (North China ERO, 2016b). The former, a pay-as-(generator-)bid, would tend to advantage consumers. The single-sided pay-as-bid system in England and Wales has been shown to lead to greater consumer surplus (i.e. lower prices for the end-user) at the expense of overall efficiency (Federico and Rahman, 2003). Clearly, the Chinese system, by choosing the lower end of the price range of matched buyers and sellers is creating even more benefits for consumers.

Finally, while these markets are predominantly used to contract energy, another type of contract known as generation rights trading (*fadianquan jiaoyi* | 发电权交易) also exists in Inner Mongolia (roughly 15% of exchanged quantities in January-August 2017) and in other parts of China mostly in limited amounts. For these contracts, the annual plan quota is essentially converted into a tradable permit, and low efficiency generators or those the government desires to shut down are encouraged to sell this right to generate to higher-efficiency power plants. This was envisioned as one method to encourage adoption of energy-efficient dispatch (NDRC et al., 2007). The eastern province of Jiangsu has the most extensive generation rights trading program, which also revealed some of its limitations without broader reforms: when coal prices rose in 2008, efficient generators were unwilling to purchase the rights, causing inefficient generators to either turn back on or lose

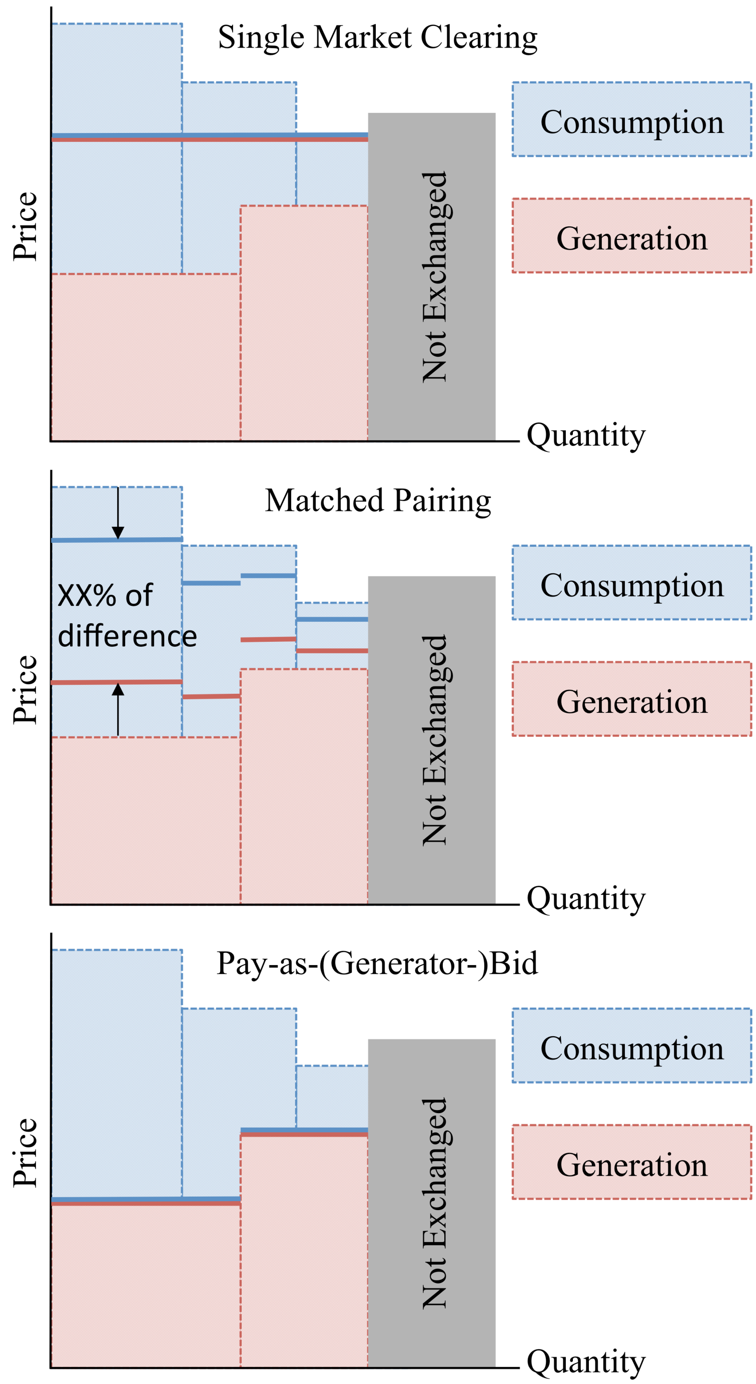


Figure 3.13: Three price formation processes for centralized dual-sided auctions. In matched pairing, the percent of the difference returned each to generators and consumers varies: e.g., 10% in Yunnan day-ahead and 50% in Guangdong monthly. Sources: (YN IIC, 2017; North China ERO, 2016b; GD EIC, 2016).

	Bilateral Negotiations	*Listed Auction*	*Centralized (Dual-Sided) Auction*
Government-determined parameters:			
Entry	Minimum consumer threshold Generator type and size threshold	Minimum consumer threshold Generator type and size threshold	Minimum consumer threshold Generator type and size threshold
Quantity	Overall target Participant caps	Fixed, or overall target Participant caps	Fixed upper limit Participant caps
Price	Price restrictions: e.g., price bands	Fixed price, or bid restrictions: e.g., price bands	Bid restrictions: e.g., price bands Price formation: e.g., pay-as-(generator-)bid, matched pairing
Process	Independent negotiations Reporting window	Centralized bidding period, possible multiple bid rounds	Centralized bidding period
Average Price Reduction	−0.068 yuan / kWh	−0.143 yuan / kWh	—

Table 3.8: Transaction types, government-determined market parameters, and price reductions in Inner Mongolia, January-August 2017. Sources: Inner Mongolia Electricity News (2017c); North China ERO (2016b,a).

out on their quota (Liu, 2013). This is similar to the phenomenon of large-scale power shortages of 2011, which were blamed by some on generators unwilling to generate at a loss as benchmark tariffs did not keep up with rising coal prices (Bradsher, 2011). Recently, including in Inner Mongolia, this has also been an encouraged method for renewable energy generators to purchase some quota from coal plants in order to reduce curtailment (IM Government, 2016).

The above transaction types, government influence on market operation, and resulting price reductions in Inner Mongolia are shown in Figure 3.8. Generally, less centralized forms of contracting (such as bilateral negotiations) result in smaller price reductions, while more centralized forms of contracting result in larger reductions and hence, consumer benefits.

Overall, the design, operation and outcomes of the various exchanges demonstrate provincial government officials' keen desire to reduce electricity rates, particularly for a set of favored industry groups. This results in large consumer savings, regularly touted by the government, and grumblings from producers as their profits shrink. Inner Mongolia's centralized markets are at the extreme end of international experiences in terms of allocating market surplus to consumers as compared to producers. Nevertheless, market shares of over two-thirds of electricity could not be secured without buy-in from generation companies. On this, at the generation group level (i.e., parent companies of multiple plants), there is strong evidence that market exchanges result in more generation (Inner Mongolia Electricity News, 2017a). In addition, the government adjusted the price bands three times over 2016 and 2017 in response to rises in coal prices that were putting pressure on generators (Inner Mongolia Electricity News, 2017d). This is a necessary function of the provincial government as a result of the use of a pricing system linked to the central benchmark tariff, which moves slowly with respect to coal price changes.

It is interesting to note that bilateral contracts as a predominant form of electricity exchange were pioneered in the UK, though the motivations were substantially different from China's. In the UK, a centralized pool (i.e., single market-clearing price) was adopted following unbundling, but because of high market concentration between essentially two suppliers, there were concerns that high prices were caused by market power. The government argued that more decentralized contracts (such as bilateral negotiations, or over-the-counter (OTC) exchanges) would have more straightforward price formation, and thus be more competitive (Newberry, 2002).

The Inner Mongolia government's motivations appear to be quite different, and with different ultimate impacts on price. In line with provincial government officials desire to reduce industrial electricity rates, the government's design of bilateral markets essentially *institutionalizes* consumer power: both pay-as-(generator-)bid and industry-specific price bands give advantages to specific large consumers in price-setting. Through various means, the government is allocating more surplus to consumers and away from generators.

Wind Energy Exchanges

Wind farms in Western Inner Mongolia, though starting to participate in exchanges only as recently as 2015, already sell approximately the same fraction of their energy in exchanges as do coal plants. Wind accounted for 22% of generation in 2016, and roughly 20% of long-term (annual) exchanges in 2017 (Inner Mongolia Electricity News, 2017d; IMPC, 2017). The share is slightly higher for listed auctions, and no breakdown for monthly negotiated contracts was given in the latest statistics.

The abnormal wind energy auction that reduced tariffs by 50% is strong evidence that wind farms perceive that it will result in substantial additional generation, confirmed by respondents[15D4, 15D6]. Compared to coal plants, whose variable fuel costs are a significant portion of their total expenses, wind farms have very little variable costs (i.e., proportional to output) and would in theory be willing to accept very little in exchange for their generation once the farm is built. On the other hand, a much more common form of price competition in wind energy, practiced in many European countries as well as China prior to 2009, is a long-term concession auction: in this market, developers bid for a contract for the right to build a farm at a certain location and receive a fixed price for most or all of the life of the project (e.g., 15-20 years). In this case, without sunk costs in building the installation, wind would theoretically bid its levelized cost including fixed costs. The eventual feed-in-tariff and subsequent adjustments (which have ranged from 0.51 to 0.40 yuan / kWh in W. Inner Mongolia) are designed to incorporate both cost components. The long-term impact in terms of continued investment of wind energy if annual or shorter auctions of around 0.25 yuan/kWh continue could be severe.

One potential cause of the difference in perception of market benefits compared with other regions comes from Inner Mongolia's more consistent use of a standard quota for wind power. Prior to launching the wind exchanges, the government set 2000 hours (23% capacity factor) as a minimum quota for wind power in W. Inner Mongolia (1800 in E. Inner Mongolia), and charged the grid company to meet as well as other generators to help with balancing (IM Government, 2015). Multiple sources confirmed that the province was using 2000 hours as its minimum quota for intra-regional sales at the full tariff and that exchanges were explicitly beyond that, e.g., 500 hours, calculated *ex-post*[15D4, 15D6]. A sample contract between wind farms and a large aluminum plant explicitly includes this threshold: any actual generation amount above the threshold can be sold through the contract, and if the month's exchange amount was not met after removing the planned generation, this would be rolled over to the next month (IM Grid, 2015). This is a stronger guarantee than was evidently communicated to Northwest wind farms.

In fact, as annual statistics demonstrate, wind farms did not reach their 2000 hours in 2015 (NEA, 2016d). Managers had noted even before year-end that this was likely; nevertheless, they still did not focus excessively on the planned quota, instead paying attention to curtailment rates, wind resource, and equipment availability[15D6]. Despite the same difficulties in assessing precisely the contribution of the exchange to actual generation, they seemed content with the results of the verification meetings hosted by the grid company in which they could see all wind farms' operating hours.

The particular contract structure of specifying a level above which is excess and exchanged, tabulated monthly, offers features of the more traditional, inflexible physical contracts predominant in China as well as more flexible features akin to financial contracts. A financial contract, which could also be between parties that are neither consumers nor producers, is simply a settlement mechanism that affects what each party pays and receives, but does not directly affect dispatch. Under these wind energy contracts, the amount is tabulated *ex-post* as in a financial contract. However, it still carries with it an implicit physical nature, because of the threat that the grid company may *not* dispatch more from wind farms that did not sign such contracts.

Wind contracts with self-generation plants to compensate for reducing their output has also been encouraged, as a way around their different peaking obligations to the grid company. These accounted for ~10% of wind market exchanges in Western Inner Mongolia in 2015 (IM Government, 2016). They are also in place in other regions, including Gansu, which traded 1.4 bn kWh of generation in this fashion in 2015—aiming to expand to 4 bn kWh by 2020 (Gansu DRC, 2016). By targeting specifically low-load hours when self-generation plant outputs are relatively higher, these pilots are similar to the Northeast peaking ancillary services market, though some key differences remain: bilateral contracts are tied to specific generators and are thus more restrictive in terms of dispatch, the medium-term (month to annual) contracts lock-in the trading over a long period and would be more challenging to respond to changing wind conditions, and the contract approach causes wind to compensate at 100% of the foregone value to conventional plants, as opposed to around 30% through the peaking market.

3.6.4 North China Grid Exports

W. Inner Mongolia is considered part of the North Grid by regulators in the National Energy Administration. All new exchange regulations or broad electricity sector measures should be approved by the same regional office that oversees the major electricity centers Beijing, Tianjin, Hebei, Shandong and Shanxi. Still, because it is a separate company from State Grid, which controls the rest of North Grid, transmission between the areas is rigidly structured, more akin to cross-regional rather than within-region exchanges. This translates into rather independent and self-contained system operation, as discussed above.

Export links exist with the rest of the North Grid, as well as small amounts with the Northwest (through Shaanxi) and the country of Mongolia. The high-voltage link of 4 GW capacity connecting Zhunge'er with Hebei is the predominant export corridor. Prior to 2010, total exports through this line were negotiated annually and there was a rather large difference between exports during "normal" and "valley" demand hours: from 3.9 GW during the day down to only 1.95 GW at night (approximately 10pm to 7am) when wind is typically most plentiful. Through further negotiations, the valley export capacity was raised to 2.1 GW, which would translate to 5 bn kWh of additional exports if sustained throughout the year (Chen and Ma, 2010).

Beginning in 2011, the two grid companies organized the first exchange involving wind power, raising the valley export capacity by an additional 1 GW in a trial run, with tariffs set by the central government (IM SASAC, 2011). Over 2012, these valley transfers (through listed exchanges) resulted in 3.1 bn kWh of additional wind, which corresponds to 0.95 GW average power during valley hours, indicating that it was maintained throughout the year (SERC, 2013). Over the next two years, the program continued, helping raise overall utilization of the IM-North China line from 81% to 86%[17].

Since the causes of wind curtailment in Inner Mongolia which give rise to the desire to export wind are also reasons to seek greater exports of coal electricity, a natural tension arises: during the critical hours when load is low, coal plant minimum outputs are high, and wind is plentiful, who does the grid ask to back down and who can continue to generate? Even as excess wind exchanges were picking up, in 2014, the State Council released its medium-term energy strategy, which called for a massive consolidation of coal mining, coal-fired power, and coal power exports in key regions (State Council, 2014). In particular, W. Inner Mongolia would be the site of two "10-gigawatt-scale" coal power bases[18]. Right at the beginning of the export line to North Grid, Zhunge'er is one of the major coal mining bases (Sohu.com, 2017). While W. Inner Mongolia has

[17]Total exchange amounts of 28.5, 30.0, and 30.2 in 2013, 2014, and 2015, respectively. Sources: (IMPC, 2015, 2014).

[18]The term "10-gigawatt" is used more as an indication of its importance and is generally not an upper limit for coal installations.

access to the large North China demand, wind farm managers lamented that new transmission lines typically come with new coal plant approvals to fill those lines, and wind's share may not increase substantially[15D4, 15D8]. After a transmission line expansion was approved, it was noted that wind farms need special approval from the grid company to access the extra capacity[15D8].

By 2015, in fact, the excess wind valley exchanges had fallen down from 3.1 bn kWh in 2012 to 1.5 bn kWh, or less than 0.5 GW average power over the year (SERC, 2013; IM Government, 2016). Over the first seven months of 2017, valley exchanges had fallen further, to only 0.15 bn kWh, or 0.08 GW average power (Inner Mongolia Electricity News, 2017b). Since over 90% of the exports are through the typical annual planning process as opposed to listed exchanges, it is impossible to know precisely how much additional space is being made available for wind power over the entire year. Nevertheless, the numbers indicate that there is fierce competition for (shrinking) export capacity to North Grid, and that exchanges designed more directly to address wind curtailment have fallen out of favor.

3.6.5 Comparing Eastern and Western Inner Mongolia

Before elaborating on the main argument of why W. IM had better wind integration than its neighbor E. IM up until recently, the substantial exogenous differences between these two cases must be reiterated, which complicates a clean adjacent case comparison—and simultaneously demonstrates why more complex power system models are necessary for attribution. First, the power mix is different, in terms of wind capacity, coal capacity (including must-run cogeneration), and demand. Shares of wind capacity in the overall power mix in W. IM are lower than E. IM but higher than the Northeast Grid as a whole, though the latter has grown faster over the last several years (see Figure 3.14). A simple comparison of how much renewable energy each area has integrated shows the complexity: the largest daily fraction of *local demand* met through wind energy has been 44% in W. IM and at least 103% in E. IM[19] (Zhang, 2017). E. IM contains roughly one-third of the entire Northeast Grid's wind capacity but less than 10% of its electricity demand, meaning it is heavily reliant on intra-regional transmission. Looking across the entire Northeast Grid, this daily

[19]These are calculated by simply dividing instantaneous wind generation by local demand. Wind generation greater than 100% of local demand implies that some excess is exported. A conclusive number on this in State Grid exchange reports for E. IM is only available for the year 2013 (NECG, 2014).

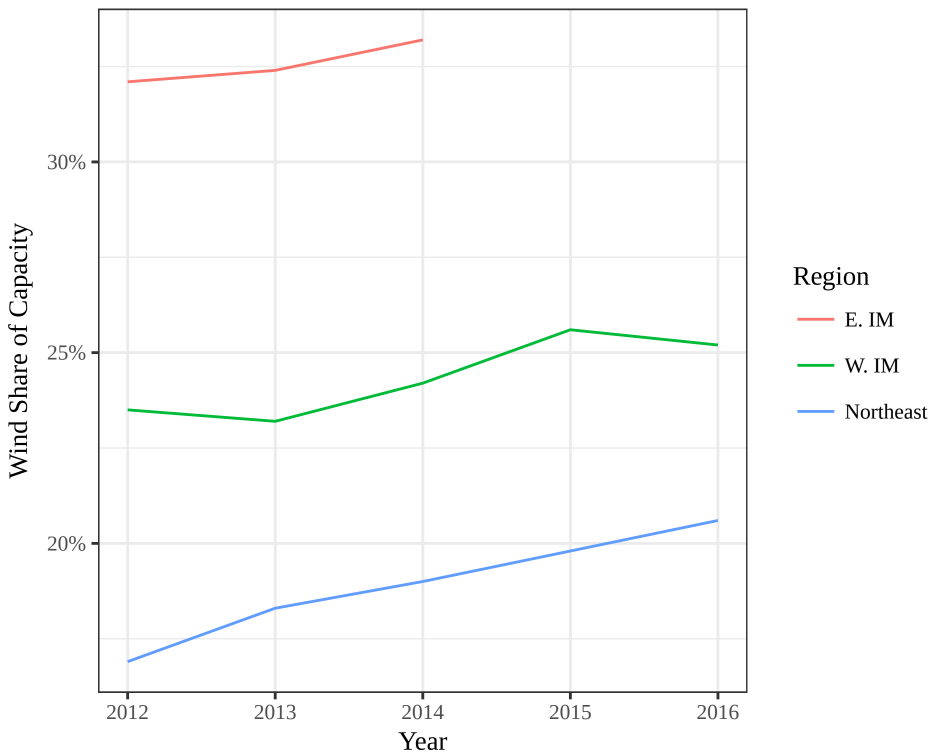


Figure 3.14: Wind shares of capacity for Western Inner Mongolia, Eastern Inner Mongolia, and Northeast Grid, 2012-2016. Source: author's calculations based on NEA, W. IM Grid and State Grid exchange reports. (More recent years' reports did not include an E. IM breakdown.)

fraction met by wind is less than W. IM, closer to 20-30%[20].

Additionally, central government treatment of the regions differs: the wind FIT for E. IM has been roughly 6% higher than W. IM up until the most recent adjustment (rising to 12%, to take effect post-2018). Given that the inherent wind resource is fairly comparable across W. and E. IM, the setting of the FIT must also include other considerations, such as local demand and benchmark tariffs. With curtailment rates of 15-20%, the difference in revenue for wind farms in both locations is more strongly related to grid conditions than wind availability. The more recent adjustment may thus be endogenous to grid conditions, as lower curtailment rates in W. IM (until recently) would require a lower FIT for wind farm profitability. Similarly, the central minimum RE quotas established in 2016 are slightly higher for W. IM—2000 hours (22.8%) compared to 1900 (21.7%)—which may also be endogenous to grid conditions.

[20]In 2014, there was a day when 23% of Northeast *generation* was met by wind energy (converting to local demand and accounting for losses and exports would raise this a few percentage points) (NECG, 2015a). More recent years' data were unavailable.

Curtailment Type	Causes	Primary Evidence (Qual/Quant)
Technical	Coal flexibility / must-run	Quant
	Grid flexibility (e.g. local congestion)	Quant
	High wind penetration relative to demand	Quant
	Export capacity and receiving region demand	Quant
Institutional	Grid management (e.g., of plans)	Qual & Quant
	Market pilots	Qual
	Negotiated export totals	Qual & Quant

Table 3.9: Primary sources of evidence for various causes of curtailment in W. IM and E. IM adjacent case comparison. Quant refers primarily to model-derived data but can also include statistical totals.

Returning to the main question, which of the two hypotheses for causes of curtailment—technical vs. institutional—dominate in these two regions, Table 3.9 outlines some of the specific causes in each category, and whether primarily qualitative or quantitative evidence can provide support for the plausibility of mechanisms or help rule out certain factors. Quantitative evidence includes some basic statistical totals (such as exports to North Grid), but is mostly derived from results of the grid model in Chapter 5. Here, I will primarily focus on what the interviews and archival analysis tell us about causes, and how they have changed over time.

Grid Management

Since its creation, the Inner Mongolia Grid serving W. IM benefited from stronger alignment of the grid company and provincial government. This can have a number of impacts, but one clear difference for IM Grid compared to State Grid (in particular, the Northeast) is the more flexible discretion granted to the primary dispatching grid (the whole IM Grid vs. the province in State Grid) for meeting the planned quantities. W. IM did not create monthly plans, whereas in State Grid areas the provincial government has set benchmarks for where generation should be in each month (though all grids noted that there is increasingly room for rolling over). This allows W. IM to make shorter-time period commitment decisions, rather than determining for an entire month the list of plants that will be turned on. Additionally, the inter-provincial ties within the Northeast, operated and verified by separate provincial grid companies, constrains the ability to use all of the region's resources effectively. W. IM does not have similar verification requirements between its demand regions. Modeling results related to this "provincial dispatch" in Chapter 5 demonstrate this point in more detail.

As noted in the Northeast case, from an overall perspective, intra-regional trading has been falling, which would seem to indicate that the inter-provincial ties are being more restricted. However, this measure is imperfect, because it does not distinguish between the time period of the exchanges (i.e., determined annually or shorter) and targeted generation types, if any. Thus, there is mixed evidence that grid management is improving through centralization in the Northeast, while W. IM shows a more consistent and flexible dispatch over the time period of interest.

Market Pilots

In terms of the market rule-making process, it was clear that W. IM had more explicit guarantees (including in the contracts) that exchanges would more consistently result in additional generation, above and beyond the quota. This translated to the implementation process, as well, based on perceptions of wind farm managers in W. IM who were less concerned about this. There were more questions raised in the Northeast (and other State Grid regions) about what the full-tariff quota might be and whether the full-tariff quota would be settled first before moving on to the reduced-price exchange amounts. The structure of the W. IM to North Grid excess wind exchange, tying a specific capacity to hours of the day when wind curtailment is likely, may also contribute to a perception of (if not actual) additional wind generation on the grid. Other aspects of the rule process, such as accountability processes through the monthly grid-generation company meetings, appear to be consistent across the two regions.

Some of these conditions began to change in 2014 and 2015 when the Northeast launched its peaking ancillary services market, which as noted above, is directly attributable to increasing wind integration intra-regionally by shortening the time period of a portion of intra-regional exchanges from a year down to a few hours (though potentially at a high cost). This market required increasing centralization across the region, a general trend that was noted by respondents[16B3]. The excess wind exchanges, despite the concerns about how additional the integration would be, did increase over the period. Despite the overall drop in intra-regional exchanges over the period, thus, the addition of these types of exchanges likely contributed to a larger fraction of intra-regional trading at times when wind curtailment was occurring.

Export Capacity and Negotiations

W. IM also historically had better export opportunities than E. IM, in terms of its inter-regional transmission infrastructure and the high utilization of its export lines. Inner Mongolia's substantial coal deposits made it an essential part of central energy planning to supply neighboring demand centers. W. IM and E. IM diverged as a result of historical differences in ownership and grid management outlined above which led to the decision to prioritize W. IM exports to North Grid to ensure reliable supply for Beijing and E. IM exports to the industrial bases in the Northeast Grid (CEAEC, 2013). Transmission infrastructure put in place before the 2002 reforms solidified this separation, such that the Northeast Grid of the newly-formed State Grid encompassed the SPC as well as several neighboring local grids in E. IM. Connections between the Northeast and the North went through Liaoning, and were lower capacity than W. IM until very recently. Ultra-high voltage (UHV) lines directly from E. IM to North Grid have now begun testing, which could more than triple export capacity out of the region (Ni, 2017).

Second, W. IM has been a favored grid for pilots by the central government[15D1]. W. IM has the longest-running multi-lateral electricity exchanges, which have been praised by the State Council. By contrast, the Northeast was one of the earliest failed attempts at electricity markets, which may have led the central government to focus on other areas this round[16A1].

As the Northeast industrial base declined, and electricity overcapacity worsened, there was increasing pressure to accommodate out-of-region exports. Additional transmission lines were put in place in 2012, and again in 2015 through a direct connection between the 3600-MW coal plant at Suizhong (绥中) to North Grid (CEC, 2016). Both absolute exports and transmission line utilization (total exports divided by available capacity) increased from 2010 to 2016, with total NE exports in 2016 comparable with W. IM (see Figure 3.15).

Given the decline in W. IM exports in 2015-2016, including those specifically tied to valley wind exchanges falling from above 2 bn kWh in 2013 down to 1.5 bn kWh in 2015 and even lower in the first part of 2017, this must reflect a shifting prioritization in Beijing toward also addressing the Northeast overcapacity and wind integration issues at the expense of W. IM. Thus, these data

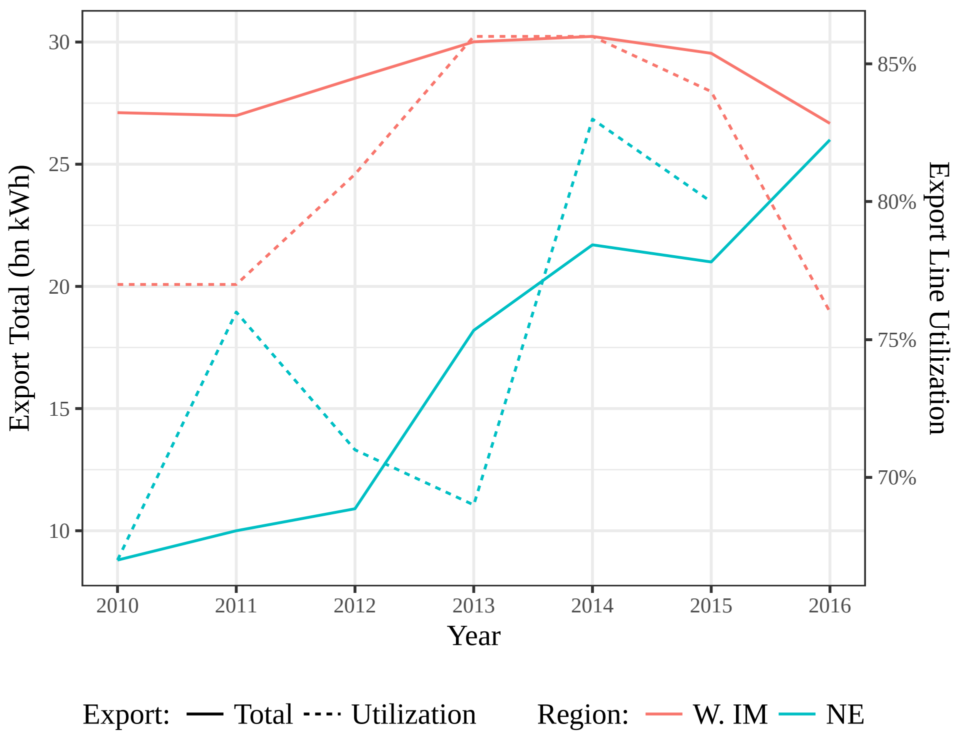


Figure 3.15: Exports to North Grid from W. IM and Northeast Grid. Source: author's calculation based on NEA, State Grid exchange reports, W. IM Grid reports. Note: the Suizhong coal plant in NE was connected directly to North Grid mid-2015, thus there is no clear line utilization percentage for 2016.

indicate that additional exports may have played an important role in the equalization of wind capacity factors across the two regions of Inner Mongolia. This is easily modelable, and in the next chapters, we will find that additional exports are not the whole story.

Future Trends and Implications

In August 2016, a new export line from E. IM to Shandong in North Grid was approved. At 10-GW, the UHV-DC line would more than triple the current export capacity from the region, and with its sending station in Tongliao (通辽), one of the major sites of wind power in E. IM, some wind integration challenges could be eased in that region as a result. This line is already completed and testing as of late 2017, and will be one of the most rapid expansions of transmission capacity in the country (Ni, 2017). The scope of the benefit to wind will largely depend on how much additional coal capacity goes in around the new line, and how much electricity Shandong negotiates to purchase. Exports and some of the other specific technical inputs to integration are explored through modeling in the next chapters.

What this qualitative comparative case study tells us is that exchanges and exports from W. IM and E. IM changed dramatically over the period 2012-2016, both of which likely contributed to the equalization of wind capacity factors in the two regions. These findings indicate that multiple-province markets can be coordinated through regional entities reaching levels of *effectiveness* (i.e., wind integration outcomes) similar to intra-province markets, which have innate advantages of better coordination and interest alignment. This regionalization is achieved through substantial negotiation and the continuation of many levers for governments to intervene as desired, which overall may decrease the *efficiency* (i.e., cost of achieving wind integration outcomes). Finally, the central government and, more generally, large eastern demand centers continue to wield significant levers in terms of governing cross-regional flows, which can be used to increase the size of the pie as well as to redistribute to different regions, particularly in response to changing integration conditions.

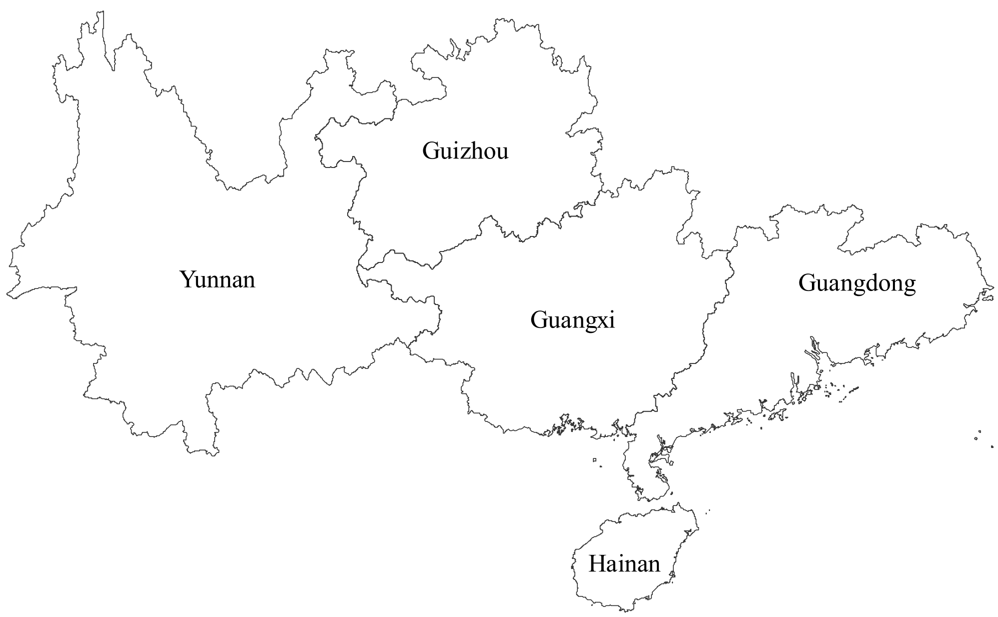


Figure 3.16: Southern grid region

3.7 Yunnan (Southern Grid)

3.7.1 Sending Hydropower Eastward

Yunnan is a mountainous province in southwestern China whose urbanization and industrialization came very late compared to the eastern demand centers and some of its southern neighbors. For much of its history, it relied on small to medium-scale hydropower (up to 100 MW, though frequently around 10 MW) in the western, southern and northern regions for its electricity, in addition to a handful of coal power installations supplied by mines in the eastern regions (CEAEC, 2009). It was mainly self-sufficient: Yunnan was connected to some of its neighbors in the 1970s, though at the time for reliability reasons (i.e., in case a plant went offline) instead of net power transfers (Guizhou Committee, 1998).

During the country-wide electricity shortages in the 1980s, Yunnan also expanded the sector in response to central relaxation of investment rules and changes to tariff design. Local investment opportunities were good in smaller hydropower installations, due to quick construction times and less required grid investments, and took off even as coal installations were behind schedule (CEAEC, 2009). These small hydropower plants were predominantly inflexible run-of-river installations, meaning they had no reservoirs to store water and must generate according to river flows. By 2002, after almost two decades since the new investment guidelines, 89% of hydropower capacity was run-of-river, and only 720 MW of hydropower capacity could be adjusted to a desired dispatch (CEAEC, 2009).

With the rainy season concentrated in less than half the year, the system faced particular balancing problems: when rain was plentiful, some of the hydropower was curtailed (i.e., water was spilled without generating electricity) because of low demand and the relatively inflexible coal fleet turned on as backup. During the dry season, there were frequent shortages, up to 20% during the 8th Five-Year Plan (1991-1995), which were exacerbated by coal supply shortages (CEAEC, 2009).

Still, Yunnan's hydropower resources are massive, and as early as the 1980s the province began planning electricity exports, in particular to heavily industrialized Guangdong province (see Figure 3.16). Guangdong and Yunnan do not share a border, but transmission expansions were being planned in both traditional AC lines as well as UHV-DC lines through intermediate Guangxi and Guizhou provinces. Guangdong and Yunnan jointly invested in hydropower projects in Yunnan from 1988, signed agreements for electricity transfers in 1991, and the first long-term electricity contracts began in 1993 (CEAEC, 2009). The next year, 1994, was the first year in decades that Guangzhou, the capitol of Guangdong, did not have summer electricity shortages (CEAEC, 2009).

Yunnan's role in regional energy planning increased over the 1990s, with phrases such as "sending western electricity east" (*xidian dongsong* | 西电东送) coming into use, which would later become the default name for exports from Yunnan to Guangdong and other southern provinces. From peak transfers of 300 MW during daytime in the rainy seasons of the mid-1990s, central plans around 2000 were studying expansions to 8,000 MW by 2010 and up to 45,000 MW by 2020 (CEAEC, 2009). The challenges of expanding these transfers includes the same persistent issue Yunnan faced with its own system: the seasonality of hydropower is much more variable than demand. Thus, cross-provincial hydropower contracts, which typically mandate specific load profiles based on time of day and season, must incorporate some of these aspects, but the receiving province may negotiate for flatter profiles, and once the contracts are signed, they become inflexible flow requirements that must be met regardless of rainfall. It mirrors exactly the issues of inter-regional wind power exchanges in the north.

The rigid, multi-year negotiated hydropower contracts between Guangdong and Yunnan were borne out of the 1980s investment reforms, which set up settlement systems between provincial grids and strengthened the province as a unit, which have only recently begun to relax through excess hydropower exchanges (discussed below). Grid functions were first taken over by the Yunnan Electric Company (云南省电力公司) in 1993, which was the same as the government electricity board (*dianliju* | 电力局) under the model of "two signs, one organization" (*liangkuai paizi yitao jigou* | 两块牌子，一套机构). In 1998, these became part of the Yunnan Electric Power Group (云南电力集团有限公司), which was the dominant player, including various other economic activities such as tourism and real estate (CEAEC, 2009). The current setup was established in 2002, with the Power Group becoming a subsidiary of the newly created China Southern Grid, and the government management functions (including annual generation planning) moved to the Industry and Informatization Commission (CEAEC, 2009).

Demand for electricity did not keep up with Yunnan's hydropower and other electricity infrastructure build-out, leading to difficulties in integrating and utilizing renewable energy, and prompting experiments with reducing prices through out-of-plan transactions. In 2015, Yunnan's total curtailment of hydropower, wind, and solar reached 15.3 bn kWh, which was cited as a major reason for Yunnan choosing to become an electricity reform pilot in early 2016 (Yunnan Government, 2016).

Given large industrial demand in Guangdong, increasing exports to the east through listed auctions has been a favored market method, explored in the case below on excess hydropower exchanges. Within Yunnan, there have been numerous markets put in place to expand lower-priced electricity and encourage local industrial growth. In aluminum, steel, cement, and other industries, utilization rates started to rise toward the end of 2016—in response to national economic conditions as well—and industrial value-added growth was 9.9% year-on-year (YoY) in the first half of 2017 (2017H1) (Kunming Electricity Exchange, 2017a).

Wind power became a major energy source in Yunnan only in the last several years, surpassing each of the Northeastern provinces in terms of capacity in 2016. This recent expansion was encouraged by central restrictions in the northern provinces with high curtailment rates, and is a key policy in the 13th Five-Year Plan (2016-2020) on Wind Power Development (NEA, 2017b, 2016a). Yunnan's wind sector is still less than other large provinces as a share of total generation (6% in 2016), though it is growing rapidly. Wind curtailment rates (~5%) are on the lower end of other provinces at these historical wind levels, closest to Liaoning province in 2013-2014 (see Figure 3.3).

Nevertheless, the Yunnan government has moved aggressively to push wind and solar farms to sell power through market transactions, nearly 50% of wind and over 90% of solar for the large generation groups in 2017H1, the largest shares in the country (CEC, 2017a; see Table 3.4). Early attempts by the provincial government at lowering renewable energy tariffs set the on-grid tariffs equal to the average market prices for centralized hydropower auctions, which are significantly lower than the benchmark tariff. A group of wind and solar companies (including Yunnan subsidiaries of most of the major generation groups) roundly criticized that proposal as violating the distinction between full purchase and market electricity set out by the NEA (Huaneng, 2016). Current regulations now specify a series of market-based mechanisms whose transactions are settled first, with the left-over electricity at a market-average tariff higher than the originally proposed hydropower-based one. These new settlement regulations are explored in the second case below, on the day-ahead exchange.

3.7.2 System Operation

The annual production planning process is structured today along the lines of its establishment in the 1980s, with the major changes over the last three decades being transfering some functions among departments of the state-owned grid company and the provincial government. In the 1990s, the planning office (*jihuachu* | 计划处) of the Yunnan Electric Power Company (previously, the Yunnan Electricity Board) created an annual plan based on a company-wide meeting, which included detailed targets for generation, sales, coal usage, line losses, labor, etc. Exports to Guangdong and any separately contracted plants would be fixed in the plan at this time. All would be accomplished according to the *sangong* principles of "equal shares", and other departments would make decisions based on these plans, e.g., plant managers prioritizing maintenance during off-peak seasons (CEAEC, 2009). The dispatch center, since it was centralized at the provincial level in 1982, has handled the functions of planning sub-annual generation to meet annual targets as well as keeping track of exchanges.

Generation planning at the annual level is based, foremost, on forecasts for demand, forecasted hydropower availability, and negotiated exports[16K1]. The plans are organized by the Yunnan Industry and Informatization Commission, as in other provinces. These are segmented into wet (June-October) and dry seasons, because of the high seasonality of hydropower, and then into months. For hydropower, there may be three different scenarios considered (e.g., high, medium, low). Approximately 45 out of 55 GW of Yunnan's hydropower capacity is not readily controllable, meaning it cannot easily store water to the dry season or to the next year[16K1]. This is the most pressing issue for system operation and generation planning, and the focus of most of the market reforms in the region.

Yunnan's generation plans further breakout a class of generation known as "priority generation" (*youxian fadian* | 优先发电), which includes considerations for a range of items, including grid security constraints as well as economic or political priorities such as old contracts. For example, some limited amount of coal plants (4% of generation in 2017H1) are designated in long-term plans to be run in order to meet local grid security requirements (Kunming Electricity Exchange, 2017a). Other "priority generation" includes hydropower built prior to 2004 and various small plants. Roughly 30% of total generation in 2017H1 was classified as priority generation (Kunming

Electricity Exchange, 2017a). The remaining generation is allocated to exchanges and non-priority generation. The Kunming Electricity Exchange manages these non-plan contracts, sending totals to the dispatch center, which in turn verifies that grid constraints can be met. The dispatch center may frequently make adjustments at this time[16K1].

Monthly coal commitment plans are based on these priority generation, and a calculation of meeting minimum and maximum demand (2 load points) over each day. There is flexibility in changing these plans to respond to load and hydro conditions[16K1]; hence, there does not appear to be the equivalent of a rigid weekly or monthly commitment schedule as in the other cases. Yunnan has the country's only day-ahead exchange, operated during weekdays and limited to intra-provincial consumers and generators (ESCN, 2017). There is some coordination between the exchange center and dispatch within the month, though the outcomes of these exchanges (described in the case below) indicate that these are, in fact, primarily settlement mechanisms and not affecting dispatch much, if at all. By contrast, monthly exchange quantities are considered prioritized[16J3], which at least in Guangdong can over-constrain dispatch. Levels of exchanges greater than 30% could create difficult problems for dispatch to manage, for which there were no clear guidelines as of 2016[16J4].

Intra-day adjustments are typically small, with wind and solar variability managed primarily by hydropower, not coal power[16K1]. Real-time changes are managed within province, and reserve generation is not shared[16K1]. With the installation of new infrastructure at provincial borders in the Southern Grid known as back-to-back DC convertors, designed to improve security by isolating grid disturbances, intra-provincial balancing responsibility has increased[16F2].

Inter-provincial trade is frequently the largest input to daily system operation. During the 2016 rainy season, Yunnan was at one point generating 33.7 GW of electricity while exporting 21.7 GW; thus, only 35% of its generation went to meeting provincial demand (Zhang, 2016). The majority of these exports are negotiated through the eastward electricity export framework, which specifies prices and totals primarily between Yunnan and Guangdong, with a secondary portion to Guangxi province. The precise allocation of generation is performed monthly by Yunnan, and includes allocations for large centrally-dispatched plants like Xiluodu hydropower (溪洛渡水电站; dispatched by Southern Grid's central dispatch center) as well as any carry-over of unmet generation in previous months (Kunming Electricity Exchange, 2017c). The remaining exports are determined through various market measures such as the monthly excess hydropower listed auctions discussed below.

Guangdong's import profile is fixed in these contracts, and is only infrequently adjusted based on supply availability or demand changes—except for predicted changes from weekend to weekday[16J3, 16J4]. Flexibility in operation has been increasing slightly: in the last few years, on a few instances some Guangdong coal plants were shut down within the week to accommodate imports[16J3]. These import profiles are based loosely on Guangdong's demand, specified in terms of ratios of output during peak or normal hours and valley hours, with ratios such as 2 to 1 (Guangzhou Electricity Exchange, 2017c). The central dispatcher, which is in charge of large Yunnan hydropower, will make day-ahead dispatch profiles based on forecasts from the provinces, which are usually unaltered in real-time[16J3, 16J4].

3.7.3 Inter-Provincial Excess Hydropower Exchanges

The Southern Grid has a wide range of market products, at timescales extending from the year down to day-ahead. Within the grid region, exchanges that cross provincial borders are handled by the Guangzhou Electricity Exchange, and intra-provincial transactions by the respective provincial exchanges, e.g., the Kunming Electricity Exchange for Yunnan. These markets are unique among the cases in this dissertation in terms of the close coordination of several complex types and the convergence of prices, particularly between within-province and inter-provincial exchanges. The general goals of introducing electricity markets according to the Yunnan government is to "preserve existing generation and expand additional" (*wenzhule cunliang, tuozhanle zengliang* | 稳住了存量，拓展了增量) (Yunnan Committee, 2015, p. 70). The dominance of electricity production in the Yunnan economy coupled with severe overcapacity led the province to become one of the first pilots in the new round of reforms, with the twin goals of reducing local electricity tariffs to stimulate the economy and increasing exports[16K1].

In the exchanges within Yunnan and between Yunnan and its other Southern Grid neighbors, some price convergence is enforced by design: for example, some inter-provincial exchanges set the price of the listed auction equal to the average of cleared prices in the two intra-provincial markets (corrected for transmission costs) (Guangzhou Electricity Exchange, 2017a). Others are the result of trading. In either case, prices converging would indicate the markets are becoming

	Within-province	Inter-province
Annual		
Benchmark	0.356†	0.267
Bilateral Negotiations	0.191	
Monthly		
Bilateral Negotiations	0.214	
Listed Auctions	0.203 ~ 0.235	0.203‡ ~ 0.235
Dual-Sided Auctions	0.236	
Day-Ahead		
Dual-Sided Auctions	0.245	
All Exchange	0.214	

Table 3.10: Average generation prices (yuan / kWh) for market transactions within Yunnan and between Yunnan and Southern Grid, 2017H1. Sources: (Kunming Electricity Exchange, 2017a; Guangzhou Electricity Exchange, 2017b; Pang, 2017). Highlighted cells are explored in this section. †Coal benchmark tariff, typically higher than the full plan-based hydropower tariff. ‡Lower range is "outside-framework" excess hydropower exchange.

coupled, which would increase system benefits by allowing access to a greater diversity of resources. Analyses conducted by the Kunming and Guangzhou electricity exchanges demonstrate that price convergence is an important objective of their market designs[21], a clear example of attempting to limit government intervention in the markets. Prices for various exchanges over the first half of 2017, together with coal benchmark and inter-provincial "sending western electricity eastward" framework prices, are shown in Table 3.10. As hydropower installations get individually approved tariffs—depending on location, vintage, etc.—the plan-based tariff is typically lower than the coal benchmark.

The first item to notice is that bilateral contracts—which, at 50%, are the largest in terms of volume—typically result in the lowest price (i.e., largest benefit for consumers). It is uncertain why this is reversed with respect to the Inner Mongolia markets, where listed auctions were lowest. One conjecture is because of the influence of price bands and pay-as-(generator-)bid rules in Inner Mongolia's listed auctions. Nevertheless, other possibilities include industry structure: for example,

[21]E.g., Kunming Exchange's report notes that centralized exchange prices are becoming important inputs to bilateral negotiations (Kunming Electricity Exchange, 2017a).

the bilateral negotiating power of consumers may be larger in Southern Grid.

Listed auctions (i.e., one-sided) are the next largest in terms of volume, and there are many varieties, ranging from regular mechanisms designed to allocate annual totals (e.g., Yunnan exports to Guangdong) to temporary or interim auctions whose totals are determined by unmatched bids from previous exchanges. The latter, unsurprisingly, result in lower prices, particularly during the rainy season when there is excess supply. Dual-sided auctions have the highest prices, particularly in the day-ahead exchange, and can be partially explained by some peculiarities in transaction volume toward the end of the month (discussed in the next section).

Akin to inter-regional contracts (e.g., the *DeBao* line between Northwest and Central grids discussed in the Gansu case), negotiations for selling Yunnan power to Guangdong include specific seasonal and daily profiles. For example, these agreements typically specify outputs for each month or season and based on valley, normal, and/or peak hours of the day. Similar to the instance of Central Grid negotiating to increase its exports based on rainfall conditions, Yunnan has sought to increase its own generation exports through more frequent negotiation.

For the specific case of hydropower, if the totals are negotiated annually (or over longer periods), they are regarded as "within the sending-western-electricity-eastward framework" (*xidian dongsong kuangjia xieyinei* | 西电东送框架协议内). If the totals are negotiated monthly on top of the longer-term plans, they are regarded as "outside-framework" (*kuangjia xieyiwai* | 框架协议外). It is these outside-framework exchanges—which take on many names—that I will be referring to as inter-provincial "excess hydropower exchanges".

Portions of the "within-framework" and almost all of the "outside-framework" electricity are exchanged through listed auctions[16J6]. For within-framework generation, at each month, some is allocated directly to plants such as Xiluodu and other priority generation, and if there is remaining it is allocated according to listed exchanges. However, during some months, participation in these "within-framework" exchanges are limited to a single hydropower plant, making it effectively a government-negotiated allocation (Kunming Electricity Exchange, 2016).

In 2016, these "within-framework" auctions also included a "repayment factor" (*fanhuan xishu* | 返还系数) designed to entice greater generator participation, and address concerns of very low priced hydropower auctions. Specifically, the factor would specify that if a generator bid to reduce their power price, e.g., by 0.05 yuan / kWh, then it would receive some amount back on top of the clearing price, e.g., 0.03 yuan / kWh (YN IIC, 2016). Once quantities are fixed, the Yunnan government has a clear interest in propping up generation prices, and Guangdong generators (e.g., coal plants) do not want to see very low priced electricity flooding its market and potentially driving down prices [16J6]. The repayment factor was no longer included in the 2017 market guidelines (YN IIC, 2017).

Yunnan's "outside-framework", or excess hydropower exchanges, are increasing: over the first half of 2017, they were roughly 30% of all Yunnan's electricity exports to the Southern Grid (Kunming Electricity Exchange, 2017a). These market arrangements are more ad-hoc, in that the Yunnan Industrial and Information Commission (IIC) can organize—and the Kunming Electricity Exchange implement—them multiple times per month, with quantities potentially determined by what is left-over from previous rounds, and go by a range of names (e.g., 月度挂牌, 月度增量挂牌, 月内临时挂牌, 月度富余电能增量挂牌). Dual-sided auctions are also explicitly allowed in the market rules, though it appears that none was opened in 2017[22].

These exchanges are for monthly quantities of electricity, and as mentioned above, the call for the auction tends to specify a two-step power profile (i.e., valley and non-valley hours). This is sufficient for hydropower, especially larger reservoirs, which can typically adjust output over the day or week and whose main uncertainty is monthly or seasonal rainfall. Or, to put another way, more frequent hydropower exchanges (e.g., day-ahead) would be unnecessary to efficiently allocate most of Yunnan's excess hydropower. One operator indicated that because of this and the necessity for governments to continue to determine monthly auction totals, there was not a large difference compared to traditional planning, and that these auctions do not lend themselves to developing into a day-ahead market[16J3].

The remaining inter-provincial excess hydropower exchanges are centralized dual-sided auctions for generation rights. In these auctions, Yunnan hydro plants will bid for portions of the contracts of coal or nuclear plants in other provinces—which can be planned totals, bilateral contracts, or any other contract. One version, known as "contract transfer" (*hetong zhuanrang* | 合同转让), pairs Guangdong and Yunnan plants. Another, known as "hydro-coal exchange" (*shuihuo zhihuan* | 水火置换), has been used by Guizhou coal plants to sell their Guangdong export allocation to Yunnan

[22] Market rules are in Guangzhou Electricity Exchange (2017a). Market announcements are available at: www.gzpec.cn .

hydro plants (Pang, 2017; Guangzhou Electricity Exchange, 2017d). Both are relatively new, only begun in the latter half of 2017.

In sum, there are some functional differences in the inter-provincial "excess hydropower exchanges" relative to negotiated annual planning, which increase the efficiency of the markets through more frequent transactions less encumbered by political constraints: quantities can be renegotiated and raised on a sub-annual basis (e.g., in response to changing economic or hydropower conditions); and price limits and government interventions in price determination play a smaller role (and decreasingly so since 2017). Particularly compared to the "price bands" of Inner Mongolia's internal exchanges, and to the fixed price North China export auctions, Yunnan's export exchanges show a reduced role of the government in determining market outcomes.

With respect to dispatch, recall in the northern cases the pervasive concern that exchanges would not result in direct additional generation, and therefore, there is a disincentive to participate because of potential lost generation at the full tariff. With respondents in the Southern Grid, there was some ambiguity about the extent to which exchanges affected dispatch. If exchanges reached too high (e.g., >30%), some noted it will present problems for dispatch[16J4]. Since most exchanges are bilateral and on a monthly basis, the likely constraint is in meeting the contracted amounts by the end of the month. On the other hand, with reportedly 48% of wind and 86% of solar energy exchanged through markets (CEC, 2017a), it is extremely unlikely this is all additional (i.e., would otherwise be curtailed); hence, some fraction of exchanges are used for settlement only and do not enter dispatch. In the next section, the day-ahead exchange is examined, and procedures for settlement help clarify some of these questions.

3.7.4 Day-Ahead Exchange

Yunnan has the country's only day-ahead energy market in the international sense—distinguishing from the Northeast's peaking ancillary services market, whose product is not energy—operating since mid-2016. In addition, it is rumored that the Southern Grid will be the first to put in place what is being referred to as a spot market, possibly as early as 2018 in Guangdong, and later in Yunnan (NengJian, 2017). For this reason, Yunnan's experience is instructive not only for addressing its own hydropower supply challenges, but also other intermittent renewables like wind and solar.

The day-ahead (DA) energy exchange (*riqian dianliang jiaoyi* | 日前电量交易) operated by the Kunming Electricity Exchange, formerly known as the day-ahead excess energy exchange (*riqian zengliang jiaoyi* | 日前增量交易), is conducted on every business day (weekends and holiday energy are cleared on the previous business day). It follows the basic dual-sided auction rules as described in the Inner Mongolia case, with an important difference in final price formation: both sides of the pair have a variant of pay-as-bid, with their respective cleared prices of the generator or consumer reduced or increased, respectively, by 10% of the gap between the matched pair (recall Figure 3.13). The remaining 80% of the difference is paid into a "settlement balancing mechanism" (*jiesuan pingheng jizhi* | 结算平衡机制), which reimburses generators for contracts they could not meet due to grid constraints or for peaking services provided, at administrative prices (YN IIC, 2017). By not using a single market-clearing price (SMP), it diverges from the centralized day-ahead auctions found in integrated markets such as the U.S. It also diverges from the balancing mechanism in the UK in timescales (day-ahead vs. hour-ahead in the UK), product (energy vs. imbalance), and pricing (pay-as-bid vs. average prices of marginal bidders)[23].

Yunnan's market rules are explicit with the order of settlement of contracts[24], which appear to be followed based on an analysis of DA bidding behavior below. First, on a daily basis all DA quantities and prices are settled against actual generation and consumption, with excess counting towards monthly plans. If generators produce less or consumers consume less than their DA bid, they will be penalized at 0.03 yuan / kWh if the deviation exceeds 3%.

On a monthly basis, the cumulative DA exchange totals are subtracted, and bilateral contracts (annual and then monthly) are first settled (see Table 3.11). Next are the various intra-provincial centralized exchanges (listed and dual-sided) and the "outside-framework" exports. These are settled at their respective prices. Finally, the "within-framework" exports are settled. If generators under-produce (for reasons other than designated peaking or grid-related issues, which are compensated at the full benchmark tariff) or if consumers under-consume by more than 3%, they will be penalized. Within the month, there are no methods to sell off contracted energy that will not be consumed—such as through a generation rights trading scheme—hence, there is a strong incentive

[23]For a description of the integration between power exchanges and the balancing mechanism in the UK, see Konstantinidis and Strbac (2015)

[24]The following DA market rules are based on YN IIC (2017), which do not differ significantly from the 2016 market rules.

	Generation	Consumption
1.	Day-ahead (cumulative)	
2.	Bilateral contracts	
3.	Intra-provincial centralized	
4.	"Outside-framework" exports	
5.	"Within-framework" exports	
Remaining, priced at:	Hydro, coal: monthly auction's lowest cleared generator bid Wind, solar: monthly average dual-sided auction price	Larger of (a) 20% above the previous year's average generation tariff, and (b) month's highest cleared generator bid
If over-contracted (remaining < 0), penalty:	0.03 yuan/kWh if under-production/consumption more than 3%	

Table 3.11: Monthly settlement procedures for Yunnan electricity exchanges. Source: (YN IIC, 2017).

to avoid over-contracting in the long-term.

The remaining amounts after all exchanges are settled tend to have very unfavorable tariffs, thus discouraging under-contracting as well: consumers must pay 20% above the previous year's average generation tariff or the month's highest cleared generator bid, whichever is largest; hydro and coal plants receive the month's lowest cleared generator bid as their tariff; and wind and solar receive the average monthly dual-sided auction price—which was roughly 0.12 yuan/kWh less than the benchmark tariff in Table 3.10. Respondents noted there is still some flexibility to roll-over generation from month to month[16J4, 16J5], which could mitigate some of the uncertainty on the generator's side, though it is unclear if this option is available to consumers.

Based on this settlement procedure, alone, the role of the day-ahead market is clear: generators/consumers should use it to closely match their monthly production/consumption to their exchange totals in order to avoid penalties or unfavorable default tariffs. There are strong incentives to neither over- nor under-contract. These rules help explain why, looking at the country's biggest generator groups, Yunnan has the largest amount of hydropower contracted through market exchanges (both absolute and percentage), the second largest in wind, and the largest percentage in solar (CEC, 2017a).

Analysis of day-ahead bidding behavior

The Kunming Exchange publishes a significant level of detail in reports and on web portals (www.kmpex.com). By looking at daily bidding behavior of consumers in the market, I can make some observations about the final conjecture of the previous section, the true purpose of the day-ahead exchange (see Figure 3.17). I argue that the only situation that makes sense is if day-ahead exchanges are used to “top-up” exchanges toward the end of the month in order to maximize the percentage of consumption met through market transactions prior to monthly settlements.

The first observation is that buyers set the total DA exchanged quantity for most of the first half of the year. Thus, on most days (except for the period around Chinese New Year in January), all demand bids are accepted, which would imply that there is an oversupply in the DA market.

Second, there is a very noticeable rise in bids and exchanged amounts toward the end of each month, particularly at the end of April and May, after which the DA market falls to nearly zero on the first day of the month. The accompanying description of this figure explains this is due to the uncertainty of (industrial) production. Looking at prices (Figure 3.17, bottom), DA prices at the beginning of the month match closely the monthly dual-sided centralized exchange for most of the period. In months where all of the consumer bids are cleared in the final days (i.e., February, March, May), the price also rises toward the end. Furthermore, average market prices (which include bilateral contracts) are substantially less.

The drop-off beginning in June corresponds to the rainy season, when there is an even greater oversupply from hydropower plants seeking to contract off generation. The price plummets for the entire months of July-October to 0.13 yuan/kWh, what is presumably the price floor, before rising again in November (Kunming Electricity Exchange, 2017b). Quantities traded still show spikes at the end of each month, which reflect demand bidding behavior prior to settlement.

The day-ahead market demonstrates some aspects of a spot market: its seasonal trends reflect scarcity and surplus (in this case, predominantly surplus), and daily auctions reflect rational bidding behavior with regards to DA contracts. It is also an example of a short-term financial contract— which, as described in the literature review, refers to a situation in which the market outcome does not directly influence dispatch, and is an important element of most modern electricity markets.

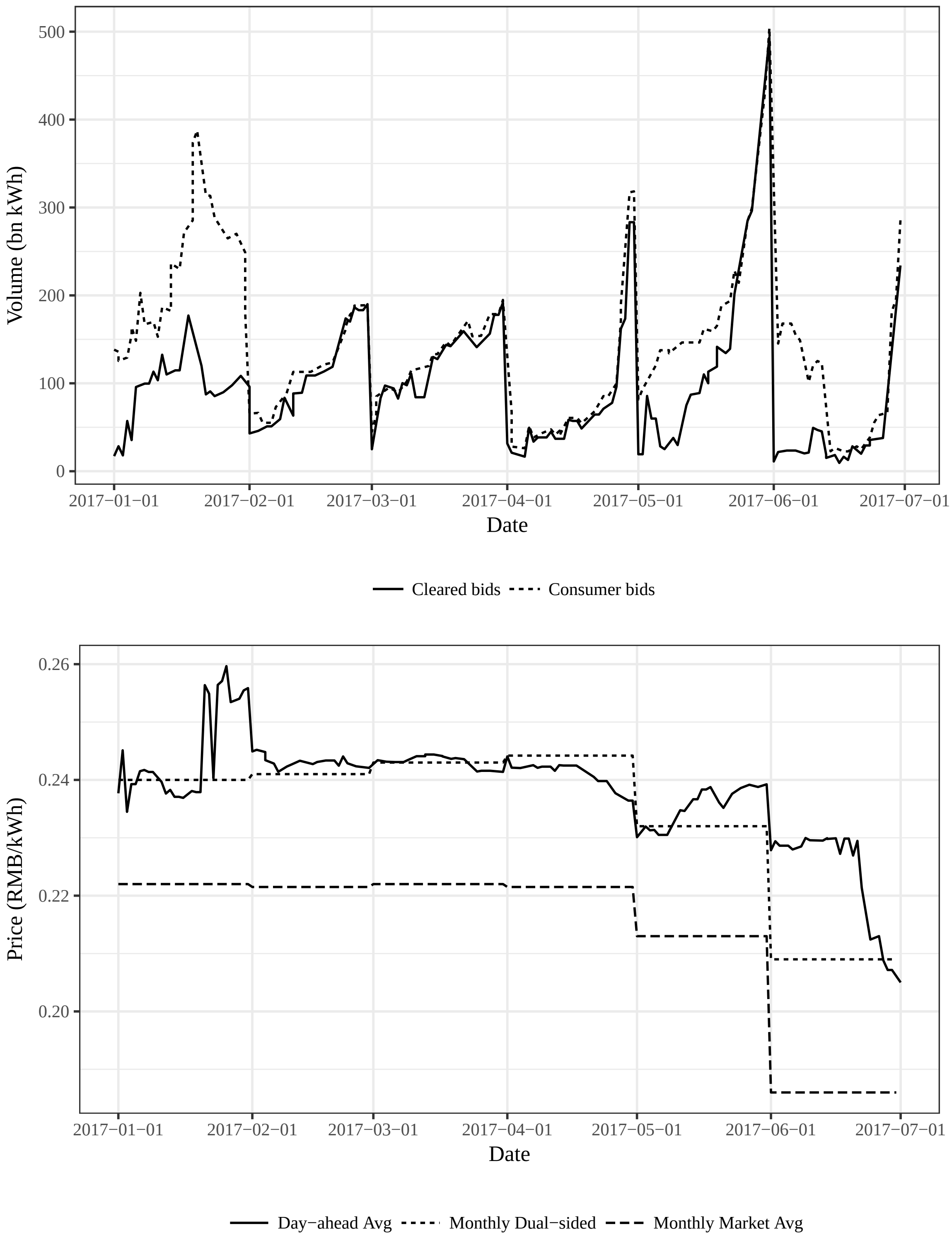


Figure 3.17: Yunnan day-ahead exchange consumer bids and market-cleared quantities (*top*); average day-ahead, monthly dual-sided and overall market prices (*bottom*), 2017H1. Source: (Kunming Electricity Exchange, 2017a).

However, it diverges substantially from traditional spot markets in many other ways: it does not reflect daily scarcity in electricity supply; rather, it reflects demand for the contract driven by the arbitrary monthly settlement window. Because of this, day-ahead prices do not represent short-term signals for flexibility, and hence, provide little to no benefit for addressing shorter-term variability in the system caused by inflexibilities or uncertainties in supply. For example, in a traditional market, a high day-ahead price may be caused by low forecasts of wind and solar the next day, inviting more generators into the market to meet the shortfall. Yunnan's day-ahead prices do not respond to these sorts of conditions.

Furthermore, consumers do not appear to use it to adjust daily consumption schedules—or if they do, this effect is swamped by the monthly settlement effect. For example, in a traditional market, an increase in demand could also cause an increase in day-ahead prices. There is no reason or evidence, however, that consumers dramatically change consumption on the last day of the month. The benefits of financial contracts in other systems are predicated on having a real-time merit-order dispatch that makes the final cost-minimizing dispatch decisions. Yunnan practice is likely closer to this ideal dispatch than other Chinese regions because of its high amounts of low-variable cost power, though significant administrative components influencing operations remain.

More fundamentally, the purpose of a spot market is to create a price signal that as close as possible reflects network conditions and scarcity, in order to efficiently balance supply and demand (Schweppe et al., 1988). These are, by the nature of electricity systems, short-term price signals. This underlying price signal then ideally influences all longer-term decisions. The Yunnan DA market is essentially backwards with regard to the price signal: short-term auctions are driven primarily by long-term auctions and regulatory decisions.

Additionally, the pay-as-bid variant (recall, generators are paid what they bid plus 10% of the difference between the matched consumer bid) is problematic compared to a single market-clearing price (SMP). It is not setup to encourage efficient investment decisions, because generators would tend to under-recover fixed costs, which represent a large fraction for renewable energy. For markets with high amounts of low-variable cost power, there are well-recognized challenges with under-recovery even in a traditional SMP market, which has higher generation tariffs than pay-as-bid (Pollitt and Anaya, 2016). However, Yunnan's monthly auctions tend to converge (either by bidding strategy or by explicit design) on similar prices for intra-provincial and inter-provincial, which means that Yunnan's market is linked to coal-dominant Guangdong's. As of yet, this linkage through monthly and longer price variations does not efficiently balance the two sets of resources on scales relevant for spot markets. A Yunnan-style DA market, if expanded to Southern Grid, would thus face similar challenges.

3.8 Cross-Case Thematic Analysis

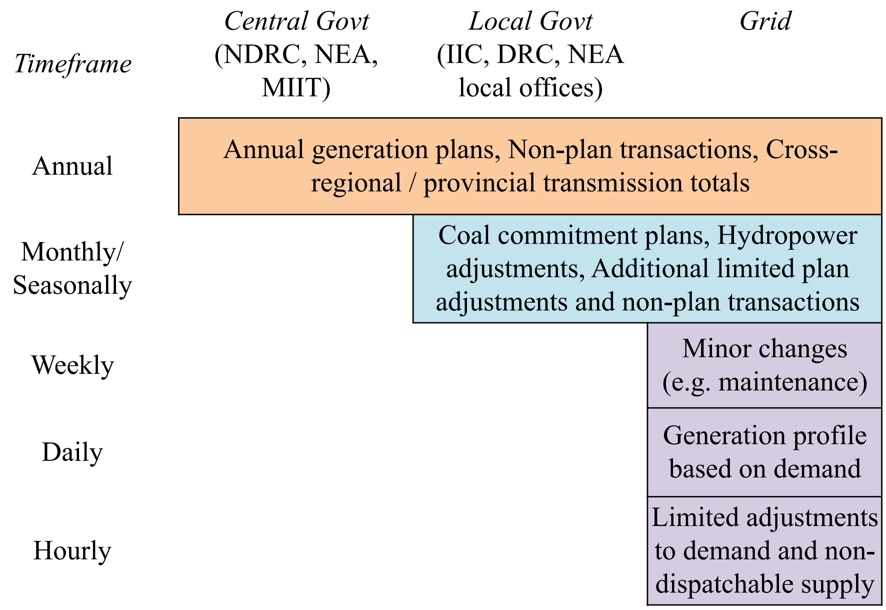
In this section, I generalize some of these case observations into themes—some of which were identified during the study design, and others during the course of the study. This serves several goals: simplify some of the generic processes—at the risk of over-simplification—that occur in every Chinese sub-national electricity system; aggregate multiple factors into a larger context, i.e., engineering constraints; and to make some conclusions on the reasonableness of assumptions for validity of the quantitative model discussed in the next chapter.

3.8.1 Dispatch Planning Timeline

Rule-making process: converting goals to operational regulations

Concentrating on important decision points in annual and sub-annual electricity system operations, a picture emerges of a power system in transition between traditional government-led production planning processes and actors responding to market-driven prices. Overarching central goals are to maintain fairness in dispatch according to the *sangong* principles—a relatively straightforward process if all generators are of the same type (coal) and similar size. With increasing system operational complications—renewable energy integration and balancing—as well as broader market creation goals, these principles have been carried forward and incorporated in various ways. Nevertheless, as with the many examples of allocation of wind generation to either plan or market transaction, there is still significant ambiguity.

In terms of plan decision-making, local and central governments, grid companies, and generation companies engage in a highly structured annual planning process that determines a large portion of expected production totals for the year. Similar to other sectors of China's liberalizing economy, the remaining fraction allocated to newer market mechanisms involve degrees of competition. This is further broken down into seasonal and monthly decision points, where adjustments to the plan



NDRC: National Development and Reform Commission
NEA: National Energy Administration
MIIT: Ministry of Industry and Information Technology
IIC: Industry and Information Commission (MIIT local bureau)
DRC: Development and Reform Commission (NDRC local bureau)

Figure 3.18: Overview of dispatch planning process

and additional out-of-plan exchanges take place. Implementation of provincial government plans and market transactions is the responsibility of the grid company which handles all sub-monthly adjustments, and whose decisions in most cases are restricted to maintenance scheduling and daily balancing functions. These short-term decisions typically do not adjust coal plant commitment decisions or inter-provincial transmission flows. Day-ahead exchanges in Yunnan do not appear to affect dispatch significantly, while the Northeast peaking ancillary services market does result in lower coal outputs though no significant plant commitment changes (see Figure 3.18).

The number of actors and diversity of interests have increased relative to pre-reform production planning processes. The provincial planning process is governed by Economic Information Commissions or Industrial Information Commissions, local bureaus of the Ministry of Industry and Information Technology (MIIT). These take the lead and make the final decision on annual plans with significant input from grid companies, and can adjust monthly plans through opening market exchanges. Inter-provincial trade that occurs within a single grid region is negotiated between relevant parties prior to this stage and typically sets boundary conditions for the provincial plan, though there may be an iterative process based on concerns surfaced within provinces.

Cross-regional trade amounts are essentially decided by central agencies, NDRC and NEA, or in the receiving grid, based on national strategies such as large-scale plans for energy transfer from west to east and to substitute polluting coal-fired generation in load centers (NEA, 2014a). This structure has been confirmed by multiple grid operators and by other researchers (Kahrl and Wang, 2014). This represents another aspect in which China differs from other federalist systems, such as the U.S., where federal regulations govern market design but specific trades are determined bilaterally between market regions (O'Neill et al., 2006). Once trade totals are decided (typically annually and adjusted monthly), there are various methods at the local level of allocating to generation firms, including bid-based markets such as between generators in Ningxia and load in Shandong via the *NingDong* (宁东线) ultra-high voltage line; allocation mechanisms such as Northeast Grid-North Grid excess wind electricity exchanges in which NE generators "bid" amounts into a centralized exchange; and through typical provincial planning processes.

Discretion and accountability

Once directions are set by central and provincial governments, virtually all implementation on a sub-annual basis is left to grid companies and exchange centers. Formal points of interaction between the grid and other stakeholders have increased over the years, to currently, the monthly meetings where grid companies present their progress toward meeting the plan and non-plan contracts. Exchange centers—which are owned and/or predominantly run by the grid companies—collect all bilateral contracts and run the centralized auctions. The results of the transactions may be altered post-hoc by the grid company for grid security reasons, and by the provincial government (on rare occasions) opening/re-opening trading for political reasons.

The central government observes this process, and of the local branches of central ministries, central priorities appear to be most represented in the NEA local offices. They have the nominal authority to ensure central priorities are carried out, although regulators in both regions confirmed that the power of the local NEA office is heavily constrained. They do not have the *de facto* power to approve or reject plans; rather, in the rare case they raise objections, this serves the purpose of prompting further negotiation[16B2]. While the provincial IICs are also nominally one of their regulated entities, the local NEA offices' responsibilities appear to be to restricted primarily to evaluating grid company actions.

3.8.2 Grid Company Roles

In determining which generator gets dispatched when and by how much, the grid company is more than an agent implementing the wishes of government officials. In the annual planning process, the provincial government takes the lead role, but the grid company can put limits in terms of how much generation it says it requires from various units for technical reasons. At seasonal and monthly intervals, this situation is reversed: the grid company's exchange center has authority to clear various contracts, while the provincial government may influence the creation of monthly contracts. On monthly and shorter intervals, the grid company's dispatch control center has almost complete autonomy in determining the commitments of units and output schedules. These should nominally meet the monthly totals, but all grid company respondents confirmed that there is flexibility in this process as long as annual totals are met.

Grid company discretion throughout this process is enhanced when annual plans cannot be met precisely, for example, when demand growth fell much below expectations in recent years or when dealing with uncontrollable resources such as wind, solar, and hydropower. Under *sangong* principles, if demand is less than expected, the relative shares of each generator in total production should be unchanged. In practice, this may be difficult to achieve, especially with multiple additional exchanges occurring throughout the year, and it could conceivably be used as a method of discrimination to give more production to preferred generators, though complaints of this among respondents were rare. There are numerous reported examples of violations, such as higher production to lower efficiency generators (SERC, 2011b; NEA, 2016b). While there are policies such as *sangong* to follow, grid companies face no specific penalty for failing to comply, unlike generators which can be fined for not meeting their production contracts.

The grid company's interests do not completely align with the local or central governments. First, local grid company revenues come from the difference between the selling and buying price of electricity (for provincial grids). Hence, local grid companies will seek to reduce the price at which it buys electricity. Hydropower is generally the least expensive energy, subject to long-term, fixed-price contracts. Coal and renewable energy under the annual plan have the same price for grid companies, with the renewable energy subsidy paid by the central government, though the two are very different from government perspectives of employment and tax revenues. Further accommodating variable renewable energy also makes the grid company's task of equitably allocating generation to coal plants more difficult.

Second, provincial, regional and national grid companies gain revenue from cross-provincial transmission tariffs based on a volumetric basis (i.e., per MWh sent or received)[16A13]. Hence, these grids should seek to expand and increase usage of cross-border transmission networks. By contrast, protectionist governments will aim to restrict imports and increase exports through the annual planning processes.

Crucially, these make grid companies not independent parties to dispatch and network expansion, particularly of long-distance, high-voltage lines which receive the highest administratively-determined usage fees. State Grid's role as a policy entrepreneur in pushing for widespread ultra-high-voltage (UHV) transmission expansion aligns with these incentives as well as the potential political benefits of centralizing dispatch (Xu, 2016). Current plans to change grid compensation according to the 2015 reforms are to move from this "difference"-based approach to a "cost-plus" approach, a commonly used regulatory scheme in other countries wherein the grid company is simply paid back its costs plus a reasonable rate of return (State Council, 2015). Respondents noted that this would cause large shifts in the above incentives, though no significant changes have been implemented yet in the regions studied.

3.8.3 Changing Engineering Context

Respondents from all regions and types of institutions highlighted a range of technical constraints that prevent efficient integration of wind energy. Some of the factors highlighted as contributors to curtailment include:

- Must-run cogeneration units with high minimum modes
- Technical inflexibility of coal plants—particularly, high minimum outputs and long startup times
- Limited flexible generation (e.g., reservoir hydropower, pumped hydropower, natural gas)
- Limited transmission evacuation capacity—from wind farms to demand centers and across regions

- Solar energy coincident curtailment
- Power stability concerns (e.g., voltage stability)

In addition, low utilization (capacity factors) of installed wind capacity has been blamed on turbine quality and reliability, as well as poor farm-level turbine micrositing[15D6].

Many of these technical constraints have, in fact, been increasing over the recent period of rapid wind development. With growing urbanization, northern regions were encouraged to permit new CHP plants also providing some heating load (NDRC and MOC, 2007). While revenue from providing heat is substantially lower than electricity, developers could make a trade-off in exchange for permit approval and eventual priority dispatch. At first, this was a binary indicator, which encouraged plants to provide only a minimal amount of heating, and which need not be restricted to district heating—it could be for industrial heating loads, possibly co-developed. Later, some minimum fractions of heating (i.e., as a percentage of plant output) were instituted (NDRC, 2011). An effect of this trend is to increase the minimum mode (must-run amount) in winter heating seasons, when wind is most plentiful in northern China.

The centrally-coordinated development and deployment of more advanced coal power technologies—supercritical and ultra-supercritical coal-fired plants—to replace retiring older units also vastly remade the generation mix across China, particularly since 2005. Newer units can raise efficiency from around 30% up to 40+%, but they also have different technical characteristics that may decrease flexibility. First, to achieve these high efficiencies, SC/USC plants should run at high outputs, typically above around 70%. Below that level, they may cease to be supercritical. By way of comparison, at an output of 500 MW, a 1000 MW unit may be less efficient than a 600 MW unit (Zhong et al., 2015). Larger units also have vastly longer preferred minimum up times, in part due to higher direct fuel costs but also due to more complicated maintenance burdens.

As a result of central policies (notably, regional feed-in-tariff), wind development has also been concentrated into certain areas and technologies. Within northern regions, this has led to concentration at the sub-provincial level, complicating dispatch[15B1, 15D1, 15D8].

Transmission expansion planning also lagged the rapid and concentrated wind farm development. Wind farms can be permitted and constructed within a year (following 1-2 years of wind data collection), while transmission infrastructure takes years, even decades, due to more complex system-level planning, right-of-way issues, and numerous stakeholders at various government levels. In addition, as noted above, large-scale transmission projects will usually be approved with new conventional generation projects to ensure sufficient revenue for the grid company, thus diluting its impact on existing wind, solar and conventional facilities[15D8].

Solar power development was delayed but followed a similar trend to wind, with a FIT structure encouraging massive build-up in certain regions. Good solar resources and beneficial tariff structures also coincide with large areas of wind development, including Inner Mongolia and the Northwest. In these regions, coincident solar and wind output is increasing, creating conditions for daytime wind curtailment, in contrast to typical nighttime curtailment when demand is low.

3.8.4 Government Interventions in Electricity Markets

Since the 2002 reforms, Chinese official policy in the electricity sector is to embrace the creation of electricity markets, in particular through competition in generation, in order to increase efficiency and reduce costs. While no system achieves the ideal market design set out by economists, it does provide a useful benchmark. Government interventions are thus any actions that distort ideal market functioning from this benchmark, and thus serve as an important gauge of market reforms in China. In particular, benchmark designs and international lessons demonstrate that to achieve satisfactorily competitive conditions, the most critical components are a wholesale energy market that is reflective of temporal and geographic network conditions; market operation and participation should be separated to reduce conflicts of interest; and independent regulators should police the various new actors, monitoring for any strategic manipulation such as the exercise of market power (Joskow, 2008).

In the above electricity market cases, there are numerous instances of governments intervening to affect generation, price, and consumption. As shown, there are a range of levers affecting entry conditions, total quantity allowed in the market, price restrictions, and the process of determining which bids clear (see Table 3.8). At the highest and most important level, local governments typically specify the total amount of generation allowed to be exchanged outside the government-run planning process. Entry conditions specify who can participate in terms of the minimum size of the consumer (e.g., giving preference to heavy industry), as well as which energy types and what minimum size capacity. Additionally, in several instances, the price itself is either fixed (in the case of the Northeast excess wind exchange) or else given price caps and floors that are frequently hit because of oversupply and hence amount to a government-set price and quantity—not diverging significantly from traditional planning methods.

In terms of price, several exchanges surveyed operate with the rather uncommon pay-as-bid price formation, instead of a single market-clearing price (SMP), or a variant of it that includes a separate parameter to re-allocate consumer, producer and grid surplus. There can be other conditions imposed by the market designers (i.e., provincial EICs/IICs) such as in Gansu, which has found a way to force firms to expand production by using even more electricity, requiring four units of additional coal generation for every unit of discounted renewable generation. There are also more extreme examples of governments nullifying exchanges whose outcomes they did not like, which clearly degrades confidence in the markets as a long-term signal for investment, among other things. A summary of the markets surveyed and some of the challenges is in Table 3.12.

Maintaining multiple levers of control even after directly giving up non-planned electricity, government officials and regulators appear to be motivated by a desire to reduce frictions with market introduction, in addition to the traditional motivations of providing extra stimulus to industry. In the Northeast peaking market, a key parameter—the minimum output threshold of coal plants—was set at least partially to match the size of the market with the previous administrative compensation scheme. In the South, hydropower auction prices were propped up to ensure profitability of an important provincial industry as well as keep coal plants in neighboring provinces happy. Methods and even stated objectives in many cases are strikingly similar with how these departments conduct traditional planning.

Still, as one respondent noted, it is not accurate to say that there is no market behavior: otherwise, there would not be the examples of extreme competition and oversubscription[16G8]. Wind generators have slowly embraced some aspects of the markets—though, not all, and not uniformly—which can be interpreted as a resignation to the inevitability of marketization given widespread government trends, since wind companies rarely benefit from them compared to the old system. While wind farms participate in these markets, when they describe their ideal situation they do not advocate for completely unfettered markets either. Respondents from all farms expressed a desire to have an unambiguous "plan" quantity on top of which they could engage in exchanges. While it would ideally be the high amount set by the central government, they would accept lower amounts, as long as the plan would essentially cover their fixed costs. Markets could then, it is argued, be used for making a profit[16G2, 16G5]. This would essentially turn back part of the market reforms, establishing a traditional cost-of-service or benchmark level for wind generators that would still require government participation in terms of setting these quantities.

Looking over the wide range of market types (e.g., bilateral, listed auctions, dual-sided auctions) co-existing over multiple timeframes, it is clear that these regions are still a long way from creating a relatively simple set of standardized transactions. Yunnan and the Southern Grid appear to have the most consistent connection between sequential markets as well as a trusted settlement mechanism, which provides one possible future for other regions of China. However, local energy mixes lead to different prices for these different markets, which would also affect local governments' willingness to adopt them. For example, in Gansu, centralized exchanges have tended to be more competitive in terms of price reductions, which, facing pushback from many corners, have been replaced by bilateral contracts. Bilateral contracts encourage relationship-building between wind farms and large users, which is advantageous to wind farms in that it diminishes the users' desire to go out in search of a better price[16G7]. In Yunnan, bilateral contracts have the lowest prices, though this may be skewed downward by the large number of hydropower generators participating, which typically have low project-specific default tariffs and much lower variable costs than coal power.

Assessing government interventions in the market is further complicated by the three-way relationship of government-grid-regulator. The regulator most closely aligned with the central government—the local office of the NEA—does not have significant authority in many areas over the local government. Its authority over the grid company is greater, focused on implementation of *sangong* and other policies related to market functioning and renewable integration. However, the grid company itself holds the models and data, and is a key decision-maker in both the traditional planning allocation as well as the exchanges. Furthermore, incentives of the grid company and local government do not directly align.

3.8.5 Barriers to Wind Electricity Trading

Jointly managing renewable energy over larger distances—whether through centralized dispatch or trading—is seen as one of the best ways of managing its intermittency, resulting in reductions of curtailment and the cost of balancing services by other generators. As seen in the studied regions,

Region: Market	**Nominal Purpose**	**Design / Implementation Challenges**
Northeast:		
Excess Wind Exchanges	Increase wind energy exports to North Grid	Unclear link between participation and additional dispatch Fixed price and proportional allocation when oversubscribed results in *de facto* administrative system
Peaking Ancillary Services Market	Increase wind integration space by lowering coal minimum outputs	Unclear whether bid should reflect opportunity cost of foregone generation High cost burden on wind generators
Gansu (Northwest):		
Wind Bilateral Contracts	Encourage greater wind energy consumption	Unclear pre-contract guaranteed quota hours Consumers must contract greater quantity of coal to participate
Western Inner Mongolia:		
Excess Wind Exchanges	Encourage greater wind energy consumption	More confidence by participants of additional generation Wind-only auction leads to low prices that may not recover fixed costs
Yunnan (Southern Grid):		
Excess Hydropower Exchanges	Increase hydropower exports	Early implementations include "repayment factor" distorting final price
Day-Ahead Exchange	Increase market-based pricing	Participants use to "top up" before arbitrary monthly settlement Price does not reflect daily scarcity or encourage consumption when surplus

Table 3.12: Summary of design and implementation challenges of market experiment cases

power system operations in China are heavily province-centric, with numerous institutional barriers to more flexibly integrating renewable energy across provincial borders. Beginning with the annual planning process, inter-provincial transmission amounts are negotiated up to a year in advance, which is designed for dispatchable resources, not variable wind power. Cross-regional transmission is based more on demand than on supply availability, and if it incorporates the time-varying value of electricity, it is based on a fixed set of hours of the day from historical demand, not supply, patterns. It is also difficult for regions to modify operation of large-scale transmission projects, requiring lengthy approval processes.

Furthermore, by almost exclusively engaging in grid-grid transactions across provinces as opposed to generator-consumer transactions as in intra-provincial bilateral contracts, the benefits to the receiving government and users of potentially capturing lower-cost generation elsewhere is captured to a large extent (and in some cases, 100%) by the various grid companies. This increases the appetite of the grid company to promote exchanges while decreasing the willingness of other stakeholders such as provincial governments to pursue these options to lower system costs.

New transmission projects are held up as a major, if not the most important, avenue to address renewable integration challenges. By increasing the size of transmission corridors, it is reasonable to assume that renewable energy can achieve some benefits even with inflexible inter-regional dispatch procedures. Nevertheless, in all northern case regions, respondents from both the wind industry and grid companies noted that major UHV transmission lines are frequently paired with new generation at the sending end to maintain high utilization of the lines. These coal plants are dispatched at very high rates (such as in Ningxia), and take up a large portion of the new transmission capacity. Efficient use of long-distance transmission infrastructure to address renewable energy goals cannot be separated from the dispatch methods on either end.

Fundamental issues with the wind energy markets (whether bilateral or multilateral) derive from institutions developed post-unbundling to satisfy a variety of equity concerns, each of which is addressed at the provincial level in different ways. First, the fundamental principles of *sangong* are interpreted in different manners, the most restrictive of which is that only similar types of units (e.g., same fuel type and similar capacity) within a single province need to be treated fairly: hence, there is no requirement to treat wind farms in neighboring provinces "fairly". Relatedly, priority dispatch for renewables and "energy-efficient dispatch" directives are largely implemented within provincial borders, if at all, and do not apply to how electricity is sold across borders. Second, the unambiguous basic "plan" amount that is supposed to be allocated to wind power was not achieved anywhere, and for the most part differs across neighboring provinces (and even within a province). Third, relating to bid-based exchanges, price caps and assurances that these will not reduce the amount of full-tariff generation are underspecified, leaving wind companies with an uncertain market strategy.

To illustrate the role of grid operations and electricity sector institutions in creating barriers to trade, here I describe two types of barriers—which I call "short-term" and "long-term"—and compare to the consequence of a typical barrier (import tariff) for a more traditional product, an automobile (see Table 3.13). Long-term barriers may result from protectionist measures such as seeking to increase local tax revenue, industrial growth potential, and investment indicators. With an import tariff, this is a simple remittance. With electricity restrictions, this requires a relatively complex allocation mechanism. Short-term barriers may also be protectionist to protect local generators such as renewable energy with limited supply. However, they may also be bureaucratic in nature: separate dispatch organizations may be unable to coordinate on the required time intervals to trade. Electricity systems also include different types of products known as "ancillary services", such as reserve generation, which is the unused capacity of generators able to respond within seconds or minutes of system condition changes. There is no analogue to automobiles and virtually all other products.

When compared to the automobile example, trade barriers in electricity system operations involve a wider range of actors and some may be the result of bureaucratic structures interacting with technical complexity, rather than intentional restrictions. This has important implications for research that takes interest alignment as the fundamental lever for successful reforms (e.g., Lema and Ruby, 2007). For example, one could misattribute a particular outcome such as low inter-provincial electricity trade as primarily the result of interest politics, which may be perfectly reasonable in the case of other traded goods, while in fact for electricity systems there may be alternative explanations—i.e., multiple pathways to explain this outcome.

	Electricity	**Automobiles**
"Long-Term"	**Restriction:** Total annual imported electricity **Consequence**: Allocation of limit to monthly plans (possibly evenly), and eventual conversion to actual transmission flows	**Restriction:** Import tariff **Consequence:** Remit to government at time of purchase or on regular basis
"Short-Term"	**Restriction**: Limited ability to change transmission flows over short periods (e.g., intra-hourly) **Consequence**: Provincial grids must handle internally short-time period imbalances. *Limited trade in reserve generation.*	N/A

Table 3.13: Illustrative Barriers to Trade for Electricity and Automobiles

3.8.6 Assumptions for Validity of Quantitative Model

The quantitative dispatch model outlined in Sec 3.3.2 and elaborated in the next chapter rests on at least four assumptions that I explored through the qualitative interviews. Greater confidence in the model results will result from evidence that these hold or that the extent to which they do not hold does not depend on the institutional treatments above.

Welfare maximization

Current practice in China does not incorporate a short-term optimization that strictly dispatches generators according to least marginal cost, commonly referred to as a "merit order", which is the fundamental requirement for welfare maximization in electricity markets. There are various directives such as energy-efficient dispatch and mandatory dispatch of renewables that would tend to encourage alignment with marginal costs, while other directives such as *sangong* that seek to maintain equitability across generators and are, in a sense, the explicit lack of a merit order principle. Hence, it cannot be argued that the quantitative model is an accurate representation of the precise decision-making situation faced by Chinese grid operators. The *sangong* directive is primarily implemented on a longer-term basis of months to years. When commitment schedules are determined (e.g., at monthly to weekly time periods), constraints of meeting minimum and maximum load (e.g., two points per day) are consistently considered, representing a similar though simplified procedure to model presented in this dissertation with 24 load points per day. One additional consideration that was rejected has to do with conflicts of interest in dispatch: favoritism was not noted by any wind generators as a serious issue, in contrast to reported widespread favoritism in the 1990s (Bai and Qian, 2010).

On an intra-daily basis, all grid operator respondents confirmed that renewable energy is allowed to fill up the remaining space once conventional units are fixed (according to whatever procedure). Yunnan's dispatch has also for some time used a procedure that ramps down coal plants in order to accommodate more hydropower. These correspond to a short-term priority dispatch for renewables *once conventional plant commitments and operating limits are fixed*, which would approximate a short-term welfare maximization given the low variable costs of renewable energy. Some limited form of optimization may also be implemented to minimize deviations with the day-ahead schedule (Yang and Tang, 2011). The current grid software in wide use across China—D5000—has, in fact, the capability of conducting more detailed optimizations such as the model presented in this dissertation, an important consideration for recommendations for policy later.

Hence, some of the political conflicts modeled in this dissertation—e.g., generation quotas and market transactions, and inter-provincial transmission contracts—are clearly seen and implemented in practice as constraints, with an intention to minimize some type of cost (e.g., fuel costs) once these are met. For example, consistently across regions, the grid company does not compensate generators if it fails to meet their contracts—the grid company simply must meet them within a small tolerance threshold. As there is no compensation for curtailment or penalty of the grid for failure to meet quotas or exchanges, additional penalty terms need not be considered in the objective function presently.

In practice, reserves are considered in Chinese systems, though there are no explicit requirements of these constraints made public, and it appears these may be considered more based on circumstances, rather than a precise limit. Up reserves (i.e., ability to ramp up output on short notice) are generally not expected to be limited because of high overcapacity in the regions studied. Down reserves may be limited, and are important in renewable energy systems to accommodate changes over short time periods. In the systems studied, minimum outputs of coal plants are set at relatively high thresholds (50-60%) and, except where system security is threatened, are not compelled to ramp down. In these cases, renewable energy is curtailed. By setting an explicit reserve requirement, this dissertation's model would thus tend to underestimate curtailment caused by these lower limits.

Single optimizing agent

Dispatch is indeed centralized in Chinese systems, as opposed to other models such as self-scheduling in the UK. Bilateral contracts are conducted in terms of energy on longer-term horizons, and are thus seen more appropriately as constraints to the centralized dispatch. Furthermore, for the two cases of short-term exchanges (Yunnan's day-ahead exchange, and the Northeast's peaking ancillary services market), the effects of market power—which would cause the central optimization to differ from the market equilibrium—do not enter dispatch in any noticeable way: the Yunnan DA market is primarily a settlement mechanism, and there is no evidence that Northeast generators exercise market power in their bids.

In terms of the level at which the system is centralized, these cases appear to be somewhere between the provincial dispatch optimization (where each province is an optimizing agent) and the regional dispatch optimization (all provinces co-optimized without consideration of borders). The provincial dispatch—in this instance, approximated with barriers to trading under a central dispatch—is supported as close to actual. The counterfactual of regional dispatch is also reasonable to consider, given that some plants are already dispatched by the regional operator and there is infrastructure in place to facilitate more centralization of dispatch.

Perfect information

The model solves simultaneously an entire week's commitments and dispatch, assuming perfect knowledge of demand and wind. This is not an accurate description of reality since forecast errors of both can be substantial. Complete analysis would include a two-stage model that modeled uncertain realizations of wind and load forecasts, and performed statistical analysis on actual costs (Constantinescu et al., 2011). However, China's day-ahead plans (both generation and transmission decisions) are seen by dispatch operators as constraints to be met, rather than scheduling guidelines that can be superseded by changes in real-time. Hence, this model is arguably *no worse* than what China does in practice. The modeled institutions do not directly implicate changes in how forecasts are utilized, so I argue they are not co-dependent. However, if day-ahead decisions on transmission interconnects were to be more flexible—such as is the case in Northwest, the subject of future modeling scenarios—then a full uncertainty analysis could become relevant.

A simplified two-stage model appropriate to approximate the context of these systems makes scheduling decisions based on the worst expected wind level (including, possibly, setting to zero), and then adjusts dispatch in real-time according to wind conditions. This extension is added to the model in the next chapter.

Zonal demand and supply

Intra-provincial constraints can be relevant, and are possibly the greatest limitation of this analysis. For example, wind power concentrated in certain areas (e.g., Baicheng in western Jilin and Jiuquan in northern Gansu) may be unable to export to the rest of the province. In the model with provincial zones, increasing wind in these areas would not violate any transmission constraints except at provincial borders, and hence model results would tend to underestimate the network-related causes of curtailment. It is for this reason that in the model I split Gansu into two different zones representing wind in the north and demand centers in the south. These further impact reserve requirements, because generators behind a congested line cannot provide some reserves to the rest of the province. Quotas and inter-provincial transmission are less affected by this. The choice to largely ignore intra-provincial networks in modeling is because of the lack of detailed network data and a consistent dataset of precise generator locations. As virtually all regulatory interventions occur at the provincial level, the effect of this simplification is not expected to have a large impact with respect to institutional causes.

3.9 Summary of Findings

The cases of system operation and market experiments in this chapter demonstrate how technical requirements for reliable system operation interact with the political economy of the sector in unique ways at the provincial level. The common features of these systems in terms of operations, markets and causes of wind integration difficulties are summarized here in a handful of findings.

Finding #1: Local governments and grids have the incentive and ability to contravene central government commitments to wind deployment, creating non-technical contributors to curtailment.

As has been described elsewhere, local governments derive more tax benefits from coal than renewable energy plants, and have strong incentives to maintain even under-performing coal plants (Zhao et al., 2013; Williams and Kahrl, 2008). Many of the wind-rich provinces examined here also have extensive coal mining operations, a key source of local employment. Coal generation's high variable costs correlate with the output and profitability of the mining sector, creating an incentive to raise shares of electricity from coal relative to low-variable cost renewable energy. Finally, due to minimum size restrictions on coal plants, the one-time investment infusion of a new coal power plant vastly outweighs that from a smaller wind farm.

Furthermore, provincial governments have the ability to influence generation allocation in line with these priorities through the annual production planning processes and various out-of-plan market mechanisms. Generation quotas are more clearly defined for conventional than renewable energy—also within the purview of provincial governments.

Grid companies have priorities of meeting both plan and market contracts equitably (following *sangong* principles), which are in conflict with "energy-efficient dispatch" and standard merit order dispatch practices in other countries. Secondary incentives that disadvantage wind energy exist in the long-distance transmission planning process, where in order to ensure high revenues, grid companies would like to see additional coal generation at the source end.

Even "technical" causes of curtailment may share a range of institutional drivers, blurring the lines between the two, and extending the influence of political and grid actors over operations further. For example, coal generator minimum outputs are a technical input to any system, but in the cases examined they are set administratively: in traditional planning, by the grid company, but likely self-submitted by the generators; in the peaking markets, by the regulator, after discussion with all stakeholders. These quasi-technical causes are examined further with modeling tools in Chapter 5.

Finding #2: Markets have been primarily used as supplements to administrative measures, with narrow purposes and varied impacts on supply-side dispatch.

Because of overcapacity and centralized benchmark tariff-setting, provincial governments have a strong incentive to pursue markets as a means to lower costs for its energy-intensive industries. Competitive market prices are likely lower than the central benchmark tariffs, and provincial governments do not have direct authority to alter these plan prices. Instead, provincial governments gain this ability by retaining primary control over the choice, design, and oversight of electricity market experiments. The primary methods of market-oriented electricity sales are through bilateral contracts and listed central auctions. For these, provincial governments set specific entry barriers—and frequently, allowable price ranges—that ensure only large generators and consumers can participate. Illustrating this overlap of government planning and market elements, the same department in charge of organizing generation plan quotas also approves market guidelines (Economic and Information Commissions (EIC) or Industrial and Information Commissions (IIC)), which can then use market rules to maintain preferential treatment of specific sectors.

Furthermore, virtually all market pilots have imprecise or ambiguous connections with dispatch, thus diminishing their effects on supply-side efficiency. Some are settlement-only, where underlying dispatch protocols—governed by *sangong*—are unchanged. They may simply be used for accounting at the end of the month. If they do influence dispatch (e.g., a more binding constraint than the plan quota at the monthly level), it does not affect the basic process of conventional unit scheduling in which commitment plans are made weeks in advance. Intermittent energies such as wind and solar cannot be treated equally in this case. Combined with the lack of a government promise to a planned quantity for renewable energy at the guaranteed central feed-in-tariff, this leads many wind sector respondents to feel unclear about the precise benefits of markets such as excess wind exchanges.

Yunnan's day-ahead exchange—the only short-term energy exchange currently operating in China—does not function according to international theory or practice. By construction and through examination of bidding behavior, it is designed to "top up" monthly exchange totals to avoid less preferential prices arising from under-contracting. Prices do not reflect daily scarcity in supply, and it is explicitly settlement-only—i.e., no connection to dispatch.

Finding #3: "Benchmark" product markets—whose value is defined relative to administrative reference parameters—are popular but do not reflect the underlying value of electricity and are thus inefficient.

From the perspective of efficiently integrating renewable energy, electricity market design is crucial. In contrast to an energy market tied to the value of the underlying "natural" commodity of electricity, many Chinese electricity market pilots create products whose value is relative to a benchmark. The benchmark can be directly determined administratively, such as the Northeast peaking market, where the amount of "peaking" provided is in reference to the standard minimum output, a government-determined parameter that is set considering political criteria. Another example are W. Inner Mongolia exchanges that bid "differences" with respect to the planned price, maintaining preferential rates to certain industries. Finally, the Yunnan day-ahead exchange can be seen as a "benchmark" product, since it is tied to the arbitrary monthly settlement period.

Benchmark approaches clearly facilitate market introduction because of their enhanced political feasibility: they are, in most cases, layering components onto existing schemes without fundamentally altering electricity settlement or dispatch processes. They can directly maintain existing industrial policy, thus guaranteeing certain preferred directions in market outcomes. They can also easily be tuned by the government through adjustment of the benchmark.

For these same reasons, benchmark markets are likely inefficient. Prices do not reflect the underlying value of electricity. They create not only dual-track prices (a characteristic feature of "growing out of the plan"), but also multi-component prices, further separated from underlying value. The benchmark, and hence the entire market, is subject to large political uncertainty. As a result, these prices should have little value to efficient long-term investment decisions, one of the important purposes of an energy market. If more natural markets were adopted, they have the potential to lay bare substantial inefficiencies of current planning practice as market values are recalibrated, demonstrating another reason why benchmark approaches are more politically palatable.

Finding #4: Local governments retain levers over markets of various complexities, which are used to guide outcomes toward desired (possibly, narrowly-defined) goals.

As laid out in Table 3.8, exchanges can increase in complexity, but the levers for government control or guiding market outcomes do not disappear. Bilateral contracts are the easiest form of exchange to create, with minimal additional bureaucracy required, and levers include entry and allowable quantities and prices. A natural progression occurs to (one-sided) listed centralized auctions and to dual-sided centralized auctions, each of which adds additional parameters and steps through which to intervene. Several regions further announce these centralized exchanges on an ad-hoc manner, allowing government planners to carefully control market size. Government levers will generally distort outcomes from an efficiency perspective, allowing governments to favor certain industries or generators, control the size of the market for political purposes, or distribute rents in an equitable but inefficient manner. More complicated markets may only look similar to standard models but have administrative features guiding them that need to be analyzed in close detail to understand market functioning.

With these levers, there are many examples of markets thus achieving the desired goals of their creators, such as reducing prices for specific industries. The Inner Mongolia bilateral contracts, framed in similar terms to industrial policies with preferential tariffs, both set and achieve these narrow goals. The Northeast peaking market is designed to improve wind integration, and it is effective at this narrow purpose though at high cost to wind generators. On the other hand, other market mechanisms to integrate wind appear to be less effective (discussed next). Rather than viewing this as a failure, however, it is more reasonable to view these as sharing multiple goals, of which reducing electricity tariffs is a higher priority. The implications for future market directions given these multiple goals are discussed in Sec 7.2.3.

Finding #5: Markets can improve flexibility of the system to cope with wind variability, but at varied costs, and hampered by their ambiguous relationship to mandatory dispatch planning.

Highly targeted markets can lead to additional flexibility, and hence integration, for wind energy. The Northeast peaking market is a clear example, since it targets precisely hours and generators when and where additional system flexibility is needed. This is an effective market for wind energy integration. However, it is also a very expensive method (for wind producers) to increase flexibility compared to previous administrative measures—hence, it is inefficient. Generation rights trading pilots that have wind producers buy directly a coal generator's quota (typically, on a monthly or seasonal basis) can also have an impact but are less effective than the peaking market. Coal generators are guaranteed to be ramped down, similar to a bilateral peaking market, though the hours in which they ramp down do not necessarily correspond to when wind curtailment is highest. In addition, the opportunity cost of the coal generator's quota may be much higher than what wind generators are willing to pay. Finally, the lowest cost options for wind farms to engage in markets, such as excess wind energy exchanges, have even less determinate impacts on dispatch, leading to a further decline in effectiveness.

Renewable energy producers are weighing these two aspects of efficiency and effectiveness when deciding whether and how much to participate in these varied markets. Current central government policy requires mandatory dispatch of renewable energy, though these requirements and quotas are frequently unmet. With reference to current planning mechanisms, these producers must consider, is the exchange settled first or the plan? Does/how does the grid company use exchange totals during dispatch? These cases show governments exploiting this ambiguity to avoid paying full tariffs to renewable energy, and grid companies facing difficulty in modifying dispatch to accommodate further constraints from exchanges.

Finding #6: Grid companies are implementing agents of plans and markets, but are not impartial.

The grid company is an implementing agent whose ultimate responsibility is to ensure that all long-term contracts are reliably met, and within this has a variety of autonomies. The traditional quota system is allocated from year to month with some discretion for the grid company to roll-over contract amounts between months. Market contracts that are not settlement-only have more rigid requirements, with typically hard monthly targets. This developing trend tends to reduce discretion of the grid company—making its implementation more predictable—but at the same time reduces flexibility, which can disproportionately harm renewable energy sources. The precise levels of grid discretion are one of the most contentious ongoing subjects of current reforms.

While the electricity markets literature suggests that more discretion and autonomy for dispatch enhances efficiency, this assumes a system operator independent of market actors and transactions (Joskow, 2008). However, grid companies in China are not impartial. Their net revenues are still largely based on differences between buying and selling. Inter-provincial transmission tariffs accrue at multiple levels, not necessarily in line with system costs. For long-distance lines, revenues are based on the amount of energy transmitted, which gives a clear incentive to dispatch more through the more expensive lines. The cases studied are still very far from more standard "cost-of-service" revenue schemes that guarantee cost recovery to the grid independent of network usage. In the interim, the grid company will continue to have multiple roles and interests in electricity market creation.

Chapter 4

Engineering-Economic Models of China's Grid Operations

Electric power systems are complex machines, encompassing large geographic areas and with a range of technical criteria that must be held to within small tolerances for proper functioning. Generation, transmission and delivery of electricity has large economic salience due to its size, such that efficiency of the sector has significant implications for economy-wide productivity, in addition to political salience, as affordability and access are viewed as basic rights in most countries. Engineering-economic models—which consider engineering details of the physical processes of production to delivery with an explicit economic objective of maximizing social welfare (typically, equivalent to minimizing cost)—are therefore widespread in the electric power sector, and provide a natural modeling framework for this study.

Engineering-economic models exist for decisions considering a range of time horizons, physical realities, and economic costs. This chapter describes the unit commitment and economic dispatch optimization (UC), a standard model used in most systems to determine scheduling of generators on a daily basis in order to reliably meet a projected electricity demand at least cost. Some enhancements to this model, including clustering of computationally-expensive binary commitment variables, are made for tractability and to facilitate a broader range of institutional sensitivities.

The core methodological contribution is then presented: the formulation of a range of institutional conflicts within the quantitative modeling framework to assess their individual and interacting impacts on system outcomes of interest. The conflicts are drawn from the literature and case studies described in Chapter 3, and separated into conflicts common to all of China and those specific to individual cases.

4.1 Literature Review

Electricity systems operation and management entail decisions made over a wide time horizon and varying degrees of frequency. On the shortest time scales, automated control systems to maintain system balance and frequency within acceptable ranges run on the scale of seconds, and on the longest, decisions on where to invest in new generation or new network infrastructure consider construction times of years and lifetimes of decades (see Figure 4.1). Grid operations, the focus of this study, will be used to refer to decisions (or research about decisions) about how to operate existing components of the system, without considering investments to add or modify the system architecture. These still encompass a relatively large range: from the relatively infrequent annual (or longer) planning for hydropower availability and scheduled maintenance down-time for generators and lines, to daily scheduling of start-ups of combustion generators, and dispatch on the order of hours or minutes determining precisely at what levels and other criteria that generators should output (Momoh, 2009).

Computational decision-support tools in the electricity sector date back to as early as the 1950s, and can be divided into three different classes of modeling types: centralized optimizations, decentralized optimizations, and simulation or mixed formulations. With the creation of algorithms and hardware able to rapidly solve large linear optimization problems, earlier heuristic methods to determine operational scheduling could be replaced with more efficient solutions obtained with centralized optimizations while capturing important engineering details (Momoh, 2009).

Since the 1980s, with the reforms of vertically-integrated utilities (VIUs) to incorporate competition among multiple actors in some segments of the sector, models to analyze the behavior of multiple independent agents have become increasingly important. Decentralized optimizations assuming profit-maximizing agents are more general than a centralized single-objective optimization, and can be used to support decisions of individual firms, policy-makers and market monitors that ensure fair market operation (Ruiz et al., 2013).

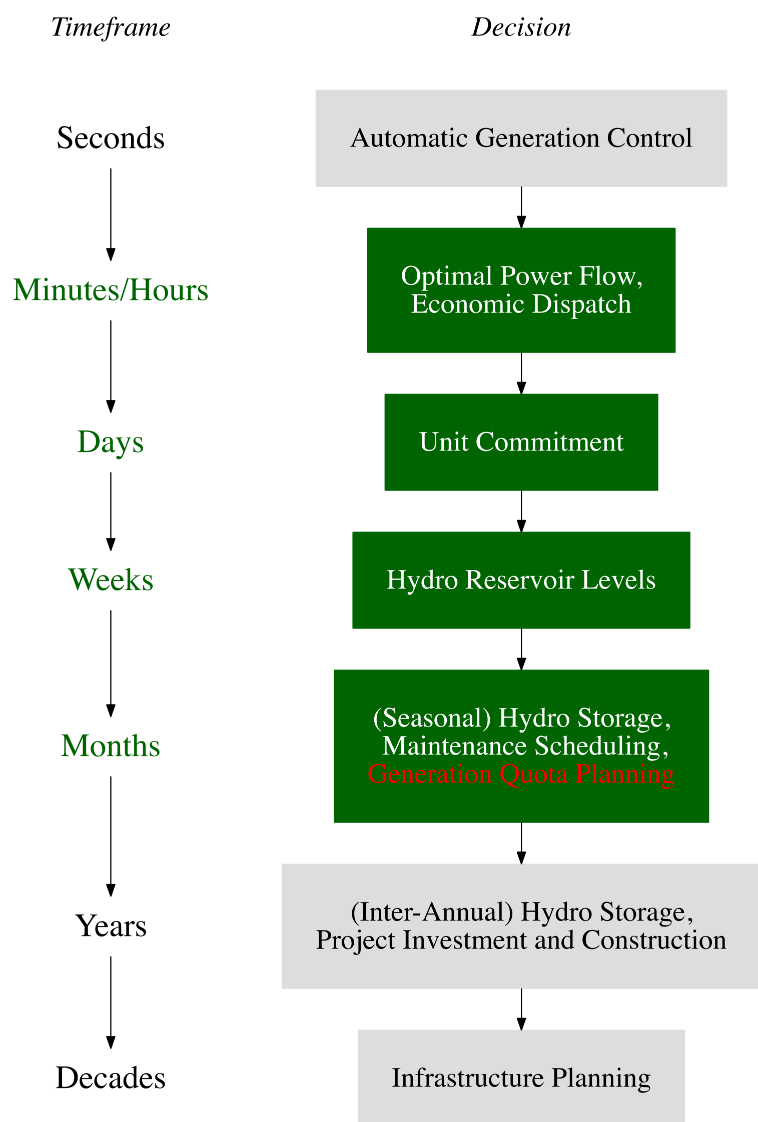


Figure 4.1: Overview of typical grid decisions and timeframes (red indicates Chinese system-specific). Dark shaded are the focus of this dissertation. Modified from: (Momoh, 2009).

The third type is simulation or mixed optimization/simulation, which uses heuristics (rules of thumb) without claim of optimality to make decisions or simulate behaviors of one or more agents. These are both the oldest type of engineering-economic model used in electric power systems (e.g., "priority lists" of generators that rank scheduling in advance based on a limited number of attributes (Momoh, 2009)) as well as an active area of research for problems that are intractable for pure optimization methods, typically involving high dimensionality such as incorporating uncertainty.

4.1.1 Centralized Optimization Formulations

The largest class of models for grid operations, in both research and practice, is the centralized optimization problem. Optimization programs seek to minimize or maximize an objective function over a number of variables that are constrained to fall within an allowable "feasible space". In electric power, the objective function is frequently the cost of production (i.e., fuel costs, start-up costs, etc.); the variables may include the output of each generator at each time step (e.g., hourly or less); and the constraints incorporate various physical realities of operation such as heating up a combustion boiler and transmission flow limits. As a result, variables and constraints can number in the hundreds of thousands for a single model run.

These massive computations were made feasible through a combination of algorithmic work beginning in the 1940s and increases in computation power. In particular, for the specific class of linear programs (LPs)—optimization problems where the objective and various constraints are linear combinations of continuous variables without any higher-order or cross-product terms—most solvers rely upon the "simplex method" developed to solve logistics problems following World War II. Because of its computational advantages, much work over the last half-century has been devoted to reformulating a large number of problems as LPs (Schrijver, 2005).

An important class of problems in power systems (and many other applications) is the mixed integer linear program (MILP), which restricts certain variables to take on only discrete choices: either integers $\mathbb{Z} = \{..., -2, -1, 0, 1, 2, ...\}$ or binary variables $\{0, 1\}$. (In many applications, only non-negative integers $\mathbb{Z}_{\geq 0} = \{0, 1, 2, ...\}$ are also used.) MILPs are computationally much more demanding than LPs: typical solution methods may require solving hundreds or more of separate LPs to arrive at a solution, and exact solutions can rarely be guaranteed—instead, algorithms incorporate a target optimality tolerance to constrain the difference between the solution and the best possible objective (Bertsimas and Tsitsiklis, 1997).

Across the range of grid operations models in Figure 4.1, one of the most essential to efficient operation is the unit commitment optimization (UC). This is run on a daily basis in most power systems, and solves for the "commitment" decisions (referring to starting up a generator) and the expected dispatch of generators at lowest cost subject to meeting expected demand and other constraints such as availability of reserves (spare generation capacity able to respond to unpredicted changes at short notice) (Momoh, 2009; Padhy, 2004). The UC is a MILP because commitment decisions are binary, reflecting that it takes time and additional costs for a boiler (coal, natural gas, nuclear, etc.) to heat up and generate power, and that there is a range of outputs that are not available to the generator once it completes its start-up cycle. With more complex and larger generators, expanding system sizes leading to greater gains from improved scheduling, and more complicated system planning needs, the centrality of the UC model has only increased (Momoh, 2009). In a restructured competitive environment, the accuracy of the algorithm is even more crucial: small deviations in total costs can lead to large redistributive impacts in terms of payments to individual generators (Sioshansi et al., 2008a). Figure 4.2 shows a schematic of main features and relative sizes of a sample UC problem.

It is instructive to contrast these models with statistical estimation techniques commonly used in political analyses and cross-country restructuring studies. A statistical approach to understand drivers for wind curtailment might use a panel regression at the unit of the province with covariates for various institutions and power system data (e.g., deployed wind capacity). Here, the basic issues will be low statistical power given limited sub-annual data availability, technically infeasible or highly uneconomic production schedules, and non-linear interactions among institutions and with un-modeled technical constraints. Infeasible schedules could arise when extrapolating from a treatment effect (e.g., the coal quota on wind curtailment) beyond the support for a given set of covariates: for example, there may be network and technology-specific features which prevent coal generation from going below certain thresholds. Interaction terms (e.g., of inflexible power supply and deployed wind) will also be inadequate as proxies to capture relevant technical constraints, because they are overly coarse in the time dimension and still diminish the importance of threshold effects.

The UC model dramatically enhances the time resolution with respect to statistical models, creating an optimization problem with on the order of a million variables. Of course, considering such a massive number of variables would typically lead to concerns of overfitting in estimation techniques, but in an optimization framework they are addressed by heavily constraining physical and economic criteria—362,000 constraints in the basic formulation used for this study (see Figure 4.2 below, further described in Sec 4.2).

Prior to the mid-2000s, the most widely used solution method to the UC was an approximate method known as Lagrangian Relaxation that involved solving smaller, separable LPs and iterating over a number of multipliers that captured coupling constraints (constraints that could not be separated, including terms from multiple sub-problems). In practice, the LR performed poorly on reducing the optimality gap and could not specify how far away from optimal the final solution was (Hobbs et al., 2002). A MILP implementation of the UC has been around for several decades (Garver, 1962), though only since the 2000s has it begun to be adopted by system operators (Sioshansi et al., 2008a). This is mostly the result of improvements in computational capability and algorithms, particularly to branch-and-cut methods which repeatedly apply simplex to various linearizations fixing or constraining the integer variables (Bertsimas and Tsitsiklis, 1997). These have led to reduced computation times as well as increased accuracy, reducing the optimality gap from as much as 2% down to typical values of ~ 0.1% (Hobbs et al., 2002; Rothleder, 2010).

Another trend in engineering-economic models of the power system is to incorporate operational details in longer time-horizon optimizations such as multi-annual investment planning or annual decisions such as fuel contracts or maintenance (Ramos et al., 2010). These are frequently motivated by increasing penetrations of intermittent renewable energy, which have more complex interactions and hence costs on the system, requiring new operational practices such as improved reserve calculations, and better planning of transmission and generation infrastructure (Palmintier and Webster, 2014; Dowds et al., 2015; de Sisternes et al., 2016; Ma et al., 2013; Shortt et al., 2013). Running a UC for the entire lifetime of a wind asset (~ 15 years) or transmission line (> 60 years) is highly intractable. Instead, one or more of three basic techniques are frequently adopted:

1. Ignore commitment variables;
2. "Cluster" similar generators into a unit with a single integer commitment variable; or
3. Solve for subsets of the full time period and assume they are representative.

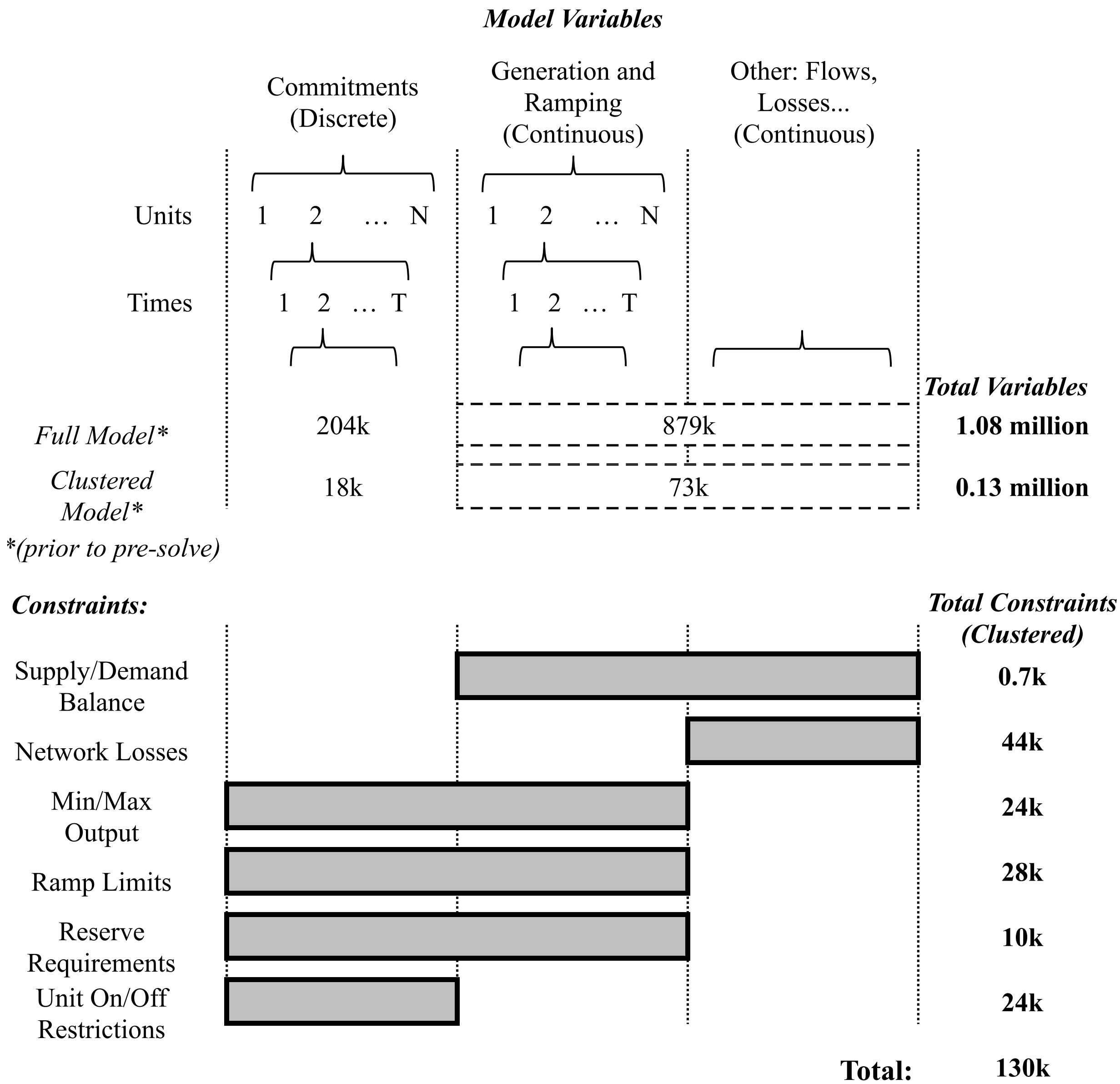


Figure 4.2: Structure of variables and constraints in unit commitment (UC) model. Blocks under constraints indicate which variables are included in equation systems. Totals shown here are for the Northeast 2011 system. Full Model: $N = 492$, $T = 168$. Clustered Model: $N = 4 \cdot 12 = 48$ (# provinces x # clusters), $T = 168$.

This study employs the latter two techniques, as detailed in Sec 4.2.

Ignoring commitment variables converts the entire problem to an easily-solvable LP, which can be solved for all or a selected subset of 8760 hours in the year and combined with investment decisions (Mai et al., 2012). This model choice neglects some important operational details of thermal power generation facilities: it does not incorporate the costs and time ($3 \sim 24$ hours for coal) for boiler startup; and it permits a range of outputs larger than those physically allowed (including, e.g., below the stable minimum generation output). Larger analyses, such as the Renewable Electricity Futures Study by the U.S. National Renewable Energy Laboratory, supplement these planning models with separate detailed operational models to capture these constraints at finer time resolutions; hence, calculating cost and reliability of the already optimized planning scenarios (Mai et al., 2012).

In systems with large renewable energy capacity, this model choice should be closely examined: greater variability and uncertainty in the availability of intermittent renewable energy lead to increases in ramping (changing output while maintaining commitment status), cycling (turning on and off), and reserve requirements (spare generation capacity to meet short-term changes in network conditions) of conventional units (Holttinen et al., 2011; Xie et al., 2011). Thus, system inflexibilities can have a large impact on renewable energy outcomes. The errors in terms of system outcomes from ignoring commitment variables has been shown to be highly system-specific and to increase with supply variability (Shortt et al., 2013).

Clustering commitments of similar units into a single larger generator is a hybrid approach that captures some of these inflexibilities while leading to greater tractability. It has been employed for several decades, originally to address computational limitations in solving the UC problem simultaneously with longer-term maintenance scheduling (i.e., downtime) (Hara et al., 1966), and, more recently, to incorporate operational details in planning models (Palmintier and Webster, 2014). The key concept is to replace the many binary variables of individual similar units with a single integer variable, thereby capturing some of the discreteness of commitments (all the UC costs and constraints have analogues in the integer formulation, as described in 4.2.2). This introduces errors that have been shown to be manageable on single-node networks (Palmintier and Webster, 2014). The multi-node network application is unexplored in the literature, which this thesis attempts to fill.

The last simplification of UC operational constraints commonly used in the planning model literature is to select representative time periods (e.g., days or weeks) and replicate the operational profiles of these representative periods (inclusive of commitments) over the longer time series (de Sisternes and Webster, 2013; de Sisternes et al., 2016; Ma et al., 2013). This entails fixing the number of representative periods and some method of choosing what is representative. It has been shown that typical methods of choosing a fixed number of periods from each season randomly can lead to large differences in the effective load duration curves over the year and on outcomes such as number of commitments (de Sisternes and Webster, 2013). Even with better selection techniques designed to capture representativeness and net load (i.e., demand minus non-dispatchable renewable availability), simulating the entire year based on 1 or 2 weeks can still be problematic (de Sisternes and Webster, 2013). Four weeks has yielded acceptable errors in some analyses (de Sisternes et al., 2016).

4.1.2 Decentralized Optimization Formulations

In contrast to the above, decentralized or multiple-agent formulations consider the behavior of multiple agents each pursuing their own objective such as profit maximization. These can model the interactions of a broader range of decision-makers and are thus highly useful in analyzing markets. In practice, these are most often formulated as complementarity models that enforce a market-clearing relationship between prices and quantity (known as a complementarity constraint): e.g., firms will continue to produce until their marginal profit is equal to zero. Market power is of great concern in electricity markets, because its effects can be exacerbated by physical constraints of the system, high localization and temporality of price signals, and low demand elasticity (Borenstein et al., 2002). In the case where agents cannot unilaterally affect the price through their own decisions (i.e., price-taking, or perfect competition), the equilibrium conditions are in fact the same as the Karush-Kuhn-Tucker (KKT) conditions for a single centralized agent maximizing total social welfare (Ruiz et al., 2013). Where there is strategic behavior (i.e., actors can unilaterally affect the price), the resulting complementarity model is solved simultaneously for a supply function equilibrium (SFE) (Bushnell et al., 2008).

Fundamentally, these complementarity conditions are derived from an inverse demand function, which relates the price to changes in supply from each market actor. These range from perfect competition where all firms are price-takers, to on the other extreme, Cournot competition where all firms can affect the price with their decisions. Comparing to actual outcomes, market monitors can identify if market power was exercised (Ruiz et al., 2013). The connections between different markets—e.g., long-term contracts and short-term spot market—can also be handled easily with appropriate enumeration of complementarity constraints (Bushnell et al., 2008).

However, equilibrium models do come with computational trade-offs: if there are constraints coupling different agent's decision variables (e.g., a common electricity demand to meet), the solution requires various non-linear program (NLP) solving techniques (Ruiz et al., 2013). Computationally, NLP techniques are much slower and more demanding than those built on linear solvers such as simplex, though they are still tractable for some real-world systems.

For a mixed-integer problem such as unit commitment that incorporates discrete decisions, however, an equilibrium formulation has difficulty solving a real-world system tractably (i.e., within reasonable computational limits). Techniques to improve tractability require relaxing one or both of the integrality or complementarity constraints (Gabriel et al., 2013). Hence, these models still lack important physical realism for problems involving discrete (binary, integer) decisions such as turning off and on conventional units.

4.1.3 Heuristic-Based Simulations

A third class uses heuristics (rules of thumb) to make decisions or simulate behavior of decision-makers. It appears that the earliest operational rule in dispatching multiple generators in a system was to run generators which have the same incremental cost, and turning off generators when output dropped low enough such that fixed costs became too large (Momoh, 2009). This did not, however, provide a guarantee of the cost-effectiveness of such commitment decisions.

In the 1960s, still prior to large-scale use of linear optimization models (and later, mixed integer formulations) for system operation, system operators began to make commitment decisions of thermal generators based on a "priority list"—a ranking of generators based on a combination of marginal cost, startup costs, and potentially other unit-specific criteria. With this ordering in place, the decision to turn off the last committed generator could be based on some simple rules, computed sequentially for each hour (Momoh, 2009; Baldwin et al., 1959):

- Can load be met without the unit on?
- Can the unit be restarted before the load reaches this level again?
- Do the fuel cost savings of shutting down outweigh the startup costs?
- If yes to all three, then the unit can be shut down.

With new technologies and markets, the drawbacks of the "priority list" compared to optimization became more salient. New techniques that can solve for discrete decisions were necessary to incorporate: a wider range of sizes of units and more complex startup/shutdown dynamics stretching over many hours; the importance of smaller percentage cost gains to system and market operation; and the need for more complicated system planning models (Momoh, 2009).

Simulations that model sequentially a single optimizing agent or multiple decentralized agents are also used in research. Work in the operations management field has recognized the importance of in-depth characterization of human behavior, in particular assumptions surrounding decision-making, in order to effectively prescribe alternative models (Bendoly et al., 2006). In complex domains such as humanitarian logistics, it can be possible through experiments to elucidate a set of qualitative indicators for objectives and perceived constraints that have an algorithmic character (Gralla et al., 2016). Formulating these as sequential "decision rules", a model can capture more nuanced behavior assuming they are implemented consistently (Gralla, 2012).

These "behavioral" approaches can dive into intermediate processes, which have stronger internal validity in complex situations that do not reflect simplifying assumptions used in prescriptive optimization models. Due to the high context-specificity, model development takes longer as do data collection needs for model parameterization. The opportunities in complex decision-making environments such as the power sector are numerous, where significant uncertainty and complex interactions require even more simplified assumptions in optimization frameworks as outlined above.

4.1.4 Model Choice for This Study

A single objective UC optimization model was chosen for this study, balancing the needs for 1) physical realism in the supply and transport of electricity; 2) ability to capture relevant institutional decision-making structures; and 3) computational tractability. The basic approach within this framework is to start with a reference optimization model that captures the "ideal" case under cost-minimization, and then to "layer" on various institutions, examining the precise impacts for various counterfactuals. The benefits of this unified approach is that impacts of each (and respective interactions) are thus measured against a consistent benchmark. The potential economic and renewable integration gains of counterfactual operational institutions have been examined in the case of European electricity bidding zones (Aravena and Papavasiliou, 2017). A limited set of planning literature on China, without details on dispatch, has incorporated minimum generation thresholds (Chen et al., 2010). No UC work to the best of my knowledge has focused on modeling operations under the range of institutions such as China's quota and the degrees of inter-provincial trade barriers described in Chapter 3.

Equilibrium formulations were considered and rejected for this study for two reasons. First, the construction of complementarity constraints for markets is in terms of an inverse demand function, relating price to changes in supply and demand offers. However, as shown in Chapter 3, under China's quota and dispatch system, there is no direct connection between the price of a generator and its short-term dispatch. Additionally, the majority of electricity tariffs are determined by the government. While there is significant generation market concentration at the provincial level in China, there are no clear principles with which to develop a short-term inverse demand function. Specifying a long-term inverse demand function, e.g., for imports between provinces or for long-term contract markets, is difficult though worth considering in future work and may yield additional insights. As shown in Chapter 3, price formation in inter-provincial transmission arrangements is also highly constrained by administrative procedures and politics. It is not clear if a well-behaved function could fit observed data.

Second, the combination of high amounts of inflexible coal-fired power and changing system impacts under increased wind penetration make considering some aspects of unit commitment highly desirable to ensure realism. There are no tractable equilibrium formulations that maintain the discreteness of UC decision variables.

Constructing simulations using heuristics such as priority lists for the purposes of comparing to an optimal dispatch was also rejected. First, the amount of data necessary to reliably parameterize these decision-making situations across various regions is both prohibitively large and unobtainable at sufficient granularity. Second, even with an appropriate parameterization, the biases in the heuristic simulation could differ substantially from those of the optimization method—hence, by extension, model outputs may differ for various model specification reasons as opposed to the treatments of different institutional combinations. Furthermore, model validation using aggregate production statistics does not guarantee the accuracy of the heuristics on short timescales, which makes attributing causes to specific institutions challenging. By contrast, within a single modeling framework such as the centralized optimization, effects of specific changes can be analyzed in greater detail, preserving the validity of evaluating "relative" changes caused by institutions.

Another advantage of optimization methods over heuristic or sequential simulation-based techniques is that solutions also create "dual variables" for constraints and continuous variables, which can usefully be interpreted as system-level impacts of specific model attributes. Electricity prices are the most commonly used dual variable (Schweppe et al., 1988), though others include the costs of alleviating specific constraints (Bertsimas and Tsitsiklis, 1997).

The largest caveat of this modeling choice is that gaps still remain between observed system outcomes and even the most heavily-constrained optimization (that which includes a range of political institutions that deviate from optimal operation). This is primarily addressed by ensuring model tractability sufficient to run a wide range of sensitivities on uncertain parameters. Irreducible gaps between reality and model outputs across the range of these parameters is then attributed to institutions not captured in the model (and possibly identified in Chapter 3). These considerations are elaborated further in Chapter 6.

4.2 Unit Commitment and Economic Dispatch

4.2.1 Standard Unit Commitment

The standard UC problem seeks to minimize operational costs of meeting a given electricity demand, whose objective consists of variable generation costs and the startup (commitment) costs of thermal generators. We start with classic formulations (Padhy, 2004) and linearize the objective function as in (Ostrowski et al., 2012):

$$\min \quad \sum_{g \in G} \sum_{t \in T} \left(p_g^{su} \boldsymbol{v}_{g,t}^{up} + p_g^{var} \boldsymbol{y}_{g,t} \right) + \sum_{p \in P,\, t \in T} p_{NSE} \boldsymbol{NSE_{p,t}} \tag{4.1}$$

where $\boldsymbol{y}_{g,t}$ is the dispatch (continuous) level and $\boldsymbol{v}^{up}_{g,t}$ the startup decision of generator g at time t, p^{var}_g and p^{su}_g are variable and startup costs (respectively) of generator g, p_{NSE} is the price of non-served energy, and $\boldsymbol{NSE_{p,t}}$ is the non-served energy at node p and time t. G is the set of generators, T the set of time periods. Throughout, **bold typeface** refer to decision variables. This is subject to electricity demand and transmission constraints (Kirchhoff's first law):

$$\sum_{g \in G_p} \boldsymbol{y}_{g,t} - \sum_{p' \neq p} \left[\boldsymbol{f}_{p,p',t} + \boldsymbol{l}_{p,p',t}/2 \right] = d_{p,t} + \boldsymbol{NSE_{p,t}} \ , \ \forall p \in P \tag{4.2}$$

where $d_{p,t}$ is the electricity demand at provincial node p at time t, $\boldsymbol{f}_{p,p',t}$ is transmission flow from p to p' at time t, and $\boldsymbol{l}_{p,p',t}$ is the non-negative transmission loss associated with that flow. Intra-provincial networks are not considered in this analysis, due to unavailability of reliable data on transmission parameters, and because accounting for the quota requires clustering at the provincial level. Further, inter-provincial lines are assumed to be connected to provincial geographic centers for the purpose of estimating losses. These assumptions imply that the network no longer corresponds to an exact physical description, and angles calculated through Kirchhoff's second law would not be realistic. This modeling choice could affect aggregate inter-provincial flows and overestimate effective transmission interconnection.

Network losses are functions of sinusoids of the angle differences between nodes, frequently approximated piecewise linearly such as in combination with the DC approximation of the optimal power flow problem (DC-OPF) (Fitiwi et al., 2016). In longer-time horizon models such as unit commitment or expansion planning, losses are typically ignored altogether (e.g., Ostrowski et al., 2012). However, given the long transmission distances between provincial nodes, losses should not be neglected, and a piece-wise linear loss formulation in terms of flow decision variables is adopted as in Fitiwi et al. (2016):

$$
\begin{aligned}
\boldsymbol{f}_{p,p',t} &= -\boldsymbol{f}_{p',p,t} && (4.3)\\
\boldsymbol{f}_{p,p',t} &= \boldsymbol{f}^+_{p,p',t} - \boldsymbol{f}^-_{p,p',t} && (4.4)\\
\sum_s \boldsymbol{j}_{p,p',t,s} &= \boldsymbol{f}^+_{p,p',t} + \boldsymbol{f}^-_{p,p',t} && (4.5)\\
\boldsymbol{f}_{p,p',t} + \boldsymbol{l}_{p,p',t}/2 &\leq \overline{F}_{p,p'} && (4.6)\\
\boldsymbol{l}_{p,p',t} &= \mu_{p,p'} \sum_s \alpha_{p,p',s} \boldsymbol{j}_{p,p',t,s} && (4.7)\\
\alpha_{p,p',s} &= (2s-1)\,\Delta f_{p,p'}\,, && (4.8)\\
& \qquad \forall s = 1..S &&\\
\Delta f_{p,p'} &= \overline{F}_{p,p'}/S && (4.9)\\
\boldsymbol{l}_{p,p',t}, \boldsymbol{f}^+_{p,p',t}, \boldsymbol{f}^-_{p,p',t}, \boldsymbol{j}_{p,p',t,s} &\geq 0 && (4.10)\\
& \forall t \in T,\ p, p' \in P &&
\end{aligned}
$$

where $\boldsymbol{f}^+_{p,p',t}$, $\boldsymbol{f}^-_{p,p',t}$ are the positive and negative components of the flow from p to p' at time t ($\left|\boldsymbol{f}_{p,p',t}\right| = \boldsymbol{f}^+_{p,p',t} + \boldsymbol{f}^-_{p,p',t}$), and $\overline{F}_{p,p'}$ is the available transmission capacity from p to p'. Available capacity is divided into $S = 20$ pieces indexed by s, with flow in each segment given by $\boldsymbol{j}_{p,p',t,s}$, and maximum flow in each segment by $\Delta f_{p,p'}$. Resistive loss coefficients are $\mu_{p,p'}$, and the linear slope of the quadratic linearization by $\alpha_{p,p',s}$.

Generator constraints on production and commitment:

$$
\underline{P}_g \boldsymbol{u}_{g,t} \leq \boldsymbol{y}_{g,t} \leq \overline{P}_g \boldsymbol{u}_{g,t}\ ,\ \forall g \in G_{thermal} \tag{4.11}
$$

$$
0 \leq \boldsymbol{y}_{g,t} \leq W_{g,t}\ ,\ \forall g \in G_{wind} \tag{4.12}
$$

$$
\boldsymbol{w}_{g,t} = \boldsymbol{y}_{g,t} - \underline{P}_g \boldsymbol{u}_{g,t} \tag{4.13}
$$

$$
\begin{aligned}
\boldsymbol{w}_{g,t} - \boldsymbol{w}_{g,t-1} &\leq RU_g && (4.14)\\
\boldsymbol{w}_{g,t-1} - \boldsymbol{w}_{g,t} &\leq RD_g && (4.15)
\end{aligned}
$$

$$\begin{aligned}
\boldsymbol{u}_{g,t} &\geq \sum_{t'=t-MU_g}^{t} \boldsymbol{v}^{up}_{g,t'} && (4.16)\\
1-\boldsymbol{u}_{g,t} &\geq \sum_{t'=t-MD_g}^{t} \boldsymbol{v}^{dn}_{g,t'} && (4.17)\\
\boldsymbol{u}_{g,t}-\boldsymbol{u}_{g,t-1} &= \boldsymbol{v}^{up}_{g,t}-\boldsymbol{v}^{dn}_{g,t} && (4.18)\\
& \forall g \in G_{thermal}, t \in T
\end{aligned}$$

where $(\boldsymbol{v}^{up}_{g,t},\ \boldsymbol{v}^{dn}_{g,t})$ are startup and shutdown decisions, $\boldsymbol{w}_{g,t}$ is an auxiliary ramping variable, $(\underline{P}_g,\ \overline{P}_g)$ are minimum and maximum outputs, $(RU_g,\ RD_g)$ are maximum upward and downward ramp rates, $(MU_g,\ MD_g)$ are minimum up and down times, G_{wind} is the set of wind generators, and $W_{g,t}$ is the available wind power by wind generator g at time t. To ensure feasibility of ramping and commitment decisions at the beginning and end of the time period, periodic boundary conditions are assumed (i.e., for negative time indices $-t' \equiv T - t'$).

Spinning reserves to ensure sufficient flexibility to respond to unpredicted changes in demand and supply are calculated from all committed units based on technical limits:

$$\begin{aligned}
\boldsymbol{r}_{g,t} &\leq \boldsymbol{u}_{g,t}\overline{P}_g - \boldsymbol{y}_{g,t} && (4.19)\\
\boldsymbol{s}_{g,t} &\leq \boldsymbol{y}_{g,t} - \boldsymbol{u}_{g,t}\underline{P}_g && (4.20)\\
\boldsymbol{r}_{g,t} &\leq RU_g && (4.21)\\
\boldsymbol{s}_{g,t} &\leq RD_g && (4.22)\\
& \forall g \in G, t \in T
\end{aligned}$$

$$\begin{aligned}
\sum_{g\in G_{res}} \boldsymbol{r}_{g,t} &\geq \overline{RES}_t && (4.23)\\
\sum_{g\in G_{res}} \boldsymbol{s}_{g,t} &\geq \underline{RES}_t && (4.24)\\
& \forall t \in T
\end{aligned}$$

where $(\boldsymbol{r}_{g,t},\ \boldsymbol{s}_{g,t})$ are upward and downward reserve variables, $(\overline{RES}_t,\ \underline{RES}_t)$ are upward and downward system-wide reserve requirements, and G_{res} is the set of generators providing reserves.

Reserve requirements are held constant over the week, set at the province by its peak load, wind capacity and largest unit as contingency. Additional reserve requirements due to wind power are difficult to estimate because of inaccurate wind power forecast error models, and correlations with other imbalances (i.e., load) in the system (Holttinen et al., 2012). In a meta-survey for systems of up to 10% wind penetration by energy, 4% of wind capacity was the reasonable upper end of additional procurement necessary (excluding one outlier study at 15%) (Holttinen et al., 2009). Regulation and load-following reserves in total are set at 3% of peak load:

$$\begin{aligned} \overline{RES}_p &= 3\% \cdot MaxLoad_p + 4\% \cdot WindCap_p \\ &\quad + LargestUnit_p \end{aligned} \tag{4.25}$$

$$\underline{RES}_p = 3\% \cdot MaxLoad_p + 4\% \cdot WindCap_p \tag{4.26}$$

where $LargestUnit_p = 700$ MW is a contingency reserve, $\overline{RES}_p$ is the up reserve requirement for p, and $\underline{RES}_p$ is the down reserve requirement.

Combined heat and power

Combined heat and power (CHP) for district heating is widespread in northern China, where much residential heating in urban areas as well as process steam for industrial applications are provided by centralized cogeneration facilities (Zhao et al., 2012a). These primarily coal-fired cogeneration units are considered "must-run" and have distinct operational constraints co-dependent on heat and electricity output, related to minimum and maximum stable boiler outputs, and minimum condenser threshold (Bartnik and Buryn, 2011). The latter leads to increasing $\underline{P}_g$ with heat output, while maximum boiler outputs lead to decreasing $\overline{P}_g$ with heat output. These two constrain the feasible range of electricity outputs under high heat extraction compared to electricity-only units. Note that this model does not co-optimize heat and electricity production (Rong et al., 2006).

A simplifying assumption used by Chinese grid operators for dispatch purposes is to specify for each CHP unit a fixed minimum electricity output that does not vary with changes in heating load over the day. Rather, this may take on different constant values throughout the heating season, typically divided into three stages: early, middle and late, with higher heating loads in the middle. This corresponds to adjusting ($\underline{P}_g$, $\overline{P}_g$) for $g \in G_{CHP}$, the set of CHP generators. For this paper, these new constraints are assumed constant over the day.

Hydropower

Hydrothermal coordination models may consider multiple time horizons to predict, plan and adjust dispatch based on expected hydropower availability, for example optimized over a full year, then a month or week, and finally daily. Production functions converting water flow into electricity generation may be approximated as linear (Ramos et al., 2010). These models must consider a range of additional constraints related to other water uses such as irrigation, tourism and fisheries.

The main focus of the present study is not to endogenize these constraints—which would also require significant additional data collection—hence I use historical hydropower production data at the provincial level to bound the ranges of allowable hydropower use, and assume hydropower is a flexible resource over the model horizon within those bounds. Thus, inflows are given by model year historic generation levels (which already include applicable inter-season storage) and must equal total average production over the model horizon:

$$
\begin{aligned}
\boldsymbol{h}_{g,t} - \boldsymbol{h}_{g,t-1} &= H_g - \boldsymbol{y}_{g,t} && (4.27)\\
\boldsymbol{h}_{g,t} &= HL_{g,t}\ ,\ t \in \{1, |T|\} && (4.28)\\
\boldsymbol{h}_{g,t} &\geq 0 && (4.29)\\
& \forall g \in G_{hydro}, t \in T
\end{aligned}
$$

where $\boldsymbol{h}_{g,t}$ is the water level in units of generation, H_g is mean inflow of generator g over a timestep, G_{hydro} the set of hydro generators, $HL_{g,t}$ for $t = \{1, |T|\}$ are the fixed initial and final levels. Additionally, there are two different formulations (Form) to bound hydropower use within the model horizon. The first is to specify lower and upper water levels, $\underline{HL}_g$ and $\overline{HL}_g$, respectively:

Hydro Form 1: $$\underline{HL}_g \leq \boldsymbol{h}_{g,t} \leq \overline{HL}_g,\ \forall g \in G_{hydro}, t \in T \qquad (4.30)$$

The second is to set minimum and maximum power outputs:

Hydro Form 2: $$0 < \underline{P}_g \leq \boldsymbol{y}_{g,t} \leq \overline{P}_g < C_g, \ \forall g \in G_{hydro} \tag{4.31}$$

where C_g is the capacity of hydropower generator g. Because of the provincial aggregation of hydropower and lack of detailed reservoir data, the second formulation (4.31) is preferred, particularly for regions with large hydropower with complex reservoirs (e.g., Northwest and South). In this case, historic production levels (controlling for new capacity by converting to capacity factors) over a longer horizon (e.g., a decade) are used to establish average power limits.

Hydropower can provide reserves, but as with the minimum and maximum power outputs, the precise amount depends on various factors. For simplicity, hydropower is assumed to provide reserves equal to one third of its inflow:

$$\begin{aligned} \boldsymbol{r}_{g,t} &\leq 0.3H_g && (4.32) \\ \boldsymbol{s}_{g,t} &\leq 0.3H_g && (4.33) \\ & \forall g \in G_{hydro}, t \in T \end{aligned}$$

4.2.2 Clustering

Improving computational performance of UC models is a major area of research with aims of coupling operational technical characteristics in planning models, incorporating uncertainty and other high-dimension methods, and improving solution reliability of current practices (Padhy, 2004; Ostrowski et al., 2012; Palmintier and Webster, 2014; Ramos et al., 2010; Papavasiliou et al., 2011; Morales-Espana et al., 2013; Carrión and Arroyo, 2006; de Sisternes and Webster, 2013; Cerisola et al., 2009). The key complicating feature is the trio of binary commitment variables ($\boldsymbol{u}_{g,t}$, $\boldsymbol{v}^{up}_{g,t}$, $\boldsymbol{v}^{dn}_{g,t}$) that historically required Lagrangian relaxation methods and is now commonly solved using branch-and-bound methods. Efforts that aim to preserve feasibility while improving solution times involve tightening bounds by finding valid inequalities (Ostrowski et al., 2012; Morales-Espana et al., 2013) and reducing the number of binary variables (Carrión and Arroyo, 2006).

In addition to speeding up computation for sensitivity analysis with uncertain political parameters, the appropriate UC model for China must consider the complicating constraint arising from the annual generation quota. Considering the entire year would be intractable, and even at shorter time scales, this coupling constraint can slow convergence, in ways analogous to incorporating unit startup/shutdown decisions into expansion planning models. Reduction techniques generally fall into categories of time dimension reduction through the use of representative days and weeks (Papavasiliou et al., 2011; de Sisternes and Webster, 2013) and homogeneous or similar unit clustering (Palmintier and Webster, 2014; Cerisola et al., 2009).

I employ here a formulation based on Palmintier and Webster (2014) that clusters multiple binary commitment variables of similar units into integer variables over the combined cluster of generators. Here, we refer to "clustering" as transforming the set of decision variables for multiple units into a new, smaller set for a cluster. We distinguish this from "aggregation" introduced in Section 4.4.2, which only refers to making similar units identical across some set of generation parameters, but which does not alter the set of decision variables. I extend the original formulation to a multi-node system, testing the validity of this approximation in Sec IV. Indexing over generator types $k \in K$ within each $p \in P$, the basic structure involves the variable transformations:

$$(\boldsymbol{y}_{g,t},\, \boldsymbol{w}_{g,t}) \;\;\rightarrow\;\; (\mathbf{Y}_{p,k,t},\, \mathbf{W}_{p,k,t}) \tag{4.34}$$

$$(\boldsymbol{u}_{g,t},\, \boldsymbol{v}^{up}_{g,t},\, \boldsymbol{v}^{dn}_{g,t}) \;\;\rightarrow\;\; (\mathbf{U}_{p,k,t},\, \mathbf{V}^{up}_{p,k,t},\, \mathbf{V}^{dn}_{p,k,t}) \tag{4.35}$$

$$(\boldsymbol{r}_{g,t},\, \boldsymbol{s}_{g,t}) \;\;\rightarrow\;\; (\mathbf{R}_{p,k,t},\, \mathbf{S}_{p,k,t}) \tag{4.36}$$

where $\mathbf{U}$, $\mathbf{V}^{up}$, $\mathbf{V}^{dn} \in \mathbb{Z}_{\geq 0}$. Wind and hydropower are aggregated at the provincial level for all formulations and do not require special treatment. Generator parameters such as $(\underline{P}_g,\, \overline{P}_g)$ are converted to their clustered equivalent.

This is mostly a "drop-in" formulation, with equation structures of (4.1)-(4.31) unchanged and only variable substitutions to their clustered equivalents, summed over the new indices $p \in P, k \in K$ as in (4.34)-(4.36). Throughout, **bold** capitalized variables refer to their clustered equivalents (e.g., $\mathbf{W}_{p,k,t}$ is the clustered $\boldsymbol{w}_{g,t}$). The full cluster model is in Appendix A.

Some specific changes include integer commitments, which cannot exceed the number of installed clustered units $G_{p,k}$:

$$\mathbf{U}_{p,k,t} \leq |G_{p,k}|, \forall p \in P, k \in K, t \in T \tag{4.37}$$

Furthermore, some modifications to the commitment state equations (4.16)-(4.18) are required:

$$\begin{aligned} \mathbf{U}_{p,k,t} &\geq \sum_{t'=t-MU_k}^{t} \mathbf{V}^{up}_{p,k,t'} && (4.38)\\ |G_{p,k}| - \mathbf{U}_{p,k,t} &\geq \sum_{t'=t-MD_k}^{t} \mathbf{V}^{dn}_{p,k,t'} && (4.39)\\ \mathbf{U}_{p,k,t} - \mathbf{U}_{p,k,t-1} &= \mathbf{V}^{up}_{p,k,t} - \mathbf{V}^{dn}_{p,k,t} && (4.40)\\ &\forall p \in P, k \in K, t \in T \end{aligned}$$

Ramping constraints (4.13)-(4.15) are modified to account for startups:

$$\begin{aligned} \mathbf{W}_{p,k,t} &= \mathbf{Y}_{p,k,t} - \underline{P}_k \mathbf{U}_{p,k,t} && (4.41)\\ \mathbf{W}_{g,t} - \mathbf{W}_{g,t-1} &\leq \mathbf{U}_{p,k,t} RU_k && (4.42)\\ \mathbf{W}_{g,t-1} - \mathbf{W}_{g,t} &\leq \mathbf{U}_{p,k,t} RD_k && (4.43)\\ &\forall p \in P, k \in K, t \in T \end{aligned}$$

Finally, some reserve constraints (4.19)-(4.20), (4.23)-(4.24), (4.51)-(4.52) are transformed $g \rightarrow (p, k)$ in a similar manner as above. The remainder (4.21)-(4.22) require a slight modification to account for the number of committed units:

$$\begin{aligned} \mathbf{R}_{p,k,t} &\leq \mathbf{U}_{p,k,t} RU_k && (4.44)\\ \mathbf{S}_{p,k,t} &\leq \mathbf{U}_{p,k,t} RD_k && (4.45)\\ &\forall p \in P, k \in K, t \in T \end{aligned}$$

4.2.3 Two-Stage Model Incorporating Uncertainty

The model assumes deterministic wind (4.12) and demand (4.2) profiles—that is, a perfect forecast for the entire horizon (week). In all real-world systems, forecast errors exist on this time horizon —i.e., actual demand or renewable energy generation differ from expectations. This dissertation does not consider demand forecast uncertainty, which is less pronounced in China due to the high share of industrial demand and low electrification of heating and cooling. CHP minimum electricity outputs are assumed constant over the week, described in Section 4.2.1, and thus are not subject to weather uncertainty.

A significant body of UC work is devoted to wind power uncertainty and how to tractably consider the properties of forecast errors in the unit commitment stage (Zheng et al., 2015). If the UC is performed daily, then day-ahead forecasts can provide information for better commitment scheduling (Mauch, 2012). Beyond several days, e.g. if the UC is performed weekly or longer as in this model, precise forecasts have much less value, and expected seasonal patterns (e.g., nighttime winter winds) may be more useful.

In Chinese systems, as noted in Chapter 3, conventional generator commitments are typically determined at weekly to monthly intervals in order to meet mandatory monthly quota or physical contract totals. These commitments are made well in advance of accurate forecasts, and thus tend to exacerbate inherent uncertainties in demand and wind.

To better simulate system operation procedures and the potential interaction with wind power uncertainty, I construct a two-stage model, where commitments are fixed using a certain wind profile prior to actual wind realizations. Two conservative scheduling procedures are proposed:

1. The system operator commits units assuming a limited amount of wind power, equal to the minimum of the wind profiles in this study (*Min Wind*)

2. The system operator commits units assuming no wind power (*Zero Wind*)

Commitments are determined based on this "minimum wind" or "zero wind" availability, and a second stage model optimizes dispatch based on the "realized" wind, which is the same set of deterministic wind scenarios used in other formulations. The *Min Wind* scenario retains some diurnal wind patterns of the season, providing a reasonable bound on the benefits of forecasts given UC practices. The *Zero Wind* scenario is, in fact, the stated procedure according to respondents in several regions. Crucially, because realized wind profiles are the same across the scenarios, these are directly comparable to the deterministic case. Some related work removes reserve constraints in the second stage because wind is already realized and thus not an uncertain parameter (Papavasiliou et al., 2011). I choose to retain the reserve constraints, because contingency and load following are much larger than the wind capacity summand in reserve requirements (4.25)-(4.26). Additionally, reserve requirements should be equal for comparability with the deterministic case.

4.3 Data Sources

Conducting this analysis in China presents substantial additional difficulties in terms of data collection compared to more commonly studied power systems. In the U.S., numerous sources for generator data exist: for example, the EPA publishes the Emissions & Generation Resource Integrated Database (eGRID), which contains detail on virtually every unit including heat rates and emissions characteristics. Many commercial software packages come preloaded with generator data and networks. Demand, price, generation by type, reserve requirements and many other parameters at hourly levels are available online and by request from numerous grid regions. For Europe, similar types of data exist for many countries, updated on a daily basis.

By contrast, Chinese statistical agencies tend to publish aggregate information (at the monthly or longer time horizons), present the data in non-easily accessible formats (e.g. non-machine readable pdf documents), and do not appear to collect—even for internal use—similar levels of detail from sub-national jurisdictions[1]. In addition, there are persistent concerns about the reliability of Chinese data, particularly economic and energy data at the local level (Ma et al., 2014). Finally, because China's power system is changing rapidly, using data from five years ago may be inappropriate for certain tasks, while this is relatively commonplace in U.S. and European studies.

Through the course of this dissertation, I have collected substantial amounts of online data and reports, accumulated several Chinese engineering journal articles with system data from CNKI Scholar (scholar.cnki.net), obtained statistical tables through a paid subscription with CEIC Data, obtained proprietary data from companies, and acquired printed books in order to digitize tables therein. In some cases, the raw data cannot be published because of use restrictions. The concerns of not providing full access to underlying data have been noted particularly in energy research (Pfenninger et al., 2017), and I will make best efforts to provide as much as possible on my website (www.mdavidson.org). In addition, some English-language aggregators of data on the Chinese

[1] China does have an information request system similar to Freedom Of Information Act in the U.S., which has been used successfully by other researchers to obtain government data. I requested daily electricity consumption data by province beyond that produced by the SERC in 2012-3 described below, and received a polite reply that they do not make or store such data.

energy sector that have been helpful to my research include China Energy Portal (chinaenergyportal.org), Professor Gang He (http://www.ganghe.net/research/data), the Lawrence Berkeley National Laboratory China Energy Databook (https://china.lbl.gov/research-projects/china-energy-databook), and CoalSwarm (coalswarm.org).

In developing models for China, a key consideration is to appropriately tune the level of detail in the model to the level of detail and confidence in the underlying data. If only aggregate generation capacity data were available, then a unit commitment model would have substantially less value, since large assumptions would need to be made to convert that to unit-level detail. Similarly, a detailed load flow model with only a relatively coarse transmission network would be inappropriate. Throughout, I conduct sensitivities with particularly important parameters (such as the number and capacity of committed must-run cogeneration units), and make model simplifications to accommodate available data that may reduce realism (such as ignoring Kirchhoff's second law). I describe below the construction of datasets for each of the key inputs of the unit commitment model and for the modelable institutional conflicts in Sec 4.4.

4.3.1 Generator List and Characteristics

Coal-fired units in China range in size from $\leq$ 6 MW up to 1000 MW for the most advanced units. This wide distribution of unit sizes impacts efficiency and generator constraints important for commitment and dispatch schedules, and will be the main source of variation in production costs for the system. As smaller units are typically older and slated first for early retirement under strong energy efficiency policy incentives, the exact composition is changing each year. Hence, accurate unit-level data is important. Note that coal power plants may consist of as many as 10 units, and aggregate plant level data is less useful than the specifics of each unit: for example, a plant with 3x200MW units will behave differently than 1x600MW unit.

There are a variety of websites that have lists of coal plants in China such as CoalSwarm, that are updated relatively frequently and contain proposed and permitted plants. However, they do tend to focus only on the newer, larger units: for example, the smallest operating unit in the CoalSwarm database for the Northwest region is 50MW, and the next largest is 110MW. By contrast, using the approach below I was able to identify at least 38 units less than 100MW.

The China Electricity Council, the primary industry association for the sector, publishes a printed volume of annual plant-level data, which was chosen as the most authoritative source for this analysis (CEC, 2011, 2015). These books were scanned[2], and digitized using a combination of text recognition and manual input by Chinese colleagues and myself[3]. These plant level data were further converted to unit-level data (for the case of multiple units inside the fence) and identified as electricity-only or CHP through information obtained in the plant names, cross-checking with grid exchange reports (described in Sec 4.3.2), English-language coal plant databases, generation company websites, and other online sources. For the cases of Inner Mongolia (where the western and eastern parts are in two different grid regions) and Gansu (which due to its elongated nature should be considered as two different zones), I conducted additional separations by prefecture, searching on the names of geographic regions and locations provided through company websites.

While there are some published aggregate statistics on fractions of must-run CHP (Zhao et al., 2012b, 2013), these vary substantially, likely depending on whether all units inside the fence or just the active subset are considered CHP, and on the method of assigning cut-offs for CHP. By fixing the minimum generating outputs of must-run cogeneration units, a significant amount of integration space is locked in, which has a large impact on results. However, not all cogeneration units are turned on at all times—some may be reserved for different time periods—and the units that will be committed must be specified. Again, previous work can guide this determination, but are also subject to data availability concerns. Because of the uncertainty involved, the amount of CHP is a key modeling sensitivity.

Next, I clustered thermal units into six different sizes observed frequently during the above cross-checking: 25, 50, 135, 200, 350 and 600 MW. Combined with the binary CHP indicator, this leads to 12 clusters per province. As the specific cogeneration technology—extraction-condensing or backpressure—is not available for all units, 25 MW was used a cut-off for backpressure, above which all are assumed extraction-condensing. These sizes were used to assign the heat rates of the various generators according to some typical values (see Table 4.1), as data on individual heat rates are unobserved or unreliable.

In previous clustering studies (Palmintier and Webster, 2013), size thresholds were defined for each fuel type (e.g., small, medium, and large) and all units smaller than the threshold were

[2] I would like to thank Professor Thomas Rawski at University of Pittsburgh for procuring the 2015 edition.
[3] I would like to thank Weiming Xiong and Xiaodan Huang at Tsinghua University for their invaluable assistance.

Unit size (MW)	Heat rate (gce/kWh)	Heat rate (BTU/kWh)
600	299	8300
350	340	9438
200	375	10410
135	410	11382
50	440	12214
25	500	13880

Table 4.1: Typical heat rates used in this study. Source: Author's calculation based on Asian Development Bank in Ma (2009). (gce = grams-coal-equivalent)

homogenized into a single type of generator with size equal to the mean of the aggregated units in that class. This approach would lead to smaller average capacities relative to the thresholds.

Instead, in this work, units were clustered according to the closest size threshold (either above or below). In order to have comparable unit types across the region of modeling, I let the homogenized unit be the average capacity of units in all provinces for a given type. This leads to minor deviations in total capacity by province compared to the full set of units, the implications of which are explored below.

4.3.2 Transmission Network

The voltages, loss rates, and capacities of inter-provincial lines were constructed from a range of sources. No single authoritative source exists for this in the public domain. First, a threshold commonly used in Chinese power system planning is that ultra-high-voltage (UHV) lines are those that are DC with voltage $\geq$ 500kV (typically written $\pm$500kV to distinguish from AC), or AC $\geq$ 1000kV. UHV lines are typically longer, part of a highly-visible central planning process such as the "air pollution prevention corridors", and hence, have more complete data. The set of UHV lines used in this study are in Table 4.2. Non-UHV lines (i.e., AC $\leq$ 750kV) require substantially more searching.

The following resources were consulted:

- Grid company yearbooks (e.g., State Grid, 2012b). These contain reference to new lines built in that year.

- State grid provincial, regional and national grid exchange reports (e.g., State Grid Shaanxi,

Line Name (Chinese)	Start			End			Voltage (kV)	Length (km)	Capacity (MW)	Operational
DeBao (德宝直流)	Baoji	Shaanxi	NW	Deyang	Sichuan	C	±500	534	3,000	Apr-10
TianZhong (天中直流)	Hami	Xinjiang	NW	Zhengzhou	Henan	C	±800	2192	8,000	Jan-14
HuLiao / YiMu (伊穆直流 / 呼辽直流)	Hulunbuir	E. Inn. Mongolia	NE	Mujiazhen	Liaoning	NE	±500	906	3,000	Sep-10
YinDong (银东直流)	Yinchuan	Ningxia	NW	Qingdao	Shandong	N	±660	1334	4,000	Feb-11

Table 4.2: Ultra-high-voltage (UHV) lines considered in this study. Sources: Zeng et al. (2016); ANL (2015); Various. Prepared by: Alix de Monts.

2015; NECG, 2015b; State Grid, 2012a). These reports hold a wealth of information, including at quarterly levels.

- Provincial five-year plans on electricity development (e.g., Jilin Energy Administration, 2017)
- Google or Baidu image searches (e.g., "2011 甘肃电网地理接线图")
- News articles on large expansions (e.g., 750kV network expansion in the Northwest (Chen, 2010a))

In addition, some assumptions were made when considering upgrades:

- All recent 200kV lines are plant connections or short intra-provincial lines—not inter-provincial.
- No 200kV lines were taken out to upgrade to 500kV. (This has a limited impact on total capacity and computed losses.)

From these data—primarily voltages and approximate transformer locations on either end—capacities and loss rates can be calculated with a handful of assumptions (see Table 4.3). Loss rates for a given power, voltage and distance are documented in the literature: for example, a 500-kV line with 1000-MW loading has a loss rate of 1.3% per 100 miles (161 km) (PJM, 2010). Capacities are more complicated to estimate directly from voltage, and for this study a conservative assumption is made that the Surge Impedance Loading at 300 miles (480 km) is the reliable limit (St. Clair, 1953; Dunlop et al., 1979). While distances between provincial centers are longer (and used for calculating losses), the specific inter-provincial line segments are in fact shorter; hence, 300 miles is a reasonable upper limit. The 750kV lines in the Northwest are further reduced in Table 4.3, because distances are longer. Further, in the model, the 750kV line capacities are further halved because these grid installations are typically twinned for contingency reasons; hence, there is less available capacity.

4.3.3 Demand Profiles

Because there are no publicly available hourly load curves at the provincial level in China, I developed a method to construct these. This thesis expands on a construction for each province and export region in each season of interest in Davidson et al. (2016b). Briefly, the basic procedure for a given province P in season S is as follows:

Voltage	Capacity	Losses at 1000MW, 100 miles		
	MW	MW	%	Source
AC				
220 kV	200	42.50	4.20%	*same as 330kV*
330 kV	400	42.50	4.20%	AEP (345kV)
500 kV	900	12.60	1.30%	AEP
750 kV	1800	5.47	0.55%	ABB, AEP (800kV)
1000 kV	*as reported*	5.47	0.55%	*same as 750kV*
DC				
±500 kV	*as reported*	4.51	0.45%	ABB, Siemens
±600 kV	*as reported*	3.83	0.38%	ABB
±750 kV	*as reported*	3.06	0.31%	ABB

Table 4.3: Typical transmission line capacities and loss rates used in this study. Sources: (AEP, 2008; Dunlop et al., 1979; Siemens, 2012); ABB: (Weimers, 2011). PJM (2010) also cites and reports some of the AEP data.

1. A typical daily load profile for P in S is normalized (i.e. sum to unity over the day). (Source: Davidson et al., 2016b)

2. Daily electricity consumption totals by province (and in some cases, sub-province) for the period August 2012-June 2013[4] are extrapolated to cover the full season S. (Source: SERC, 2013)

3. A full hourly consumption profile for P is constructed by multiplying 1 and 2.

4. Monthly provincial consumption data in the model year and season (e.g. winter 2015 = Jan, Feb, Mar) are used to scale up the profile to match actual totals. (Source: NBS, 2016)

5. Reported peak and valley demands for P in S (if available) are used to further refine the demand profile—e.g., shrink the peak/valley ratio while maintaining the same average demand. (Source: various grid exchange reports)

6. A single week from the profile is chosen where demand is approximately at the mean for the season.

[4] July daily totals were not available, which does not directly affect this study since July demand was not simulated. For the purposes of creating an annual load profile, however, July was approximated from June and August in order to maintain consistent annual aggregate totals as in Davidson et al. (2016b).

This procedure will most likely not recreate precisely the load profiles in the provinces of interest, but at minimum, it should capture hourly variation (e.g., the difference between maximum and minimum load points over a day) and daily variation (e.g., between weekends and weekdays), while being representative at the seasonal levels (e.g., the chosen week will represent reasonably common conditions).

This load profile is derived from historical consumption (notably, 2012-2013 data on daily consumption, and pre-2015 data on hourly profiles), which may change in the future. One of the biggest potential changes is an increasingly "peaky" load profile as a result of a decreasing share of traditional heavy industry which have relatively flat loads. Instead, commercial and residential loads are expected to increase in China, as they have in other countries with increasing affluence. Under this scenario, demands will be more sharply peaked during certain hours of the day, which on average do not align with maximum wind—which occur at nighttime in northern China. A handful of representative city demand profiles were also used in Davidson et al. (2016b) and used to create a "city profile" in step 1 above as opposed to the default "province profile".

4.3.4 Wind Resource Profiles

Hourly wind generation data are not available for any of the regions. In addition, recorded wind generation would already include an unknown reduction due to curtailment, which I am trying to explicitly calculate. Instead, province-wide average wind capacity factors were generated in MATLAB using Modern Era Retrospective-analysis for Research and Applications (MERRA) boundary layer flux data, a high temporal resolution (one hour) atmospheric dataset with 0.5° latitude by 0.67° longitude spatial resolution (approx. 56 km x 61 km at mid-latitudes), available for years 1979-2016. Wind speeds evaluated at the lowest model layer (LML, typically around 50m) were extrapolated up to a height of 80m using the "log law" from Monin-Obukhov similarity theory under a neutral stability assumption (Jacobson, 2005):

$$u(80) = \frac{u_{LML}}{\kappa} \log(\frac{80 - h_{LML}}{z_0}) \tag{4.46}$$

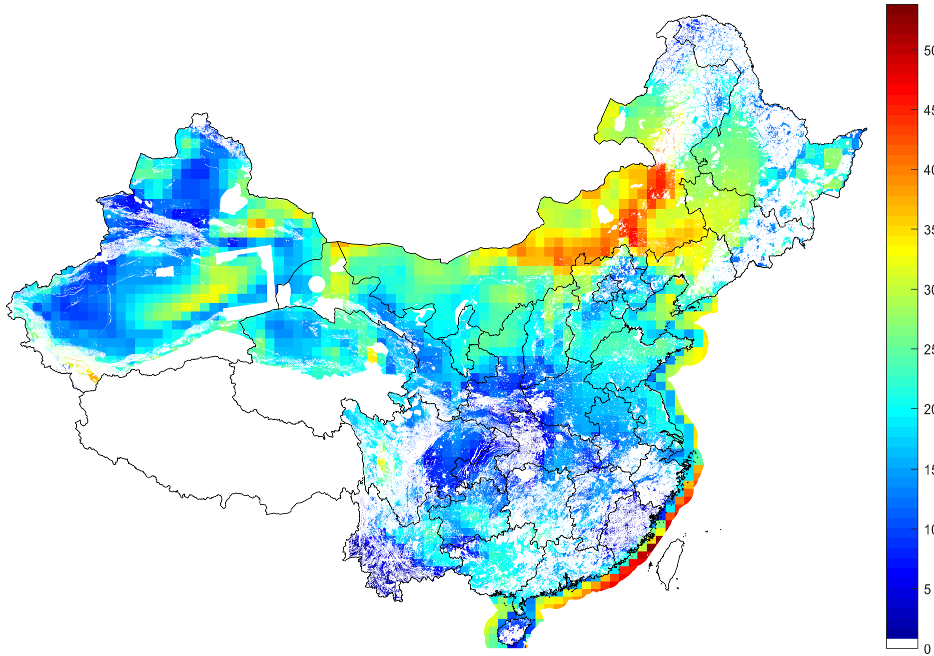


Figure 4.3: Wind capacity factors (%) in China constructed using MERRA, 1979-2015 average. (White areas are deemed unsuitable for wind development.) Source: (Davidson et al., 2016b).

where where h_{LML} is the height at the center of the lowest model layer, u_{LML} is the wind speed at LML, z_0 is the surface roughness, and $\kappa = 0.4$ is the von Kármán constant[5]. Forests, urban areas, slopes greater than 10% and geographic features such as lakes and rivers were excluded as in other assessments (Davidson et al., 2016b; McElroy et al., 2009). The power curve—converting wind speed to power output—of a Sinovel 1.5-MW wind turbine with 82-meter hub height, common in Chinese onshore applications, was used (see Figure 4.3).

Smoothed province-wide wind capacity factors for each hour were then constructed by an average of production in all cells within the province weighted by the available land area. To capture the variability of wind resources, six weeks were taken from the model year (either 2011 or 2015) in the winterseason: first three weeks of January and March.

[5]Reconstructing wind profiles at different heights is the subject of ongoing research, particularly taking into account various surface layer dynamics (Emeis, 2013). Based on my comparison with a handful of wind tower datasets, this formulation performed best in terms of hourly correlation.

4.3.5 Hydropower Resource

For the Northeast, which has limited hydropower installations, some level of detail for a single reservoir (*Lianhua*), including typical and minimum/maximum reservoir levels and corresponding generation rates could be obtained for 2011, in order to parameterize (4.30). Nevertheless, extending to future years and to other regions with larger and more complex reservoirs, this method was abandoned in favor of (4.31), using historical monthly hydropower production to bound minimum and maximum *power outputs* (NBS, 2016).

4.3.6 Generation Quotas

Planned generation for large plants in many provinces are reported in grid exchange reports. However, not all plants are available and the data are not consistently reported across a given region. As quotas are politically negotiated to achieve a level of fairness across generators, I take as my reference quota the actual average thermal capacity factors by province in 2012 and fix across all generator sizes (CEC, 2014a). These are converted to the winter season as described in 4.4.2.

4.3.7 Inter-Provincial Transmission Agreements

The majority of electricity exchanged across borders is planned on a monthly or annual basis (Zeng et al., 2016). While the actual agreements are not public, the planned and actual generation (on a quarterly basis) do not typically deviate significantly in grid exchange reports. It is important to note that these exchanges are better interpreted as supply contracts and not flows: they may report exchanges in both directions, or zero in one direction, and in some cases they include transfers between provinces not directly connected (e.g., between Qinghai and Ningxia in State Grid Qinghai (2015)). Converting total energy contracted over a quarter to power at each hour requires additional assumptions, elaborated below in Sec 4.4.1. For the purposes of this thesis, two different assumptions are used: the average power implied by the flows represent limits on transmission capacity, or the receiving region's demand profile dictates the transmission supply. The latter is substantiated by numerous interviews, and, e.g., contracting for peak and off-peak power transfers between Western Inner Mongolia and North China Grid (SERC, 2013).

4.4 Modelable Institutional Conflicts

The standard unit commitment model (4.1)-(4.31) is a useful benchmark for examining operational impacts of high renewable penetrations and inflexibilities of CHP, but is insufficient to describe the complex institutional environment that persists in China during its restructuring process, as examined in detail through the cases in Chapter 3. In this section, a subset of institutional conflicts identified in the literature and case studies are formulated as additions to the standard UC to better reflect reality and evaluate efficiency losses. Specifically, common to all regions of China are the strong role and autonomy of provincial balancing authorities and minimum generation quotas.

4.4.1 Provincial Dispatch

There are at least two important changes that occur when dispatch is no longer centralized across provinces: transmission line capacities are constrained below their limits, and reserve requirements must be calculated separately for each province. These reflect, respectively, *long-term inflexibilities* associated with inter-provincial transmission contracts and *short-term inflexibilities* due to coordination challenges between distinct operators in charge of balancing operations (< 1 hour). The latter is similar to a pilot reserve-sharing mechanisms begun in 2014 in East China Grid, which was noted by regulators to lower costs and enhance security in the case of contingencies in long-distance transmission lines (NEA, 2016b).

Inter-provincial transmission constraints are essentially derived from annual energy production and consumption planning, and then converted to power transfers on sub-monthly scales (Kahrl et al., 2013, and Interviews). Ideally, granular data on fine temporal scales (e.g., weekly or daily) would be used to fix a narrow range of allowable transmission quantities; though, these data are not directly available and need to be constructed.

Transmission limits are fixed to a narrow range ("band") according to the total net amount of over-generation or over-consumption given by inter-provincial supply contracts, normalized according to the *receiving province/region* demand profile. Hence, I replace (4.6) with:

$$\boldsymbol{og}_{p,t} = \sum_{g \in G_p} \boldsymbol{y}_{g,t} - d_{p,t} + \boldsymbol{NSE_{p,t}} \tag{4.47}$$

$$(1-\beta)\overline{NF}^*_{p,t} \leq \boldsymbol{og}_{p,t} \leq (1+\beta)\overline{NF}^*_{p,t},\ \forall p, t\ s.t.\ \overline{NF}^*_{p,t} \geq 0 \tag{4.48}$$

$$(1+\beta)\overline{NF}^*_{p,t} \leq \boldsymbol{og}_{p,t} \leq (1-\beta)\overline{NF}^*_{p,t},\ \forall p, t\ s.t.\ \overline{NF}^*_{p,t} < 0 \tag{4.49}$$

$$\overline{NF}^*_{p,t} = \sum_{p'} \overline{FA}_{p,p'} \frac{d_{p',t}}{\bar{d}_{p'}} - \sum_{p'} \overline{FA}_{p',p} \frac{d_{p,t}}{\bar{d}_p},\ \forall p, t \tag{4.50}$$

where $\boldsymbol{og}_{p,t}$ is the over-generation in each time period, $\overline{NF}^*_{p,t}$ is the middle of the transmission band as determined by the mean historical power transfer $\overline{FA}_{p,p'}$, $\bar{d}_p$ is the average demand, and β is a parameter defining the size of the band, set to 0.1 by default. $\overline{FA}_{p,p'}$ is the average power transacted, or the mean of $FA_{p,p'}$ over the time period (e.g., quarterly in later years). Note that these transactions are typically recorded in grid exchange reports separately for exports vs. imports. Hence, they are not *net* exports; and, in general, $\overline{FA}_{p,p'} \neq -\overline{FA}_{p',p}$. For earlier year model runs (i.e., 2011), only annual data are available. In later years, seasonal data are available.

In the standard UC model, aggregate reserve constraints (4.23)-(4.24) are imposed for the entire region. Under provincial dispatch, we also require each province to meet its reserve requirements internally, replacing (4.23)-(4.24) with:

$$\sum_{g \in G_{res} \cap G_p} \boldsymbol{r}_{g,t} \geq \overline{RES}_p \tag{4.51}$$

$$\sum_{g \in G_{res} \cap G_p} \boldsymbol{s}_{g,t} \geq \underline{RES}_p \tag{4.52}$$

$$\forall t \in T, p \in P$$

where reserve requirements are again held constant over the week (e.g., $\overline{RES}_{p,t} = \overline{RES}_p$, $\forall t$).

Model parameterization

Provincial dispatch thus relies on the following data:

- $FA_{p,p'}$: inter-provincial supply contracts / transfers
- $\overline{RES}_p$, $\underline{RES}_p$: upper and lower reserve requirements

4.4.2 Minimum Generation Quotas

Similar to modeling hydro-thermal coordination and mid-term maintenance scheduling, the requirement that each generator achieves a minimum amount of generation over the course of the year introduces a large coupling constraint. Extending the time horizon T to an entire year would require significant simplifications to remain tractable, therefore minimum generation constraints on aggregated similar cost units is proposed. This allows a unit to not be committed during the model horizon without violating its annual quota. Instead, all generators of a given type k must collectively meet the quota, as the clustered unit variables include only the total number of committed generators and the generation from those generators.

For example, let us assume that half of the available units of a given type are committed during the model week, and the other half are not committed. All units have a quota equivalent to a fraction $Q_{p,k}$ of their capacity. In determining the least cost solution of achieving this quota, the model may generate $2 * Q * 168$ from the committed units and 0 from uncommitted units during the model week. As the units are clustered and seen as equivalent, the system cost is equal regardless of which generator is chosen to be committed. Hence, for the same solution, it would be equivalent for the system operator to choose a different set of generators to commit and assign energy. Meeting this quota for each week in the quota timeframe (e.g. winter heating season) ensures that all generators on average can achieve their quota.

This is similar to solving the entire problem simultaneously except for 1) possible underestimation of commitment costs outside of the week; and 2) any commitment time constraints at the model boundary (assumed periodic), which are likely small because startup times $\ll$ 168 hours.

Additionally, it is not assumed that the constraint is constant throughout the year. In particular, as cogeneration units must be committed to provide district heating in the roughly six-month winter heating season, non-cogeneration units are preferentially committed in summer to maintain comparable generation amounts over the year. There is a trade-off when selecting the length of the time horizon T such that, on one hand, sufficient flexibility is allowed for meeting the quota constraint and, on the other, the problem remains tractable. In its general form, this constraint is given by:

$$\sum_{g \in G_{p,k}} \sum_{t \in T} \boldsymbol{y}_{g,t} \geq Q_{p,k} \cdot |T| \cdot \sum_{g \in G_{p,k}} \overline{P}_g, \ \forall p \in P, k \in K \tag{4.53}$$

where $k \in K$ indexes clustered generators with minimum generation quotas, $Q_{p,k}$ is the capacity factor quota for generators of type k in province p, and $G_{p,k}$ is the set of these generators.

Model parameterization

The quota system is designed to ensure equitable dispatch and revenue sufficiency for generators. Both criteria can vary substantially across provinces. For example, as the NE has excess thermal capacity, the generation that can be allocated per coal plant is lower, which has the effect of reducing quotas. The parameters necessary for the quota formulation are therefore:

- $Q_{p,k}$: minimum annual quota for generator type k in province p

The quota is an annual minimum constraint on individual generators, but clustering allows us to consider seasonal averages over sums of similar type units as in (4.53). In the three northern regions, the different seasonal operations of CHP units should be considered: to calculate the heating season ("winter") average, it is assumed that CHP units will achieve most of their quota during the high must-run winter months. By contrast, electricity-only units will predominate in the non-winter heating season ("summer"). If the maximum capacity factor they can achieve in summer is 80% due to availability of units and common loadings, then we can roughly approximate the minimum capacity factor they must achieve in the winter based on annual averages. Due to data availability, I use average thermal capacity factors in 2012 (CEC, 2014a). I also let the quotas be constant across all sizes (i.e., $Q_{p,k} = Q_p$).

4.4.3 Summary

In this chapter, I introduced the core quantitative model for the dissertation, elaborating on the range of data inputs and optional parameters in the power systems engineering literature. These represent a best guess of optimal system operation given engineering realities. I then incorporate several modelable features of China's system operation institutions—provincial reserve requirements, pre-scheduled inter-provincial flows, and minimum generation quotas—as well as a two-stage formulation capturing China's scheduling inflexibility together with some technical limits on wind forecasting. In the next chapter, I will evaluate the reference system combined with each of these

—in separation and in interactions—to quantify to what extent each of these institutions causes divergence from the optimal cost and wind integration.

Chapter 5

Computational Results

5.1 Experimental Setup

The computational model is formulated for three of the four grid regions in the study: the Northeast (NE), W. Inner Mongolia (W. IM), and the Northwest (NW). Based on fundamental endowments of the regions (e.g., limited hydropower in NE, multiple export lines in NW, etc.) and the qualitative findings from Chapter 3, there are differences in each region's formulation, described in each region's section below.

The experimental setup consists of running the UC model over a one-week horizon in winter (168 hourly time-steps) and averaging results for six different scenarios of wind availability (from the model year and season) while keeping other inputs (e.g., demand) constant. Periodic boundary conditions are assumed—such that coupling constraints before or after the model horizon are carried over into the same model—and the entire week's results are kept, in contrast to shorter 2-3 day UC models where only the next day's results are typically kept.

A week horizon was chosen for several reasons:

1. Captures sufficient variation in demand and wind on timescales long enough to incorporate coal unit inflexibilities;

2. Reflects commitment scheduling processes (based on Chapter 3 discussions with grid operators in the regions studied) by aligning with, or not exceeding, the shortest timeframes of current practice; and

3. Balances computational tractability compared to a longer horizon.

A longer horizon could incorporate greater flexibility in meeting quota or medium- to long-term contract constraints, as the grid company typically verifies these on a monthly basis. Thus, reducing this constraint to a weekly timeframe would over-constrain dispatch schedules. However, as noted in Section 4.4.2, one contribution of this model is implementing, in effect, a seasonal or annual constraint on a week-long model horizon through the use of clustering. In particular, the clustered formulation of the quota (4.53) is not equivalent to requiring each generator meet its quota for the given week. Instead, all generators of a given type must collectively meet the quota. The clustered unit variables include only the total number of committed generators and the generation from those generators.

Longer horizons would lead to other, more subtle, complications, including:

1. Overlapping with maintenance scheduling to take units offline; and

2. Long-term forecasting errors (of demand, generator availability, renewable resources, etc.) and readjustment processes.

The second aspect—particularly for wind power uncertainty—is still relevant even on a weekly horizon, and is investigated through a two-stage model that simulates how outcomes differ when one does not have perfect foresight on wind production.

Winter seasons were chosen because they represent the higher fraction of wind curtailment in northern China, when average wind speeds are higher and other constraints such as cogeneration are more important. Therefore, these results are not representative of annual averages. There is still summer curtailment, complicated in the Northwest, for example, by hydropower reservoir planning given larger rainfalls.

Wind power variability—i.e., differences in output over similar timeframes even if they could be perfectly forecasted—is addressed by running the same scenarios for six different profiles from the given season and averaging the results (average curtailment rates are calculated via the totals of wind curtailment and production, not by directly averaging the rates). The individual results for wind scenarios across several runs demonstrate that there is significant variation in costs and wind integration depending on wind availability, and conclusions based on differences in average results between runs are appropriately scoped, if necessary, to accommodate.

	Regional Reserves		Provincial Reserves	
	Full Transmission	Restricted Transmission	Full Transmission	Restricted Transmission
No Quota	R	RT	P	PT
Quota	RQ	RTQ	PQ	PTQ

Table 5.1: Three basic institutions in full factorial representation used throughout this chapter.

The models are implemented in GAMS and solved using ILOG CPLEX 12.6.2. Each scenario is run using up to 8 parallel threads on a dual-socket 12-core 2.5 GHz Intel Xeon machine with 128 GB RAM. The MIP optimality tolerance is set to 10^{-3} and resource limit to 360 minutes. Analysis of the results is carried out in R using RStudio.

5.1.1 Parameter Selection and Sensitivity Analysis

Three essential legacy institutions of the planning era were introduced in Chapter 4, the separate and interactive effects of which I am investigating: 1) inter-provincial transmission limits according to long-term contracting; 2) low or zero amounts of inter-provincial reserve sharing; and 3) conventional generator quotas. A "full factorial" set of experiments simulates the same system with all possible combinations of on/off states of these institutions. Thus, a basic set of eight (8) runs will be repeated throughout this chapter, denoted in Table 5.1.

A wide range of additional sensitivities are necessary because of fundamental uncertainties in input parameters, as well as to test the robustness of results to potential future changes in system conditions. In most cases, one parameter is chosen (e.g., the number of committed must-run CHP units) and varied over a range for each of the eight institutional combinations, with defaults for the other unvaried parameters. In a typical example, if a large sensitivity of a parameter or parameters representing an institution does not result in large changes in outcomes, the model effectively rules out this as a cause. By contrast, a strong sensitivity of outcomes over likely parameter ranges provides greater evidence of plausibility. Another strong indicator is when outcomes change under interaction of multiple mechanisms as opposed to each individually. A much larger enterprise would be to conduct joint sensitivities across multiple parameters with more advanced sampling techniques and statistical estimation (Box and Liu, 1999). This method would also require selecting probability distributions for these uncertain parameters.

Results from all regions demonstrate that the system is constrained in numerous dimensions, resulting in infeasibilities or high penalties for non-served energy for some combinations of otherwise reasonable default parameters. An infeasibility refers to when the optimization cannot find a set of decision variables that simultaneously satisfies all constraints. When infeasibility or infeasibility-like conditions arise in this UC model, there are several possibilities:

1. There are errors in input datasets (e.g., categorizing coal units into CHP, network limits, etc.);

2. Common parameters used in international systems are not appropriate or not used in Chinese systems (e.g., reserve requirements); and/or

3. There are additional flexibilities in operation not captured in the model formulation (e.g., ad-hoc coordination).

The above robustness checks can test 1 and 2, providing some reasonable bounds for the effects of different institutions across the range of likely parameters. For 3, there is always the possibility that special circumstances will warrant moving beyond standard operational procedures. These ad-hoc measures are particularly challenging to implement in the current modeling framework, though we know they exist in various cases (e.g., special export scheduling for sudden demand drops over the Chinese New Year). Care has been taken to select demand profiles (a common difference across the model season) in the center of distribution (e.g., avoiding New Year demand irregularities). The general approach to assess the third possibility:

1. Relax parameter until the model becomes feasible

2. If applicable, assess how far this diverges from common practice in other systems

3. If possible, put in context of qualitative evidence of system operation from Chapter 3

The latter will be discussed in the iterative analysis in Chapter 6.

5.1.2 Quantitative Assessment of Political Economy and Engineering Expectations

Several expectations on the causes of system inefficiency and poor wind integration outcomes were introduced and explored through qualitative data in Chapter 3. I reproduce the same table from

Chapter 3 here in Table 5.2. Readers can also return to Table 3.9 in Chapter 3 (p. 118) for a breakdown of causes that can be tested with qualitative vs. quantitative evidence.

First and foremost, determining the extent of technical causes of curtailment, such as transmission and conventional generator inflexibilities, requires a detailed grid model. Additionally, the impact of market context and some of the rules of system operation deviating from region-wide least-cost dispatch are amenable to modeling. The quota represents a long-term physical contract—not determined in a strictly merit order fashion—whose fulfillment is integral to grid operations, and whose impact on system flexibility was raised by respondents. Finally, some of the particular elements of the province-centric nature of system operation—such as trading arrangements derived from coordination issues and protectionism—can be estimated using constraints and clustering introduced in Chapter 4.

Political Economy Expectations	**Engineering Expectations**
Physical Contracts: Long-term physical contracts restrict short-term balancing, increasing curtailment.	***Poor Demand Correlation***: Low demand during hours of high wind penetrations result in excess wind curtailed.
Provincial Authority: Provincial governments give preference to (within-province) conventional energy through its planning, operations and market authority.	***Must-Run Generation***: Combined heat and power (CHP) plants, classified as must-run, reduce integration space for wind.
Inter-Provincial Trading Rules: Different trading rules across provinces and regions inhibit short-term trading, restricting renewable exports and increasing curtailment.	***Conventional Plant Inflexibility***: Technical criteria of conventional plants (e.g., minimum outputs, start-up times, etc.) limit the system's ability to manage wind's variability.
	Grid Inflexibility: Transmission network or reliability constraints limit integration potential.
	Export Potential: Inter-regional export capacity and receiving region demand determine wind integration.

Table 5.2: Political economy and engineering expectations of China's wind integration outcomes based on prior literature

5.1.3 Solution Algorithm

For binary formulations, with 125,000 discrete variables and 344,000 constraints following the CPLEX presolve stage of model simplification, there is varied performance in terms of solution times and optimality gaps when the quota constraint is activated. This arises from the difficulty of solving this coupling constraint across a large number of variables. Besides the quota, the next most important coupling constraint is demand, which connects all generators, but separately for each hour. I adjusted the scale of the problem using SCALEOPT in GAMS and changed the following CPLEX options, resulting in significant gains[1]:

- MIPSTART. Solve first the minimum wind scenario and use this as initial feasible integer solution for each of the wind profiles.
- Barrier algorithm for linear subproblems. In contrast to the default dual simplex method, the barrier method (interior point) reached optimality more quickly, likely because of the large, sparse constraint matrices.
- Relaxation Induced Neighborhood Search (RINS). After a specified number of nodes explored (a value of 100 was tested), the solver searches in the neighborhood of the current incumbent for an improved solution, thus potentially paring down lengthy search trees.

Solution times for all formulations for the NE 2011 winter model are shown in Table 5.3, inclusive of solving the initial minimum wind scenario. In moving from the full binary formulation (considering each unit's reported minimum and maximum output, and scaled ramp rates) to the aggregated binary formulation (units are homogenized into one of the twelve categories, still with individual binary commitments), solution times unexpectedly increase dramatically for the constrained transmission case. In addition, several wind scenarios do not converge, and a handful do not even find a feasible solution. In the clustered formulation (integer commitments), solve times reduced by 30-1300 times compared to the aggregated-binary.

The poor performance of the aggregated formulation compared to the full binary is likely attributable to the degeneracies of similar units, and further work could examine in what circumstances similar time penalties should be expected. The addition of transmission losses also affects

[1] I thank Andrés Ramos for this advice on enhancing solution performance.

RUN	FULL UNITS	12 TYPE	CLUSTER
R	18.19	12.90	1.59
P	22.37	15.26	1.35
RT	160.00	480.52*	2.32
PT	101.14	1996.62*	1.84
RQ		317.68	4.46
PQ		774.21*	40.16
RTQ		627.33*	9.42
PTQ		2522.04*	69.53

R: Regional reserves. P: Provincial reserves.

T: Limited transmission. Q: Quota.

*One or more wind scenarios did not solve to optimality.

Table 5.3: Solution times (minutes) for binary (full units), aggregated-binary (12-type) and aggregated-integer (Clustered) formulations, Northeast 2011.

solution times—increasing times in the aggregated case, but *decreasing* solution times by an order of magnitude or larger for the provincial-reserves transmission-constrained (PT) full binary.

5.1.4 Aggregation / Clustering Errors

Examining the effects of aggregation and clustering, these two sequential simplification steps have a small impact on two outcome variables of interest: objective and wind total. Comparing the aggregated binary (12-type) and aggregated integer (Clustered) formulations for the Northeast 2011 system, the errors introduced with respect to using the full set of units and unmodified capacities are very small over the entire system: objectives are within 0.02%, and wind totals within 0.14% (see Figure 5.1). These errors are magnified at the individual provincial node in the objective, ranging from $-1.4\% \sim +2.4\%$ for the 12-type and $-2.1\% \sim +3.1\%$ for the clustered formulations. Wind totals at the province are within $\pm 0.75\%$. Collectively, these demonstrate that clustering can be used on this network with the given set of parameters.

Additionally, given the comparable errors of the integer and binary commitment formulations in the objective, it is clear that the loss in accuracy is primarily caused by the aggregation step —i.e., making several heterogeneous units have the same parameters. Thus, if errors become too large, increasing the number of clusters is a viable approach while maintaining the benefits (e.g., coupling constraints exceeding the model horizon).

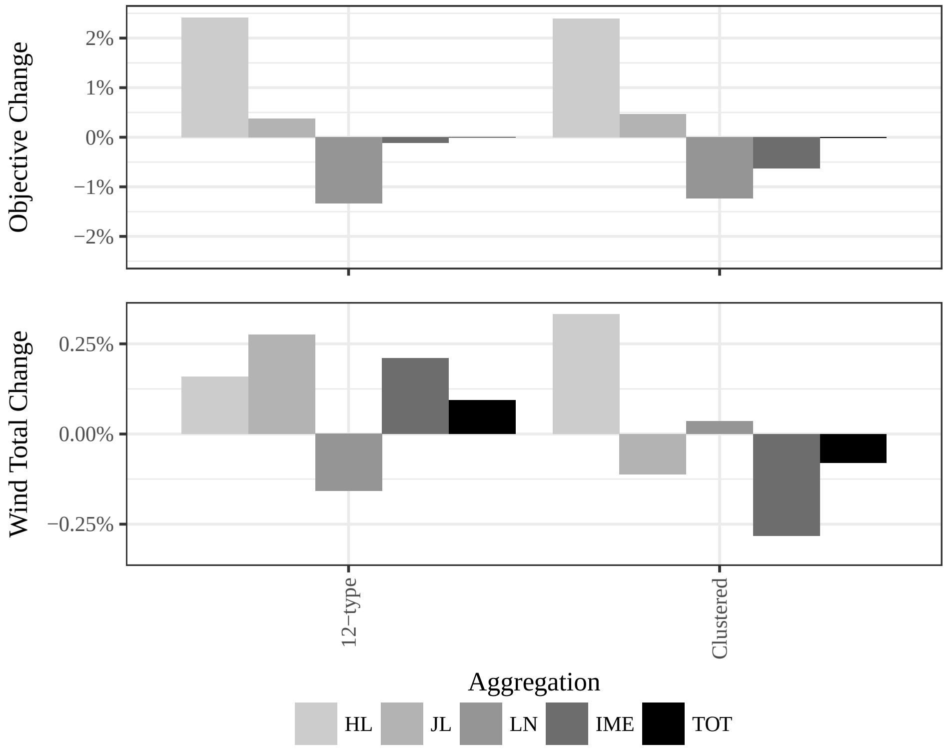


Figure 5.1: Aggregation errors of objective and wind totals with respect to full-binary formulation by province for aggregated-binary (12-type) and aggregated-integer (Clustered), Northeast 2011 reference case

5.2 Northeast Grid

5.2.1 Region-Specific Modeling Inputs

Northeast load profiles are relatively flat in the largest demand center Liaoning and the less populated E. Inner Mongolia, with slightly more variation in Heilongjiang and Jilin (see Figure 5.2).

Six winter wind profiles for the Northeast—three from January (abbreviated 'Ja') and three from March ('Ma')—are shown in Figure 5.2.

Generation from hydropower is concentrated in the rainy seasons, as determined by reservoir capacity and other needs of water management. Thus, winter flows are relatively small. The year 2015 was also low compared to the historical period of the last decade. Hydropower inflows were calculated using average monthly *generation* totals (as described in Chapter 4) in order to incorporate these other more complicated constraints. For these winter runs, weekly generation

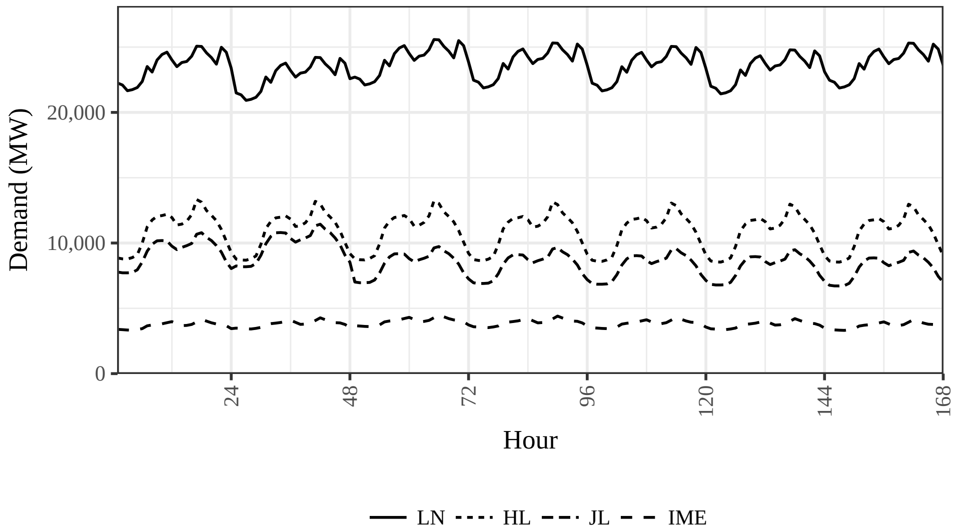


Figure 5.2: Northeast demand

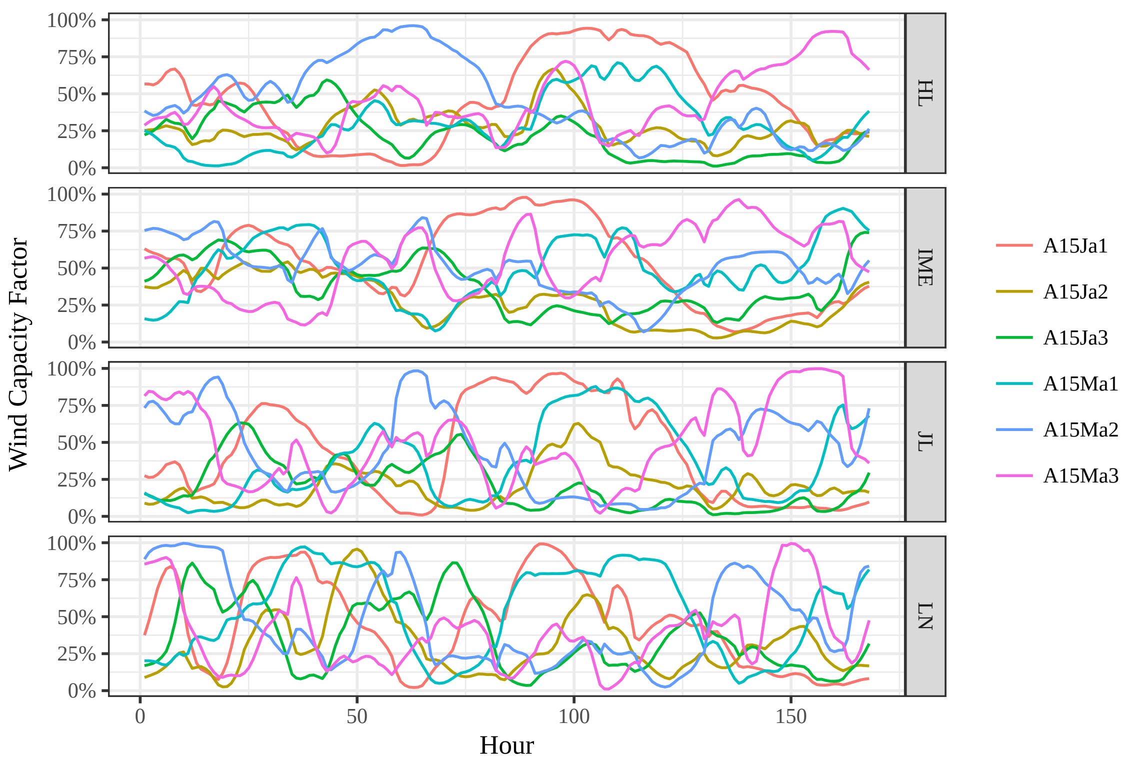


Figure 5.3: Northeast wind profiles

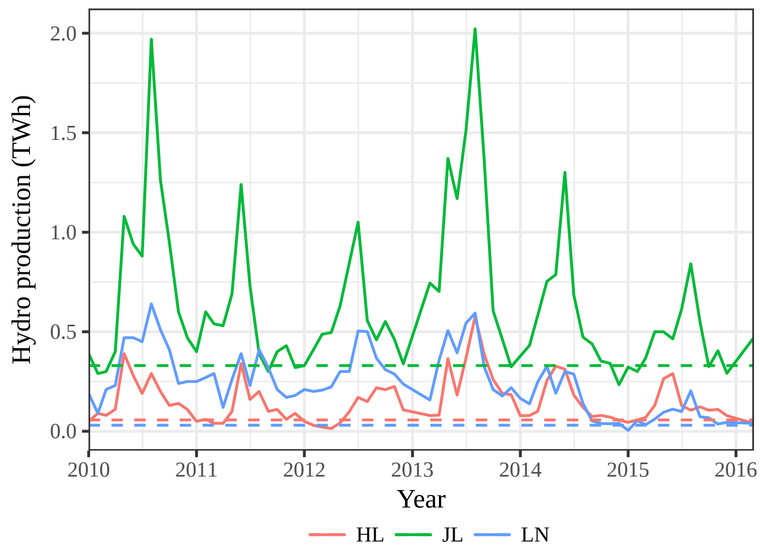


Figure 5.4: Northeast hydropower production and 2015 winter monthly average. Source: (NBS, 2016).

was created from a January-March average (see Figure 5.4).

5.2.2 Reference Results

The reference results relative to norms for each generation type, in the absence of any institutions constraining efficient operation, produces high capacity factors from must-run cogeneration units, wind, and high-efficiency coal (600 MW). All other generators are relatively unused, and production from low-efficiency non-cogeneration units are basically zero (see Figure 5.5). A reasonable reference scenario is used throughout the Northeast results (unless otherwise noted) with default parameters described above and in Chapter 4, with the additional modification of decommitting a certain number of CHP units. **In the base case, roughly two of each type of CHP (*cogen25*, *cogen50*, ... *cogen350*) are decommitted per province**, corresponding to around 80% of the minimum mode of full commitment, which is designed to reflect redundancy of units in some heating grids as well as possible mis-categorization of cogeneration units. This sensitivity and precise calculation of the minimum modes are explored further in Section 5.2.6. Throughout the Northeast section, unless otherwise noted, this will be the default CHP minimum mode.

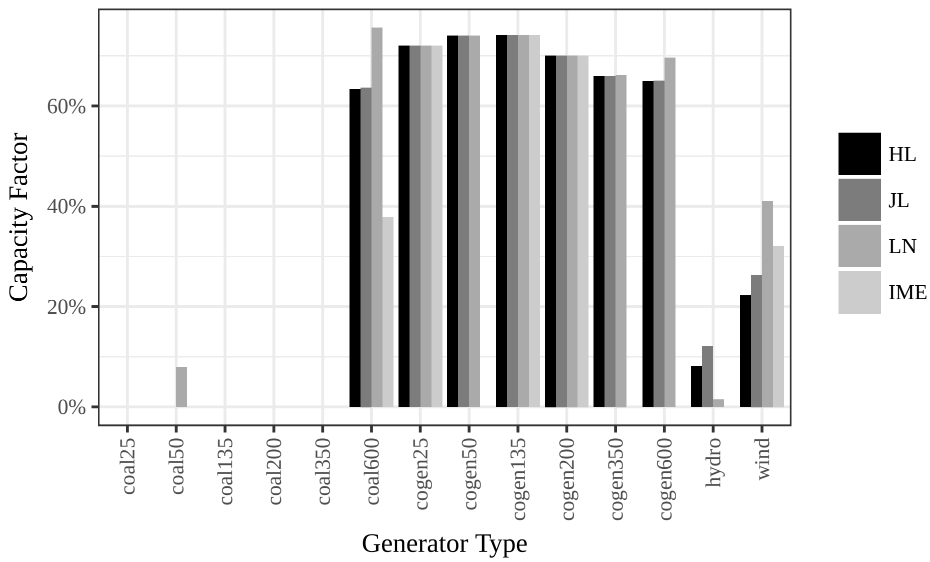


Figure 5.5: Capacity factors in reference case, Northeast. (full reserves)

One of the week's generation profiles is shown in Figure 5.6. Wind is highly variable over the week, and almost all of this balanced by efficient 600 MW coal generators. Daily changes in demand are also balanced by *coal600*. Cogeneration units operate at their minimums for most of the week. Wind curtailment occurs at night or early morning, when demand is lowest, as well as over multi-day stretches when there is a lot of coincident wind across the region and conventional units are at their minimum outputs. The limited hydropower availability in the Jilin winter is also used to meet some peak demand periods, ramping down during valley hours.

5.2.3 Commitment Scheduling and Two-Stage Model Results

In the reference case, commitment schedules and dispatch are made at the same time, based on perfect forecasts for wind. Two other scheduling processes are explored using the two-stage model, which cause the largest differences in model outcomes. In this setup, coal commitments are made for the entire week based on different assumptions of wind availability (*Min Wind* or *Zero Wind*), and in a second stage dispatch is calculated given actual wind and committed generators from the first stage.

These two alternate assumptions reflect two important aspects of the UC problem in these systems: the inherent unpredictability of wind as well as the inflexibility of long-horizon commitment scheduling practiced in the Chinese cases. The reference case assumes perfect foresight (*Perfect*)

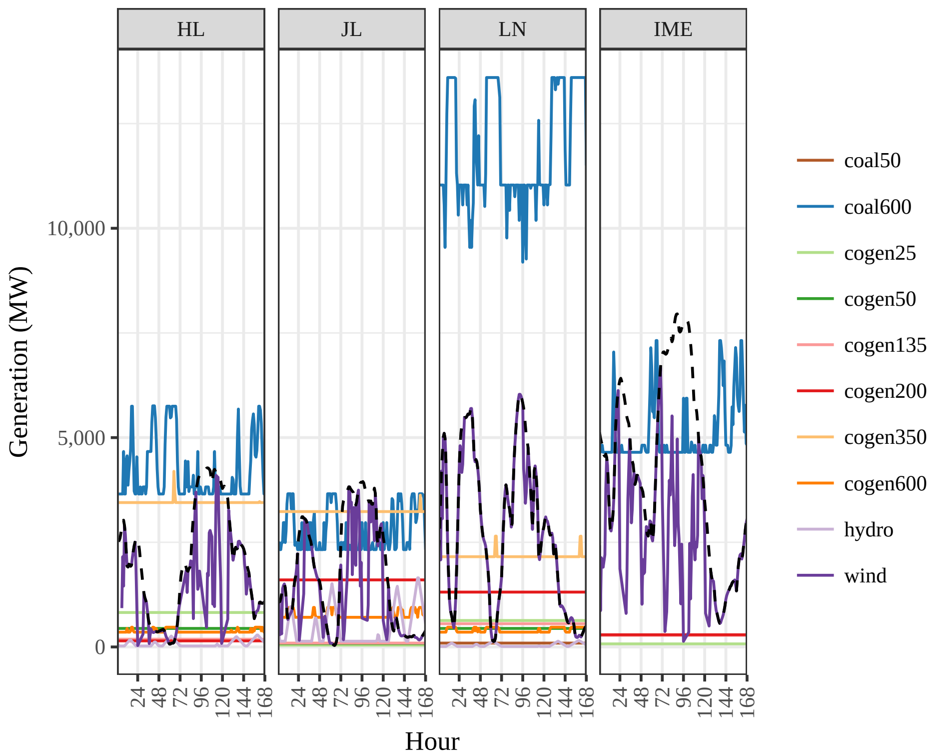


Figure 5.6: Single week generation profile for one wind scenario in the reference case, Northeast. Dotted lines are pre-curtailment wind. (full reserves)

and is not strictly realistic. However, the imperfect foresight scenarios (*Min Wind* and *Zero Wind*) schedule commitments for the entire week based on the poor (or no) wind forecasts available, which is a consequence of the rigid commitment schedule imposed on these systems.

In Figure 5.7, the changes in capacity factors across provinces for major generating types are shown. Wind's capacity factor is reduced in all provinces (i.e., curtailed) as scheduling assumptions become more rigid. The cause is that under a zero wind assumption, more high-efficiency coal units in East Inner Mongolia (IME) are committed, which are then operating at their minimum output for most of the week once wind is added onto the dispatch. Here, the fundamental problem with long horizon commitment scheduling is revealed: overcommitment of units that raises the minimum mode of the system, decreasing flexibility to absorb large wind episodes.

One might argue that because the model forces (primarily) monthly-settled quotas to be met for each week, it will have less flexibility than the actual system, which could in theory transfer quota generation between weeks. For example, in the NE (and most other surveyed systems), coal commitments are made on a monthly basis. However, precisely because the commitments are made well in advance of realizations of wind uncertainties, there is no realistic expectation that operations can optimize quota achievement within the month based on wind availability alone. This leaves the only viable option as assuming constancy across weeks. Demand could possibly vary predictably weeks in advance (in particular, around Chinese New Year), but that uncertainty is not considered in any of the modeled scenarios.

5.2.4 Reserve Requirements Sensitivity

Another influential parameter affecting outcomes is the reserve requirement, which, recalling from Chapter 4, is the minimum amount of available generation space (both upward and downward) of committed generators in order to respond to unexpected changes in system conditions. The default reserve requirements were set according to common international practice in 4.25-4.26 on p. 177. These requirements are the subject of significant power systems engineering research, particularly in the context of growing renewable energy penetrations. Precise and visible reserve requirements, as such, do not exist in the Chinese systems I studied, where there appeared to be more rules of thumb, possibly informed by extensive historical knowledge of the network and common conditions.

Wind energy itself can provide some reserves to the system, subject to some constraints de-

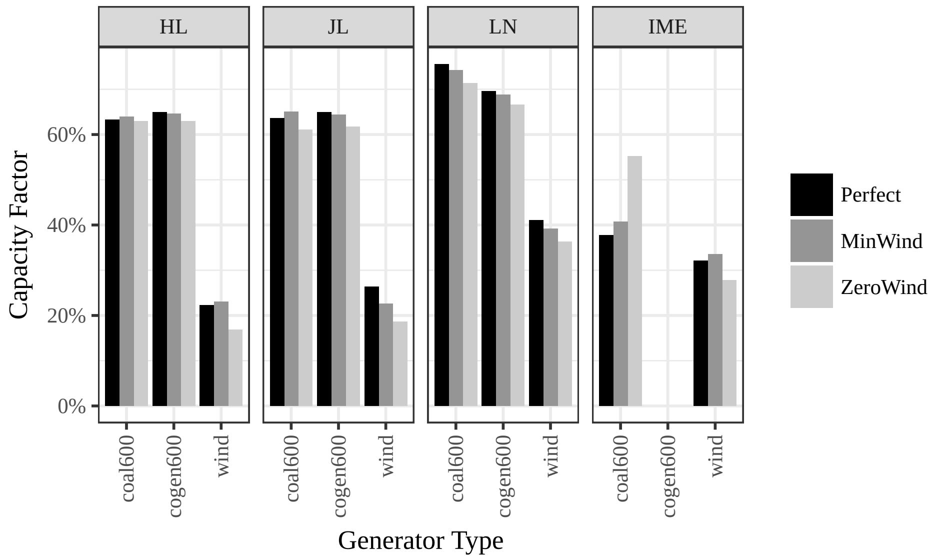


Figure 5.7: Capacity factors of large coal and wind by province for different commitment scheduling assumptions, Northeast.

scribed in Chapter 4. Here, I focus only on down reserves. These incorporate primarily the ability of generators to ramp down when there is an unexpected drop in demand (or equivalently, an increase in renewable energy availability). Roughly 20% of total region-wide down reserves are associated with the additional component to handle unexpected increases in wind generation. No operator in any of the cases said that wind energy is used to provide reserves. Making commitment schedules a week or more in advance creates a lot of uncertainty about how much wind could provide in each hour, as reserves are limited by actual wind generation.

The two scenarios of wind providing no reserves and wind providing down reserves (up to its generation in that hour) are shown in Figure 5.8. Increasing reserve requirements has a non-linear impact on both costs and curtailment, and there is a substantial difference in the two scenarios. Current practice is more closely aligned with the no reserves case, while the down reserves case is instructive for what could happen with more granular scheduling, reserve requirement calculations, and wind farm automation.

5.2.5 Three Legacy Institutional Conflicts

Incorporating the three basic legacy institutions in Table 5.1 into the model vastly alters the feasible space of the model, indicating that the system becomes increasingly constrained. As discussed in

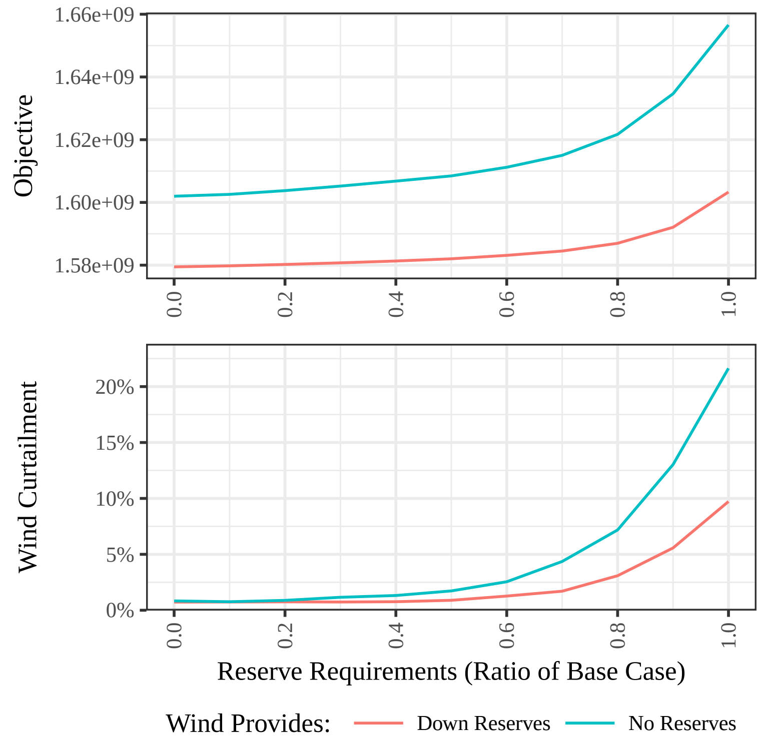


Figure 5.8: Objectives and wind curtailment for range of reserve requirements and wind reserve ability in reference case, Northeast.

Section 5.1.1, it is possible that international practice for essential system constraints such as reserve requirements may not be fully achieved or there is additional flexibility in system operation (such as through ad-hoc measures) that is not captured in the model.

One of the most influential parameters affecting feasibility is the reserve requirement, which had a large effect on reference outcomes in the last section. When layering on the institution (P) to meet all reserve requirements of a province within its borders, the system becomes infeasible above 90% of the base case requirement. When reserves must be met locally and there is limited transmission due to inter-provincial contracts (PT), it becomes infeasible above 60% of the base case requirement. See below for a sensitivity on this. For comparability across runs and to ensure feasibility, the **reserve requirement is lowered to 50% of the base case for the remainder of the results on institutional conflicts**. Note that it is possible that, in practice, provided reserves are above this level in all hours, pointing to the possibility for additional (ad-hoc) flexibility not captured in the model.

Adding these legacy institutions, total production costs increase, with the largest increase coming from imposing the quota (see Figure 5.9). A smaller cost impact comes from imposing the inter-provincial transmission constraint (e.g., moving from R→RT, RQ→RTQ). However, the combination of within-province reserve requirements and limited transmission interconnection (PT, PTQ) decreases flexibility substantially, causing additional costs and tripling wind curtailment. Note that the relative magnitudes of each of these institutions change under different reserve requirement levels (see sensitivity below).

Interactions with commitment scheduling

When combining these three institutions with the various commit scheduling assumptions (*Min Wind*, *Zero Wind*), costs and curtailment increase as in Figure 5.10. For example, the Zero Wind assumption—scheduling commitments assuming no wind availability—increases curtailment in PTQ from 6% to 30%, and in RTQ from 2% to 37%.

Interestingly, the restricted transmission cases under regional reserves (RT/RTQ) show larger effects between the scheduling assumptions than provincial reserves (PT/PTQ). The reason lies in how the system is optimized to reduce costs subject to the transmission band constraints. If wind is assumed to be low or zero but is realized at a much higher level, the new wind levels

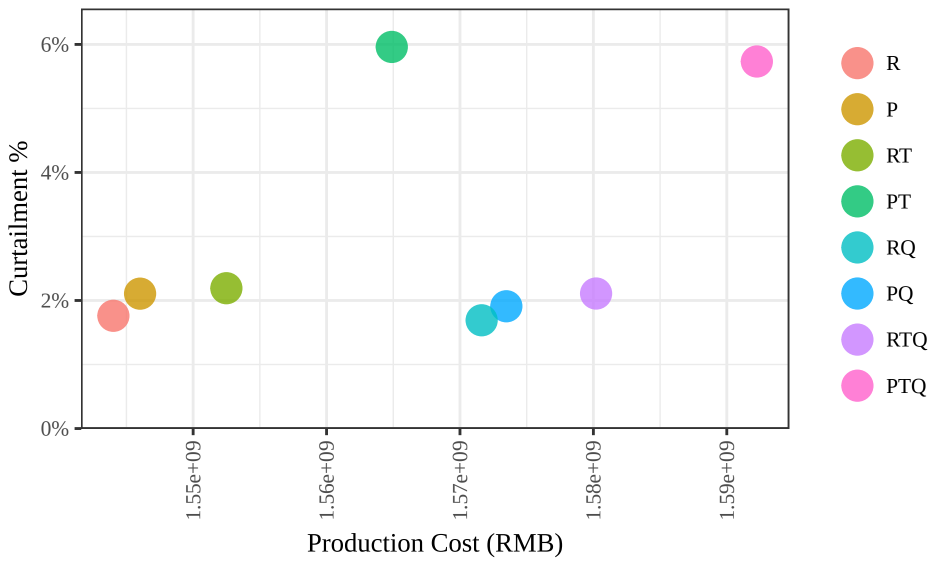


Figure 5.9: Costs and curtailment for three legacy institutions, Northeast.

should be balanced with the committed units at the provincial level to maintain the prescribed transmission flows. Under regional reserves, there can be greater asymmetries in commitments between provinces because there is no additional requirement at the provincial level. By contrast, the provincial reserves case creates more flexibility at the individual province-level, which aids in responding to changes in wind levels. In the most extreme case (*Zero Wind*), the quota adds to curtailment—an effect not seen in the perfect forecast model.

These results also show that the precise level of the reserve requirement matters less than the constraints on transmission flows when considering other aspects of system scheduling. Here, the interaction of restricted transmission (T) and long-horizon commitment scheduling are more important for wind integration. Put another way, the ambiguity around precise reserve levels may not be the leading contributor to curtailment under the current system, though appropriately setting reserves is important and will be increasingly important as scheduling decisions improve.

Transmission band sensitivity

The tolerance of the transmission band—i.e., how much flows are allowed to deviate from the pre-set schedule—is a measure of the rigidity of operational practices, and adjusting it represents one possible method of incorporating greater flexibility in inter-provincial transmission. Figure 5.11 shows the hourly results of a single wind scenario of PTQ for each province's net generation

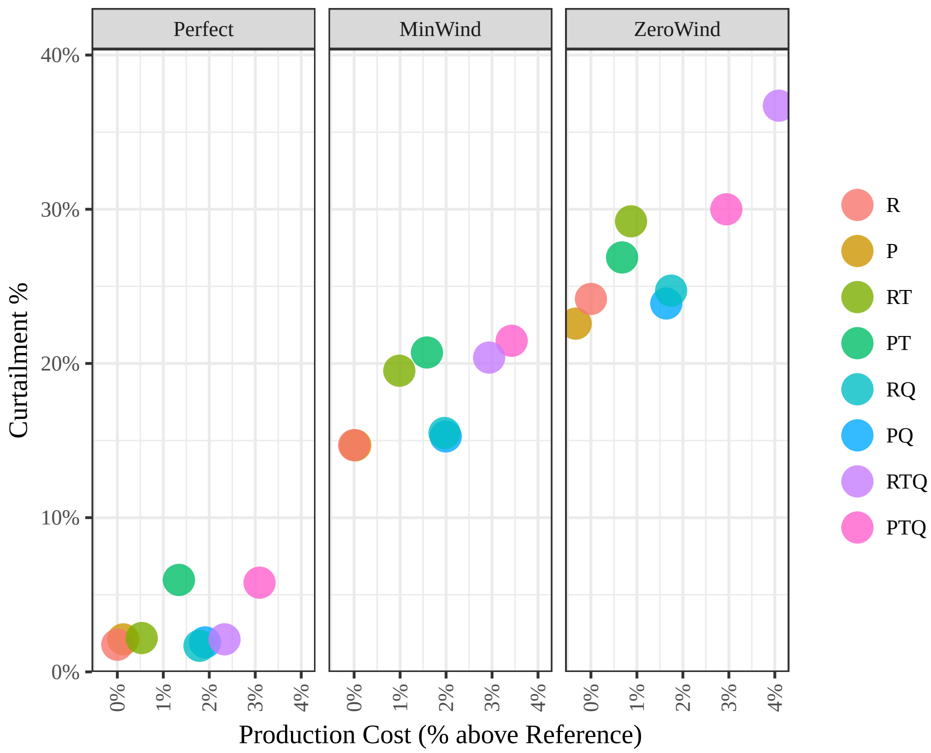


Figure 5.10: Curtailment percentage and production cost changes (above reference scenario) for different commitment scheduling, Northeast.

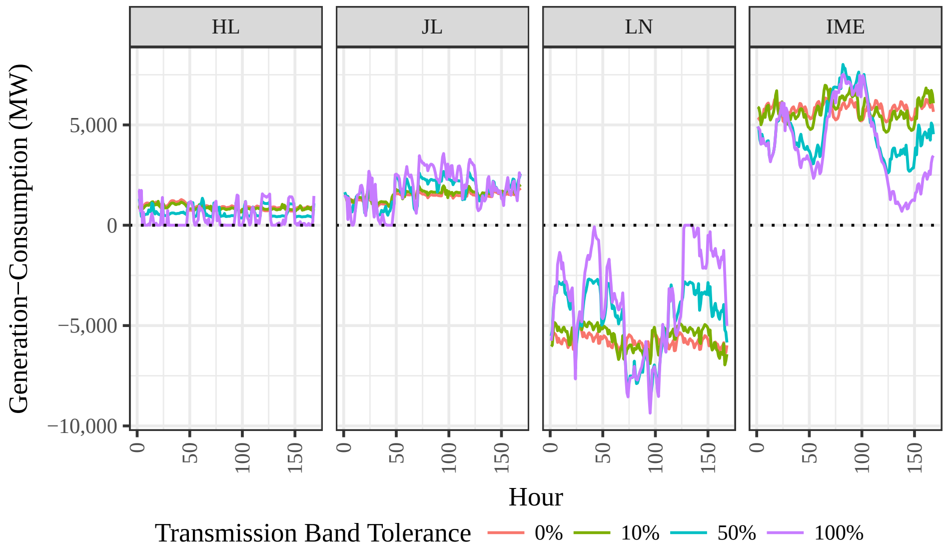


Figure 5.11: Net excess generation by province for transmission band tolerance sensitivity, Northeast PTQ run. (A15Ja1 wind profile)

at various tolerance thresholds. Two major effects are present: first, the large demand center Liaoning will generate more on average within its province, reducing imports from its neighbors, e.g., E. Inner Mongolia. Second, there are larger swings in transmission flows, with greater flows to Liaoning corresponding to large wind availability, e.g., in Jilin and E. Inner Mongolia. Eliminating the provincial reserve requirement reduces Liaoning's imports further.

Examining the curtailment rates in Figure 5.12, these transmission constraints primarily hamper Jilin's integration capabilities, with a secondary effect on Heilongjiang (which is connected to Liaoning through Jilin). These improvements occur when there are still provincial reserve requirements, which points to the possibility of addressing renewable integration by first introducing flexibility in balancing energy, and later regionalizing reserve requirements. Note that relaxing this parameter results in different total exchanged amounts; hence, adjusting this tolerance has political economy implications for negotiations between provinces, and is not strictly a "drop-in" solution.

Reserve requirements

Findings regarding wind curtailment from the base set of institutional results above in Figure 5.9 hold across a range of reserve requirements. In Figure 5.13, curtailment of PT and PTQ track each other, while all the rest are clustered. Thus, under perfect forecast commitment scheduling, there

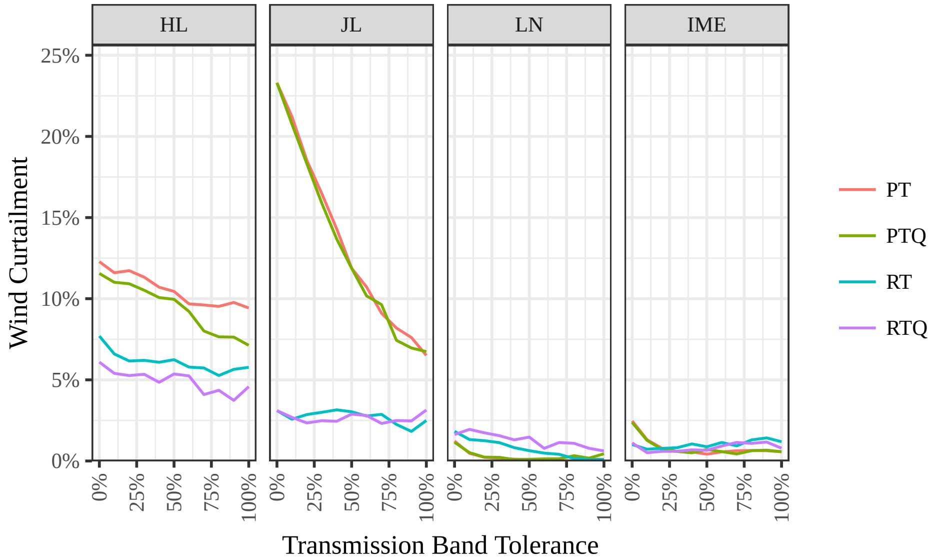


Figure 5.12: Curtailment by province for transmission band tolerance sensitivity, Northeast.

is strong evidence that the interaction of these two is a key determinant of integration difficulties.

Costs also change with reserves (top of Figure 5.13). At zero reserve requirement, R and P, RT and PT, etc., are equivalent. Adding reserves, all costs tend to increase, though the rate of increase is much larger for provincial reserve cases. This is expected, as the costs of reserves are not the same across provinces, and the regional reserve case will find the cheapest throughout the region.

These results also provide some qualification to the relative role of the quota in determining system costs. As reserve requirements increase, the provincial reserves case (P) overtakes the regional reserves with quota case (RQ), as does PQ over RTQ. This indicates the possibility that the quota—the most visible transfer of production to inefficient generation—may be less influential than invisible constraints on the system like reserves. While the full reserve requirement is not feasible for the P cases, any additional flexibility through ad-hoc measures would at best continue this trend (and likely do worse than the optimal).

5.2.6 Other Parameter Sensitivities

Must-run cogeneration

The must-run output from combined heat-and-power (CHP) units is one of the largest technical inflexibilities in northern China, with as much as half of coal plants committed to be on and with

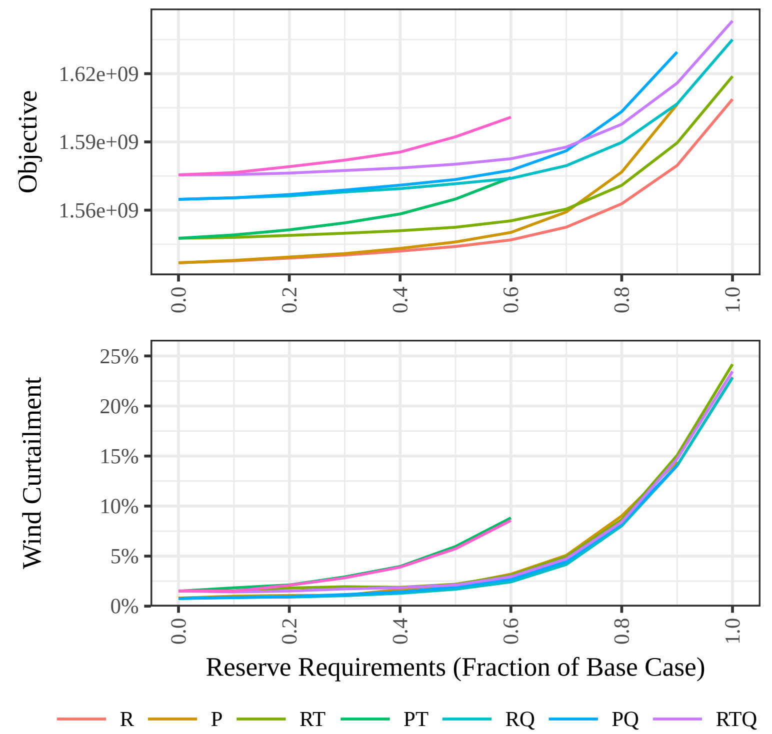


Figure 5.13: Objective and curtailment results for reserve requirement sensitivity, Northeast.

higher-than-normal minimum outputs. It is also a significant source of model uncertainty: not all units are turned on throughout the winter season; there can be assignment error of CHP vs. electricity-only; CHP units may provide different heating profiles for industrial and district heating loads; and heat extraction as a ratio of total plant output varies by size and efficiency of the heating grid and depends on the outside temperature.

A sensitivity across must-run CHP outputs was constructed by starting with full commitments of all CHP units—operating above their winter heating season minimum output—and reducing the number of online units for each type and province by one. Because there are very few 600 MW CHP units, which thus likely have no backup, *cogen600* commitment totals are not changed. The correspondence between this sensitivity and minimum modes is in Figure 5.14.

The highest CHP must-run amount is infeasible for the PT/PTQ cases (i.e., provincial reserves and constrained transmission). This is not unexpected given what we know about the high inflexibility associated with CHP in the Northeast, and because we do not expect all units to be online at any given moment. As the effective minimum mode is reduced, objectives and wind curtailment

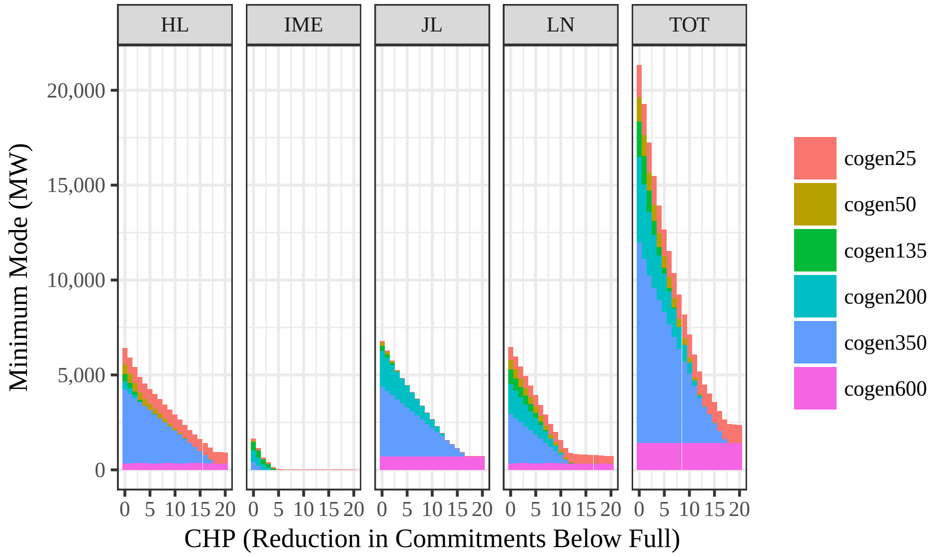


Figure 5.14: Must-run minimum modes for CHP sensitivity, Northeast.

decrease (see Figure 5.16). The relative impact of the institutions are similar across most of the range, indicating robustness of the reference results.

In particular, objectives have a strong linear relationship with minimum modes, indicating that from a cost perspective, electricity from CHP is being replaced with similar efficient generators (i.e., *coal600*) across the different scenarios. Curtailment, by contrast, shows a much stronger dependence with PT/PTQ. Examining the individual provinces, this effect is largest in Jilin, as expected given its very high CHP fraction (see Figure 5.16).

Minimum up and down times

Physical constraints or additional costs on coal plant startup and shutdown were often cited as important aspects of coal plant inflexibility. This inflexibility, together with the requirement of meeting quotas and contracts, is used to justify the weekly or longer commitment scheduling decisions. Though, engineering limits are frequently much less rigid than cited in practice. The default minimum up times are closer to what is technically feasible (12 hours for large coal generators, 6 hours for medium, etc.). Though, if more conservative assumptions are used, curtailment and objectives do not appreciably change even under different scheduling assumptions. In Figure 5.17, curtailment rates for minimum up and down times ranging from 0 (i.e., no minimum time limit) up to 10 times the base case (i.e., 120 hours for large generators) demonstrate that there is no

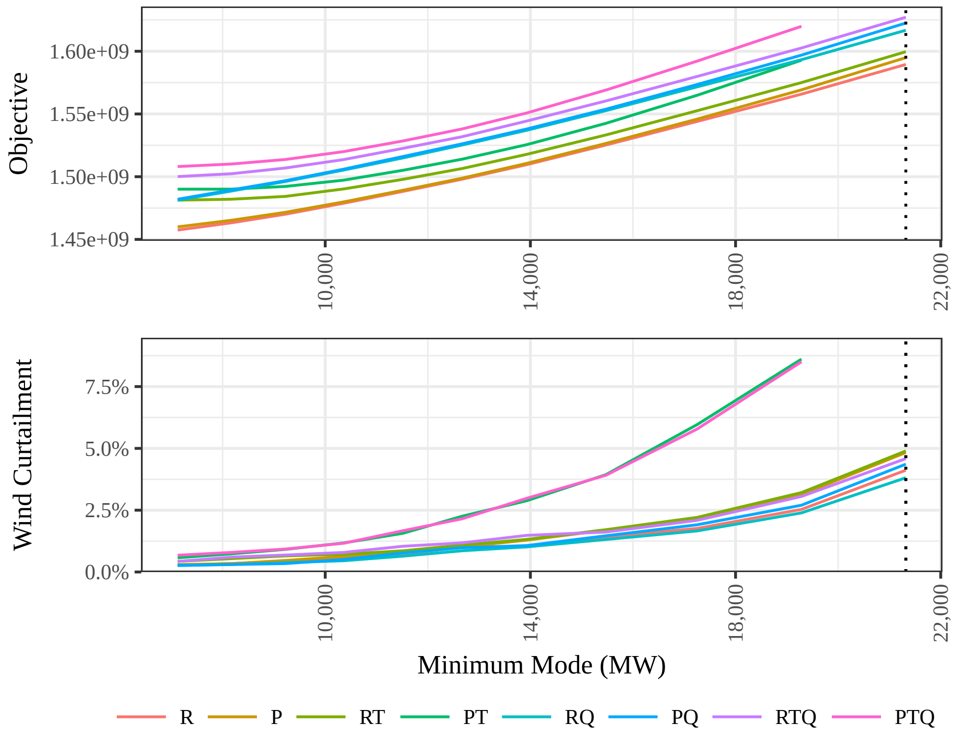


Figure 5.15: Objective and curtailment results for CHP sensitivity, Northeast. (dotted line indicates full CHP commitment)

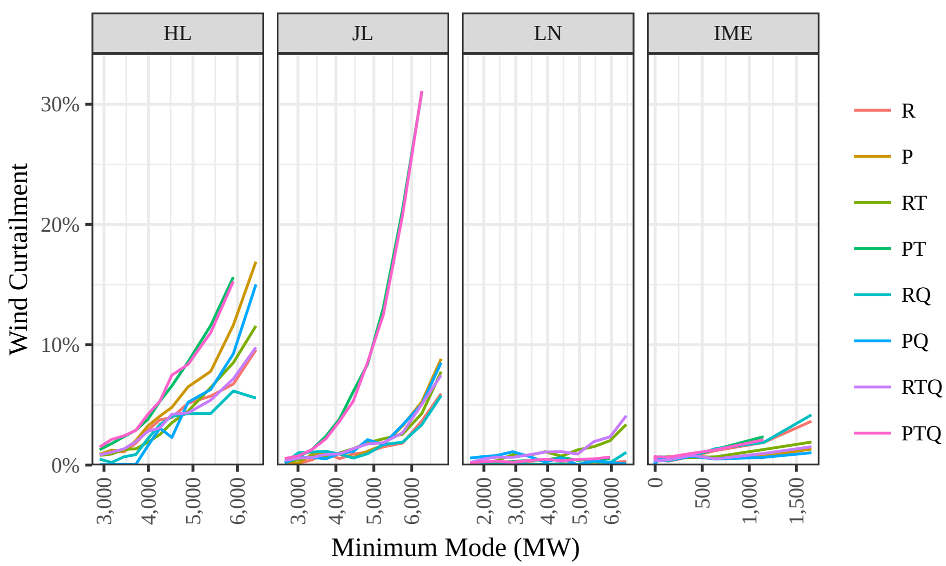


Figure 5.16: Objective and curtailment results for CHP sensitivity, Northeast.

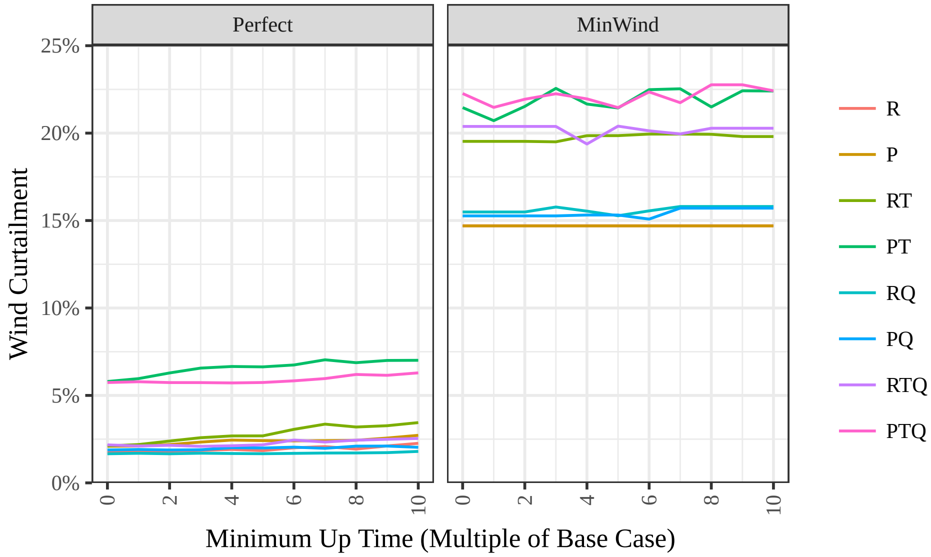


Figure 5.17: Curtailment of minimum up time sensitivity for different scheduling assumptions, Northeast.

significant dependence between the two. Objectives (not shown) show the same behavior.

In the section on the Northwest, minimum up times are compared to other aspects of plant flexibility (e.g., minimum outputs). Similar results on the insensitivity to minimum up times occur there, which is a useful insight into what technical levers can and should be used at the plant level to improve integration and costs.

However, long minimum up times cannot be entirely separated from the commitment scheduling process. If minimum up times are constrained to be days instead of hours (which, if for technical reasons, is only likely to be nuclear plants), then scheduling decisions may not be able to take advantage of more accurate forecasts in adjusting commitments. Thus, the perfect scheduling assumption may be unachievable.

Year	HL	JL	LN	IME
2011	1860	2208	3380	3232
2015	4537	4079	6083	8130

Table 5.4: Wind capacity in NE, 2011 and 2015 (beginning of years). (MW) Source: NEA

5.3 Northeast Grid: Longitudinal 2011~2015 Results

5.3.1 Changing Regional Context

Model input data were also collected for the Northeast region for 2011, providing the only longitudinal case in this study, over a period of rapid changes in the sector. Over this period, wind capacity nearly tripled (see Table 5.4) and coal capacity (including must-run CHP) increased by 24%. Demand grew by roughly 6% in the Northeastern provinces (excluding Inner Mongolia), much slower than the national average of 23% for the period. From these parameters alone, it is expected that wind integration would become much more difficult.

Quantifiable parameters related to institutions also changed over this period, most notably the increase in exports to North Grid, as discussed in Section 3.6.5. This was due to the construction of additional lines from Liaoning, as well as overall increases in line utilization that were likely the result of enhanced negotiations. At the same time, intra-regional dispatch totals have fallen (Figure 2 of Chapter 3), though these totals do not disaggregate between inflexible trading (e.g., fixed annual plans) and more flexible trading (e.g., peaking ancillary services market). Overall, the regional system operation appears to be increasingly centralized to respond to renewable integration and overcapacity concerns.

Due to data availability, provincial demand profiles for this earlier period were assumed to be the same, equal to a typical winter daily load curve for the entire region published by the grid company (available in Davidson (2014)). Quarterly demand totals were not available either, and thus annual changes in demand from 2013 (when daily data are available) back to 2011 were used to scale demand.

Due to data availability, annual totals of inter-provincial transmission (as opposed to quarterly data for 2015) were used to determine average exchanges and create transmission bands between provinces (State Grid, 2012a). Due to the small export totals to North Grid (accounting for only

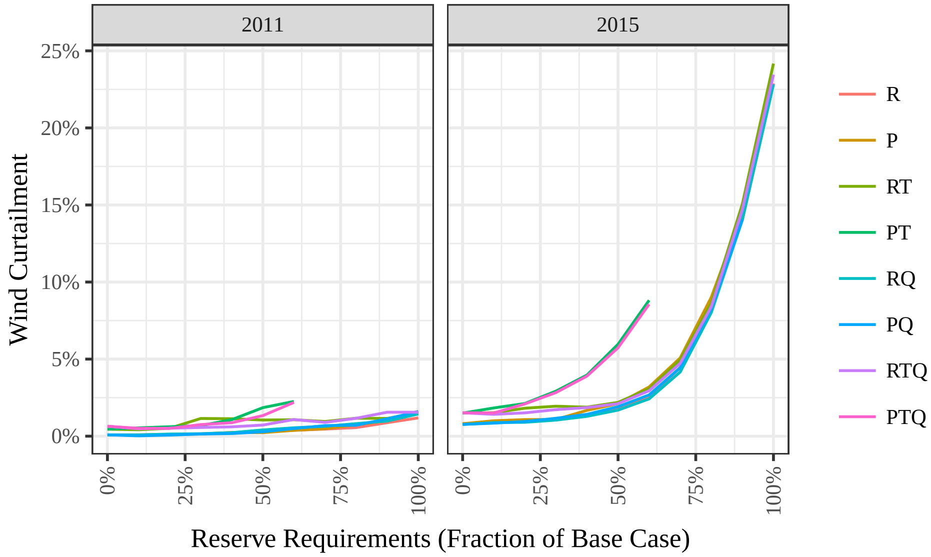


Figure 5.18: Curtailment rates for reserve requirement sensitivity, Northeast 2011 and 2015.

3% of total generation), no inter-regional transmission was added to the 2011 model.

5.3.2 Results Comparison

Three Legacy Institutions

The general finding holds in 2011 that provincial reserve requirements combined with restricted transmission due to scheduled flows result in larger wind curtailment and costs. However, model results show that the system as a whole has become increasingly constrained since 2011. At full reserve requirements in the reference case with roughly 80% CHP commitments (comparable to 2015), curtailment never rises above 5% in 2011 winter. By comparison, 2015 model results for the same sensitivity reach 25% (see Figure 5.18). Additionally, up until the 2011 model becomes infeasible, the effects of PT/PTQ are measurable, though significantly lower than in 2015.

North Grid export sensitivity

A more direct comparison of within-region changes—both technical and institutional—comes from excluding exports to North Grid in the 2015 model (see Figure 5.19). When reducing demand to just that within the Northeast region, curtailment rises more quickly (reaching 35% compared to 25% in the full reserve reference cases). Results for PT/PTQ are, in fact, comparable to the exports

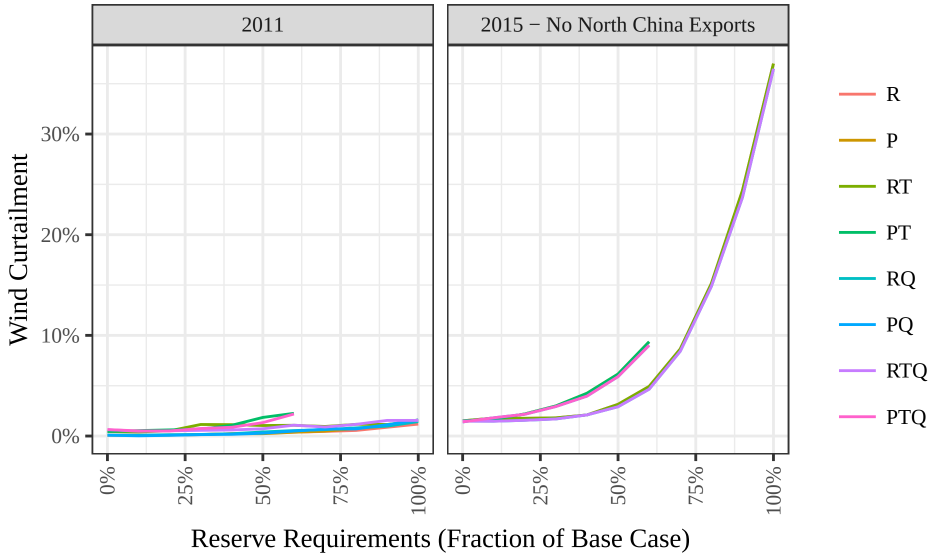


Figure 5.19: Curtailment rates for reserve requirement sensitivity, Northeast 2011 and 2015 (no North Grid exports).

case for feasible reserves, indicating that the benefits of exports occur primarily when the system is heavily constrained.

Comparing curtailment causes

Model results demonstrate that similar sets of factors (e.g., reserve requirements, transmission bands, etc.) determine levels of wind integration in both 2011 and 2015. The values of some of these factors have changed dramatically in the four intervening years, which overall creates a much worse curtailment situation in 2015. As mentioned, there has been some increased centralization of operation, which has helped mitigate some of the rise. Since these factors are unlikely to return to pre-2011 levels, greater efforts are needed to address these causes to maintain low curtailment levels into the future.

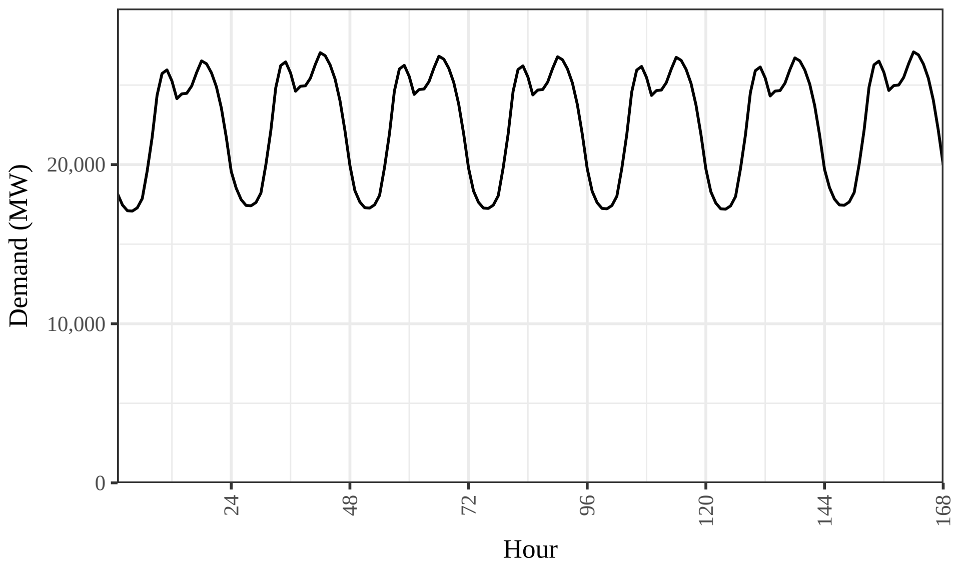


Figure 5.20: W. Inner Mongolia demand curve

5.4 Western Inner Mongolia Grid

5.4.1 Region-Specific Modeling Inputs

A grid-wide typical daily demand profile was not available for Western Inner Mongolia (from now on, W. Inner Mongolia, or simply, W. IM). Hence, an average of Northeast and North grid city profiles was used. This is most likely "peakier" than actual demand, and results should be compared with other regions as demand profiles change shape. The single province demand curve used for modeling is in Figure 5.20.

Inner Mongolia's best wind resources are near the border between E. and W. Inner Mongolia (see Figure 4.3, p. 191). Wind installations are also more heavily concentrated in these areas. W. Inner Mongolia stretches far to the west where capacity factors drop off, and thus the standard method of averaging hourly capacity factors across the entire region underestimates the actual wind resource quality. The E. IM profile is better representative of this region of dense wind farm installations, also because it is more heavily weighted in the border regions due to exclusion of large forested areas in the north. To provide a better representation of the high-quality wind resources in W. IM, the profile for E. IM is thus used for both halves of Inner Mongolia.

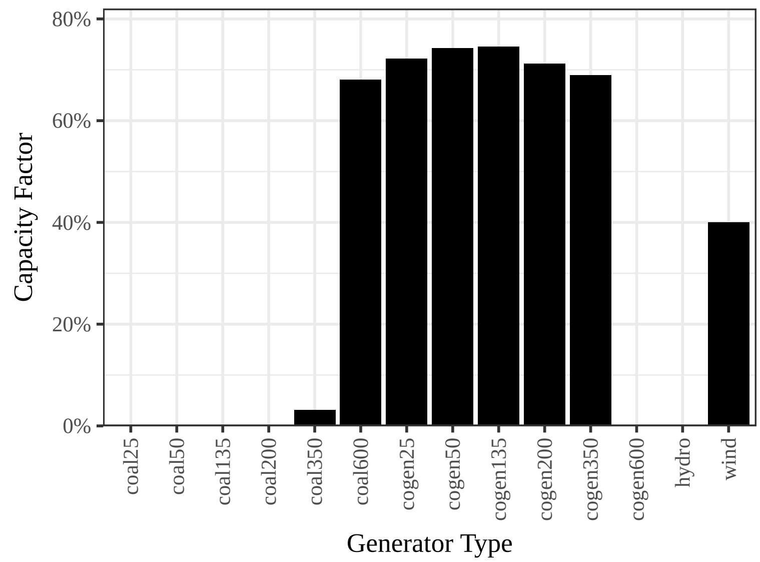


Figure 5.21: Capacity factors in reference case, W. Inner Mongolia.

5.4.2 Reference Results

The reference model results in high capacity factors from must-run cogeneration units, wind, and high-efficiency coal (600 MW). The next most efficient coal class (350 MW) has some small generation, and all other generators are essentially unused (see Figure 5.21). For this region, similar to the Northeast, a reasonable reference scenario is used with default parameters and the modification that not all CHP units are committed. Precisely two of each type are decommitted per province (including the largest, 600 MW cogeneration), corresponding to around 80% of the minimum mode of full commitment. This sensitivity and precise calculation of the minimum modes are explored further in the next section.

One of the week's generation profiles is shown in Figure 5.22. Wind is highly variable over the week, and most is balanced by the efficient and flexible 600 MW coal generator. To a greater extent than in the Northeast, the less efficient 350 MW coal also provides support during long periods of low wind (e.g., see hours 48-96 in Figure 5.22). The predominant cogeneration type (*cogen350*) provides the remaining balancing.

Wind curtailment is concentrated in early morning hours when demand is lowest. Even during the wind lull in the middle of the week, some wind is curtailed because additional 600 MW coal generators were committed to provide support, and these units hit their minimum outputs during

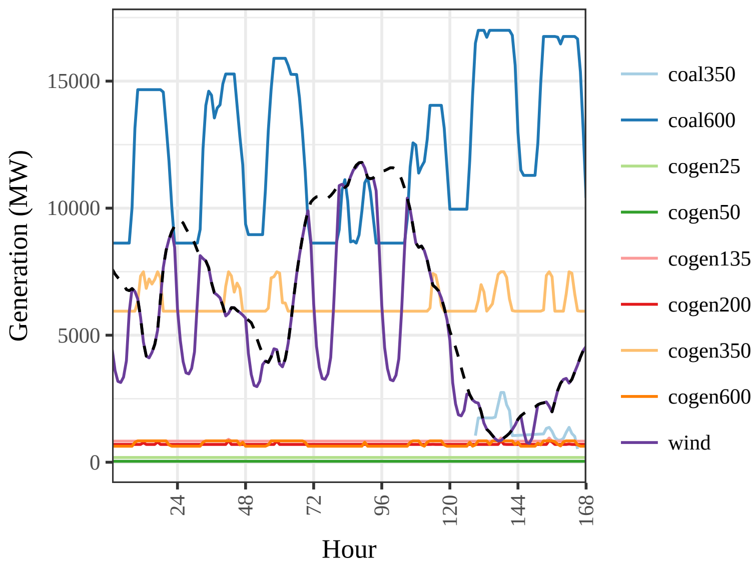


Figure 5.22: A single week's generation profiles in the reference case, W. IM. Dotted line indicates pre-curtailment wind. (15Ja1 wind profile)

nighttime hours. This type of flexible commitment scheduling helps prevent what would be virtually complete curtailment during nights in the latter part of the week.

5.4.3 Must-Run Cogeneration Sensitivity

Similar to the Northeast, CHP minimum modes are important for costs and wind integration. The sensitivity is constructed the same as before, reducing the number of committed CHP units by one for each, except for the single 600 MW CHP unit, which is always committed (see Figure 5.23).

Curtailment varies close to linearly with CHP must-run for high minimum modes, reflecting additional curtailment during low-demand nighttime hours as shown in Figure 5.22. As CHP capacity declines, wind curtailment flattens out, indicating a transition to a different regime where other inflexibilities dominate—e.g., conventional unit minimum outputs. The quota leads to higher costs across the range of CHP must-run amounts, as expected. Additionally, the quota does not cause any noticeable change in curtailment. Hence, the relative impact of the institutions are similar across most of the range, indicating robustness of the reference results.

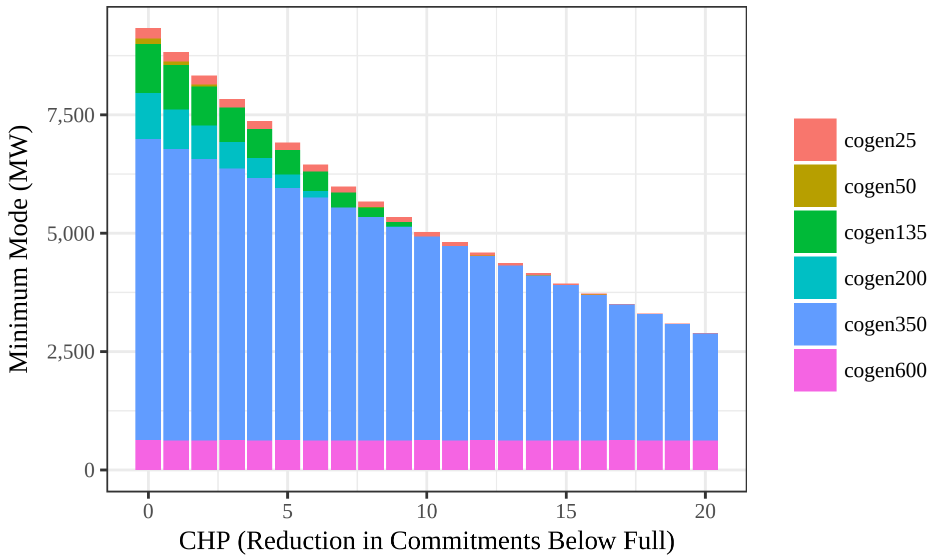


Figure 5.23: Must-run Minimum Modes for CHP sensitivity, W. IM.

5.4.4 Commitment Scheduling and Two-Stage Model Results

Because W. Inner Mongolia is modeled here as a single node, two of the institutions considered in the Northeast (provincial vs. regional reserves and restricted intra-regional transmission) are not applicable. In Figure 5.25, the effects of commitment scheduling assumptions are explored when interacted with the quota and the CHP sensitivity. As in the Northeast, scheduling commitments assuming a low or zero amount of wind leads to greater integration difficulties with realized wind. This situation is particularly enhanced under high CHP minimum modes when meeting the quota. These results are similar to the Northeast in Figure 5.10 in that certain constraints derived from grid operation institutions are enhanced when separating commitment and dispatch by a long time period.

In W. Inner Mongolia, the quota (RQ) coupled with the *Zero Wind* scheduling assumption leads to a sharp increase in curtailment, approaching 50% under full CHP commitment. This follows from the need to commit a certain number of smaller units to meet the quota. These units then run up against their minimum outputs when wind is higher than expected. By contrast, if only large units are committed among the non-cogeneration set (as in case R), a smaller number is needed, and their minimum outputs when combined with CHP minimum modes are lower, providing more wind integration space.

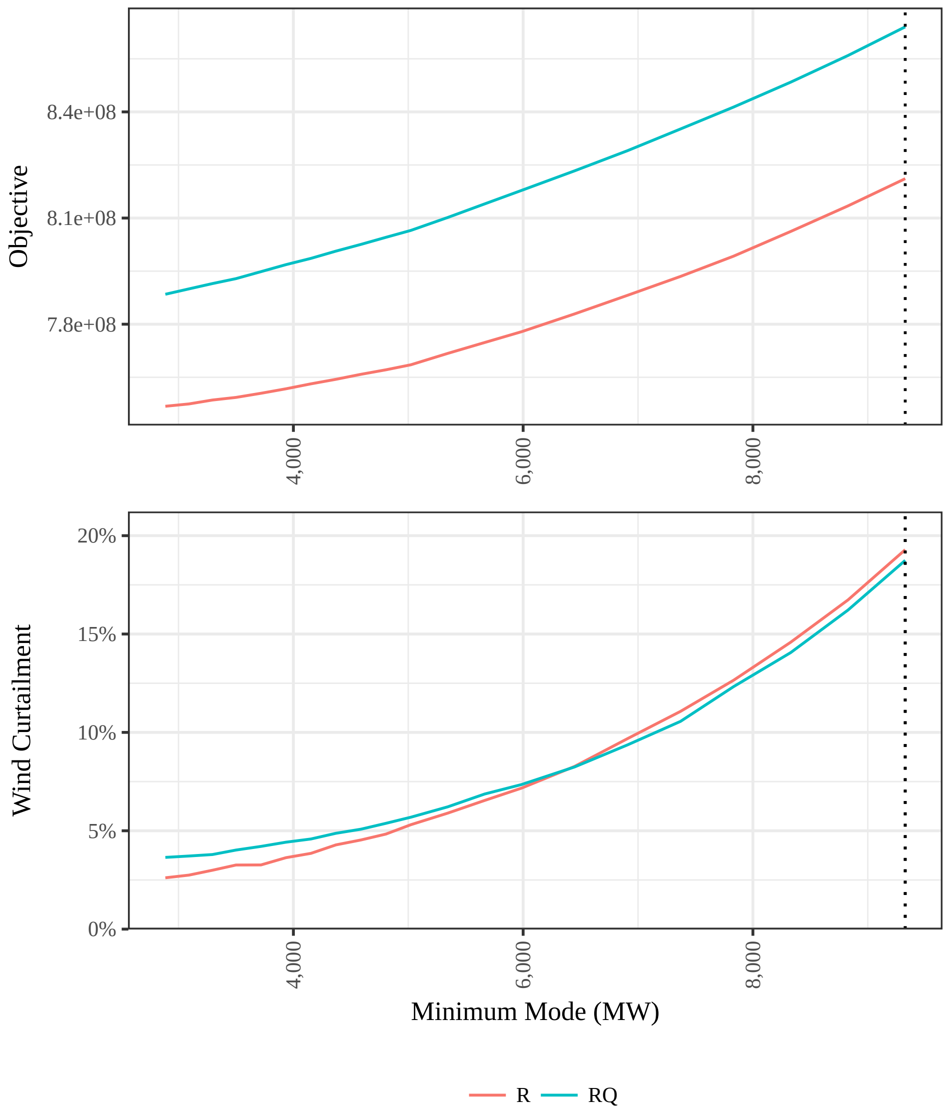


Figure 5.24: Objective and curtailment results for CHP Sensitivity, W. IM. (dashed line = full CHP commitment)

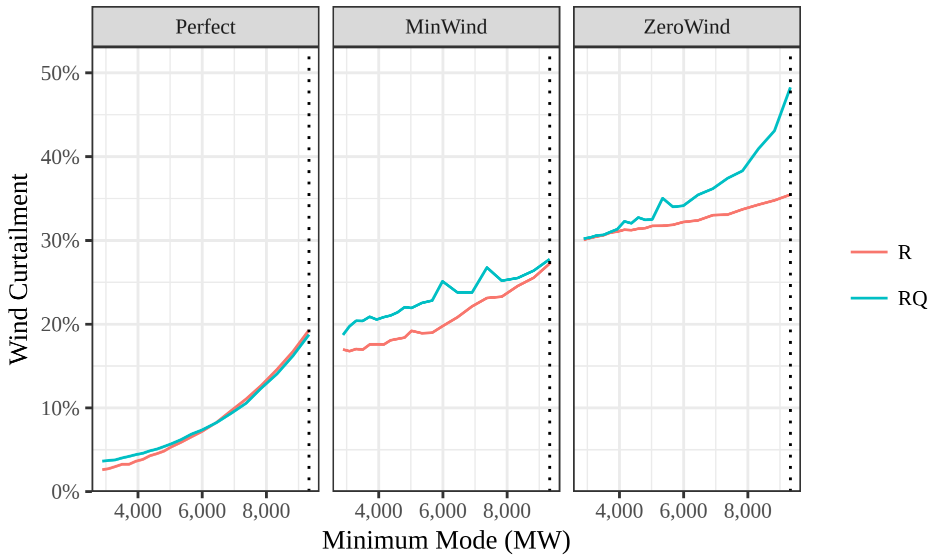


Figure 5.25: Curtailment for CHP sensitivity under different commitment scheduling assumptions, W. Inner Mongolia. (dashed line = full CHP commitment)

5.4.5 North Grid Export Sensitivity

As explored in Chapter 3, exports to North Grid represent one of the major central government levers to reduce curtailment in adjacent regions. Exports have risen slightly for W. IM since wind penetrations have become appreciable, though not as fast as for the Northeast. An extreme—and unrealistic—scenario is if all exports ceased, and W. IM has only its internal demand to meet. Under this scenario, the highest CHP must-run is infeasible, as in Northeast, but for lower CHP values, the system is feasible and with much greater wind integration challenges. Curtailment doubles across nearly the entire range (see Figure 5.26).

Coal use in W. IM increases when including North China exports, by roughly 20% in both the reference and quota cases. While wind curtailment decreases under this scenario, the hours of curtailment do not match entirely with the fixed transmission profile to North China, thus ensuring that additional generation is a mix of coal and wind. In fact, by comparing wind generation and total generation before and after connecting the North Grid, I estimate that in the highest reference case, roughly 30% of the additional export demand is met through wind (see Figure 5.27). This fraction declines as CHP minimum modes within the province decline, as there is greater space to integrate the wind within W. IM borders.

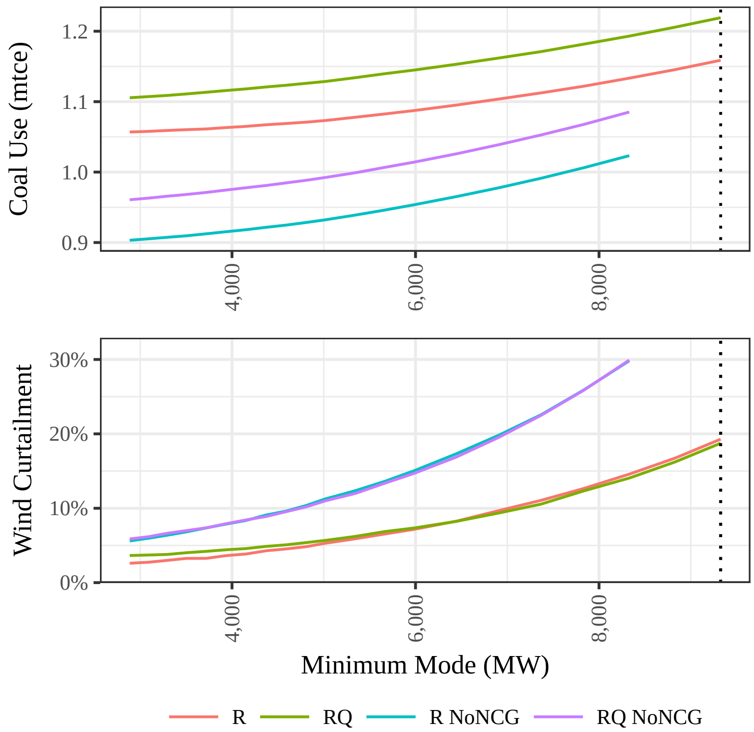


Figure 5.26: Coal use and curtailment with and without North China Grid (NCG) exports for CHP sensitivity, W. Inner Mongolia.

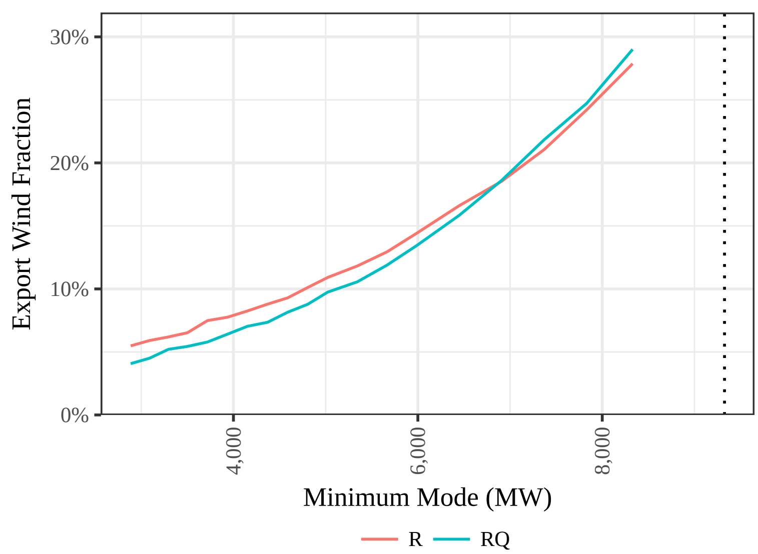


Figure 5.27: Export wind fractions for CHP sensitivity, W. IM

5.4.6 Eastern and Western Inner Mongolia Comparison

In Section 3.6.5, I presented the differences over time in wind integration between the two halves of Inner Mongolia and claimed that primarily institutional changes are responsible for the convergence in capacity factors since around 2015. While intra-regional trading had fallen in the Northeast, there were new exchanges that targeted hours in which wind is curtailed, representing some evidence (albeit not conclusive) that the fraction of intra-regional trading that benefited wind increased. These exchanges were helped by a broad trend of centralization in the region's system operation. Finally, export out of the Northeast increased over this period, helped by both increased capacity of export lines as well as average utilization of these lines. Average utilization increases indicate enhanced political negotiations opening up import space in North Grid.

Modeling results of the Northeast confirm the importance of institutional causes: even as the Northeast system has become increasingly technically-constrained, wind integration has essentially equalized with its neighbor. Increasing CHP minimum modes raise baseline curtailment rates substantially, a trend that has been counteracted with improved institutions (including changing administrative parameters like minimum outputs on conventional generators) as well as exports.

Between regional system operation institutions and exports (both capacity and enhanced utilization), there is also evidence that improved system operation institutions had a larger impact. The regions demonstrate a differential impact of exports to North Grid on local wind integration: when considering exports (which were approximately equal by 2016), curtailment rates reduce by half in the case of W. IM versus only one-third in the Northeast. The benefits attributable to exports in the Northeast are also less when the system becomes more flexible (e.g., under increasing centralization, corresponding to relaxing inter-provincial trade constraints). There are competing forces pushing the system, with primarily technical causes becoming more heavily constrained (e.g., CHP minimum modes) and institutional causes becoming less constrained (e.g., relaxing PT/PTQ). These results indicate that institutional relaxations are an important changing element in the Northeast, helping to partially offset increased technical inflexibility.

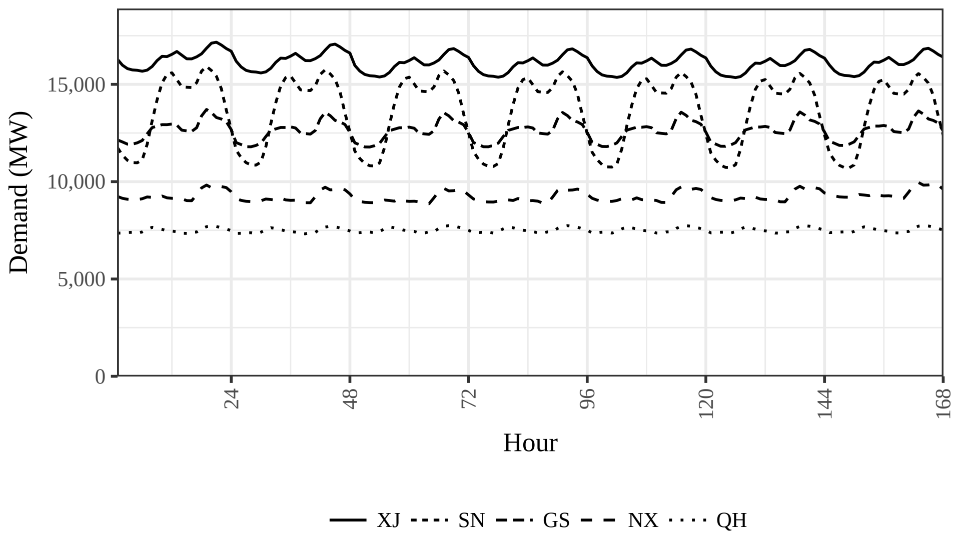


Figure 5.28: Northwest demand

5.5 Northwest Grid

5.5.1 Region-Specific Modeling Inputs

Northwest demand profiles vary in terms of their peakiness: Xinjiang is the largest demand center, which also has the flattest profile. Shaanxi has the most variability (see Figure 5.28).

Six winter wind profiles for the Northwest—three from January (abbreviated 'Ja') and three from March ('Ma')—are used to represent variability in the model (see Figure 5.28).

The Northwest has developed a substantial solar capacity in the last half-decade, which, as several respondents noted, has become consequential for wind integration outcomes. In terms of capacity, it is already half that of wind in Gansu (see Table 5.5). When facing coincident curtailment, grid operators largely have discretion in choosing which generating type to ramp down. According to several accounts, solar has historically been given greater priority—resulting in much lower curtailment rates. In the Northwest model, I use the assumption that solar is must-take. Specifically, solar generation is subtracted from demand prior to solving the model. This choice would tend to overestimate actual wind curtailment rates. In very recent data, solar curtailment rates have risen to be comparable with wind in several of the provinces NEA (2017a). Solar capacity factors are calculated as in Davidson et al. (2016b): using a winter week from actual measurements in a sunny California location, and adjusting by two hours to account for different

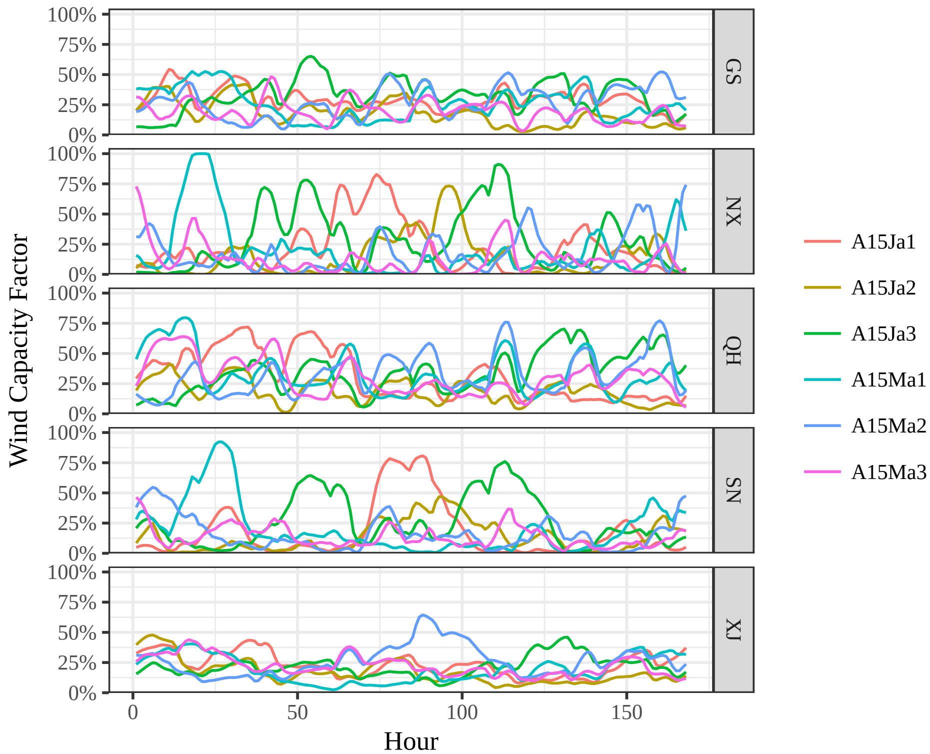


Figure 5.29: Northwest wind profiles

	GS	NX	QH	SN	XJ
Wind	10,075	4,178	318	1,303	8,039
Solar	5,170	2,170	4,130	550	2,750

Table 5.5: Wind and solar capacities in Northwest provinces, 2015 (year beginning). (MW) Source: NEA

solar times in the far Northwest (NREL, 2017).

While hydropower generation in the Northwest is concentrated in the rainy seasons, there is still significant production in the winter. Parameterizing a more detailed inter-seasonal storage model is outside the scope of here, but historical data are a guide to limits on the system, including reservoir management and run-of-river production. Inflows were calculated using average monthly generation totals for the first three months of the model year 2015. In addition, more restrictive minimum and maximum outputs were calculated using historical capacity factors at the monthly levels. These are conservative estimates of what is possible in each province's system, and ensure that hydropower flexibility is not vastly overestimated. These extrema were calculated from the last six years of production data (see Figure 5.30).

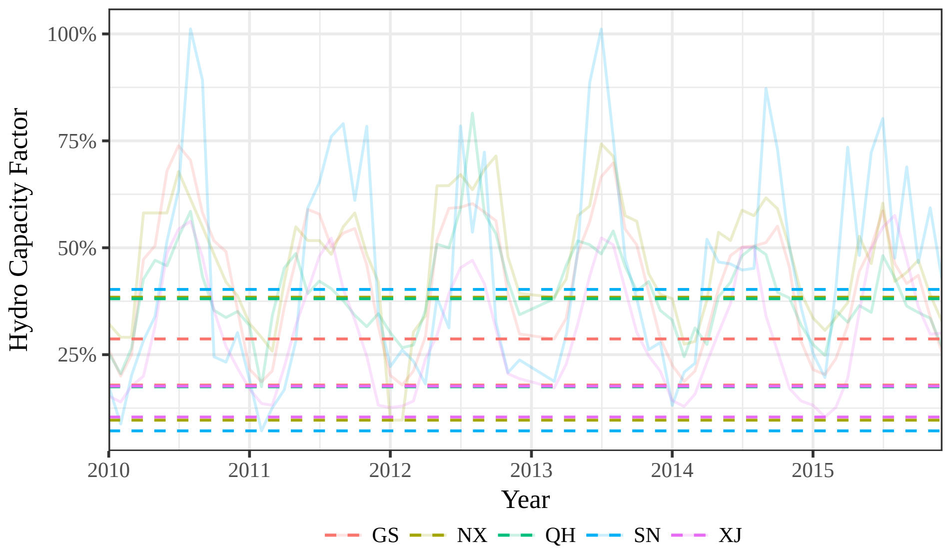


Figure 5.30: Monthly hydro capacity factors and minimum / maximum (dashed) for 2010-2015 winters. Source: (NBS, 2016).

The Northwest covers a vast area with large distances, within a single province in some cases, separating generation and demand centers. This is particularly relevant for Gansu, where the majority of wind is constructed in the west and north, and is connected via transmission along the Hexi corridor to demand centers in southern Gansu, and from there to Shaanxi and other provinces. A separate set of transmission lines connects W. Gansu to Xinjiang and Qinghai. Thus, in addition to province-province capacities, I separate Gansu into two parts—S. Gansu (GSS) and W. Gansu (GSW)—according to Figure 5.31. Generators are assigned to the two regions, and demand is split between GSS / GSW by a 68% / 32% ratio, according to consumption data of major cities (NBS, 2017).

5.5.2 Reference Results

Under reference assumptions, the model for the Northwest—after reducing CHP units according to the same procedure for the Northeast and W. Inner Mongolia—results in a lot of flexibility to accommodate wind power. Under these assumptions, there is no wind curtailment. In contrast to the Northeast, where wind's variability is balanced mostly by the largest generators, here, many of the coal generator types participate in ramping and integrating wind (see Figure 5.32). Additionally, as the CHP must-run amounts are smaller as a proportion of demand compared to the other regions

Figure 5.31: Northwest grid provinces, with S. Gansu and W. Gansu subdivision.

studied, electricity-only generators are typically not at their minimum outputs. This, combined with flexible transmission assumptions among all the provinces, creates sufficient flexibility to manage existing wind.

There are several reasons why these results may be over-optimistic, explored below in sensitivities. Considering forecast accuracy requires looking at different scheduling assumptions (see two-stage model results in next section). Reference transmission capacities are set according to their individual limits (considering voltages and distances), while the model does not account for network flows that deviate from the "transport" flow model (i.e., ignoring Kirchhoff's second law). Intra-provincial transmission constraints besides those already considered between W. and S. Gansu may be important and binding during windy hours. Additionally, there may be further constraints on hydropower utilization than considered in the historical minimum/maximum limits calculated above, which could also affect its contribution to reserves.

There are also additional institutional aspects, for which there is uncertainty or difficulty in modeling. Actual minimum outputs may be larger than the reference assumptions (54% for *coal600*), for example, due to a high fraction of self-generation units that may self-schedule higher outputs (see minimum output sensitivity below). Reserve carrying levels, important determinants of curtailment in the other cases, were reported to be on average much larger than necessary in 2011, the last time there was a publicly-available national accounting of such levels (Kahrl and Wang, 2014).

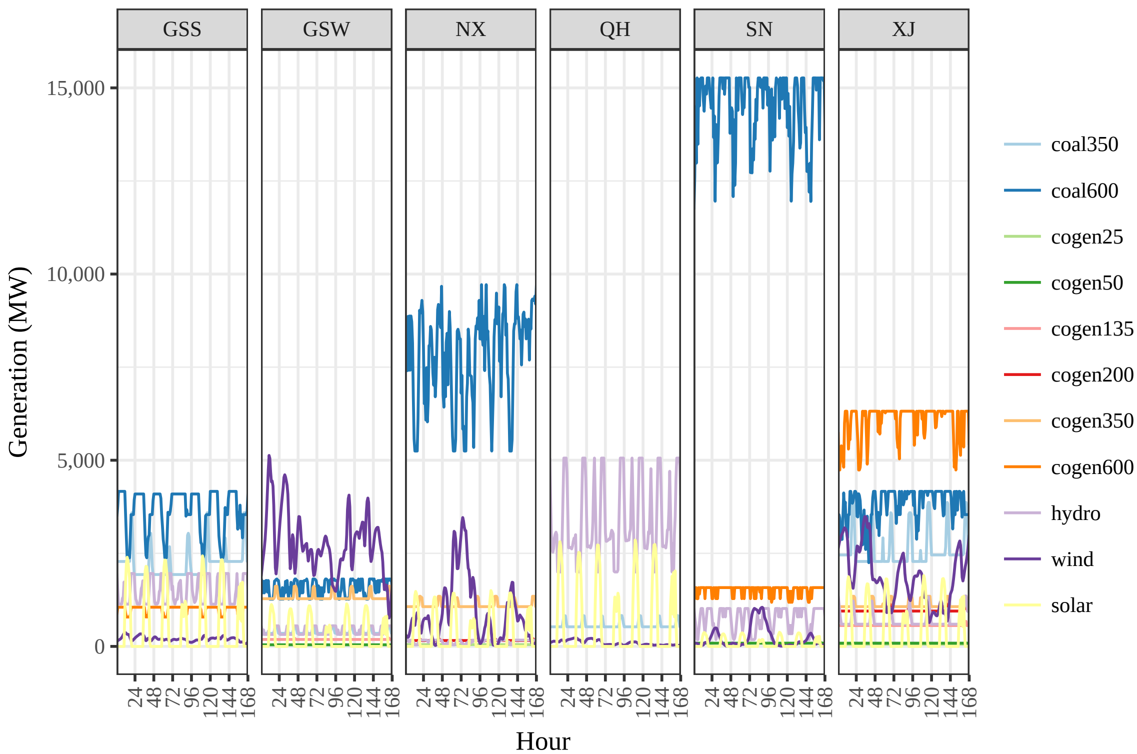


Figure 5.32: Generation profile of single week for reference case, Northwest.

This could be an indication of a range of inefficient dispatch practices including overcommitments.

5.5.3 Commitment Scheduling and Two-Stage Model Results

As in the Northeast setup, alternative commitment scheduling assumptions (based on minimum wind or zero wind) are modeled to understand the effect of the long-horizon commitment decision-making as well as wind forecast errors. Keeping all other parameters constant, there is some transfer from high-efficiency generators (primarily, *coal600* and *cogen600*) to less efficient generators (see Figure 5.33). Capacity factors of these larger units are still well above their minimum outputs. As a result, even under the most restrictive *Zero Wind* assumption, wind curtailment is still zero.

5.5.4 Minimum Output Sensitivity

Minimum up / down times were tested and had insignificant impacts on system outcomes. Hence, the primary dimension of plant-level flexibility is the minimum output, whose default is 54% for electricity-only units. In practice, besides cogeneration plants, Northwest has a large number of

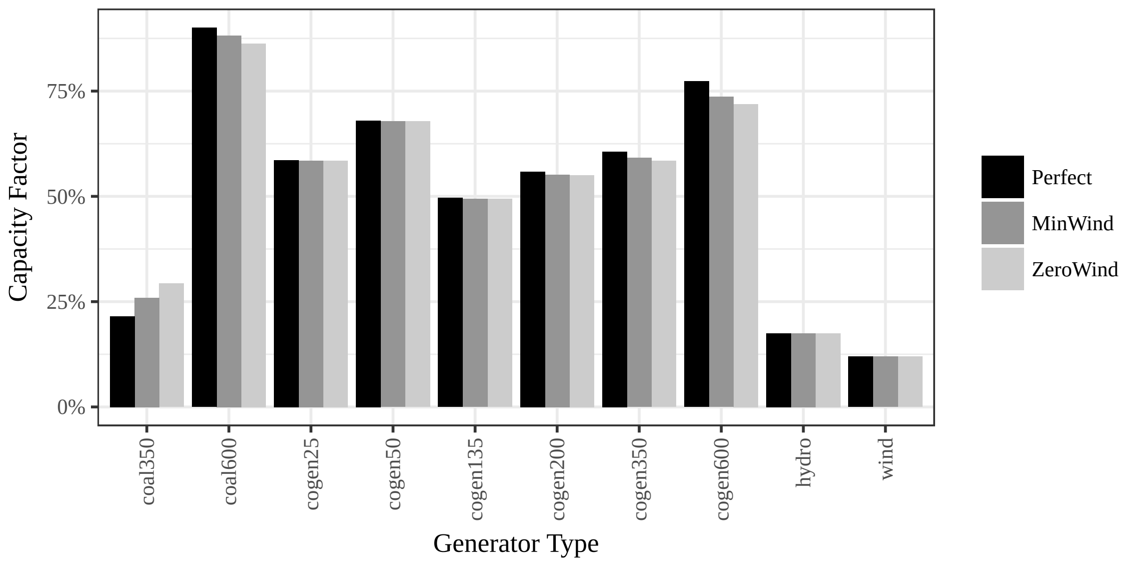


Figure 5.33: Capacity factors for different commitment scheduling assumptions in reference case, Northwest.

self-generation units, which are operated to meet certain loads on site. These loads are considered in the total demand curves, but the model does not constrain self-generation units to meet individual demand. As a result, from the perspective of dispatch, the minimum outputs of these self-generation units may be larger than the reference 54%.

Combining a sensitivity over minimum outputs with the above scheduling assumptions yields Figure 5.34. When minimum outputs increase by 10% in the zero wind case, wind curtailment begins to occur, holding other parameters constant. Curtailment and objectives then increase non-linearly as minimum outputs are further increased, reaching 30% in an extreme case of minimum output at 1.5 times base case ($\rightarrow$ 80% of capacity).

5.5.5 Three Legacy Institutional Conflicts

When considering the three legacy institutional conflicts in Table 5.1, the Northwest Grid appears to be less constrained than the Northeast: the model is largely feasible over the reference parameter ranges. For example, full reserve requirements are feasible for all combinations. There are several possible reasons: different transmission bands allowing sufficient commitments within province to provide local reserves requirements, lower fraction of CHP units (which do not provide reserves), more flexible hydropower (which do provide reserves).

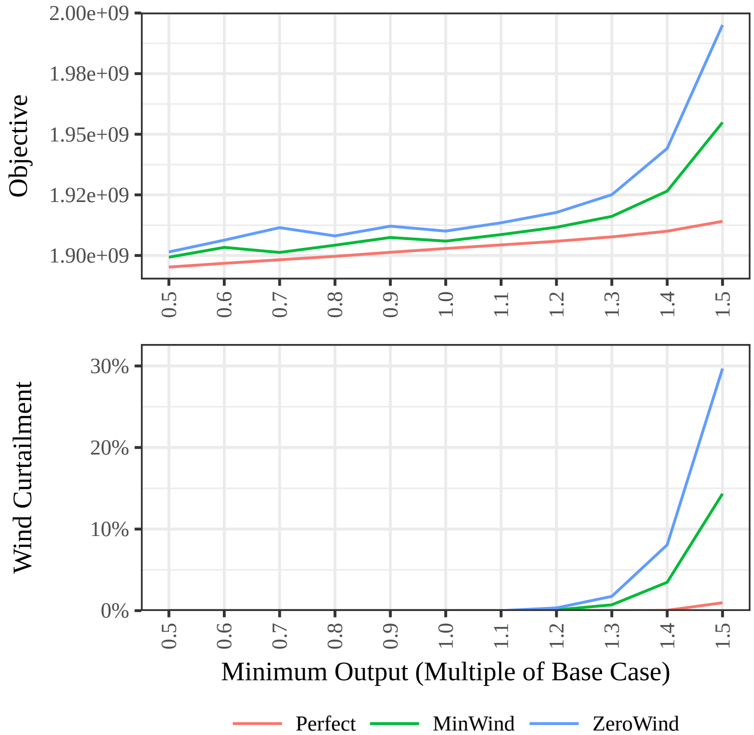


Figure 5.34: Objective and curtailment for different commitment scheduling assumptions and minimum output sensitivity, Northwest.

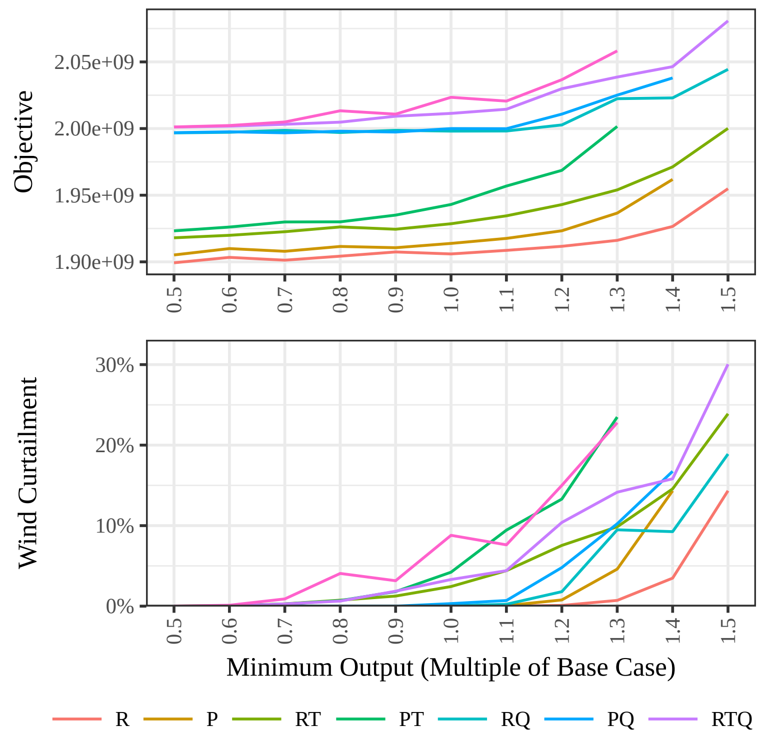


Figure 5.35: Objective and wind curtailment for *MinWind* commitment scheduling and minimum output sensitivity, Northwest.

In order to result in high curtailment without these legacy institutions, the model should have either high minimum outputs, inflexible commitment scheduling, or both. When layering on the legacy institutions, the interaction of provincial reserves and constrained transmission, as in the Northeast, surfaces again as an important determinant of integration outcomes (see Figure 5.35, which shows results assuming *Min Wind*). It is also worth highlighting that similar to the Northeast, the quota results in very large additional costs and minimal impacts on integration at reference minimum outputs. However, as minimum outputs increase, cases such as R and RQ begin to diverge. Thus, the level of the quota can be a binding factor on system flexibility (explored below).

Wind development is unequal across Northwest provinces, with heavy build-out in Gansu (particularly the west), Xinjiang, and Ningxia, and much smaller capacities in other provinces. Curtailment rates tend to increase a little faster in Xinjiang, while other provinces are comparable. Figure 5.36 shows absolute curtailment totals across the provinces for *Zero Wind* scheduling.

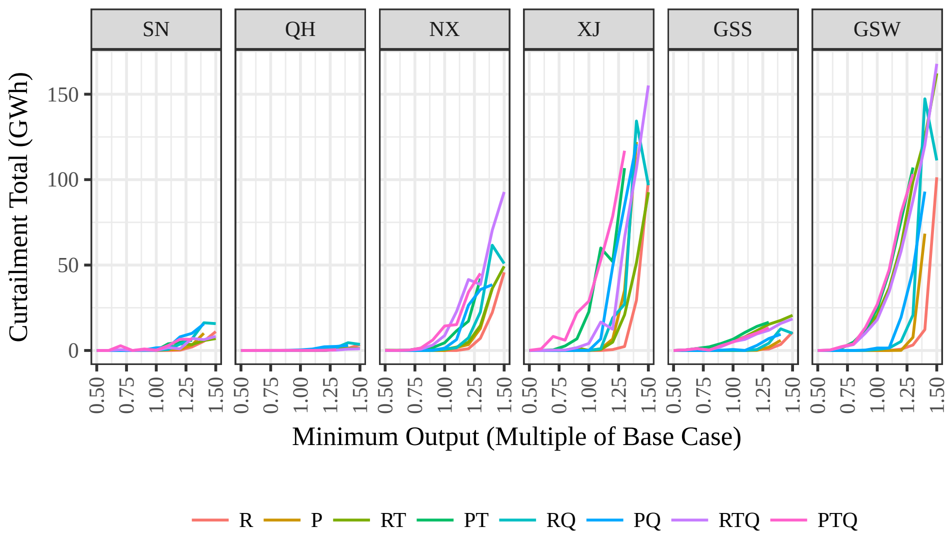


Figure 5.36: Curtailment totals for *ZeroWind* commitment scheduling and minimum output sensitivity, Northwest.

Quota sensitivity

The quota increases costs in a predictable manner. For wind integration, curtailment rates are unchanged up to around 130% of the default quota, above which they increase sharply. This effect, furthermore, is much larger for more rigid scheduling assumptions (see Figure 5.37). These results are in line with those of the Northeast: the level of the quota on its own has limited impact on wind integration space. However, when combined with other institutions that are connected to the quota, such as weekly to monthly commitment scheduling, its effect increases.

Transmission band sensitivity

Adjusting the tolerance of the transmission bands is one of the existing methods used by the Northwest Grid to manage imbalances, particularly arising from renewable energy. In the constrained transmission cases above, $\pm 10\%$ is used as the range of allowable deviations from the pre-scheduled flows. As this tolerance is relaxed in the Northwest, wind curtailment drops rapidly until reaching comparable low levels (see Figure 5.38). As in the Northeast case, this does result in different exchanged totals; hence, it differs from current practice in which the planned exchange totals (e.g., at the quarterly level) should approximately be met, perhaps by enforcing some counter-trades at a later time in the same settlement period.

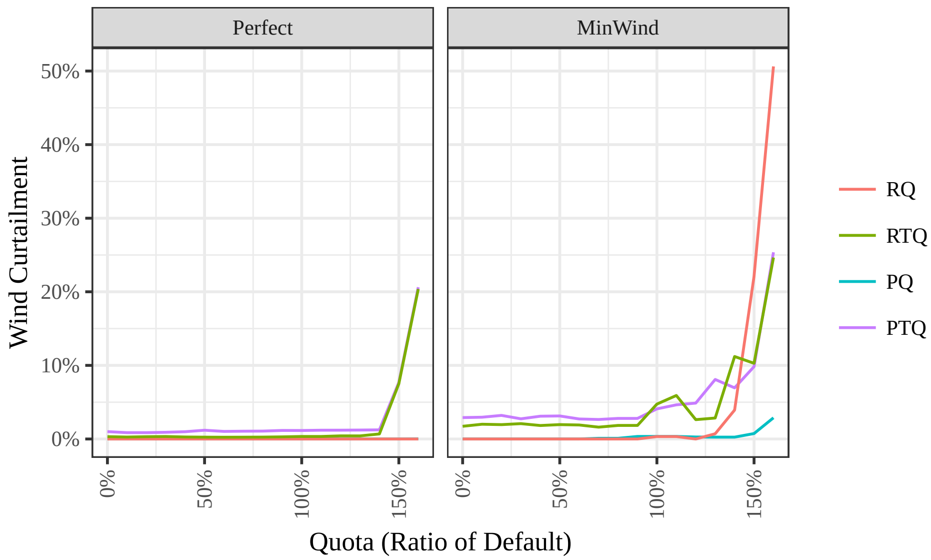


Figure 5.37: Objectives and wind curtailment for different scheduling assumptions and quota sensitivity, Northwest.

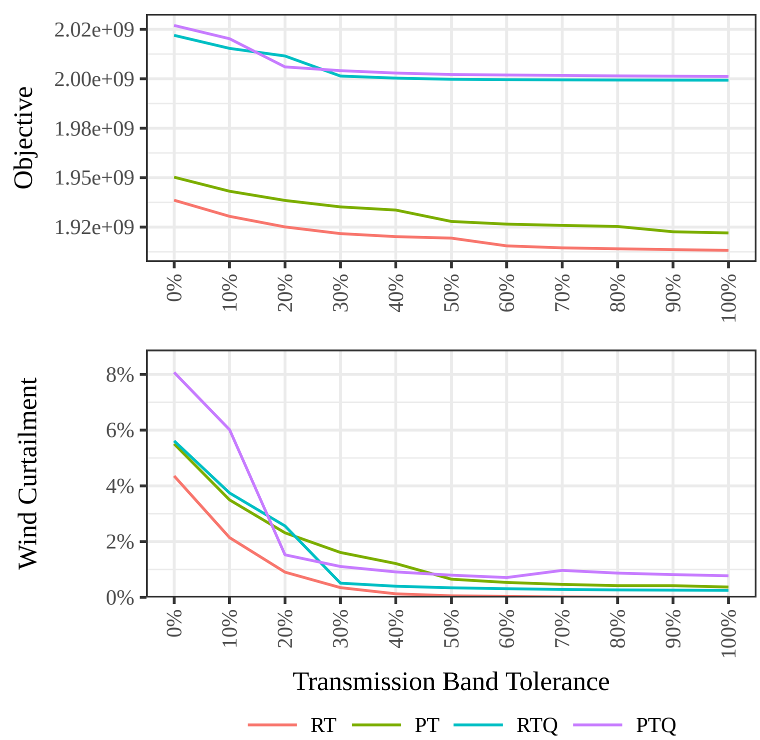


Figure 5.38: Objectives and wind curtailment for *Min Wind* commitments and transmission band tolerance sensitivity, Northwest.

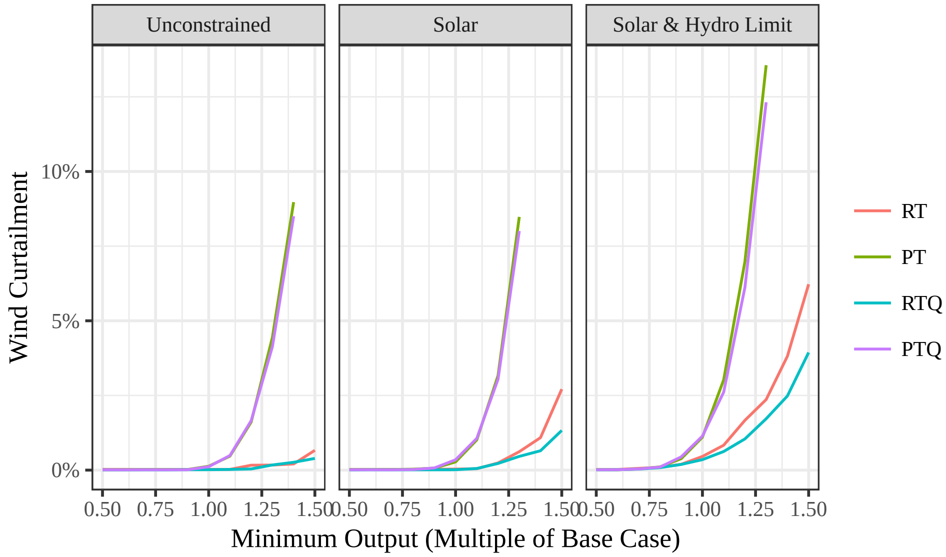


Figure 5.39: Curtailment rates for (conventional unit) minimum output sensitivity with unconstrained (full hydro and no solar), solar, and solar with hydro limits (default), Northwest restricted transmission cases.

5.5.6 Solar Competition and Hydropower Flexibility

The default case adjusts demand according to a representative solar profile and further restricts hydropower minimum/maximum outputs according to historical levels. Without these constraints, there is a wider range of feasible model parameters and lower wind curtailment. Examining across the sensitivity of conventional unit minimum outputs, adding solar effectively causes similar wind curtailment rates at 10% lower minimums. Adding hydropower limits—reducing the amount of peaking support the reservoirs can provide, but keeping hydropower reserve contributions constant—then nearly doubles curtailment. As clarified above, this model assumes solar is must-run; thus, any coincident curtailment—which the model is estimating—is all attributed to wind.

5.6 Summary of Findings: Engineering Context and Causes of Curtailment

Across the modeled regions, there are clear engineering constraints on the level of wind that can be integrated. As is well known, constraints will increase the objective, and I have identified some of the more costly constraints among those modeled. Here, I am using engineering context and causes to refer to outcomes under a system that is efficiently run according to the objectives of the model and standard regulatory practice. This is to distinguish from scenarios implementing formulations of institutions identified from the cases.

Finding #1: Must-run CHP strongly affects wind integration, and is strongly correlated with curtailment in winter.

Must-run combined heat and power (CHP) plants with limited flexibility have minimum outputs that must be considered during dispatch. Collectively, their "minimum mode" of electricity generation is strongly correlated with wind curtailment, as expected: when wind as a share of demand is high, there is limited ability of the remaining generators to ramp down to accommodate wind. Another consequence of CHP minimum mode is that non-CHP generators (e.g., *coal600*) must generate less. These other plants are committed by the model to provide lower cost generation when demand is high, and to provide reserves (which CHP does not). However, their minimum outputs are also reached during windy hours (e.g., in W. Inner Mongolia, Figure 5.22).

CHP constraints also increase total costs; however, care must be taken in interpreting these costs. CHP plants provide another form of energy—heat—which is not considered in the objective. Much more data on heating demands and costs would be necessary to co-optimize electricity and heat. Such a model should include alternatives to a CHP plant, e.g., to use a (small) coal-fired boiler (with a lower efficiency of delivery) or electric heating. The latter has high efficiency losses in the generation of that electricity if from coal, compared to simply burning the fuel.

The CHP minimum modes are difficult to specify precisely, for which I ran a wide sensitivity analysis. This range was designed to capture differences in heating loads across plants as well as redundancy in certain heating grids. Model results indicate that, keeping other parameters at base case levels, wind curtailment drops significantly with lower CHP minimum modes. For example, curtailment is halved if Jilin's minimum mode is reduced from 6,000 MW to 5,000 MW (see Figure 5.16). High CHP is a strong predictor of curtailment in these models of the winter season.

Finding #2: Minimum outputs of coal plants strongly correlate with wind curtailment and system costs.

Wind curtailment largely occurs when coal plants are operating at their minimum outputs, recognizing that the plants will ramp down to their lowest allowable output before wind is wasted As these minimum outputs are, in fact, the result of a combined technical and administrative process, which can be tuned through technical improvements, fiats, and/or markets, it is reasonable to consider the level of the outputs as a cause of curtailment. Once commitments are fixed, these minimum outputs determine to a large extent curtailment rates during low demand hours. In the Northwest case, curtailment starts to increase at just 10% above the reference minimum output (which is set at 54% of capacity). These effects are enhanced when rigid commitment scheduling is taken into account: that is, when more coal units are committed, the precise level of the minimum output increases in importance.

The base case minimum output for all regions is set close to the guidelines of the Northeast peaking market and in the middle of the range indicated by various respondents. There is uncertainty, however, in the value used in practice for plants across the cases. Even in the Northeast, the peaking market threshold was set with political considerations (related to the desired size of the market) and was adjusted downward in later rounds, again not likely tied to technical improvements in the plants. It is reasonable that other regions without the structured peaking market will have higher minimum outputs.

In addition, self-generation units (on-site generation for large industrial facilities) are less controlled by the dispatch center. In particular, they may have higher minimums (i.e., may not participate in peaking to the same extent as a traditional generator). For these reasons, the higher range of the sensitivity around minimum outputs—particularly in the Northwest—is instructive of where current practice might be.

Reducing technical minimum outputs is the focus of central government efforts, especially in relation to improving renewable energy utilization, with calls for further study into "deep peaking" to go much below the 54% levels modeled here (NDRC and NEA, 2015a). These results confirm the value to renewable energy of these initiatives. For example, curtailment decreases 4-fold when minimum outputs in the Northwest are reduced 25% down to reference levels (see Figure 5.39), considering solar and hydropower constraints.

Modeled costs are similarly much larger for the high minimum output cases, as lower efficiency generators cannot be ramped down. However, these cost savings are likely overestimates, as the model does not incorporate part-load heat rates—that is, the efficiency of a coal generator declining as output is lowered. For "deep peaking" at outputs below around 40%, additional fuel inputs such as oil are also required, which raises marginal production costs and emissions.

Finding #3: Minimum up and down time constraints on coal plants are the least influential aspect of coal plant flexibility.

The minimum times between startup and shutdown (up time) and shutdown and startup (down time) constrain when coal units can be committed or decommitted, and thus implicate many aspects of plant-level flexibility (e.g., minimum modes of all committed units). These results show, however, that this is the least important aspect of coal plant flexibility (see Figure 5.17). Even the extreme case of increasing minimum up times ten-fold to 120 hours for large generators results in only a small increase in curtailment in the reference case.

Long minimum times cannot be fully separated from the commitment scheduling process, in that the benefits of more flexible scheduling may not be achieved if minimum up times remain in the days. This is not directly modeled here, as the reference case assumes perfect foresight of wind, and thus commitments can be arranged throughout the week to accommodate changes in wind. Assuming poor forecasts *and* a more flexible commitment scheduling process (e.g., daily, as in many international systems), these time constraints may become more important, and should be the focus of future study.

Finding #4: Reserve requirements lead to additional coal commitments and raise overall minimum outputs in the system, causing increased curtailment.

Reserves are a necessary part of system operation, allowing the operator to meet unexpected changes in supply and demand on short time intervals. In the systems studied, there were inconsistent accounts and relative lack of emphasis by respondents on the setting of these requirements (see

Section 3.8.6). This is likely because, under normal circumstances, there are plenty of reserves given excess coal commitments, and no reserve sharing mechanisms that require detailed accounting. Special measures for particular types of grid conditions (e.g., low demand during Chinese New Year), by contrast, would be dealt with on an ad-hoc basis. In the default modeling cases, simple rules of thumb were used from international systems, including some additional requirements to meet wind forecast error. These results, particularly in the Northeast, show a strong correlation between the level of required reserves and wind curtailment, as well as costs. Some uncertainty on the percentage of hydropower available for reserves (assumed 30%) changes how much reserves must be found elsewhere, hence the sensitivity across a large range is important.

Finding #5: Quotas for coal plants raise costs but do not have a large, direct impact on wind curtailment.

Across the regions studied, including the quota constraint causes a larger share of generation to come from less-efficient coal plants, which leads to higher production costs. However, wind curtailment remains constant when turning on the quota, whose reference value is seasonally-adjusted based on average provincial thermal capacity factors. In fact, curtailment remains constant over a large range of the quota, only increasing in the Northwest model runs when the quota reaches 50% larger than reference levels (see Figure 5.37). As will be discussed in the next chapter, the quota is linked to the scheduling institutions, which do have a significant impact on wind curtailment. However, these results demonstrate that if the coal quota were reduced or replaced with some other minimum generation constraint (e.g., through an annual bilateral contract), the benefits to wind might be minimal.

Chapter 6

Integrated Analysis of Technical and Institutional Factors

This dissertation uses two methods of obtaining evidence to characterize the system and explain outcomes: qualitative process-tracing of the decision-making processes in electricity systems operations, and a quantitative grid model to assess optimized operational outcomes given various constraints and parameters. These combine, respectively, "bottom-up" and "top-down" approaches. In Figure 6.1—repeated from Chapter 2—the relationship between these is described in relation to three causes of outcomes:

- Institutional: decision-makers have preferences for specific system outcomes, the scope to act, and the necessary information.
- Technical: given a specification of the engineering model, including technical boundaries and objectives of the system, certain outcomes result.
- Mixed interaction of technical and institutional: decision-makers have preferences for specific outcomes and a constrained scope to act (subject to technical realities), and outcomes combining these two result.

Chapter 3 provided process-tracing (PT) evidence for these different mechanisms, starting from the bottom of the figure. Chapter 5 described the various modeling results, from the top of the figure, and separated into the mechanisms, where able, through a range of sensitivities. This chapter

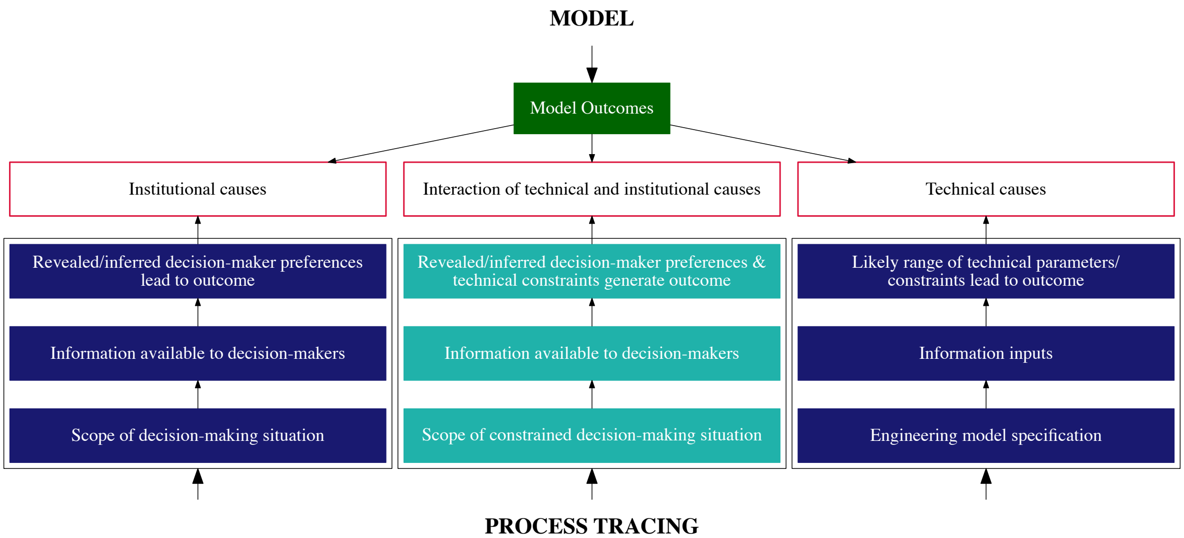


Figure 6.1: Integration of quantitative model and process-tracing analysis in this chapter

brings together the case studies and modeling results to assess the weight of various conclusions, provide integrative explanations, and establish more parsimonious scoping conditions. These findings do not represent the entire universe of factors affecting system operations in China, instead focusing on particular issues (e.g., wind integration) where institutions are likely to play a bigger role.

The first section is a simple set of triangulation results, highlighting where these two different methods produced similar or contrasting results. This corresponds in the figure to arrows entering a box from both top and bottom. The second section expands on the *mixed* mechanism (middle of Figure 6.1) though examining interactions with an integrated lens. These interactions are particularly complex to disaggregate using a single method, and thus differ substantively from triangulation. Finally, the third section summarizes what the combined results say about the expectations for wind outcomes introduced in Chapter 3.

6.1 Triangulation

The most fundamental utility of using multiple methods is triangulation—using multiple streams of evidence with different inherent biases to address the same question. Using terminology from findings from Chapter 5, the causes (or potential causes) of system inefficiency and wind curtailment fall into three basic categories—engineering context/technical causes, market context, and bureaucratic context. In this section, I summarize reinforcing results and conflicting results for each.

6.1.1 Engineering Context / Technical Causes

All of the systems studied are heavily constrained by technical operation criteria—e.g., poor demand correlation, inadequate transmission infrastructure, conventional generator limitations, etc.—which are major contributors to curtailment. Both respondents and model output confirm the crucial role of high minimum modes of CHP plants in the northern winter season in causing wind curtailment. Over a wide range of technical parameters in the Northeast and W. Inner Mongolia, curtailment rates, in fact, scale linearly with CHP minimum mode. In these regions, there is substantial evidence that CHP is a strong predictor of high curtailment. The growth of CHP over the 2011-2015 longitudinal NE case was another major factor in growing integration challenges. In the Northwest results, CHP must-run amounts are a smaller fraction of demand, one contributor to lower reference curtailment.

Inflexibilities of electricity-only coal plants leading to curtailment were also confirmed by qualitative and quantitative evidence. In W. IM, model results show substantial curtailment while *coal600* is at its minimum output, and in the Northwest, raising minimum outputs by 10% has a strong, non-linear impact. It is important to note, however, that these minimum outputs are currently determined through a combined technical assessment and administrative process that does not guarantee truly efficient outcomes: they are fixed (e.g., annually) by the grid company, based on self-reported criteria of plants (which are incentivized to over-estimate) as well as generic parameters of unit type and size. In addition, self-generation units—common in the Northwest and across China—have different dispatch criteria that can result in higher minimum outputs. Recognition of this connection with wind integration was the primary reason for the peaking ancillary services markets piloted in the Northeast and now expanding to other regions. This market has led to additional wind on the grid, though at a high cost to wind farms.

In terms of transmission infrastructure, as noted, the model does not capture intra-provincial congestion, which respondents listed among contributors to integration difficulties. For inter-provincial transmission infrastructure, optimistic assumptions allowing full (unconstrained) utilization show that in most cases the lines do not cause significant curtailment.

Inter-regional lines (e.g., to North Grid) provide another source of demand and thus cause a reduction in wind curtailment in exporting regions. Similar to minimum outputs, these exports are not determined on a cost-efficient basis, but rather the precise export amounts are negotiated. However, the lines may reach their maximum output at certain hours, indicating they are likely being utilized efficiently during those times (e.g., day-time transfers from W. IM to North Grid). Thus, there is strong evidence that increasing interconnection capacity will reduce curtailment in exporting regions, though the amount will depend on negotiated flows, additional planning, and accompanying changes to dispatch. Note that these results only address curtailment in the *exporting region*: where the importing region also has large installed wind capacity (such as northern Hebei in North Grid), additional modeling is required to assess if there is shifting of wind power production due to coincident curtailment—similar to what was observed with Liaoning in the Northeast when relaxing the transmission band tolerance.

Solar profiles were implemented in the model of the Northwest, where there is rapid development in recent years. Similar to previous results (Davidson et al., 2016b), wind curtailment increased, reiterating an important consideration in renewables planning: co-optimized development of renewable energy is important to reduce integration frictions. Up until recently, solar has been given priority—which as discussed is mostly a discretionary decision by the grid operator—which would continue to incentivize solar in areas already facing high wind curtailment. Recent data for solar curtailment rates in the Northwest indicate a more equitable curtailment division, and potentially more rational co-development.

6.1.2 Market Context: Medium- to Long-Term Physical Contracts

All of the systems studied are primarily organized around medium- to long-term physical contracts, either with the grid company, or with consumers mediated by the grid company and its exchange center. The traditional arrangement is for the provincial government and stakeholders to set annual quotas, which are then allocated to months, and whose fulfillment is a main responsibility of the grid company's planning and dispatch departments. These contracts create constraints on dispatch, which are expected to restrict short-term balancing.

Through tracing the system operations of each of the grid regions and provinces in this dissertation, I find that the traditional arrangement is still dominant, undergoing some changes through increased transparency as well as additional discretion to grid companies to "carry-over" some portion of monthly totals. In order to meet these monthly requirements, grid companies plan commitments of conventional coal units at relatively long time horizons (weeks to months), increase their minimum commitment times beyond technical requirements, and set minimum outputs according to a combined technical and administrative assessment that likely does not reflect true engineering limits of conventional generators. This scheduling procedure does indeed restrict the flexibility of grid operators in short-term balancing. In addition, across the various cases, this scheduling procedure is maintained—and possibly enhanced—when quotas are replaced by medium- to long-term market-determined contracts.

Model results confirm that some aspects of the quota system increase curtailment, while calling into question the relevance of others to renewables integration. Most directly, long-term commitment scheduling (weeks to months) limiting how frequently the grid company can startup or shutdown generators over the model week has a large effect on both costs and curtailment. This factor—established through a two-stage model also capturing the benefits of using better wind forecasts—is one of the most consequential for wind curtailment across all the regions.

The quota requirement itself, parameterized according to historical capacity factors (already rather low in most of the provinces studied), is not a key factor contributing to wind curtailment in most systems and sets of parameters. Costs do increase appreciably, because the quota diverts production from more efficient generators. However, the addition of the quota constraint has only minimal impact on wind integration when modeling current systems, except in heavily constrained sensitivities or unrealistically high quota situations. Here, model results show a clear divergence between the two primary system outcomes of interest—a conclusion that conflicts with accepted wisdom and the views of several respondents.

In general, costs are reduced when curtailment is reduced, because wind is substituting for high variable cost conventional sources. However, as this example shows, the converse does not necessarily hold. There can be interventions that reduce costs without changing the economic integration space for wind. Quotas are the most visible of legacy institutions, and the most direct lever permitting gradations from planning to markets, but changing them has minimal impacts on the integration space for wind, keeping commitment scheduling practices constant.

There are at least two interpretations of these conflicting results: first, respondents overestimate the importance of the quota system to wind integration space, because it is an inherent advantage given to conventional generators and thus seen as detrimental to new energy sources. The quota has specific obligations on the grid company, which can be quantified and audited at regular intervals. Renewable energy dispatch, by contrast, has less specific and quantifiable obligations.

Second, respondents may conflate two components of the quota system: establishing long horizon commitment plans to satisfy the quota, and the level of the quota itself. With greater flexibility in dispatch—e.g., making commitment decisions for coal units after some renewable forecasts are available—model results show that the quota can be met without severely impacting renewable integration. This flexibility is not exercised in the grids; hence, it is difficult to isolate this as the cause of integration difficulties from historical observation. Though, one operator in a Southern Grid province noted that some more frequent coal commitment scheduling has taken place in recent years to respond to hydropower[16J3].

Newer market exchanges—which are an increasing fraction of total electricity sold—alter this at the plan determination stage by diminishing the direct role of government planning bureaus. This would be equivalent in the modeling framework to reducing the quota assigned to all generators, and potentially increasing it for contract parties (presumably, the more efficient generators). As the quota constraint for more efficient generators is not binding, the primary effect is from reducing the quota on other generators. Hence, this is similar to a no- or low-quota case.

However, if and how increasing contracts may alter short-term balancing is less clear: there are examples of bilateral contracts being given greater weight in dispatch, in settlement, or in both. In some cases, there were concerns that increasing the share of market contracts will overly constrain dispatch, suggesting an upper threshold of around 30% in one province[16J4]. In others and in official documents from Yunnan's exchange center, the market contracts were primarily seen as settlement mechanisms, and thus not essential to daily grid dispatch functions.

The modeling sensitivity of commitment scheduling captures, to some extent, these two extremes: more frequent commitments imply a flexibility to adjust coal plant generation within the month—hence, this represents either a more flexible quota/contract carry-over system, or settlement-only contracts. Less frequent commitments imply more rigid monthly plans—corresponding to inflexible carry-over policies and must-meet exchange contracts.

6.1.3 Bureaucratic Context: Trading Arrangements

There is strong agreement between model results and the case studies that exports have a large impact on renewable integration. Trading arrangements, both between provinces in the same region and between grid regions, are thus important elements to the story.

First, it is clear that there are differences in trading arrangements across and between provinces, as dispatch plans are constructed primarily at the provincial level with exports typically fixed at longer intervals and/or with specified profiles. If inter-provincial markets exist, they are usually different in nature—quantities, entry, price formation, etc.—than intra-provincial counterparts.

Two exceptions are worth noting. The Northeast peaking ancillary services market, which is cleared region-wide and thus is an example where there is no intra-provincial counterpart. This has a direct impact on short-term dispatch by reducing certain coal generator outputs. Another exception is some types of excess hydropower exchanges in Southern Grid, those which (administratively) enforce price convergence between intra-provincial and inter-provincial contracts. The latter alters monthly exchange totals, but for similar reasons raised in the previous section may not directly modify intra-provincial dispatch.

For most other trading through traditional dispatch and exchanges, which includes the simplified representation of provincial dispatch in the grid model, the differences in treatment of intra- and inter-provincial trading do affect short-term operations, greatly increasing curtailment. The Northwest has accommodated some more flexible intra-provincial dispatch precisely to address this issue, acknowledging the importance to renewable integration. The Northeast peaking market is an explicit recognition that previous short-term dispatch procedures were insufficient. Modeling results, particularly varying the transmission band tolerance that controls how closely provinces must meet pre-scheduled flows, demonstrate a high sensitivity to this dispatch rigidity. Though, most of the gains of more flexible transmission come from increasing the allowable range to just $\pm 20 - 30\%$, assuming that there is no hard constraint on total exchanged amounts.

Cross-regional exports offer similar conclusions, though prospects for harmonizing trading rules are more distant. In the default model specification, out-of-region exports are fixed according to receiving region demand profiles and totals, similar to the inter-provincial restricted transmission.

Altering this to accommodate different profiles can have a large impact on wind integration. However, there is no currently piloted method to adjust profiles on periods of days. In fact, cross-regional exchanges are organized mostly seasonally and annually, and even in these cases, they are all of the listed exchange type with a fixed quantity and profile (and sometimes, price). As in the example of the *DeBao* line connecting Northwest and Central grids, altering these agreements requires going through substantial bureaucratic layers, which would be infeasible on timeframes relevant for wind energy.

6.2 Interactions From an Integrated Lens

Numerous modeling results highlight the importance of interactions in generating system outcomes —i.e., the simultaneous presence of multiple treatments creates a non-linear response, distinct from the additive effects of individual treatments. A typical example of this is the interaction of CHP minimum modes and reserve requirements, which at high levels create ever-increasing rates of curtailment. Another is the interaction of long-term (transmission contracts) and short-term (reserve sharing) trading arrangements. In the qualitative data, respondents identified numerous trade-offs (e.g., participation in excess wind markets at reduced tariffs for uncertain additional dispatch) whose effect on system outcomes depends on a range of parameters. More generally, these indicate that electricity systems throughout China are heavily constrained by multiple factors and highly sensitive to the specific types of power sector reforms such as price formation, entry restrictions and timing of market designs.

While main effects are the primary focus of multi-method approaches overviewed in Chapter 2, interactions do appear frequently in separate discussions of qualitative and quantitative methods. Purely qualitative research may seek to address necessary and/or sufficient configurations of causes for particular outcomes (Goertz and Mahoney, 2012). Quantitative estimation techniques should consider—at least at first—a range of interaction terms before possibly eliminating irrelevant ones (Angrist and Pischke, 2008). In one methodological study on how to more closely integrate qualitative and quantitative analysis, passing mentions of interactions occur, e.g., using small-N case study results to identify new interactions for large-N analysis (Lieberman, 2005).

For the complexity of the system being captured in this dissertation's quantitative model, the importance of interaction terms deserves greater emphasis. Outcomes in electricity systems are determined according to various thresholds defined at hourly to annual granularity, whose adjustment by small amounts (e.g., a few percentage points on the minimum output) can result in large differences in wind integration. By contrast, for large-N statistical analyses with covariates coarse in time and geographic dimensions (e.g., the total capacity of inflexible power supply), interaction terms may be inadequate and not give significant effects.

Another key distinction with regards to interaction effects in estimation techniques is the lack of support from observational data for all combinations of interactive terms. One must extrapolate with care beyond this support. Related to this, certain decision-making structures may co-exist in all current systems: interactions provide no additional value for these types of collinear treatments. For example, the quota institution implies several overlapping decision-making structures (e.g., level of the quota and long-term commitment scheduling), many of which independently affect operations. In practice, there is no real-world system with just one part of the structure. However, the quantitative grid model can analyze the individual components, which is important for forward-looking reform insights.

Recalling the discussion in Chapter 2 on multi-method research more generally, a range of ways exist for integrating PT with quantitative techniques, which address four main purposes (Lieberman, 2005; Lorentzen et al., 2015; Seawright, 2016):

1. Case selection
2. Measurement validity
3. Mechanism evaluation
4. Model building

This dissertation does not fully integrate the quantitative model with case selection—all regions were chosen prior to modeling results, though I did seek some diversity on the chosen market mechanisms based on results suggesting the importance of cross-provincial trade barriers.

The validity of inputs to the quantitative model was the focus of a subset of interviews—particularly in early case exploration. These inputs include, among others, typical minimum outputs of electricity-only and CHP generators, typical commitment times, and tolerance thresholds for transmission contracts. While respondents confirmed that there are likely errors in reported curtailment rates (dependent variable), it was not clear how to incorporate these into the analysis.

The rest of the section is devoted to the last two integration techniques: evaluating mechanisms —broadly, the plausibility and likelihood of various processes implied by the model—and model building—the entire process from making appropriate assumptions to choosing formulations for institutions (e.g., constraints). Semi-structured interviews with experts with operational experience can generate valuable ground-truthing on hypothesized underlying causes and can provide insights into the feasibility of hypothetical model changes.

6.2.1 Disaggregating Quota and Scheduling Institutions

Beginning with the conventional wisdom that the quota generates constraints on operation leading to inefficiencies, interviews focused on several aspects of how this quota is fulfilled. Across most of the regions, some form of monthly energy accounting inclusive of quotas and contracts is tied to a commitment schedule that must be made well in advance of accurate wind forecasts, and ensures long minimum up times for conventional generators. Deviations from this occur infrequently in response to hydropower availability (Southern Grid) and appear to be more flexible within more tightly integrated provincial grids (W. Inner Mongolia). Constraints at the monthly level—increasing under must-meet market exchanges—were recognized by grid operators as decreasing flexibility. In sum, first-hand accounts of the constraints of quotas (and some newer markets) on grid operator decision-making situations strongly indicate a coupled set of institutions that support quota fulfillment and impact wind integration outcomes:

1. Long-horizon commitment scheduling (weeks to months)

2. Long up times for conventional units

3. Adjustments at end of (arbitrary) settlement period

Model results attempting to capture the assumptions around commitment scheduling—*Perfect Forecast*, *Min Wind* and *Zero Wind*—confirm that long-horizon commitment scheduling—i.e., before accurate wind forecasts are available—is the largest independent contributor to wind curtailment in all regions. Broadly speaking, the most conservative (*Zero Wind*) is close to simple rules of stated practice, though current practice (including plant-level specifics and some ad-hoc flexibility) is likely somewhere between *Zero* and *Min Wind*. The detailed PT thus helps bound where the current frontier is. Similarly, the ideal frontier may be less optimistic than the deterministic model (*Perfect Forecast*), based on the respondents' stated disutility of current forecasts. Thus, the precise benefit of making more frequent and flexible commitment scheduling—in the absence of changes to forecasting systems—has an upper bound between these results (e.g., see Figure 5.10 in Chapter 5, p. 216).

Through extensive qualitative analysis of current market designs and implementation, these mechanisms of decision-making in system operation may well extend into the future market reform era. Contracts are typically treated with the same or even greater level of scrutiny in grid dispatch. Furthermore, the month is a very common time interval for both quotas and contracts. Thus, the divergence calculated through the model may hold even with progress toward moving the quota to medium- to long-term contracts: outcomes will highly depend on to what extent contracts continue to drive scheduling.

By contrast, minimum up times demonstrate little effect on model results for any of the scheduling scenarios, across a wide range of tested parameters. Grid operators consistently rejected the low theoretical minimum up times ($<$ 12 hours for the largest units) that other integration studies have indicated are important to improve renewable energy outcomes (Cochran et al., 2013). Here, in a similar fashion to the quota institutions, I separate coal commitment flexibility into respective components: technical issues related to startup procedures and institutional issues related to scheduling frequency. Primarily the latter has a large effect. Assuming that quotas and contracts are gone or no-longer must-meet criteria, future model development could incorporate a more precise description of how improved wind forecasts could be incorporated such as through a rolling horizon UC that recalculates commitments daily (or more frequently) based on updating forecasts. Prior to changing this scheduling process, however, the benefits of forecasts will continue to remain limited.

6.2.2 Long- and Short-Term Trading Arrangements: Reserve Sharing and Transmission Scheduling

The crucial role of reserve requirements in determining wind curtailment was one of the most underemphasized topics in unstructured conversations with grid respondents. Many operators did not say precisely how reserves are calculated in their systems, while others noted that reserves are plentiful (typically referring to upward reserves), and some were not aware of reserve sharing rules (or lack thereof) in their region. A detailed report on China's system operation conclude that reserve requirements, particularly load-following ones, have multiple definitions and are ambiguously used (Kahrl and Wang, 2014). Reserve sharing is, of course, highlighted in many international integration studies (e.g., GE, 2010), but without these rather conclusive modeling results, I would likely not have focused subsequent fieldwork on this particular aspect. Data from subsequent trips helped justify the two parameter choices of current practice (i.e., provincial) and ideal practice (i.e., regional).

The reserves discussion is complicated by its interaction with the rigid transmission capacity allocation between provinces and regions. Across a wide range of parameters (including reserve requirements), the constraint imposed by transmission bands causes a large increase in curtailment when reserves must be met entirely locally. This relates to the non-intuitive nature of barriers to electricity trade highlighted in Chapter 3: electricity is quite distinct from other products in the way that trade barriers are manifested by protectionist policies as well as bureaucratic coordination difficulties. These two concepts were not jointly raised by any of the respondents. Instead, if raised at all, more flexible transmission alone was highlighted as important to wind integration.

Combined with the previous section, the three basic legacy institutions (quota, reserves and transmission) demonstrate the essential non-linearity of the system and the complexity of underlying causal mechanisms. Certainly the quota is the most visible constraint on the system—with the most direct and heavy government involvement in operations, and the largest re-allocations of economic production—yet it is significantly less important than less visible institutions like how neighboring dispatch centers coordinate. The method of fulfilling the quota (i.e., long horizon commitment schedules) as opposed to the precise quota level is a crucial determinant of system inflexibility. This non-intuitive finding relates to the fact that shifting production to less efficient generators does not, in most cases, substantially alter the total technical minima of committed coal units, thereby leaving the integration space for wind untouched.

6.2.3 Plant-Level Flexibility vs. Grid Scheduling Flexibility

In the absence of changing longer-term commitment scheduling practice, the preferred approach for improving flexibility of coal plants appears to be mostly geared at reducing minimum outputs. This is evident in the design of the Northeast peaking market, the administrative compensation for peaking services, the wind-to-heat pilots (effectively reducing CHP minimum modes), as well as technical pilots on plant flexibility. These typically include scope for de-commitments, but in practice this is rarely exercised.

The distinction rests on which decisions are considered open to adjustment (possibly through market mechanisms) and which are fixed as boundary conditions. Under traditional dispatch, commitments and minimum outputs remain unchanged in response to typical changes in system conditions. In these examples, minimum outputs are somewhat flexible, but commitments are still fixed according to the traditional process. No experiment yet effectively integrates plant-level and scheduling flexibility.

Modeling results confirm that minimum outputs are extremely important for wind integration. Wind curtailment largely occurs when electricity-only coal plants are operating at their minimums. The precise levels used can differ across plants based on technical specifications as well as whether they are self-generation and thus somewhat less dispatchable. In the Northwest model, which is relatively flexible at the reference outputs used in the Northeast, raising minimums by just 10% above the reference level starts to increase curtailment (see Figure 5.34). The effects are enhanced —i.e., more than additive—when coupled with rigid commitment scheduling (*Min Wind* or *Zero Wind*), because more coal units must be committed under rigid scheduling with limited assumptions of wind availability. High electricity-only minimum outputs and high CHP minimum modes lead to the same type of inflexibility, thus the same effects on wind curtailment are observed under high CHP minimum modes.

Analysis of programs to incentivize reducing minimum outputs reveal that they are successfully implemented precisely because they do not alter the underlying commitment approach and settlement mechanisms. Virtually all compensation to electricity generators is in terms of energy (which includes “energy reductions” in peaking markets) and does not frequently consider costs resulting from binary decisions such as commitments that have only a partial energy analogue. Additionally, committing a generator for the month and reducing its output provides a more precise lever for grid companies to meet monthly contracts and calculate foregone generation if necessary.

Moving beyond compensation tied solely to energy quantities is also complicated by several of the market exchanges which use simple long-term pay-as-bid prices as opposed to single market-clearing prices (SMP) possibly the result of complex bidding. In a typical (energy-only) electricity market, the SMP includes extra producer surplus that precisely equates in the long-run an efficient balance of fixed and variable costs. Complex bids incorporate constraints such as startup times and trajectories that allow generators more precisely to specify marginal costs. If pay-as-bid markets (or their variants) increase in importance in China’s future reforms, the difficulty in recovering fixed costs would continue to hamper the incentive of certain conventional plants to increase flexibility.

Still, these results do indicate significant space to improve wind outcomes immediately by adjusting coal plant minimum outputs without commitment scheduling changes. Beyond the Northeast, other regions are experimenting with peaking markets. Administrative changes—either to outputs or to compensation for peaking—can also have a direct effect. Both markets and administrative measures can be effective, though not necessarily efficient, means of increasing wind. A large untapped potential appears to be the fleet of self-generation plants over which the dispatch center has less discretion. Reducing their minimum outputs could have a large impact in the Northwest, among other regions.

6.3 Summary of All Findings

In this section and Table 6.1 and Table 6.2, I summarize findings from Chapters 3 and 5, framed around an assessment of the various political economy and engineering expectations for wind outcomes introduced in Chapter 3. Model results as well as some case study analysis inform each factor’s (which could be a constraint, parameter setting, or institution) overall importance to wind integration outcomes. In order to assess current management, I generalize process tracing results across cases, and rank the feasibility of changing these processes according to an assessment of the “stickiness” of institutions. Finally, I highlight relevant current markets or other institutional change efforts examined in this dissertation. These are elaborated below.

6.3.1 Importance to Wind Integration Outcomes

I rank the importance of factors on a scale of low / medium / high, which is primarily based on the sensitivity of modeled wind curtailment rates to this factor in the Chapter 5 results. For example, a ranking of "high" indicates that the difference in curtailment between reference scenarios with and without this factor is large. Interactions among multiple factors are not included in the table. Interested readers are directed to the summary findings in Chapter 5 for detail on each.

Overall, many of the expectations are observed in the modeled systems, with either medium or high importance to wind integration. A handful of **Engineering Expectations** were found to be less critical (e.g., minimum up / down time, and intra-regional transmission capacity), while widely-acknowledged parameters like must-run generation were, indeed, found to have a large impact. Among the institutions (**Political Economy Expectations**), scheduling inflexibilities—***Physical Contracts*** and ***Trading Rules***—had the highest impact, while preferences to conventional generators through the quota (***Provincial Authority***) had a smaller than expected impact (if the quota institution is disaggregated into its respective level-setting and scheduling components).

6.3.2 Current Approach

This column represents traditional approaches, roughly in place since at least 2002. For technical parameters, this reflects the typical current method of setting the parameter. For institutions, these are the various processes that contribute to the expectation. There are several layers of inflexibilities in current management, which are is summarized in Section 3.8.1 on dispatch planning.

6.3.3 Feasibility of Changing Approach

The most speculative finding, this column ranking low / medium / high represents my overall assessment of feasibility or ease of changing the factor—the parameter itself and/or the underlying institution. Thus, a ranking of "high" indicates that changes can be relatively easily incorporated into existing practice, interest reallocations are small, and there may already be flexibility in place under certain circumstances or through market mechanisms. For institutions, one should interpret this as an inverse measure of the "stickiness" of this particular institution.

For example, ***Physical Contracts*** have a high importance to wind integration outcome but a low feasibility of changing current practice. This is based on the near-universal procedures of creating monthly (or longer) must-meet energy contracts, for which only minimal variations are allowed in current market-based or other efforts. I rank this as the "stickiest" of the relevant institutions for wind integration.

6.3.4 Relevant Markets and Efforts

For most factors, there is some ongoing effort (possibly, a market) to adjust current practices. I note relevant ones (and their region) that are discussed in the dissertation (see Chapter 3). These include efforts targeted at wind (e.g., Northeast peaking market) as well as non-targeted efforts that nevertheless affect system operation and constraints on wind (e.g., rolling over conventional energy monthly allowances).

These show a mixed picture of China's efforts to use markets to address wind integration challenges. Among the factors of high importance, only the Northeast peaking market targeting minimum coal outputs is functioning as expected. Efforts that adjust ***Physical Contracts*** are small in scope and non-market-based ("roll-over") or are fundamentally divergent from expectations from other systems (Yunnan's day-ahead exchange).

Factors ranking medium importance, by far, have the widest adoption, as measures to implement more market-oriented mechanisms (e.g., "out-of-plan" markets) or to address wind curtailment and overcapacity challenges (e.g., inter-regional excess power exchanges). As described in the findings of Chapter 5 and in Section 6.2.1, moving quotas to "out-of-plan" markets addresses only one aspect of inflexibilities arising from the traditional quota institution, and wind outcomes caused by this institution cannot improve without addressing each of its components.

Relying on exports to address wind curtailment may also have limited scope: while it will increase supply from the sending region, this must be shared with conventional energy according to current trading rules; and it will be competing with renewable energy and coal overcapacity challenges in the receiving region. More substantial inter-regional coordination leads to benefits transfers from receiving to sending regions, which can only be accomplished with strong central government intervention and/or negotiations on sharing the increased surplus from trade—both of which appear to be limited at the moment. I speculate on some of the causes for this misalignment, arising from the origins of China's electricity market reform agenda and how legacy institutions shape its implementation, in the next chapter.

Expectation	Importance to Wind Integration Outcomes	Current Approach	Feasibility of Changing	Relevant Markets / Efforts (Region)
Engineering Expectations				
Poor Demand Correlation: Low demand when high wind	**Medium**	None specifically	**Low**	Wind-to-heat facilities (NE)
Must-Run Generation: Combined heat and power minimum modes	**High**	Modes fixed by season, historical data	**Medium**	Wind-to-heat facilities (NE)
Conventional Plant Inflexibility: Technical criteria of plants	**High** (min outputs), **Low** (min up/down time)	Administratively fixed by type, some self-scheduling (e.g., self-generation)	**High**	Peaking ancillary services markets (NE)
Grid Inflexibility: Transmission network or reliability constraints	**Low** (intra-regional transmission), **High** (reserves)	Typical reliability metrics (transmission), Less explicit requirements (reserves)	**High**	Ad-hoc adjustments (e.g., Chinese New Year) (All)
Export Potential: Inter-regional export capacity and demand	**Medium**	Annual negotiated totals and profiles (acc. receiving region demand)	**Medium**	Excess wind and hydro exchanges (All)

Table 6.1: Summary of results on key engineering expectations for wind integration outcomes and current markets or other efforts to change relevant institutions (discussed in this dissertation in the given region)

Expectation	Importance to Wind Integration Outcomes	Current Approach	Feasibility of Changing	Relevant Markets / Efforts (Region)
Political Economy Expectations				
Physical Contracts: Long-term physical contracts restricting short-term balancing	**High**	Must-meet energy totals (monthly to annually), Coal commitment schedules (weekly to monthly)	**Low**	Monthly exchanges and "roll-over" allowances (All) Day-ahead exchange (SoG)
Provincial Authority: Preference to (within-province) conventional energy through planning, operations, and market authority	**Medium**	Annual production quotas (conventional only)	**High**	Various "out-of-plan" markets (All) Wind bilateral contracts, exchanges (NW, WIM)
Inter-Provincial Trading Rules: Rules differ across provinces and/ regions, inhibiting short-term trading	**High**	Negotiated and pre-scheduled inter-provincial flows, Provincial balancing (reserves)	**Medium**	Region-wide markets (NE, SoG) Relaxing transmission bands (NW)

Table 6.2: Summary of results on key political economy expectations for wind integration outcomes and current markets or other efforts to change relevant institutions (discussed in this dissertation in the given region)

Chapter 7

Discussion

This concluding chapter brings together the results and findings of the dissertation to highlight core contributions to methodology and specific domains of political economy of electricity market transitions, renewable energy politics and Chinese market regulation. In addition to specific references to sections where the reader can find further supporting information, some findings from the qualitative (Chapter 3) and modeling (Chapter 5) components are highlighted in parentheses. These are located in Section 3.9 and Section 5.6, respectively. The chapter concludes with policy implications for the market reform agenda and recommendations toward achieving efficient electricity markets that reduce environmental impacts.

7.1 Methodological Contributions and Notes

7.1.1 Broadening Multi-Method Political Economy Research

Beyond statistical models

Multi-method research combining qualitative and quantitative methods is increasing in popularity, in large part because of the expanded scope of questions and potential to generalize across multiple complex cases. While not a new phenomenon—especially in the traditional usage of triangulation —recently, there is a developing body of work seeking to enhance the rigor of this combination. This includes broader epistemological debates into whether these represent two different "cultures" of understanding or are fundamentally similar ways of pursuing inquiry.

Multi-methods designs proposed as canonical in the literature overwhelmingly focus on a single approach: large-N statistical analyses subsequent, prior, or in parallel with qualitative case studies. The basic idea is to generate a set of statistical relationships across a large number of units and test some of the hypothesized causal mechanisms in a handful of cases. In addition, intermediate stages of the statistical analysis or case studies can provide useful inputs to the other method: for example, case studies can test measurement validity of input data to the statistical component, and statistical analyses can help with case selection for the qualitative component.

This dissertation demonstrates a fundamentally different approach, which has been shown here to be effective at examining a class of phenomena for which primarily statistical analysis is insufficient as discussed in Chapter 2. In the highly technical electricity sector—with various physical constraints, complex economic production functions, and overlapping institutions—there are numerous interactions and thresholds that require a more realistic quantitative model to capture. A typical optimization model used by grid operators around the world is adopted and modified for purpose.

By contrast, a statistical approach to understand drivers of wind curtailment might use a panel regression at the unit of province-year with covariates for various institutions and power system data (e.g., deployed wind capacity). Here, the basic analytical issues are three-fold: 1) low statistical power given limited sub-annual data; 2) technically infeasible or highly uneconomic production schedules when extrapolating beyond the support of covariates; and 3) non-linear interactions among institutions and un-modeled technical constraints that only appear on short timescales.

This complexity is also not reasonably ascertained by qualitative methods alone even within a single case. With limited real-world systems and a large number of exogenous conditions, institutions, and variable parameters, it is difficult to evaluate independent contributions of each factor to outcomes based on observations alone. Instead, I build a parallel quantitative model to test counterfactuals of the cases, iterating throughout the process with qualitative fieldwork. This function is more akin to a formal model with significantly less abstracted variables.

Optimization models do present new shortcomings in execution and interpretation compared to statistical regression-based methods. They work when we have some prior knowledge of the structure of the physical relationship (e.g., objective functions and constraints). While they may have similar analytical purposes, a constraint between two variables is not the same as an interaction term. Additionally, the number of variables—which number in the hundreds of thousands in this dissertation's model—does not result in "overfitting" concerns, but is mainly of concern in computation of the solution and when interpreting results.

Model-building and process tracing

The approach to building the quantitative model in this dissertation, in Chapter 4, is to start with a reference model of operation according to a standard set of objectives, and then layer on various identified institutions and case-specific variables. An alternative approach, discussed in Section 4.1.4 but not chosen, is to build up a model of decision-making from the ground-up in a sequential decision-making manner.

Starting with a reference model and adding more dimensions of the real-world decision-making situation has a long history in a more generic sense as a constrained rational choice model. A simple parallel is moving from a unitary decision-maker model to a pluralistic model incorporating bureaucratic politics. This dissertation builds on that tradition of breaking down the black box of decision-making into subcomponents whose interactions frequently cause the system to deviate from some reference social optimum.

Layering on institutions in this sense is more complicated than adding covariates to a regression, and in this dissertation I use multiple field visits over several years and process tracing to iteratively build up and validate the model. First, I systematically test four key assumptions of the quantitative model (Section 3.8.6). Part of the interviews are structured to assess whether and to what extent these assumptions hold.

Second, tracing the steps through which routinized decisions are made in the actual system helps construct more realistic quantitative representations. Some were straightforward to specify but require new formulations to solve—such as the quota—while others were derived from interviews and observations in control rooms—such as the restricted transmission bands. Fieldwork conducted over multiple visits helped hone questions in response to initial model results—such as reserve sharing rules.

Third, the results of the quantitative model are appropriately scoped according to the qualitative analysis in the case studies. Widespread convergence on the assignment of authorities over system operation in all cases gives strong evidence of external validity (Section 3.8.1). There are also many combinations of institutions and unknown parameters that produce similar wind integration outcomes (equifinality), and qualitative analysis help scope the reasonableness of these choices and whether they have been changing over time (see, e.g., the longitudinal Northeast case, Section 5.3). Additionally, the model captures routinized behavior and does not easily incorporate ad-hoc decisions in response to certain extreme conditions, which has been identified in interviews. This provides one reasonable interpretation for difficult-to-solve or infeasible models.

Triangulation and integrative analysis

In combining the results of both approaches, I demonstrate several traditional triangulation results —where the same question is addressed from methods with different inherent biases. In addition, and more interesting from the perspective of analyzing interacting institutions, I show how integrative analysis of the two sets of findings can generate novel insights. This is necessary for certain portions of the system, for which neither method can capture sufficient detail. I highlight here two aspects: mechanism evaluation identified by the quantitative model and generalizability conditions of case studies.

The quantitative model easily constructs counterfactuals, for which treatment effects are evaluated. The validity of this rests on the broader model assumptions (last section) as well as how might changing this particular institution occur in practice. For example, simply eliminating the quota has little effect on wind outcomes of interest across many model specifications, but through interviews it is clear that the quota is actually composed of multiple institutions (including, e.g., monthly scheduling plans) which do affect model outcomes. These institutions occur together in practice—and are in some cases enhanced under market reforms—thus indicating difficulty in altering just one. On the other hand, this also points to possible second-best prescriptions while satisfying certain political objectives.

A further benefit of the quantitative model—and future work for this study—is the ability to test these mechanisms on out-of-sample cases. This is not trivial, as each new region requires data collection and parameterization, but it is easier than adding an entirely new set of field visits. The quantitative results of these out-of-sample regions can be used to strengthen certain explanations for which mechanisms appear to share similar impacts.

7.1.2 Adapting Grid Models to Real-World Institutions

Multi-node clustered optimization model with coupling constraints

Much research into the unit commitment model has been aimed at improving computational performance of the solution algorithm, incorporating uncertainty, and widening the scope of decisions beyond operational timeframes. In particular, clustering and other model reduction techniques have been typically geared toward incorporating investment decisions, thus creating an operationally-valid set of assets in the long-run with closer to actual production cost estimates.

This dissertation formulates and validates a multi-node clustered optimization model based on earlier single-node clustering models, developing a clustering technique to capture heterogeneity across different dispatch areas. This clustering approach is shown to have acceptable errors in outcomes of cost and wind integration, thus making it possible to extend it to longer timeframe modeling studies with renewable energy. It is highly computationally tractable, allowing greater scenario and uncertainty analysis.

The clustering technique also facilitates consideration of a coupling constraint over longer timeframes than the model horizon. The key recognition is of the equivalence of various clustered plants, allowing, for example, a unit to have a range of commitment and production schedules during the model horizon without violating its annual constraint. Instead, all generators within the cluster must collectively meet their long-term coupling constraint. Meeting this quota for each week in the quota timeframe (e.g. winter heating season) ensures that all generators on average meet their constraints. In this dissertation, the annual production quota represents the key long-term regulatory constraint. Other long-term coupling constraints that could be explored include maintenance scheduling and hydro-thermal coordination.

Complex legacy institutional arrangements

In terms of analyzing institutional factors and degrees of restructuring, some existing work has looked at high-level market design questions—such as the difference between zonal and nodal market designs—and related it to integrating renewable energy. However, no UC work to my knowledge has focused on modeling operations under multiple, overlapping political constraints established during transitions such as China's partially-restructured electricity system.

This dissertation formulates a new UC model with details of key political institutions influencing system operations in China and applies it to three different regions (four regions in total were studied in the dissertation). These institutions—province-centric hierarchical dispatch, production quotas, long-term commitment scheduling—are formulated within a UC and compared to reference outcomes. Model results confirm that interactions, particularly occurring on short-time intervals, are important to understand outcomes in this system. Modeling separately interactions among these institutions and ranges of other technical criteria help identify which results are more robust.

Through examination of the impact of individual political constraints, this type of modeling approach—compared to statistical estimation techniques—can provide better guidance for the relative importance of different reform options under consideration toward achieving near-efficient outcomes and facilitating other policy priorities such as renewable energy integration. For example, quantifying the benefits of improved coal unit commitment scheduling and minimum generation outputs (Chapter 5, Finding #2; and Section 6.2.1) highlights the benefits of modifying current primarily administrative scheduling practices. Future work can expand to other network and generator configurations, and explore optimal unit aggregation techniques.

7.1.3 Limitations

Electricity systems are complex to engineer and regulate, giving multi-method approaches a strong advantage in terms of enhancing internal validity of findings. However, as an extension of case study work, the costs of model building and evaluation are onerous and only useful for certain types of research. In particular, this dissertation examines questions related to operational decisions, for which the scope of decision-makers is heavily constrained by engineering criteria and thus cannot easily be ignored. Longer-term decisions, such as investments, typically have fewer engineering constraints because they abstract many aspects of short-term system operation, and thus evaluating the political process of investment planning may require less detail in engineering models.

As an extension of engineering research (after having already chosen a system or systems), numerous trips of fieldwork to take advantage of iteration can also be prohibitive. A simpler design could organize these two sequentially and achieve some research goals, if it is not necessary to refine interview protocols based on model findings.

Once a quantitative framework is chosen, there are limitations as to which political conflicts are modelable. Generally, these models allow for more diverse parameterizations than simple linear covariates. However, they are restricted to specifically quantifiable mechanisms, and may have difficulty handling heterogeneous strategic behavior of actors. The model itself also has various limitations: input data availability and uncertainty, evaluative criteria, and tractability as the modeling framework increases in complexity. An important part of the model-building process is totest underlying assumptions. This might reveal certain conditions lacking, which may require further model development or abandonment altogether of the quantitative approach, though this was not encountered in this study.

7.2 Contributions to Political Economy

7.2.1 Political Economy of Electricity Market Transitions

Restructuring electricity sectors to incorporate markets entails a complex reorganization of many government and private institutions, which are large as a share of output but also in terms of their impacts on inputs to production across an economy. Despite an accepted "standard liberalization prescription" in the regulatory economics literature, countries can differ substantially in the design, order, and extent to which certain activities are privatized and competition created. Far from aberrations, these divergences from standard models are commonplace and persistent. The partially-restructured system in China is unique in its particulars, but not in its complex intermingling of multiple government institutions, priorities, and political economies.

This transition appears to be more difficult in emerging economies, where objectives of reforms may not be primarily to give large discretion to the private sector for overall efficiency and whose market regulatory institutions are frequently underdeveloped. This dissertation demonstrates through multiple cases of market experiments that China has a number of these difficulties, many of which can be attributed to underdeveloped market institutions such as the lack of an impartial bureaucracy, independent regulation, and secure property rights. China is thus not distinct from other emerging economies, and these elements which are pervasive in the country's electricity sector reforms present substantial roadblocks to achieving an efficient market design that effectively integrates renewable energy.

Given that achieving the standard model is unlikely in the medium-term in China, this study asks an important substantive question: which elements of the partially-restructured system contribute the most to system outcomes of interest—in this case, production cost and wind integration? Attributing the role of specific institutions is fundamentally complicated by technical realities of electricity system operation, which are ineffectively captured in typical statistical analyses that have units of analysis of country-year and/or include highly abstracted covariates like whether or not an independent regulator exists. Some engineering studies using detailed models of system performance have examined different market designs, but typically around a relatively small number of questions—such as zonal vs. nodal prices—and almost exclusively in contexts already with well-developed institutions.

This dissertation adds to the literature by examining a greater variety of institutions arising in a country without satisfactorily competitive conditions, and assessing with greater parsimony the contribution of each. As has been documented in previous statistical work, findings largely support the contention that individual institutions interact with each other. Furthermore, institutions interact with various technical parameters, and these effects can be non-linear. For example, while some institutional changes—such as increasing flexibility of coal commitment scheduling—entail large efficiency benefits, the amount is enhanced or moderated by changes in other variables (e.g., Sections 5.2.5, 5.4.4). Yet other institutions—such as the generation planning quota—have an impact only when combined with other sources of inflexibility (Chapter 5, Finding #5).

Broadly, these results point to three cross-cutting themes that are useful when examining the politics and outcomes of electricity systems transitioning away from central planning to markets. First, where centralized government planning is being replaced incompletely with new methods of allocating production, it is important to disaggregate the planning and power scheduling institutions. Government officials typically make or direct production plans on long time horizons, though there are multiple steps to actualizing that production at the hourly level in an electricity system. In China's case, this involves setting monthly production and consumption contracts on grid companies, within which the grid companies schedule commitments of coal plants and minimum outputs. The monthly contracts—even though implemented at arms-length from direct political interventions—nevertheless constrain dispatch and make it difficult to integrate renewable energy.

Second, provincial governments, benefitting from relatively autonomous grid operations, frequently engage in protectionist behavior on behalf of their own generators and/or prefer to maintain autonomy over their system, thus preventing close inter-provincial coordination of dispatch. There are multiple flavors of trade barriers, for which simple analogies with other sectors are inadequate. At a basic level, government officials are more likely to understand long-term barriers to trade, such as limiting the total amount of energy their region purchases from another, and therefore frame protectionist policies in these terms. But, how these policies are translated to the short-term—exchanges of power at the daily or hourly level—can change the effect of the barrier substantially (Section 3.8.5). Other barriers to trade may arise from institutional coordination issues, such as the inability to share reserves, which may or may not be intended protectionist policy.

Third, introduced markets can address multiple types of production decisions, creating different aspects of flexibility in the system. Perhaps the simplest dichotomy is plant-level flexibility vs. grid scheduling flexibility (Section 6.2.3). Do markets seek to make production decisions more efficient within each plant, make system-wide operation and scheduling more efficient, or both? The former is easier to implement as it layers onto existing operation institutions more easily, while the latter will likely generate even greater system-wide benefits.

7.2.2 Renewable Energy Politics

Wind and solar energy generators are emerging actors in a large industry, with typically large geographic constraints and visible subsidies relative to traditional incumbents. These features have driven much of the literature to date on the politics of renewable energy, focusing on siting impacts, politics of tackling incumbency, and various cost allocation issues (Haggett, 2008; Stokes, 2013; Aklin and Urpelainen, 2018). Underlying much of the normative portions of this work is how to effectively use and generate government support for these energies, necessary to address externalities of incumbents. I will refer to this as the "subsidy politics" of renewable energy. Hydropower, the largest source of renewable energy for electricity globally, is qualitatively different in terms of impacts and industry maturity in many countries, and thus politics research compared to solar and wind has sharply differed.

We are entering a new era of wind and solar energy as capital costs decline to levels that allow long-term contract prices to already beat those of conventional energy in some jurisdictions. The trend is likely to continue and expand elsewhere with the introduction of more stringent climate change and environmental policies. With this, up-front subsidies, and hence the argument for more direct government intervention, will decline. In its place, as renewable energy becomes a larger share of energy in the system, the political conflicts over inefficiencies in renewable support policies, cross-subsidies implicit in system operation, and market design, will grow in importance.

This "integration politics" looks downstream, how various assets are operated once built, and the distributive politics of the entire electricity supply chain including its transmission. The set of actors expands to include all types of grid-related companies and institutions including regulatory bodies and market operators. There are decades of previous work in the regulatory economics literature on optimally structuring these institutions, but more is needed to understand their functioning in rapidly evolving political contexts (as noted above) and given the increasing role of renewable energy with different production characteristics.

A crucial element to understanding this new politics is the grid company and technical details of the system. Engineering models are necessary to diagnose complex phenomena such as how the distributive politics of transmission influences renewable energy integration outcomes. In-depth case studies are also important to understand the exact process of dispatch, which may differ from *de jure* specifications.

This dissertation presents a constellation of political economy issues associated with integrating wind energy in the world's largest electricity sector. In terms of overlap with traditional renewable energy politics questions, the incumbency advantage of conventional energy is still prevalent. It plays out through governments preserving conventional energy's access to markets through mandated quotas, and indirectly through market design.

Pricing systems also appear in both sets of politics: in subsidy politics, it is the level of government support. In integration politics, it is price formation through long-term markets as well as whether and how short-term prices are calculated. Renewable energy, as a near-zero marginal cost resource, has an advantage in systems with merit order dispatch, and a disadvantage in systems with average cost dispatch or its variants (discussed below). Average cost dispatch may reveal status quo bias as well as a conceptual struggle of recognizing how the heterogeneous nature of electricity over space and time affects price.

Integration politics diverge from subsidy politics when moving to the level of scheduling, the planning of production over time horizons of hours to months. In China, centralized utilities—

which are corporatized but state-owned—receive strong government directions and thus develop and maintain scheduling institutions to meet these relatively rigid requirements. These institutions —in particular, the various levels of grid company hierarchies and their interactions—are not well-suited to intermittent renewable energy, which requires more nimble dispatch. Grid companies, for the most part, display technical capabilities for flexibility, but the bureaucracies documented in the cases are deeply entrenched, leading to coordination failures that persist even with the introduction of markets.

Conventional and renewable energies both have strong economies of scale that are enhanced with increased transmission and trade with neighboring markets. Early cooperation between neighboring utilities in the U.S. helped generate interest in organized markets, becoming a driver for sub-national coordination and electricity trade. For renewable energy, with variability across geographic distances, these drivers are enhanced. However, every country's federalist structure is different, affecting cooperation and competition among sub-national jurisdictions and the relative authority of the central government. In China, strong provincial government autonomies restrict trade, which the central government has been remarkably unwilling and unable to challenge.

Finally, a key aspect of markets and renewable integration is the regulatory regime. With politically-determined subsidies as exogenous inputs, independent regulators have objectives to maximize social welfare, which in most cases tends to favor renewable energy. In China and in other so-called "developmental states", this distinction is blurred as related or the same government agencies both set and implement policy. How this non-independence of the regulator affects renewable energy requires study in each case, though in China, it appears to be largely a dis-benefit.

This dissertation presents both descriptive findings in integration politics, illuminating frictions in the market's interactions with other policy objectives, as well as prescriptive results in terms of "second-best" policies to fit context. Beyond electricity, this research can speak to the political economy of accommodating technologies with new characteristics into legacy infrastructures such as transportation and other energy systems. Similar transitions from subsidy politics to integration politics could occur in these sectors. For example, electric vehicles (EVs) are currently subsidized and create new challenges for balancing the grid due to charging patterns. Current grid tariffs, which penalize intense power use, make deployment of public fast-charging infrastructure costly (Fitzgerald and Nelder, 2017). In a future with substantially more EVs, these charges will likely need to be offset with flexible charging strategies and new tariff designs to reduce integration costs (Tuffner and Kintner-Meyer, 2011).

7.2.3 Creating and Regulating China's Markets

China's four decades of economic reforms have challenged theories of economic growth, sparked new fields of state-centered development economics, and frustrated countless liberalization-oriented economists. Of the range of explanations attempting to generalize China's approach to creating markets in the place of state planning, the classic theories of "growing out of the plan" supported by "market-preserving" federalist structures between central and local governments appear to be most salient for this thesis (Naughton, 1995; Montinola et al., 1995). "Growing out of the plan" refers to when portions of government production quotas are set aside in a dual-track pricing scheme in order to encourage firms to become efficient to compete on price, which could in theory create a self-sustaining ratcheting of liberalization reforms. "Market-preserving" federalist structures occur when decentralization of authority leads to limits on the central government's ability to direct electricity sector decisions, creating incentives for jurisdictions to compete to relax government restrictions and promote markets. While electricity reforms largely adopt dual-track (or even greater numbers) pricing, and provincial governments have increasing autonomy over market decisions, the effect in the electricity sector may be quite different from other experiences from which this theory was developed.

First, despite decades of efforts, electricity has been one of the most difficult sectors to liberalize in China. While theories documenting the drivers of major economic growth focus on new entrants—whether private, foreign, or local government-owned such as township and village enterprises (TVEs)—SOEs continue to dominate electricity. Provincially-owned generators, the major booming sector from the mid-1980s, have been widely consolidated into central SOEs starting in the mid-2000s with the small plant retirement program. Firms outside of the original five generation companies spun off of the State Power Corporation are for the most part state-owned and in some cases vertically-integrated from their core business, such as the coal mining giant Shenhua. The sector is essentially excluded from current state-owned enterprise reforms, and instead being further consolidated. Thus, the first pillar of "growing out of the plan"—new entrants threatening incumbents and forcing efficiency gains—is basically non-existent.

In terms of the second mechanism—incumbents becoming efficient and lobbying to accelerate liberalization—there is little evidence of this. Decades after efforts began, generation companies are suffering one of the worst overcapacity situations in history, which leads to price depression and sometimes loss-making years. Current market efforts seem to largely benefit consumers (in particular, energy-intensive industry), and generation companies have little incentive to advocate for further reforms. One of the other hypothesized mechanisms—inter-jurisdictional competition causing firms to advocate for pro-market policies in their locality—is muted because of the balkanized nature of electricity systems operation and trade barriers. Firms largely compete with other firms in the same province, and provinces enact protectionist policies to the extent possible to prevent outside competition.

Does electricity thus represent a fundamental counter-example of the successful "growing out of the plan" strategy? Certainly many of the conditions that allowed private, foreign and TVEs to flourish in the 1980s and 1990s are not present in electricity. Electricity generation capacity growth has occurred rapidly during the era of guaranteed production quotas (early 2000s) as well as in the midst of the expansion of various market experiments (2015). Efficiency or productivity are better metrics than output, though it is too early to estimate these from current market experiments separately from price depression induced by overcapacity. The electricity sector raises the possibility that "growing out of the plan" may not be a one-size-fits-all approach to establishing markets.

It does provide a cautionary tale about official pronouncements of "marketization rates" given how heavily controlled some markets are. Gansu supposedly has four-fifths of coal generation sold through market contracts, and Yunnan the same amount in hydro generation (CEC, 2017a). However, this does not mean that these regions are four-fifths of the way toward a standard electricity market. Examining the inner-workings of multiple market experiments across China, this dissertation has shown that "market" means different things to different localities and stakeholders. This ambiguity extends to the literature equating "markets" with "growth" when defining success of Chinese economic reforms—even when the reforms cement an interventionist government role. In electricity, this is complicated by the fact that outcomes in short-run efficiency may differ from long-run-based policies, contrary to expectations in a functioning electricity market: the most prominent example being inefficiencies in the case of over-contracting under rigid scheduling.

From the perspective of the conditions for "market-preserving federalism", a concept developed to explain China's economic success despite limited political reform, electricity also falls short on several counts. Electricity markets are indeed primarily under the authority of the province, but the central government has limits to its ability to police inter-provincial trade (hence, the lack of any major regional markets), and provincial governments face no hard budget constraint when attempting to squeeze centrally-owned generators. Furthermore, the market experiments are fundamentally shifting the authority of price-making from the center down to the provinces, hence lacking any institutional durability.

This style of federalism has also been used to reinterpret the notion of property rights, demonstrating how traditional notions of private property and contract law can be modified in China while achieving similar effect. By contrast, this dissertation demonstrates how the fundamental property right in electricity sector operation—government-provided production quotas—is unilaterally reneged by local governments through the introduction of markets and generally ambiguous in the case of renewable energy. The many examples of how this influences market actor behavior is one more indication that "Chinese-style" property rights are not equivalent to typical conceptions.

Given provincial government protectionism, Ang (2016) importantly questions the basic assumption of firm mobility underlying "market-preserving federalism". In the case of electricity, factors in favor of mobility (i.e., a firm has freedom to choose in which province to invest and produce depending on favorability of government policies) include the low physical costs of transporting electricity across borders and promises of stimulated demand from energy-intensive industry wherever production is located. On the other hand, electricity assets are extremely long-lived and thus there is no credible threat of relocation once built. The institutional barriers to trade—in spite of the low cost of transmission—are widespread, meaning a generation plant is essentially tied to its own province's economic development. Plan tariffs—still representing a large portion of revenue—are set centrally and differ by province in a way not directly tied to its market favorability.

In terms of the stages of China's market reforms outlined in Ang (2016)—market-building, stimulating institutional development, and market-preserving—electricity appears to be at a very early stage, if following this pattern at all. These stages were developed using a dependent variable of investment, which is only part of the story of China's developing electricity markets. Furthermore, virtually all investment in the sector is state capital or state-backed capital, as opposed to foreign and private sources emphasized in the book. If "strong" market-preserving institutions mean more "selective" investments, giving more discretion to local governments in electricity appears to not stimulate "strong" institutions at all, as witnessed by the massive, unnecessary, and indiscriminate coal capacity expansion in 2015. Finally, many major wind and solar provinces also have large and growing conventional sectors—except where prohibited by central fiat.

The dominant counter-narrative to decentralization as the driving force of market reforms looks instead to elite politics and factional struggles—i.e., intra-party competition between competing groups of officials, typically identified by a faction leader—and not any formal changes in fiscal or decision-making autonomy. As postulated in Cai and Treisman (2006), local officials used various market opening policies to impress higher-level officials within their faction, who encouraged risk-taking in order to gain an advantage in central politics. Fundamentally, this rests on the motivations and connections of local officials, which are hard to disentangle from more formal autonomies toward electricity market experiments, because there have been few clear discontinuities in central policy. Following 2015, virtually all provinces have engaged in widespread marketization—though, as it is now essentially central policy to experiment, the lack of marketization would be conspicuous. The example of massive local permitting of coal power projects in 2015, however, shows a clear case connecting specific formal electricity decision-making powers granted to provinces and their local outcomes.

Similar thinking—promoting investment, expanding energy-intensive industry, and predating on centrally-owned generators—appears to guide electricity market design choices, indicating that decentralization is, in fact, a large part of the story. The case studies do not focus in depth on motivations of policy-makers, but there is likely a strong incentive for local governments to lower energy prices with less regard for profits of (centrally-owned) generators. Maintaining or enhancing preferential electricity rates for local energy-intensive industries is likely seen as a key engine of economic growth. Given this, local governments will seek to push markets as far and as long as they benefit these constituencies (Chapter 3, Finding #4). They will also avoid any dramatic, non-incremental reforms for fear of repercussions from the center for failure.

If local autonomy is the theme of the current electricity market reforms, the stickiness of institutions such as local government control and the rigid scheduling processes are largely the cause of their incomplete nature. As Cai and Treisman (2006) suggest, the ability to replicate model experiences across the country requires significant centralization, and thus provincial dominance in market approaches would indicate difficulty in achieving and spreading more harmonized market designs. Leaving it to the provinces to stimulate action may have, in fact, doomed China to an extended period of a multiplicity of incompatible systems. Enhanced centralization and oversight may be required to move beyond these initial attempts and toward more efficient market development.

The experiences of these market experiments make strong arguments for independent regulation, as much research on economic reforms advocates, but they also demonstrate why truly independent regulation is unlikely to take hold in the electricity sector. The reasons are familiar to other attempts by China to create independent regulators, relating to fragmentary decision-making and the lack of political authority of the regulator (Pearson, 2007). Despite the strong long-term economic and environmental goals for the electricity sector by the center, reforms over the last several years have given up authority to the provinces who have little incentive to create independent regulators. The more closely centrally-aligned government bodies—local bureaus of the National Energy Administration—lack any substantive authority over local governments. Even the center is fragmented in its approach to electricity reforms—observed in the potluck approach of the No. 9 document, e.g., calling for "more comprehensive electricity planning and scientific oversight" ("加强电力统筹规划和科学监管") at the same time as "enhancing the impact of market mechanisms" ("发挥市场机制的作用") (State Council, 2015).

Finally, this dissertation offers many examples of the importance of the third "strong" market institution—property rights. The production quota, the predominant right within the generation sector, is one of many examples of ambiguous property rights that have historically relied upon informal connections among government and firm stakeholders (Montinola et al., 1995; Oi and Walder, 1999). In the absence of clear institutions beyond the *sangong* principles, this right is now subject to provincial government predation under market experiments, such as unilaterally reducing the guaranteed generation quotas by forcing generators to participate in markets. Central government failure to enforce minimum "full purchase" amounts for renewable energy creates a similar ambiguity that is exploited by provincial governments to benefit certain industries.

However, while secure property rights (whether formal or informal) are seen in the literature as essential to China's market reforms, this dissertation offers a markedly different interpretation: the rapid scale-up of electricity market reforms has been greased precisely by local government predation on insecure property rights. This is not without consequence: market actor behavior is not aligned with social welfare goals and buy-in to reforms suffer. In numerous examples, participants complained about the lack of clarity. Similar to local government autonomy, the property rights ambiguity may have kick-started reforms, but it is also delaying and derailing more effective markets from evolving.

7.3 Policy Implications and Recommendations

This section extracts the observations and implications for China's electricity sector policy, making recommendations to achieve the two objectives of interest—efficiency and renewable energy integration. In the first subsection, I analyze the electricity market reform agenda, connecting the discussion on political economy in the previous section to specifics of electricity. At a macro level, broader trends call for markets, but the gradualist approach and characteristics of electricity put into question whether and how long-term benefits will be achieved. In this interim period, administrative measures should be sustained to achieve system objectives.

Second, I highlight several specific challenges of existing electricity market experiments in China, ranging from their pricing systems to the downsides of piece-meal solutions. Third, I make recommendations for existing and future potential market experiments. Some of these recommendations must be implemented centrally—strengthening the oversight authority of central agencies over local implementers—while others could be incorporated by local governments experimentally into market designs. Note that these incorporate several aspects of feasibility and likelihood of the Chinese system, and are not repetitive of textbook liberalization recommendations.

In the fourth and final section, I connect these electricity market lessons to China's broader climate change and environmental agenda. Many electricity market reforms do not sufficiently consider these goals, which could be remedied in the policy design and evaluation stages by explicitly accounting for the many impacts of market experiments on renewable energy examined in this dissertation. Achieving environmental outcomes will also require better coordination of electricity sector policies and other efforts not explicitly under the 2015 reform blueprint, such as cap-and-trade pilots and air pollution control policies.

7.3.1 Electricity Market Reform Agenda in China

Market reform clarion calls

Local government officials' preferred governing methods involve control: administratively-determined incentives or fiats, closely monitored and scheduled reforms, and large public ownership through which additional direction can be given. However, the overall reform agenda in China, even more since the 18th Party Congress Third Plenum in 2013, is to nominally enhance markets by giving them a "decisive role" in the economy (CPCCC, 2013). There are clearly some ambiguous messages sent from the center with regards to markets—e.g., the call for a greater role for markets at the same time as expanding and consolidating leading state-owned champions, such as the merger of China's largest coal company, Shenhua, and one of the big five central generation companies, Guodian (Bloomberg, 2017)—but local governments would have less discretion to openly flaunt this directive; may score political points if they successfully incorporate a market-based solution to a problem; and, in fact, may have wider scope to intervene in the economy under the banner of markets.

In electricity, as in many other sectors, there is very little independent regulation of local government market experiments. Those agencies with relatively larger independence have little real authority over the local government departments in charge of initiating, designing and adjusting parameters of markets. The natural incentive when faced with an issue in the sector—and what I find repeated across multiple cases in this dissertation—is thus for local governments to create a structure that incorporates some market elements and that can be augmented, adjusted or cancelled if outcomes do not align with specific government objectives.

All markets—and electricity, in particular, given its central role to economy and society—have government regulation, and thus the degree of government intervention is more properly seen as a spectrum. Using the word "market" in a very general sense—buyers or sellers of electricity nominally competing with each other outside of the traditional planning process—dimensions of this spectrum include: 1) limits on who can participate, exchanging which products; 2) the size of the decision-making space of decentralized actors compared to that of government departments, grid companies, etc.; and 3) the ability to exercise out-of-market power, e.g., regulatory capture. Qualitatively, all three are substantially different in China than in developed electricity markets, such as the U.S. and EU.

A generic process for how these varied market experiments arise may be as follows: local government officials face a problem (e.g., stalling growth of energy-intensive firms) and identify a preferred / traditional fix (e.g., lower electricity tariffs). Price bands and other basic parameters deemed important to solving the problem are decided, and a market design that facilitates these is chosen (e.g., listed auctions). Ad-hoc markets that can be called on as governments track progress are advantageous. In this example, local governments also see an opportunity to strengthen their role over the local economy as benchmark electricity tariffs are outside of their traditional authority. More complicated markets (e.g., Northeast peaking market) require more levers over outcomes, because of their uncertainty and complexity, to get local government support. The main constraint on local governments is to justify these with respect to the equity principles of *sangong*, which preclude favoritism at a micro-level (e.g., preferential treatment among very similar firms), but do not prevent reallocation of benefits between industries or between different sizes or types of generating technologies.

New experiments—either new in form or to a locality—used to either get ad-hoc approvals by central agencies or else operate without central approval. This process has been standardized following the No. 9 document and supplementary documents, which specify the types of acceptable electricity markets. However, the list is broad enough to encompass virtually any type of conceivable market—including even conventional spot markets—and has few constraints on any of the above dimensions of control over market functioning. The result is the proliferation of electricity markets around the country, leading to exceedingly high "marketization rates", many with very little resemblance to traditional models or even to neighboring provinces.

Gradualism in interest reallocation

Chinese policy-making is known for its consensus-based elements among a crowded field of overlapping authorities, which is resolved through negotiation and diffuse decision-making to avoid bogging down in bureaucracy. This theory has been largely developed to describe how central and local governments interact and to explain the incremental nature of some reforms. Decentralizing authority—such as through policy experimentation—is thus a method of bypassing incrementalism and enacting ambitious pro-growth reforms. However, rather than interpret incrementalism as a consequence, case interviews indicate it as a guiding principle throughout institutional changes, such as regulators tuning the size of the Northeast peaking ancillary services market to match the previous administrative compensation.

Electricity markets in China, if created along standard models and accompanied with independent regulation, would lead to massive interest reallocations overnight. Among coal generators, a large share of capacity would become loss-making and, potentially over time, bankrupt. Other generators—which, besides natural gas, all have lower marginal costs than coal—would see increases in their share of electricity production. Consumers would see dramatic reductions in their electricity rates, hurting all electricity generators, slightly offset by expected increases in consumption. These distributional impacts would be enormous, particularly at the provincial-level, where investment, employment, and tax revenues are all integrally tied with electricity delivery. Provincial government officials would be held accountable for any disruptions in the economy.

The effect of these two interpretations may, in fact, be similar in practice: the conventional view that decisions need to be largely consensus-driven and thus do not dramatically upset any established interests, and the alternative view that certain officials have significant autonomy but choose to consider the likely responses of their constituents for fear of repercussion by the center if complaints are loud enough. In either case, it points to a deficiency in the current system of policy evaluation, where distributional concerns of minority stakeholders far outweigh efficiency concerns at a societal level. In the latter situation—substantial autonomy of decision-makers—changing and appropriately signaling different metrics for success would be sufficient to encourage more consequential reforms; whereas in the former, it would require taking away decision-making power from regulated entities and peripheral institutions, presumably much more difficult.

Electricity market experiments, originating from the provinces, thus typically satisfy a basic condition that they should not alter interest reallocations too greatly or too quickly compared to the previous administrative system. Gradually raising the shares of out-of-plan market allocations, ratcheting down the entry size thresholds, and setting price floors as well as ceilings in exchanges are all methods to ensure gradualism. The process is also self-correcting: over-zealous contracting as in the case of Gansu's coal or Yunnan's wind and solar is met with strong pushback by generators that lobby for a partial rollback.

"Benchmark" market approaches—whose value is defined relative to an administrative reference parameter—are highly desirable from a gradualist perspective. Not only do they provide a direct administrative lever over the market, they also do not supplant the primacy of existing settlement mechanisms. The market is a “bonus” on top of standard production and settlement, assuaging all parties that interest reallocations will be capped.

Long-term benefits of “poor” markets?

With reference to ideal system operation, these market experiments frequently do not reflect the “true” value of electricity—equivalently, they are not “market-conforming” as in “getting prices right” (Hsueh, 2011). If these markets are poorly reflecting supply and demand conditions for the above reasons, then it is reasonable to ask, are there long-term benefits to society of promoting “poor” markets? Interpreting “growing out of the plan” as an incomplete, multi-price, and thus “poor” market, the conventional logic goes that because market reforms are self-reinforcing, even poor markets will lead to substantial, positive long-term improvements.

It is helpful to reflect on the benefits of electricity markets: they create incentives for actors to solve system-level problems in ways that are impossible or more costly to achieve using administrative means. From a social welfare perspective, markets ideally align with the outcomes of an omniscient vertically-integrated utility. As China has already cut loose from the latter, the natural progression of enhancing social welfare is to advance toward more efficiently-run markets. Given other constraints on the system, such as environmental policy, efficient markets will also help achieve them at lowest cost, and thus possibly allow for more ambitious targets such as larger emissions reductions.

With respect to the future evolution of China’s current electricity reforms, there are two opposing views, over which there is still substantial uncertainty. On the one hand, I have argued above that electricity may be a fundamental counter-example of the standard “growing out of the plan” reform approach—that is, dual-track pricing and markets on the margin may not be a one-size-fits-all solution to implementing markets. In electricity, creating certain types of markets can decrease flexibility, leading to gaps with respect to efficient market outcomes, and causing divergences between multiple objectives of reforms—e.g., cost and renewable energy integration. Broad institutional change necessary to achieve real system-wide efficiencies with an increasingly diverse supply mix may be neglected in favor of easy reductions in prices. Addressing other objectives—

such as renewable energy integration—may lead to more administrative measures (traditional, or disguised as markets), thus eroding the benefits of the reform package. Finally, once the initial gains are had, the reform moment may be passed—as electricity reforms seem to occur on decadal cycles of action. Certain industries gain a quick RMB, but reform is stalled before broader social benefits accrue. I argue that this is what will occur business-as-usual given current reform experiences.

On the other hand, despite the flaws in current market designs, getting market actors accustomed to responding to price incentives and reducing average electricity tariffs below the above-market central benchmark offer clear benefits. Replacing price-insensitive methods of seeking production—capture, cronyism, or entitlement—with price-sensitive ones requires tracking costs and incorporating efficiency into management decisions. The results of several exchanges examined in this dissertation support the view of firms making rational decisions—as one respondent noted, examples of extreme competition and oversubscription demonstrate that there is market behavior. Further, as the share of revenues from market-determined rates increase, firms are incentivized to seek out efficiency gains through process improvements like energy efficiency upgrades. With stable market-determined shares and market value projections, firms can make investments in new facilities and products, leading to long-term improvements.

By lowering generation tariffs, they will also get closer to reflecting macro-level market conditions such as the oversupply situation across the country. The sudden revaluation when introducing efficient markets could thus be reduced as average prices are already closer to efficient rates. This could *increase* the likelihood of provinces taking on more systemic reforms based on the gradualist argument.

Ultimately, which of these two will play out depends on the relative autonomy of local governments, the stickiness of various institutions, and the entrepreneurial risk tolerance of local decision-makers. This requires further study, focused on the motivations of policy-makers in various locales with market experiments. My best guess is that once initial gains are had, there will be reduced appetite for further market-based reforms. While revaluing average tariffs creates space for entrepreneurial local governments to pursue international electricity market designs, they will have little incentive to do so. Current spot markets in planning may instead end up reflecting arbitrary settlement procedures as in the case of Yunnan's day-ahead exchange. Finally, as more administrative measures are put in place to address renewable energy integration challenges, it will be less pressing and more challenging for the center to enact nationwide policies for markets to support system flexibility.

Sustained role for administrative fiats

Electricity markets were traditionally developed first around the notion of supply elasticity: firms have multiple competing generating technologies with different supply curves, based on which they will make efficient investments. Demand is viewed as more inelastic—reflecting its high value of uninterrupted availability and logistical difficulties of providing real-time price signals to consumers. Demand should be made flexible—i.e., responsive to price signals—in order to enhance efficiency and decrease cross-subsidization, but this requires greater efforts (Hunt, 2002). This staging can be seen in the patchwork of competitive retail markets among the areas that have adopted competitive generation markets.

Supply-side elasticity in short-run energy markets translates to supply-side flexibility and improved dispatch for renewable energy. By contrast, many Chinese market experiments do not consider short-run supply-side elasticity, instead focusing on long-run average costs. One justification for this—the technical causes of wind curtailment explored throughout this dissertation—is that there is, in fact, truly no more flexibility on the supply side. The only solution to improving renewable energy outcomes, according to this view, is to increase demand, and thus generation space for new energies, by lowering prices to consumers. This appears to be the preferred approach of local governments.

This begs the first question: in contrast to most other electricity markets, is demand more price-elastic than supply in China? "Softer" budget constraints of central generators that have a social obligation to serve compared to "harder" budget constraints of local industrial firms, is a strong argument in this direction.

The second question: assuming demand is elastic, will increasing it encourage a resurgence of supply investments, thus perpetuating the overcapacity situation? Without substantial reworking of the state sector and local government incentives—difficult in the short-term—it is unlikely that short-run market signals will act as a deterrent for over-investment. Easy capital (increasingly easy with SOE consolidation), soft budget constraints, and simplistic output-based performance metrics will continue to dominate. As when permitting authority was given to the provinces in 2015, local governments wildly expanded despite mounting overcapacity. Even slight upticks in demand could be used to justify more permitting.

Under the implicit assumption of demand resurgence made by local governments, there will continue to be a strong need for aggressive supply-side restrictions alongside market expansion, at least in the near- to medium-term. There is sufficient capacity to handle significant demand increases, and potentially at very low additional social cost in terms of utilizing curtailed renewable energy. Additional conventional capacity (with higher minimum capacity factors than renewable energy) would cut into these potential gains. Some metrics to determine these supply-side restrictions include calculating the "excess capacity" at the provincial level (Yuan et al., 2016), or following an "integrated resource planning" approach to determine other least-cost ways of meeting demand (Dupuy et al., 2015).

If, on the other hand, the assumption of demand resurgence is unjustified, there will be a stronger need for dispatch fiats to support renewable energy. Contracts will increasingly constrain dispatch and, in the absence of strong short-run price incentives, will cut into the space for renewables. More administrative measures such as strengthening mandatory dispatch, "green dispatch", and minimum full purchase amounts will be necessary to prevent upticks in curtailment. These would further constrain dispatch, and likely lead to some new equilibrium involving negotiated resolutions for increasing the share of renewable energy in long-term contracts and purchasing integration space from conventional generators.

7.3.2 Challenges Facing China's Electricity Markets

Average cost energy pricing

Spot markets are at the core of ensuring an efficient and competitive market. In particular, locational marginal prices inclusive of system constraints create appropriate short-run incentives that align with efficient long-run investment. To date, where China's electricity market experiments contract in terms of energy, prices are determined via longer-term contracts with reference to benchmark tariffs. Benchmark tariffs are nominally supposed to be average costs plus allowable returns, but given the highly politicized nature of electricity pricing, they may diverge. Even as contracting removes some of the premiums awarded by central planners, the average costs in these contracts will not be equivalent to marginal costs.

There are cases where both producers and consumers can benefit from contracting electricity amounts prior to the spot market. These forward contracts can be seen as hedges of real-time prices and can reduce the ability and incentive for generators to exercise market power in the spot market. However, to efficiently price these long-term contracts, participants need to have spot prices against which forward transactions are measured.

Additionally, much of these long-term contract benefits are realized when the contracts are financial not physical—i.e., settlement-only and not inputs to dispatch. If, as in many of China's experiment, they are physical and hence constraints to dispatch, it is possible to lock-in portions of supply out-of-merit-order. This can occur even if the long-term contracts themselves were competitive, as real-time system conditions change the costs and value of marginal production at each location in the network. For example, in outputting 500 MW, a 600 MW unit may have lower marginal costs than a 1000 MW, even though the average cost differential (determined with reference to a different operational profile, i.e., full loading) goes the other way.

"Benchmark" approaches to markets

There are also examples of markets that do not even represent some form of average costs, and instead exchange "benchmark" products, whose value is determined with reference to administrative parameters. These include the Northeast peaking market, difference-based auctions of Inner Mongolia, day-ahead exchange in Yunnan, and generation rights trading. These have been desirable from the perspectives of maintaining institutional structures as they are easily tuned to government preferences and, by layering on existing institutions, do not assert broader authority.

However, the efficiency penalties of this could be significant. Muted price incentives—by restricting the size of these benchmark markets—do not fully incentivize supply-side efficiency and flexibility. Additionally, political uncertainty over setting the benchmark leads to unreliable long-term investment signals. It is possible to mimic purely average costs using benchmarks, but attempts to integrate with marginal costs are complicated such as in the peaking market.

A benchmark differs from permit allocation such as in a cap-and-trade, where initial permit allocation has no impact on overall efficiency. In a cap-and-trade market, equivalent efficiency is guaranteed by having the same carbon price, which arises regardless of the specific allocation scheme (Stavins, 2008). However, this economic conclusion does not carry over to the peaking market and other benchmark approaches. First, there is no equivalent of a fixed amount of "peaking" permits that are being allocated and traded. Firms are free to offer more or less, and the demand will depend on a lot of factors including uncertain wind availability. Second, the setting of the threshold—the "benchmark"—directly impacts the price in a way more analogous to raising or lowering the cap, which does affect price, and thus efficiency.

Dual- or multi-track pricing

Dual-track pricing—the preferred process of marketization in the cases and in other sectors—has flaws when applied to electricity, deriving from the combination of the above two. Whether explicitly benchmark or not, the dual-track prices connect the market to the administratively-determined average tariffs, ensuring that production decisions are still based not solely on economic costs. With even greater numbers of prices—as in the case of at least five different exchanges in Yunnan—the effectiveness of any given price signal is diminished.

Many electricity markets have multiple products, such as ancillary services, capacity payments, and specialized products like ramping services, all of which suffer from this same basic issue. The analytical basis for most rests on correcting deficiencies in the spot market. They will never be as efficient as an unrestricted energy market, though in these international systems, the primacy of the spot market is never in question.

Targeted market interventions in lieu of system-level changes

As markets are designed, launched, and tinkered with to achieve ever narrowing objectives (e.g., from lowering industrial tariffs to adjusting hourly minimum outputs of coal plants), the connection to efficient system-level outcomes becomes more tenuous. The Northeast peaking market is effective at increasing wind utilization because it is geared to precisely address the least flexible hours and units. However, it is also restricted in the available ways to enhance flexibility, thereby increasing costs. This is a more general problem of the market reform agenda that encourages piece-meal solutions to problems as they arise.

One might contend that each additional mechanism increases efficiency in some part of the system, and therefore, is a step along the gradualist path to long-term benefits—akin to "growing out of the plan". However, a number of factors work against such an outcome. First, each additional mechanism must be carefully designed in relation to all previous layers. There may be unintended consequences of this complexity resulting from poor decisions or strategic behavior. Each additional layer is also one more potential sticky institution when deeper reforms are considered.

Second, narrower interventions tend to encourage more similar responses. Coal plants reducing their minimum output during nighttime are essentially the only profitable response to the peaking market. However, integrating renewable energy efficiently will require a diversity of approaches and heterogeneous firm strategies, such as some units investing in quicker startups and others providing better ramping and reserves.

Third, the pilot-by-pilot approach also does not create a strong incentive for plants to position to be the best for a future system. The pilots may address the challenge at the moment, but in five or ten years time, conditions may change. Perhaps there are investment decisions in the interim that would allow for better operation under those future conditions, but the incentives to make those investments would only occur after the political and bureaucratic response to create new pilots for the changed system.

Rather than a piece-meal approach, a different approach might be to start conceptually with the full package of market reforms and take out or modify the particularly difficult elements, calculating efficiency losses along the way. Some may be too difficult to change immediately (e.g., province-centric dispatch), but adjustments with respect to the ideal as opposed to old benchmarks are more likely to achieve a second best outcome. There will also be a clearer trajectory to ratcheting up reforms later.

Transmission pricing

The particular revenue structure of the grid—based on energy-based "postage stamp" fees for each border crossing—combined with the non-independence of the three basic grid functions—network ownership, operation, and markets—is a pervasive conflict of interest that can affect every aspect of reform. Well-functioning wholesale electricity markets require non-discriminatory system operation free of considerations beyond efficiency and grid reliability. In China's case, system operators have financial interests in certain transactions, which can result in discriminatory dispatch (e.g., dispatching such that more expensive lines are utilized). There are clear indications that this influences large long-distance transmission investment and operation, and due to the opacity of system operation to outside regulators there can be many more subtle ways to do this at smaller scales.

Theoretically, the current integration of the three grid functions could be maintained if the revenue incentive structure were modified along the lines of a regulated cost-of-service approach and transmission planning were closely regulated. However, it is difficult to imagine an independent regulator in China appropriately auditing grid company costs, overseeing all manner of dispatch decisions, and assessing the justification of proposed transmission investments. Furthermore, even in countries with strong independent regulators, these three functions are typically separated—either isolating markets from ownership and operation, or isolating ownership from operation and markets.

Balkanized system operation

All the cases demonstrate strong roles for the provincial government and provincial grid subsidiary in determining system operation. There are few examples of provinces giving up autonomy over their systems to enhance regional coordination, the kind of which led to the earliest markets in the U.S., and which is even more critical for successful integration of variable renewable energy. The basic delineation of authorities that creates a strongly decentralized system—while encouraging experimental reforms, as discussed in Section 7.2.3—is a persistent barrier to effective reforms.

Some of the benefits of enhanced coordination could occur within a single grid region: for example, relaxing strict transmission flow requirements, and sharing resources and reserves. There are also ample opportunities to utilize connections between windy northern regions, with large amounts of spare coal capacity to provide balancing. Looking to the future, to get a substantially low-carbon grid, even greater coordination will likely be required. Hydropower, for the most part located in the center and south, is a natural, flexible option to manage variability of wind and solar in the north. Current system operations preclude managing any variability on timeframes shorter than seasonal.

7.3.3 Policy Recommendations for China's Electricity Markets

Considering the above barriers to reforming China's electricity sector institutions, I put forward several recommendations that appropriately balance feasibility and impact. This is not intended to reproduce other analyses based on direct comparisons with international best practice (e.g., Pollitt et al., 2017), and I am not downplaying the importance of any elements of the standard prescription that do not appear here (e.g., a well-functioning spot market). Rather, drawing on the assessments in Tables 6.1 and 6.2, I emphasize changes that could be made with reasonable effectiveness in time periods relevant for current policy discussions (~5 years). Most of these simultaneously provide building blocks for more significant reforms later on, and future work could provide a more dynamic view of how certain institutional changes may be reinforcing. The first three—transition costs, renewable energy quotas, and settlement and dispatch—apply to all ongoing market experiments. The fourth—regional market pilots—recommends expanding the scope of current efforts. The fifth and sixth—inter-provincial deviations and monthly roll-over—are recommendations for improving the current hybrid system of the plan and physical contracts, though should be phased out as more effective markets develop. Finally, the seventh—reserve accounting and sharing—can be implemented alongside a range of energy markets, and initially could be mandatory, compensated at administrative pricing, or the result of competitive bidding.

Recommendation #1: Create consistent policy on "transition costs"

The production quota is a classic example of ambiguous property rights which can be subject to provincial government predation. Under the regulatory bargain of most plants—built prior to significant marketization—the quota, combined with the benchmark tariff, was seen as an implicit guarantee of sufficient revenues once given permit approval. As a result, in most electricity market experiments currently, there is substantial ambiguity as to the relationship of market to plan. This affects market strategy, prices, and general willingness to participate in reforms. In contrast to the virtuous cycle of firms lobbying for more reforms and stronger institutions by "growing out of the plan", the transition is widely opposed by generation firms, who do not capture much of the efficiency benefits.

Transition costs are a problem common to many restructuring situations. A typical situation is a plant that was built under cost-of-service and that is no longer competitive at wholesale market rates. In this case, the regulator could approve a subsidy to compensate for that difference and socialize it to all customers. The overriding logic—which could be equally applied in China by decision-makers who are impartial with respect to individual market transactions—is that markets will place first priority on system-wide efficiency. Distributional issues can be dealt with secondarily, for example using extra surplus from the gains of the market.

In China, there is precedence for converting quotas into more formal property rights, such as generation rights, that plants could enjoy for some period (e.g., around 3 years in the small plant retirement program). However, current reforms are remarkably silent on how to accommodate the reallocation of benefits under new market regimes. This is, admittedly, an atypical issue under the traditional gradualist approach of "growing out of the plan", where the pace of reforms limits reallocation, and thus does not require large-scale "transition mechanisms".

A reasonable solution to the current situation of the overcapacity of many new plants is to calculate the impact of various market measures on individual participants. A fraction of losses resulting from changing the regulatory bargain could be socialized and returned to plants, while maintaining incentives to participate in markets to the extent possible. Together with this policy should be an explicit lack of protection for new plants, who should not enjoy the regulatory bargain of a guaranteed quota.

Recommendation #2: Specify unambiguous renewable energy quotas

In the renewable energy exchange cases, a similar situation to the ambiguous quota rights arises. Some provinces may set a plan total, which is a guaranteed full-purchase amount above which is all exchange; others may notify parties informally of their expectation; or some may simply assign the small amount of generation left-over after exchanges to be the plan. As long as renewable energy is forced to participate in long-term exchanges, this ambiguity needs to be resolved.

I will note that the FIT plus mandatory dispatch were a regulatory bargain, in an even more explicit way than coal quotas: requiring that all energy up until endangering grid security would be taken on and compensated at the specified price. Intra-provincial renewable energy exchanges are fundamentally abrogating this agreement because they result in lower prices without altering the underlying grid security constraints. Ideally, these would be forbidden, or the central government should conduct a robust process of recalculating appropriate tariffs based on reasonable cost recovery for existing plants. Inter-provincial renewable energy exchanges are more nebulous, since mandatory dispatch does not necessarily extend to renewables in another province. Some guidance on this could be provided in an updated mandatory dispatch regulation.

The full-purchase safeguards announced by NEA in 2016 were an attempt to address this ambiguity, but the levels were so unrealistically high that the measure was largely ignored by provinces. NEA and the NDRC could revisit this with more reasonable levels, perhaps tuned to assessments of cost recovery, and create clear enforcement guidelines. Crucially, the safeguards are for "full-purchase", meaning that it provides a floor for compensation at FIT levels, and should give plants recourse if they are not given that amount.

The proposed mandatory renewable energy certificate (REC) programs must also be carefully designed to eliminate this ambiguity. If the program is to be applied to all new projects as discussed (Ng, 2017), then this effectively changes the quota determination to aggregate province-wide or country-wide totals. Prospective wind developers should thus respond to market supply and demand in making investment decisions. One important distinction is that while renewable purchase obligations are frequently met with multi-year contracts elsewhere, China's markets largely end at the year. This would represent a substantially less stable cash flow than the current subsidy arrangement. Care must also be taken if combining this trading with other market mechanisms targeted at existing projects such as the excess wind exchanges.

Recommendation #3: Clarify connection between exchange settlement and dispatch

Once generation property rights are clarified, there needs to be unambiguous guidelines connecting the settlement and dispatch procedures. If purely financial, then settlement is conducted ex-post after dispatch is completed. This is where the system needs to go in the future, together with clear merit order dispatch priorities. Note that the primary incentive in other markets to engage in long-term financial contracts is risk hedging. In China, for generators, it is either implicitly mandated or else not truly financial because it alters dispatch ex-ante. Consumers engage in markets to avoid high default tariffs, not to reduce risk.

Though not preferred for multiple reasons outlined throughout this dissertation, if contracts are nevertheless physical, then the procedure through which this is converted to a dispatch schedule should be precisely specified as well. If there are specified days and minimum outputs, then this can provide better tools for plants to assess their marginal costs, improving convergence of long-term prices. Additionally, once specified, this creates the space for adjustments—and possible exchanges —intra-monthly, which could improve commitment scheduling. The mandatory REC market, if applied to all new projects, would not be expected to alter dispatch for these, but how the grid company will make dispatch or curtailment decisions between different-priced projects under the legacy system and newer REC arrangements will be important to clarify.

The benefits of clear connections can be seen in Yunnan, where the various exchanges combine to produce an expected market behavior in the day-ahead market. While the DA market does not generate useful scarcity pricing, it does demonstrate that Chinese generators can respond to clear market incentives with rational bidding.

Recommendation #4: Prioritize regional market pilots

Without strong central government guidance and involvement, current reforms are in danger of devolving into numerous systems at the provincial level, designed to address and satisfy local constituencies, and with tenuous linkages to experiments elsewhere. Only regional experiments—with a larger volume than the Northeast peaking market, and with a more conventional energy product—can demonstrate to decision-makers the benefits of more closely integrating provincial grids, and potentially harmonize some of the competing systems. The closest to this currently are the long-term auctions in parts of North Grid—Beijing, Tianjin, and Northern Hebei (Wang, 2016). Central government interests are closely tied with Beijing, indicating the likelihood that a strong central government role was necessary to make this regional market happen.

Recognizing distributional impacts of markets is important, which should be weighed by decision-makers against the efficiency and environmental impacts when designing markets. Compensation, where appropriate, for losses due to trade impacts could be part of the package. It is possible that a large portion of this could be accommodated even within province through appropriate reapportionment of consumer surplus (increasing) and producer surplus (decreasing) under larger markets.

Recommendation #5: Widen allowable inter-provincial trade deviations

While work on the regional integrated market pilot commences, other efforts can be made in the near-term to improve flexibility of inter-provincial transmission. Currently, transmission profiles are pre-scheduled based on the result of longer-term inter-jurisdictional negotiation. Most of the gains of more flexible transmission come from increasing the allowable range to just $\pm 20-30\%$, assuming that there is no hard constraint on total exchanged amounts (Section 5.5.5). The province's interests are ensured by maintaining autonomy of the dispatch center, creating further coordination challenges. However, as with generation rights, if the transmission totals are converted to something formal, they could be adjusted and compensated for in Pareto-improving ways.

For example, the natural method is for all the parties to negotiate a financial contract specifying the total amounts expected to be exchanged over a period (e.g., month). This contract further includes a price for net deviations settled ex-post. Each grid company can maintain a targeted over-generation / under-generation schedule, but can also communicate with regional and neighboring grids about transmission bands on a daily and hourly basis. If a province stands to gain for generating beyond the scheduled flow (as determined by the purchase price and deviation payment), then it communicates this to the respective grids. If other provinces see benefit in under-generating, then transmission flows are adjusted. The transmission flow scheduling system could be integrated with existing dispatch software and cleared at multiple time-intervals—e.g., day-ahead and hourly.

This setup is still not the efficient outcome—which could only occur with completely centralized dispatch—but it does provide a working near-term solution. It also creates a system for more flexibly reallocating transmission capacity, which will be necessary for regional markets.

Recommendation #6: Extend monthly "roll-over" to physical contracts

Dispatch centers have relatively more flexibility in meeting the quota than they do market contracts. The primary difference is in how unmet totals are "rolled-over" to subsequent months. Contracts, mostly deemed physical, are must-meet and create hard constraints on dispatch and scheduling. Quotas have a slight tolerance threshold, such that portions could be met in subsequent months. This provides increased flexibility to dispatch, and the physical contract situation is a major barrier to increasing market share as well as a large potential barrier for increased renewable energy integration.

Exchanges could maintain monthly settlement, but allow for roll-over of contracts in the same way as the quota, and both tolerance thresholds could be increased. An extension of this would be, at the end of the year, rather than making contracts and quotas must-meet, allow for compensation of the difference in generation that equates opportunity costs of the generators (subject to minimum availability requirements). This would require more intrusive regulation to audit opportunity costs, without which there may be some perverse over-contracting incentives.

Recommendation #7: Reserve accounting and sharing

Reserve requirements and levels are under-discussed and under-audited. I have shown in this dissertation how restricting reserves to within provincial borders has a deleterious impact on renewables. It is also possible to more easily remedy without large distributional trade impacts. As intermittent renewables increase beyond small penetration levels, and in order to rein in the inefficiencies of overcapacity and over-commitments, systems will need to adopt more transparent reserve calculation and reserve availability methods. The last public nationwide analysis appears to be by the former regulator in 2012, which at the same time revealed a number of red flags about substantial excesses of reserves.

By requiring all grid companies to publish both the requirements as well as the total availability, central agencies can more closely monitor the efficiency of dispatch and scheduling. The calculations of availability would also provide greater clarity to grids on the flexibility of various units, helping to prioritize and possibly compensate flexibility. The communication and control infrastructure to allow wind power to provide down reserves should also be explored, as this can increase the available integration space.

The above system is a necessary precursor to region-wide reserve sharing, whose benefits can be captured even without large changes to pre-scheduled transmission flows. Regional reserve sharing works by first identifying which provinces or smaller areas have excess or low-cost reserves, and adjusting the minimum requirements in neighboring areas, which in turn can lead to additional space for renewable energy. As more data are collected, the collective reserve requirements could be lowered to account for anti-correlations of supply / demand across provinces through a joint reliability analysis. This further reduces the cost of carrying reserves and the impacts on renewable energy integration.

7.3.4 China's Climate Change and Environmental Policy Agenda

This dissertation examines the complex nature of electricity market creation through a lens of efficiency as well as renewable energy integration outcomes. Increasing renewable energy is an important policy goal to address climate change and local environmental pollution, given the dominance of pollution from the electricity sector. Addressing these externalities is a stated goal of electricity market reforms, and is the subject of a suite of additional policies that interact with the electricity sector.

Renewable energy considerations in electricity market design, implementation and oversight

In traditional market designs—namely, those operating on bid-based locational marginal pricing —efficiency and renewable integration are, in most cases, closely aligned. Renewable energy is dispatched ahead of most of conventional units because of its lower marginal cost, even before pricing externalities through carbon taxes or trading. When facing grid security constraints or in rare cases of negative prices when it is costly to further ramp down conventional units, there may be economically efficient curtailment. This dissertation has shown that there can be large gaps between this efficient level of curtailment and current practice in China's grids.

While enhancing renewable energy utilization is a stated goal of market reforms, many of the most common market experiments do little to help renewable energy and may even harm its prospects by over-constraining dispatch with physical contracts. As China works toward improving its market design—with the eventual goal of achieving alignment of efficiency and renewable energy integration—the effect of various experiments on renewables is an important consideration. Relatively simple models and grid operator intuition can reveal deficiencies in pilots. If trading off between quick routes to lower the cost of supply and more complex pathways that also enhance flexibility, then these should be made explicit through, e.g., central government requirements for feasibility and impact assessments. These assessments should encompass market design, conditions for launching, and institute frequent oversight opportunities to monitor local government and grid company implementation.

Renewable energy planning

Future development of renewable energy will be mostly based on tariffs (benchmark FITs as well as exchange prices), administrative restrictions on siting, and transmission infrastructure. This dissertation has highlighted numerous issues with the evolving plan/market hybrid tariff scheme, which should be addressed through clear specification of full-purchase quotas, possible adjustment of FITs to reflect costs and integration potential, and careful oversight of dispatch and scheduling.

Parallel to the differential deployment incentives, the central government has also instituted restrictions (in some cases, moratoria) on new builds based on curtailment rates. These are important in the near-term before curtailment creates strong enough price incentives to deter development—there is evidence that wind development companies are considering these issues much more carefully than just a few years ago. Green-lighting projects in the relatively-untapped central, southern and eastern regions also can lead to more efficient deployment, balancing variability, and tapping into a larger set of conventional units in scheduling flexibly around renewable energy availability.

Transmission infrastructure will continue to be critical to meet long-term goals, though there are clear areas for improvement in the planning process: planning should not be pegged to a certain utilization rate, it should be coordinated with proposed or projected renewable energy development, and compensation should follow a typical regulated model like cost-of-service. Under the current scheme, there is an incentive to both build more lines and to force higher utilization of those lines, which could be accomplished through discriminatory dispatch but also through coordinated expansion of unneeded conventional resources. All proposed lines should undergo a cost-benefit analysis (inclusive of reliability benefits) that evaluates system-wide impacts, and if approved and built, cost recovery should be guaranteed so as to avoid improperly influencing dispatch.

Cap-and-trade pilots

China's carbon cap-and-trade pilots are more examples of how benchmark approaches are adopted and become feasible but inefficient ways of introducing some form of markets into a sector involving rigid government planning. China has piloted seven provincial cap-and-trade schemes since 2014 in preparation for launching a nation-wide system. The pilots have each generated their own rules on covered sectors, emissions allowances, and market functioning, in a diversity reminiscent of provincial electricity market experiments.

A typical cap-and-trade market sets a total cap on emissions across a sector, an economy, or a region, and any emitting firm must acquire and "retire" a same number of permits equal to its emissions. This scheme is supported by firms getting a certain amount of allowances (either freely given away by the market regulator or auctioned, or some combination), and then trading with other firms as needed to meet their caps. The carbon price is thus the marginal cost of an allowance on the market, and raises the price of carbon-emitting activities and all activities that rely indirectly on carbon carbon emissions. The setup ensures the economically most efficient way of reducing carbon emissions while allowing governments to set arbitrary rules regarding the initial allocation (Stavins, 2008). Furthermore, because permits are typically required by the entity producing emissions (i.e., the generator), consumers of electricity have no direct obligation. Nevertheless, "pass-through" of the costs can be facilitated through markets by an increase in the price according to the marginal generator's carbon price, or through tariff rate regulation for vertically-integrated or traditionally regulated utilities.

Due to the various electricity dispatch procedures in China, this market would not effectively incentivize generators to either reduce emissions intensity or reduce production in favor of a more efficient generator. In the regime of fixed prices, other methods such as benchmarking and historical intensity are some of the ways to facilitate the allocation process (Pang and Duan, 2016). Additionally, due to the fixed electricity tariffs, consumers would not see any "pass-through" and thus have no incentive to reduce consumption. In some international examples, "indirect" emissions allowances are considered, which typically fix the carbon intensity of electricity (i.e., carbon emissions per unit of electricity) and then require consumers to purchase permits equal to their indirect emissions (Teng et al., 2017). China, in fact, uses both approaches in its cap-and-trade pilots, effectively counting electricity sector emissions twice (Munnings et al., 2016). China is thus trading carbon without an explicit cap. This "rate-based" approach has strengths in terms of political feasibility (particularly under uncertain economic growth prospects) but does not provide consistent economy-wide emissions reduction price signals and is thus less efficient than a "mass-based" system with a cap (Goulder and Morgenstern, 2018).

These pilots—and the eventual national system—will create incentives for reducing carbon through an implied carbon price, but the outcome—in the electricity sector, and hence across the market—will fall short of a true cap-and-trade in finding least-cost emissions reductions options. It is difficult to imagine an efficient method of integrating the indirect cost pass-through work-arounds within a single price carbon market. Cap-and-trade may be an important long-term tool for carbon mitigation in China, but its effectiveness will be largely contingent on effective electricity sector reforms.

Air pollution control policies

Mitigating air pollution in major cities is another major central government priority that is strongly connected to the electricity sector. Air pollution action plans have instituted a range of additional administrative restrictions on the sector, such as coal consumption caps, forced retirements, and coal mine-mouth plant developments at a distance from urban areas. Price incentives from improved power markets can interact with these policies in a variety of ways.

First, efficient power sector pricing will reduce total coal use through switching to more efficient generators and priority dispatch for renewable energy, which is beneficial for reducing air pollution. These efforts need to be coupled with stringent enforcement of environmental control equipment standards, which add costs and without intervention would put cleaner plants at a disadvantage. Natural gas is a more expensive but cleaner option within cities, which is already encouraged in places through measures such as subsidies and forced coal retirements. These could be continued, but carefully analyzed for their impacts on power prices.

Second, generation sources may be geographically distant from consumption, which can displace emissions to areas that are not responsible for them and create large regional inequities. Ideally, costs of the pollution would be internalized into the market. Internalization would create an incentive to more efficiently dispatch conventional and renewable energy generators across long-distance lines, which could increase renewable energy utilization in exporting regions and thereby decrease the need for coal export bases. In their absence, the current approach is likely to continue: central government permitting large power bases in western areas away from rich eastern demand centers and transmission lines to connect them. Some government officials have coined the term and used the greater "environmental capacity" (*huanjing rongliang* | 环境容量) of the west as justification for these coal expansion policies. Given the populations in these areas are poorer and often from minority groups, the environmental justice questions are profound.

Third, more frequent dispatch, scheduling, and electricity price calculations could help improve the response of the system to formation of particulate matter, the worst component of China's urban air pollution. Air pollution episodes can have a rapid onset, helped by numerous primary and secondary formation mechanisms, of which coal power plant emissions are an important precursor. Current methods to limit episodes are relatively crude—shutting down factories and plants locally to ensure a window of "blue sky" in high-profile areas. With better modeling of air pollution formation, this type of response could be evaluated everyday and nationwide: for example, identifying when the response of particulate matter formation to coal plant emissions is highest and reduce output through either a strong short-term price penalty or mandatory rescheduling.

Appendix A

Clustered Unit Commitment Model

Nomenclature

Sets:

$k \in G$: clustered generator types

$t \in T$: time periods

$p \in P$: provincial nodes

$G_p \subset G$: generators in province p

$G_{p,k} \subset G_p$: generators of cluster type k in province p

$G_{wind} \subset G$: wind generators

$G_{hydro} \subset G$: hydro generators

$G_{res} \subset G$: generators providing reserves

$G_{thermal} \subset G$: thermal generators

$G_{CHP} \subset G_{thermal}$: combined heat and power generators

$G_{quota} \subset G_{thermal}$: thermal generators with quotas

Decision Variables:

$\boldsymbol{y}_{p,k,t} \geq 0$: production of cluster k in p at time t

$\boldsymbol{w}_{p,k,t}$: auxiliary ramping variable, cluster k in p at time t

$(\boldsymbol{u}_{p,k,t},\, \boldsymbol{v}^{up}_{p,k,t},\, \boldsymbol{v}^{dn}_{p,k,t}) \in (\mathbb{Z}_{\geq 0})^3$: commitment variables in clustered formulation

$\boldsymbol{r}_{p,k,t},\, \boldsymbol{s}_{p,k,t} \geq 0$: up and down reserve capabilities in clustered formulation

$\boldsymbol{f}_{p,p',t}$: flow from p to p' at time t

$\boldsymbol{f}^{+}_{p,p',t}$, $\boldsymbol{f}^{-}_{p,p',t}$: positive and negative components of $\boldsymbol{f}_{p,p',t}$

$\boldsymbol{l}_{p,p',t}$: transmission losses due to flow $\boldsymbol{f}_{p,p',t}$

$\boldsymbol{j}_{p,p',t,s}$: sth piece-wise segment of the flow $\boldsymbol{f}_{p,p',t}$

$\boldsymbol{h}_{p,k,t}$: hydro reservoir level of hydro generator cluster k in p, in units of generation

$\boldsymbol{og}_{p,t}$: over-generation in p at time t

Parameters:

$d_{p,t}$: demand at p at time t

p_k^{var}: variable cost of generator type k

p_k^{su}: startup cost of generator type k

$\underline{P}_k$, $\overline{P}_k$: minimum and maximum outputs of generator k

$\overline{F}_{p,p'}$: transmission flow limit from p to p'

$\mu_{p,p'}$: quadratic resistive loss coefficient of path p to p'

$W_{p,k,t}$: available wind power of generator type k in province p at time t

RD_k, RU_k: down and up ramp rate limits of generator type k

MD_k, MU_k: minimum down and up times of generator type k

$\underline{RES}_t$, $\overline{RES}_t$: down and up regional reserve requirements at time t

$\underline{RES}_{p,t}$, $\overline{RES}_{p,t}$: down and up provincial reserve requirements in p at time t

$H_{p,k}$: mean hydro inflow of cluster k in p over a timestep

$HL_{p,k,t}$, $t = \{1, |T|\}$: initial and final levels of hydropower cluster k in p

$Q_{p,k}$: minimum generation quota at p for generator cluster k

$\overline{FA}_{p,p'}$: mean historical power transfer from p to p'

$\overline{NF}^{*}_{p,t}$: center of transmission band (over-generation) in p at time t

β: tolerance parameter of transmission band, 0.1 by default

Model

$$\min \qquad \textstyle\sum_{p\in P}\sum_{k\in K}\sum_{t\in T}\left(p_k^{su}\boldsymbol{v}^{up}_{p,k,t} + p_k^{var}\boldsymbol{y}_{p,k,t}\right) + \sum_{p\in P,\, t\in T} p_{NSE}\boldsymbol{NSE_{p,t}} \tag{A.1}$$

$$s.t.$$

$$\tag{A.2}$$

Supply/Demand Balance

$$\sum_{k \in K} \boldsymbol{y}_{p,k,t} - \sum_{p' \neq p} \left[\boldsymbol{f}_{p,p',t} + \boldsymbol{l}_{p,p',t}/2 \right] = d_{p,t} + \boldsymbol{NSE_{p,t}} \ , \ \forall p \in P \tag{A.3}$$

$$\boldsymbol{f}_{p,p',t} = -\boldsymbol{f}_{p',p,t} \tag{A.4}$$

$$\boldsymbol{f}_{p,p',t} = \boldsymbol{f}^{+}_{p,p',t} - \boldsymbol{f}^{-}_{p,p',t} \tag{A.5}$$

$$\sum_{s} \boldsymbol{j}_{p,p',t,s} = \boldsymbol{f}^{+}_{p,p',t} + \boldsymbol{f}^{-}_{p,p',t} \tag{A.6}$$

$$\forall t \in T, \ p, p' \in P \tag{A.7}$$

Transmission Losses

$$\boldsymbol{f}_{p,p',t} + \boldsymbol{l}_{p,p',t}/2 \leq \overline{F}_{p,p'} \tag{A.8}$$

$$\boldsymbol{l}_{p,p',t} = \mu_{p,p'} \sum_{s} \alpha_{p,p',s} \boldsymbol{j}_{p,p',t,s} \tag{A.9}$$

$$\alpha_{p,p',s} = (2s-1)\, \Delta f_{p,p'} \ , \tag{A.10}$$

$$\forall s = 1..S$$

$$\Delta f_{p,p'} = \overline{F}_{p,p'}/S \tag{A.11}$$

$$\boldsymbol{l}_{p,p',t}, \boldsymbol{f}^{+}_{p,p',t}, \boldsymbol{f}^{-}_{p,p',t}, \boldsymbol{j}_{p,p',t,s} \geq 0 \tag{A.12}$$

$$\forall t \in T, \ p, p' \in P$$

$$\tag{A.13}$$

Minimum/Maximum Outputs

$$\underline{P}_k \boldsymbol{u}_{p,k,t} \leq \boldsymbol{y}_{p,k,t} \leq \overline{P}_k \boldsymbol{u}_{p,k,t} \ , \ \forall p \in P, k \in G_{thermal} \tag{A.14}$$

$$0 \leq \boldsymbol{y}_{p,k,t} \leq W_{p,k,t} \ , \ \forall p \in P, k \in G_{wind} \tag{A.15}$$

$$\tag{A.16}$$

Ramp Limits

$$\boldsymbol{w}_{p,k,t} = \boldsymbol{y}_{p,k,t} - \underline{P}_k \boldsymbol{u}_{p,k,t} \tag{A.17}$$

$$\boldsymbol{w}_{p,k,t} - \boldsymbol{w}_{p,k,t-1} \leq \boldsymbol{u}_{p,k,t} RU_k \tag{A.18}$$

$$\boldsymbol{w}_{p,k,t-1} - \boldsymbol{w}_{p,k,t} \leq \boldsymbol{u}_{p,k,t} RD_k \tag{A.19}$$

$$\forall p \in P, k \in K, t \in T$$

(A.20)

Minimum Up/Down Times

$$\boldsymbol{u}_{p,k,t} \leq |G_{p,k}| \tag{A.21}$$

$$\boldsymbol{u}_{p,k,t} \geq \sum_{t'=t-MU_k}^{t} \boldsymbol{v}^{up}_{p,k,t'} \tag{A.22}$$

$$|G_{p,k}| - \boldsymbol{u}_{p,k,t} \geq \sum_{t'=t-MD_k}^{t} \boldsymbol{v}^{dn}_{p,k,t'} \tag{A.23}$$

$$\boldsymbol{u}_{p,k,t} - \boldsymbol{u}_{p,k,t-1} = \boldsymbol{v}^{up}_{p,k,t} - \boldsymbol{v}^{dn}_{p,k,t} \tag{A.24}$$

$$\forall p \in P, k \in K, t \in T$$

(A.25)

District Heating Requirements

$$\underline{P}_k \leq \boldsymbol{y}_{p,k,t} \leq \overline{P}_k \ , \ \forall p \in P, k \in G_{CHP} \tag{A.26}$$

(A.27)

Hydropower Storage

$$
\begin{aligned}
\boldsymbol{h}_{p,k,t} - \boldsymbol{h}_{p,k,t-1} &= H_{p,k} - \boldsymbol{y}_{p,k,t} && \text{(A.28)} \\
\boldsymbol{h}_{p,k,t} &= HL_{p,k,t}\ ,\ t \in \{1, |T|\} && \text{(A.29)} \\
\boldsymbol{h}_{p,k,t} &\geq 0 && \text{(A.30)} \\
& \forall p \in P, k \in G_{hydro}, t \in T
\end{aligned}
$$

Hydro Form # 1: $$\underline{HL}_k \leq \boldsymbol{h}_{k,t} \leq \overline{HL}_k,\ \forall k \in G_{hydro}, t \in T \quad \text{(A.31)}$$

Hydro Form # 2: $$0 < \underline{P}_k \leq \boldsymbol{y}_{k,t} \leq \overline{P}_k < C_k,\ \forall k \in G_{hydro} \quad \text{(A.32)}$$

(A.33)

Reserve Requirements

$$\boldsymbol{r}_{p,k,t} \leq \boldsymbol{u}_{p,k,t}\overline{P}_k - \boldsymbol{y}_{p,k,t} \quad (A.34)$$

$$\boldsymbol{s}_{p,k,t} \leq \boldsymbol{y}_{p,k,t} - \boldsymbol{u}_{p,k,t}\underline{P}_k \quad (A.35)$$

$$\boldsymbol{r}_{p,k,t} \leq \boldsymbol{u}_{p,k,t}RU_k \quad (A.36)$$

$$\boldsymbol{s}_{p,k,t} \leq \boldsymbol{u}_{p,k,t}RD_k \quad (A.37)$$

$$\forall p \in P, k \in G_{res}, t \in T$$

$$\boldsymbol{r}_{k,t} \leq 0.3H_k \quad (A.38)$$

$$\boldsymbol{s}_{k,t} \leq 0.3H_k \quad (A.39)$$

$$\forall k \in G_{hydro}, t \in T$$

$$\sum_{k \in G_{res}} \boldsymbol{r}_{p,k,t} \geq \overline{RES}_{p,t} \quad (A.40)$$

$$\sum_{k \in G_{res}} \boldsymbol{s}_{p,k,t} \geq \underline{RES}_{p,t} \quad (A.41)$$

$$\forall t \in T, p \in P$$

$$\overline{RES}_p = 3\% \cdot MaxLoad_p + 4\% \cdot WindCap_p \quad (A.42)$$

$$+LargestUnit_p$$

$$\underline{RES}_p = 3\% \cdot MaxLoad_p + 4\% \cdot WindCap_p \quad (A.43)$$

$$\forall p \in P$$

$$(A.44)$$

Minimum Generation Quotas

$$\sum_{t \in T} \boldsymbol{y}_{p,k,t} \geq Q_{p,k} \cdot |T| \cdot |G_{p,k}| \cdot \overline{P}_g, \ \forall p \in P, k \in G_{quota} \quad (A.45)$$

Transmission Bands

$$\boldsymbol{og}_{p,t} = \sum_{g \in G_p} \boldsymbol{y}_{g,t} - d_{p,t} + \boldsymbol{NSE_{p,t}},\ \forall p, t \tag{A.46}$$

$$(1-\beta)\overline{NF}^*_{p,t} \leq \boldsymbol{og}_{p,t} \leq (1+\beta)\overline{NF}^*_{p,t},\ \forall p, t\ s.t.\ \overline{NF}^*_{p,t} \geq 0 \tag{A.47}$$

$$(1+\beta)\overline{NF}^*_{p,t} \leq \boldsymbol{og}_{p,t} \leq (1-\beta)\overline{NF}^*_{p,t},\ \forall p, t\ s.t.\ \overline{NF}^*_{p,t} < 0 \tag{A.48}$$

$$\overline{NF}^*_{p,t} = \sum_{p'} \overline{FA}_{p,p'} \frac{d_{p',t}}{\bar{d}_{p'}} - \sum_{p'} \overline{FA}_{p',p} \frac{d_{p,t}}{\bar{d}_p},\ \forall p, t \tag{A.49}$$

Table A.1: Generator parameters for aggregated types

	$\underline{P}_g$ (%)	RD_g, RU_g (% / h)	MU_g, MD_g h	p_g^{var} Yuan/MWh	p_g^{su} Yuan/MW
coal25	54	15	3	350	600
coal50	54	15	3	308	600
coal135	54	15	6	287	600
coal200	54	15	6	263	600
coal350	54	15	12	238	600
coal600	54	15	12	209	600
cogen25	72	15	3	350	600
cogen50	74	15	3	308	600
cogen135	74	15	6	287	600
cogen200	70	15	6	263	600
cogen350	66	15	12	238	600
cogen600	60	15	12	209	600

Appendix B

Interview Protocols and Reflections

B.1 Structuring the Interview

Interviews lasting from 1-2 hours were conducted in Chinese[1] in a semi-structured manner, sometimes referred to as "responsive interviews", with question guides tailored to the respondent's position, ensuring sufficient time to explore topics not previously identified or emphasized (Rubin and Rubin, 2005). Locations were in offices or public spaces such as cafes. While some interviews were conducted together with other researchers, I did not collect or use any data from interviews conducted in my absence, for example, following a structured interview guide. Most interviews were not audio recorded by the request of the respondent and later by intention to encourage more open conversation. In earlier explorations of a topic, I typically began with a description of my research topic communicating a desire to understand overall aspects of electricity systems operations or markets, which could take 15 minutes or longer. In later interviews, as I achieved saturation on a given topic, I would attempt to establish my understanding of the topic early in the interview in order to move beyond the big picture to more nuanced questions.

I planned out and grouped the flow of questions into roughly three main topics per interview (see Table B.1). These were elaborations on three larger study questions that I shared with respondents

[1] A handful were conducted in English, when the respondents preferred. While not a native speaker, I began formally studying Mandarin Chinese 7 years prior to the beginning of this research, including 14 months of intensive language training and immersion in-country. For interviews when native speaking researchers were also present, we ensured that sufficient time following the interview was allotted to go over our shared notes. During this review, both myself and native speakers would agree on most main answers while finding some additional aspects that the other had missed. Through this, I became confident that my language abilities were sufficient to capture and understand much of the important elements and nuance of the respondents' answers.

in advance. In addition, I prepared checklists of various process aspects of markets or operations that I noted in the margins or on small sheets of paper in advance. As precise dispatch procedures and their level of routinization were the focus of all cases, I developed a detailed checklist of questions for this (see Table B.2).

In general, I began with easier and more descriptive topics, building up to more difficult or sensitive topics, aiming to only ask a handful of very challenging questions. I elicited information using a variety of techniques, including probing though verbal and non-verbal cues (Bernard, 2000). With many respondents in various roles as engineers and implementers of higher-level directives, one particularly effective probe was to ask about political details by communicating my understanding of the difficulty of technical challenges: "You have a tough job managing these multiple priorities. How do you do it?" In some respects, these operators resemble more officials acting as street-level bureaucrats with policy conflicts and "informal pressures from local stakeholders" than technical personnel following a well-defined set of rules (Zhan et al., 2014). My role as an engineer from a well-known university facilitated this process (see next section).

B.2 Interview Coding Example

As described in Section 3.3.1, interview notes were coded using categories, working through the entire case with around five categories at a time. Multiple categories and respondents can be attached to each observation, and a final script cleans up and replicates the data across all categories for easy viewing. I illustrate here for a sample observation.

In this run, I examine five categories related to rule-making and implementation processes:

1. What does the rule-making process for electricity systems operations look like? How does it convert goals of policy-makers into operational regulations? [polmak]

2. Who has discretion to implement these rules and what accountability processes are in place? [polimp]

3. What accountability processes are in place? [account]

4. What conflicts, if any, arise in implementing rules from different authorities, and how are these resolved? [conimp]

Study questions (typically shared in advance)	
Q1	How have grid structure, management and coordination with neighboring provinces and regions contributed to wind integration outcomes in China?
Q2	How might experiences in market-oriented reforms to pricing and planning inform future policies to improve wind integration in the electricity sector?
Q3	How is long-distance transmission of wind energy coordinated across regions and with other generation firms?
Interview topics example	
Q1	How do you coordinate with the grid company on establishing and implementing dispatch rules?
Q2	What interaction do you have with provincial departments, and what are their roles over electricity sector management?
Q3	How does your province manage renewable energy integration, particularly given reduced economic growth?
Single topic checklist example	
Bilateral contracts	Allocation process, consumer participation thresholds and bidding, producer participation thresholds and bidding, bidding strategies, grid tariffs, dispatch or security-related adjustments, market outcomes and measurement, relationship to other trading products

Table B.1: Interview question guide example for regulatory official

Topic	Checklist
Overall dispatch procedure	• How much is dispatched month-ahead, day ahead? How many changes are made hour-ahead? • What happens on sub-hourly basis?
Factors incorporated during commitment and dispatch	• Startup/shutdown costs, startup/shutdown times • Ramp rates • Min generator outputs • Heat rates (part-load or full-load) • Reserve requirements • Transmission losses
Inter-provincial transmission	• What are voltages of various wind dispatch authorities? • How is this considered during commitment/dispatch? • When are inter-provincial transmission amounts fixed? • When are transmission contract amounts verified? • Is this same/different for inter-regional transmission?
Cogeneration / district heating	• Does heating load determine electricity load? If so, how is this implemented with heating companies? • How is heating load projected? Who does this projection?
Wind and solar dispatch	• Does dispatch center have forecasting capability? • What are forecast accuracy rates? • How are wind projects told to curtail? (electronic, phone call, direct control⋯) • When is the decision to curtail made?
Reserve generation	• What is the classification of reserves? (spinning vs. non-spinning, balancing, regulation⋯) • How are they scheduled and compensated?
Hydro reservoirs / pumped hydro	• Does dispatch have direct control over hydro? • Are there additional constraints on hydropower usage? (e.g., agriculture) • What is period of optimization? Week/month/year?
Demand response	• How does dispatch interact with large loads? • Are there any compensated demand resources?

Table B.2: Dispatch process question checklist

5. How do market participants behave with respect to implemented rules? Is there non-compliance or other strategic behavior? [stratbeh]

The following observation is in the notes:

> 16G2
>
> ...
>
> New wind development plans need center approval. If curtailment > 20%, cannot permit.

This is recorded in the case file as follows, adding an additional category "permit" because this relates to permitting:

> 3. What accountability processes are in place? [account]
>
> New wind development plans need center approval {16G2} [permit]
>
> - curtailment > 20% => cannot permit new

B.3 Biases and Reflections

As a white, male American coming from a prestigious foreign engineering school, interpersonal interactions with respondents and potential respondents do have an effect on the qualitative data collected. For many of the conclusions, I have attempted to cross-check with academic respondents, news and government reports, and published data. However, some findings still rest to a large extent on my qualitative analysis. In this section, I lay out as best I can the main implications. While difficult to utilize directly to modify the analysis of my data, these may be helpful for other researchers who have conducted similar studies or are planning to do so, and find inconsistencies with my observations.

B.3.1 Recruitment

For many, getting access to respondents is the most difficult aspect of studying Chinese politics and bureaucratic decision-making. In this study, I utilized as many networks as I could, throwing everything at the wall and "seeing what sticks." Earlier in the research, I had as much success in non-introduced settings (such as cold calls, cold emails, and conferences) as with introduced settings (e.g., through Chinese research partners). Later on (2015~), access became more difficult, corresponding to high-level changes in Chinese government policy toward academic research and openness. Introduced settings tended to work best in later years.

I believe the majority of respondents agreed to be interviewed (a) out of curiosity of a foreigner interested in their work; and (b) because of eagerness to exchange with an MIT engineer, who also presumably has access to relevant international experiences. In only one example I am aware of did my age and status as a student result in less interest. On the contrary, a high-profile professor may have caused an escalation in formality, reducing the chances for an interview (see below). Virtually all of the respondents (>95%) were male, reflecting the heavily male engineering profession, and I believe I, as a male, was advantaged by avoiding any potential gender discrimination.

Throughout the dissertation, I was a member of the Tsinghua-MIT China Energy and Climate Project, a collaboration between my MIT research lab and a research lab at China's leading engineering university in Beijing. Particularly for non-introduced settings, this provided an interesting lens into how potential respondents view academic researchers. A common inquiry in response to my request for interview was regarding my "status" to conduct this research ("你是用什么样的身份或项目与我交流？").

On the one hand, Tsinghua University, as a leading domestic university, is considered as highly credible and as an "insider", and people may be eager to engage as a result. One situation I recall illustrates this aspect. My Chinese research assistant called a government office to discuss the project. The official was positive and even offered to meet my assistant that afternoon because there is too much to talk about over the phone. My assistant further described that the project is joint with the foreign university MIT and that the lead researcher would be interested in joining. The official immediately changed attitude, and wanted to look at the research questions to send to a supervisor for approval. I followed up, explained the project further, and offered that I could send my assistant in alone if preferred. The official was non-confrontational, saying it had nothing to do with my being a foreigner: all research at government departments needed approval of an "official study invitation" (调研函). Nevertheless, it was clear that communicating with organizations "outside of the system" (体制外) was the key problem.

On the other, emphasizing the close connection and high-profile connection with Tsinghua may also trigger a desire for higher-level official approval. On one occasion, I cold-called a manager in a grid company and introduced the topic, after which I was told that the manager did not know about the research project and could not accept (“我不知道你的课题是哪里来的。”).

B.3.2 The Interview

In speaking with a foreign researcher, I have found Chinese respondents to have incentives to both under- and over-explain details of internal processes. First, in line with official policies designed to limit interactions with researchers, there is a natural incentive to avoid saying anything that would reflect poorly on their practice or the system as a whole. Thus, several conversations began with idealized descriptions of how things work, similar to international best practices, and only after probing with information about details of scheduling practices in other parts of China did the respondents reveal the closer-to-actual (imperfect) operating practices.

However, as any foreigner who has spent time in China has surely encountered, a common reaction to any perceived criticism from the outside is that China’s “national circumstances” (*guoqing* | 国情) are different from the West and difficult to understand. This invites further questions of precisely which circumstances lead to certain practices, with the by-product of making tacit knowledge explicit. Questions which seem obtuse coming from a Chinese researcher may seem perfectly normal from an outsider. On the other hand, as mentioned above, initial conversations of generalities including “national circumstances” can last 15+ minutes, which can reduce the time available for more probing questions.

I believe I have a reasonably unique position among other researchers who have examined Chinese electricity sector institutions through extensive qualitative fieldwork, most of whom come from political science, sociology or anthropology departments. Coming from an engineering systems department (translated as “工程系统系”), engineer respondents tend to treat me as their peer, and manager respondents may view my interest primarily through a “technical” rather than socio-political lens. On sum, I believe this has resulted in more honest responses. A common base of knowledge based on formal training in power systems has also allowed me to accelerate past boilerplate technical explanations to the important constraints and realities driving system operation. I strongly encourage engineering researchers who are interested in institutional questions to consider adding qualitative fieldwork to their project: even one summer of targeted work could generate some unique insights into combined socio-technical processes.

In order to test this assumption that we do in fact share a common base of knowledge, I examined several introductory texts in the standard curriculum at a major power systems engineering university: in the areas of power systems economics I found virtually the same concepts as comparable international textbooks (even if they are not applied *per se* in China). An interesting separate study would be to explore how engineers re-interpret their formal training in response to institutional constraints once in the workplace.

B.3.3 Interpretation

Growing up and being educated in the U.S., I have my own set of biases that I bring to the study of China. I follow a long line of academics who have come to China with accepted international models of economic policy and market functioning, and think in terms of political institutions causing "deviations" from optimal. In the case of China, much of this deviation is attributed to its non-democratic political institutions, which are seen as "backwards" and incompatible with U.S. norms. Leaving aside the extent to which this is supported in the literature, this is a perspective implicit in my society and much of my academic training.

I have developed a more nuanced view of my role as an outside researcher through (a) examining objective assessments of the effectiveness of some of China's idiosyncratic institutions, and (b) exploring / critiquing the history of international advisors in China. In the first category, China's unprecedented economic growth, outpacing many other similarly situated developing countries with more democratic institutions, is a constant reminder that we do not understand all aspects of what generates growth and well-being (Ang, 2016). In the second, taking just the electricity sector, international institutions such as the World Bank and Asian Development Bank have actively promoted a very specific set of institutions—even before they were widely adopted and "proven" in more advanced economies[2] —and in many aspects divorced from China's institutional realities. China largely adopted the reform blueprint, which faced substantial implementation hurdles following 2002, and many important elements were abandoned. Additionally, this process has been criticized as being co-opted by various government elites for personal benefit (Chen, 2010b).

Assuming satisfactorily competitive markets with minimal institutional frictions and comparing

[2]Xu (2016) recounts how World Bank experts were not confident in their proposed electricity institutional reforms for China in 1993 and 1994 (p. 48). However, Chinese officials, may have felt pressured to follow these guidelines to attract foreign investment (Yeh and Lewis, 2004).

to current practice is a useful academic exercise to highlight the importance and possibly prioritize reforms. I have adopted this perspective in both the modeling results of Chapter 5 and in analyzing intermediate processes of markets in Chapter 3. At the same time, I have also attempted to incorporate observations on the "stickiness" of institutions by actors within the system when making policy recommendations in Chapter 7. These intentionally fall short of the idealized international model, hopefully reflecting China's unique "circumstances", in an attempt to develop usable recommendations for decision-makers rather than adding yet another book to the pile of international lessons without context.

Bibliography

AEP (2008). Transmission facts. Technical report, American Electric Power.

Ahlstrom, M., Ela, E., Riesz, J., O'Sullivan, J., Hobbs, B. F., O'Malley, M., Milligan, M., Sotkiewicz, P., and Caldwell, J. (2015). The Evolution of the Market: Designing a Market for High Levels of Variable Generation. *IEEE Power and Energy Magazine*, 13(6):60–66.

Aklin, M. and Urpelainen, J. (2018). *Renewables: The Politics of a Global Energy Transition*. MIT Press.

Allison, G. T. (1969). Conceptual models and the Cuban missile crisis. *American political science review*, 63(03):689–718.

Andrews-Speed, P. (2013). Reform Postponed: The Evolution of China's Electricity Markets. In *Evolution of Global Electricity Markets: New Paradigms, New Challenges, New Approaches*, pages 531–567. Elsevier, Waltham, MA.

Ang, Y. Y. (2016). *How China Escaped the Poverty Trap*. Cornell University Press.

Angrist, J. and Pischke, J.-S. (2008). *Mostly Harmless Econometrics: An Empiricist's Companion*. Princeton University Press.

ANL (2015). Power Play: China's Ultra-high Voltage Technology and Global Standards. Technical report, The Paulson Institute.

Apt, J. and Jaramillo, P. (2014). *Variable renewable energy and the electricity grid*. RFF Press, New York.

Aravena, I. and Papavasiliou, A. (2017). Renewable Energy Integration in Zonal Markets. *IEEE Transactions on Power Systems*, 32(2):1334–1349.

Arent, D., Arndt, C., Miller, M., Tarp, F., and Zinaman, O., editors (2017). *The Political Economy of Clean Energy Transitions*. Oxford University Press.

Bai, C.-E. and Qian, Y. (2010). Infrastructure development in China: The cases of electricity, highways, and railways. *Journal of Comparative Economics*, 38(1):34–51.

Baldwin, C. J., Dale, K. M., and Dittrich, R. F. (1959). A study of the economic shutdown of generating units in daily dispatch. *Transactions of the American Institute of Electrical Engineers. Part III: Power Apparatus and Systems*, 78(4):1272–1282.

Bartnik, R. and Buryn, Z. (2011). *Conversion of Coal-Fired Power Plants to Cogeneration and Combined-Cycle*. Springer London, London.

Bendoly, E., Donohue, K., and Schultz, K. L. (2006). Behavior in operations management: Assessing recent findings and revisiting old assumptions. *Journal of Operations Management*, 24(6):737–752.

Bennett, A. and Checkel, J. T. (2015a). Introduction. In *Process tracing: from metaphor to analytic tool*. Cambridge University Press, Cambridge, UK.

Bennett, A. and Checkel, J. T. (2015b). *Process tracing: from metaphor to analytic tool*. Cambridge University Press, Cambridge, UK.

Bernard, H. (2000). Chapter 6: Interviewing. In *Social Research Methods*. SAGE Publications.

Bertsimas, D. and Tsitsiklis, J. N. (1997). *Introduction to Linear Optimization*. Athena Scientific, Belmont, MA.

Bird, L., Cochran, J., and Wang, X. (2014). Wind and solar energy curtailment: Experience and practices in the United States. Technical report, National Renewable Energy Laboratory.

BJX.com.cn (2015). Ningxia's First Matched Pairing Electricity Exchanges Completed 10.5 bn kWh. Retrieved from `http://shoudian.bjx.com.cn/html/20150508/616370.shtml`. 《宁夏首次电力集中撮合交易完成 105 亿千瓦时》.

Bloomberg (2017). China Is Creating the World's Largest Power Company. Bloomberg.com. Retrieved from `https://www.bloomberg.com/news/articles/2017-08-28/china-approves-guodian-shenhua-group-to-merge`.

Borenstein, S., Bushnell, J. B., and Wolak, F. A. (2002). Measuring Market Inefficiencies in California's Restructured Wholesale Electricity Market. *The American Economic Review*, (5):1376.

Box, G. E. P. and Liu, P. Y. T. (1999). Statistics as a catalyst to learning by scientific method part I–an example. *Journal of Quality Technology*, 31(1):1–15.

Bozzuto, C., editor (2009). *Clean Combustion Technologies*. Alstom, Windsor, CT, 5th edition.

Bradsher, K. (2011). China's Utilities Cut Energy Production, Defying Beijing. New York Times. Retrieved from `https://www.nytimes.com/2011/05/25/business/energy-environment/25coal.html`.

Brooks, C. (2015). The Periodic Table of the Electric Utility Landscape: A Series of Visual Tools for Enhanced Policy Analysis. *The Electricity Journal*, 28(6):82–95.

Bushnell, J. B., Mansur, E. T., and Saravia, C. (2008). Vertical Arrangements, Market Structure, and Competition An Analysis of Restructured US Electricity Markets. *American Economic Review*, 98(1):237–266.

Cai, H. and Treisman, D. (2006). Did Government Decentralization Cause China's Economic Miracle? *World Politics*, 58(04):505–535.

Carrión, M. and Arroyo, J. M. (2006). A computationally efficient mixed-integer linear formulation for the thermal unit commitment problem. *IEEE Transactions on Power Systems*, 21(3):1371–1378.

CEAEC (2009). *Yunnan Electricity Sector Annals (1991-2002)*. China Electricity Annals Editorial Committee. China Electric Power Press. 《云南省电力工业志（1991-2002）》.

CEAEC (2010). *Gansu Electricity Sector Annals (1991-2002)*. China Electricity Annals Editorial Committee. China Electric Power Press. 《甘肃省电力工业志（1991-2002）》.

CEAEC (2013). *Inner Mongolia Electricity Sector Annals (1991-2003).* China Electricity Annals Editorial Committee. China Electric Power Press. 《内蒙古自治区电力工业志（1991-2003)》.

CEC (2011). 2010 Electricity Industry Statistical Collection. China Electricity Council. 《2010 电力统计资料汇编》.

CEC (2014a). Power Generating Equipment Capacity (1994-2014). China Electricity Council. CEIC Database.

CEC (2014b). Power Generating Equipment Utilization: Thermal Power. China Electricity Council. CEIC Database.

CEC (2015). 2014 Electricity Industry Statistical Collection. China Electricity Council. 《2010 电力统计资料汇编》.

CEC (2016). China Electricity Industry 2016 Annual Development Report. China Electricity Council. 《中国电力行业年度发展报告 2016》.

CEC (2017a). 2017h1 National Electricity Market Exchange Data. China Electricity Council. 《2017 年上半年全国电力市场交易数据》.

CEC (2017b). Overview of Electric Power Industry (Various: 2003-2016). China Electricity Council.

CEC (2017c). Power Generating Equipment Capacity (1994-2016). China Electricity Council. CEIC Database.

CEC (2018). 2017 National Electricity Market Information Summary. China Electricity Council. 《2017 年度全国电力市场交易信息简要分析》.

Cerisola, S., Baíllo, A., Fernández-López, J., Ramos, A., and Gollmer, R. (2009). Stochastic Power Generation Unit Commitment in Electricity Markets: A Novel Formulation and a Comparison of Solution Methods. *Operations Research*, 57(1):32–46.

Chen, H. (2010a). Gansu Grid Rapidly Upgrading. Gansu Daily. Retrieved from `http://gansu.gansudaily.com.cn/system/2010/10/29/011748574.shtml`. 《这是一条神奇的" 天路": 甘肃电网全面升级速记-电网-每日甘肃-甘肃》.

Chen, L. (2010b). Playing the Market Reform Card: The Changing Patterns of Political Struggle in China's Electric Power Sector. *China Journal*, 64:69–95.

Chen, Q., Kang, C., Xia, Q., and Zhong, J. (2010). Power Generation Expansion Planning Model Towards Low-Carbon Economy and Its Application in China. *IEEE Transactions on Power Systems*, 25(2):1117–1125.

Chen, R. and Ma, L. (2010). Inner Mongolia Grid Company: Promoting Wind Power Develoment and Contributing to Energy-Savings and Emissions Reductions. People.cn. Retrieved from http://www.china.com.cn/economic/txt/2010-01/08/content_19204130.htm.

Chung, J. H., Lai, H., and Joo, J.-H. (2009). Assessing the "Revive the Northeast" (zhenxing dongbei) Programme: Origins, Policies and Implementation. *The China Quarterly*, 197:108–125.

Cicala, S. (2017). Imperfect Markets versus Imperfect Regulation in U.S. Electricity Generation. *National Bureau of Economic Research Working Paper*.

Cochran, J., Lew, D., and Kumar, N. (2013). Flexible Coal: Evolution from Baseload to Peaking Plant. Technical report, National Renewable Energy Laboratory, Golden, CO.

Constantinescu, E., Zavala, V., Rocklin, M., Lee, S., and Anitescu, M. (2011). A Computational Framework for Uncertainty Quantification and Stochastic Optimization in Unit Commitment With Wind Power Generation. *IEEE Transactions on Power Systems*, 26(1):431–441.

CPCCC (2013). Third Plenary Session Communiqué: Major Issues in Comprehensively Deepening Reform. Communist Party of China 18th Central Committee.

CPNN.com.cn (2017). Inner Mongolia's Electricity Industry is the Province's Main Development Engine. Retrieved from http://www.cec.org.cn/xinwenpingxi/2017-08-01/171573.html. 《内蒙古电力工业为自治区发展注入强大动力》.

Creswell, J. (2009). *Research design: Qualitative, quantitative, and mixed methods approaches*. SAGE Publications.

Crozier, M. (1964). *The Bureaucratic Phenomenon*. University of Chicago Press, Chicago.

Dai, J. (2013). Northeast electricity market reform experiments. Energy. Retrieved from http://finance.sina.com.cn/leadership/mroll/20130708/141916049734.shtml. 《东北区域电力市场改革试验》.

Dai, Y. (2015). Who Drives Climate-Relevant Policy Implementation in China? Working Paper 134, Institute of Development Studies, Sussex, UK.

Dai, Y. and Xue, L. (2015). China's policy initiatives for the development of wind energy technology. *Climate Policy*, 15(1):30–57.

Davidson, M. R. (2014). Regulatory and Technical Barriers to Wind Energy Integration in Northeast China. Master's thesis, Massachusetts Institute of Technology.

Davidson, M. R., Kahrl, F., and Karplus, V. (2016a). Towards a Political Economy Framework for Wind Power: Does China Break the Mould? Technical Report 32, United Nations University World Institute for Development Economics Research.

Davidson, M. R., Kahrl, F., and Karplus, V. J. (2017). Towards a political economy framework for wind power: Does China break the mould? In Arent, D., Arndt, C., Miller, M., Tarp, F., and Zinaman, O., editors, *The Political Economy of Clean Energy Transitions*, pages 250–270. Oxford University Press.

Davidson, M. R., Zhang, D., Xiong, W., Zhang, X., and Karplus, V. J. (2016b). Modelling the potential for wind energy integration on China's coal-heavy electricity grid. *Nature Energy*, 1:16086.

de Sisternes, F. J., Jenkins, J. D., and Botterud, A. (2016). The value of energy storage in decarbonizing the electricity sector. *Applied Energy*, 175:368–379.

de Sisternes, F. J. and Webster, M. D. (2013). Selection of Sample Weeks for Approximating the Net Load in Generation Planning Problems. ESD Working Paper, Massachusetts Institute of Technology.

DECC (2015). Electricity Market Reform: Contracts for Difference. Technical report, UK Department of Energy and Climate Change.

Deng, G. and Kennedy, S. (2010). Big business and industry association lobbying in China: The paradox of contrasting styles. *The China Journal*, pages 101–125.

Ding, Y. and Yang, H. (2013). Promoting energy-saving and environmentally friendly generation dispatching model in China: Phase development and case studies. *Energy Policy*, 57:109–118.

Dowds, J., Hines, P., Ryan, T., Buchanan, W., Kirby, E., Apt, J., and Jaramillo, P. (2015). A review of large-scale wind integration studies. *Renewable and Sustainable Energy Reviews*, 49:768–794.

Dunlop, R. D., Gutman, R., and Marchenko, P. (1979). Analytical development of loadability characteristics for EHV and UHV transmission lines. *IEEE Transactions on Power Apparatus and Systems*, (2):606–617.

Dupuy, M., Weston, F., and Hove, A. (2015). Power Sector: Deepening Reform to Reduce Emissions, Improve Air Quality and Promote Economic Growth. Technical report, Paulson Institute, Beijing.

Economy, E. (2017). Why China Is No Climate Leader. *Politico Magazine*.

Emeis, S. (2013). *Wind Energy Meteorology*. Green Energy and Technology. Springer Berlin Heidelberg, Berlin, Heidelberg.

EPRI (2013). Quantifying the Value of Hydropower in the Electric Grid. Technical report, Electric Power Research Institute, Palo Alto, CA.

ESCN (2017). Kunming Electricity Exchange Publishes Nation's First Day-Ahead Electricity Exchange K-Curve. China Energy Storage News. Retrieved from `http://www.escn.com.cn/news/show-448907.html`. 《昆明电力交易中心发布全国首个日前电量交易 K 线》.

Federico, G. and Rahman, D. (2003). Bidding in an Electricity Pay-as-Bid Auction. *Journal of Regulatory Economics*, 24(2):175–211.

Fingar, T. (1987). Implementing Energy Policy: The Rise and Demise of the State Energy Commission. In *Policy implementation in post-Mao China*, pages 190–224. University of California Press, Berkeley.

Fink, S., Mudd, C., Porter, K., and Morgenstern, B. (2009). Wind Energy Curtailment Case Studies. Technical report, National Renewable Energy Laboratory.

Fischlein, M., Larson, J., Hall, D. M., Chaudhry, R., Rai Peterson, T., Stephens, J. C., and Wilson, E. J. (2010). Policy stakeholders and deployment of wind power in the sub-national context: A comparison of four U.S. states. *Energy Policy*, 38(8):4429–4439.

Fitiwi, D. Z., Olmos, L., Rivier, M., de Cuadra, F., and Pérez-Arriaga, J. I. (2016). Finding a representative network losses model for large-scale transmission expansion planning with renewable energy sources. *Energy*, 101:343–358.

Fitzgerald, G. and Nelder, C. (2017). EVgo Fleet and Tariff Analysis - Phase 1: California. Rocky Mountain Institute.

Gabriel, S. A., Conejo, A. J., Ruiz, C., and Siddiqui, S. (2013). Solving discretely constrained, mixed linear complementarity problems with applications in energy. *Computers & Operations Research*, 40(5):1339–1350.

Gansu DRC (2016). Gansu Renewable Energy Local Integration Pilot Plan. Gansu Development and Reform Commission. 《甘肃省可再生能源就近消纳试点方案》.

Gansu Electricity Exchange (2016a). 2016h1 Gansu Direct Electricity Exchange Market Announcement. Gansu Electricity Exchange Center. 《2016 年甘肃省下半年电能直接交易市场公告》.

Gansu Electricity Exchange (2016b). 2016h2 Huanghe Ganliu Hydropower Curtailment and New Energy Company 1.5 Billion kWh Direct Exchange Announcement. Gansu Electricity Exchange. 《2016 年下半年黄河干流水电弃水减量新能源企业增发 15 亿千瓦时电能直接交易公告》.

Garver, L. L. (1962). Power generation scheduling by integer programming-development of theory. *Transactions of the American Institute of Electrical Engineers. Part III: Power Apparatus and Systems*, 81(3):730–734.

GD EIC (2016). Notice Regarding Adjustments to Centralized Exchange Procedures. Guangdong Economic and Information Commission. 《广东省经济和信息化委关于集中竞争交易规则调整有关事项的通知》(粤经信电力函 [2015]1136 号).

GE (2010). Western Wind and Solar Integration Study. Technical report, National Renewable Energy Laboratory (NREL), Golden, CO.

Geddes, B. (1990). How the cases you choose affect the answers you get: Selection bias in comparative politics. *Political analysis*, 2(1):131–150.

George, A. L. and Bennett, A. (2005). *Case studies and theory development in the social sciences.* MIT Press, Cambridge, MA.

Goertz, G. and Mahoney, J. (2012). *A tale of two cultures: Qualitative and quantitative research in the social sciences.* Princeton University Press.

Goulder, L. H. and Morgenstern, R. D. (2018). China’s Rate-based Approach to Reducing CO2 Emissions: Strengths, Limitations, and Alternatives. page 19, Philadelphia.

Gralla, E., Goentzel, J., and Fine, C. (2016). Problem Formulation and Solution Mechanisms: A Behavioral Study of Humanitarian Transportation Planning. *Production and Operations Management*, 25(1):22–35.

Gralla, E. L. (2012). *Human and modeling approaches for humanitarian transportation planning.* Ph.D. Thesis, Massachusetts Institute of Technology.

Grubb, M., Sha, F., Spencer, T., Hughes, N., Zhang, Z., and Agnolucci, P. (2015). A review of Chinese CO2 emission projections to 2030: the role of economic structure and policy. *Climate Policy*, 15(sup1):S7–S39.

Guangzhou Committee (2001). *Guangzhou Electricity Sector Annals (1888-2000).* Guangzhou Electricity Sector Annals Editorial Committee. 《广州市电力工业志（1888-2000)》.

Guangzhou Electricity Exchange (2017a). Guidelines for Southern Grid Cross-Provincial Monthly Electricity Exchanges (Provisional). Guangzhou Electricity Exchange. 《南方区域跨区跨省月度电力交易规则（试行)》广州交易 [2017]65 号.

Guangzhou Electricity Exchange (2017b). Notice of Opening April Yunnan to Guangdong Monthly Temporary Listed Auction. 《关于开展 4 月云南送广东月内临时挂牌交易的通知》.

Guangzhou Electricity Exchange (2017c). Notice of Results of April Yunnan to Guangdong Monthly Temporary Listed Auction. 《关于发布 4 月云南送广东月内临时挂牌交易结果的通知》.

Guangzhou Electricity Exchange (2017d). Notice of Results of September Yunnan-Guizhou Hydro-Coal Exchange. 《关于发布 9 月云贵水火置换交易结果的通知》.

Guizhou Committee, editor (1998). *Guizhou Electricity Center Dispatch Annals*. Guizhou Electricity Center Dispatch Annals Editorial Committee. Guiyang, Guizhou. 《贵州电力中心调度所志》.

Haggett, C. (2008). Over the Sea and Far Away? A Consideration of the Planning, Politics and Public Perception of Offshore Wind Farms. *Journal of Environmental Policy & Planning*, 10(3):289–306.

Hara, K., Kimura, M., and Honda, N. (1966). A method for planning economic unit commitment and maintenance of thermal power systems. *IEEE Transactions on Power Apparatus and Systems*, (5):427–436.

Hayek, F. A. (1948). *Individualism and Economic Order*. University of Chicago Press.

Heilmann, S. (2008). From Local Experiments to National Policy: The Origins of China's Distinctive Policy Process. *The China Journal*, (59):1–30.

Hobbs, B. F., Stewart Jr., W. R., Bixby, R. E., Rothkopf, M. H., O'Neill, R. P., and Chao, H.-p. (2002). Why this Book? New Capabilities and New Needs for Unit Commitment Modeling. In Hobbs, B. F., Rothkopf, M. H., O'Neill, R. P., and Chao, H.-p., editors, *The Next Generation of Electric Power Unit Commitment Models*, number 36 in International Series in Operations Research & Management Science, pages 1–14. Springer US.

Hogan, W. W. (2003). Transmission Market Design. Faculty Research Working Paper Series, Harvard University.

Hogan, W. W. (2013). Electricity scarcity pricing through operating reserves. *Economics of Energy & Environmental Policy*, 2(2):65–86.

Holttinen, H., Meibom, P., Orths, A., Lange, B., O'Malley, M., Tande, J. O., Estanqueiro, A., Gomez, E., Soder, L., and Strbac, G. (2011). Impacts of large amounts of wind power on design and operation of power systems, results of IEA collaboration. *Wind Energy*, 14(2):179–192.

Holttinen, H., Milligan, M., Ela, E., Menemenlis, N., Dobschinski, J., Rawn, B., Bessa, R., Flynn, D., Gomez-Lazaro, E., and Detlefsen, N. (2012). Methodologies to Determine Operating Reserves Due to Increased Wind Power. *IEEE Transactions on Sustainable Energy*, 3(4):713–723.

Holttinen, H., Milligan, M. R., and Ela, E. (2009). *Design and operation of power systems with large amounts of wind power: final report, IEA Wind Task 25, Phase One, 2006-2008*. VTT Technical Research Centre of Finland, Espoo, Finland.

Hsueh, R. (2011). *China's Regulatory State: A New Strategy for Globalization*. Cornell University Press, Ithaca, NY.

Huaneng (2016). Response to Opinion Seeking Comments on Yunnan Wind and Solar Tariff Policies. Huaneng New Energy Company, Yunnan Branch. 《关于征求云南风电、光伏发电电价政策意见的反馈》.

Hunt, S. (2002). *Making Competition Work in Electricity*. John Wiley & Sons, New York.

Ichniowski, C. and Shaw, K. (2003). Beyond Incentive Pay: Insiders' Estimates of the Value of Complementary Human Resource Management Practices. *The Journal of Economic Perspectives*, 17(1):155–180.

IM DRC (2016). Notice Regarding Lowering Coal Electricity On-Grid Tariffs. Inner Mongolia Development and Reform Commission. 《内蒙古自治区发展和改革委员会关于降低我区燃煤发电上网电价有关事宜的通知》(内发改价字 [2016]285 号).

IM EIC (2016). Notice of Adjustment of Quantity and Price Restrictions of Western Inner Mongolia Grid Multi-Lateral Electricity Exchange. Inner Mongolia Economic and Information Commission. 《内经信电力字 [2016]30 号调整蒙西电网电力多边交易电量限值、电价限值的通知》.

IM EIC (2017). Inner Mongolia's First Listed Electricity Exchange Without Price Limits Leads to Consumer Prices Falling to 0.26 Yuan per kWh. Inner Mongolia Economic and Information Commission. Retrieved from `http://www.nmg.gov.cn/fabu/xwdt/nmg/201607/t20160725_562061.html`. 《内蒙古电力多边交易市场首次挂牌交易实现最低到户电价不到 0.26 元/每千瓦时》.

IM Government (2009). Opinion Regarding Further Construction of Multi-Lateral Electricity Exchange Markets. 《内蒙古自治区人民政府关于进一步推进电力多边交易市场建设的意见》.

IM Government (2015). Guiding Opinion on Building an Effective Long-term System for Renewable Energy Purchase Safeguards. 《内蒙古自治区人民政府办公厅关于建立可再生能源保障性收购长效机制的指导意见》.

IM Government (2016). Inner Mongolia Renewable Energy Local Integration Pilot Plan. 《内蒙古自治区可再生能源就近消纳试点方案》.

IM Grid (2015). Western Inner Mongolia Grid Annual Direct Electricity Contract (Wind and Aluminum Factory Version). Inner Mongolia Grid Company. 《内蒙古西部电网大用户直购电年度合同 (希铝风电版)》.

IM SASAC (2011). Western Inner Mongolia Excess Wind Electricity Begins Inter-Provincial Trading. Inner Mongolia State-Owned Assets Supervision and Administration Commission. 《蒙西电网富余风电电量开始进行跨省交易》.

IMPC (2014). Inner Mongolia Grid 2013 Social Responsibility Report. Inner Mongolia Power Company. 《内蒙古电力公司 2013 年社会责任报告》.

IMPC (2015). Inner Mongolia Grid 2014 Social Responsibility Report. Inner Mongolia Power Company. 《内蒙古电力公司 2014 年社会责任报告》.

IMPC (2017). Inner Mongolia Grid 2016 Social Responsibility Report. Inner Mongolia Power Company. 《内蒙古电力公司 2016 年社会责任报告》.

Inner Mongolia Electricity News (2017a). Generation-Side Exchange Conditions - October 2017. 《2017-10-发电侧交易情况》.

Inner Mongolia Electricity News (2017b). Inter-Regional Exchanges - July 2017. 《2017-7-区外交易情况》.

Inner Mongolia Electricity News (2017c). Monthly Exchange Settements - August 2017. 《交易结算-2017 年 8 月数据》.

Inner Mongolia Electricity News (2017d). Overall Situation of Multi-Lateral Exchange Settements - October 2017. 《2017-10-多边交易总体成交情况》.

Jacobson, M. Z. (2005). *Fundamentals of Atmospheric Modeling.* Cambridge University Press.

Jacoby, H. D., Chen, Y.-H. H., and Flannery, B. P. (2017). Informing transparency in the Paris Agreement: the role of economic models. *Climate Policy*, 17(7):873–890.

Jamasb, T. (2006). Between the state and market: Electricity sector reform in developing countries. *Utilities Policy*, 14(1):14–30.

Jamasb, T., Nepal, R., and Timilsina, G. R. (2017). A Quarter Century Effort Yet to Come of Age: A Survey of Electricity Sector Reform in Developing Countries. *The Energy Journal*, 38(3).

Jilin DRC (2016). Jilin Renewable Energy Local Integration Pilot Plan. Jilin Development and Reform Commission. 《吉林省可再生能源就近消纳试点方案》.

Jilin Energy Administration (2017). Jilin 13th Five-Year Electricity Development Plan. Jilin Energy Administration. 《吉林省电力发展“十三五”规划》.

Johnson, C. (1982). *MITI and the Japanese miracle: The Growth of Industrial Policy: 1925-1975.* Stanford University Press.

Joskow, P. L. (2008). Lessons learned from electricity market liberalization. *The Energy Journal*, 29(2):9–42.

Joskow, P. L. (2014). Incentive regulation in theory and practice: electricity distribution and transmission networks. In Rose, N., editor, *Economic Regulation and Its Reform: What Have We Learned?*, pages 291–344. University of Chicago Press.

Joskow, P. L. and Schmalensee, R. (1983). *Markets for Power: An analysis of electric power deregulation.* MIT Press, Cambridge, MA.

Kahrl, F. and Wang, X. (2014). Integrating Renewables into Power Systems in China: A Technical Primer - Power System Operations. Regulatory Assistance Project.

Kahrl, F., Williams, J. H., and Hu, J. (2013). The political economy of electricity dispatch reform in China. *Energy Policy*, 53:361–369.

Kang, J., Yuan, J., Hu, Z., and Xu, Y. (2012). Review on wind power development and relevant policies in China during the 11th Five-Year-Plan period. *Renewable and Sustainable Energy Reviews*, 16(4):1907–1915.

Kiser, L. and Ostrom, E. (1982). Three Worlds of Action: A Metatheoretical Synthesis of Institutional Approaches. In Ostrom, E., editor, *Strategies of political inquiry*. Sage Publications, Beverly Hills.

Kong, J. (2010). Part III: Electricity Industry Management Reform. In *China Public Services Management Reform*. China Financial and Economic Publishing House, Beijing. 《中国公共服务监管体制改革》.

Konstantinidis, C. and Strbac, G. (2015). Empirics of Intraday and Real-time Markets in Europe: Great Britain. Technical report, Deutsches Institut für Wirtschaftsforschung, Berlin.

Krishna, C., Sagar, A. D., and Spratt, S. (2015). The Political Economy of Low-carbon Investments: Insights from the Wind and Solar Power Sectors in India. Technical report, Institute of Development Studies, Sussex, UK.

Kunming Electricity Exchange (2016). September 2016 Yunnan Electricity Market Exchange Summary. 《2016 年 9 月云南电力市场化交易简报》.

Kunming Electricity Exchange (2017a). 2017h1 Yunnan Electricity Market Exchange Analysis and 2017h2 Forecast Report. 《2017 年上半年云南电力市场化交易分析及下半年形势预测报告》.

Kunming Electricity Exchange (2017b). Market Exchanges. Retrieved from `http://www.kmpex.com/web/kmdljyzx/80`. 《市场交易 - 昆明电力交易中心》.

Kunming Electricity Exchange (2017c). May 2017 Electricity Market Exchange Information.《2017 年 5 月电力市场化交易信息披露》.

Landry, P. F. (2008). *Decentralized authoritarianism in China*. Cambridge University Press, New York.

Lehmann, P., Creutzig, F., Ehlers, M.-H., Friedrichsen, N., Heuson, C., Hirth, L., and Pietzcker, R. (2012). Carbon Lock-Out: Advancing Renewable Energy Policy in Europe. *Energies (19961073)*, 5(2):323–354.

Lema, A. and Ruby, K. (2007). Between fragmented authoritarianism and policy coordination: Creating a Chinese market for wind energy. *Energy Policy*, 35(7):3879–3890.

Levitsky, S. and Murillo, M. V. (2009). Variation in institutional strength. *Annual Review of Political Science*, 12:115–133.

Li, C. (2017). Coal electricity co-movement expected by year end, may raise electricity prices and relieve coal electricity contradictions. Securities Daily. Retrieved from `http://www.p5w.net/news/gncj/201710/t20171026_1999481.htm`. 《煤电联动有望年底启动或上调电价缓解煤电矛盾》.

Li, C. (2018). Mandatory green certificate trading to begin in 2018. Zhongguo Caijing. Retrieved from `http://www.cnenergy.org/xny_183/201801/t20180131_450522.html`. 《绿证强制约束交易 2018 年将适时启动》.

Li, H. and Zhou, L.-A. (2005). Political turnover and economic performance: the incentive role of personnel control in China. *Journal of Public Economics*, 89(9–10):1743–1762.

Li, J., Cai, F., Qiao, L., Xie, H., Gao, H., Yang, X., Tang, W., Wang, W., and Li, X. (2012). China Wind Energy Outlook. Technical report, Chinese Renewable Energy Industries Association—Global Wind Energy Council—Greenpeace.

Lieberman, E. S. (2005). Nested Analysis as a Mixed-Method Strategy for Comparative Research. *American Political Science Review*, 99(3).

Lieberthal, K. and Oksenberg, M. (1988). *Policy making in China: Leaders, structures, and processes*. Princeton University Press.

Liu, Q. (2013). How to Implement Energy Efficient Dispatch Compensation: Jiangsu's Experience. *Power and Electricity Engineers*, 26.

Lorentzen, P. L., Fravel, M. T., and Paine, J. (2015). Using Process Tracing to Evaluate Formal Models. Social Science Research Network.

Lu, X., McElroy, M. B., Peng, W., Liu, S., Nielsen, C. P., and Wang, H. (2016). Challenges faced by China compared with the US in developing wind power. *Nature Energy*, 1(6):16061.

Luo, G.-l., Zhi, F., and Zhang, X. (2012). Inconsistencies between China's wind power development and grid planning: An institutional perspective. *Renewable Energy*, 48:52–56.

Ma, B., Song, G., Zhang, L., and Sonnenfeld, D. A. (2014). Explaining sectoral discrepancies between national and provincial statistics in China. *China Economic Review*, 30:353–369.

Ma, C. and He, L. (2008). From state monopoly to renewable portfolio: Restructuring China's electric utility. *Energy Policy*, 36(5):1697–1711.

Ma, J., Silva, V., Belhomme, R., Kirschen, D. S., and Ochoa, L. F. (2013). Evaluating and Planning Flexibility in Sustainable Power Systems. *IEEE Transactions on Sustainable Energy*, 4(1):200–209.

Ma, J. L. (2011). On-grid electricity tariffs in China: Development, reform and prospects. *Energy Policy*, 39(5):2633–2645.

Ma, L. (2009). WP2–Future Energy Technology Perspectives: Coal Technology Assessment. Technical report, NZEC.

Mahoney, J. and Thelen, K. (2010). A Theory of Gradual Institutional Change. In Mahoney, J. and Thelen, K., editors, *Explaining Institutional Change: Ambiguity, Agency, and Power*. Cambridge University Press.

Mai, T., Wiser, R., Sandor, D., Brinkman, G. L., Heath, G., Denholm, P., Hostick, D. J., Darghouth, N., Schlosser, A., and Strzepek, K. (2012). Exploration of high-penetration renewable electricity futures. In *Renewable Electricity Futures Study*, volume vol. 1. National Renewable Energy Laboratory, Golden, CO. NREL/TP-6A20-52409.

Mansur, E. T. and White, M. (2012). Market organization and efficiency in electricity markets. Working Paper, Dartmouth University, Hanover, NH.

Matus, K., Nam, K. M., Selin, N. E., Lamsal, L. N., Reilly, J. M., and Paltsev, S. (2012). Health damages from air pollution in China. *Global Environmental Change-Human and Policy Dimensions*, 22(1):55–66.

Mauch, B. K. (2012). *Managing Wind Power Forecast Uncertainty in Electric Grids*. Ph.D. Thesis, Instituto Superior Técnico, Lisbon, Portugal. http://repository.cmu.edu/dissertations/199/.

McElroy, M. B., Lu, X., Nielsen, C. P., and Wang, Y. X. (2009). Potential for wind-generated electricity in China. *Science*, 325(5946):1378–1380.

Megginson, W. L. and Netter, J. M. (2001). From State to Market: A Survey of Empirical Studies on Privatization. *Journal of Economic Literature*, 39(2):321–389.

Mertha, A. (2009). "Fragmented Authoritarianism 2.0" : Political Pluralization in the Chinese Policy Process. *The China Quarterly*, 200:995.

MITEI (2016). *Utility of the Future*. MIT Energy Initiative, Cambridge, MA.

Momoh, J. A. (2009). *Electric power system applications of optimization*. CRC Press, Boca Raton, 2nd ed. edition.

Montinola, G., Qian, Y., and Weingast, B. R. (1995). Federalism, Chinese style: the political basis for economic success in China. *World Politics*, 48(01):50–81.

Morales-Espana, Latorre, J. M., and Ramos, A. (2013). Tight and Compact MILP Formulation for the Thermal Unit Commitment Problem. *IEEE Transactions on Power Systems*, 28(4):4897–4908.

Morey, M. and Kirsch, L. (2016). Retail Choice in Electricity: What Have We Learned in 20 Years? Electricity Markets Research Foundation.

Morton, R. B. (2009). Formal Modeling and Empirical Analysis in Political Science. In *Methoden der vergleichenden Politik-und Sozialwissenschaft*, pages 27–35. Springer.

Munnings, C., Morgenstern, R. D., Wang, Z., and Liu, X. (2016). Assessing the design of three carbon trading pilot programs in China. *Energy Policy*, 96(Supplement C):688–699.

Nahm, J. and Steinfeld, E. S. (2014). Scale-up Nation: China’s Specialization in Innovative Manufacturing. *World Development*, 54:288–300.

Nathan, A. J. (1973). A Factionalism Model for CCP Politics. *The China Quarterly*, (53):34–66.

Naughton, B. (1995). *Growing out of the plan: Chinese economic reform, 1978-1993*. New York, NY : Cambridge University Press, 1995.

Naughton, B. and Tsai, K. S. (2015). State Capitalism and the Chinese Economic Miracle. In Naughton, B. and Tsai, K. S., editors, *State Capitalism, Institutional Adaptation, and the Chinese Miracle*, Comparative Perspectives in Business History, pages 1–24. Cambridge University Press.

NBS (2016). *Monthly Electricity Production (2001-2015)*. National Bureau of Statistics, CEIC Data.

NBS (2017). *Annual Electricity Consumption by City*. National Bureau of Statistics, CEIC Data.

NDRC (2007). Medium and Long-Term Development Plan for Renewable Energy. National Development and Reform Commission.

NDRC (2009). Notice of Perfecting Onshore Wind Benchmark On-Grid Tariff. National Development and Reform Commission. 《关于完善风力发电上网电价政策的通知》.

NDRC (2010). China’s autonomous domestic mitigation actions. National Development and Reform Commission.

NDRC (2011). Regulations Regarding Combined Heat and Power Development. National Development and Reform Commission. 《关于发展热电联产的规定》.

NDRC (2014). Notice of Adjustment of Onshore Wind Benchmark On-Grid Tariff. National Development and Reform Commission. 《关于适当调整陆上风电标杆上网电价的通知 (发改价格 [2014]3008 号)》.

NDRC (2015a). Enhanced Actions on Climate Change (INDC). National Development and Reform Commission.

NDRC (2015b). Implementing Opinion on Orderly Opening Up of Electricity Plans. National Development and Reform Commission. 《关于有序放开发用电计划的实施意见》.

NDRC (2015c). Notice Regarding Improving Inter-Provincial Inter-Regional Electricity Trade Price Arrangements. National Development and Reform Commission. 《关于完善跨省跨区电能交易价格形成机制有关问题的通知（发改价格 [2015]962 号)》.

NDRC (2016a). Notice on Adjustments to Onshore Wind and Solar PV Benchmark Tariffs. National Development and Reform Commission. 《关于调整光伏发电陆上风电标杆上网电价的通知 (发改价格 [2016]2729 号)》 (Translation by chinaenergyportal.org).

NDRC (2016b). Renewable Energy Full Purchase Safeguards Management Rules. National Development and Reform Commission. 《可再生能源发电全额保障性收购管理办法》.

NDRC, MEP, SERC, and NEWG (2007). Implementation Guidelines for Energy Efficient Dispatch Pilots (Provisional). National Development and Reform Commission. 《关于印发节能发电调度试点工作方案和实施细则（试行）的通知》.

NDRC and MOC (2007). Temporary Measures for Comprehensive Utilization of Combined Heat and Power and Waste Coal. National Development and Reform Commission. 《热电联产和煤矸石综合利用发电项目建设管理暂行规定》.

NDRC and NEA (2015a). Guiding Opinion Regarding Improving Electricity System Operational Adjustments for Increased and Complete Clean Energy Generation. National Development and Reform Commission. 《关于改善电力运行调节促进清洁能源多发满发的指导意见 (发改运行 [2015]518 号)》.

NDRC and NEA (2015b). Notice Regarding Electricity Planning Following Project Approval Release. National Energy Administration. 《关于做好电力项目核准权限下放后规划建设有关工作的通知》.

NDRC and NEA (2016). Notice Regarding Implementing Wind and Solar Full Purchase Safeguard Management Work. National Development and Reform Commission. 《关于做好风电、光伏发电全额保障性收购管理工作的通知》.

NEA (2014a). Energy Sector Strengthening Air Pollution Prevention Plan. National Energy Administration. 《关于印发能源行业加强大气污染防治工作方案的通知》.

NEA (2014b). Summary Note on Management Rules of Northeast Electricity Peaking Market Compensation. National Energy Administration, Northeast China Energy Regulatory Bureau. 《东北电力调峰市场化补偿管理办法》编制说明.

NEA (2016a). 13th Five-Year Plan on Wind Development. National Energy Administration. 《风电发展“十三五”规划》.

NEA (2016b). 2015 National Electricity Dispatch Exchange and Market Operations Supervision Report. National Energy Administration. 《能源局公布 2015 年全国电力调度交易与市场秩序监管报告》.

NEA (2016c). Notice for Comment Regarding Completing Work of Electricity Market Construction. National Energy Administration. 《国家能源局综合司关于征求做好电力市场建设有关工作的通知（征求意见稿）意见的函》.

NEA (2016d). Wind Industry Development Statistics 2015. National Energy Administration. 《2015 年风电产业发展统计数据》.

NEA (2017a). 2016 National Renewable Power Development Monitoring and Evaluation Report. National Energy Administration. 《国家能源局关于 2016 年度全国可再生能源电力发展监测评价的通报》(Translation by chinaenergyportal.org).

NEA (2017b). 2016 Northwest Wind and PV Output and Curtailment Statistics. National Energy Administration. 《2016 年西北区域新能源并网运行情况通报》.

NEA (2017a). Notice Regarding 2017 Monitoring Warning Results of Wind Power Investment. National Energy Administration. 《国家能源局关于发布 2017 年度风电投资监测预警结果的通知》.

NEA (2017b). Wind Industry Development Statistics 2016. National Energy Administration. 《2016 年风电并网运行情况》.

NECG (2014). Northeast Grid 2013 Annual Electricity Market Information Report. State Grid Northeast Region. 《国网东北分部 2013 年年度电力市场交易信息》.

NECG (2014). Northeast Grid 2014q1 Electricity Market Information Report. State Grid Northeast Region. 《东北电网 2014 年一季度电力市场信息》.

NECG (2015a). Northeast Grid 2014 Annual Electricity Market Information Report. State Grid Northeast Region. 《国网东北分部 2014 年年度电力市场交易信息》.

NECG (2015b). Northeast Grid 2014 Electricity Market Exchange Report. Northeast China Grid. 《东北电网 2014 年年度电力市场信息报告》.

NengJian (2017). NDRC: First Electricity Spot Market Pilots About to Start. Neng Jian. Retrieved from http://wap.nengapp.com/news/953654. 《国家发改委：首批电力现货市场试点即将启动》.

Neuhoff, K., Wolter, S., and Schwenen, S. (2016). Power markets with Renewables: New perspectives for the European Target Model. *The Energy Journal*, 37(01).

Newberry, D. M. (2002). *Privatization, restructuring, and regulation of network utilities*, volume 2. MIT Press, Cambridge, MA.

Ng, E. (2017). Why China's costly "green energy certificate" has not helped cash-strapped renewable energy firms. South China Morning Post. Retrieved from http://www.scmp.com/business/commodities/article/2116131/why-chinas-costly-green-energy-certificate-has-not-helped-cash.

Ni, W. (2017). Zarute-Qingzhou ±800 kV UHV-DC Starts to Carry Electricity. ChinaPower.com.cn. Retrieved from http://www.chinapower.com.cn/dwtgy/20171017/93958.html. 《扎鲁特-青州 ±800 千伏特高压直流工程启动带电》.

North, D. C. (1990). *Institutions, Institutional Change and Economic Performance*. Cambridge University Press.

North China ERO (2016a). North China Grid Inner Mongolia Multi-Lateral Electricity Trading Large Consumer Eligibility and Management Measures. National Energy Administration North China Office. 《华北区域电力市场内蒙古电力多边交易市场主体准入和管理办法》.

North China ERO (2016b). North China Grid Inner Mongolia Multi-Lateral Electricity Trading Market Operation Guidines (2016 Revision). National Energy Administration North China Office. 《华北区域电力市场内蒙古电力多边交易市场运营规则（2016 修订版）》.

North China SERC (2010). North China Grid Inner Mongolia Multi-Lateral Electricity Trading Large Consumer Eligibility and Management Measures. State Electricity Regulatory Commission. 《华北区域电力市场内蒙古电力多边交易市场方案大用户准入及管理办法》.

Northeast Electricity Exchange (2016). Notice Regarding Commencing 2016h2 Northeast Excess Wind Electricity Uni-Lateral Exports to North China Grid. Northeast China Electricity Exchange Center. 《关于开展 2016 年上半年东北电网富余风电送华北单边电量交易的通知》.

Northeast ERO (2015). Measures for Northeast Coal Power Exports to North Grid (Provisional). Northeast China Energy Regulatory Office. 《东北电网富余风电送华北电量交易组织暂行办法》.

Northeast ERO (2016). Operating Measures for Northeast Electricity Ancillary Services Market (Provisional). Northeast Energy Regulatory Office. 《东北电力辅助服务市场运营规则（试行）》.

Northeast SERC (2013). Temporary Measures for Northeast Excess Wind Electricity Exports to North Grid. State Electricity Regulatory Commission Northeast Office. 《东北电网富余风电送华北电量交易组织暂行办法》.

Northwest Grid (2015). 2014q4 Northwest Grid-Generator Joint Meeting Materials. State Grid. 《2014 年四季度西北电网厂网联席会议信息发布材料》.

NPC (2009). Renewable Energy Law of the People's Republic of China (Amended). China's National People's Congress.

NREL (2017). Solar Power Data for Integration Studies. National Renewable Energy Laboratory.

Ofgem (2014). Electricity Balancing Significant Code Review: Final Policy Decision. Office of Gas and Electricity Markets.

Oi, J. C. (1992). Fiscal reform and the economic foundations of local state corporatism in China. *World Politics*, 45(01):99–126.

Oi, J. C. (1999). *Rural China takes off : institutional foundations of economic reform*. University of California Press, Berkeley.

Oi, J. C. and Walder, A. G. (1999). *Property Rights and Economic Reform in China*. Stanford University Press.

Olivier, J., Schure, K., and Peters, J. (2017). Trends in Global CO2 and Total Greenhouse Gas Emissions: 2017 Report. PBL Netherlands Environmental Assessment Agency.

O'Neill, R., Helman, U., Hobbs, B., and Baldick, R. (2006). Independent System Operators in the USA: History, Lessons Learned and Prospects. In Sioshansi, F. P. and Pfaffenberger, W., editors, *Electricity Market Reform: An International Perspective*. Elsevier, Amsterdam.

Ostrowski, J., Anjos, M. F., and Vannelli, A. (2012). Tight Mixed Integer Linear Programming Formulations for the Unit Commitment Problem. *IEEE Transactions on Power Systems*, 27(1):39–46.

Padhy, N. (2004). Unit Commitment: A Bibliographical Survey. *IEEE Transactions on Power Systems*, 19(2):1196–1205.

Paine, J. (2015). Set-Theoretic Comparative Methods: Less Distinctive Than Claimed. Social Science Research Network.

Palmintier, B. and Webster, M. (2014). Heterogeneous Unit Clustering for Efficient Operational Flexibility Modeling. *IEEE Transactions on Power Systems*, 29(3):1089–1098.

Palmintier, B. S. and Webster, M. D. (2013). Heterogeneous Unit Clustering for Efficient Operational Flexibility Modeling for Strategic Models. ESD Working Paper ESD-WP-2013-04, Massachusetts Institute of Technology.

Pang, C. (2017). Innovating Sending Western Electricity East Market Mechanisms, Southern Grid Realizes First "Hydro-Coal Exchange". Retrieved from `http://news.hexun.com/2017-09-19/190913806.html`. 《创新西电东送市场化交易机制南方电网首次实现“水火置换”》.

Pang, T. and Duan, M. (2016). Cap setting and allowance allocation in China's emissions trading pilot programmes: special issues and innovative solutions. *Climate Policy*, 16(7):815–835.

Papavasiliou, A., Oren, S., and O'Neill, R. (2011). Reserve Requirements for Wind Power Integration: A Scenario-Based Stochastic Programming Framework. *IEEE Transactions on Power Systems*, 26(4):2197–2206.

Pearson, M. M. (2005). The Business of Governing Business in China: Institutions and Norms of the Emerging Regulatory State. *World Politics*, (2):296.

Pearson, M. M. (2007). Governing the Chinese Economy: Regulatory Reform in the Service of the State. *Public Administration Review*, 67(4):718–730.

Pearson, M. M. (2015). State-Owned Business and Party-State Regulation in China's Modern Political Economy. In Naughton, B. and Tsai, K. S., editors, *State Capitalism, Institutional Adaptation, and the Chinese Miracle*, Comparative Perspectives in Business History, pages 27–45. Cambridge University Press.

Pfenninger, S., DeCarolis, J., Hirth, L., Quoilin, S., and Staffell, I. (2017). The importance of open data and software: Is energy research lagging behind? *Energy Policy*, 101:211–215.

PJM (2010). A Survey of Transmission Cost Allocation Issues, Methods and Practices. Technical Report Docket No. ER05-121-006, Federal Energy Regulatory Commission.

Pollitt, M. G. and Anaya, K. L. (2016). Can current electricity markets cope with high shares of renewables? A comparison of approaches in Germany, the UK and the State of New York. *The Energy Journal*, 37(01).

Pollitt, M. G., Yang, C.-H., and Chen, H. (2017). Reforming the Chinese Electricity Supply Sector: Lessons from International Experience. Technical report, University of Cambridge.

Pérez-Arriaga, J. I. (2013). Preface. In Pérez-Arriaga, J. I., editor, *Regulation of the Power Sector*. Springer, London.

Pérez-Arriaga, J. I. and Meseguer, C. (1997). Wholesale marginal prices in competitive generation markets. *IEEE Transactions on Power Systems*, 12(2):710–717.

Qianzhan (2017). 2016 Direct Electricity Exchanges Nearly 800 bn kWh, Bilateral Negotiations and Centralized Auctions Primary Methods. Qianzhan Industry Research. 《2016 年电力直接交易量接近 8000 亿千瓦时双边协商和集中竞价成为主要形式》.

Ramos, A., Cerisola, S., and Latorre, J. M. (2010). A Decision Support System for Generation Planning and Operation in Electricity Markets. In *Handbook of Power Systems Ii*, pages 315–335.

Rawski, T. G. (1995). Implications of China's Reform Experience. *The China Quarterly*, (144):1150.

Roland, G. (2002). The Political Economy of Transition. *The Journal of Economic Perspectives*, 16(1):29–50.

Rong, A. Y., Hakonen, H., and Lahdelma, R. (2006). An efficient linear model and optimisation algorithm for multi-site combined heat and power production. *European Journal of Operational Research*, 168(2).

Rothleder, M. (2010). Unit Commitment at the CAISO. California Independent System Operator.

Rubin, H. and Rubin, I. (2005). *Qualitative Interviewing: The Art of Hearing Data*. SAGE Publications.

Ruiz, C., Conejo, A. J., Fuller, J. D., Gabriel, S. A., and Hobbs, B. F. (2013). A tutorial review of complementarity models for decision-making in energy markets. *EURO Journal on Decision Processes*, 2(1-2):91–120.

Sauvage, J. and Bahar, H. (2013). Cross-Border Trade in Electricity and the Development of Renewables-Based Electric Power: Lessons from Europe. OECD Trade and Environment Working Papers 2013/02.

SCEO (2015). Intersection: Gansu Bilateral Contracts Difficulties. *Southern China Energy Observer*. 《十字路口：甘肃直购电难局》.

Schreifels, J. J., Fu, Y., and Wilson, E. J. (2012). Sulfur dioxide control in China: policy evolution during the 10th and 11th Five-year Plans and lessons for the future. *Energy Policy*, 48:779–789.

Schrijver, A. (2005). On the history of combinatorial optimization (till 1960). *Handbooks in operations research and management science*, 12:1–68.

Schurmann, F. (1968). *Ideology and organization in Communist China*. Berkeley, University of California Press.

Schweppe, F. C., Caramanis, M. C., Tabors, R. D., and Bohn, R. E. (1988). *Spot Pricing of Electricity*. The Kluwer International Series in Engineering and Computer Science, Power Electronics & Power Systems. Springer, Boston, MA.

Seawright, J. (2016). *Multi-method social science: Combining qualitative and quantitative tools*. Cambridge University Press.

Sen, A., Nepal, R., and Jamasb, T. (2018). Have Model, Will Reform: Assessing the Outcomes of Electricity Reforms in Non-OECD Asia. *The Energy Journal*, 39(4):181–209.

SERC (2003a). Temporary Implementing Measures of the Northeast Regional Electricity Market. State Electricity Regulatory Commission. 《东北区域电力市场实施方案（暂行)》.

SERC (2003b). Temporary Measures for Transparent, Fair, and Just Electricity Dispatch. State Electricity Regulatory Commission. 《关于促进电力调度公开、公平、公正的暂行办法》.

SERC (2006). Temporary Measures for Ancillary Services Management for Interconnected Generators. State Electricity Regulatory Commission. 《并网发电厂辅助服务管理暂行办法》(电监市场 [2006]43 号).

SERC (2007). Regulatory Measures for Grid Company Full Purchase of Renewable Electricity. State Electricity Regulatory Commission. 电网企业全额收购可再生能源电量监管办法（电监会令第 25 号）.

SERC (2009). Basic Guidelines for Electricity Consumers and Generator Direct Exchange Pilots (Provisional). State Electricity Regulatory Commission. 《电力用户与发电企业直接交易试点基本规则（试行)》.

SERC (2011a). 2010 Annual Electricity Regulation Report. State Electricity Regulatory Commission. 《电力监管年度报告（2010)》.

SERC (2011b). National Electricity Exchange and Market Operations Supervision Report. State Electricity Regulatory Commission. 《全国电力交易与市场秩序监管报告》.

SERC (2013). Daily Electricity Consumption by Province. CEIC Data.

SERC, N. C. (2010). North China Grid Inner Mongolia Multi-Lateral Electricity Trading Market Plan. State Electricity Regulatory Commission. 《华北区域电力市场内蒙古电力多边交易市场方案》.

SERC, N. C. (2013). Western Inner Mongolia Off-Peak Excess Wind Electricity Exchanges Remarkably Successful. Retrieved from `http://www.cpnn.com.cn/dljg/201302/t20130220_558185.html`. 《蒙西电网低谷富余风电消纳交易成效显著》.

Shih, V., Adolph, C., and Liu, M. (2012). Getting Ahead in the Communist Party: Explaining the Advancement of Central Committee Members in China. *American Political Science Review*, 106(01):166–187.

Shortt, A., Kiviluoma, J., and O'Malley, M. (2013). Accommodating variability in generation planning. *IEEE Transactions on Power Systems*, 28(1):158–169.

Siemens (2012). Fact sheet: High-voltage direct current transmission (HVDC). Siemens.

Sioshansi, F. P., editor (2013). *Evolution of Global Electricity Markets: New paradigms, new challenges, new approaches*. Academic Press.

Sioshansi, F. P. and Pfaffenberger, W., editors (2006). *Electricity market reform: an international perspective*. Elsevier, Amsterdam.

Sioshansi, R., O'Neill, R., and Oren, S. (2008a). Economic Consequences of Alternative Solution Methods for Centralized Unit Commitment in Day-Ahead Electricity Markets. *IEEE Transactions on Power Systems*, 23(2):344–352.

Sioshansi, R., Oren, S. S., and O'Neill, R. P. (2008b). The Cost of Anarchy in Self-Commitment-Based Electricity Markets. In Sioshansi, F. P., editor, *Competitive electricity markets : design, implementation, performance*. Elsevier, Amsterdam.

Sohu.com (2017). Three Agencies: How Are the Nine Coal Power Bases Coming Along? Retrieved from `http://www.sohu.com/a/169589348_651522`. 《三部委：9 大煤电基地如今怎样了?》.

St. Clair, H. P. (1953). Practical concepts in capability and performance of transmission lines. *Transactions of the American Institute of Electrical Engineers*.

State Council (1985). Notice Regarding Provisional Guidelines for Encouraging Electricity Investment and Implementing Multiple Electricity Tariffs. 《国家经济委员会、国家计划委员会、水利电力部、国家物价局关于鼓励集资办电和实行多种电价的暂行规定的通知》.

State Council (1988). Notice Regarding Electricity Industry Management Reform Plan. State Council. 《国务院关于印发电力工业管理体制改革方案的通知》.

State Council (1998). Opinion Regarding Issues Deepening Electricity Sector Reform (No. 146). State Council. 《关于深化电力工业体制改革有关问题意见》.

State Council (2002). Electricity Sector Reform Plan. State Council. 《电力体制改革方案》.

State Council (2013). Action Plan on Prevention and Control of Air Pollution. State Council. 《大气污染防治行动计划》.

State Council (2014). Energy Development Strategy Action Plan (2014-2020). State Council. 《能源发展战略行动计划（2014-2020 年)》.

State Council (2015). Opinion Regarding Deepening Electricity Sector Reform. State Council. 《中共中央国务院关于进一步深化电力体制改革的若干意见》.

State Grid (2012a). 2011 Power Exchange Report. State Grid. 《国家电网公司 2011 年电力市场交易年报》.

State Grid (2012b). *State Grid 2012 Yearbook*. China Electric Power Press, Beijing.

State Grid Qinghai (2015). 2015q1 Qinghai Electricity Market Information Report. State Grid. 《国网青海电力公司 2015 年第一季度电力市场交易信息》.

State Grid Shaanxi (2015). Shaanxi 2014 Electricity Exchange Annual Report. State Grid. 《陕西电力公司 2014 年电力交易年报》.

Stavins, R. N. (2008). A Meaningful US Cap-and-Trade System to Address Climate Change. *Harvard Environmental Law Review*, 32:293–371.

Steiner, F. (2000). Regulation, industry structure, and performance in the electricity supply industry. Economics Department Working Papers No.238, OECD Publishing, Paris.

Steinfeld, E. S. (1998). *Forging Reform in China: The Fate of State-owned Industry.* Cambridge University Press, Cambridge, UK.

Steinfeld, E. S. (2004). Market Visions: The Interplay of Ideas and Institutions in Chinese Financial Restructuring. *Political Studies*, 52(4):643–663.

Stoft, S. (2002). *Power system economics.* John Wiley & Sons.

Stokes, L. C. (2013). The politics of renewable energy policies: The case of feed-in tariffs in Ontario, Canada. *Energy Policy*, 56:490–500.

Sun, Y. L., Wang, Z. F., Fu, P. Q., Yang, T., Jiang, Q., Dong, H. B., Li, J., and Jia, J. J. (2013). Aerosol composition, sources and processes during wintertime in Beijing, China. *Atmos. Chem. Phys.*, 13(9):4577–4592.

Szajnfarber, Z. and Gralla, E. (2017). Qualitative methods for engineering systems: Why we need them and how to use them. *Systems Engineering*, 20(6):497–511.

Tashakkori, A. and Teddlie, C. (1998). *Mixed methodology: Combining qualitative and quantitative approaches.* SAGE Publications.

Teixeira, C., Albano, M., Skou, A., Dueñas, L. P., Antonacci, F., Ferreira, R., Lotzfeldt Pedersen, K., and Scalari, S. (2014). Convergence to the European Energy Policy in European Countries: Case Studies and Comparison. *Social Technologies*, 4(1):7–24.

Teng, F., Jotzo, F., and Wang, X. (2017). Interactions between Market Reform and a Carbon Price in China's Power Sector. *Economics of Energy & Environmental Policy*, 6(2).

The World Bank (2017). China - Overview. Retrieved from `http://www.worldbank.org/en/country/china/overview`.

The World Bank and DRC (2013). *China 2030: Building a Modern, Harmonious, and Creative Society.* The World Bank and State Council Development Research Center.

Tong, J., Zhang, X., Ren, J., Tang, Y., Xu, X., Jiang, X., and Li, N. (2011). Energy-Efficient Dispatch Implementation Analysis and Policy Recommendations. Technical report, Energy Foundation.

Trussart, S., Messier, D., Roquet, V., and Aki, S. (2002). Hydropower projects: a review of most effective mitigation measures. *Energy Policy*, 30(14):1251–1259.

Tsai, C.-M. (2011). The Reform Paradox and Regulatory Dilemma in China's Electricity Industry. *Asian Survey*, 51(3):520–539.

Tuffner, F. K. and Kintner-Meyer, M. C. (2011). *Using electric vehicles to meet balancing requirements associated with wind power*. Pacific Northwest National Laboratory.

Van der Heijden, J. (2011). Institutional layering: A review of the use of the concept. *Politics*, 31(1):9–18.

Varley, C. (2006). China's power sector reforms: where to next? Technical report, OECD Publishing.

Ventosa, M., Linares, P., and Pérez-Arriaga, J. I. (2013). Power System Economics. In Pérez-Arriaga, I. J., editor, *Regulation of the Power Sector*, pages 47–124. Springer, London.

Wang, L. (2016). Another Milestone in New Electricity Reforms: First Regional Electricity Market Begins. Economic Information Daily. Retrieved from `http://energy.people.com.cn/n1/2016/0801/c71661-28599616.html`. 《新电改再下一城首个区域电力市场启动》.

Wang, Q. and Chen, X. (2012). China's electricity market-oriented reform: From an absolute to a relative monopoly. *Energy Policy*, 51:143–148.

Weber, M. (1947). *The Theory of Social and Economic Organizations*. Free Press, New York.

Weijde, A. H. v. d. and Hobbs, B. F. (2011). Locational-based coupling of electricity markets: benefits from coordinating unit commitment and balancing markets. *Journal of Regulatory Economics*, 39(3):223–251.

Weimers, L. (2011). Bulk power transmission at extra high voltages, a comparison between transmission lines for HVDC at voltages above 600 kV DC and 800 kV AC. ABB Power Technologies.

Weingast, B. R. (1995). The Economic Role of Political Institutions: Market-Preserving Federalism and Economic Development. *Journal of Law, Economics, & Organization*, 11(1):1–31.

Williams, J. and Ghanadan, R. (2006). Electricity reform in developing and transition countries: A reappraisal. *Energy*, 31(6-7):815–844.

Williams, J. H. and Kahrl, F. (2008). Electricity reform and sustainable development in China. *Environmental Research Letters*, 3(4):044009.

Williamson, O. (1985). *The Economic Institutions of Capitalism*. Free Press, New York.

Wirtshafter, R. M. and Shih, E. (1990). Decentralization of China's electricity sector: Is small beautiful? *World Development*, 18(4):505–512.

Wiser, R. and Bolinger, M. (2017). 2016 Wind Technologies Market Report. Technical report, U.S. Department of Energy.

Xiao, Q. (2016). Gansu Renewable Energy Purchase Safeguards Policy is Halted. China Energy News. Retrieved from `http://paper.people.com.cn/zgnyb/html/2016-08/29/content_1708657.htm`. 《甘肃新能源保障收购小时政策遭叫停》.

Xie, L., Carvalho, P., Ferreira, L., Liu, J., Krogh, B., Popli, N., and Ilic, M. (2011). Wind Integration in Power Systems: Operational Challenges and Possible Solutions. *Proceedings of the IEEE*, 99(1):214–232.

Xinhua (2017). State Council Lauds 22 Model Experiences. Retrieved from `http://news.xinhuanet.com/politics/2017-10/01/c_1121756199.htm`. 《国办通报表扬国务院第四次大督查发现的二十二项典型经验做法》.

Xu, S. and Chen, W. (2006). The reform of electricity power sector in the PR of China. *Energy Policy*, 34(16):2455–2465.

Xu, Y.-c. (2005). *Electricity Reform in China, India and Russia: The World Bank template and the politics of power*. Edward Elgar, Cheltenham.

Xu, Y.-c. (2016). *Sinews of Power: The Politics of the State Grid Corporation of China*. Oxford University Press, Oxford.

Xu, Y.-c. (2017). China’s Giant State-Owned Enterprises as Policy Advocates: The Case of the State Grid Corporation of China. *The China Journal*, 79:21–39.

Yang, Z. and Tang, G. (2011). A Generation Scheduling Optimization Model Suitable to Complete Period and Variable Intervals and Conforming to Principles of Openness, Equity and Justness. *Power System Technology*, 35(2). 《全周期变时段“三公”调度发电计划优化模型》.

Yeh, E. T. and Lewis, J. I. (2004). State Power and the Logic of Reform in China's Electricity Sector. *Pacific Affairs*, (3):437.

YN IIC (2016). Implementiation Plan for 2016 Yunnan Electricity Market Exchanges. Yunnan Provincial Industry and Informatization Commission. 《2016 年云南电力市场化交易实施方案》.

YN IIC (2017). Implementiation Plan for 2017 Yunnan Electricity Market Exchanges. Yunnan Provincial Industry and Informatization Commission. 《2017 年云南电力市场化交易实施方案》.

Yuan, J., Li, P., Wang, Y., Liu, Q., Shen, X., Zhang, K., and Dong, L. (2016). Coal power overcapacity and investment bubble in China during 2015–2020. *Energy Policy*, 97:136–144.

Yunnan Committee, editor (2015). *2015 Yunnan Electric Power Yearbook*. Yunnan Electric Power Yearbook Ediorial Committee. Yunnan People's Press. 《云南电力年鉴 2015》.

Yunnan Government (2016). Pilot Plan Deepening Yunnan's Electricity Sector Reforms. 《云南省进一步深化电力体制改革试点方案》.

Yunos, J. M. and Hawdon, D. (1997). The efficiency of the national electricity board in Malaysia: An intercountry comparison using DEA. *Energy Economics*, 19(2):255–269.

Zeng, M., Peng, L., Fan, Q., and Zhang, Y. (2016). Trans-regional electricity transmission in China: Status, issues and strategies. *Renewable and Sustainable Energy Reviews*, 66:572–583.

Zhan, X., Lo, C. W.-H., and Tang, S.-Y. (2014). Contextual Changes and Environmental Policy Implementation: A Longitudinal Study of Street-Level Bureaucrats in Guangzhou, China. *Journal of Public Administration Research and Theory*, 24(4):1005–1035.

Zhang, C. (2015). New Electricity Reforms: Analysis of New Electricity Reform Pathways. thede.cn. Retrieved from http://www.thede.cn/index.php?c=article&id=550. 《新电改系列之三：新电力体制改革路径分析预测》.

Zhang, C. and Heller, T. C. (2007). Reform of the Chinese electric power market: economics and institutions. In Victor, D. G. and Heller, T. C., editors, *The political economy of power sector reform: the experiences of five major developing countries*. Cambridge University Press, Cambridge.

Zhang, C. and Song, W. (2016). Northeast Grid Peaking Ancillary Services Market Reform Demonstration Commences. CPNN.com. Retrieved from http://www.cpnn.com.cn/dljg/201611/t20161122_936439.html. 《东北电力辅助服务市场专项改革试点工作启动》.

Zhang, L., Liu, L., Zhao, Y., Gong, S., Zhang, X., Henze, D. K., Capps, S. L., Fu, T.-M., Zhang, Q., and Wang, Y. (2015). Source attribution of particulate matter pollution over North China with the adjoint method. *Environmental Research Letters*, 10(8):084011.

Zhang, V. Y. and Chen, Y. (2011). Vertical relationships in China’s electricity industry: The quest for competition? *Utilities Policy*, 19(3):142–151.

Zhang, X. (2016). Yunnan Grid Sets New Record for Largest Generation, Largest Eastern Exports. People.cn. Retrieved from http://yn.people.com.cn/news/yunnan/n2/2016/0805/c361579-28789583.html. 《云南电网最大发电负荷、最大西电东送电力等再创新高》.

Zhang, X. and Parsons, J. E. (2008). Market power and electricity market reform in Northeast China. Technical report, MIT Center for Energy and Environmental Policy Research.

Zhang, Y.-F. and Gao, P. (2016). Integrating environmental considerations into economic regulation of China’s electricity sector. *Utilities Policy*, 38:62–71.

Zhang, Y.-F., Parker, D., and Kirkpatrick, C. (2008). Electricity sector reform in developing countries: an econometric assessment of the effects of privatization, competition and regulation. *Journal of Regulatory Economics*, 33(2):159–178.

Zhang, Z. (2017). Western Inner Mongolia's Renewable Energy Integration Experience. China Energy News. Retrieved from http://guangfu.bjx.com.cn/news/20170720/838433.shtml. 《新能源消纳的“蒙西经验”》.

Zhao, X., Wang, F., and Wang, M. (2012a). Large-scale utilization of wind power in China: Obstacles of conflict between market and planning. *Energy Policy*, 48:222–232.

Zhao, X., Zhang, S., Yang, R., and Wang, M. (2012b). Constraints on the effective utilization of wind power in China: An illustration from the northeast China grid. *Renewable and Sustainable Energy Reviews*, 16(7):4508–4514.

Zhao, X., Zhang, S., Zou, Y., and Yao, J. (2013). To what extent does wind power deployment affect vested interests? A case study of the Northeast China Grid. *Energy Policy*, 63:814–822.

Zhao, X., Zhang, X., Xu, X., Xu, J., Meng, W., and Pu, W. (2009). Seasonal and diurnal variations of ambient PM2.5 concentration in urban and rural environments in Beijing. *Atmospheric Environment*, 43(18):2893–2900.

Zheng, Q., Wang, J., and Liu, A. (2015). Stochastic Optimization for Unit Commitment–A Review. *IEEE Transactions on Power Systems*, 30(4):1913–1924.

Zhong, H., Xia, Q., Chen, Y., and Kang, C. (2015). Energy-saving generation dispatch toward a sustainable electric power industry in China. *Energy Policy*, 83:14–25.

Zysman, J. (1994). How institutions create historically rooted trajectories of growth. *Industrial and corporate change*, 3(1):243–283.