Regulatory and Technical Barriers to Wind Energy Integration in Northeast China

by

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Abstract

China leads the world in installed wind capacity, which forms an integral part of its long-term goals to reduce the environmental impacts of the electricity sector. This primarily centrally-managed wind policy has concentrated wind development in a handful of regions, challenging regulatory frameworks and grid architectures to cost-effectively integrate wind. In 2013, according to official statistics, wind accounted for 2.7% of national generation, while the rate of curtailment (available wind not accepted by the grid operator onto the system) reached 12%.

Wind integration challenges have arisen in China for technical, economic and institutional reasons. From a technology standpoint, the variability and unpredictability of wind resources interact with technical limits of conventional generators, resulting in efficiency losses and grid stability concerns. Existing coal-based electricity and district heating installations play a large role in grid integration challenges because of the inflexible operation of coal plants relative to natural gas and hydropower, and the "must-run" nature of cogeneration units supplying residential heat. A competing set of hypotheses to explain current rates of wind spillage focus on institutional imperfections in China's power sector, such as poorly designed market incentives, inadequate oversight, and a mixture of conflicting policies that are the result of an incomplete transition to a market-driven electricity system.

A unit commitment and dispatch optimization was developed to understand the underlying technical factors leading to wind curtailment in northeastern China. It incorporates electricity output restrictions from exogenous district heating demands, a hydro-thermal coordination component considering inter-seasonal storage, and transmission between adjacent provincial nodes. Averaging over six historic wind profiles, a curtailment rate of 6.6% was observed in the reference case from various forms of inflexibility and insufficient demand. The impacts of several technology-based solutions on total cost, coal use and wind curtailment, were also examined: more flexible operation of coal units, temporary heat storage and minimum cogeneration outputs that vary with heat load.

Contributing to the existing body of qualitative work on the effects of these factors, this thesis developed a straightforward methodology to assess the relative contribution of regulatory and technical causes. Two important institutional arrangements – the decentralization of dispatch to individual provinces and minimum generation quotas allocated to all coal generators – were quantified in an optimization framework, and found to be significant contributors of power system operational inflexibility.

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Analyzing the drivers of wind integration challenges must draw on multiple disciplines, and I have been fortunate in developing this thesis to have many thoughtful mentors to help guide me through the process.

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Of course, this thesis is aimed at understanding wind energy and grid operation in China. I am therefore grateful to the grid operators and researchers in Beijing and northeast China who have provided invaluable guidance to me on operational aspects of China's power system.

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Chapter 1

Introduction

China's electricity generation has grown 180% over the decade 2003-2013 [1], met largely by a reliance on coal, which accounts for 80% of all power generation. The associated environmental, health and climate impacts of China's coal use are of key concern to research communities as well as Chinese policy-makers. The International Energy Agency has indicated the need for an 88% reduction in GHG emissions from coal-fired electricity in China by 2035, compared to business as usual, in order to meet a 450ppm climate stabilization scenario [2].

To reduce the environmental impacts of the energy sector, mitigate climate change, and promote domestic industry, the central government has prioritized renewable energy deployment. In addition to hydropower, which has long benefited from central government support, China has in recent years experimented with several policy instruments to encourage the deployment of other forms of renewable energy, and in particular, wind power. China's *Renewable Energy Law of 2006* and subsequent regulations instituted regional feed-in tariffs (FITs), tax relief, direct subsidies, and mandatory connection requirements for wind projects [3]. By the end of 2013, China's wind installations reached 77 GW, the world's largest, and wind generated 137 Terawatt-hours (TWh) annually, second to the U.S. [4]. By 2020, the current official government target is 200 Gigawatts (GW) of capacity and 390 TWh of annual wind generation [5].

Integrating wind electricity into China's power grid is a well-documented challenge: in 2012, while wind contributed only 2% of total electricity supply, around 20 TWh (or 17%) of wind-generated electricity was curtailed by the grid operator [6, 7], equivalent to burning 9 million additional tons of coal. Curtailment occurs when available wind turbines are prevented from supplying the grid. While official statistics are aggregated at the provincial level, the Chinese Wind Energy Association noted that in some areas up to 40–50% of wind was curtailed [8]. In 2013, official statistics note that curtailment was reduced to 11% nationally [4], likely the result of increased central government pressure on local grids to accommodate wind as well as increased integration space from rebounding electricity consumption growth. Nevertheless, curtailment in select provinces still reached 20% (see Figure 1.1).

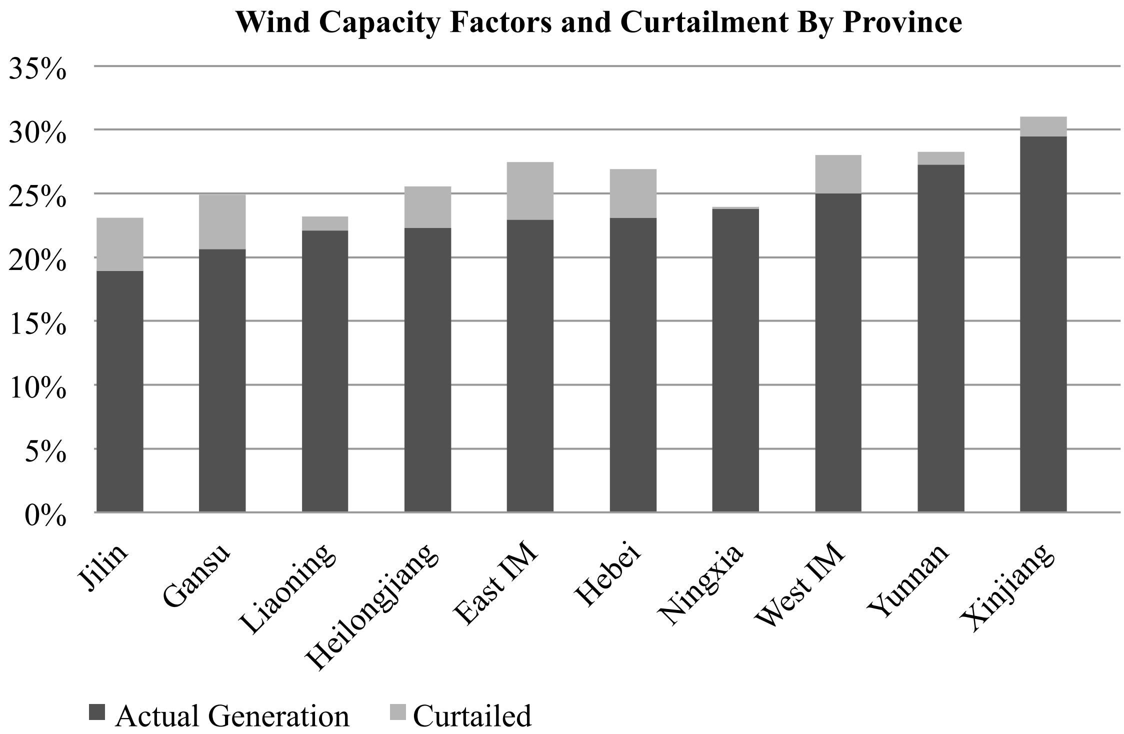

Figure 1.1 Wind generation and estimated curtailment for select provinces in 2013. IM = Inner Mongolia. Source: [9].

Wind curtailment has arisen in China for technical, economic and institutional reasons. From a technology standpoint, the variability and unpredictability of wind resources interact with technical limits of conventional generators, resulting in efficiency losses and grid stability concerns. Existing coal-based electricity and district heating installations play a large role in grid integration challenges because of the inflexible operation of coal plants relative to natural gas and hydropower (see Chapter 2). Insufficient demand when wind electricity is being generated couples these various inflexibilities and can lead to available wind generators not being dispatched by the system operator. A competing set of hypotheses to explain current rates of wind spillage include poorly designed market incentives, concentration of firms, and inadequate oversight, largely the result of an incomplete transition to a market-driven electricity system (see Chapter 3).

In general, policies have rewarded wind facility construction, creating only weak incentives to consider wind characteristics and grid architecture at the construction location. At the end of 2013, roughly 17% of wind capacity was not yet connected to the grid (not shown in Figure 1.1) [4, 10]. The concentration of wind power will likely continue: nine areas have been designated "10-gigawatt wind power bases" by the National Energy Administration (NEA), which are expected to account for 79 GW of wind capacity by 2015 [5]. Except for one in centrally-located Jiangsu, these bases are in three northern grids – Northeast, North and Northwest – mostly distant from electricity demand centers. To address this imbalance, State Grid and Southern Grid are embarking on massive transmission expansions, sometimes stretching several thousand kilometers [11].

This thesis focuses on the Northeast Grid, consisting of Heilongjiang, Jilin and Liaoning provinces, and eastern Inner Mongolia Autonomous Region. The Northeast Grid accounted for 27% of grid-connected wind power capacity and wind generation in 2013, and was home to 41% of China's total wind curtailment [9]. Typical of other large wind centers in the north, the Northeast Grid is a highly inflexible grid, as measured by its ability to respond to changes in demand and variable supply over different time scales, with 75% coal by capacity and limited hydropower.

The Northeast Grid is additionally inflexible to wind integration due to the types of coal-fired generating units in use: during its cold winters, the several large population centers in the Northeast are equipped with coal boilers constructed or retrofitted as combined heat and power (CHP) plants. These plants face additional operating constraints to satisfy demand on local district heating grids, decreasing the space for wind integration (see Chapter 2). CHP plants are also typically smaller, with one technology limited to 50 Megawatts (MW) or less per unit, which inhibits the replacement of older and less efficient units with potentially more flexible, larger units.

In this thesis, I investigate the various causal mechanisms of wind integration challenges in the Northeast Grid, focusing on two important interaction effects: the electricity/heat co-dispatch problem, and the institutional imperfections from an incomplete market transition. No research known to the author has attempted to model the specific effects on wind integration of CHP and other operational constraints over a suitably large area in China, in this case the entire grid region. In particular, minimum outputs, maximum ramp rates and extended startup/shutdown times of coal-fired power plants can have a large impact on wind integration potential, with additional complexities for CHP units. Incorporating these additional constraints gives a more precise view of the daily activities of Northeast Grid operators and more accurate estimates of the effectiveness of various proposed policies to address wind integration.

To address these constraints, I develop a "unit commitment" power systems optimization model incorporating operational constraints of generation technologies and the basic grid operator functions of committing units to determine the optimal power dispatch minimizing cost. Going beyond the existing literature, I use a plant-level database of CHP and electricity-only generators to approximate dispatch constraints arising from district heating loads, and reconstruct an estimated optimal wind curtailment given the existing generation mix. Due to data availability on plant-level capacities, I use 2011 as the model benchmark year (2010 year end capacity data). I incorporate a computationally-inexpensive hydro-thermal coordination allowing for inter-seasonal storage.

Institutionally, China's power system is the product of decades of reforms designed to ease away from government-managed vertically-integrated utilities toward a more market-driven industry. These changes have included allowing private and foreign investment in generation assets, separating grid and generation functions, and several experiments to create competitive wholesale electricity markets. Taking place in the context of broader economic reforms, in particular the reshuffling of state-owned enterprises in the late 1990s, researchers have often analyzed the power sector reforms as another example of industrial reorganization. This lens, however, typically ignores important physical and economic constraints to power sector operation, which restrict the available regulatory options and create a host of complex interactions among political actors.

Beginning with policies and formal grid operation directives, I catalogue incentives currently in place for power generation and grid companies and assess their level of implementation from literature. Institutions from the pre-reform period, such as centralized tariff-setting, interact with newer reforms, such as providing market access to independent power producers, to create opaque and overlapping regulatory frameworks for new sources of energy such as wind power. These varied policies impact wind integration directly through the dispatch order, which is the decision by power system operators of which power plants to call on to generate in a given time period. They also impact investment decisions, changing the structure of generation and network assets, which is outside the scope of this thesis.

These particular regulatory factors influence wind integration in non-trivial ways, and no research known to the author has attempted to include these interactions in a quantitative study of wind curtailment in China. Within the traditional unit commitment problem, I reformulate these regulatory interactions as additional sets of constraints. I compare these to an optimal case where there is a single cost-minimizing grid operator subject to the proposed technical and economic causes of wind curtailment. Together, these two steps systematically address the complexities of introducing wind power into an inflexible power system.

This thesis divides the background and literature review into two parts: Chapter 2 introduces the operation of a power system under high wind penetration and the relevant constraints of different generation technologies, while Chapter 3 outlines the basic regulatory structures adopted by China in the context of approaches globally to introduce power markets. The next two chapters construct the model, beginning with the unit commitment formulation in Chapter 4, and the various sources of data needed as inputs to the model in Chapter 5. Results are shown in Chapter 6, and analysis is left to Chapter 7. The thesis concludes with a short discussion in Chapter 8.

Chapter 2

Power Systems Operation Under High Wind Penetration

On operational time horizons, ranging from weeks to seconds, electric power systems are heavily managed by central system operators to ensure an adequate, reliable and affordable supply of electricity. Section 2.1 introduces several types of optimization algorithms in use today, which are fine-tuned to each system based on technical characteristics and cost data of the generators, as well as their locations relative to the transmission network and loads (consumers). Traditional uncertainties, such as those introduced by generator unavailability and load variability, are well-known and managed by incorporating additional flexible generation options.

Wind power variability (predictable, unmanageable variations in output) and uncertainty (inaccuracies in wind power forecasts) present new challenges for system operators. For example, wind power forecast errors are generally larger than load forecast errors, and observed ramping induced by large penetrations of wind can exceed current flexibility requirements for grid operation. Section 2.2 discusses these new considerations for grid operators.

Wind power integration challenges are intensified with increasing inflexibility of the remaining generation mix, complicating assessment of causal linkages as well as proper allocation of the integration cost burden. In Section 2.3, a definition of flexibility in power systems is presented and applied to the Northeast China power grid, including its relatively inflexible generation mix. Finally, Section 2.4 outlines current best practice of analyzing operational impacts of wind power integration comparing relevant studies in the US and EU to China.

2.1 Fundamentals of Power System Operation

Electricity is stored in an electromagnetic field traveling outside of conducting wires at near the speed of light. Across distances relevant for power systems, there is thus no time lag between generation and consumption of electricity. Electricity storage technologies, which consume and regenerate electricity at controllable intervals with losses, can alter this requirement but, due to their cost and physical constraints, are limited in size and location. Hence, the most crucial task of the system operator is to instantaneously equate supply and demand.

The system operator uses an economic dispatch model to minimize total cost for a series of time periods, typically 15-minutes to one-hour each, creating a schedule of amount and duration of electricity supply from each generator. The efficiency of a generator may depend on its output, introducing a quadratic term in the objective function, which may be neglected or assumed piece-wise constant to enhance computational tractability.

In addition, electricity generating technologies place a number of constraints on efficient system operation arising from the mechanics of their energy conversion processes, in particular in terms of their hour-to-hour changes. For conventional thermal generators (e.g., coal, natural gas, nuclear), these include foremost maximum ramping rates, associated costs of ramping, minimum stable generation outputs, minimum shutdown and startup times, and costs of shutdown and startup. The strong influence of shutdown/startup constraints and minimum stable outputs on feasible generation schedules requires the system operator to create a complementary schedule of the time and expected duration of each unit's "commitment" status. A **unit commitment (UC)** model, typically run at least 12 hours in advance for a 36-hour or longer period, minimizes the total cost of unit startups and dispatch, and is the focus of this thesis.

Diurnal and seasonal variability of load, which is projected from historical data and weather forecasts, is incorporated in the combined commitment and dispatch schedule. Due to uncertainties in exact load, a number of standby generators able to turn on/off or flexibly ramp up/down are included in the optimization as "reserves". In real-world applications, contingencies of failures of the largest lines and generators of optimal power flow models are commonly added to the optimization, called a security-constrained unit commitment model.

2.2 Additional Demands on Power System Operation from Wind

Wind integration challenges arise from the variability and unpredictability of wind resources interacting with the electricity demand profile as well as technical constraints and performance criteria of conventional generators. A common cause of poor wind utilization is insufficient demand when wind electricity is being generated. Frequent ramping and startup requirements of thermal generators may also result in efficiency losses for these plants as they run up against technical limits in their operation. An option available to mitigate this is to procure greater reserves able to flexibly respond to changes in net load [12]. As system operators are concerned with both reliability and cost, there are trade-offs in how the system is operated.

Renewable resources such as wind, solar and run-of-the-river hydropower, due to their diurnal and seasonal variability as well as short-term unpredictability, create new complications for the above operational models. System operators may simplify predicted supply variability by subtracting it from load to create a **net load curve**. The variation in supply, however, may be much larger than load variability, creating steeper and more frequent ramp requirements (see Figure). This complicates commitment schedules by requiring large changes in power output on time scales potentially shorter than startup/shutdown times. In addition, when renewable resources are generating at or near full capacity, they may push the net load curve below the minimum operating thresholds of scheduled base load generation.

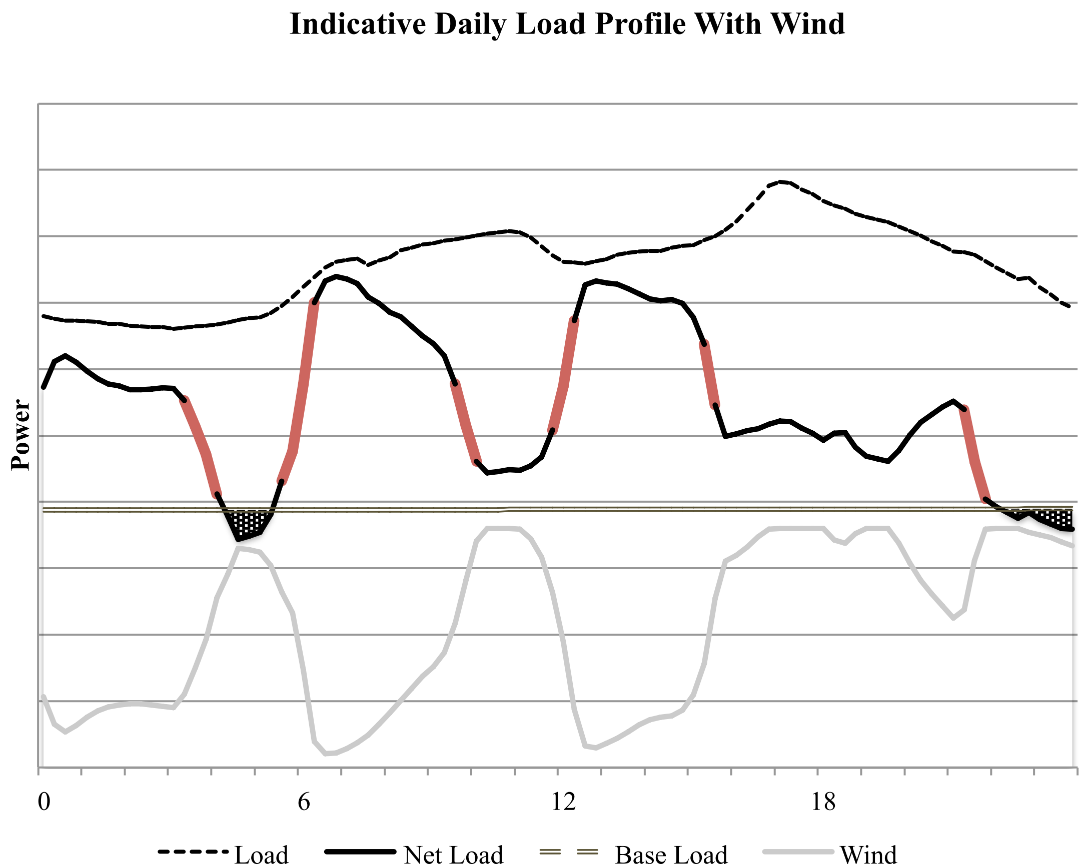

Figure 2.1 – An example daily load profile, indicating key impacts on net load from high penetration of wind: ramping events (thick red lines) and low operating thresholds (shaded)

Wind power forecasts on scales of minutes to days rely on numerical weather prediction models and statistical tools, which can entail significant uncertainty and are highly location-dependent. In addition, as wind power output is roughly proportional to the cube of wind speed, errors are magnified when translating from geophysical quantities to electricity production. In this manner, wind power forecast errors are larger than load forecast errors: for example, day-ahead wind forecasts may deviate from actual production by up to 20% [13]. System operators will need to schedule greater reserves and other flexibility measures to ensure reliable operation with wind.

2.3 Flexibilities of a Power System and Generating Technologies

Operational flexibility is arguably the most important quality of the power system with respect to wind integration. A useful definition for this context:

> *The term flexibility describes the ability of a power system to cope with variability and uncertainty in both generation and demand, while maintaining a satisfactory level of reliability at a reasonable cost, over different time horizons. [14]*

A typical result of wind integration studies is the “cost” of balancing wind, in terms of additional costs of reserves or dispatching more costly flexible generation. This calculation is a straightforward simulation result, but it neglects the complementary burden placed on the system by incumbent generators with strict operational constraints, such as steam-based plants.

Instead, as this definition suggests, flexibility is a system-level property, drawing on multiple components with complex interactions and over several time horizons. Thus, there is a need for better methods to understand these interactions and attribute costs for system inflexibility correctly. Instead of accruing all costs to additional wind, each generator type should be examined for its specific effects on system-wide operation, and possible contribution to wind curtailment.

2.3.1 Coal-fired power generation

In the case of coal-fired power generation, startup procedures to raise water vapor from ambient to saturated temperatures and pressures can take several hours or longer depending on boiler type. Similarly, cooling the boiler requires a proper shutdown sequence that engages a controlled lowering of output [15]. These thermodynamic considerations, known as **cycling**, give rise to minimum startup times – from cold-start to generation at minimum output – and shutdown times – from minimum generation to off and cooled sufficiently to startup.

Cycling also entails additional costs, in particular: maintenance costs increase and expected equipment lifetime may decrease from fatigue on components by repeated thermal expansion. Additionally, expensive fuel (such as oil) is typically injected to pre-heat the boiler and there are efficiency penalties when raising output [16, 17]. These collectively form the startup costs, and may be used as inputs in the UC model when minimizing cost of a commitment and dispatch schedule.

Changing output while operating, also called **ramping**, faces thermodynamic and cost considerations, and is generally limited to 1.5%-3.0% of capacity per hour [16]. Higher rates may be possible, entailing additional maintenance costs. Within the technical output limits, coal plant efficiencies (the inverse of which is known as the **heat rate**) also vary, on the order of 10%. Finally, all thermal boilers have **minimum stable generation outputs** related to the throughput and temperatures needed to maintain stable combustion. For coal-fired boilers, these are in the range 30-40% [17].

Unit size and technology type diversity are particularly important in China where significant new coal builds have taken place in the last decade. Supercritical units, mostly 600 MW and larger, have steam temperatures above 374ºC and higher efficiencies, which have led to their rapid deployment since they were first introduced in 2003 [18]. Subcritical units are more flexible, however, with respect to startup/shutdowns because of less thermal inertia and less complicated procedures [16].

2.3.2 Coal-fired combined heat and power (CHP)

Steam-based power plants, by using heat as an intermediate between primary fuel and electrical energy, lose efficiency at several stages. A thermodynamic threshold known as the Carnot efficiency caps theoretical conversion efficiency as a function of source and sink temperatures and is around 70% for advanced coal units. In addition, thermal losses in the boiler, turbine and generator may each contribute losses of 10% [19]. Several technologies exist to reuse or divert heat from the boiler and thereby increase overall energy efficiency: common applications include natural gas-fired combined-cycle plants, and combined heat and power (CHP) plants.

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 facilities through massive urban heating grids [20]. Two basic technologies are in use, which have very different flexibility impacts on the grid: extraction-condensing (typically for larger applications) and backpressure (only small applications, ≤ 50 MW).

Extraction-condensing CHP plants (or simply, extraction CHP, E-CHP) modify the functioning of an electricity-only power plant by connecting one or more valves between the boiler, generator and condenser to extract steam for direct use [15]. Since hot water is preferred to steam in the design of large residential heating grids, this extracted steam can be at a lower temperature and pressure than that required to drive a turbine, and hence may be partially considered "waste heat".

Based on the heating load and the minimum stable boiler output, feasible electricity outputs vary, determined by a system of mass and energy flow balance equations. These can become non-linear as the efficiency of the turbines depends on steam pressures, which vary in response to the extracted steam [21]. This is similar to output-dependent heat rates, where peak efficiency is only achieved at some nominal output, but which are frequently assumed to be constant for computational tractability.

A simplified graphical representation of this system of equations for a single extraction configuration is shown in Figure 2.2 and is sometimes referred to as "equivalent enthalpy drop" in the Chinese literature [22, 23]. Starting with zero extraction, one can derive minimum and maximum power outputs under pure electricity operation from the minimum and maximum stable boiler outputs. As steam is extracted, the line of feasible states shifts to the left, corresponding to a smaller fraction of the boiler steam entering the turbine. At high extractions, a minimum condenser output threshold is reached, corresponding to maintaining a low backpressure on the turbine. Minimum power output then increases with extraction.

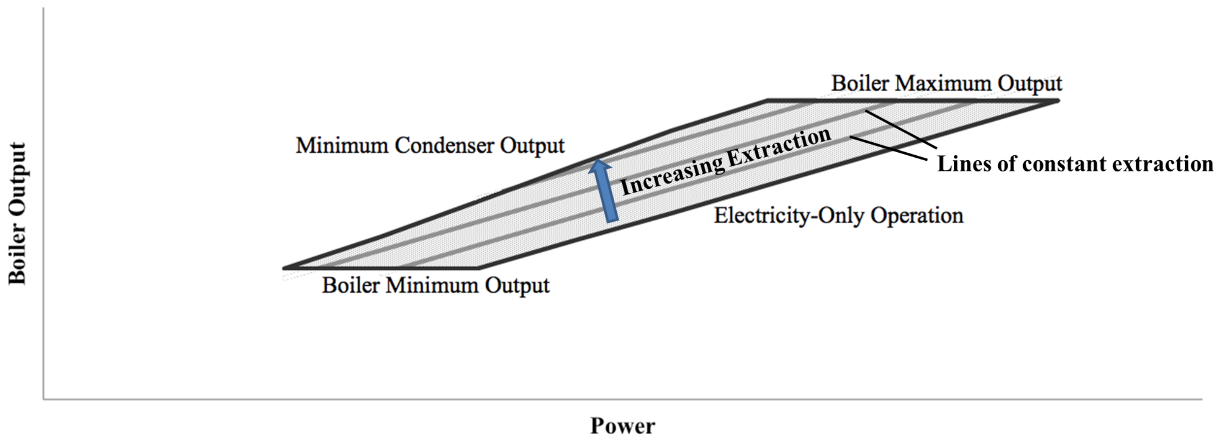

Figure 2.2. Indicative diagram of feasible boiler output, power and extraction states for a single extraction CHP unit. Source: [23].

Figure 2.3 transforms this relationship to power-heat coordinates. As in Figure 2.2, for small extraction amounts, minimum power output decreases, corresponding to the minimum boiler curve. After a threshold extraction steam amount q*, power output rises along the minimum condenser curve. This linearized depiction is common in the literature [24, 25].

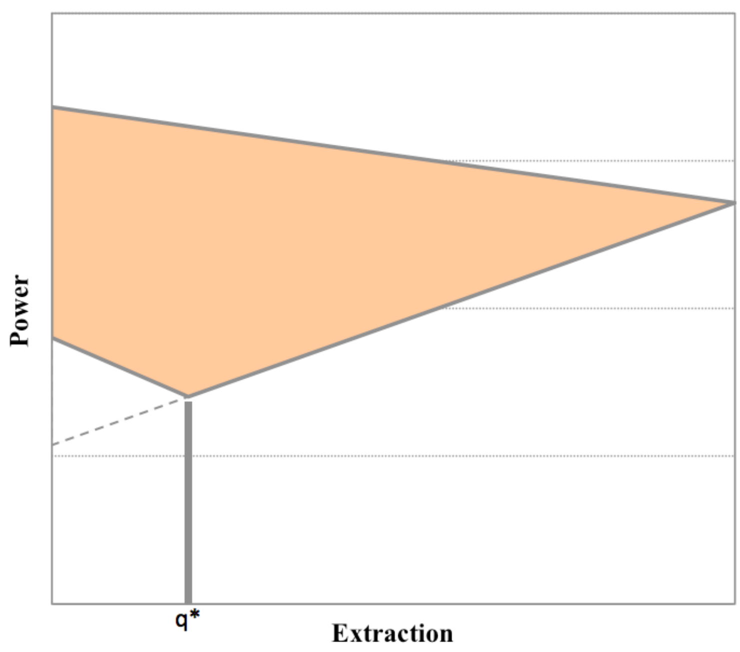

Figure 2.3. Feasible power-heat states for an extraction CHP, based on Figure 2.2.

Backpressure CHP plants (B-CHP) do not have a condenser (e.g., cooling tower) installed and hence use all the turbine exhaust steam is used directly [15, 26]. In both residential and industrial applications, the pressure/temperature requirements for heat (the "backpressure") have a narrow range, hence the heating load exactly determines the electricity output and is equivalent to constraining operation to the far left condenser threshold in Figure 2.2.

If there is only one plant servicing a given heating area, CHP plants generally cannot cycle. Ramping is restricted to E-CHP only, but because of the increased minimum output, its range is diminished. While the most efficient from an overall energy conversion perspective, B-CHP is only practical in applications of 50 MW or less because of limits on local demand for heat. Furthermore, its contribution to grid inflexibility creates some limits on its widespread adoption.

2.3.3 Hydropower

Hydroelectric power with a reservoir is a very flexible generation source, as it is not dependent on slow thermodynamic processes. Startup and ramping to full capacity can be achieved in minutes, and minimum stable output is near-zero [17]. However, in some regions, it may face constraints for irrigation, storm management or fisheries that reduce its flexibility [19]. Small hydroelectric power is typically "run-of-river" (i.e., without a reservoir to store water) and hence is similar to other non-dispatchable renewable energy like wind, providing little flexibility to the system.

In Northeast China, hydropower resources are limited, but of those available, the reservoir type dominates. These provide additional flexibility to the grid and provide daily as well as annual balancing functions [27]. There are no significant competing priorities such as for agriculture.

Pumped hydropower, wherein water is pumped up to an elevated natural reservoir and stored for release later, provides the greatest flexibility. From 2010-2015, 31 GW of new pumped hydro (3.4 GW in Northeast) is scheduled to begin construction [28]. The only pumped hydro facility currently in Northeast, at Pushihe, began operation in 2012, after the model year assumed for the analysis in this thesis.

2.3.4 Nuclear

Nuclear technologies are steam-based boiler generators subject to the same constraints as coal-fired plants. In addition, owing to the complexity of maintaining a stable nuclear reaction, they have higher minimum loads and require long startup times, a day or longer [17]. China's nuclear fleet is relatively new and the two units in the Northeast only came into operation in 2013 and 2014, after the model year examined in this thesis. By 2018, eight units totaling 9.2 GW are slated to become operational in the Northeast [29], which will further decrease grid flexibility.

2.4 Wind Integration Studies

Methodologies to quantify the system-wide effects of increased wind energy penetration can be separated into three basic types [30]: statistical analyses of the impact of wind variability on ancillary service requirements; production cost simulations estimating integration costs and thresholds; and reliability simulations of short-time scale impacts. The first and third methods are typically concerned with sub-hourly impacts such as frequency regulation that are outside typical dispatch and unit commitment formulations. The second builds on wind variability statistics and typically uses UC, possibly in combination with optimal power flow results, to look at daily and seasonal impacts, and is where this thesis intends to make contributions.

Production cost simulations can distinguish between various causes of poor wind utilization. A common cause is a low demand profile when wind electricity is being generated, which pushes down the net load curve close to base load operation. Curtailment, if it occurs, relate to different sources of grid inflexibility. During low net load periods, for example, cycling costs of thermal generators may drive down wholesale electricity prices below their cost of production, reflecting their willingness to generate at a loss to avoid costly shutdowns. Forced curtailment by the grid operator may occur to ensure transmission lines are within their safe operational limits or to meet certain contingency requirements. Similarly, the cost of maintaining suitable reserve capacity has led some grids to place limits on the allowable power ramping from wind [31].

Researchers focusing on wind integration in regions of China have examined a subset of these challenges using production cost methods. Dispatch optimizations examining changes in operational costs have estimated increased fuel and reserve costs [32, 33]. Using a benchmark of $5 / MWh as the ramping cost due to physical deterioration, and a heat rate that is 10% less efficient at minimum output, [33] found for 3-7% wind penetration in Jiangsu province, increased fuel costs from lower generation outputs are roughly double those of ramping.

Using EnergyPLAN, an energy input/output simulation model that optimizes electricity, heat and transport sectors over a single year, [34] found that wind penetration nationally above 16% in a 2007 baseline leads to economic curtailment. Critically, this analysis did not include transmission constraints, instead treating China as a single node, and did not incorporate temporal restrictions such as unit commitments and ramping. At a provincial level, [35] imposed a range of minimum thermal generation constraints and calculated curtailment for various wind penetrations in Jiangsu province: at 20% wind penetration, 4-20% of wind is curtailed; and at 42% wind penetration, 30-75% is curtailed.

The large share of coal-fired cogeneration facilities in the Northeast gives it a specific set of integration challenges for China different from Jiangsu, which is frequently used as a provincial case study due to data availability. In [32], the effect of wind penetration on dispatch in the largest northeastern province, Liaoning, was examined. To account for and simplify the heat-electricity interaction effect, thermal shutdowns were not allowed but minimum outputs were left unchanged. In this analysis, pumped hydro played a crucial role in providing up reserves.

A common simplification used in the Chinese literature is to calculate the space available for wind integration by tallying the "peaking capacity" of thermal plants, which is the available capacity between minimum and maximum output for the given time period. These will differ by heating/non-heating season. In addition to rules of thumb and official regulations such as assuming 40% for 600MW+ units and 50% for units < 600MW, these may also be based on minimum output requirements submitted to grid companies by generators for the purposes of yearly planning described in Chapter 3. For example, [27] tabulated minimum outputs and other dispatch constraints of all Northeast generators in 2009. Depending on these assumptions, from 0-10 GW of wind could be integrated with limited curtailment in 2010.

Using a region-wide dispatch optimization model, no research known to the author has attempted to model the specific effects on wind integration of cogeneration, unit commitment and other operational constraints. In particular, as is shown in Chapter 5, ignoring either changes in minimum output based on heat load or the unit commitment problem has a large impact on the estimated wind integration potential. Incorporating these additional constraints would give the Northeast grid operator a more precise daily commitment and dispatch problem.

Finally, while existing studies [27, 35] recognize that wind integration and curtailment rates are highly sensitive to assumptions on minimum outputs, which are frequently imposed through regulation or in the annual planning process, no work has been done to simulate other regulatory constraints such as annual generation quotas described in Chapter 3.

Chapter 3

Regulation of Power Systems Operation in China

China is in the midst of a long transition from a traditional vertically-integrated state-run utility to partial liberalization in which wholesale and retail markets are unbundled from regulated transmission and distribution monopolies. In Section 3.1, I review the principles of liberalization, including the underlying drivers and common institutional pathways taken by other countries.

Similar to transitions in other countries, entrenched relationships between government and industry in China have complicated shake-ups of ownership and regulatory authority. Section 3.2 provides a timeline of the planned reforms, which initially followed internationally-accepted principles of power sector liberalization. Taking place against the backdrop of a wave of industrial reorganization and privatization in the 1990s, these accounts typically focus on the broader industrial reorganization, ignoring important physical and economic constraints of the power sector outlined in Chapter 2.

Even as the electricity sector was seen as an important national industry whose efficiency could be a lever for economic growth, further reform momentum slowed or completely stalled. In Section 3.3, I review the array of policies and institutions affecting wind integration that have been developed over the last several decades. Functional wholesale markets and fully-regulated transmission and distribution utilities have not been created, which has led in some cases to direct conflict with wind promotion policies. I discuss several inefficiencies that arise from poor coordination among electricity regulators, policy-makers and other energy services, in particular, district heating.

This chapter lays out the unique regulatory frameworks and institutional actors in the Chinese power sector. These opaque interactions complicate quantitative modeling of current circumstances and policy effectiveness, and hence are typically neglected in optimization or simulation-based wind integration studies. In Section 3.4, I argue that a coupled approach that formulates the technical operation in the context of imperfect regulation is appropriate for the Chinese case.

3.1 Fundamentals of Power Systems Regulation

Until the 1980s, electricity generation, transmission and distribution in every country were combined into individual entities with exclusive regional or national coverage, and central governments played key roles in planning and regulating their expansion. In some countries, such as China, private entities were denied access to this market, while in others, such as the U.S., privately-run franchises with a heavily regulated pricing scheme were the norm. Ensuring reliability of an essential input to economic growth took precedence over cost efficiency. Typically, an independent government regulator was charged with assessing the costs of all the functions of the vertically-integrated utilities, as they were later known, in order to protect consumers from monopoly rents and ensure service quality [36].

Beginning with Chile's experience in 1981, new models of power sector regulation were proposed to introduce competition, with the goals of promoting private industry, improving cost efficiency and increasing access to capital. Central to this transition was separating potentially competitive aspects of the electricity sector (e.g., generation and retail) from services better described as natural monopolies (e.g., transmission and distribution) [37]. The latter – similar to railroads, telephone lines, and many other "network" industries – are expanded by not allowing costly competition in creating the network, but rather in regulating the access and pricing of a monopolistic network. This creates the following idealized market [37]: generators compete in wholesale markets with competitive access and pricing for transmission capacity, and retail electricity suppliers, with competitive access to the distribution network, compete for customers by buying efficiently on the wholesale markets.

Due to the unique physical components of electricity delivery, such as maintaining supply/demand balance, a system operator independent in ownership and political affiliation from all market players (generation, transmission, distribution and retail) is generally thought to be necessary to impartially create commitment and dispatch schedules [38]. Creating the above competition without sufficiently addressing system operation may lead to increased costs, as has been documented for the California energy crisis [38]. System inflexibility in turn may impact the integration of renewable energy sources. Each country has approached these aspects differently and, in some cases, in different orders, but it is widely acknowledged that all are necessary to create a competitive electricity sector [36-38].

3.2 History of Power Sector Reform in China

Under the largely centrally-planned economy of the period 1949-1978 before economic reforms were launched in China, the entire electricity sector was organized into a single entity, the Ministry of Water Resources and Electric Power. This was simultaneously the policy-maker, regulator, state-owned assets manager, and network and generation company [39]. Under the ministry were organized various provincial and regional power entities with a similar vertically-integrated structure. These departments would set retail prices through annual catalogs, gain profits and reinvest in projects [40].

Largely in response to power shortages in the 1970s and early 1980s, China opened the power generation sector to outside investors, including local governments and foreign companies [41]. These independent power producers (IPPs) competed on an uneven playing field with the vertically-integrated ministry. In addition, as regional entities gained in prominence so did the local government influence over their operation, which led to a rise in local protectionism and stifled regional integration of electricity production and transmission [40].

In 1997, the state-run utility was converted into separate regulatory and business entities: the Ministry of Electric Power and the State Power Corporation (SPC). The vertically-integrated SPC owned almost of half the generation assets and nearly all of the transmission assets in the country. In 2002, China followed the arc of other international deregulation efforts in further separating generation from the SPC into five new state-owned power companies [42]. This was part of a larger trend of liberalization in China, of privatizing or devolving former monopoly industries throughout the economy into several state-owned companies who would ideally compete in the market to increase efficiency. The State Development and Planning Commission (SDPC), later the National Development and Reform Commission (NDRC), took over regulation and tariff-setting [40].

The 2002 reform plan was the result of political bargaining between several ministries as well as the quasi-governmental SPC. SPC argued that a prerequisite for generation competition was establishing a well-interconnected grid network, while reform voices lobbied for the creation of provincial-level network companies and provincial exchanges for power producers [43]. SPC ultimately won, though as a compromise it was split up into China State Grid, which owns all major transmission and distribution infrastructure in the north, and China Southern Grid.

State Grid is organized into a central office and five regional grid subsidiaries, with Northeast China Grid Company (NECGC) chosen as the unit of analysis for this thesis. NECGC is both the primary system operator and the transmission and distribution company overseeing grid construction and maintenance, ensuring safety of supply, grid planning, regional electricity markets planning, and regional electricity dispatch [44]. Three provinces in the northeast region further have grid subsidiaries which handles these functions within provincial boundaries, where the majority of balancing currently takes place [45].

The State Electricity Regulatory Commission (SERC) was created as a nominal independent regulator in 2003. Since that time until it was merged with the National Energy Administration (NEA) in March 2013, SERC had mandates to inspect markets and regional trading, handle customer service complaints, and grant permits for new generation, transmission and distribution companies. However, SERC frequently faced criticism of capture, cronyism and inadequate authority [39]. It shared its offices with its primary regulated entity, State Grid, at 86 Chang'an Avenue in Beijing, and its authority was frequently undermined by the NDRC and the NEA, which carry broad policy-making responsibilities [41]. The former head of SERC has taken over at NEA, which will have expanded authority over project approvals, though price-setting power rests with the NDRC [46].

Analyses of this transition from a single ministry to regional unbundling have noted several industrial reorganization aspects such as ownership reform [47], politicization of investment and approvals [48], and local protectionism [40]. Broadly speaking, while the theory of power sector liberalization outlined in Section 3.1 emphasizes efficiency and reliability, the industrial organization literature focuses on the underlying political motivations to change power dynamics among government and regulated entities. This reflects the contemporary discourse between the reform and conservative camps, where reform proposals were largely designed and advocated for on the basis of reducing the power of the State Power Corporation: for example, the leading proposal by the SDPC called for breaking up SPC into separate vertically-integrated utilities for each province [47].

Central government interventions in the power sector have since 2006 placed increasing emphasis on energy efficiency and resource conservation. In the 11th Five-Year Plan (2006-2010), the central government ordered the closure of outdated, low-efficiency coal-fired power plants together with older production capacity in cement, steel and other sectors [49]. These small thermal power units were replaced by larger, more efficient plants, accelerating a shift in the power mix toward a large fraction of 300 MW and larger units, detailed in Chapter 5.

In addition, the central government has prioritized the construction and retrofitting of coal-fired combined heat and power (CHP) plants through accelerated approval processes, with specific targets beginning in 2007 [50]. According to official statistics, there was 167 GW of CHP capacity installed at the end of 2010 [51]. These totals are typically derived from the entire capacity of a plant regardless of how many of its units supply district heating and hence may overestimate the exact percentage [52]. Nevertheless, CHP is growing rapidly and the central government aims for 200 GW of installed capacity by 2020 [52], a target it would likely exceed given extensive government support for CHP.

3.3 Key Operational Policies and Directives Affecting Wind Integration

Examining the effectiveness of China's power sector reform solely through the size or particular regional aggregation of utilities may disregard important differences between the power sector and other industries. Some researchers have noted the need, for example, of separating transmission and distribution networks into different entities for competitive markets to emerge [53, 54], though the creation of an independent system operator overseeing a bundled transmission and distribution company is considered a best practice for an efficient and reliable power system [38].

Vestiges of the Ministry of Electric Power and early iterations have been retained in the reform process and are the subject of continued debate to promote broad economic, environmental, and social goals. In particular, as a result of the uneven localization of power sector regulation beginning with the initial 1985 reforms, operation policies on commitment and dispatch are a mixture of directives, for different actors, and of varying degrees of implementation [45, 55].

These policies were designed for a relatively simple power system fueled solely by coal and hydropower, without any significant price competition or substitution between different fuels. Wind and other new energy sources such as nuclear power upset this traditional hierarchy as their main advantage lies in having a low marginal cost, which is preferentially dispatched in cost minimizing systems. Ill equipped to handle these price effects as well as the additional complications of incorporating wind's variability, these operational policies are potential barriers to integrating wind. This can be explained by viewing China's promotion of wind primarily as industrial development, as opposed to energy or environmental, policy [56].

3.3.1 Centrally-Administered Electricity Tariffs

Prior to 2001, wholesale tariffs for IPP thermal generators were based on published costs with an allowed rate of return (12-15%), and co-existed with the internal costs of vertically-integrated utilities [55]. Following unbundling, these two systems were merged into a **benchmark electricity tariff**[1], which is fixed by province based on the "average social cost of advanced units" [55]. In practice, this reflects unpublished cost and return expectations, as well as affordability based on the economic development of the province. This structure, sometimes referred to as a

[1] In Chinese: 标杆电价.

yardstick tariff, was only intended as a temporary measure before competitive wholesale regional markets were fully implemented [39, 55]. The tariff in regional markets envisioned in the 2002 reform document was two-part: capacity charges set by the government and energy charges determined by the market.

Other energy types are similarly centrally-administered: hydropower and nuclear contracts are set by NDRC on a project-by-project basis. Wind and solar power have nationwide, differentiated feed-in-tariffs starting at 0.51 and 1.00 CNY / kWh ($0.08 and $0.16), respectively. Since 2004, an additional policy recognizing changes in coal prices would allow NDRC to consider a thermal tariff increase if coal prices changed by more than 5% over a given period, at least six months [57]. NDRC can choose to ignore this signal, however, and prices over the last decade demonstrate that government control of tariffs have been ineffective at reflecting actual costs of production [58]. Ancillary services in China are mandatory and uncompensated, though there is some early stage exploration of creating compensation [59].

The lack of wholesale competition leads to large costs in China's coal-dominated power sector that are frequently socialized, and do not promote efficient usage of renewable energy. The current tariff adjustment mechanism has reportedly led to tense standoffs between the central regulator and generators threatening to withhold supply unless tariffs are raised, ensuring that political clout more than costs of generation drive electricity tariffs [59]. Finally, the regulatory uncertainty and insufficient compensation from wholesale tariffs create significant barriers to entry for private investments [48], including innovative ways of integrating wind.

3.3.2 Annual Quota for Thermal Generators

In addition to fixed tariffs for coal-fired electricity, quantity is also fixed in each province according to "**generation quotas**," or sometimes referred to as "average dispatch"[2]. As actual costs differ from the expected cost of an advanced unit, and there is no consistent framework of adjusting price based on cost factors, this quantity instrument guarantees a minimum annual revenue [45]. With the introduction of non-state investment following 1985, this could be seen as an additional lever both to retain state control over the sector, but also to protect older generation investments from facing direct competition. In other countries' transition to a market-driven power sector, stranded assets or inadequate compensation under new market rules may be compensated separately from tariffs by the regulator [36]. However, no such system was created in China.

In practice, on an annual basis power plants do generate different amounts, which reflects some flexibility in the provincial quota-setting process—a process that is highly political [60]. In addition, together with policies to retire small, inefficient coal plants, electricity "exchanges" were created in 2008 whereby these quotas became tradable permits [61]. The value of these permits would be given by the difference in marginal costs between buyer (more efficient plant) and seller (less efficient plant) [62]. They still represent a relatively small fraction, however: in 2011, roughly 1% of total generation Jilin province was traded in these exchanges [63].

[2] In Chinese: 配额制度 or 平均调度.

3.3.3 Dispatch Priorities

The tightly-controlled tariff and quantity levers ensure that dispatch priority of generators is not based on marginal cost. Nevertheless, Chinese regulators have strengthened measures to prioritize renewable energy and more efficient thermal generators in the dispatch order. Starting in 2007, SERC mandated that grid companies purchase all available renewable energy (excepting cases risking grid stability) or face penalties – though, there was no case of SERC imposing a fee for failing to give priority [64].

Also in 2007, the NDRC began pilots of "**energy efficient dispatch**" (or "energy-saving dispatch"[3]), which prioritizes renewables and nuclear in the dispatch order, and continuing with coal units in decreasing order of efficiency. Implementation was uneven, speculated to be because of a fear of stranded assets made by provincial governments in the years before unbundling [65]. This dispatch priority could also conflict with the quota for low-efficiency units, which would lead to unacceptably low capacity factors [45]. It was noted by SERC in 2010 that in Shanghai and Jilin, among others, low-efficiency thermal units had larger capacity factors than high-efficiency units [66].

During the heating season (roughly October – April), combined heat and power plants are designated must-run units. Backpressure units, which have no flexibility to adjust electricity output, take precedence in any dispatch scenario. Extraction units, which have a limited range of flexibility, are dispatchable only after meeting their minimum load requirements.

3.3.4 Inter-Provincial and Inter-Regional Dispatch Coordination

Due to the array of operational priorities, defining the relevant balancing areas for a given region can be ambiguous. Most dispatch is at the provincial level, where grid operators attempt to maintain supply/demand balance to a first approximation. Adjustments for planned oversupply can be negotiated in the annual and monthly dispatch plans through transmission capacity allocation. Unplanned oversupply (or undersupply) is coordinated on an *ad hoc* basis by the regional grid operator. In 2010, inter-provincial transmission in Northeast Grid totaled 19 billion kWh, 6.7% of total generation [67]. The former State Power Corporation lobbied for regional integration of dispatch and transmission in the 2002 reforms [47], and attempted regional power pool pilots as early as 2000, with limited progress [39].

Transmission between regions is even more limited, though growing quickly. In 2011, concluded inter-regional transmission contracts nationally amounted to 13% of generation, of which 57% was initiated by the central government for large power projects such as southern hydropower [68]. Planned transfers for State Grid regions in 2014 will reach 63.2 billion kWh, and schedules from Northeast Grid to North China Grid are 21.5 billion kWh (~6% of generation) [67, 69].

[3] In Chinese: 节能调度.

3.3.5 Transmission Tariffs

Remuneration to the grid companies for transmission and distribution services is based on the residuals between the administratively-set retail and wholesale prices [70]. Though there is no direct mechanism to adjust tariffs based on cost, starting in 2006, grid companies were required to report their costs to SERC in accordance with national enterprise accounting reform [71]. The average remuneration to State Grid for transmission and distribution in 2010 was 165 RMB / MWh ($26.40 / MWh) [70].

Cross-boundary transmission is priced in terms of energy, and because of the above dispatch coordination issues, the lines may be underutilized and it is possible that grid companies do not fully recover their costs. This creates disincentives for the effective transmission of wind power. A price cap of 30 RMB / MWh ($4.84) was instituted in 2009 on all inter-regional trades [72]. Line losses on inter-provincial trades are borne fully by the grid company and there is no appropriate mechanism to account for different wind FITs in the same region [73]. In 2013, a special platform was set up to allow wind generators to avoid curtailment by selling at a reduced price [74], roughly 10% below the intra-provincial rate.

3.4 Coupled Modeling Approach of Political Economy

Over 70% of generation capacity at the end of 2011 was owned by the state, through either centrally- or provincially-managed companies [68]. Thus, in addition to complex and overlapping economic incentives, there are significant political motivations shaping the power sector. As demonstrated by the cross-section above, the introduction of wind as a new energy source tests the coupled political, economic and electricity systems' flexibility to deliver low-cost electricity while meeting other social goals such as pollution reduction.

The economic and political motives that drive operation of these assets further carry modeling implications for research into the effectiveness of specific policies and diagnosing particular causal relationships that lead to system underperformance. The modeling tools examined in Chapter 2 do not fully capture the political motivations of grid operators and generators, while the institutional analyses of China's power sector reform fail to address basic operational aspects. The next chapter outlines one approach to modify well-developed quantitative methods to incorporate political "constraints" and applies it to the case of Northeast wind integration.

Chapter 4

Modeling Framework

A typical methodology to analyze the impacts of integrating wind power is to include wind generation in a least cost dispatch optimization. This minimizes operational costs taking into account individual generator characteristics, exogenous requirements such as reliability, and in general a simplified network representation. In addition, as they are an important part of the system operator's toolkit, operational optimizations mimic what is feasible or likely under current practices.

In Section 4.1, I describe the unit commitment optimization that I developed for this thesis to calculate optimal levels of wind integration. It solves for commitment and dispatch over one-week periods, averaging the results of six historical wind profiles to approximate the stochasticity of wind. My model contributes to the literature by incorporating the operational constraints of CHP units and introduces a computationally inexpensive way of hydro-thermal coordination allowing for carry-over between seasons.

In addition, broader research on the challenges of wind power integration in China has frequently cited the importance of non-market forces in integrating wind. This descriptive body of work highlights different political incentives faced by members of the electricity sector. In particular, these indicate the limitations of the above optimization models that assume cost minimization and perfect competition. In Section 4.2, I formulate two important exogenous institutional considerations as constraints into the optimization model, and examine the implications of wind integration under incomplete power sector liberalization.

4.1 Unit Commitment Model Formulation

The unit commitment problem seeks to minimize operational costs of meeting a given electricity demand, assuming a wide variety of constraints as described in Section 2.1. The objective incorporates variable generation costs and the startup (commitment) costs of thermal generators:

$$Z = \min \sum_{p \in P} \sum_{g \in G_p} \sum_{t=1}^{T} \left(p_g^{var} x_g(t) + p_g^{start} v_g^{up}(t) \right)$$

$$p_g^{var} = C_{coal} \eta_g, \forall g \in G_{coal}$$

where $x_g(t)$ is the output of generator g at time t, $v_g^{up}(t) = 0, 1$ is the startup decision of g at time t, p_g^{var} is the variable cost of g, C_{coal} is the fuel cost of coal, η_g is the heat rate of generator g, p_g^{start} is the startup cost of g, $T = 168$ is number of hours simulated, $p \in P$ are provinces,

G_{coal} is the set of coal generators, and G_p is the set of all generators in province p. The fuel price is fixed for all simulations at $C_{coal} = 700\ RMB/ton$.

Grid operators use similar models on a daily basis to schedule day-ahead generation, with model horizons extending beyond the daily period. This thesis optimizes over a week – ($T = 168$ hours) – in order to capture wind resource variability and key interaction effects such as long minimum startup times, which conservatively could be a minimum of 24 hours for large units.

Electricity demand, transmission and logical equations for commitment states:

$$d_{p,t} = \sum_{g \in G_p} x_g(t) + (1-\mu) \sum_{p\prime \neq p} x^M_{p',p}(t)\,, \forall p, \forall t$$

$$x^M_{p',p}(t) = -x^M_{p,p'}(t), \forall t, \forall p, p' \in P$$

$$-M_{p,p'} \leq x^M_{p,p'}(t) \leq M_{p,p'}, \forall t, \forall p, p' \in P$$

$$y_g(t) = y_g(t-1) + v_g^{up}(t) - v_g^{dn}(t), \forall g \in G, \forall t$$

where $d_{p,t}$ is the electricity demand in province p at time t, $x^M_{p',p}$ is transmission from province p to p' at time t, $M_{p,p'}$ is the transmission capacity between province p and p'. μ is transmission loss between provinces, $y_g(t) = 0, 1$ is the commitment status of generator g at time t, and $v_g^{dn}(t) = 0, 1$ is the shutdown decision of g at time t.

Periodic boundary conditions are assumed in order to avoid any infeasible schedules near the beginning or end of the period.

Thermal generator constraints include minimum/maximum outputs:

$$p_g^{min} y_g(t) \leq x_g(t) \leq p_g^{min} y_g(t), \forall g \in G_E, \forall t$$

Maximum ramp rates:

$$w_g(t) = x_g(t) - p_g^{min} y_g(t), \forall g \in G, \forall t$$

$$w_g(t) - w_g(t-1) \leq R_g^{up}, \forall g \in G, \forall t$$

$$w_g(t-1) - w_g(t) \leq R_g^{dn}, \forall g \in G, \forall t$$

Minimum up/down times:

$$y_g(t) \geq \sum_{t'=t-\tau_g^{min}}^{t} v_g^{up}(t')\,, \forall g \in G, \forall t$$

$$1 - y_g(t) \geq \sum_{t'=t-\tau_g^{min}}^{t} v_g^{dn}(t')\,, \forall g \in G, \forall t$$

where p_g^{min}, p_g^{max} are minimum/maximum outputs, τ_g^{min} is minimum on/off time, and R_g^{up} / R_g^{dn} are maximum upward/downward ramp rates of generator g. An auxiliary variable, $w_g(t)$, is the downward feasible generation space, used in this formulation to allow for startups across infeasible ramping from 0 and p^{min}.

System operators typically mandate minimum reserve requirements to ensure reliable operation in case of unpredicted changes in load or supply. Here, fixed reserve requirements are assumed:

$$\sum_{g \in G_{UpRes}} \left(p_g^{max} y_g(t) - x_g(t) \right) \geq S^{up}, \forall t$$

$$\sum_{g \in G_{DnRes}} w_g(t) \geq S^{dn}, \forall t$$

where G_{UpRes} / G_{DnRes} are sets of generators participating in upward/downward reserves, and S^{up} / S^{dn} are minimum upward/downward reserve requirements. In this formulation, only committed units can provide reserves (i.e., spinning reserves). For brevity, separate requirements for non-spinning reserves are not considered. Given the long startup times of coal units, the Northeast would have few available non-spinning reserves.

4.1.1 Wind Profiles

Wind generation is assumed to be perfectly forecasted over the week planning horizon. A large body of research addresses the system impacts of wind forecast errors, such as the additional need for reserves [12], flexible commitment schedules [75], and the reduction in forecast errors with increasing geographic dispersion of wind turbines [76]. This is a ripe area of future research on wind power integration challenges in China.

Wind profiles of hourly production were generated at the provincial level. To represent the stochasticity of wind, six wind profiles were taken from historic weeks in winter and the outcomes of the model runs averaged (see Section 5.5 for detailed calculations).

Wind generation is thus constrained by the provincially installed capacity and average hourly potential production factor:

$$x_{p,wind}(t) \leq D_p \theta_p(t), \forall p, \forall t$$

where D_p is the wind capacity in province p, and $\theta_{p,t}$ is the average wind potential production per unit capacity in province p at time t. Strict inequality occurs when some wind generation is curtailed.

4.1.2 Combined Heat and Power (CHP) Plants

CHP plants couple two energy supply sectors, electricity and district heating. A suite of technologies with different characteristics and costs are available, and their interactions have been considered in the literature These range from co-optimization methods [24, 77] to input/output simulations [78]. For China, competing technologies to replace or complement coal-fired heating include gas-fired plants [79], electric space heaters [80], heat pumps [81], and centralized heat storage [34].

In contrast to investment and planning, operational decisions are much simpler in China. CHP companies providing district heating receive a flat annual fee assessed per unit area on customers. In exchange they must maintain a minimum indoor temperature during the winter heating months, which typically run from mid-October to mid-April. These plants, in turn, are monopoly suppliers and owners of the local heating grid. Customers currently have no ability to reduce their heating bill and no incentive to substitute toward other heating technologies. Hence, district heating supply can be simplified to equate a time-varying heat demand, dependent on outside temperature and proportional to the size of the heating grid.

Two basic types of CHP technologies are in use in China: condensing-extraction (E-CHP) and backpressure (B-CHP). The relationship between heating and electricity outputs differs for the two, and is also dependent on total unit size. The relative sizes and locations in the Northeast are examined in Chapter 5.

E-CHP plants extract heat from one or more intermediate stages between the boiler and final generator. Plant operators can vary the extracted heat, and the relationship described in Section 2.3.2 is used to estimate boiler output, extracted heat and electricity generation. This thesis tests two methods of determining the minimum electricity outputs, representing current practice and an improved approximation.

A simplifying assumption used by grid operators for planning purposes is to specify for each E-CHP unit a fixed minimum electricity output, or minimum mode (MM). This may be piecewise constant throughout the heating season, which is typically divided into three stages: early, middle and late. Heating loads during the early and late periods may be roughly half of the middle. Focusing on the peak heating season, the **minimum mode heat-power relationship** is given by:

$$MM_{g_H}^{min} y_{g_H}(t) \leq x_{g_H}(t) \leq MM_{g_H}^{max} y_{g_H}(t), \forall g_H \in G_{E-CHP}, \forall t$$

where $MM_{g_H}^{min}$ is the fixed minimum output and $MM_{g_H}^{max}$ is the maximum output for generator g_H.

The power-heat relationships described in Section 2.3.2 provide a first-order approximation of additional technical details in the operation of cogeneration facilities. For example, for low extractions, the minimum electricity output may be less than that of an electricity-only plant; and for high extractions, some additional flexibility may exist as heat load varies throughout the day. The **dynamic power-heat relationship**:

$$x_{g_H}(t) \geq \alpha_{g_H}^{min} y_{g_H}(t) + \beta_{g_H}^{min} q_{g_H}(t), \forall g_H \in G_{E-CHP}, \forall t$$

$$x_{g_H}(t) \geq a_{g_H} y_{g_H}(t) + b_{g_H} q_{g_H}(t), \forall g_H \in G_{E-CHP}, \forall t$$

$$x_{g_H}(t) \leq \alpha_{g_H}^{max} y_{g_H}(t) + \beta_{g_H}^{max} q_{g_H}(t), \forall g_H \in G_{E-CHP}, \forall t$$

where $q_{g_H}(t)$ is the steam extraction of generator g_H, and from Figure 2.3: $\alpha_{g_H}^{max}/\alpha_{g_H}^{min}$ and $\beta_{g_H}^{max}/\beta_{g_H}^{min}$ are the constant and linear terms of generator g_H boiler maximum/minimum thresholds, respectively; and a_{g_H} and b_{g_H} are the constant and linear terms of the condenser threshold.

B-CHP units have no flexibility in electricity output as they are constrained to the condenser threshold, the second equation above. Specifically:

$$x_{g_H}(t) = a_{g_H} y_{g_H}(t) + b_{g_H} q_{g_H}(t), \forall g_H \in G_{B-CHP}, \forall t$$

4.1.3 Hydropower Reservoirs

The Northeast has a limited amount of hydropower resources, ranging from 5-10% of generation. Almost all are reservoir-type and perform load balancing services, though with a variety of time periods over which they can optimize. Larger reservoirs may store some water across the year, while smaller units typically only adjust output on a daily basis, maintaining predetermined levels at the end of each 24-hour period [27]. Because a significant amount of the Northeast's load variation is met by hydropower, it is important to accurately capture the benefits from optimal hydropower management.

Hydrothermal coordination models consider multiple time horizons to predict, plan and adjust dispatch based on expected hydropower availability. These may be optimized over a full year, then a month or week, and finally daily. Multi-stage stochastic versions may consider several different hydropower scenarios for each water basin, and the physical connection between different units. Production functions converting water flow into electricity generation are approximated as linear [82].

Most rainfall in the Northeast occurs between June and September, coinciding with peak hydropower generation. In this model, I allow for flexible dispatch of hydropower in winter within the week horizon by (1) calculating the average daily winter inflow, (2) estimating water storage from summer months using historic data, and (3) adjusting differential provincial performance from capacity factors. Following [82], I sum hydro reservoirs within each province into a single unit. The hydropower equations of state are thus:

$$h_p(t) - h_p(t-1) = H_p^{in} - \frac{x_{p,hydro}(t)}{\lambda}, \forall p, \forall t$$

$$h_p(0) = h_p(T) = H_p^0, \forall p$$

where $h_p(t)$ is the hydro reservoir level of province p at time t, H_p^{in} is the adjusted hydro reservoir inflow per hour in province p, λ is the constant hydropower production factor, and H_p^0 is the hydro reservoir initial and final reservoir level in province p. For simplicity, inter-seasonal hydro balancing as well as production factor differences is absorbed in the inflow factor.

4.2 Regulatory Constraints

4.2.1 Provincial Dispatch

The first regulatory constraint I consider is the decentralization of most dispatch in the Northeast to the provinces. I model two important changes that occur when dispatch is no longer coordinated across all provinces: limitations to transmission line utilization, and calculation of reserves separately for each province.

To appropriately model the transmission allocation scheme described in Section 3.3.4, granular data on daily planned amounts should be used to fix a narrow range of allowable transmission quantities $x_{p,p'}^M(t)$. As only annual aggregates of these data are made public, I model this instead as a reduction in the transmission interconnection capacities, $M_{p,p'}$. The transmission capacity allocation process appears to follow some regularity in terms of origin and destination, which is used to further restrict transmission in the provincial dispatch case to be uni-directional (described further in Section 5.2).

In the above unit commitment model, aggregate reserve constraints are imposed for the entire region. Under provincial dispatch, each province must meet its basic reserve requirements, according to:

$$\sum_{g \in G_{UpRes} \cap G_p} \left(p_g^{max} y_g(t) - x_g(t) \right) \geq S_p^{up}, \forall p, \forall t$$

$$\sum_{g \in G_{DnRes} \cap G_p} w_g(t) \geq S_p^{dn}, \forall p, \forall t$$

4.2.2 Minimum Generation Quotas

All generators are allocated certain minimum generation amounts on an annual basis, as described in Section 3.3.2. In the winter months, this sets a lower bound on electricity-only generators that otherwise would not be dispatched because they are not providing required heating loads. For simplicity I group generators into type categories by size k. In a representative winter week, a certain fraction of these generators would be committed so that over the entire winter, the average capacity factor of each generator meets the minimum threshold. Thus:

$$\sum_{g \in G_k \cap G_p} \sum_{t=1}^{T} \frac{x_g(t)}{k} \geq CF_{p,k}^{min}, \forall k, \forall p$$

$$k \in \{25, 50, 135, 200, 350, 600\}$$

where G_k is the set of generators of type k, and $CF_{p,k}^{min}$ is the minimum capacity factor for generator type k in province p.

Full Set of Model Variables and Parameters

Decision Variables

$x_g(t)$: $x \geq 0$ – generation by generator g at time t
$y_g(t)$: $y = 0, 1$ – commitment status of generator g at time t
$v_g^{up}(t), v_g^{dn}(t)$: $v_g = 0, 1$ – spinning up/down of generator g at time t
$x_{p,p'}^{M}(t)$ – transmission from province p to p' at time t
$w_g(t)$ – auxiliary variable of generator g at time t
$h_p(t)$: $h \geq 0$ – hydro reservoir level of province p at time t

Generator Sets

G_E – electricity-only generators
G_{E-CHP} – condensing-extraction combined heat and power plants
G_{B-CHP} – backpressure combined heat and power plants
G_{coal} – all coal generators
G_p – generators in province p
G_{UpRes} – generators participating in upward reserves
G_{DnRes} – generators participating in downward reserves
G_k – generators of type k, where $k \in \{25MW, 50MW, 135MW, 200MW, 350MW, 600MW\}$

Generator Parameters

p_g^{var} – variable cost of generator g
p_g^{start} – startup cost of generator g
η_g – heat rate of generator g
p_g^{min} – minimum output of generator g
p_g^{max} – maximum output of generator g
τ_g^{min} – minimum on/off time of generator g
R_g^{up} – maximum upward ramp rate of generator g

R_g^{dn} – maximum downward ramp rate of generator g
$CF_{p,k}^{min}$ – minimum capacity factor of generator type k in province p (*provincial dispatch*)

Grid, Provincial Parameters
$d_{p,t}$ – electricity demand in province p at time t
$q_{g,t}, g \in G_H$ – fixed heat production for district heating by generator g at time t
μ – transmission loss between provinces
S^{up} – minimum upward reserve requirements
S^{dn} – minimum downward reserve requirements
S_p^{up} – minimum upward reserve requirements (*provincial dispatch*)
S_p^{dn} – minimum downward reserve requirements (*provincial dispatch*)
$M_{p,p'}$ – transmission capacity between province p and p'
H_p^{in} – hydro reservoir inflow per hour in province p
λ – hydropower generation factor
H_p^0 – hydro reservoir initial/final level in province p
D_p – wind capacity in province p
$\theta_{p,t}$ – wind capacity factor in province p at time t

Other Parameters
T – number of hours simulated
P – set of all provinces
Z – objective function
C_{coal} – cost of thermal coal

Chapter 5

Data

5.1 Electricity Demand

A single representative week of electricity load for each province is used for all scenarios, shown in Figure 5.1. It is constructed first from daily electricity totals by province (where Eastern Inner Mongolia is recorded separately) available for January 2013 [83]. There is limited variation in consumption from day to day and weekend to weekday, most likely owing to a high proportion of industrial loads in the region. To reconstruct daily totals in 2011, a constant scaling factor is applied to each day using monthly electricity growth figures from 2011-2013 [84]. Finally, consumption at each hour is estimated from a typical hourly load profile for a winter day published by the former State Electricity Regulatory Commission [85], reprinted in the Table A.1.

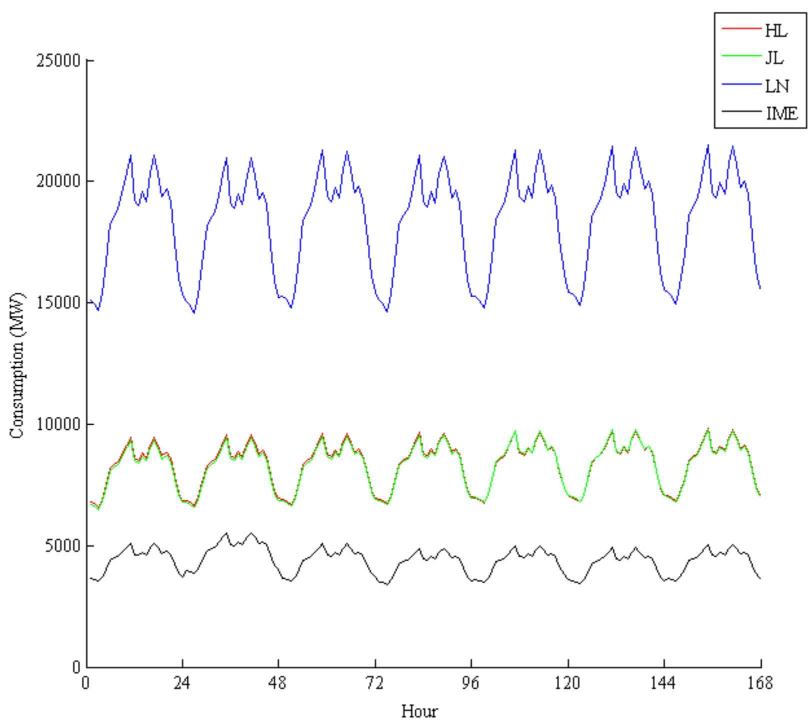

Figure 5.1. Simulated electricity load profile by province. (HL = Heilongjiang, JL = Jilin, LN = Liaoning, IME = Eastern Inner Mongolia)

5.2 Network

Intraprovincial transmission constraints are not addressed in this thesis, as I consider each province as a single node of supply and demand. Transmission is allowed between the four provincial nodes taking account of (1) capacity constraints and (2) losses from long-distance transmission.

In China, losses in the transmission and distribution infrastructure totaled 6.5% nationally in 2011 (defined by the difference between generation and consumption) [86]. Inter-provincial transmission in the Northeast is accomplished primarily at 500kV, with some additional support at 220kV. A single UHV-DC line between eastern Inner Mongolia and Liaoning became operational in 2010 [87]. Connections between major nodes in the Northeast may stretch 300-800 km. At these distances, line losses at 500kV may reach 2-6% [88]. Transmission losses are therefore assumed to be 5% ($\mu = 0.05$) across provincial boundaries.

Complete data on transmission interconnection capacities are not made public. For the most accurate description of the network, information on the characteristics of all lines in the region would be necessary. Additionally, it would be necessary to know when system operator use different values to schedule transactions based on experience with actual system operation.

This thesis relies on grid maps as well as numbers and voltages of lines that can be found in various government and grid company sources [89-91]. Using 900-MW as maximum loading of a 500 kV line and 200-MW for a 200 kV line at a distance of 500 km [88], estimates are obtained for interconnection capacities, shown in Table 5.1 and Figure 5.2. Inter-regional transmission from Northeast Grid to North Grid, which had a capacity of 1500 MW and only led to roughly 3% of generation being exported in 2010 [70], was not considered here.

	HL	JL	LN	IME
HL	0	4500	0	1800
JL	4500	0	3600	600
LN	0	3600	0	8000
IME	1800	600	8000	0

Table 5.1. Inter-provincial transmission capacities (MW). (HL = Heilongjiang, JL = Jilin, LN = Liaoning, IME = Eastern Inner Mongolia)

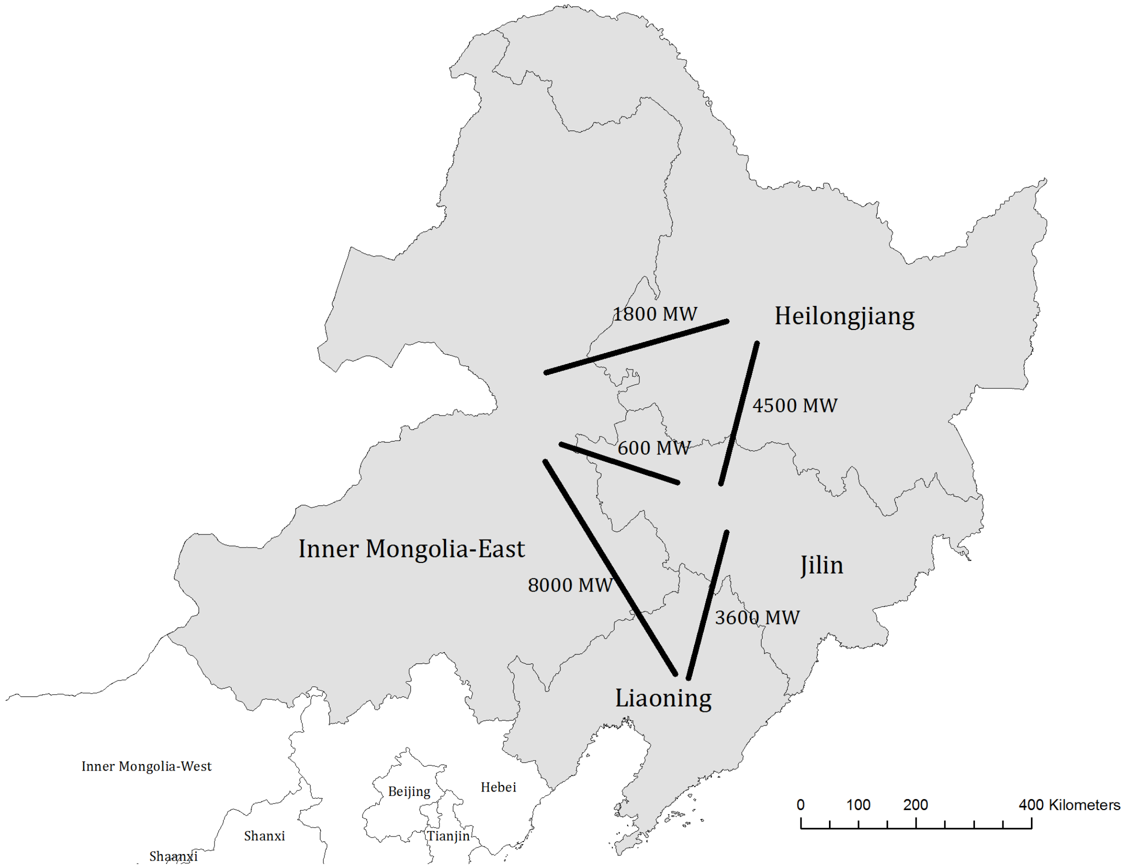

Figure 5.2. Inter-provincial transmission capacities in Northeast

In practice, as most plants are dispatched at the provincial level and transmission amounts are subject to negotiation, these transmission interconnections are not utilized at their full capacity. Based on historical transmission amounts, I approximated the effective transmission interconnection capacity for a provincial dispatch scenario (Table 5.2, Figure 5.3). Further, I take transmission interconnection to be uni-directional, reflecting the clear export/import distinction in transmission documents [67]. Note that Heilongjiang and Liaoning, which do not share a border, have an exporter/importer relationship in transmission pricing and summary statistics [67, 92]. This presumably reflects coordination in the transmission plan allocation among over-generation in Heilongjiang, under-generation in Liaoning, and intermediate Jilin province. In order to simplify this relationship, a direct transmission link is assumed in this scenario.

	2010 Exports (bn kWh)	**Assumed Interconnection Capacity in Provincial Dispatch (MW)**
HL --> JL	0.119	**0**
HL --> LN	5.257	**1200**
HL --> IME	0.426	**0**
JL --> LN	2.579	**600**
IME --> LN	10.622	**2400**

Table 5.2. Inter-provincial transmission capacities in provincial dispatch. Source of exports: [67]. (HL = Heilongjiang, JL = Jilin, LN = Liaoning, IME = Eastern Inner Mongolia)

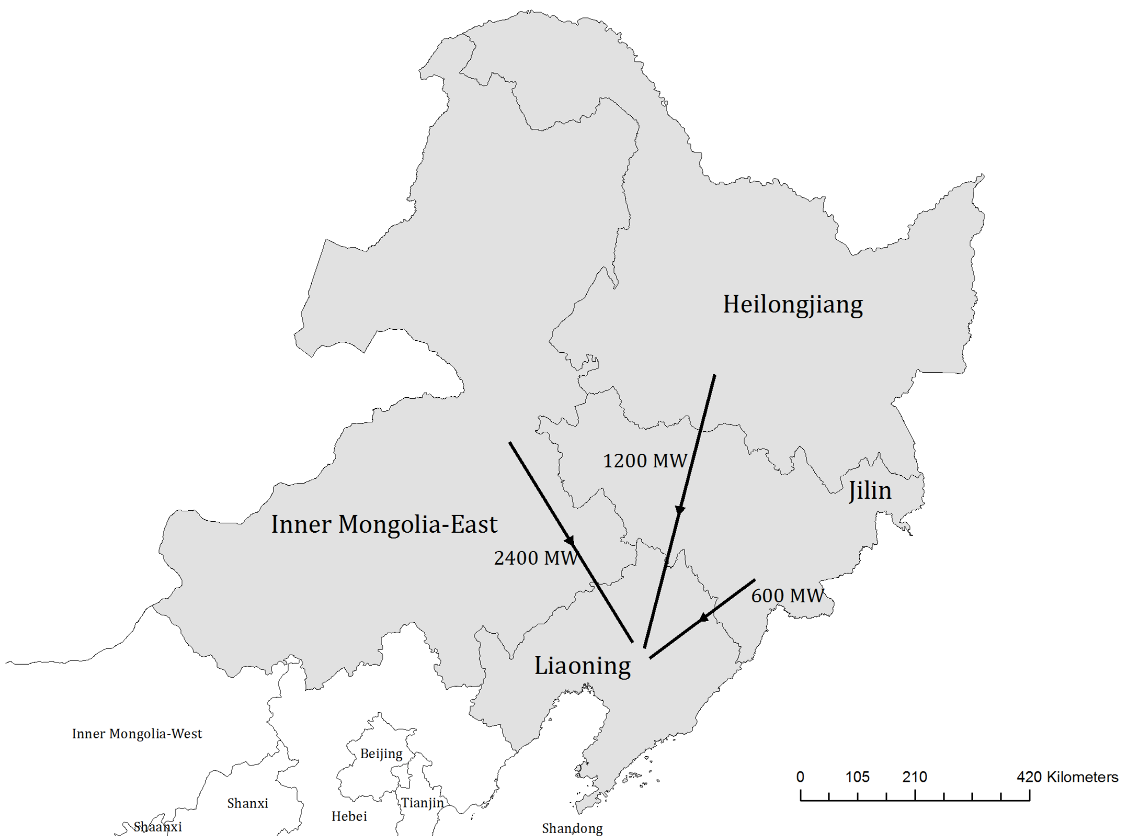

Figure 5.3. Assumed uni-directional inter-provincial transmission capacities under provincial dispatch

5.3 Unit Composition

The Northeast Grid contains three types of generators: thermal generators, hydropower, and wind. Thermal units are assumed to be entirely coal: biomass and natural gas-fired generators have very little penetration in the Northeast. Wind is roughly 12% of generating capacity, while coal makes up 80% of capacity (see Table 5.3). As mentioned above, two nuclear units came online in 2013 and 2014, after the 2011 model year examined here, which may have altered the situation.

	Capacity (MW)	%
Thermal	71,459	80.2%
Hydropower	7,005	7.9%
Wind	10,606	11.9%
Total	89,069	100.0%

Table 5.3. Generating Capacities in Northeast Grid at the end of 2010. Source: [93].

Coal-fired units in China range in size from 6 MW to 1000 MW. This wide distribution of unit sizes impacts efficiency (i.e., variable costs) as well as generator constraints important for commitment and dispatch schedules. Smaller units are typically older and slated first for early retirement under strong energy efficiency policy incentives that promote the use of advanced coal combustion technologies. As the exact composition is changing rapidly, it is difficult to find an authoritative source for all units in the Northeast.

Nevertheless, a reasonably good listing was published by the China Electricity Council for the generators nationally as of the end of 2010 [94]. These statistics include for each plant: location by province, total capacity, annual generation and other plant-level data of varying degrees of completeness, including heat rates and cogeneration requirements. I verified much of these data using other sources and clarified three important attributes for the model: eastern vs. western Inner Mongolia plants, unit composition within each plant, and cogeneration requirements.

Inner Mongolia is two distinct grid regions: the eastern portion, which is connected to the Northeast Grid and contains the four counties/cities of Chifeng, Tongliao, Hulunbei'er and Xing'an; and the remaining western portion, which makes up the Inner Mongolia Grid Company and is separate from State Grid. Typically, annual statistics do not differentiate between the two regions, and neither does the CEC database. I therefore coded each plant in Inner Mongolia by location, separating west from east, by various searches.

Critically, this database lacks information on the sizes of individual units at each plant, which have a potentially large impact on grid operation. For example, a 600-MW facility could consist of a single 600-MW ultra-super critical unit, or three 200-MW sub-critical units, and the aggregated quantities especially when dealing with integer commitment constraints, will differ. To create a reasonable assessment of this breakdown, the names and capacities of plants from [94] in the Northeast were checked against other sources of unit level data [27, 95-97], as well as websites of plant owners which sometimes provide this information. Units were then divided into six bins according to relatively common sizes: 25 MW, 50 MW, 135 MW, 200 MW, 350 MW, and 600 MW. Numbers of units were scaled to preserve the same total installed capacity.

Finally, units with cogeneration requirements were verified using the unit level data above, reclassifying several thermal units as cogeneration, if applicable. This was necessary to account for post-construction cogeneration retrofits. Figures 5.4 and 5.5 show the breakdown for electricity-only and cogeneration units, totaling 46.6 GW and 23.9 GW, respectively. The total capacity was not found to deviate significantly from provincial totals [86] and region-wide totals in Table 5.2 [93].

The fraction of CHP does deviate from other published sources, which claim CHP makes up 50% of coal-fired capacity in the Northeast [73], or 29.8 GW in Liaoning, Heilongjiang and Jilin provinces [51]. These deviations may be attributed to the particular aggregating methodology used, where if a single unit within a plant provides district heating, the entire plant's capacity is included in the total [52]. There may also be plants which were recently retrofitted or provide relatively small heating loads that I have not included in these totals.

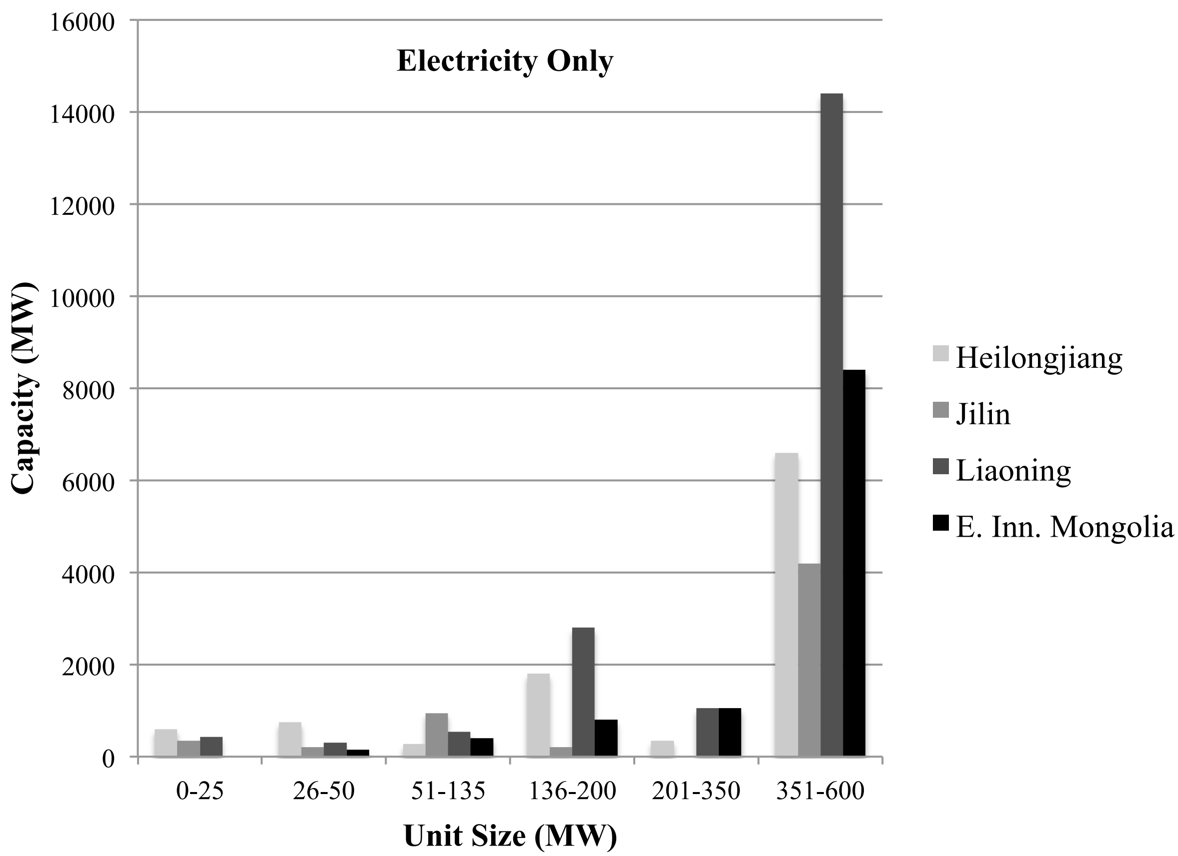

Figure 5.4. Composition of electricity-only coal-fired units by province in the Northeast.

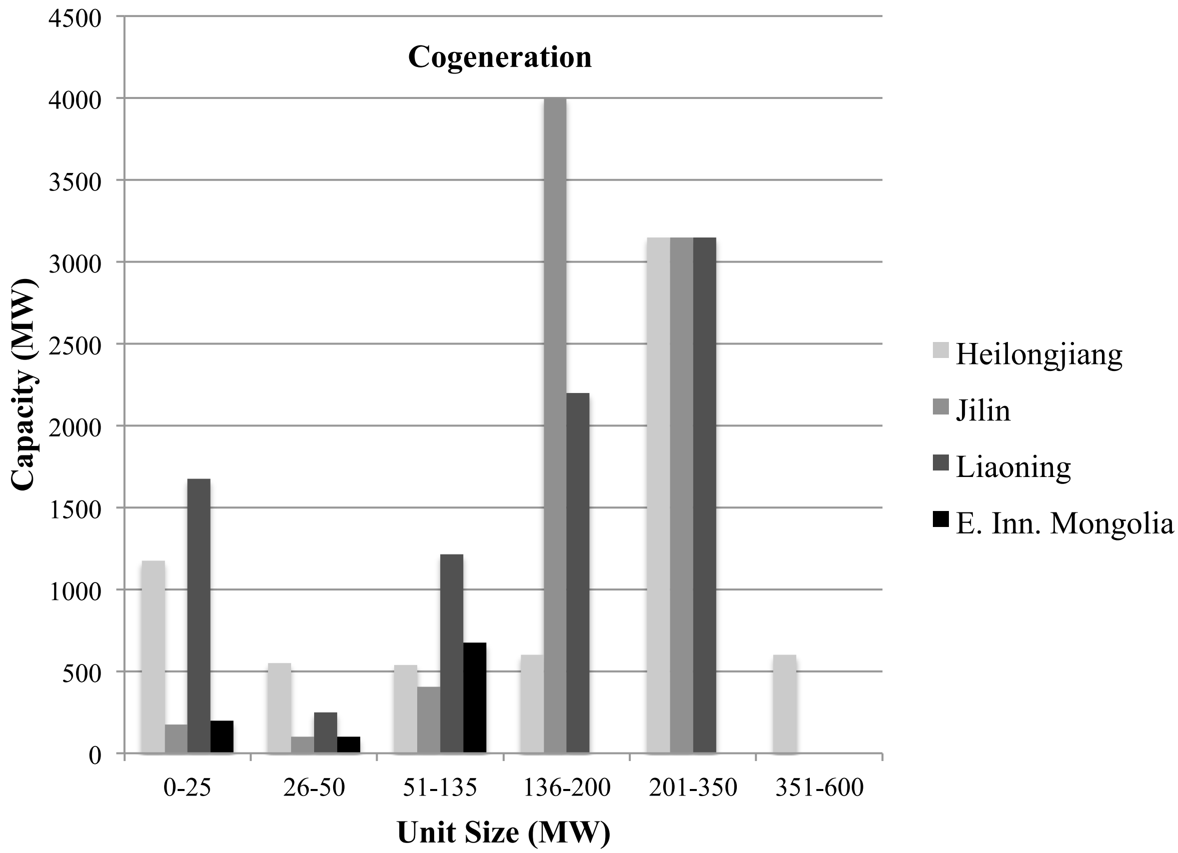

Figure 5.5. Composition of CHP coal-fired units by province in the Northeast.

The basic goal of the generation quota, or equal shares dispatch, method of capacity allocation is to ensure all size of generators have the same annual capacity factors. Since quota trading does not represent a significant fraction of generation in the Northeast, I neglect these adjustments in the formulation, using the same minimum capacity factor for all sizes.

To calculate the minimum capacity factors in winter, I started with average annual capacity factors by province. These vary significantly across provinces, with northeastern provinces having low values relative to the rest of the country (see Figure 5.6). Because of the need to dispatch and balance load primarily at the provincial level, it is reasonable to assume that these minimum capacity factors also vary by province. Based on the variation in Figure 5.6, Liaoning and Heilongjiang should have higher requirements than Jilin. The total for Inner Mongolia is aggregated for both west and east, hence it is difficult to estimate E. Inner Mongolia's minimum capacity factors. On the other hand, E. Inner Mongolia has a higher fraction of large units in its mix of thermal generators compared to other provinces, which would be dispatched under cost minimization regardless of a minimum quota requirement. Hence, E. Inner Mongolia is considered together with Jilin.

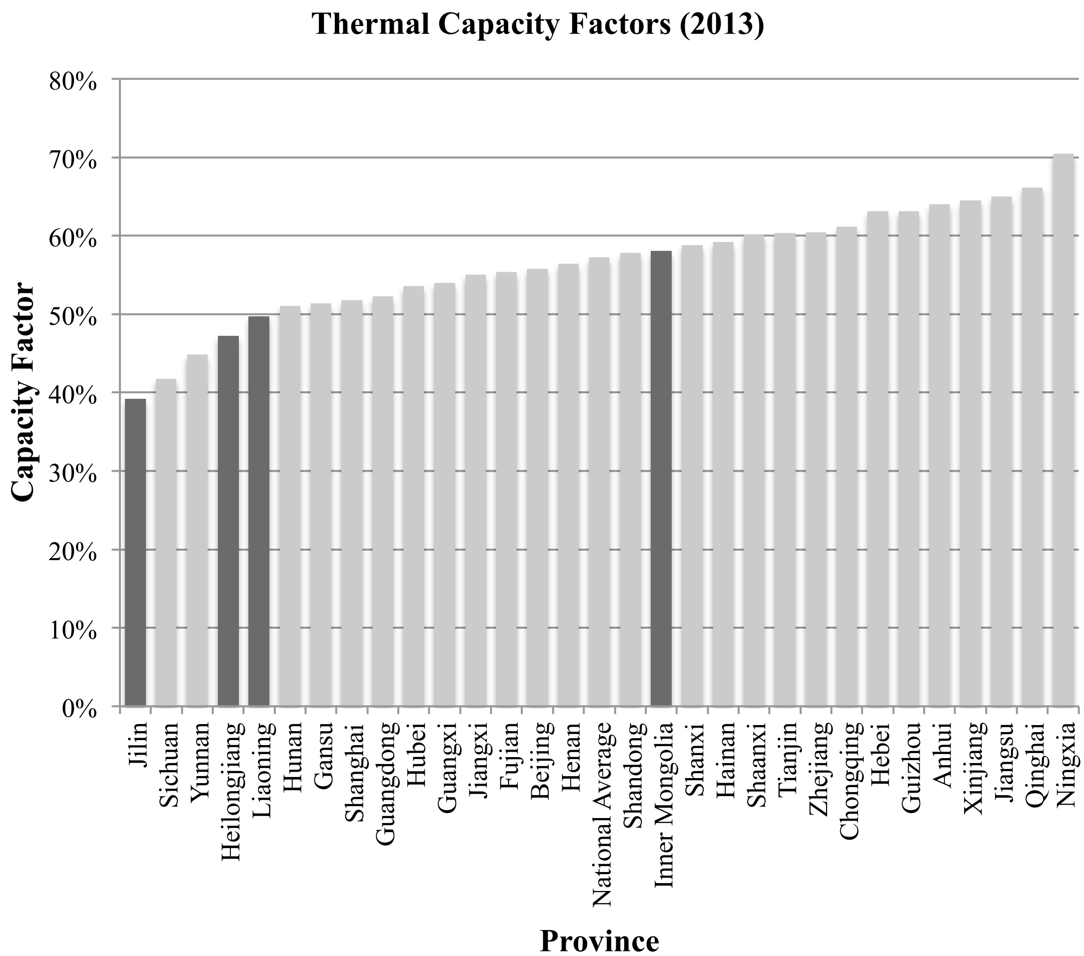

Figure 5.6. Capacity factors for thermal generators by province (2013). Northeast provinces are shaded. Source: [98].

Dividing the year into a six-month heating period and six-month non-heating period, and assuming that electricity-only units can at best achieve 70-80% capacity factors during the non-heating periods, three scenarios were created to simulate the annual quota (see Table 5.4).

	HL	JL	LN	IME
CF1	0.1	0	0.1	0
CF2	0.1	0.1	0.1	0.1
CF3	0.1	0	0.2	0

Table 5.4 Minimum capacity factors by province in three generation quota scenarios tested. (HL = Heilongjiang, JL = Jilin, LN = Liaoning, IME = Eastern Inner Mongolia)

5.4 Generator Characteristics

Accurate data on coal-fired plant performance were not available for this thesis. As plants were categorized into six bins according to size above, further granularity would not bring any additional insights. In the base case, heat rates by unit size were extrapolated from a 2006 tabulation (see Table 5.5) [18]. Up and down maximum ramp rates were assumed to be 15% of capacity per hour. Some U.S. and European power system operators claim that ramping of up to 50% of capacity per hour is possible for coal-fired units [16]. These formed a sensitivity on flexibility of coal units.

Very little is published on startup costs in China, which relate to additional maintenance costs associated with cycling as well as expensive fuel (such as oil) used to warm up the boiler. Further, generators do not make bids of these costs in China, and may not have a proper accounting themselves of the costs. Some sensitivities were performed on the effect of startup costs on operation, and the base case was taken from a Northeast Grid regulation regarding peaking compensation: 600 RMB / MW [99].

Unit size (MW)	Heat rate (gce/kWh)
6	600
12	550
25	500
50	440
100	410
300	340
600	299
1000	286

Table 5.5. Heat rates for coal-fired generators by unit size. Source: [18].

Minimum up and down times are also subject to uncertainty. Previous grid operation modeling on Northeast China assumed that units less than 200 MW are able to flexibly start up and shut down, while for larger units the costs are prohibitive [32]. During winter heating months, for the purposes of this research, it is assumed that cogeneration plants are always on. Thus, for electricity-only plants, the key distinction is whether the unit is able to cycle on a daily basis to follow net load after must-run cogeneration units are dispatched. In the base case, I assume that the minimum up/down times are 3, 6 and 12 hours for 25/50-MW, 135/200-MW, and 350/600-MW units, respectively.

Recalling Figures 2.2 and 2.3, which outlined the operational limits on CHP units, Figure 5.7 transforms this relationship to power-heat coordinates using data from a single extraction 300-MW CHP unit in Jilin province [100]. As in Figure 2.2, as extraction first increases, the diverted steam lowers both the minimum and maximum electricity outputs. After a threshold extraction steam amount (~100 t/h), the minimum condenser output is reached and feasible minimum generation then increases with larger extractions, moving up the condenser threshold until maximum extraction is reached (~400 t/h).

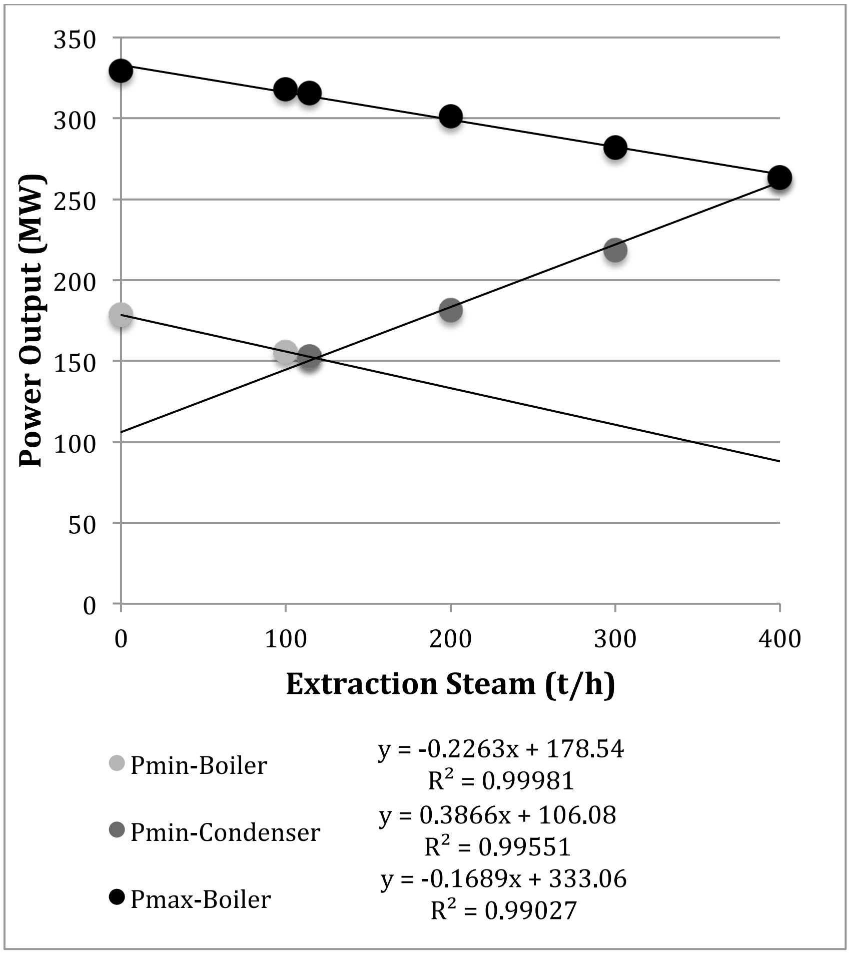

Figure 5.7. Power-heat relationship for single extraction 300-MW CHP unit. Data: [100].

The power-heat relationship will not necessarily scale linearly for different unit sizes. Smaller units will have larger heat to power ratios, because the boiler must meet minimum local heating requirements. Larger units will have smaller heat to power ratios because district heating demand has a finite upper limit due to heat grid losses and in some cases the units were retrofitted post-construction to provide heating services; hence, the boilers may be undersized. To generate power-heat curves for all unit sizes, Figure 5.7 was scaled on the vertical axis by unit size and on the horizontal axis by assumed typical maximum extraction amounts in Table 5.6. Using this method, all units have a minimum electricity output of 54% capacity under zero extraction. All coefficients are in Appendix, Tables A.2 and A.3.

Unit size (MW)	Extraction (t/h)
25	100
50	180
135	300
200	350
350	425
600	1110*

Table 5.6. Maximum extraction amounts by cogeneration unit size. *The sole 600-MW cogeneration unit in the Northeast was recently retrofitted to service a large industrial demand [101].

5.5 Heat Demand

Nationally, roughly two-thirds of district heating provides steam for industrial processes, and a third provides heat for residential and commercial buildings [52]. Industrial processes have relatively flat loads during the day and throughout the year, while residential demand only exists during the winter heating period and varies with temperature: the peak occurs in early morning and heating demand subsides in early afternoon. Therefore, the indicative daily heat load in Figure 5.8 was used. The ratio of peak to minimum heat loads is 1.51.

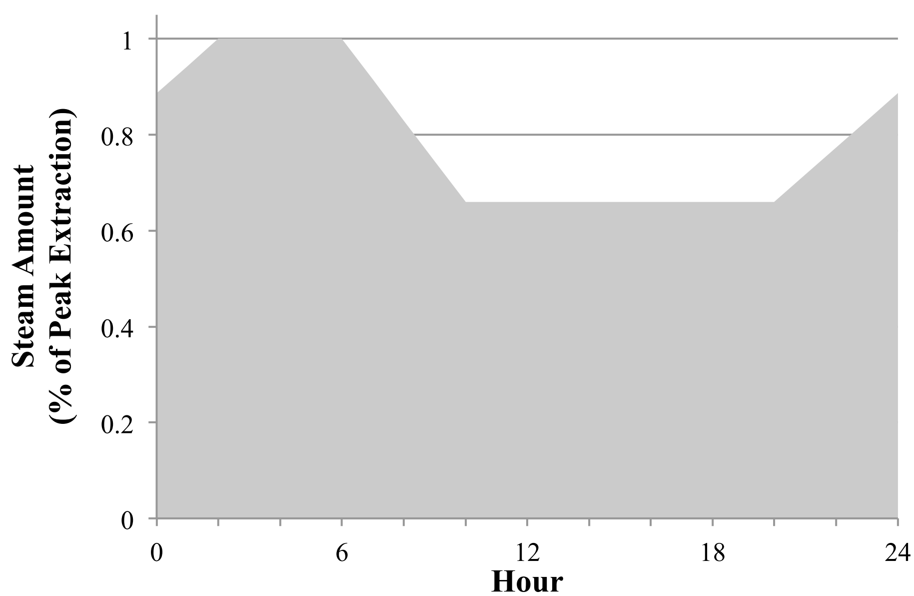

Figure 5.8. Daily heat load during peak winter period.

Current planning and dispatch in the Northeast is based on a fixed minimum electricity output, or minimum mode, which in theory should represent the technical minimum output under peak steam extraction. The minimum modes are shown in Table 5.7 together with minimum outputs under zero extraction – equivalently, electricity-only units – based on the calculated 54% cutoff are shown. These data and the power heat relationships give us the heating demand for each generator type and dynamic minimum electricity outputs can be derived using the dynamic power-heat relationship (see Figure 5.9).

Unit Size	Minimum Mode (Peak Winter)	Minimum Output (Non-Winter Heating)
25	18	13.5
50	37	27
135	100	73
200	140	108
350	230	189
600	360	324

Table 5.7. Minimum modes and electricity-only minimum outputs by unit size. Units: MW.

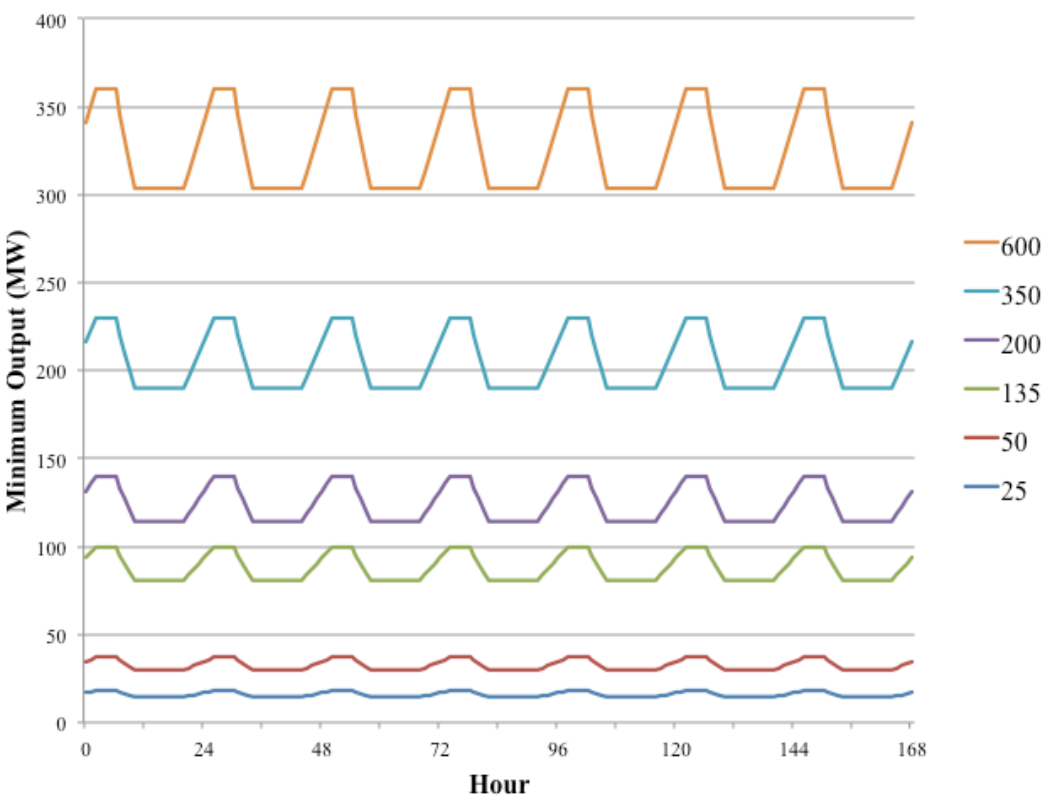

Figure 5.9. Dynamic minimum outputs of cogeneration units by unit size (MW), derived from Figures 5.7 and 5.8.

5.6 Wind Resource Profiles

Wind resource profiles for China are drawn from [102], which uses Modern Era Retrospective-analysis for Research and Applications (MERRA) boundary layer flux data, a thirty-one-year (1979-2009), 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). It is constructed from the GEOS-5 Atmospheric Data Assimilation System, as in [103].

In this analysis, forests, urban areas, slopes greater than 10% and geographic features such as lakes, rivers, and major industrial and transportation facilities are not considered available for turbine siting. An exclusion map of unavailable locations for wind turbines was constructed in the ArcGIS platform using 30-arcsecond elevation data from NASA's Shuttle Radar Topography Mission and a land-cover classification for China from satellite remote-sensing [104, 105].

MERRA generates spatial wind power density figures, which are related to wind power generation via a turbine-specific power curve. The data used in this thesis draw from [102] which is based on a Sinovel 1.5-MW wind turbine with 82-meter hub height (SL1500/82), common in Chinese onshore applications. Province-wide wind capacity factors for each hour were then constructed by averaging over the available land area and hourly production by grid cells.

The method used to generate hourly production assumes equal spatial distribution of wind turbines across the province, which is not realistic based on current installation locations and incentives to concentrate wind development. For example, an analysis of five-minute wind power data in 2008-2009 at wind farms in the Northeast found significant correlation across sites [87]. This indicates that currently operational wind farms are not sufficiently dispersed geographically to take advantage of smoothing of wind power generation from a large region such as the Northeast.

Geospatial data on wind farm locations were not available for this thesis, which could be used to aggregate wind power resources exactly where wind farms are situated. To mimic current deployment, therefore, this thesis takes the wind profile of a single representative province – East Inner Mongolia – and duplicates it across all provinces in the region. E. Inner Mongolia is the likely choice as it has the largest installed wind capacity and average wind speeds of the four Northeast provinces. It also captures some level of broadening.

To capture the variability in wind resources, six weeks from the most recent year in the dataset – 2009 – were chosen. Three weeks each from January and March, winter months when wind is most plentiful and constraints from CHP generation are largest, were chosen. All weeks used in this analysis are shown in Figure 5.10.

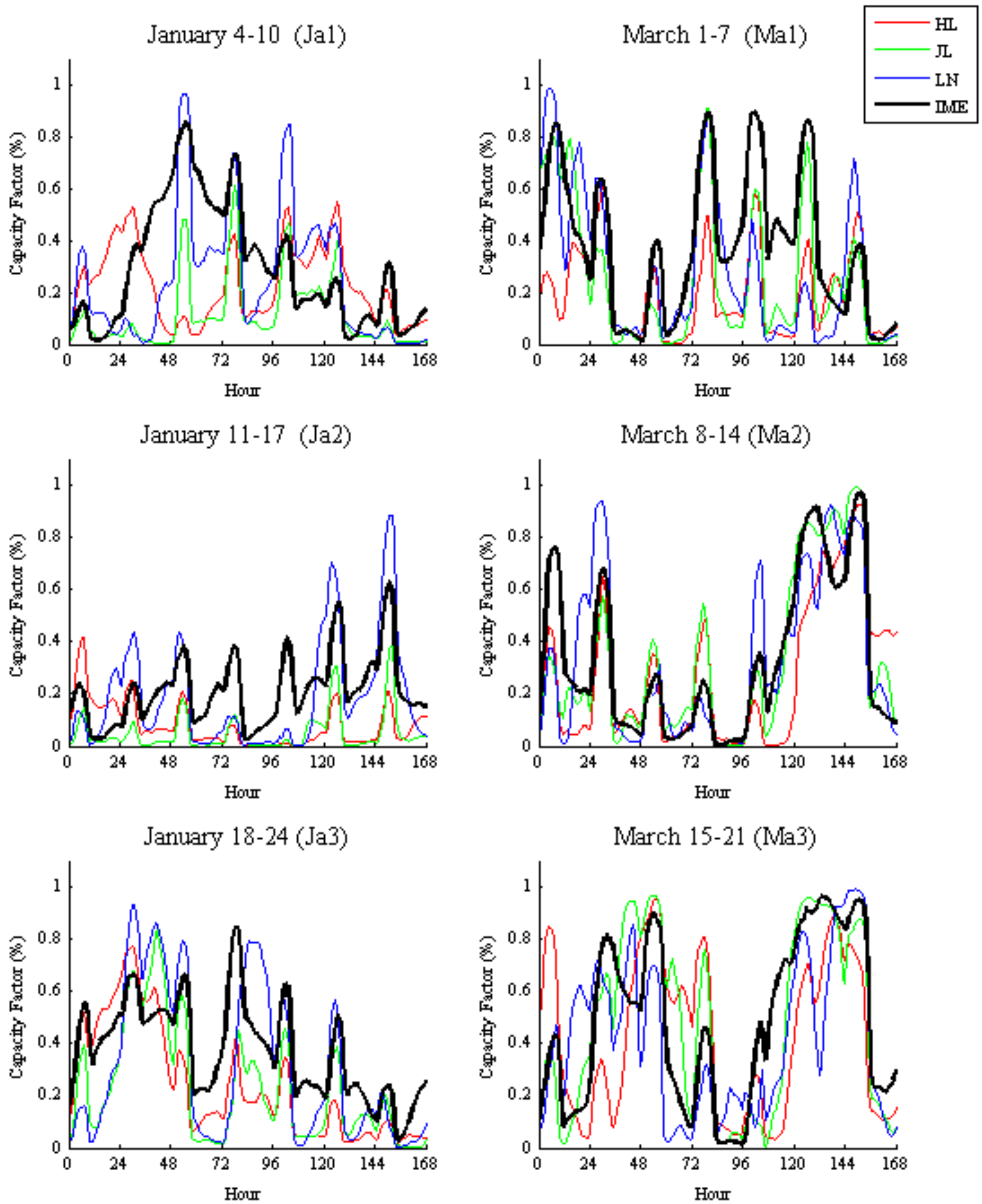

Figure 5.10. All wind profiles by week and province. Eastern Inner Mongolia (black) is the default for all provinces in this thesis. (HL = Heilongjiang, JL = Jilin, LN = Liaoning, IME = Eastern Inner Mongolia)

5.7 Hydropower Availability

I use monthly inflow and generation data from 550-MW Lianhua Reservoir in Heilongjiang province to simulate hydropower availability in the winter in Northeastern provinces by (1) calculating the average daily winter inflow, (2) estimating water storage from summer months, and (3) adjusting provincial generator performance from historic capacity factors. As there is significant interannual variation of inflows, I generate two hydropower scenarios corresponding to a representative small (2012) and large (2013) rainfall year.

A detailed annual hydrothermal coordination model was out of scope for this thesis. At Lianhua, only around 3% of reservoir inflows occur in the peak winter heating months January-March, and 7-20% in the entire winter heating season November-March [106]. Generation during January-March is larger than inflows, roughly 4-7%, reflecting water storage from heavy rainfall months June-September. Constraints such as tourism, fishing and flood prevention impact how much water can be displaced between seasons [107]. Instead of modeling these individually, current hydropower scheduling was assumed with historic rates of water availability but with flexibility to dispatch on a weekly basis.

The inflows and generation amounts of Lianhua of two representative years, 2013 and 2012, are shown in Table 5.8. Based on the difference between the annual share of inflows and generation in the first quarter (Q1), I estimated adjusted daily inflow. In addition, provinces vary in terms of capacity factors, reflecting different geographies and water availability. The differences between province-wide capacity factors and Lianhua were calculated in Table 5.9, which were used to adjust inflow amounts by province (see Table A.4 for full table). A linear production factor $\lambda = 134.8\ \mathrm{GWh/km^3}$, based on 2010 annual inflows and generation, was chosen for all years.

2013 (Large Hydro Year)

	Inflow (km^3)	(% Annual)	Generation (GWh)	(% Annual)
Jan	0.215	1.7%		
Feb	0.121	1.0%		
Mar	0.073	0.6%		
Q1 Subtotal	0.409	3.3%	91	6.5%
Annual	12.46	100.0%	1,413	100.0%
Q1 Inflow:	0.004595	km^3 / day		
Adjusted Q1 Inflow:	**0.009033**	**km^3 / day**		

2012 (Small Hydro Year)

	Inflow (km^3)	(% Annual)	Generation (GWh)	(% Annual)
Jan	0.027	0.5%		
Feb	0.06	1.0%		
Mar	0.073	1.2%		
Q1 Subtotal	0.16	2.7%	37	4.6%
Annual	5.93	100.0%	799	100.0%
Q1 Inflow:	0.001797	km^3 / day		
Adjusted Q1 Inflow:	**0.003052**	**km^3 / day**		

Table 5.8. Lianhua reservoir inflows and generation for 2012, 2013. Sources: [94, 106, 108, 109].

	Capacity (GW)	Generation (GWh)	Capacity Factor	Difference from Lianhua
Lianhua	*550*	*926*	*19.2%*	-
Heilongjiang	888	1982	25.5%	6.3%
Jilin	4,185	10012	29.4%	10.2%
Liaoning	1,817	7631	47.9%	28.7%

Table 5.9. Capacity factor adjustments by province using 2010 hydropower capacity and generation data. Sources: [94].

Chapter 6

Results

The model was implemented in GAMS using the mixed integer solver of CPLEX. Each scenario was run using 8 parallel threads on a 64-bit dual-socket quad core 2.7 GHz Intel nehalem machine with 12 GB RAM. The resource limit was set to 2 hours and the relative optimality criteria to 0.01. Besides runs with the coupling minimum capacity factor constraint or provincially-determined reserves where a feasible solution was difficult to find, all solved to optimality with greater than .001 tolerance. Where indicated, the resource limit was extended to up to 18 hours to improve the solution. Only results with better than 0.01 optimality tolerance are reported.

The results of scenarios and sensitivities are shown below, and analysis is left to Chapter 7.

6.1. Reference Scenario

The costs and wind results from the six wind profiles for the reference scenario are shown in Table 6.1. Throughout, averages are taken over the outcomes of the six wind profiles, in order to give an indication of these quantities over the entire winter season. They do not represent a separate run using averaged inputs. The weekly production of each generating type by province and for the entire region are shown in Table 6.2 as a percentage of full capacity. In this and future tables, the number following coal or cogen refers to the unit size: e.g., coal50 is an electricity-only 50-MW thermal unit.

	Objective (mil RMB)	Coal Use (Mtce)	Wind Generation (GWh)	Wind Share (% Generation)	Wind Curtailment (%)
Ja1	1,454.3	2.066	504.7	7.6%	5.0%
Ja2	1,481.4	2.109	358.6	5.4%	5.9%
Ja3	1,425.7	2.028	629.7	9.5%	5.9%
Ma1	1,432.4	2.035	606.2	9.1%	9.6%
Ma2	1,443.9	2.050	555.5	8.4%	6.9%
Ma3	1,390.3	1.972	815.2	12.3%	6.1%
Avg	**1,438.0**	**2.043**	**578.3**	**8.7%**	**6.6%**

Table 6.1. Costs, coal use and wind curtailment for each of the wind profiles in the reference scenario. Avg denotes an average of the results over the six profiles, not a separate run.

	HL	JL	LN	IME	Entire Region
	(Wind Profiles Average)				
coal25	0	0	0	0	0
coal50	0	0	0	0	0
coal135	0	0	0	0	0
coal200	0	0	0	0	0
coal350	0	0	0	0	0
coal600	63.3%	65.1%	50.4%	55.3%	56.0%
cogen25	72.3%	72.3%	72.3%	72.3%	72.3%
cogen50	74.7%	74.7%	74.7%	74.7%	74.7%
cogen135	75.0%	75.0%	74.9%	75.0%	75.0%
cogen200	72.2%	72.2%	72.1%	0	72.2%
cogen350	69.1%	69.0%	68.9%	0	69.0%
cogen600	73.2%	0	0	0	73.2%
hydro	0.8%	3.8%	2.1%	0	2.9%
wind	31.7%	32.6%	30.7%	33.8%	32.2%

Table 6.2. Weekly production by province and the entire region for each generating type in reference scenario, as a percentage of full capacity utilization. The number following coal/cogen refers to the capacity: e.g., coal50 is an electricity-only 50-MW thermal unit.

Using the Ma1 wind profile, hourly production curves by generating type are shown graphically in Figure 6.1. The shaded production quantities at the bottom of the stacked curves refer to cogeneration units, akin to base load in this system. Inter-provincial transmission totals are shown in Table 6.3. Transmission amounts are calculated as net over the entire period, where exporting is positive and importing is negative. Here, the average, minimum and maximum of the six wind profiles are shown to demonstrate the weekly variation and overall tendency of transmission during winter weeks.

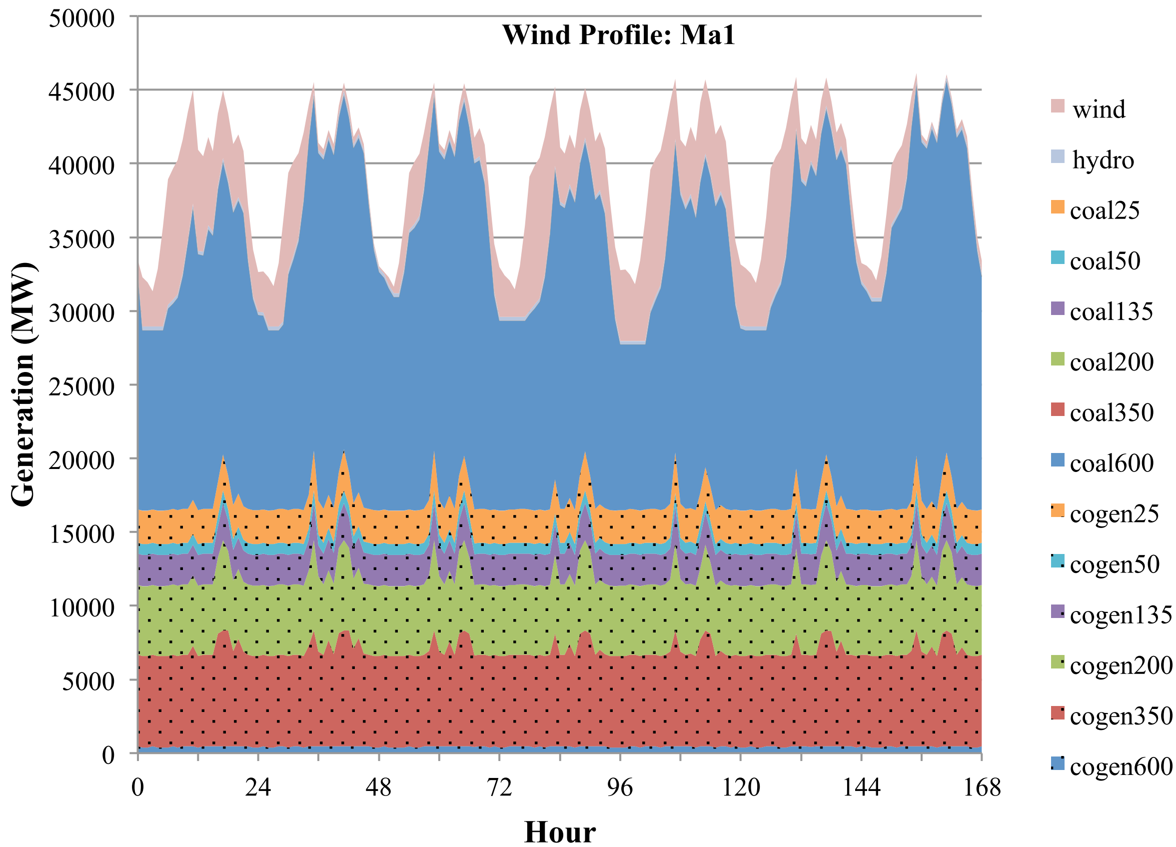

Figure 6.1. Generation by type in reference scenario. Shading refers to cogeneration units.

	Average (GWh)	Minimum (GWh)	Maximum (GWh)
	(Over Wind Profiles)		
HL --> JL	144.9	-364.5	383.0
HL --> IME	51.3	-52.8	125.6
JL --> LN	270.0	-106.1	500.0
JL --> IME	18.1	0.5	43.6
IME --> LN	423.2	-78.2	893.5

Table 6.3. Inter-provincial transmission in reference scenario

6.2. Dynamic CHP Dispatch

The cost and wind results for the sensitivity relating to the dynamic minimum load of cogeneration units are shown in Table 6.4. The average of the results over the six wind profiles is compared to the reference fixed minimum output case (minimum mode, MM). A comparison of weekly production for dynamic and MM by each generating type is in Table 6.5.

	Objective (mil RMB)	Coal Use (Mtce)	Wind Generation (GWh)	Wind Share (% Generation)	Wind Curtailment (%)
Ja1	1,440.3	2.045	500.7	7.5%	5.8%
Ja2	1,467.7	2.095	343.9	5.2%	9.8%
Ja3	1,412.3	2.012	608.0	9.2%	9.1%
Ma1	1,419.7	2.017	595.7	9.0%	11.2%
Ma2	1,430.9	2.036	538.8	8.1%	9.6%
Ma3	1,376.6	1.954	806.6	12.1%	7.1%
Avg	**1,424.6**	**2.027**	**565.6**	**8.5%**	**8.7%**
Reference	1,438.0	2.043	578.3	8.7%	6.6%
Diff	**-13.4**	**-0.017**	**-12.7**	**-0.2%**	**2.0%**

Table 6.4. Costs, coal use and wind curtailment for dynamic CHP dispatch compared to reference minimum mode (MM).

	Dynamic CHP	**MM**
coal25	0	0
coal50	0	0
coal135	0	0
coal200	0	0
coal350	0	0
coal600	58.8%	56.0%
cogen25	63.6%	72.3%
cogen50	65.8%	74.7%
cogen135	66.6%	75.0%
cogen200	66.1%	72.2%
cogen350	70.1%	69.0%
cogen600	81.8%	73.2%
hydro	2.9%	2.9%
wind	31.5%	32.2%

Table 6.5. Weekly production for dynamic CHP dispatch and reference minimum mode (MM), averaged over wind profiles.

A breakdown of the total costs into generation and startup costs of the dynamic CHP scenario is shown in Table 6.6.

	Objective (mil RMB)	Generation Costs (mil RMB)	Startup Costs (mil RMB)
Ja1	1440.3	1431.7	8.6
Ja2	1467.7	1466.7	1.1
Ja3	1412.3	1408.7	3.6
Ma1	1419.7	1412.1	7.6
Ma2	1430.9	1425.2	5.8
Ma3	1376.6	1367.6	9.0
Avg	**1424.6**	**1418.7**	**5.9**
Reference	1438.0	1430.3	7.7
Diff	**-13.4**	**-11.7**	**-1.7**

Table 6.6. Cost breakdown for dynamic CHP dispatch.

6.3. Flexible Coal

In the reference scenarios, all coal generators were assumed to have a 54% minimum output threshold and have limited ramping abilities (15% of capacity per hour). However, these may be overly conservative estimates, or improvements in plant operation may add some flexibility. The costs and wind results of this reduced minimum output are shown in Table 6.7 and compared to the reference case.

	Objective (mil RMB)	Coal Use (Mtce)	Wind Generation (GWh)	Wind Share (% Generation)	Wind Curtailment (%)
Ja1	1,442.5	2.058	518.4	7.8%	2.5%
Ja2	1,469.0	2.099	378.7	5.7%	0.6%
Ja3	1,412.5	2.016	659.7	9.9%	1.4%
Ma1	1,417.7	2.022	637.1	9.6%	5.0%
Ma2	1,431.1	2.041	577.7	8.7%	3.1%
Ma3	1,378.1	1.962	842.1	12.7%	3.0%
Avg	**1,425.2**	**2.033**	**602.3**	**9.1%**	**2.8%**
54% Min	1,438.0	2.043	578.3	8.7%	6.6%
Diff	**-12.8**	**-0.010**	**24.0**	**0.4%**	**-3.9%**

Table 6.7. Decreasing minimum outputs of electricity-only plants from 54% to 40%.

Faster ramping and shorter startup and shutdown times also increase the flexibility of coal units. In the reference case, 15% of capacity per hour was assumed, and startup/shutdown times were assumed to be 12 hours for 600 and 350 MW units, 6 hours for 200 and 135 MW units, and 3 hours for 50 and 25 MW units. In the short startup/shutdown scenario, the largest units only require 6 hours. The costs and wind results of each scenario are shown in Table 6.8.

Startup / Shutdown	Ramp Rate (% Capacity per hour)	Objective (mil RMB)	Coal Use (Mtce)	Wind Generation (GWh)	Wind Share (% Generation)	Wind Curtailment (%)
Long	15%	1,432.35	2.035	606.2	9.1%	9.6%
	50%	1,432.16	2.035	603.7	9.1%	10.0%
Short	15%	1,432.39	2.035	607.9	9.2%	9.3%
	50%	1,432.13	2.035	605.5	9.1%	9.7%

Table 6.8. Increasing ramp rates from 15% to 50% for all plants and decreasing startup/shutdown times of 350 and 600 MW units from 12 hours to 6 hours.

As grid operators may have even more conservative assumptions on the ability of large units to cycle, a greater sensitivity on startup/shutdown times was performed. The costs and wind results of varying startup/shutdown times from 24 hours to 6 hours are shown in Table 6.9.

Startup times (large, med, small) (hrs)	Objective (mil RMB)	Coal Use (Mtce)	Wind Generation (GWh)	Wind Share (% Generation)	Wind Curtailment (%)
24, 24, 6	1,432.4	2.035	603.7	9.1%	10.0%
24, 12, 6	1,432.3	2.035	606.2	9.1%	9.6%
12, 12, 6	1,432.3	2.035	606.2	9.1%	9.6%
6, 6, 6	1,432.4	2.035	604.6	9.1%	9.8%
6, 3, 3	1,432.3	2.035	606.2	9.1%	9.6%

Table 6.9. Costs, coal use and wind curtailment under various assumptions on startup/shutdown times for large (600, 350), medium (200, 135), and small (50, 25) units. Ma1 wind profile.

Similarly, the cost of startups was varied to see the effect on total costs as well as wind integration (Table 6.10). The cost breakdown between generation and startup costs for these assumptions is shown in Table 6.11.

Startup Cost (Yuan per MW)	Objective (mil RMB)	Coal Use (Mtce)	Wind Generation (GWh)	Wind Share (% Generation)	Wind Curtailment (%)
600	1,432.3	2.035	606.2	9.1%	9.6%
500	1,430.6	2.030	622.0	9.4%	7.2%
400	1,428.4	2.026	633.5	9.5%	5.5%

Table 6.10. Costs, coal use and wind curtailment under various assumptions on startup costs. (Ma1 wind profile)

Startup Cost (Yuan per MW)	Objective (mil RMB)	Generation Costs (mil RMB)	Startup Costs (mil RMB)
600	1,432.3	1424.8	7.6
500	1,430.6	1421.2	9.5
400	1,428.4	1418.3	10.1

Table 6.11. Generation and startup cost breakdown for various assumptions on startup costs. (Ma1 wind profile)

6.4. Provincial Dispatch

The above scenarios optimize across the entire region assuming a single dispatch operator and shared reserve requirements. In practice, many plants are dispatched at the provincial level, with limited real-time load balancing capabilities utilizing transmission interconnections. For the following, to simulate these relatively disconnected provinces, reserve requirements are calculated and maintained for each province according to the largest generator on the grid, 600 MW.

Additionally, transmission interconnection capacities are reduced and made uni-directional based on historical values, in order to approximate the transmission plans and quotas that are negotiated annually (see Table 5.2). Costs and wind results for each of the profiles are shown in Table 6.12.

	Objective (mil RMB)	Coal Use (Mtce)	Wind Generation (GWh)	Wind Share (% Generation)	Wind Curtailment (%)
Ja1	**1,462.7**	**2.070**	**494.2**	**7.4%**	**7.0%**
(Regional)	1,454.3	2.066	504.7	7.6%	5.0%
Ja2	**1,493.4**	**2.114**	**341.7**	**5.1%**	**10.3%**
(Regional)	1,481.4	2.109	358.6	5.4%	5.9%
Ja3	**1,436.9**	**2.034**	**612.2**	**9.2%**	**8.5%**
(Regional)	1,425.7	2.028	629.7	9.5%	5.9%
Ma1	**1,444.3**	**2.040**	**589.8**	**8.9%**	**12.0%**
(Regional)	1,432.4	2.035	606.2	9.1%	9.6%
Ma2	**1,455.6**	**2.055**	**540.0**	**8.1%**	**9.5%**
(Regional)	1,443.9	2.050	555.5	8.4%	6.9%
Ma3	**1,401.1**	**1.977**	**798.8**	**12.0%**	**8.0%**
(Regional)	1,390.3	1.972	815.2	12.3%	6.1%
Avg	**1,449.0**	**2.048**	**562.8**	**8.5%**	**9.1%**
Reference	1,438.0	2.043	578.3	8.7%	6.6%
Diff	**11.0**	**0.005**	**-15.5**	**-0.2%**	**2.5%**

Table 6.12. Costs, coal use and wind curtailment for provincial dispatch compared to regional dispatch.

6.5. Generation Quotas

Three sets of minimum generation quotas were chosen to constrain the reference cases of both regional and provincial dispatch (refer to Table 5.x). Under the computational resource limits (up to 18 hours), only the Ma1 wind profile under the CF1 scenario – corresponding to a minimum capacity factor (CF) for electricity-only units of 0.1 for Heilongjiang and Liaoning, and 0 for Jilin and East Inner Mongolia – returned an optimal solution within the optimality tolerance for both regional and provincial dispatch scenarios (see Table 6.13). The addition of these units in the dispatch can be seen in Figure 6.2.

	Objective (mil RMB)	Coal Use (Mtce)	Wind Generation (GWh)	Wind Share (% Generation)	Wind Curtailment (%)
Regional Reference	1,432.4	2.035	606.2	9.1%	9.6%
Regional (Min CF)	1,442.9	2.053	594.8	9.0%	11.3%
Provincial Reference	1,444.3	2.040	589.8	8.9%	12.0%
Provincial (Min CF)	1,454.3	2.055	592.0	8.9%	11.7%

Table 6.13. Costs, coal use and wind curtailment under minimum generation quota CF1 for regional and provincial dispatch (Ma1 wind profile only).

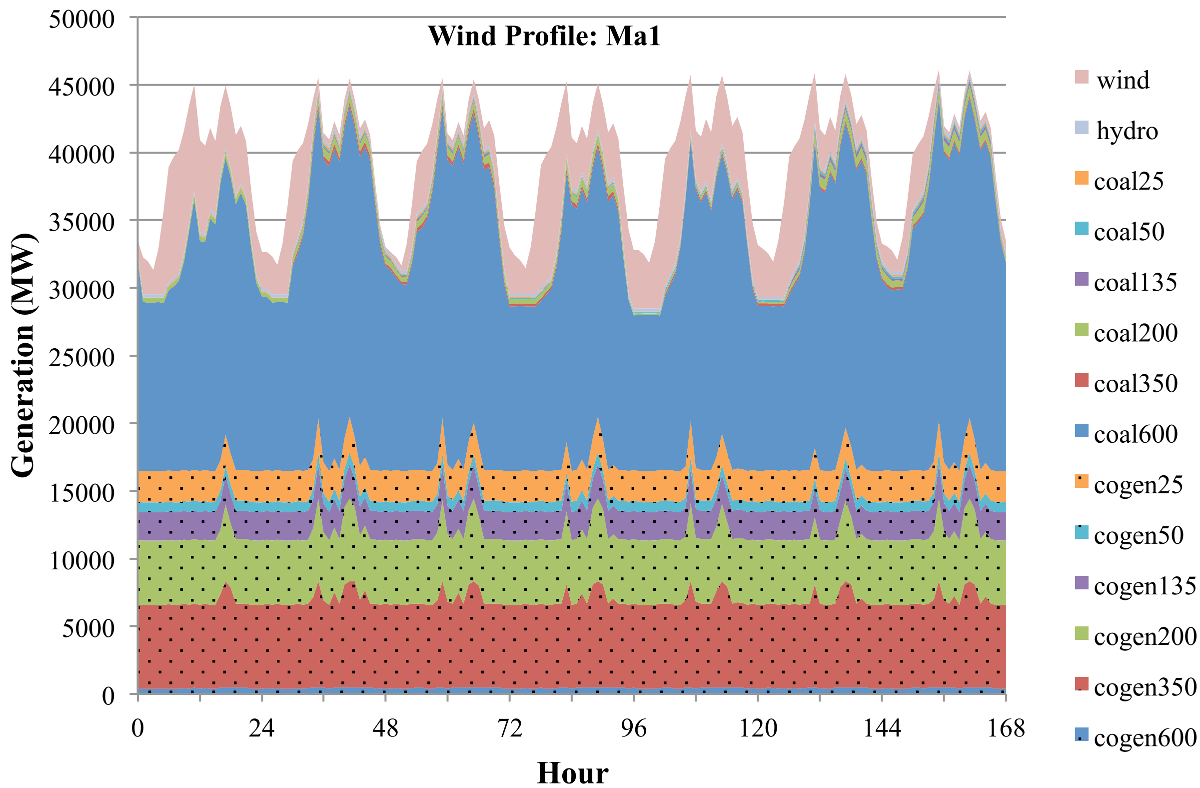

Figure 6.2. Generation by type under minimum generation quota CF1 for regional dispatch (Ma1 wind profile).

6.6. Increasing CHP Penetration to 50%

In 2011, CHP units accounted for approximately 34% of thermal capacity in the Northeast Grid region. Given central government support for retrofitting existing units to supply district heating and to preferentially approve new cogeneration units, this share will likely increase in the future. Costs and wind results of this CHP scenario are shown in Table 6.14, and individual production by generating type is in Table 6.15.

	Objective (mil RMB)	Coal Use (Mtce)	Wind Generation (GWh)	Wind Share (% Generation)	Wind Curtailment (%)
Ja1	1,489.2	2.101	500.5	7.5%	5.8%
Ja2	1,519.9	2.146	347.5	5.2%	8.8%
Ja3	1,463.7	2.067	611.3	9.2%	8.6%
Ma1	1,471.4	2.068	605.0	9.1%	9.8%
Ma2	1,483.6	2.083	550.5	8.3%	7.7%
Ma3	1,427.9	2.009	801.3	12.1%	7.7%
Avg	**1,475.9**	**2.079**	**569.3**	**8.6%**	**8.1%**
Reference	1,438.0	2.043	578.3	8.7%	6.6%
Diff	**37.9**	**0.036**	**-9.0**	**-0.1%**	**1.4%**

Table 6.14. Costs, coal use and wind curtailment under CHP retrofit scenario compared to current mix.

	50% CHP	**Reference**
	(Wind Profiles Average)	
coal25	0	0
coal50	0	0
coal135	0	0
coal200	0	0
coal350	0	0
coal600	39.1%	56.5%
cogen25	72.1%	72.1%
cogen50	74.5%	74.1%
cogen135	74.8%	74.3%
cogen200	72.0%	70.6%
cogen350	69.7%	67.2%
cogen600	73.2%	72.7%
hydro	2.9%	2.9%
wind	30.9%	33.6%

Table 6.15. Weekly production of generating types under CHP retrofit scenario compared to current mix.

6.7. Temporary Heat Storage

The costs and wind production resulting from a fixed shift of the heating load forward by 4 and 8 hours are shown in Table 6.16. For example, in the 8 hour scenario, the peak of the heating curve (see Figure 5.8) shifts from 2-6 am to 6-10 pm the previous night.

	Objective (mil RMB)	Coal Use (Mtce)	Wind Generation (GWh)	Wind Share (% Generation)	Wind Curtailment (%)
Reference (MM)	1,438.0	2.043	578.3	8.7%	6.6%
Dynamic, No Shift	1,424.6	2.027	565.6	8.5%	8.7%
4 Hour Shift	1,420.9	2.020	580.2	8.7%	6.3%
8 Hour Shift	1,412.2	2.008	606.2	9.1%	2.1%

Table 6.16. Costs, coal use and wind curtailment under heat storage scenarios.

6.8. Hydropower Availability

Finally, the sensitivity of costs and wind production to the availability of hydropower is shown in Table 6.17.

	Objective (mil RMB)	Coal Use (Mtce)	Wind Generation (GWh)	Wind Share (% Generation)	Wind Curtailment (%)
Ja1	1,432.6	2.040	507.2	7.6%	4.6%
Ja2	1,463.5	2.087	348.3	5.2%	8.6%
Ja3	1,406.7	2.003	629.8	9.5%	5.9%
Ma1	1,413.4	2.009	611.4	9.2%	8.8%
Ma2	1,426.7	2.025	558.6	8.4%	6.3%
Ma3	1,371.5	1.945	821.8	12.4%	5.3%
Avg	**1,419.1**	**2.018**	**579.5**	**8.7%**	**6.4%**
Small Hydro	1,438.0	2.043	578.3	8.7%	6.6%
Diff	**-18.9**	**-0.025**	**1.2**	**0.0%**	**-0.2%**

Table 6.17. Large hydropower year (2013) compared to small hydropower year (2012).

Chapter 7

Analysis

Through the over hundred scenarios and sensitivities described above, a number of important features of the Northeast China Grid could be determined. The inflexibility of the system, deriving from a heavy dependence on coal and, in particular, coal-fired cogeneration, was confirmed. Various technical aspects of this inflexibility were examined and several potential avenues for improving wind integration were rejected. The two important regulatory constraints modeled – minimum generation quotas and provincial dispatch – gave useful insights on the relative impact of regulatory barriers to increased wind integration and other important cost drivers in the system. The following are key results of this analysis.

- **Under a cost-minimizing dispatch and given the inflexibilities in the Northeast China Grid in model year 2011, wind curtailment rates are comparable to those observed in other highly-constrained wind regions.**

The unit commitment formulation of the Northeast China Grid has been shown to give reasonable results for describing the dispatch of generators in the presence of wind. In the reference case averaged over the six wind profiles tested, total coal use was 2.043 Mtce, wind generation was 578.3 GWh, and the curtailment rate was 6.6% (Table 6.1). By comparison, the Electricity Reliability Council of Texas (ERCOT) met 8.5% of supply with wind in 2011, while curtailing 8.5%, and this fell to 3.7% in 2012 following increased transmission interconnection [110, 111]. As will be explained in later subsections, technical inflexibilities as opposed to transmission congestion are the primary causes of curtailment in the Northeast China region.

In each of these scenarios, besides must-run cogeneration plants, only the most efficient electricity-only units (600 MW) were committed. Furthermore, this size of plant averaged 56.0% capacity factors over the weeks, less than is expected annually, but still reasonable considering the downward restrictions placed on them by a high cogeneration minimum load. Under reference assumptions of startup/shutdown times (12 hours) and ramp limits (15% capacity per hour), these 600 MW units were responsible for almost all of the load and wind balancing over the week. In hours where wind dropped significantly, some additional generation from less-efficient cogeneration units was seen.

Since the model year of 2011, which was the most recently available complete database on generators in the region, two nuclear units have become operational in Liaoning. By 2018, 9.2 GW of nuclear is expected to be online in the northeast. This has implications for system flexibility by raising the minimum generation output. Further studies could examine the change in wind dispatch as a result of these capacity mix changes.

Transmission interconnections were utilized in the reference case (see Table 6.3), and depending on the wind resource, could facilitate transmission in both directions. Over the six wind resources considered, average transmission lined up directionally with common understanding of over-supply regions. As expected, these quantities were larger than historically realized values, with the two main transmission pathways – Heilongjiang-Jilin-Liaoning, and East Inner Mongolia-Liaoning – transferring on average 5.2% and 4.0% of the published 2010 values for the entire year (Table 7.1). For comparison, if transmission were equally distributed throughout the 52 weeks, each week would account for 1.9% of the annual total.

	2010 Actual Annual (GWh)	Average (% 2010 actual annual)	Minimum (% 2010 actual annual)	Maximum (% 2010 actual annual)
HL -> JL -> LN	7955	5.2%	-5.9%	11.1%
IME -> LN	10622	4.0%	-0.7%	8.4%

Table 7.1. Transmission amounts in reference scenario as percentage of 2010 annual realized amounts. Source of 2010 export data: [67].

- **Improving flexibility of thermal generators through lower minimum outputs can significantly reduce costs and wind curtailment, while other forms of technical flexibility such as startup/shutdown times and ramp requirements have little effect.**

Compared to a reference minimum output of 54% for electricity-only units, allowing these units to maintain stable output down to 40% more than halves the curtailment, from 6.6% to 2.8% (Table 6.7). This represents, together with temporary heat storage, one very promising technical avenue of improvement for both cost efficiency and wind integration. This derives from the increased space above minimum outputs for wind power and a reduction in generation costs as high-efficiency units remain on.

Note that this analysis did not consider differential heat rates associated with low or varying outputs, in order to avoid computationally-intensive quadratic terms in the objective function. Incorporating these may increase the fuel usage of high-capacity units, making them less attractive for low ramping, and thereby increasing curtailment. It also did not account for any additional maintenance costs associated with ramping. In addition to the fixed startup/shutdown costs, coal generators may require compensation for these modes of low and varying output. Further analysis is needed to determine whether these second-order effects measurably alter the optimal solution.

Ramp rates were not seen to drive the results in a significant way. By increasing from the reference case of 15% of capacity per hour to 50%, no appreciable difference was observed (Table 6.8). This is an extreme scenario – in effect, allowing the units to ramp their entire feasible output, once warmed up, in an hour – yet, little benefit seems to be achieved by making these adjustments.

In terms of cycling flexibility, the minimum up/down times for units were also determined to have little impact on the solution. No significant differences were seen when moving from an inflexible regime, where large units are constrained to remain on or off for 24-hour periods, to an extremely flexible regime, where large units can start/stop in 6 hours and medium and small units in 3 hours. This demonstrates that the key source of inflexibility from coal generators derives from their minimum outputs.

- **Temporary heat storage improves wind integration by a larger margin than any other measure, up to 76%, illustrating the key heat-electricity interaction.**

Must-run heating units and wind profiles frequently share a peak in the early morning, also coincident with low electricity loads. This has been identified as an important cause of wind integration challenges in northeast China.

My model, with an explicit formulation of technically feasible power-heat outputs, confirms this important interaction effect. By shifting ahead the heating load to peak in late evening, significant improvements in wind integration were observed. Compared to the dynamic CHP case, a forward shift of 4 and 8 hours led to a 28% and 76% decrease in wind curtailment. Compared to the fixed minimum mode dispatch scenario, which as detailed below had lower curtailment compared to the dynamic case but at higher cost, these reductions were 5% and 68%. This model did not account for any costs associated with installing or operating this heat storage, which could be significant given the large number of district heating grids in northeast China.

- **The exact startup/shutdown cost per unit capacity has a small impact on total system cost but potentially a large impact on wind curtailment.**

The model minimizes an objective function that is a trade-off between generation and commitment costs, where the former is driven by fuel costs and the latter primarily by maintenance costs. Large units have the smallest ratio between generation and commitment costs under the assumption that cost per startup scales with capacity. As startup costs were decreased, in this example from 600 to 400 yuan / MW, this ratio increased, leading to a rebalancing toward greater startups and lower generation costs. This was achieved by encouraging more startups from large units, and in turn cutting back generation from low-efficiency units. The solution, therefore, only saw minimal movement in the total objective.

Wind integration, however, improved with increasing startups, with curtailment reducing from 9.6% to 5.5%. This can be interpreted as resulting from an increase in the available generation space above minimum output thresholds. Therefore, reducing the cost of startups could be an important lever to encourage more flexible operation of coal units.

More broadly, this has implications for the impact of other cost factors on wind integration. If fuel prices or other variable costs increase, this is similar to a reduction in startup costs assuming that fuel costs are only a small portion of the cost of startups. This would encourage more frequent cycling as observed in this case of adjusting the startup costs directly. The rebalancing toward greater commitment costs would similarly lead to better performance with respect to wind integration.

- **Allowing minimum outputs of cogeneration units to vary dynamically with heat load reduces systems costs but increases wind curtailment.**

It was established that the minimum generation outputs of cogeneration units depend on the extraction amount. Contrary to expectation, however, incorporating this additional lever of flexibility in the dispatch optimization did not improve wind integration. Total system costs were reduced compared to a fixed minimum output (minimum mode), as fuel costs and the number of commitments fell, but this resulted in greater economic curtailment of wind.

This rise in economic curtailment can be explained by the discrete choice of not shutting down a high-efficiency thermal unit during high wind periods. Under a higher must-run baseload (minimum mode), this unit would have gone offline rather than curtail excessive amounts of wind. Under a flexible cogeneration scenario, though, it is economical to keep this unit online, partially restricting the integration space for wind.

- **Provincial dispatch is identified as a source of regulatory inflexibility, increasing costs and wind curtailment.**

The additional inflexibility of (1) introducing reserve requirements to be met at the provincial level and (2) reducing the effective transmission interconnection between regions, increased total system costs and wind curtailment measurably in all wind profiles (Table 6.12). On average, curtailment increased by 38% under this scenario compared to a regional dispatch. Additionally, the highest returned curtailment of any of the scenarios – 12.0% – was observed in the Ma1 wind profile with provincial dispatch. This demonstrates the impact of this institutional feature of China's power sector on wind integration.

- **Minimum generation quotas on all units lead to higher costs and curtailment under regional dispatch, with only limited impact under provincial dispatch.**

The second key source of regulatory inflexibility – the minimum annual generation requirements on all units – led to higher costs and increased curtailment for Ma1 under regional dispatch and a slight decrease in wind curtailment under provincial dispatch. This was the only wind profile that returned an optimal solution for both provincial and regional dispatch. Costs and coal use increased roughly 0.8% under both provincial and regional dispatch, when setting a minimum capacity factor (CF) for all coal units of 0.1 for Heilongjiang and Liaoning, and 0 for Jilin and East Inner Mongolia (Table 6.13). This derives from the reduced average efficiency of the coal fleet during the week. Curtailment increased 17% and decreased 3% for regional and provincial dispatch, respectively.

Two other quota requirements (CF2 and CF3) were tested as sensitivities: these either terminated without finding an optimal solution or did not find a feasible solution. More accurate data on what the monthly allocation fractions are for each unit type could be inputted to determine what the optimal allocation of resources would be under this exogenous policy constraint.

- **Increasing the fraction of CHP in the system does increase costs, but surprisingly has only a small effect on wind curtailment.**

As must-run CHP units are seen as the key source of technical inflexibility in the region, increasing this share relative to electricity-only units would be expected to lead to much higher curtailment. Compared to the reference case, in which 34% of thermal capacity provides district heating, an increase of this fraction to one-half of all units increases curtailment by 21% in a wind profile average, less than the contribution of other technical and regulatory factors.

As the CHP fraction increases, electricity generation is diverted to lower efficiency must-run 200 MW and 350 MW units, leading to a system cost increase on the order of 3%. This cost, however, does not reflect the expected reductions in heating delivery costs from replacing small heat-only units with larger cogeneration units. In particular, extracted steam is in some cases diverted waste heat, hence capturing and putting in the heating grid would increase the overall efficiency of the combined plant. Further studies could compare these energy and cost savings to the effects on the electricity dispatch.

It should be noted that this result assumes a cost-minimizing dispatch with no other regulatory constraints. If wind were prioritized, such as in the energy efficiency dispatch, it is possible that the increase in curtailment would be mitigated even with a higher proportion of CHP units. On the other hand, higher CHP base load coupled with minimum generation quotas could exacerbate wind integration challenges. This should be a topic of further research, as district heating from cogeneration continues to expand across China.

- **The availability of hydropower had a measurable impact on total costs but relatively little impact on wind integration.**

By examining representative large (2013) and small (2012) rainfall years, the effect of this variation on wind integration potential was essentially ruled out. This is unsurprising as hydropower during winter months accounts for a small fraction of annual hydropower even after considering inter-seasonal storage. Nevertheless, the large hydropower year did decrease total system costs by over 1%, as much as many of the other measures examined here. This analysis indicates, however, that the additional flexibility benefits are limited.

Chapter 8

Discussion

The increasing penetration of wind power in China's electric grid has resulted in significant quantities of available wind not used by the grid operator, known as curtailment. These integration challenges have raised serious concerns about the ability to meet long-term wind goals, and have led to a sustained inquiry in China on the necessary measures to improve grid flexibility in an economically-viable way. This thesis contributes to the literature in a novel way by examining simultaneously the technical factors and regulatory frameworks that are responsible for historic curtailment in the Northeast China Grid, a region which has experienced consistently high curtailment rates in recent years.

For this purpose, I developed a unit commitment and dispatch optimization that minimizes total operational costs subject to standard generating characteristics as well as several key additions: output restrictions from exogenous district heating demands, a hydro-thermal coordination component considering inter-seasonal storage, and transmission between adjacent provincial nodes. Six historic wind profiles from January and March 2009 from newly available wind resource data were used as input hourly production and further averaged to approximate the stochasticity of wind in winter months. Numerous sensitivities were conducted, including hydropower availability using a large and small rainfall year, transmission availability, and several cost and technical parameters.

This analysis reaffirmed key aspects of wind integration challenges of the Northeast China Grid by calculating a wind curtailment rate of 6.6% in the absence of any regulatory constraints, on par with that observed in the Electricity Reliability Council of Texas (ERCOT), another high wind resource region. The underlying technical factors giving rise to this high rate include: high minimum base load generation, compared to the electricity demand profile of the region, from large fractions of must-run CHP units; high minimum generating outputs of coal-fired generators; and large startup/shutdown costs. Some technical factors, such as ramp limits and minimum startup/shutdown times were examined and rejected as important sources of inflexibility.

As the government heavily manages the energy sector, and in particular, new technology promotion, the conclusions of this thesis on technical flexibility have implications for future energy policy. The "must-run" nature of CHP units has raised concerns about expanding these in the northeast region, where there is already high penetration from the cogeneration sector. These results show that while the current mix is a significant contributor to curtailment, further increasing it would have a limited impact on wind under the assumption of cost-minimizing dispatch, a restrictive assumption in this context. Temporary heat storage of 4-8 hours brought about significant reductions in both system cost and curtailment, which indicates a promising future area of research to determine a break-even cost for deployment.

A competing set of hypotheses to explain current rates of wind curtailment in China is the mixture of operational policies that are the result of an incomplete transition to a market-driven electricity sector. The contributions of these regulatory frameworks to grid inflexibility have typically been addressed qualitatively in the literature through examining the industrial organization of the sector and historical analysis. This thesis attempts to fill a gap in the literature, which to the best knowledge of the author, does not include attempts to quantify these constraints and compare to the numerous technical factors shaping electricity system operation.

This thesis considered the impact of two important institutional arrangements on total system cost and wind integration: the decentralization of dispatch to individual provinces, and the minimum generation quotas allocated to all coal generators to ensure revenue sufficiency. Requiring each province to balance supply and load with limited transmission interconnection added to the inflexibility of the system and contributed to up to 25% additional curtailment in one of the wind profiles.

The minimum generation quota requirement ensures that every coal generator regardless of its marginal fuel costs generates a certain amount each year. This research confirmed these quotas to be another key source of regulatory inflexibility. As data on quotas are not made public, several scenarios were run to consider its impact on wind integration, and it increased curtailment by up to 27% under a relatively modest quota of 10% for two of the provinces. The formulation presented here could be used to examine the impact of different quotas on system performance.

The decades-long transition away from a government-managed vertically-integrated utility is incomplete in several aspects, which has left interim institutions intact and noticeably decreases grid flexibility. Common elements of electricity sector liberalization in other countries indicate that significant hurdles remain before a more flexible market-driven sector that is better integrated regionally can be created in China. This is an ongoing debate, especially as greater transmission interconnection creates advantages for centralization of operation. While reforms will likely not be implemented solely as a means of improving the integration potential of renewable energy, this thesis does make a strong case for considering the impacts of future proposals on wind energy.

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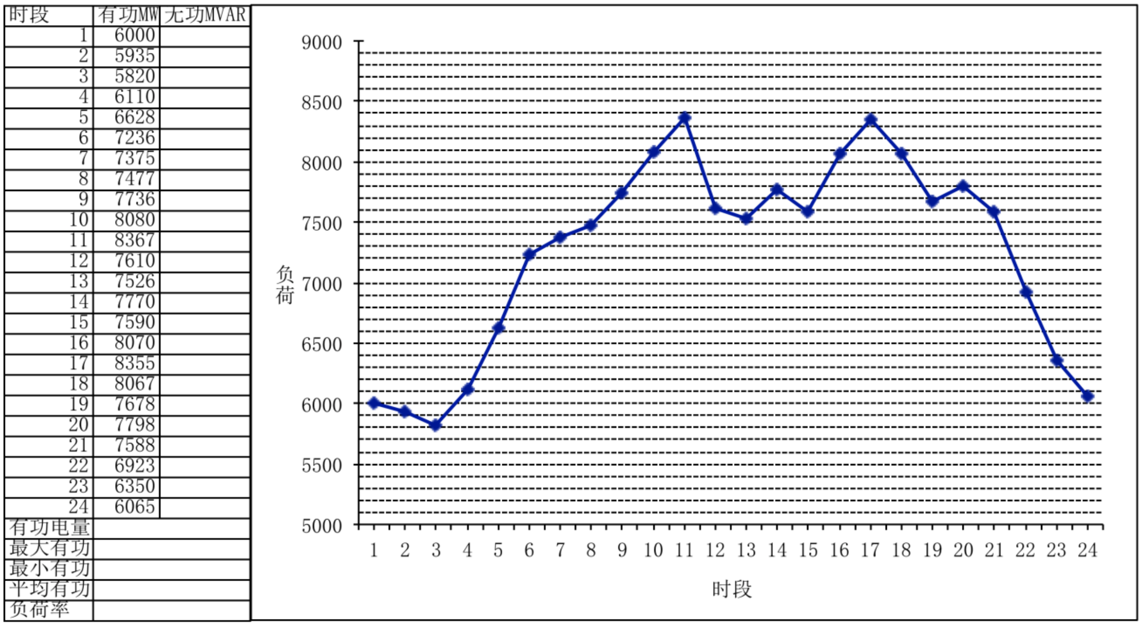
Appendix



时段	有功MW	无功MVAR
1	6000	
2	5935	
3	5820	
4	6110	
5	6628	
6	7236	
7	7375	
8	7477	
9	7736	
10	8080	
11	8367	
12	7610	
13	7526	
14	7770	
15	7590	
16	8070	
17	8355	
18	8067	
19	7678	
20	7798	
21	7588	
22	6923	
23	6350	
24	6065	
有功电量		
最大有功		
最小有功		
平均有功		
负荷率		

Figure A.1. Screenshot of daily load profile for Northeast China Grid, no longer available online. Source: [85].

	C_{coal}	η_g	p_g^{start}	R_g^{up}/R_g^{dn}	τ_g^{min}	p_g^{min}	p_g^{max}
coal600	700	299	360000	90	12	324	600
coal350	700	340	210000	52.5	12	189	350
coal200	700	375	120000	30	6	108	200
coal135	700	410	81000	20.25	6	72.9	135
coal50	700	440	30000	7.5	3	27	50
coal25	700	500	15000	3.75	3	13.5	25
cogen600	700	299	360000	90	12	325	600
cogen350	700	340	210000	52.5	12	189	350
cogen200	700	375	120000	30	6	108	200
cogen135	700	410	81000	20.25	6	73	135
cogen50	700	440	30000	7.5	3	27	50
cogen25	700	500	15000	3.75	3	13.5	25

Table A.2. Base case thermal generator characteristics

	$\alpha_{g_H}^{min}$	$\beta_{g_H}^{min}$	a_{g_H}	b_{g_H}	$\alpha_{g_H}^{max}$	$\beta_{g_H}^{max}$	$MM_{g_H}^{min}$	$MM_{g_H}^{max}$
cogen600	325	-0.148	193	0.253	600	-0.111	360	480
cogen350	189	-0.226	113	0.387	350	-0.169	230	290
cogen200	108	-0.157	64	0.268	200	-0.117	140	180
cogen135	73	-0.123	43	0.211	135	-0.092	100	120
cogen50	27	-0.076	16	0.130	50	-0.057	37	45
cogen25	14	-0.069	8	0.117	9	0.117	18	22

Table A.3. Base case power-heat coefficients for CHP units

		Capacity (MW)	H_p^0	H_p^{in}
SmallHydro	HL	888	4.762	0.0052
	JL	3885	20.839	0.0238
	LN	1817	9.745	0.0130
	IME	0	0	0
LargeHydro	HL	888	4.762	0.0155
	JL	4185	22.448	0.0757
	LN	1817	9.745	0.0384
	IME	0	0	0

Table A.4. Hydropower initial levels, final levels and inflow rates.