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Economic and environmental benefits of market-based power-system reform in China: A Case Study of the Southern Grid System

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Abstract
China, whose power system accounts for about 13% of global energy-related CO_2 emissions, has begun implementing market-based power-sector reforms. This paper simulates power system dispatch in China's Southern Grid region and examines the economic and environmental impacts of market-based operations. We find that market-based operation can increase efficiency and reduce costs in all Southern Grid provinces—reducing wholesale electricity costs by up to 35% for the entire region relative to the 2016 baseline. About 60% of the potential cost reduction can be realized by creating independent provincial markets within the region, and the rest by creating a regional market without transmission expansion. The wholesale market revenue is adequate to recover generator fixed costs; however, financial restructuring of current payment mechanisms may be necessary. Electricity markets could also reduce the Southern Grid's CO_2 emissions by up to 10% owing to more efficient thermal dispatch and avoided hydro/renewable curtailment. The benefits of regional electricity markets with expanded transmission likely will increase as China's renewable generation increases.

Keywords: China; Southern Grid; Power Market Reforms; Dispatch Modeling; CO_2 Emissions

1 Introduction

China's electricity system is the largest in the world, with an installed capacity of roughly 1,800 GW at the end of 2018 (China Electric Council 2019a). It accounts for about 45% of China's energy-related carbon dioxide (CO_2) emissions, or about 13% of total global energy-related CO_2 emissions (International Energy Agency 2018). Decarbonizing China's electricity system is thus essential to reducing CO_2 emissions from China's and the world's energy systems, as well as other economic sectors—such as transportation, industry, and buildings—in China.

Since 2015, China has embarked on a new round of power-sector reforms to expand the role of markets in allocating resources. Key areas of reform include developing market-based wholesale prices, establishing separate transmission and distribution tariffs, introducing retail electricity competition, and expanding interprovincial and interregional transmission. If successful, such reform could provide large economic and emissions-reduction benefits, significantly increase the renewable energy generation that can be reliably integrated into the grid, and accelerate the transition to a low-carbon power system in China (Lin 2018; Lin et al. 2019).

In August 2017, the China National Development and Reform Commission and China National Energy Administration identified eight provinces/regions as the first batch of wholesale market pilots, including the Southern Grid region (starting with Guangdong), West Inner Mongolia, Zhejiang, Shanxi, Shandong, Fujian, Sichuan, and Gansu (National Energy Administration 2017). By the end of June 2019, all of the eight pilots have started trial operation and by early September, Guangdong and Shanxi have actual electricity wholesale market transactions settled (National Development and Reform Commission, 2019a; China Electric Council, 2019b; Xinhua net 2019). Despite these progresses, under the current reforms, pilots for wholesale markets are mostly limited to provincial markets, with only limited trials for direct cross-provincial trades. However, many of the issues to be resolved in the power-sector reform, such as integration of renewable energy and resource adequacy, are regional in nature. Thus, it is important to explore additional economic and environmental benefits beyond the current provincial-market model. Experience elsewhere has demonstrated large economic, reliability, and environmental benefits from adopting a wider balancing area (Greening the Grid, Denholm, and Cochran 2015; Goggin et al. 2018; Holttinen et al. 2007; Corcoran, Jenkins, and Jacobson 2012; Kirby and Milligan 2008).

This paper assesses the impact of market-based power-system dispatch in China, expansion from provincial to regional markets, and expansion of transmission capacity across provinces. We use the Southern Grid region as a case study, mainly because the provinces within this region have already established significant electricity trade with each other.[1] As a result, moving to market-based powerplant dispatch may be feasible in the near term. We simulate hourly powerplant dispatch of the Southern Grid system using PLEXOS (a state-of-the-art production-cost model) for a variety of dispatch-rules scenarios, from current practices to a full regional market. For each scenario, we assess the impact on total market costs, production costs, and CO_2 emissions.

The remainder of the paper is organized as follows. Section 2 reviews the literature on assessing the economic impacts of market-based system dispatch and regionalization of electricity markets. Section 3 describes our methods and data. Section 4 describes our key results, and Section 5 presents a sensitivity analysis. Finally, Section 6 discusses conclusions and policy implications.

2. Literature review

There has been significant research on how market-based economic dispatch of the power system can reduce electricity production costs relative to regulated or self-schedule regimes. Green and Newbery found that, in the British electricity spot market, more competition led to lower electricity costs (Green and Newbery 1992). Cicala studied the effect of introducing market-based dispatch into U.S. power-control areas, finding that deregulation reduced operational costs by about 20% ($3 billion per year) and increased regional electricity trades by about 20% (Cicala 2017). Other researchers found that restructuring led to reduced production costs at the powerplant level and substantive efficiency gains (Fabrizio, Rose, and Wolfram 2007). Cicala also found that the price of coal in coal powerplants in deregulated markets dropped by 12% compared with similar non-deregulated plants (Cicala 2015). Lin et al. studied the economic and carbon-emissions impacts of transitioning to an electricity market in China's Guangdong province, finding that electricity reforms led to significant consumer savings (Lin et al. 2019). Wei et al. used an optimization model to quantify the impacts of economic dispatch on coal-fired powerplants. They found major differences in heat rates among coal powerplants and that, with economic dispatch, average electricity prices could be reduced owing to reduced coal use for power generation (Wei et al. 2018).

One criticism of energy-only wholesale markets is the "missing money" problem. In a competitive energy-only market, powerplants typically recover

[1] The Southern Grid region is in the southeastern area of China encompassing five provinces: Guangdong, Guangxi, Guizhou, Yunnan, and Hainan. The region hosts significant economic activity (~17% of national GDP in 2016), and the region's electricity load (~1,000 TWh/yr) constitutes over 20% of the national total. The Southern Power Grid Company owns and operates the region's transmission network, while the generation assets are mostly owned by the provincial generation companies. Coal and hydro powerplants dominate the current electricity generation mix, which is described in detail in the subsequent sections of this paper.

only their marginal costs. Therefore, financial restructuring and reallocation of market benefits are necessary for the powerplants to recover their fixed capacity costs (Joskow 2008). Lin et al. explored this issue in Guangdong province and concluded that mechanisms to allow generators to recover their fixed costs are likely necessary (Lin et al. 2019). In this paper, we also assess whether the wholesale market revenue is enough to cover the production and fixed costs of all powerplants.

Substantive research has also been done regarding the impacts on grid reliability and costs of increasing balancing-area size. One example of current coordination across balancing areas is the Western Energy Imbalance Market, which covers eight balancing areas across the western United States. This market system finds the lowest-cost energy to serve real-time demand across a wide geographical area and has saved over $564 million since its inception in 2014 ("Western Energy Imbalance Market" 2019). More generally, a larger balancing area—with everything else held equal—decreases system costs and improves grid reliability by decreasing peak load relative to installed capacity and thus reducing both the hours when the most expensive units run and the required operating reserves (Smith et al. 2007; DeCesaro, Porter, and Associates 2009; King et al. 2011). It also increases the load factor and minimum system load while reducing the relative load variability through geographical and temporal diversity (King et al. 2011; DeCesaro, Porter, and Associates 2009; EnerNex Corporation et al. 2006; European Climate Foundation 2010; GE Energy and NREL 2010; Gramlich and Goggin 2008; Holttinen et al. 2007; Kirby and Milligan 2008; Miller and Jordan 2006). In addition, larger balancing areas reduce capacity requirements to meet ramping rates, increase access to flexible generation, and thus reduce the overall costs to serve load (Milligan and Kirby 2008a; King et al. 2011; EnerNex Corporation et al. 2006; European Climate Foundation 2010; GE Energy and NREL 2010; Gramlich and Goggin 2008; Holttinen et al. 2007; Kirby and Milligan 2008; Ackermann et al. 2009; DeCesaro, Porter, and Associates 2009; Smith et al. 2007; Milligan and Kirby 2008b; Greening the Grid, Denholm, and Cochran 2015). Most of the existing literature has focused on the U.S. and European power systems. Little or no literature addresses such issues in China.

Research suggests that two factors affect the grid benefits due to increasing the size of balancing areas. The first factor is the additional costs associated with transmission-expansion projects that might parallel the consolidation of management across multiple smaller balancing areas. If no new extensive transmission investments are required when increasing the size of a given balancing area, decreased system costs and improved reliability are significant (Corcoran, Jenkins, and Jacobson 2012). Corcoran, Jenkins, and Jacobson studied the costs and benefits of interconnecting across different Federal Energy Regulatory Commission regions with transmission expansions. They found that, in most scenarios, benefits are outweighed by additional transmission costs. The most cost-effective interconnection scenarios were those consolidating multiple, small areas via relatively short transmission projects. Because their assumptions do not include fuel diversity, price uncertainty, and energy price differences due to congestion, more research on the impact of transmission is needed, especially across other regions and system assumptions. The second factor affecting the grid benefits of larger balancing areas is the time scale of interest. Miller and Jordan found that aggregating load provided modest benefits in the hourly time frame, but significant benefits in the five-minute and minute-to-minute time frames (Miller and Jordan 2006).

Other strategies to improve reliability include improving regional market access and sharing scheduling and area control error responsibilities across larger areas (Smith et al. 2007). In addition, in a future with increased renewable energy penetration, the benefits of increasing balancing-area size are magnified. Recent studies of market reforms in preparation for higher renewable energy penetration suggest moving towards increased flexibility and larger geographical areas (Goggin et al. 2018).

3. Methods

We simulate hourly powerplant dispatch in the Southern Grid region for the year 2016 using PLEXOS, an industry-standard unit-commitment and production-cost model. PLEXOS is one of the state-of-the-art models that allows us to model the generator unit commitment and dispatch (using direct current (DC) optimal power flow algorithm) considering a range of real-life power system constraints. We model the Southern Grid network using five nodes, one node for each province: Guangdong (GD), Guangxi (GX), Guizhou (GZ), Yunnan (YN), and Hainan (HN); see Figure 1. We also simulate the region’s exchange with other grids, such as the Southwestern Grid or Central Grid. Using the 2016 actual fleet-level electricity generation and curtailment data in each province and interprovincial import/export data, we calibrate the key parameters in our model (availability, dispatch restrictions, etc.).

Modeling the transmission network in a reduced form (single node per province) allows us to focus on the interprovincial trade issues, which are critical to setting up economic dispatch / markets. While we understand that this approach risks missing the potential congestion issues in the intra-province transmission network, in our future work, we intend to model the transmission network in a more spatially resolved manner so we can assess those. Also, data on intra-province transmission was not easily available in the public domain.

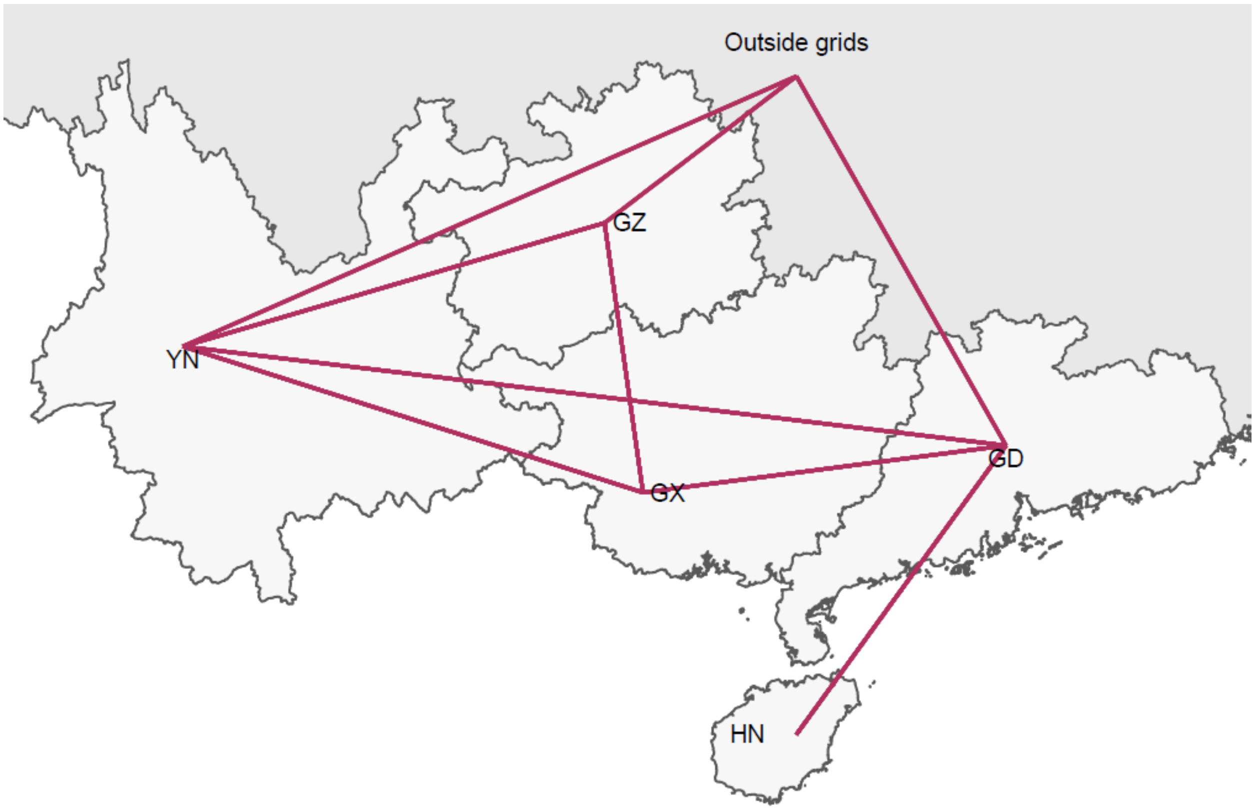

Figure 1. Five Southern Grid nodes and outside grid node modeled in the analysis

3.1 Model

We use PLEXOS to simulate Southern Grid operation at hourly resolution. PLEXOS is industry-standard software by Energy Exemplar that is used by system operators and utilities worldwide (Palchak et al. 2017; Jorgenson, Denholm, and Mehos 2014; Eichman, Denholm, and Jorgenson 2015; Abrams et al. 2013). PLEXOS uses deterministic or stochastic mixed-integer optimization to minimize the cost of meeting load given physical (e.g., generator capacities, ramp rates, transmission limits) and economic (e.g., fuel prices, startup costs, import/export limits) grid parameters. More specifically, PLEXOS simulates unit commitment and actual energy dispatch for each hour (or at 1-min interval) of a given time period. PLEXOS is also a transparent model meaning that the entire mathematical problem formulation is available to the user.

In this analysis, we use a deterministic model in PLEXOS meaning that the model assumes perfect foresight in relation to renewable energy production and load. We do not believe that this assumption changes the results significantly mainly because the current renewable energy penetration in the southern grid region is very small (less than 4% by energy). Also, majority of the electricity load is industrial that has very small forecast errors. In order to model unit commitment and outages accurately, we use mixed integer programming (MIP) in PLEXOS. Also, in order to simulate the actual scheduling practices, we simulate day-ahead operation at an hourly resolution. PLEXOS simulates daily operation as a MIP at an hourly resolution in chronological sequence. For avoiding issues with any inter-temporal constraints at the day boundaries (e.g. minimum up or down time of thermal units, or minimum load constraints), PLEXOS can 'look ahead' into the next day meaning that PLEXOS solves for the current day and the next day together, however, only results for the current day are kept. PLEXOS can fix the maintenance schedules for generation units exogenously based on actual maintenance data. Forced outages for units are calculated based on Monte Carlo simulations. Forced outages occur at random times throughout the year with frequency and severity defined by forced outage rate, mean time to repair and repair time distribution. The transmission between provinces are modeled using DC optimal power flow algorithm. At simulation run time PLEXOS dynamically constructs the linear equations for the problem and uses a solver to solve the equation. In this analysis, we used Xpress-MP solver with a duality gap set to 0.1%.

For each scenario mentioned below, we simulate Southern Grid operation at hourly resolution for the entire year of 2016 and report key model outputs such as powerplant dispatch, transmission flows between provinces, production and wholesale electricity costs, curtailment of hydro and renewable resources, CO_2 emissions, and so forth.

3.2 Scenarios

We develop three scenarios to evaluate the impacts of provincial and regional electricity markets in the Southern Grid territory. The order of the scenarios as listed below shows a gradual release on market constraints.

1. Baseline: The baseline scenario simulates the actual thermal dispatch, interprovincial imports and exports, and constraints on hydro dispatch in the Southern Grid system in 2016.

2. Provincial Market: In this scenario, we model the creation of a provincial market in the Southern Grid. We assume that, within each province, powerplant dispatch is market based—that is, based on least cost. However, existing contracts governing the interprovincial import and export of electricity are same as in the Baseline scenario i.e. we hold interprovincial imports and exports the same as in the Baseline scenario. Also, constraints on hydro dispatch are assumed to remain the same as in the Baseline scenario.

3. Regional Market: In this scenario, we model the creation of a Southern Grid-wide regional electricity market. We assume that the current interprovincial contracts are renegotiated, and the entire Southern Grid system dispatch is optimized for least cost. However, constraints on hydro dispatch are assumed to remain the same as in the Baseline scenario. Also, the current transmission line limits would still apply to the interprovincial flows.

3.3 Data and key parameters

3.3.1 Electricity demand

We use the actual annual 2016 electricity consumption in each province from the China Electric Power Statistical Yearbook 2017 (China Electric Council 2017). We construct the hourly load curve in each province based on load shapes for winter and summer typical days and monthly electricity consumption in 2016 in each province (Q Cai et al. 2014; Guangdong Statistics 2016; Yunnan Statistical Bureau 2017; Guizhou Statistical Bureau 2017; People's Government of Hainan Province 2017; People China Newspaper 2016; Zhang and Yan 2014; Yang and Li 2014; Li 2014; Lv 2013), as well as assumptions about winter and summer duration and a ratio between weekend and weekday electricity consumption. For a more detailed methodology, see Lin et al. (2019).

3.3.2 Hydro generation

We model hydro generation using the fixed hydro method, constraining monthly imports and hydro generation by historical monthly shares and fixing the hourly hydro dispatch in each province assuming a ratio between on-peak and off-peak hours in a day. For a more detailed description of this method, see Lin et al. (2019). We only had access to the hydro generation profile in Guangdong, so we assume the hydro generation profiles to be the same in all the other provinces. Because Guangdong accounts for over 50% of the electricity demand in the southern region, we do not believe this assumption would change the results significantly. We also conduct a sensitivity analysis by making the hydro dispatch flexible, albeit with the same monthly energy budgets.

3.3.3 Solar and wind generation

For each province, we take the hourly solar photovoltaic (PV) and wind energy generation profiles from the SWITCH-China model, simulating the profiles using hourly irradiance and wind-speed data at 10 sites with the best resource potential (i.e., the 10 best solar sites and the 10 best wind sites) in each province (He and Kammen 2014, 2016).

3.3.4 Powerplant operational parameters

Powerplant operational parameters—such as heat rates, ramp rates, and minimum stable generation levels—are estimated using historical fleet-level performance data, regulatory orders on heat rates and costs, international benchmarks and other relevant literature, and conversations with system operators about actual practices (China Electric Council, various years;

Abhyankar et al. 2017; Liu 2014, 2015; California ISO 2016). Please refer to SI for the values used in this paper.

3.3.5 Fuel prices

We use 2016 actual coal prices in each province (National Development and Reform Commission 2019b). Coal prices show significant month-to-month variability (Figure 2). However, the trend is largely similar in all provinces. In all provinces, coal prices are largely flat between January and August; between September and December, they increase by about 20%–40%. Coal prices in Guizhou are the lowest, while those in Guangxi are the highest.

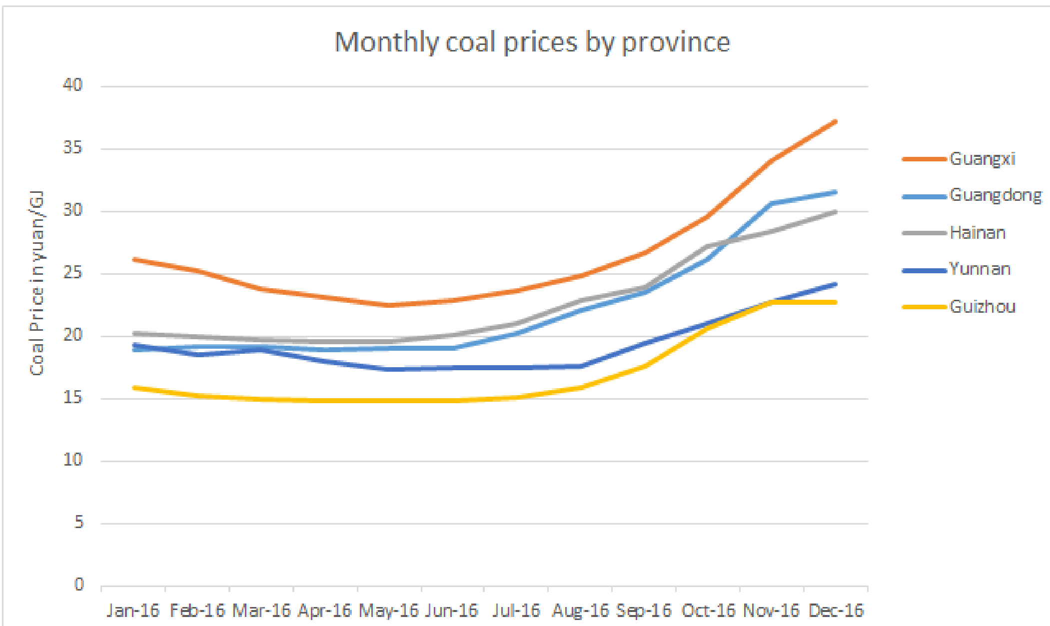

Figure 2. Monthly coal prices in each province

We did not have access to the 2016 natural gas prices by month in each province. Therefore, we use the 2016 annual average natural gas price in Guangdong (54.4 Yuan/GJ) for all provinces. We do not believe this assumption would change our results significantly, because natural gas-based power generation is very small relative to coal-based generation or overall load.

3.3.6 Exchange with other regional grids

Across all scenarios, we assume exports and imports to and from other regions are the same as the actual 2016 flows. The 2016 actual numbers are from the Electric Power Industry Statistical Compilation in 2016 (China Electric Council 2017).

3.3.7 Fuel CO_2 emission factors

We use the CO_2 emission factors for thermal power plants from the southern grid territory in 2016 reported by the National Development and Reform Commission (2017), which is equal to 0.8676 tCO_2/MWh.

3.3.8 Interprovincial transmission limits

The inter-provincial transmission limits have been taken as a sum of installed capacities all transmission lines connecting the two provinces. While we understand that in an AC network, the available transfer capacity (ATC) between two provinces would be smaller than the sum of the installed line capacities. However, estimating the ATC requires AC power flow modeling and is outside the scope of this study. In our future work, we will create scenarios on actual ATCs on transmission lines. The data sources for individual line limits are given in the SI.

3.4 Model calibration and data

We calibrate the model so that the Baseline scenario results match with the actual fleet-level dispatch in each province as well as interprovincial trade in 2016. The actual data for 2016 are from China Electric Council (2017). More specifically, for the baseline scenario, the following constraints are applied with a permissible slack of 10%: (a) within each province, the fleet level electricity generation for each technology equals the actual fleet level generation in that province, (b) inter-provincial transmission flows should equal the actual inter-provincial imports /exports. The calibration results are shown in~~-~~ Table 1~~Table 1~~.

Table ~~1~~1. Model Calibration: Comparison of 2016 Actual and Simulated (Baseline) Southern Grid Fleet-Level Generation and Key Interprovincial Transmission Flows (TWh/yr)

Total Generation or Imports/Exports (TWh/yr)	2016 Actual	Model Baseline (Simulated 2016)
Nuclear	87	86
Coal	503	500
Natural gas	0	1
Hydro	404	394
Wind + PV	31	29
Hydro and renewable energy curtailment	32	36
Total energy generation	**1,024**	**1,010**
Interprovincial flows on key corridors		
Guangxi to Guangdong	8	6

Guizhou to Guangdong	55	60
Yunnan to Guangdong	110	100

4. Results

In this section, we describe the key results of our analysis. Additional results can be found in the supplementary information.

4.1 Simulated generation mixes and marginal costs

Market operations lead to more efficient dispatch of the thermal fleet and lower overall production costs. In the Baseline scenario (current dispatch practices), all coal generators are operated at similar capacity factors irrespective of their marginal costs, resulting in a highly non-optimal dispatch as well as significant curtailment (5%–10%) of the renewable energy and hydro generation.

Table 2 ~~Table 22~~ shows total annual generation in the Southern Grid region by fuel type in all the simulated scenarios. In the Baseline scenario, coal generation accounts for about 50% of total regional electricity generation, while about 8% of the hydro and renewable energy generation must be curtailed. However, market-based dispatch reduces coal generation: by 7% under Provincial Market (market based within provinces) and 10% under Regional Market (regional market with current transmission constraints). At the same time, nuclear generation (which has very low marginal costs) increases by about 25% in all market scenarios, hydro generation increases by up to 9%, and hydro/renewable energy curtailment decreases by up to 83%.

Table 2~~2~~. Annual Generation by Source and Scenario for Southern Grid, 2016 (TWh/yr)

Source	Baseline	Provincial Market	Regional Market
Nuclear	86	107	107
Coal	500	465	450
Natural gas	1	0	0
Hydro	394	413	425
Wind	22	19	22
PV	7	6	6
Total generation	**1,010**	**1,010**	**1,010**
Hydro and renewable energy curtailment	36	21	6

Figure 3 groups annual powerplant dispatch by marginal cost of production. With market-based dispatch, plants with marginal costs less than 160 Yuan/MWh generate more electricity (subject to physical constraints), while plants with marginal costs above 160 Yuan/MWh generate less. As a result, overall production cost and the wholesale price of electricity decrease significantly.

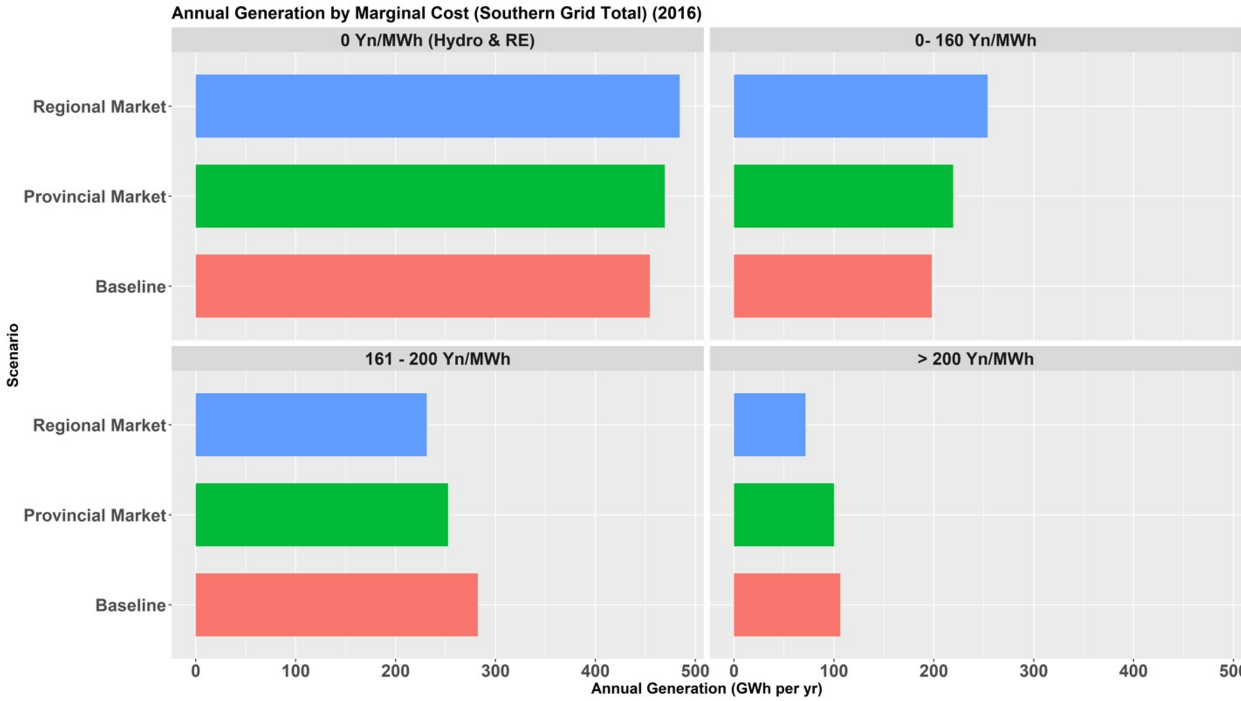

Figure 3. Annual electricity generation in Southern Grid by marginal cost of production, 2016

4.2 Economic benefits of market-based dispatch

With market-based (least-cost) powerplant dispatch, the total wholesale cost of electricity in the Southern Grid territory decreases by 20%–35% relative to the current practice of planned powerplant dispatch (Figure 4).[2] The establishment of provincial markets contributes the most to the cost reduction (20%), followed by creating a regional market (15% additional reduction). Establishing provincial markets reduces wholesale costs in all provinces relative to the baseline, and costs are reduced 10%–41% more when the market is regionalized (i.e., when transitioning from the provincial market to a regional market) in all provinces. The percentage reduction is lowest in Guangdong (~10%), indicating that the province already imports significant amount of electricity from other provinces in the region.

[2] Planned powerplant dispatch is the status quo, in which operating hours for all types of generation are planned on a year-ahead basis, and generators are paid at a fixed feed-in tariff for their net generation.

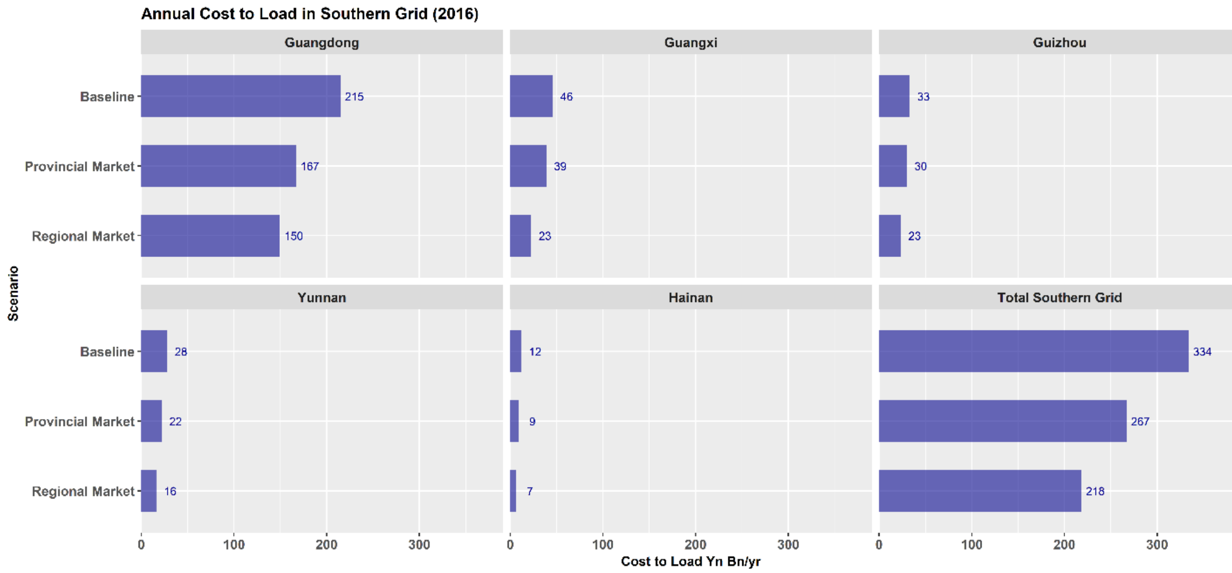

Figure 4. Annual wholesale cost of electricity in Southern Grid, 2016

4.3 Provincial generation and interprovincial transmission

Here we illustrate the generation within and transmission between provinces under each of our scenarios. Under the 2016 Baseline scenario, Guangdong has the highest generation in the region at 383 TWh, followed by Yunnan at 271 TWh (Figure 5). Guangdong is also a net importer, with imports from Guangxi, Hainan, Yunnan, and outside grids. Coal dominates the generation in Guangdong, Guizhou, and Hainan, while hydro dominates the generation in Guangxi and Yunnan. The largest net transfer of electricity between provinces occurs between Guangxi and Guangdong, with net transmission of 119 TWh from west to east.

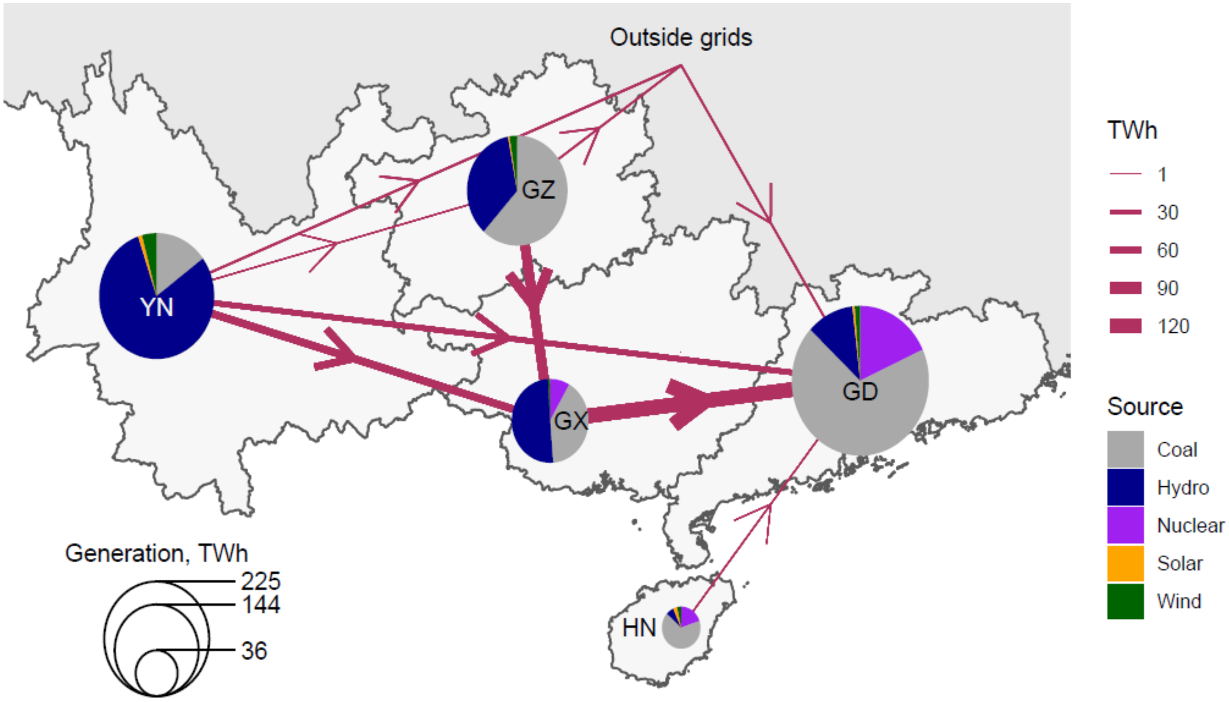

Figure 5. Electricity generation and interprovince transmission in the Southern Grid under the Baseline scenario

In the Provincial Market scenario, the total amount of generated electricity in each province and electricity imports/exports between provinces do not change (Figure 6). Instead, electricity generation within each province is optimized for the least cost, which leads to changes in the generation mix. For example, while coal still dominates Guangdong's generation, it contributes 7 TWh less (compared with the Baseline scenario) in that province, which experiences an equivalent increase in nuclear generation. For Yunnan, coal generation decreases from 40 to 25 TWh, while hydro generation increases from 216 to 235 TWh. Overall, the region experiences reduced coal generation and increased hydro generation under this provincial-level market scenario.

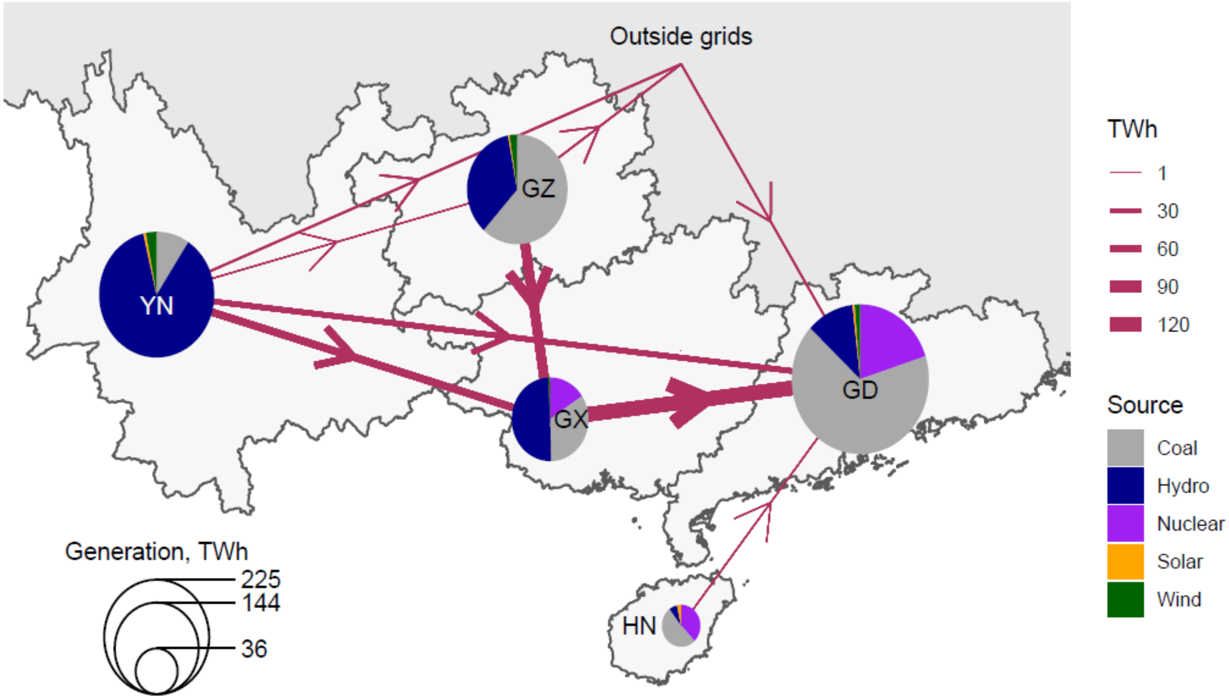

Figure 6. Electricity generation and interprovince transmission in the Southern Grid under the Provincial Market scenario

The Regional Market scenario produces more significant generation and transmission changes (Figure 7). Compared with the Baseline scenario, total provincial-level generation in Guangdong decreases from 383 to 352 TWh, with coal generation decreasing from 264 to 226 TWh. Yunnan provincial generation increases from 271 to 279 TWh, with hydro generation increasing from 216 to 247 TWh. Guangxi’s provincial generation decreases from 120 to 90 TWh, with most of the reduction from lower coal generation. On the other hand, Guizhou’s provincial generation increases from 206 to 262 TWh, with most of the increase from higher coal generation. Transmission among provinces also changes significantly. For example, Guangxi to Guangdong transmission increases from 119 to 153 TWh, while Guizhou to Guangxi transmission increases from 77 to 136 TWh. Under a regional market, Guangxi becomes a hub for electricity transmission to Guangdong while decreasing its local generation at the same time.

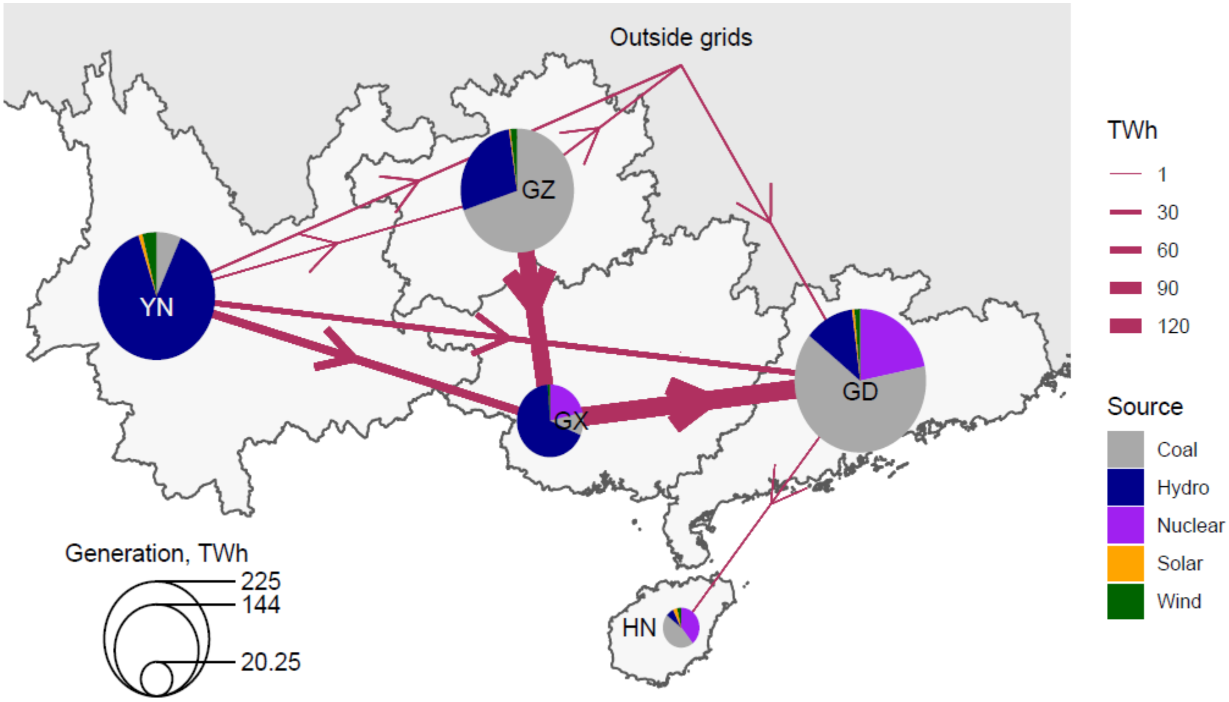

Figure 7. Electricity generation and interprovince transmission in the Southern Grid under the Regional Market scenario

4.4 CO_2 emissions reductions

Owing to the significant reduction in hydro curtailment and more efficient operation of the thermal fleet, market-based dispatch significantly reduces CO_2 emissions from the Southern Grid (Figure 8). Creating a provincial market, albeit with constraints on hydro dispatch and transmission capacity, reduces CO_2 emissions by 7% relative to the current emissions (Baseline scenario). Creating a regional market reduces the CO_2 emissions further by 3 percentage points.

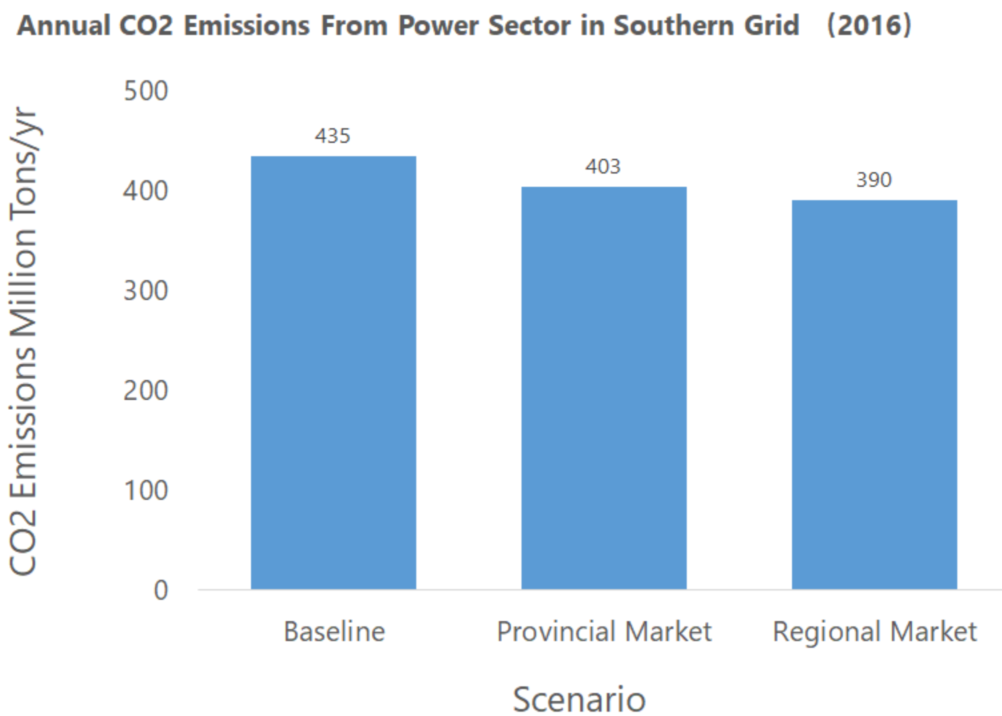

Figure 8. Annual CO_2 emissions from the Southern Grid power sector, 2016

4.5 Recovery of fixed costs

The current generation tariffs/contract prices in the Southern Grid region are significantly higher than the total fixed (mainly capital servicing and fixed O&M) and variable (fuel and variable O&M) costs of powerplants. With market-based economic dispatch, the total wholesale electricity cost (i.e., the gross revenue of generators) decreases significantly (Figure 4). However, the market revenue is still enough to meet the total generator costs (fixed and variable) under the Provincial Market and Regional Market scenarios (Figure 9).

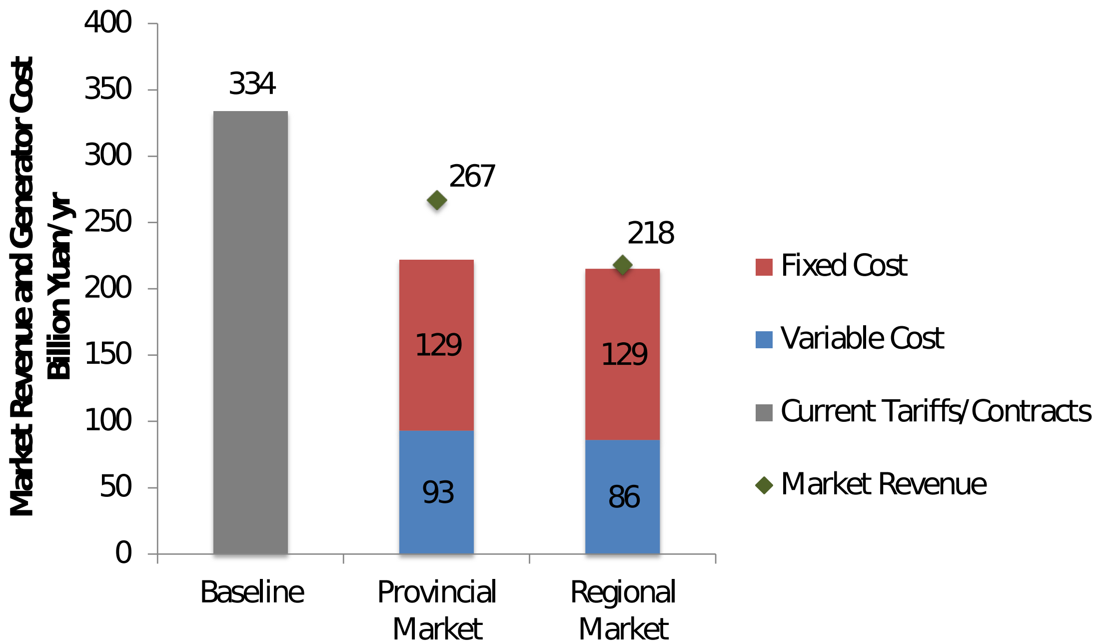

Figure 9. Annual market revenue and total generator cost in the Southern Grid, 2016

In the Provincial Market scenario, the total market revenue is 267 billion yuan/yr, which is higher than the total generator costs of 222 billion yuan/yr. In the Regional Market scenario, the generator revenue drops to 218 billion yuan/yr—still marginally higher than the total generator costs of 215 billion yuan/yr, implying that the regional and provincial market pool revenue is enough to recover the generator fixed costs at the system level. For ensuring fixed-cost recovery at the individual plant level, financial restructuring of the current contractual/payment arrangements may be necessary; assessing the details of such restructuring is outside the scope of this paper.

5. Sensitivity Analysis

To test the robustness of our findings, we conducted a sensitivity analysis by varying the coal price, the transmission capacity between provinces, and the restrictions on hydro dispatch.

5.1. Higher coal price (High_Coal)

A higher coal price affects market prices and thus savings due to market-based dispatch, because coal powerplants contribute nearly 50% of total electricity generation in the Southern Grid region. If the coal price increases by 25%, the average market price increases by nearly 12% in the Provincial Market scenario and 10% in the Regional Market scenario, so the cost to load increases to 296 billion yuan/yr in the Provincial Market scenario and 240 billion yuan/yr in the Regional Market scenario. Assuming the generation tariffs (only the variable cost part) also increase to reflect the higher coal price, the total cost to load in the Baseline scenario would increase by about 7%, to 356 billion yuan/yr. Thus, compared with the Baseline scenario, the total wholesale electricity cost would be 17% lower in the Provincial Market scenario and 33% lower in the Regional Market Scenario. These percentage reductions are smaller than in our core (lower-priced coal) analysis, where reductions are 20% in the Provincial Market scenario and 35% in the Regional Market Scenario; see Figure 4.

5.2 New transmission investments (Add_Tx)

Here we assume new investments are made in the interprovincial transmission capacity, and the available transfer capacity increases by 50% of the existing capacity under the Regional Market scenario. The expansion gives other provinces access to cheaper hydro resources from Yunnan and cheap coal resources from Guizhou, which reduces costs in net-importing provinces (Guangdong, Guangxi, and Hainan) but increases overall exports and electricity costs in Yunnan and Guizhou. However, costs in all provinces are still lower under the Regional Market Add_Tx sensitivity case than under the Baseline scenario. When summed across the entire region, the additional cost reduction in the Add_Tx sensitivity case is only 3.2% beyond the reduction in the core Regional Market scenario, which suggests that this approach has limited value given the region’s current resource mix and loads. However, as renewable energy penetration and load grow, the value of additional transmission could be significant. Finally, the Add_Tx case drives significant operational changes. At the provincial level, the increased transmission capacities make it more economical to reduce generation in Guangxi and Guangdong and increase transmission from cheaper-electricity provinces like Yunnan and Guizhou. For example, Guangdong’s total generation decreases from 383 to 293 TWh, with most of the reduction due to coal generation declining from 264 to 167 TWh (compared with the Baseline scenario); as a result, Yunnan and Guizhou become the new largest and second-largest electricity generators. Generation increases from 271 to 312 TWh in Yunnan (mostly from increased hydro generation) and from 206 to 296 TWh in Guizhou (mostly from increased coal generation); most of this increased generation is exported to Guangdong. With more transmission across all provinces, transmission from west to east increases, with Guangxi as a transmission hub to Guangdong. Details of the operational changes are provided in the Supplemental Information.

5.3 Flexible hydro dispatch (Flex_Hydro)

Because hydro powerplants supply nearly 40% of the Southern Grid’s total electricity generation, their dispatch constraints affect the wholesale electricity costs and system operations significantly. To explore the benefits of a more flexible hydro dispatch, here we allow the hydro powerplants to deviate by 25% from their fixed dispatch simulated in the Baseline scenario; they still must follow the same monthly energy budget constraints. The additional flexibility changes hydro generation little in the Regional Market scenario, but grid operation changes significantly. First, the coal dispatch becomes significantly flatter. Hydro powerplants increase output during peak periods and reduce output during off-peak periods, and thus the ramping and cycling of coal powerplants decrease significantly. Although the total coal generation remains almost the same, cheaper coal plants are dispatched more. Second, because Guizhou has some of the cheapest coal resources in the Southern Grid region, exports from Guizhou to Guangxi and Guangdong increase. Finally, most of the expensive natural gas powerplant dispatch is eliminated.[3] As a result, the wholesale electricity cost drops to 206 billion Yuan/yr in the Regional Market Flex_Hydro case, 6% lower than in the core Regional Market scenario and 38% lower than in the core Baseline scenario.

5.4 Sensitivity analysis summary for Regional Market scenario

Figure 10 summarizes the wholesale electricity cost impacts of the sensitivity cases on the Regional Market scenario. In addition to the three cases described above, it shows a case with both flexible hydro and additional transmission investments. In that case, the wholesale electricity cost is about 10% lower than in the core Regional Market scenario. Additional results can be found in the Supplemental Information.

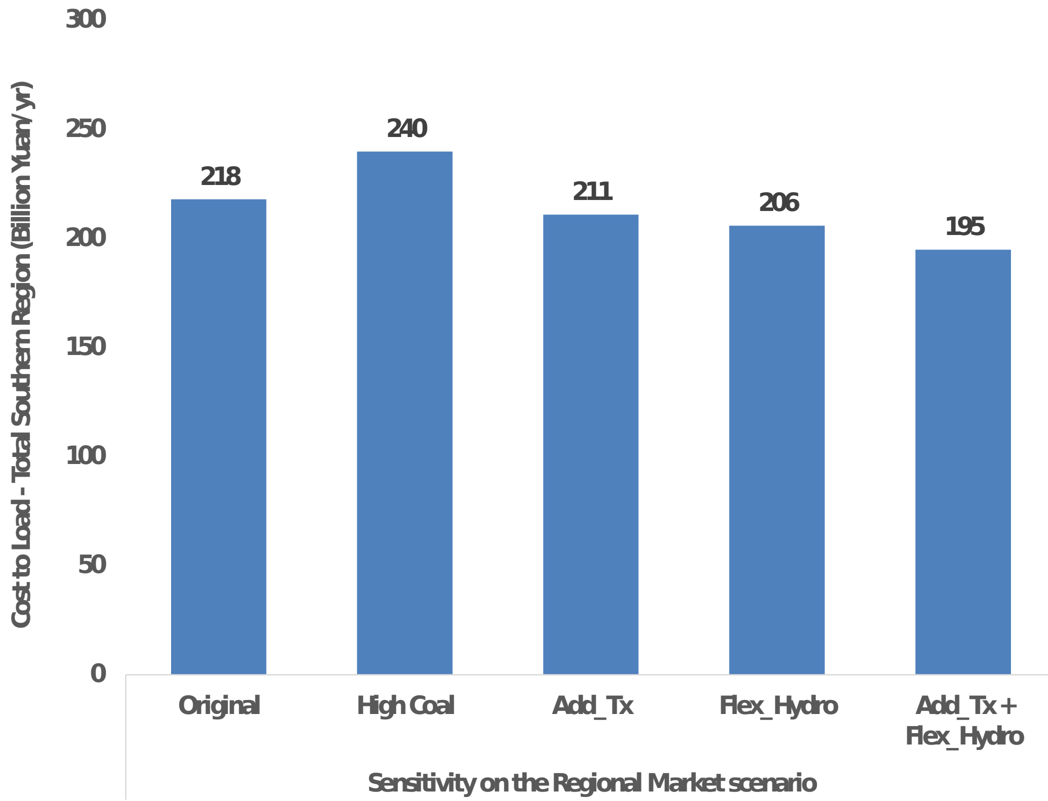

Figure 10. Sensitivity to key parameters of cost to load (total Southern Grid), Regional Market scenario, 2016

6. Conclusion and policy implications

[3] The Supplemental Information provides detailed dispatch results.

Organized wholesale markets over large balancing areas provide multiple benefits in many developed economies: reducing the costs of serving consumers, improving renewable integration, and reducing environmental footprints. Our findings suggest that market-based operation of China's Southern Grid can increase efficiency and reduce costs in all provinces—reducing wholesale electricity costs by up to 35% for the entire region. Most of the cost reduction is captured by creating independent provincial markets while maintaining the current interprovincial import/export commitments, indicating that such a policy could provide near-term benefits in conjunction with appropriate fixed-cost recovery arrangements (Lin et al. 2019).

The market-driven reductions in systemwide electricity costs might help provide the resources necessary for fixed-cost compensation. In addition, in a wholesale electricity market, transactions with generators that have the lowest marginal costs would be settled at the market price, which is likely to cover their fixed costs as well—thus, fixed-cost compensation need not be entirely additional to wholesale electricity costs. Most of the compensation would be needed for generators with high marginal costs or those that do not get dispatched at all. Our preliminary analysis of fixed costs suggests that low-cost generators would have enough excess revenue to cover their own fixed costs and compensate high-cost generators, which may require financial restructuring of current contracts/payment mechanisms. However, this topic requires further investigation, which we intend to explore in our future work.

At the provincial level, Guangdong benefits most from markets, mainly because it uses high-cost coal and imports more than 30% of its energy, even in the Baseline scenario. With the region's highest-cost coal, Guangxi's largest cost reduction stems from expanding provincial markets into a regional market, mainly because Guangxi can then import more cheap Guizhou coal power and Yunnan hydropower. Guangxi's coal generation drops significantly as a regional market develops. Because Guizhou has the region's cheapest coal, establishing a provincial market reduces costs only slightly. In a regional market, Guizhou exports significant additional coal power and imports hydropower from Yunnan, but those exchanges are limited by transmission constraints. Once those constraints are removed, other provinces import substantial Guizhou coal power, which reduces net regional costs but increases Guizhou's costs. Yunnan generally benefits with transmission-constrained market development, because hydro generation increases significantly. Expanded transmission enables other provinces to import more from Yunnan, which reduces regional costs while increasing costs in Yunnan. Electricity markets could also reduce the Southern Grid's CO_2 emissions by up to 10% owing to more efficient thermal dispatch and avoided hydro/renewable curtailment—placing electricity markets among China's most cost-effective power-sector decarbonization strategies. We understand that our overall modeling approach of only including interprovincial transmission network risks missing the potential congestion issues in the intra-province transmission network. However, in our future work, we intend to model the transmission network in a more spatially resolved manner so we can assess the intra-province transmission issues as well as actual AC transfer limits (instead of DC limits) in the network.

The environmental and economic value of the market approach likely will increase over time. For example, our analysis based on 2016 electricity systems shows only a small reduction in regional wholesale electricity cost and CO_2 emissions due to expanding transmission in a regional market. However, as China increases its renewable generation to achieve environmental goals, a regional market with expanded transmission may facilitate lower costs and larger benefits. This topic requires further research. Finally, if China institutes a power-sector carbon market, market-based electricity pricing will be needed to enable pass-through of carbon prices. As carbon prices are factored into generation costs—and the costs of solar, wind, and storage technologies continue to decline—electricity markets would facilitate large-scale renewable integration and accelerate the transition to a clean power system in China (Lin, 2018).

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Supplementary Information for

Economic and environmental benefits of market-based power-system reform in China: A Case Study of the Southern Grid System

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A. PLEXOS Unit Commitment and Economic Dispatch Optimization

The PLEXOS optimization software we use in this analysis is a unit commitment and economic dispatch model that minimizes the total operating cost of generation for a full year. This Appendix broadly describes the formulation of the optimization used in this analysis, and more detail is available in PLEXOS documentation from Energy Exemplar(2019).

The objective function for each hour of the optimization can be simplified to:

$$min \sum_{i,t} GenerationCost_{i,t} + VoLL * UnservedEnergy_t + PriceofDumpEnergy * DumpEnergy_t$$

subject to several types of operational constraints, which are described further below.

The objective function has several components:

i indexes each of the generators, which are in specific provinces within the Southern Grid region and could be thermal (natural gas, coal, nuclear, other), hydro, or variable renewable resources like wind and solar. There are several thousand generators included in the Southern Grid.

t indexes each hour in the optimization. The optimization is conducted for hourly intervals, at daily timesteps, one month at a time for a complete year.

$GenerationCost_{i,t}$ is the total hourly operating cost of generator *i*, including the fuel costs ($FC_{i,t}$), operations and maintenance costs ($O \wedge M_{i,t}$), start/shutdown costs of thermal units ($SC_{i,t}$¿, and the emissions costs of fossil units ($EC_{i,t}$¿.

$$GenerationCost_{i,t} = FC_{i,t} + O \wedge M_{i,t} + SC_{i,t}$$

Each component of $GenerationCost_{i,t}$ is defined as follows:

$$FC_{i,t} = FuelPrice_i \times HeatValue_i \times HeatRate_i \times \sum_t Generation_{i,t}$$

$FC_{i,t}$ is the fuel cost (applicable only for natural gas, coal, nuclear, and biomass generators).

$FuelPrice_i$ and $HeatValue_i$ are the price and heating value of the fuel used by generator i.

$HeatRate_i$ is the rate of electricity output given a unit of fuel input, and could be modeled as a function (linear or non-linear) depending on the generation level.

$Generation_{i,t}$ is the instantaneous electricity production from generator *i* in hour *t*. It is the main decision variable of the optimization, and also depends on the unit commitment (integer) decision variable that determines whether the generator is on or off in the particular hour, and also how much of a generator’s capacity is set aside to provide reserves.

$$O \wedge M_{i,t} = Generation_{i,t} * \text{¿}\, VO \wedge M_i$$

$O \wedge M_{i,t}$ is the cost for operations and maintenance for each generator, based on its variable $VO \wedge M_i$ cost per unit of $Generation_{i,t}$.

$$SC_{i,t} = StartCost_i \times UnitsStarted_{i,t} + ShutdownCost_i \times UnitsShutdown_{i,t}$$

$SC_{i,t}$ is the cost to start and shutdown a generator and is typically applicable only for thermal generators depending on the number of $UnitsStarted_{i,t}$ or $UnitsShutdown_{i,t}$ during the period, which are integer values that are part of the unit commitment decision.

$VoLL * UnservedEnergy_t$ is the cost of load shedding. The *VoLL* sets a maximum price above which there is $UnservedEnergy_t$. If there is not enough generation to meet load, the market price will reach the *VoLL*.

$PriceofDumpEnergy * DumpEnergy_t$ sets a *PriceofDumpEnergy* below which generators shutoff rather than $DumpEnergy_t$ or over-generate. If there is more generation than load, the market price reaches the *PriceofDumpEnergy*.

Generator unit commitment and dispatch is subject to the following selected constraints:

For each utility zone there is an energy balance constraint such that total generation (minus any over-generation) must match the $Load_t$, the total electricity demanded in hour t (minus any under-generation):

$$\sum_i Generation_{i,t} - DumpEnergy_t = Load_t - UnservedEnergy_t$$

Selected generator constraints:
Instantaneous energy from any generator must be less than or equal to its max capacity:

$$MaxCapacity_i \geq Generation_{i,t}$$

All thermal generators must abide by their ramping constraints:

$$|Generation_{i,t} - Generation_{i,t-1}| \leq RampRate_i$$

Hydropower generators have monthly energy budgets (based on the amount of water they can allocate that month) as well as minimum and maximum flows. PLEXOS first optimizes for the monthly budget through a monthly scheduling process.

Overall, the optimization is a mixed integer program of a unit commitment decision (1 or 0 whether a generator is on or off) and an economic dispatch decision (how much a generator generates).

$$UnitOn_{i,t} = UnitOn_{i,t-1} + UnitStarted_{i,t} - UnitShutdown_{i,t}$$

There are also constraints specific to the unit commitment problem for minimum stable levels, minimum up time, and minimum down time:

$$Generation_{i,t} \geq UnitOn_{i,t} * MinStableLevel_i$$

When a generator is committed ($UnitOn_{i,t} = 1$), it must operate at or above its $MinStableLevel_i$.

$MinUpTime_i$ is the minimum number of hours a generator unit must be on if committed (primarily applies to thermal generators).

$MinDownTime_i$ is the minimum number of hours a generator unit must be off if shut down (primarily applies to thermal generators).

Transmission constraints:
The optimization solves a linearized DC power flow that follows Kirchhoff's Voltage Law (the sum of voltages around a loop equal 0), and flows between

provinces j and k must not exceed $LineLimits_{jk}$. In the absence of any publicly available data on AC power flow studies or available transfer capabilities between provinces, we have taken *LineLimits* to be the installed transmission capacity between the provinces. This assumption would likely overestimate the actual power transfer capability of the lines in an AC network. Therefore, we run a sensitivity analysis case by reducing *LineLimits* to 50% of the installed transmission capacities between provinces.

Solution algorithm:

We set the Mixed Integer Program (MIP) gap, the percentage difference between the best integer solution and the best bound (through the Branch and Bound algorithm), to be 0.01%.

B. Detailed Dispatch and Cost Results

B.1 Annual energy generation and exchange between provinces in 2016

Table B.1.1 *Baseline Scenario*

		Guangdong	Guangxi	Guizhou	Yunnan	Hainan	Total Southern Grid
Total Generation (TWh/yr)		383	120	206	271	30	1010
	Nuclear	70	10	0	0	6	86
	Coal	264	48	127	40	20	500
	Gas	0	1	0	0	0	1
	Hydro	43	60	73	216	2	394
	Wind	5	1	5	11	1	22
	Solar	2	0	1	3	1	7
	Curtailment	0	0	0	2	0	2
Total Imports (TWh/yr)		195	135	10	0	0	341
	From.GD	0	0	0	0	0	0
	From.GX	119	0	0	0	0	119
	From.GZ	0	77	0	0	0	77
	From.YN	43	58	10	0	0	112
	From.HN	1	0	0	0	0	1
	From.Other.Grids	31	0	0	0	0	31
Total Exports (TWh/yr)		-16	-119	-92	-129	-1	-357
	To.GD	0	-119	0	-43	-1	-163
	To.GX	0	0	-77	-58	0	-135
	To.GZ	0	0	0	-10	0	-10
	To.YN	0	0	0	0	0	0
	To.HN	0	0	0	0	0	0
	To.Other.Grids	-16	0	-15	-17	0	-48
Net Energy Input (TWh/yr)		562	137	124	141	29	993
Load (TWh/yr)		562	137	124	141	29	993
Generation.Cost (Yuan Million/yr)		55,076	12,461	19,541	7185	4539	98,802

Table B.1.2 *Provincial Market Scenario*

		Guangdong	Guangxi	Guizhou	Yunnan	Hainan	Total Southern Grid
Total Generation (TWh/yr)		383	120	206	271	30	1010
	Nuclear	77	19	0	0	11	107
	Coal	257	41	127	25	15	465
	Gas	0	0	0	0	0	0
	Hydro	43	60	73	235	2	413
	Wind	5	1	5	8	0	19
	Solar	2	0	1	2	1	6
	Curtailment	0	0	0	5	0	6
Total Imports (TWh/yr)		195	135	10	0	0	341
	From.GD	0	0	0	0	0	0
	From.GX	119	0	0	0	0	119
	From.GZ	0	77	0	0	0	77
	From.YN	43	58	10	0	0	112
	From.HN	1	0	0	0	0	1
	From.Other.Grids	31	0	0	0	0	31
Total Exports (TWh/yr)		-16	-119	-92	-129	-1	-357
	To.GD	0	-119	0	-43	-1	-163
	To.GX	0	0	-77	-58	0	-135
	To.GZ	0	0	0	-10	0	-10
	To.YN	0	0	0	0	0	0
	To.HN	0	0	0	0	0	0
	To.Other.Grids	-16	0	-15	-17	0	-48
Net Energy Input (TWh/yr)		562	137	124	141	29	993
Load (TWh/yr)		562	137	124	141	29	993
Generation.Cost (Yuan Million/yr)		54,049	10,862	19,547	4403	3738	92,599

Table B.1.3 *Regional Market Scenario*

		Guangdong	Guangxi	Guizhou	Yunnan	Hainan	Total Southern Grid
Total Generation (TWh/yr)		352	90	262	279	27	1010
	Nuclear	77	19	0	0	11	107
	Coal	226	9	183	19	13	450
	Gas	0	0	0	0	0	0
	Hydro	43	60	73	247	2	425
	Wind	5	1	5	11	1	22
	Solar	2	0	1	3	1	6
	Curtailment	0	0	0	2	0	2
Total Imports (TWh/yr)		228	200	13	0	1	442
	From.GD	0	0	0	0	1	1
	From.GX	153	0	0	0	0	153
	From.GZ	0	136	0	0	0	136
	From.YN	43	64	13	0	0	121
	From.HN	0	0	0	0	0	0
	From.Other.Grids	31	0	0	0	0	31
Total Exports (TWh/yr)		-18	-153	-151	-138	0	-459
	To.GD	0	-153	0	-43	0	-196
	To.GX	0	0	-136	-64	0	-200
	To.GZ	0	0	0	-13	0	-13
	To.YN	0	0	0	0	0	0
	To.HN	-1	0	0	0	0	-1
	To.Other.Grids	-16	0	-15	-17	0	-48
Net Energy Input (TWh/yr)		562	137	124	141	29	993
Load (TWh/yr)		562	137	124	141	29	993
Generation.Cost (Yn Million/yr)		47439	3158	28340	3530	3267	85,733
Cost.To.Load (Yuan Million/yr)		149,508	22,641	23,466	16,161	6638	218,414
Average Price Yuan/MWh		266	166	189	114	231	220

Table B.1.4 *Regional Market Scenario: Sensitivity Add_Tx*

		Guangdong	Guangxi	Guizhou	Yunnan	Hainan	Total Southern Grid
Total Generation (TWh/yr)		293	84	296	312	24	1010
	Nuclear	77	19	0	0	11	107
	Coal	167	3	218	44	10	442
	Gas	0	0	0	0	0	0
	Hydro	43	60	73	252	2	430
	Wind	5	1	5	12	1	23
	Solar	2	0	1	4	1	7
	Curtailment	0	0	0	0	0	0
Total Imports (TWh/yr)		289	245	10	0	4	549
	From.GD	0	0	0	0	4	4
	From.GX	193	0	0	0	0	193
	From.GZ	0	167	0	0	0	167
	From.YN	65	79	10	0	0	154
	From.HN	0	0	0	0	0	0
	From.Other.Grids	31	0	0	0	0	31
Total Exports (TWh/yr)		-21	-193	-181	-171	0	-565
	To.GD	0	-193	0	-65	0	-258
	To.GX	0	0	-167	-79	0	-245
	To.GZ	0	0	0	-10	0	-10
	To.YN	0	0	0	0	0	0
	To.HN	-4	0	0	0	0	-4
	To.Other.Grids	-16	0	-15	-17	0	-48
Net Energy Input (TWh/yr)		562	137	124	141	29	993
Load (Twh/yr)		562	137	124	141	29	993
Generation.Cost (Yuan Million/yr)		35,298	1866	33,675	8207	2647	81,693
Cost.To.Load (Yuan Million/yr)		140,710	14,678	25,552	23,661	6506	211,107
Average Price Yuan/MWh		250	107	205	167	226	213

Table B.1.5 *Regional Market Scenario: Sensitivity Flex_Hydro*

		Guangdong	Guangxi	Guizhou	Yunnan	Hainan	Total Southern Grid
Total Generation (TWh/yr)		352	85	267	278	27	1010
	Nuclear	77	19	0	0	11	107
	Coal	226	4	188	17	12	448
	Gas	0	0	0	0	0	0
	Hydro	43	61	73	247	2	426
	Wind	5	1	5	11	1	22
	Solar	2	0	1	3	1	7
	Curtailment	0	0	0	2	0	2
Total Imports (TWh/yr)		228	206	12	0	2	448
	From.GD	0	0	0	0	2	2
	From.GX	155	0	0	0	0	155
	From.GZ	0	140	0	0	0	140
	From.YN	42	66	12	0	0	120
	From.HN	0	0	0	0	0	0
	From.Other.Grids	31	0	0	0	0	31
Total Exports (TWh/yr)		-18	-155	-155	-137	0	-464
	To.GD	0	-155	0	-42	0	-196
	To.GX	0	0	-140	-66	0	-206
	To.GZ	0	0	0	-12	0	-12
	To.YN	0	0	0	0	0	0
	To.HN	-2	0	0	0	0	-2
	To.Other.Grids	-16	0	-15	-17	0	-48
Net Energy Input (TWh/yr)		562	137	124	141	29	993
Load (TWh/yr)		562	137	124	141	29	993
Generation.Cost (Yuan Million/yr)		46,737	2029	29,133	3321	3169	84,388
Cost.To.Load (Yuan Million/yr)		146,112	16,031	22,892	14,355	6545	205,935
Average Price Yuan/MWh		260	117	184	102	227	207

B.2 Generation (Production) Cost

The Regional Market scenario has consistently lower system marginal cost (for the entire Southern Grid pool) for all 8,760 hours as shown in the following chart.

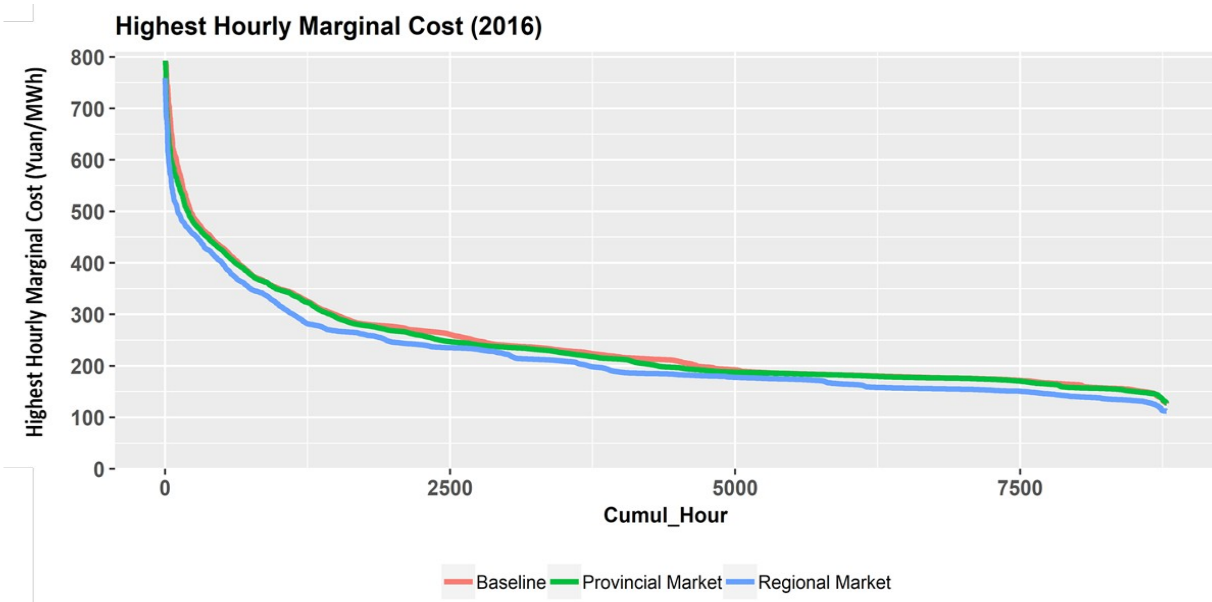


Figure B.2.1: Hourly system marginal cost (Yuan/MWh) for the Southern Grid pool, 2016

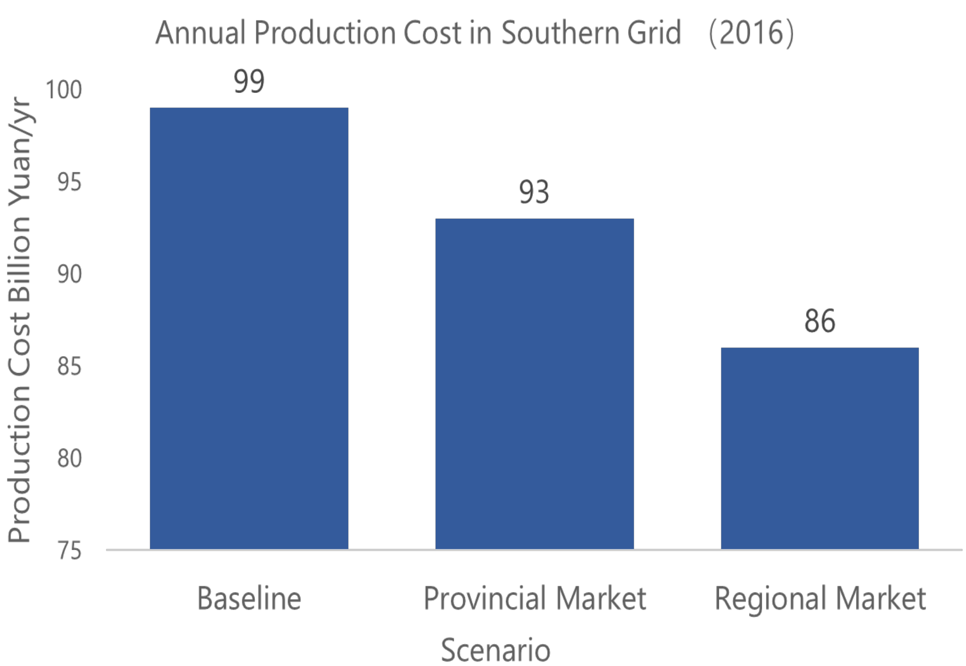
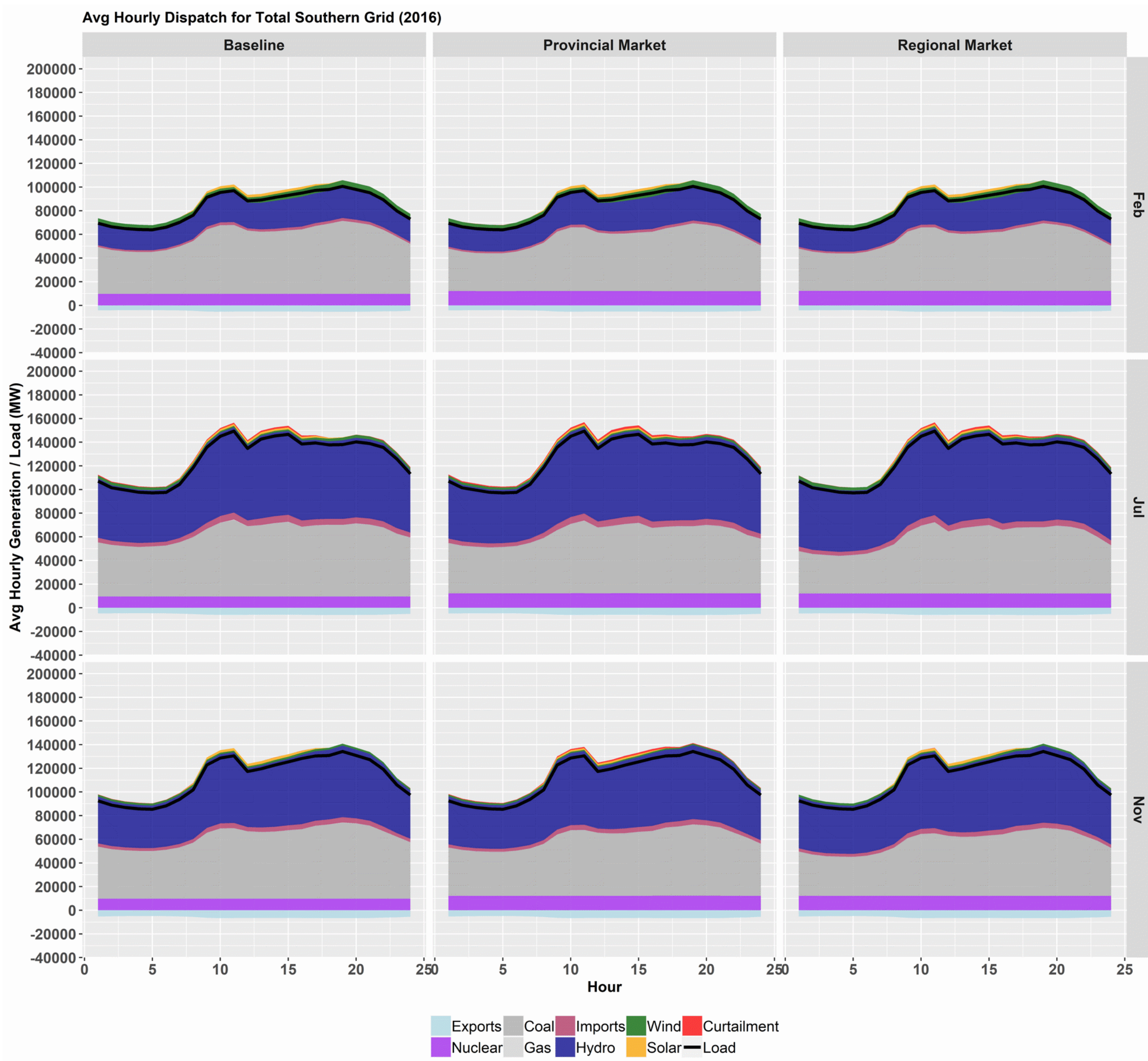
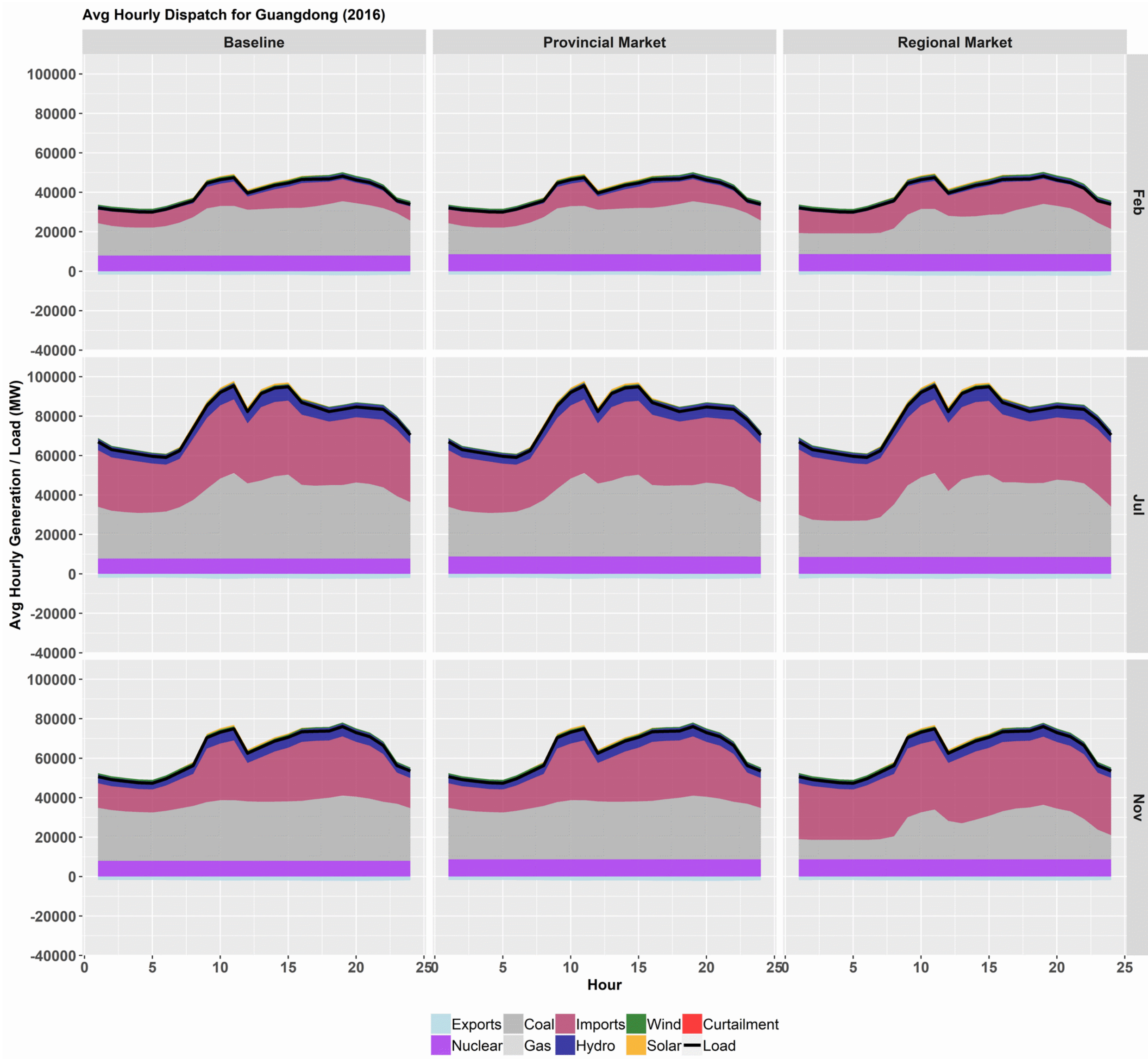


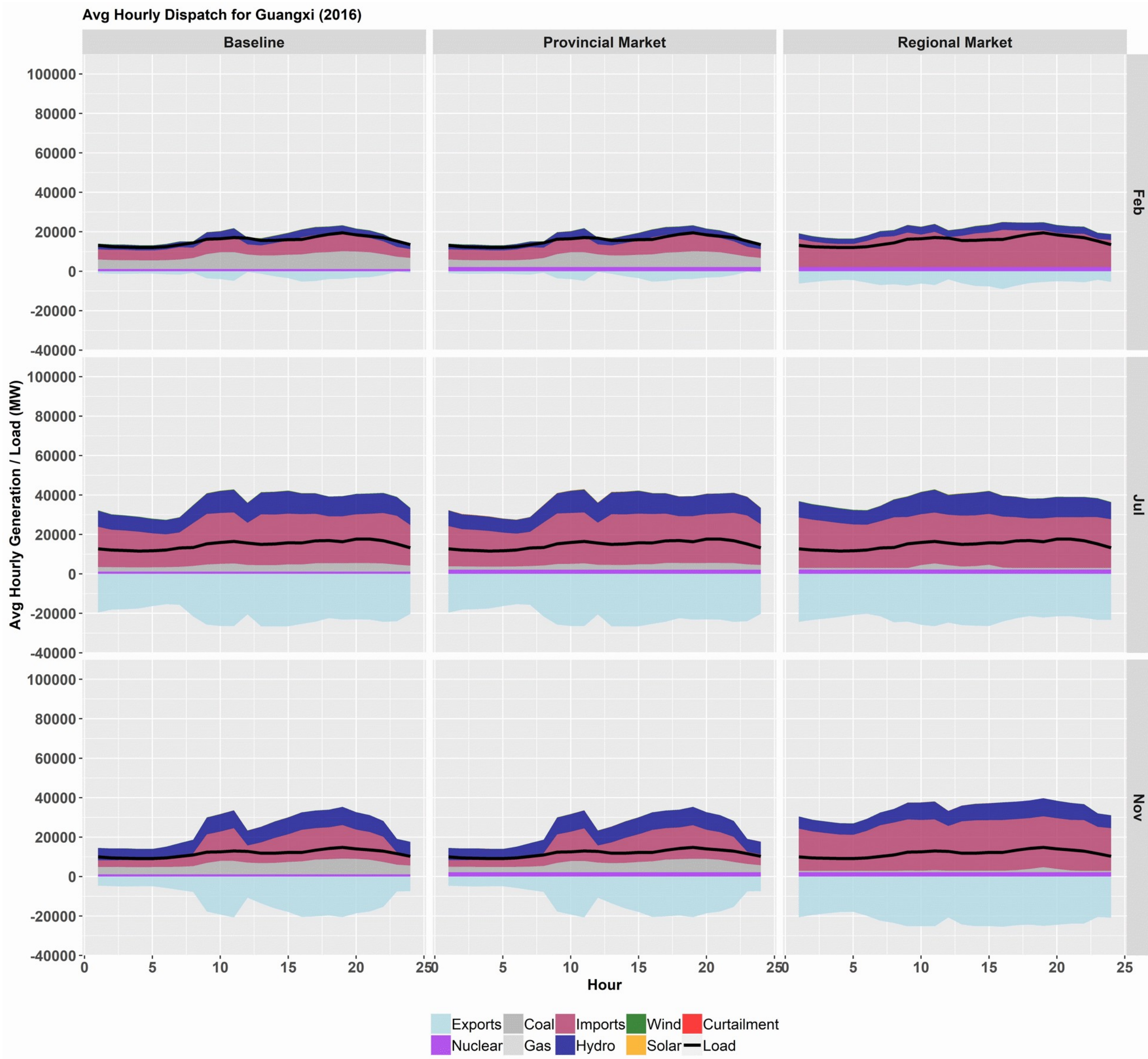
Figure B.2.2: Annual production cost (variable cost) for the Southern Grid pool (Yuan billion/yr), 2016

B.3. Dispatch Results

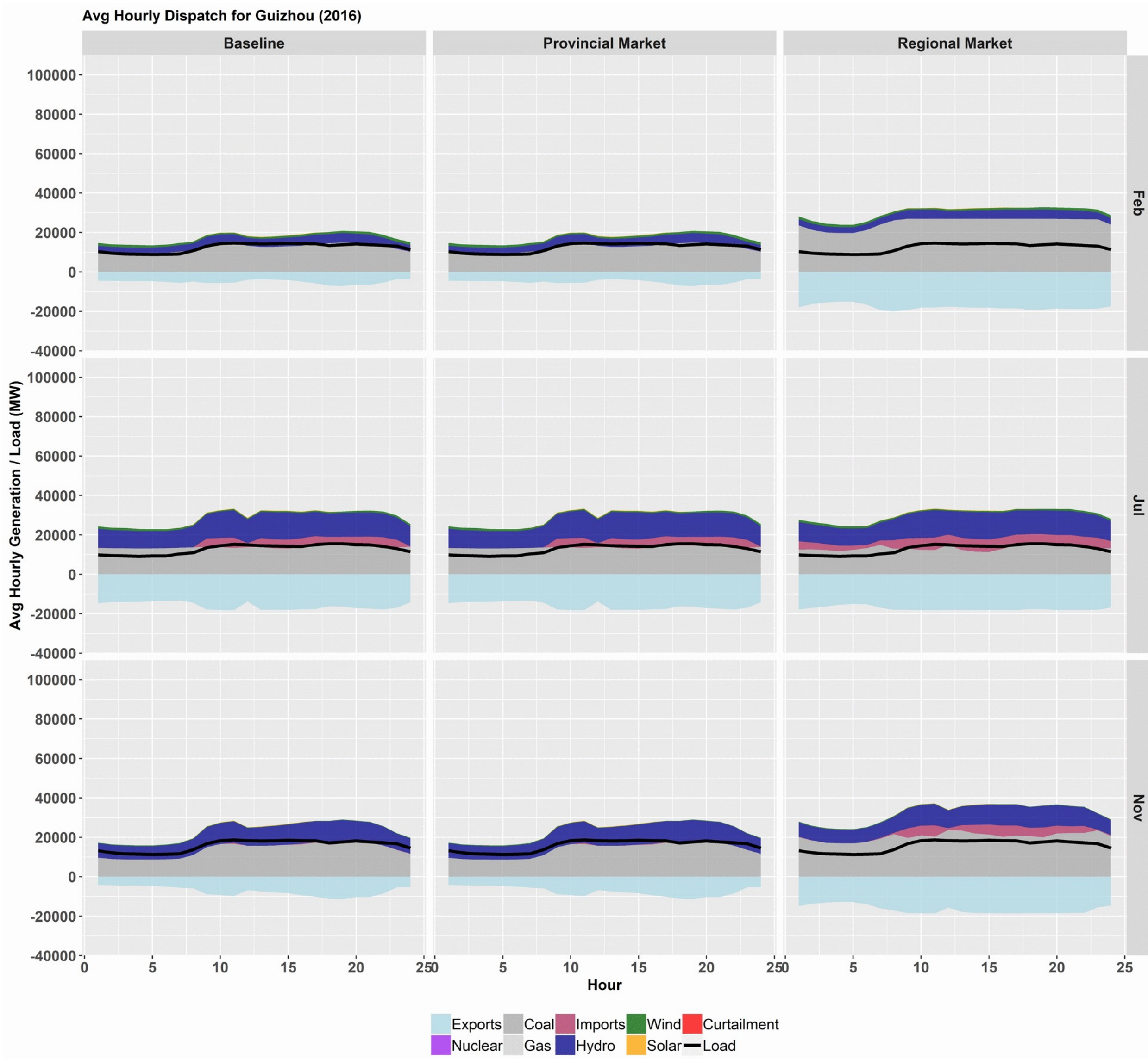
The following charts show the average monthly dispatch for each region in all scenarios for selected months: February, July (the peak load month), and November.

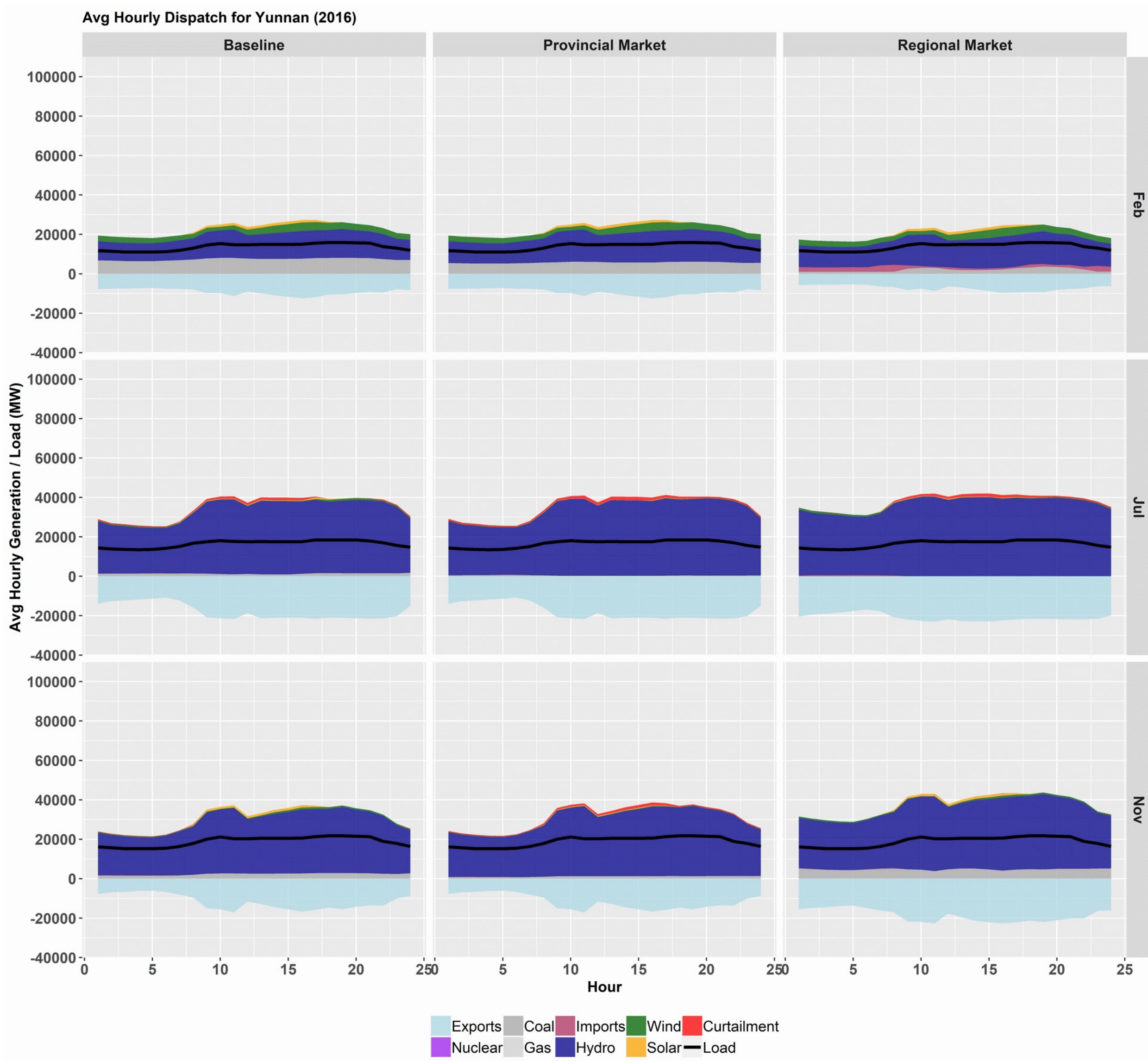


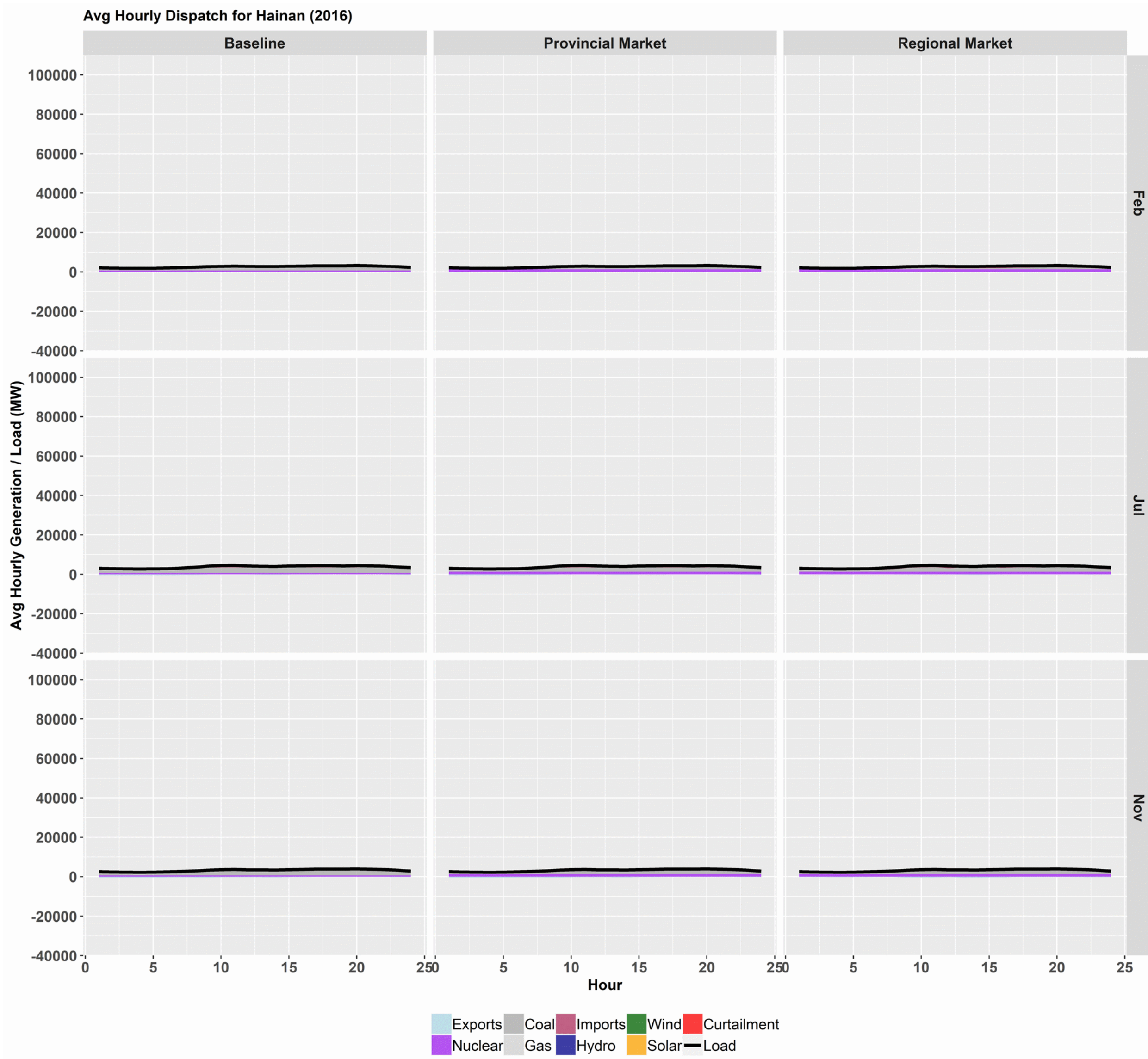

Avg Hourly Dispatch for Guangdong (2016)
Baseline
Provincial Market
Regional Market
Feb
Jul
Nov
Avg Hourly Generation / Load (MW)
Hour
Exports
Coal
Imports
Wind
Curtailment
Nuclear
Gas
Hydro
Solar
Load



Avg Hourly Dispatch for Guangxi (2016)
Baseline
Provincial Market
Regional Market
Feb
Jul
Nov
Avg Hourly Generation / Load (MW)
Hour
Exports
Coal
Imports
Wind
Curtailment
Nuclear
Gas
Hydro
Solar
Load

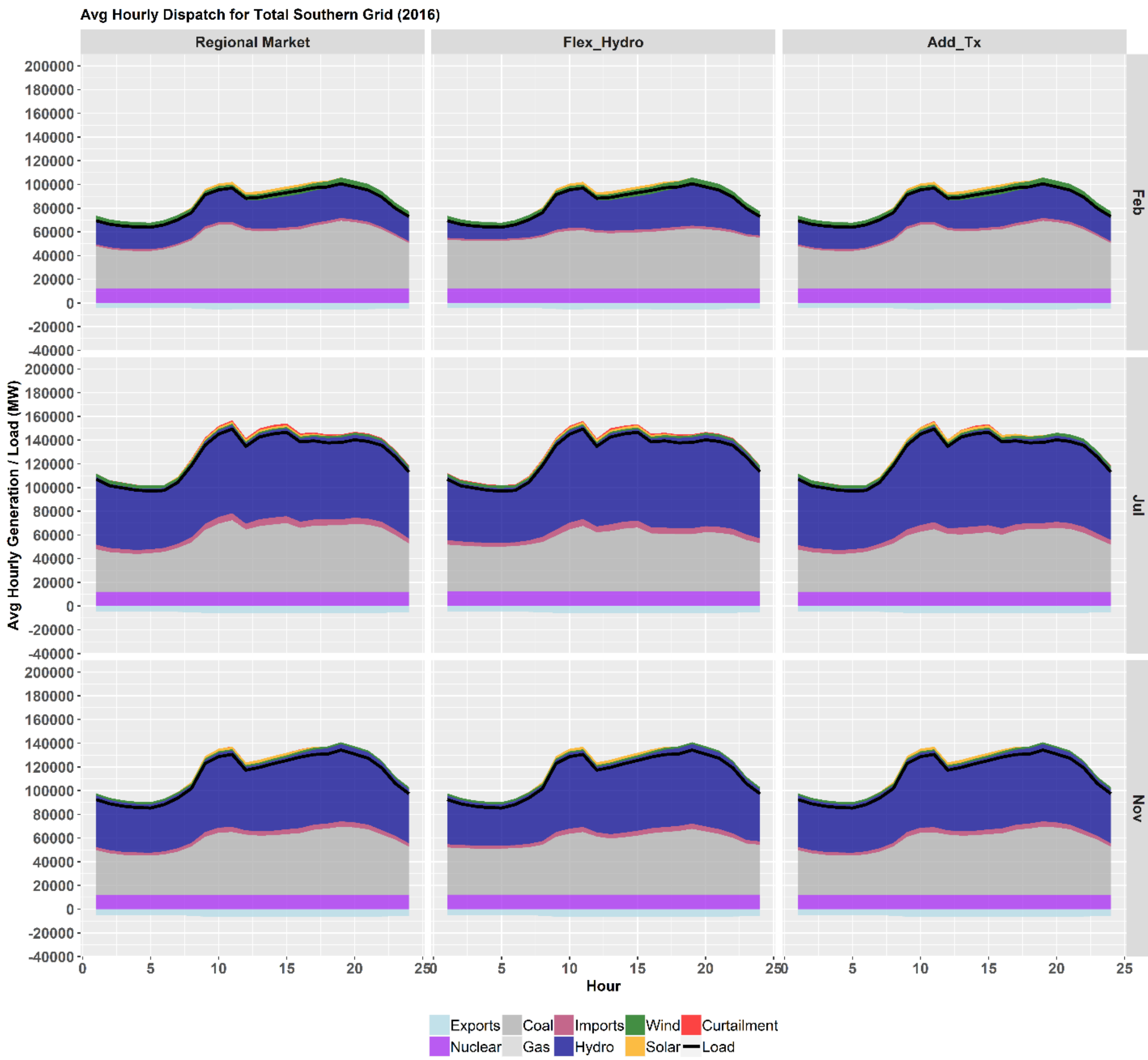

Avg Hourly Dispatch for Guizhou (2016)
Baseline
Provincial Market
Regional Market
Feb
Jul
Nov
Avg Hourly Generation / Load (MW)
Hour
100000
80000
60000
40000
20000
0
-20000
-40000
0
5
10
15
20
25
Exports
Coal
Imports
Wind
Curtailment
Nuclear
Gas
Hydro
Solar
Load

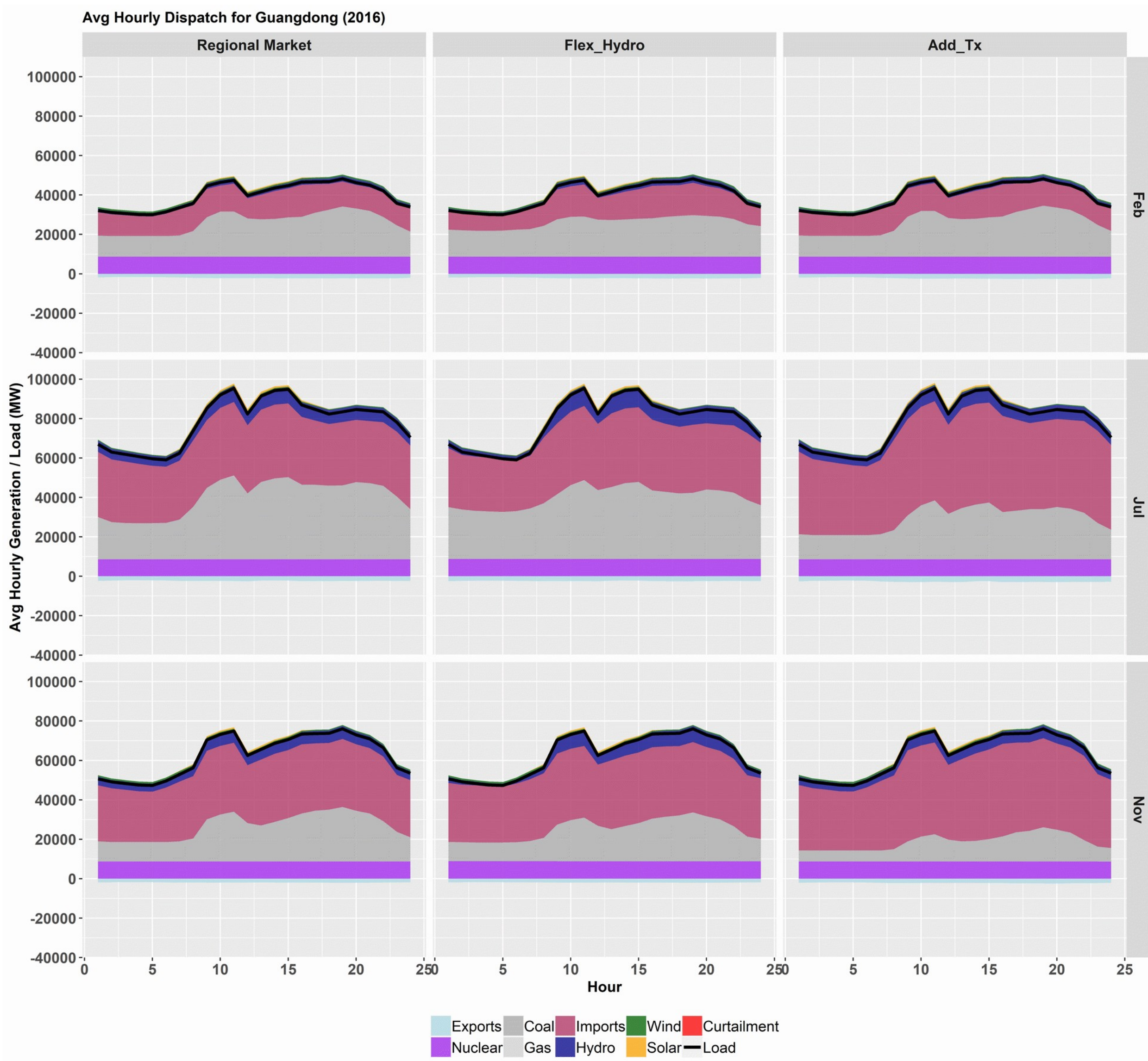

Avg Hourly Dispatch for Yunnan (2016)
Baseline
Provincial Market
Regional Market
Feb
Jul
Nov
Avg Hourly Generation / Load (MW)
Hour
100000
80000
60000
40000
20000
0
-20000
-40000
0
5
10
15
20
25
Exports
Coal
Imports
Wind
Curtailment
Nuclear
Gas
Hydro
Solar
Load



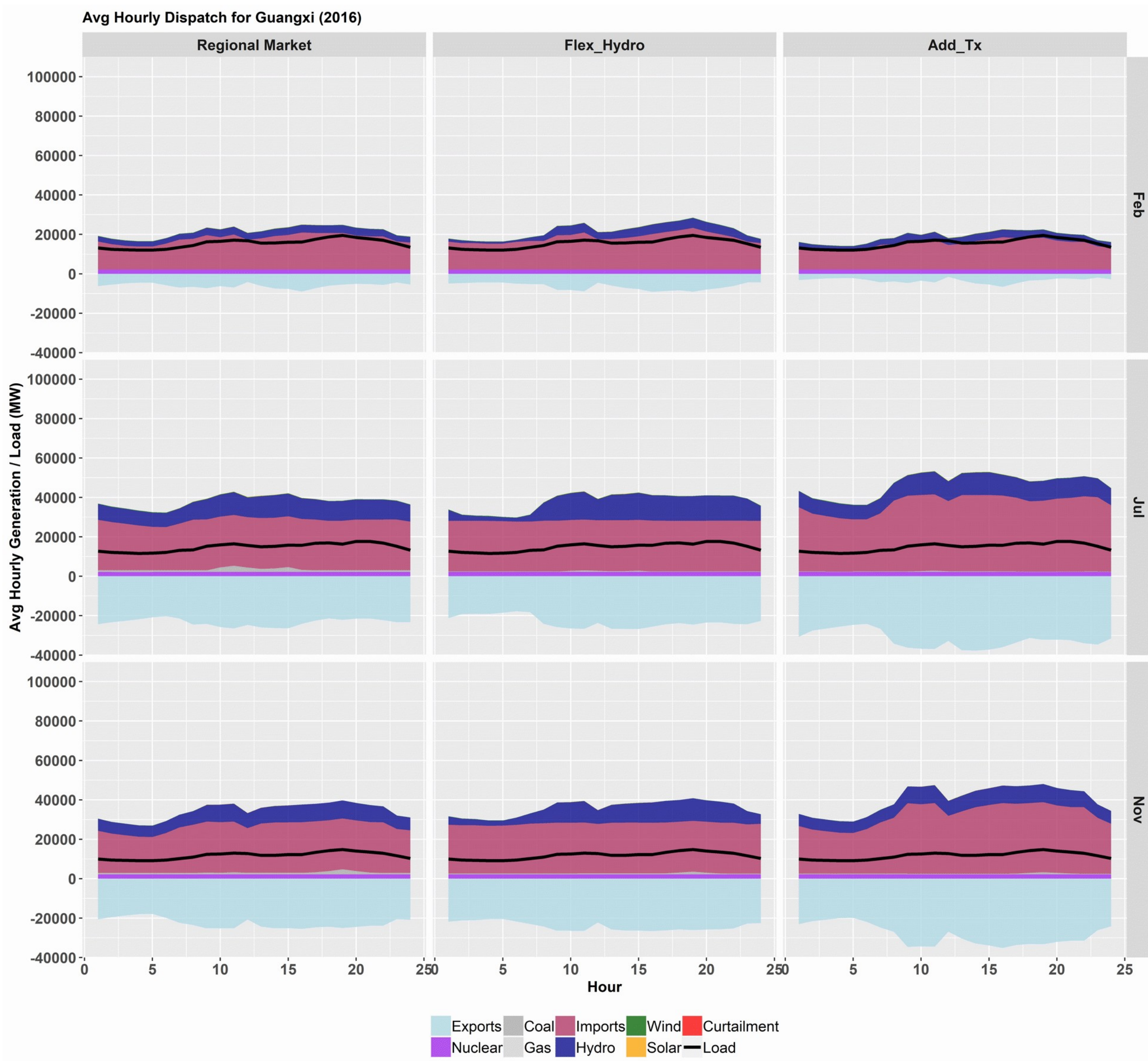
Avg Hourly Dispatch for Hainan (2016)
Baseline
Provincial Market
Regional Market
Feb
Jul
Nov
Avg Hourly Generation / Load (MW)
Hour
Exports
Coal
Imports
Wind
Curtailment
Nuclear
Gas
Hydro
Solar
Load

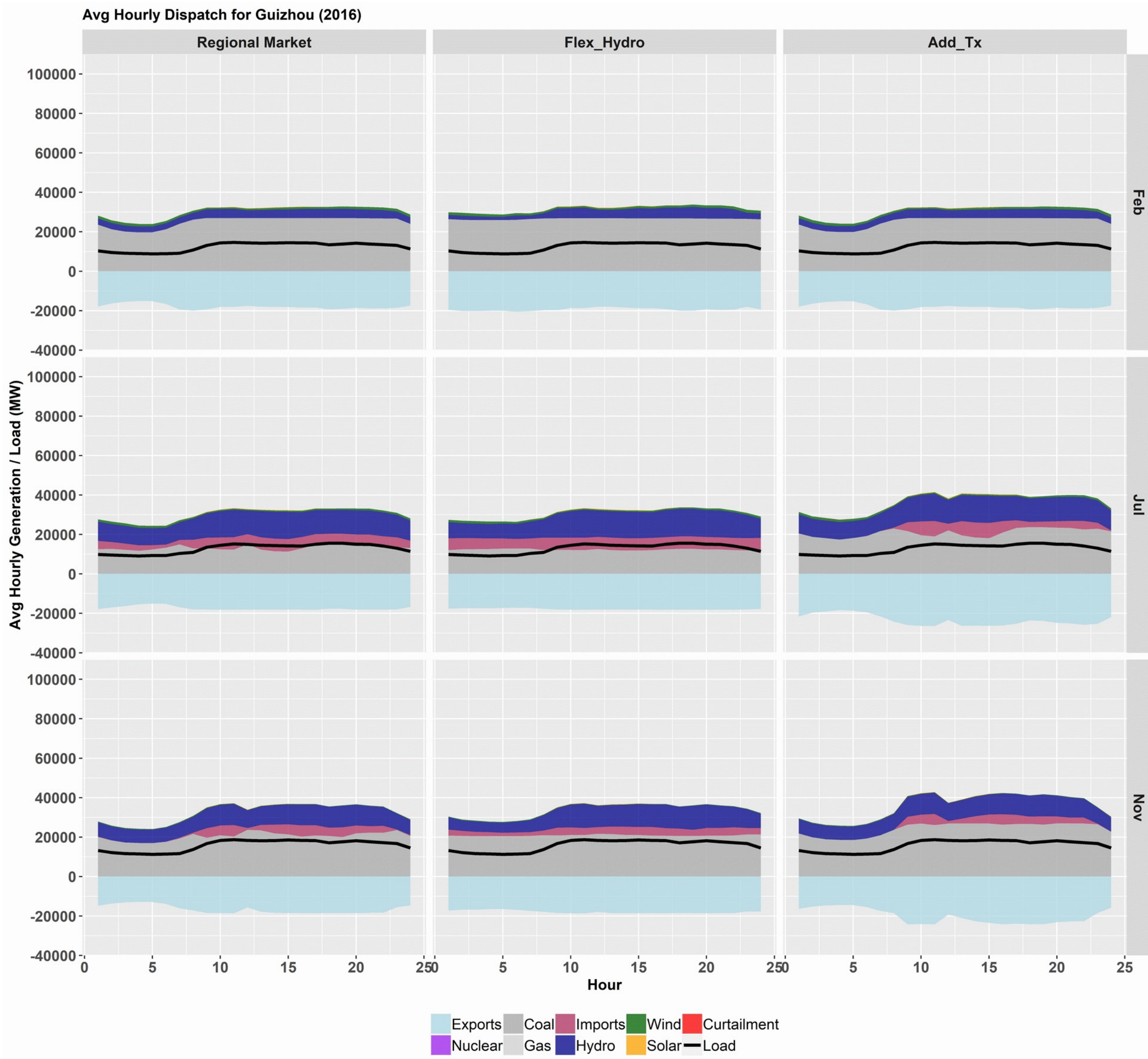
How do additional transmission investments and flexible hydro change the dispatch?

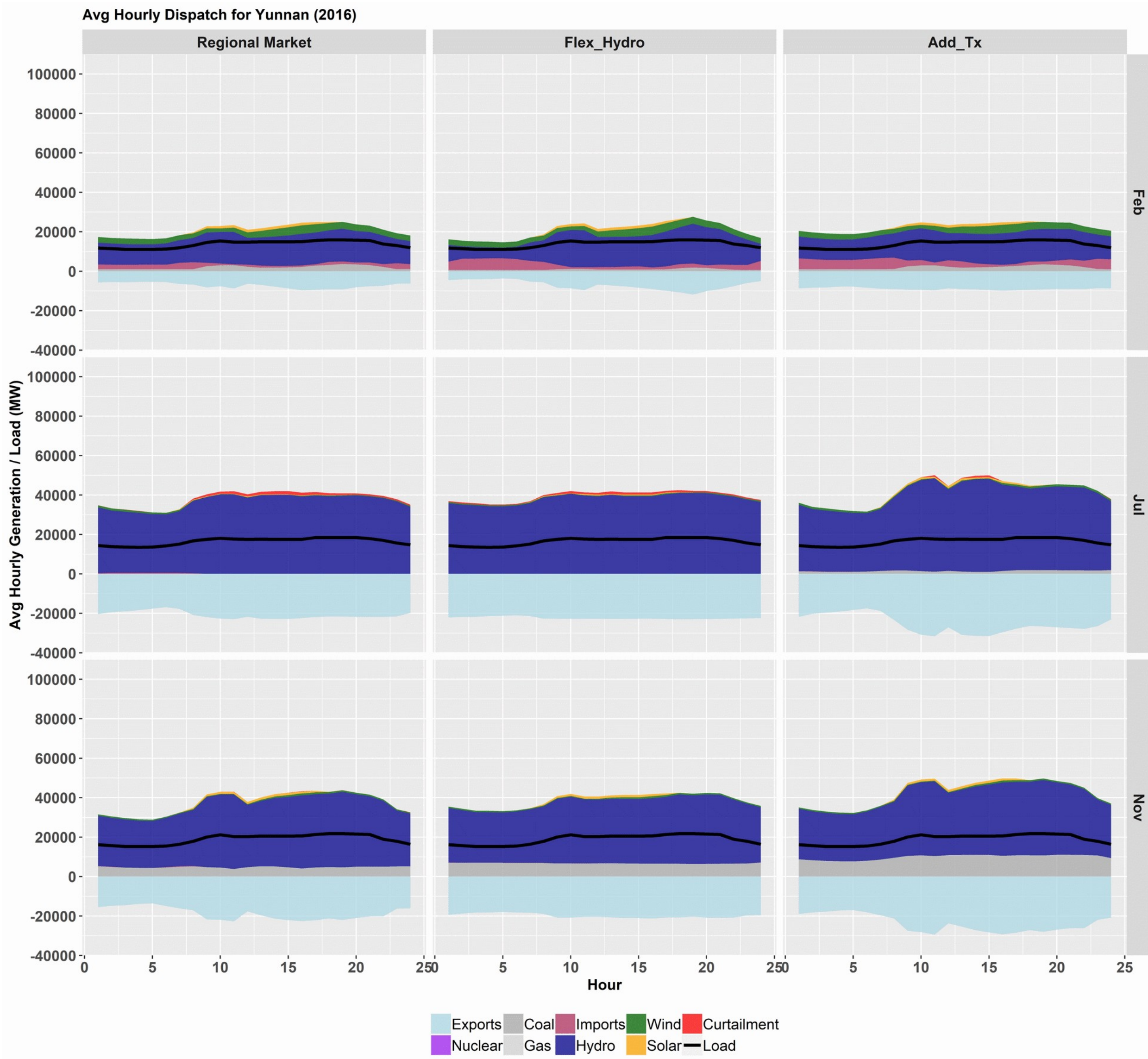


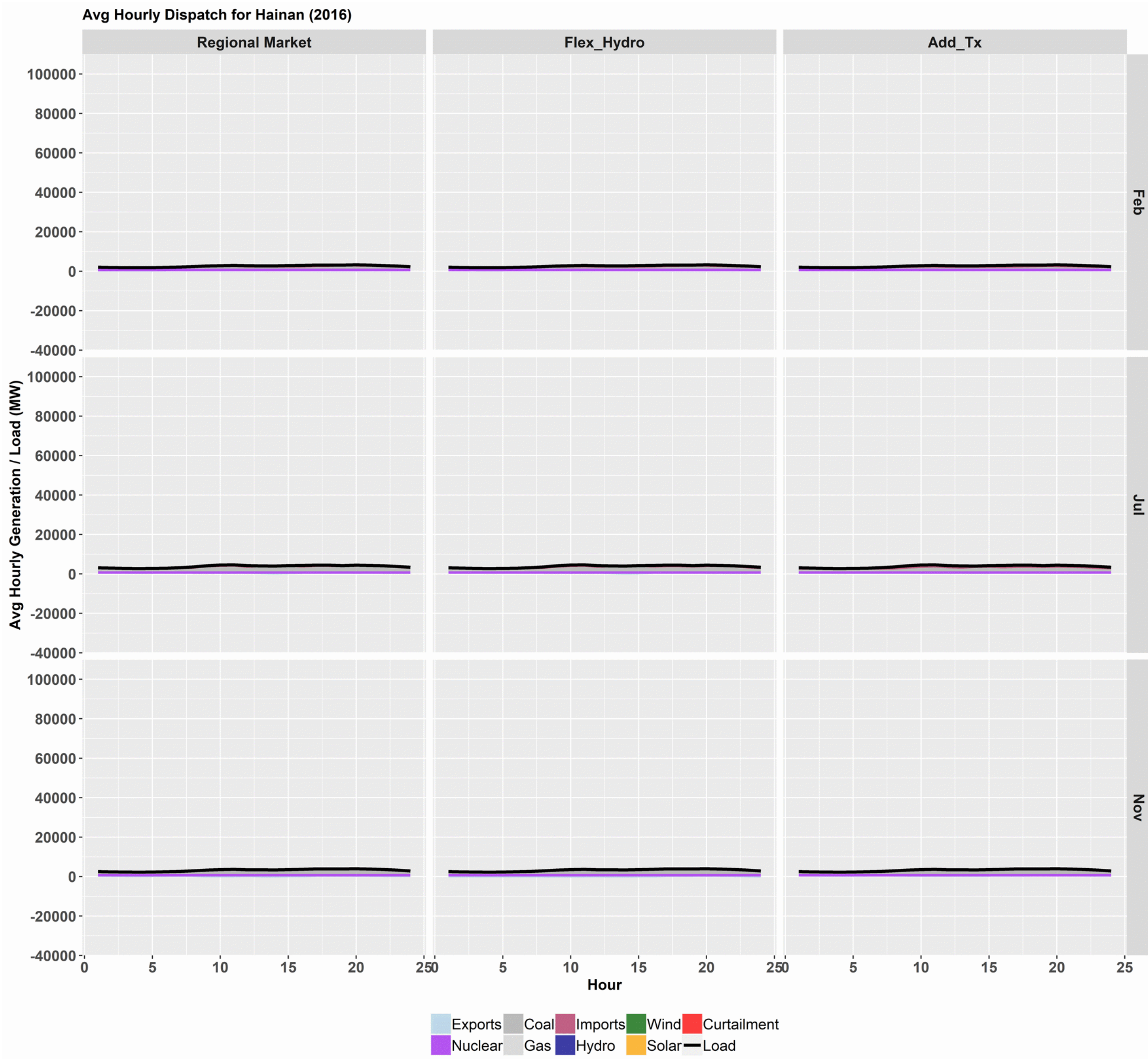


Avg Hourly Dispatch for Guangdong (2016)
Regional Market
Flex_Hydro
Add_Tx
Feb
Jul
Nov
Avg Hourly Generation / Load (MW)
Hour
Exports
Coal
Imports
Wind
Curtailment
Nuclear
Gas
Hydro
Solar
Load

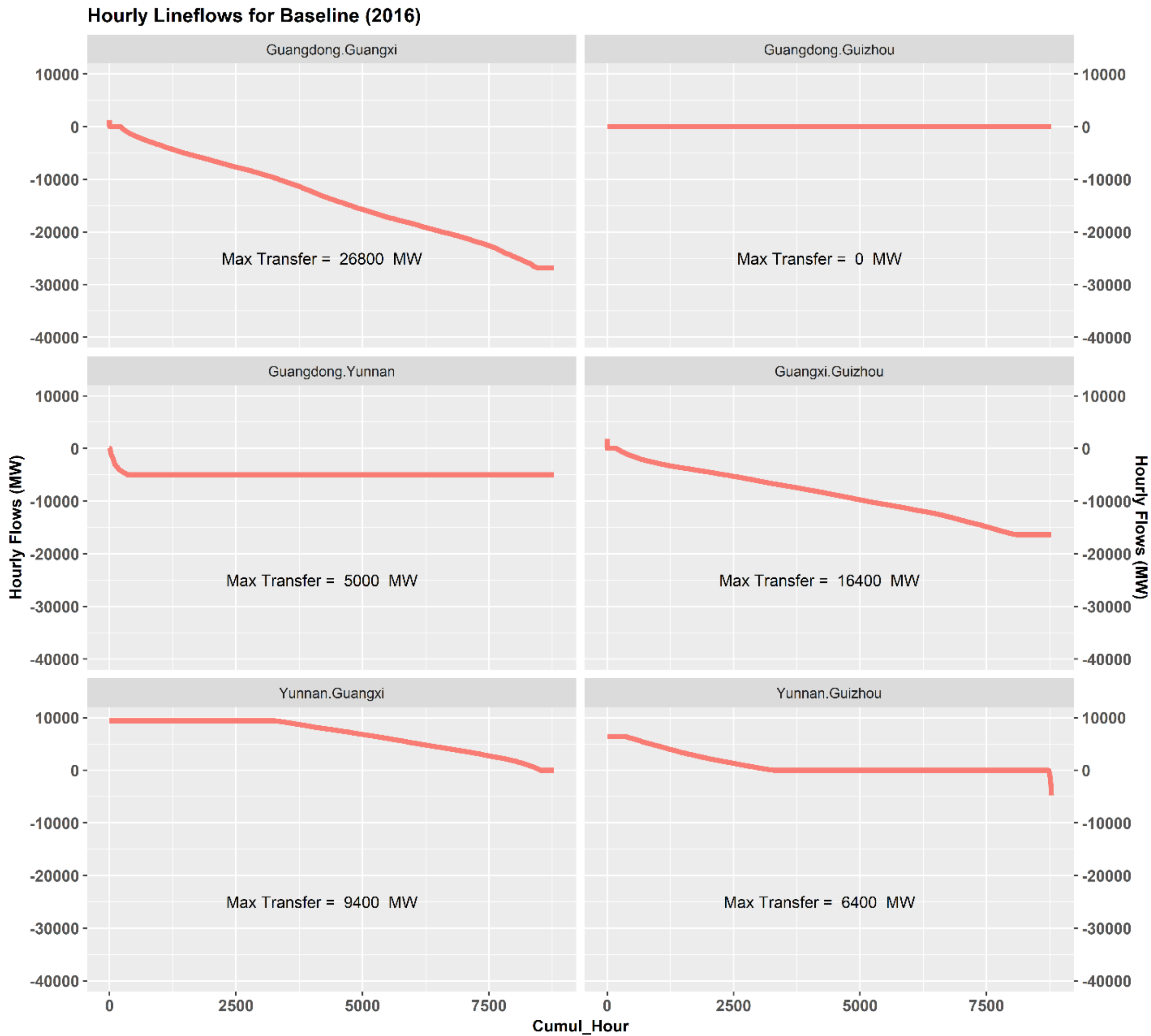

Avg Hourly Dispatch for Guangxi (2016)
Regional Market
Flex_Hydro
Add_Tx
Feb
Jul
Nov
Avg Hourly Generation / Load (MW)
Hour
Exports
Coal
Imports
Wind
Curtailment
Nuclear
Gas
Hydro
Solar
Load

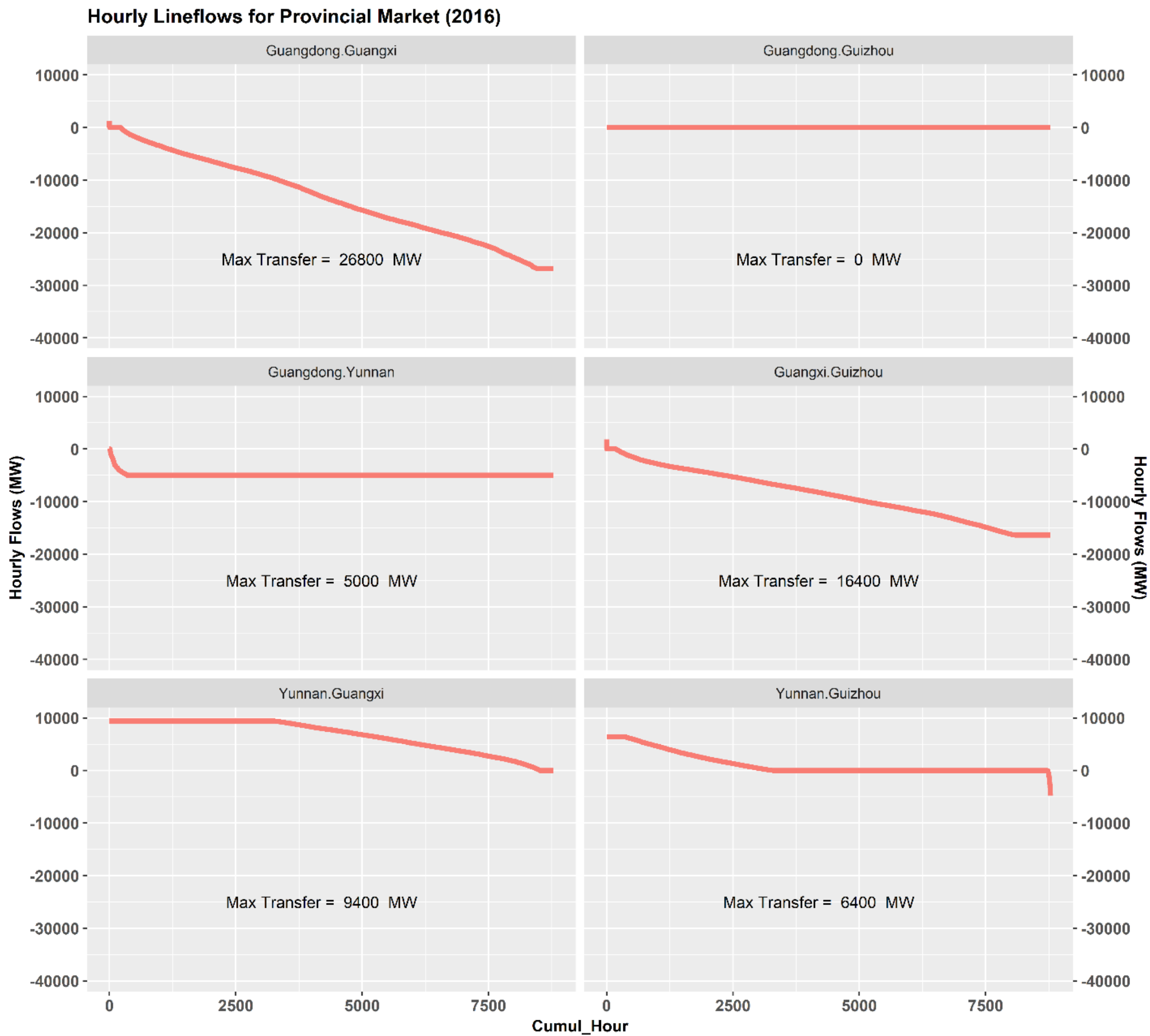

Avg Hourly Dispatch for Guizhou (2016)
Regional Market
Flex_Hydro
Add_Tx
Feb
Jul
Nov
Avg Hourly Generation / Load (MW)
Hour
Exports
Coal
Imports
Wind
Curtailment
Nuclear
Gas
Hydro
Solar
Load


Avg Hourly Dispatch for Yunnan (2016)
Regional Market
Flex_Hydro
Add_Tx
Feb
Jul
Nov
Avg Hourly Generation / Load (MW)
100000
80000
60000
40000
20000
0
-20000
-40000
0
5
10
15
20
25
Hour
Exports
Coal
Imports
Wind
Curtailment
Nuclear
Gas
Hydro
Solar
Load

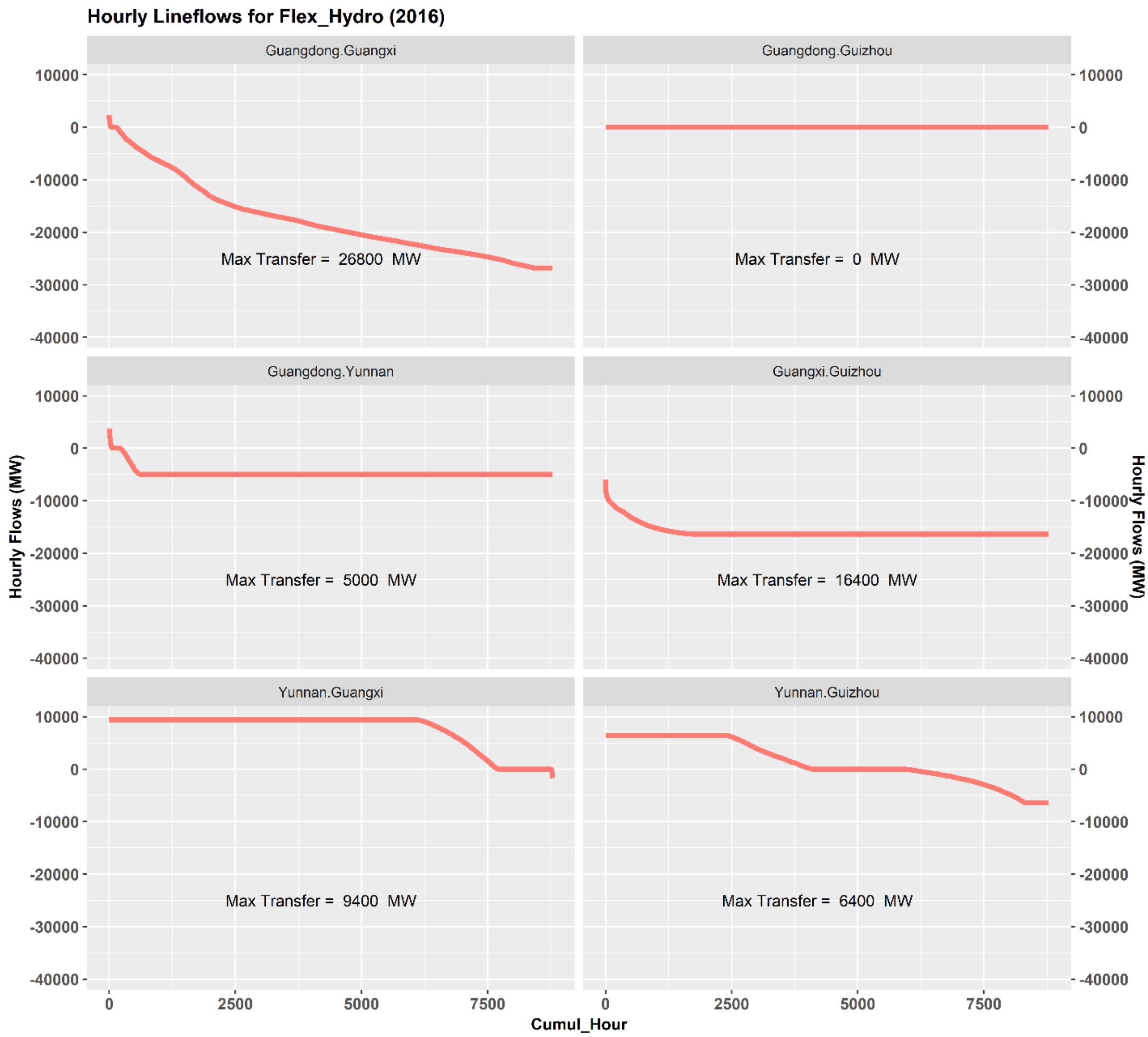


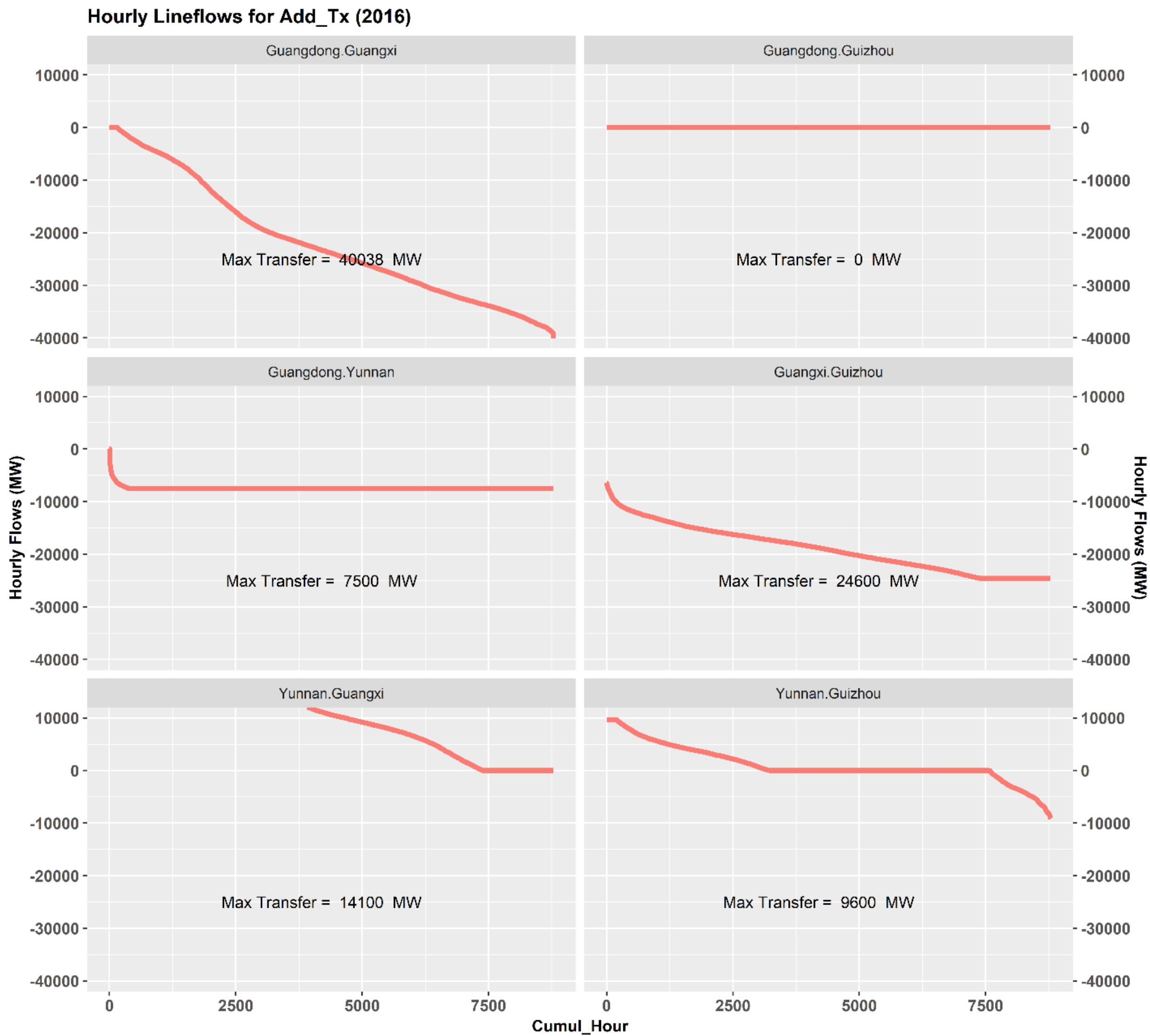
Transmission duration curves on major interfaces for all scenarios


Hourly Lineflows for Baseline (2016)
Guangdong.Guangxi
Max Transfer = 26800 MW
Guangdong.Guizhou
Max Transfer = 0 MW
Guangdong.Yunnan
Max Transfer = 5000 MW
Guangxi.Guizhou
Max Transfer = 16400 MW
Yunnan.Guangxi
Max Transfer = 9400 MW
Yunnan.Guizhou
Max Transfer = 6400 MW
Hourly Flows (MW)
Cumul_Hour
10000
0
-10000
-20000
-30000
-40000
0
2500
5000
7500


Hourly Lineflows for Provincial Market (2016)
Guangdong.Guangxi
Max Transfer = 26800 MW
Guangdong.Guizhou
Max Transfer = 0 MW
Guangdong.Yunnan
Max Transfer = 5000 MW
Guangxi.Guizhou
Max Transfer = 16400 MW
Yunnan.Guangxi
Max Transfer = 9400 MW
Yunnan.Guizhou
Max Transfer = 6400 MW
Hourly Flows (MW)
Cumul_Hour
10000
0
-10000
-20000
-30000
-40000
0
2500
5000
7500


Hourly Lineflows for Regional Market (2016)
Guangdong.Guangxi
Guangdong.Guizhou
Guangdong.Yunnan
Guangxi.Guizhou
Yunnan.Guangxi
Yunnan.Guizhou
Max Transfer = 26800 MW
Max Transfer = 0 MW
Max Transfer = 5000 MW
Max Transfer = 16400 MW
Max Transfer = 9400 MW
Max Transfer = 6400 MW
Hourly Flows (MW)
Cumul_Hour
10000
0
-10000
-20000
-30000
-40000
0
2500
5000
7500


Hourly Lineflows for Flex_Hydro (2016)
Guangdong.Guangxi
Max Transfer = 26800 MW
Guangdong.Guizhou
Max Transfer = 0 MW
Guangdong.Yunnan
Max Transfer = 5000 MW
Guangxi.Guizhou
Max Transfer = 16400 MW
Yunnan.Guangxi
Max Transfer = 9400 MW
Yunnan.Guizhou
Max Transfer = 6400 MW
Hourly Flows (MW)
Cumul_Hour
10000
0
-10000
-20000
-30000
-40000
0
2500
5000
7500


Hourly Lineflows for Add_Tx (2016)
Guangdong.Guangxi
Max Transfer = 40038 MW
Guangdong.Guizhou
Max Transfer = 0 MW
Guangdong.Yunnan
Max Transfer = 7500 MW
Guangxi.Guizhou
Max Transfer = 24600 MW
Yunnan.Guangxi
Max Transfer = 14100 MW
Yunnan.Guizhou
Max Transfer = 9600 MW
Hourly Flows (MW)
Cumul_Hour
10000
0
-10000
-20000
-30000
-40000
0
2500
5000
7500

C. Powerplant Operational Parameters

	Coal (Super-Critical)	Coal (Sub-Critical)	Gas	Nuclear
Technical Minimum Generation (% of installed capacity)	50%	55%	40% (CCGT) 10% (CT)	90%
Ramp Rate (% of installed capacity per hour)	25%	20%	30% (CCGT) 100% (CT)	NA
Auxiliary Consumption (%)	6-7%	7-9%	3-5%	8-10%
Warm-Start Cost ($/MW)	100	60	1	NA
Minimum Up Time (hours)	24	24	6 (CCGT) 1 (CT)	>96
Minimum Down Time (hours)	24	24	6 (CCGT) 1 (CT)	>96

Heat rate data for power plants were mainly collected from the Electric Power Industry Statistical Compilation published by China Electricity Council from various years. We used the most recent heat rate numbers we could get, which is 2011. For Guangdong province, we were also able to collect heat rate information for some coal power plants from energy efficiency benchmark activities in 2012 and Guangdong dispatch online monitoring monthly report in July 2017. We integrated those data to our thermal power plant database as well.

D. Inter-provincial Transmission limits and data sources

Provinces	Capacity (GW) and Names	Lines	Data Source
Yunnan to Guangdong	Total 17.6 Where 11.2 pass Guangxi TianGuang AC IV NuoZhadu DC YunGuang DC 6.4 pass Guizhou and Guangxi Xiluodu Double DC	1AC, 4 DC	http://www.cec.org.cn/yaowenkuaidi/2013-10-12/110171.h http://yxj.ndrc.gov.cn/zttp/dlyfdx/2014dlyfdx/201409/t20140917_625885.html http://www.sasac.gov.cn/n2588025/n2588124/c3798635/content.html
Guizhou to Guangdong (pass Guangxi)	10-11.6 GuiGuang DC GuiGang DC II GuiGuang Double AC Shixian Double AC	4 AC, 2 DC	https://www.ehv.csg.cn/xdds/fzlc/fzlcb/201310/t20131010_740.html http://www.chinapower.com.cn/guonei/20170622/81728.h
Yunnan to Guangxi	3.2 Jinzhong DC	1 DC	https://www.ehv.csg.cn/xdds/fzlc/fzlcb/201704/t20170424_745.html
Guangxi to Guangdong	4.2 TianGuang AC I TianGuang AC II TianGuan	3 AC, 1 DC	https://www.ehv.csg.cn/xdds/fzlc/fzlcb/201310/t20131010_734.html https://www.ehv.csg.cn/xdds/fzlc/fzlcb/201310/t20131010_735.html

	g AC III TianGuang DC		https://www.ehv.csg.cn/xdds/fzlc/fzlcb/201310/t20131010_736.htm https://www.ehv.csg.cn/xdds/fzlc/fzlcb/201310/t20131010_739.html
Hainan and Guangdong	0.6 Hainan Lianwang I	1 AC	https://www.hn.csg.cn/gsgk/gsjj/201605/t20160520_381.h
Three Gorges Dam to Guangdong	3 Sanguang DC	1 DC	http://www.geocities.jp/ps_dictionary/standard2/cc/bb12.h