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Interactions between market reform and a carbon price in China's power sector

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Abstract
The electricity sector accounts for a large share of China's carbon dioxide emissions and of the economy-wide abatement potential. China's planned national emissions trading scheme would include electricity generation, as nearly all emissions trading schemes do. The critical difference is that in most existing carbon pricing systems the power sector operates with competitive markets and cost-based pricing, while the Chinese power industry still uses a highly regulated dispatch and pricing system. Together these limitations mean that the effect of a carbon price on China is limited in terms of the impact on operational decisions for existing power stations and in terms of the effects on investment decisions. We explore the channels of interaction between electricity market reform and carbon pricing in China, and provide quantitative estimates of the effects and interactions on electricity sector emissions. A probabilistic discrete choice model is used to simulate the behavior of investors in the power sector. The analysis indicates that market reform can help reduce emissions intensity, but to meet China's 2030 targets for non-fossil fuel generation a low to moderate carbon price is also necessary; conversely, a carbon price will only be effective with market reform that provides flexibility in dispatch. Using our simplified quantitative analysis, the carbon price required for the same share of non-fossil fuel generation would be about twice as high without market reform. Combining market reform and a carbon price could achieve significant rates of decarbonization and is likely to be the most effective and most feasibly policy package to cut emissions from China's power sector.

Key words:
China, emissions trading, energy sector reform, policy interaction

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Abstract

The electricity sector accounts for a large share of China's carbon dioxide emissions and of the economy-wide abatement potential. China's planned national emissions trading scheme would include electricity generation, as nearly all emissions trading schemes do. The critical difference is that in most existing carbon pricing systems the power sector operates with competitive markets and cost-based pricing, while the Chinese power industry still uses a highly regulated dispatch and pricing system. Together these limitations mean that the effect of a carbon price on China is limited in terms of the impact on operational decisions for existing power stations and in terms of the effects on investment decisions. We explore the channels of interaction between electricity market reform and carbon pricing in China, and provide quantitative estimates of the effects and interactions on electricity sector emissions. A probabilistic discrete choice model is used to simulate the behavior of investors in the power sector. The analysis indicates that market reform can help reduce emissions intensity, but to meet China's 2030 targets for non-fossil fuel generation a low to moderate carbon price is also necessary; conversely, a carbon price will only be effective with market reform that provides flexibility in dispatch. Using our simplified quantitative analysis, the carbon price required for the same share of non-fossil fuel generation would be about twice as high without market reform. Combining market reform and a carbon price could achieve significant rates of decarbonization and is likely to be the most effective and most feasibly policy package to cut emissions from China's power sector.

Executive summary

China is intent on limiting and reducing greenhouse gas emissions, and the electricity sector is the largest contributor to China's energy related emission. Whether or not China can decarbonize its power sector will matter greatly for the national emissions trajectory. The power industry has been included in China's regional pilot emissions trading schemes and is also slated for inclusion in the planned national emissions trading scheme. Different from other jurisdictions that have ETS or carbon taxes that cover the power sector, China's electricity sector however is not liberalized and retail price is still largely under regulation. Thus the effectiveness of China's ETS will in part depend on the nature and extent of electricity sector reform, as well as the interaction between electricity reform and the design of the ETS.

This paper analyzes aspects of the interaction of the two elements of energy and climate policy in China, through qualitative assessment of the interaction and the functioning of China's electricity system, and through a preliminary quantitative assessment of selected aspects of electricity market reform and carbon pricing. We lay out three possible channels for effects and interactions of carbon pricing and electricity market reform: incentives for lower-emissions investment in power supply, changes in the merit order (the ordering in which power plants are dispatched for production) of electricity dispatch, and reduction in electricity demand in response to higher electricity prices. Moving from a regulated electricity system to a market-based system will usually affect the electricity supply mix as well as the amount of electricity used, and with it emissions.

Whether power market liberalization in itself increases or decreases emissions depends on the particular circumstances. China's electricity sector is still largely under a regulated price and operating with an "equal generation hour" dispatch rule which prescribes similar annual generation hours of similar kinds of generation units in each province.

To understand the interaction between the carbon pricing and electricity market reform in China, we use a logit model to represent the choices among various generation technologies to produce electricity. We consider four scenarios for the impact of market reform and introduction of a carbon price in China's electricity sector. A base case scenario where there is no carbon price in the electricity sector and the "equal generation hours" dispatch rules remain; a market reform scenario which assumes the power market will be liberalized in the year 2020 and that energy saving generation dispatch will be introduced, where the merit order is renewables, nuclear, cogeneration, natural gas, coal and oil generators; a carbon price scenario assuming a low to moderate carbon price of 25 RMB/tCO_2 (around USD3.6/tCO_2) in the year 2020, and increasing by 8% per year from 2020 to 2040; and a combination of market reform and ETS, where the power sector will be liberalized in year 2020, together with a carbon price.

Our analysis indicates that if China can successfully liberalize its power market by shifting dispatch rules from "equal generation hours" to energy saving dispatch, then the share of non-fossil fuel generation can be increased to 34% in 2020. A carbon price starting at 25

tCO_2 and without market reform would achieve a 30% share, only marginally higher than in the reference case. The reason is that the introduction of a carbon price does not change the merit order for generators. Both options are consistent with the national target of 15% non-fossil fuel in primary energy at 2020. For 2030 however, a low to moderate carbon price or market reform individually would not be enough to achieve the 2030 target for the share of non-fossil fuel generation; a combination of the carbon price and market reform however would achieve the goal. We also estimate that without market liberalization, in 2030 a carbon price needs to be twice as high than if a carbon price is applied with market reform, in order to achieve the same level of non-fossil fuel generation. We estimate that without further policy interventions, the future decarbonization rate in China's electricity supply would reduce to around 1% per year. By combining market reform and a carbon price, we estimate that the decarbonization rate in electricity supply can be raised to 3.5% per year in 2030.

To achieve significant change towards lower-carbon electricity generation using market instruments, it is necessary to incentivize more investment in low carbon generation technologies and to reduce the utilization hours of fossil fuel generating units. A combination of market reform and a moderate carbon price is likely to be the most effective and arguably most feasibly policy package to cut emissions in China's power sector. The design of an ETS can address the transitional impact on generators' profitability caused by the change of dispatch rules and introduction of carbon price.

1. Introduction

For China, the largest CO_2 emitter and soon to be largest economy in the world, low-carbon development has become an urgent need and policy priority. China's rapidly growing energy consumption and its heavy reliance on coal have created serious environmental problems, including local air pollution and depletion of water resources. Transition to a low-carbon energy system will not only bring significant local environmental and health benefits, but can aid with the economic structural change that China is striving for, and holds the promise of benefits for industrial innovation and energy security. Together with the expected long-term benefits in reducing climate change impacts, these factors mean that reducing greenhouse gas emissions is in China's economic self-interest (Teng and Jotzo 2014).

Energy accounts for the largest share of China's greenhouse gas emissions (77% in 2005, the latest year for which a full inventory was submitted to the UNFCCC). The electricity sector in turn is the largest contributor to China's energy emission, accounting for about 30% of carbon dioxide from fossil fuel combustion in the year 2015 (PBL Netherlands Environmental Assessment Agency, and Joint Research Centre 2016). The electricity sector will need to play a key role in achieving China's target to peak its emission around 2030 (see Table 1). In the coming decade, China's power production will very likely continue to expand, as increased demand for electricity-based energy services in industry, buildings and increasingly transport outstrips the rate of efficiency improvements. Thus whether or not China can decarbonize its power sector will matter greatly for the national emissions trajectory.

Table 1: Indicators for China's electricity production

	2006-10	*2011-15*
Electricity production, average annual growth	11.1%	5.7%
CO_2 from electricity production, average annual growth	8.7%	3.3%
Decarbonization rate (CO_2/electricity), average annual change	-2.1%	-2.8%
	2010	*2015*
Average emissions intensity of electricity, gCO_2/kWh	644	559
Share of non-fossil fuel generation in total electricity generation	19.2%	26.3%
Share of coal in electricity generation	76.7%	67.9%
Coal power generating capacity, GW	696	900

Market-based instruments such as carbon tax and emissions trading schemes (ETS, also referred to as cap-and-trade schemes) are regarded as important means to achieve greenhouse gas emissions reduction at least cost. A number of countries and subnational jurisdictions have emissions trading scheme or carbon taxes in place. China has also launched carbon pilot markets in two provinces and five cities, starting from 2013 (Zhang et al 2014, Jotzo and Loeschel 2014). A national ETS is scheduled to start in 2017. The power industry has been included in China's regional pilot schemes and is slated for inclusion in the national scheme.

In most jurisdictions that have ETS or carbon taxes that cover the power sector, the electricity sector is fully or partly liberalized, typically with markets for electricity generation and with changes in the cost of electricity generation reflected in changing electricity prices. China's electricity sector however is not liberalized. Competition has been only partly introduced in electricity generation, and retail pricing in China is still largely under regulation.

Where the pricing system has a limited role in allocating resources and investment, a price on carbon emissions will likewise only have a limited effect. Thus the effectiveness of China's ETS will in part depend on the nature and extent of electricity sector reform, as well as the interaction between electricity reform and the design of the ETS. At the same time, market reform by itself will alter the generating mix and thereby the emissions outcome.

This paper aims to make a contribution to understanding of the interaction of the two elements of energy and climate policy in China, through qualitative assessment of the interaction and the functioning of China's electricity system, and through a preliminary quantitative assessment of selected aspects of electricity market reform and carbon pricing.

This paper is organized as follows: in section 2, we provide a qualitative analysis of the effects and interactions of electricity sector reform and carbon pricing; in section 3, we review the power pricing and dispatching system in China; in section 4, we set out a framework for modelling investment decisions in the power sector and apply this framework to analyze the policy interaction between electricity reform and ETS in China; in section 5, we discuss modelling results and their implications; section 6 concludes.

2. Effects and interactions of carbon pricing and electricity market reform

As a market based instrument, a price on emissions – whether by way of tradable permits (ETS) or an emissions tax – requires prices for polluting goods and services to be set in markets in order to be effective.

In the hypothetical situation of perfect command-and-control, where the supply of a commodity like electricity and the methods for its production (or the respective prices) are fully determined by government, putting a price on emissions will not change the amount of emissions. The theory of carbon pricing – and much of the empirical modelling thereof – usually starts from the assumption of perfect markets. The reality in electricity supply is usually somewhere in-between, with markets operating close to perfectly in some aspects or situations, and imperfectly or not at all in others. The situation can differ greatly between jurisdictions and over time, depending on the regulatory framework.

Effects of carbon pricing on emissions and their prerequisites in markets

A carbon price in the power sector under market settings creates incentives to reduce emissions through three main channels:

Firstly, *incentives for lower-emissions investment in power supply*. Putting a price on carbon emissions favours investment in lower-emissions options by making lower-emissions power plants relatively more profitable. Prerequisites for the investment incentives to eventuate include that market settings allow higher profits to accrue to lower emissions plants, and for the design of carbon pricing schemes to facilitate differential financial effects on different types of power stations. In practice the investment incentives are sometimes muted through design of carbon pricing that reduces the impact of carbon prices on relative profitability, for example allocating free emissions permits to high-emitting plants for free in line with electricity output. There are also examples where the expectation that a legislated carbon price would be abolished in future neutered investment effects (O'Gorman and Jotzo 2012).

Secondly, *changes in the merit order electricity dispatch*. A carbon price increases the short-run variable cost of fossil fuel power plants, in line with their emissions intensity. Thereby lower-emissions plants move higher up the merit order (the ordering according to cost of all power stations available for dispatch on the grid), and in a market-based system of dispatch the annual operating hours for high-emissions plants (for example low-efficiency coal plants) will reduce relative to dispatchable lower-emissions plants (for example gas turbines or high-efficiency coal plants). Lower annual operating hours for high-emissions plants contribute to a reduction in their profitability and hence contribute to investment incentives.

Prerequisites for the carbon price to efficiently affect dispatch of existing power stations is for the dispatch to be based on relative costs, usually through a market system such as a wholesale spot market for electricity, or through a regulated system that is based on relative costs including carbon costs. Spot markets have been implemented in many countries in recent decades but have not always been a feature of power systems. In many countries they do not exist, or exist only to a limited extent. Spot markets typically exist in parallel with contracts for the supply of electricity to specific customers, for example industrial users or utilities.

Thirdly, *a reduction in electricity demand in response to higher electricity prices*, as carbon costs are passed through to end users who have greater incentives to save electricity or substitute to other energy sources. In a fully market based electricity system, the carbon costs are passed through via wholesale markets to industrial customers and via retail markets to domestic electricity users.

Prerequisites for full carbon cost pass through include fully market based electricity pricing, with competitive markets. This is fundamentally the case in many electricity markets, though market power may limit cost pass-through (Chernyavs'ka and Gulli 2008). In some jurisdictions, governments hold electricity prices fixed at least for some groups of users (such as residential electricity users) for political or distributional reasons.

Design of emissions trading schemes to address lack of markets

Where markets are imperfect or missing, emissions trading schemes or carbon taxes can be designed to compensate for the limitations that stem from a lack of free markets. The main application for this is where electricity supply prices are fixed.

If power prices are fixed by regulation, a straightforward way to reflect a carbon price in electricity prices is to raise the regulated price faced by end-users by an amount that is commensurate with the carbon price on the electricity supply side. This direct approach has some downsides however. In the case of an ETS with a floating price, to achieve equivalence the regulated price may need to be adjusted at regular intervals. Furthermore, it may be politically difficult to directly adjust regulated power prices.

An alternative approach is to make large users of electricity part of ETS systems, by requiring them to cover the emissions attributable to their power use by emissions permits. “Indirect emissions” from electricity use are covered in this way in the Tokyo ETS and Korean ETS (Kim and Lim 2014, Park and Hong 2014) and the Chinese ETS pilot schemes (see eg Zhang 2015, Zhang et al 2014, Wu et al 2014, Munnings et al 2016). This option has also been referred to as the “demand side levy model”, and is seen as a relatively straightforward way to achieve price-based incentives to reduce electricity demand when market liberalization is not possible (Teng et al 2014). Downsides are that there are additional transaction costs, and that the coverage is limited to large users of electricity, creating threshold effects. By contrast, where direct cost-pass through is possible, all electricity users have an automatic incentive to make extra efforts to save energy, without engaging in the carbon market.

Fixed power prices can also affect the design and effectiveness of carbon pricing schemes on the supply side. Where there is no or limited carbon cost pass-through to electricity users, regulators face increased pressures to shield electricity generators from the financial effects of carbon pricing. A ‘pure’ carbon pricing model without free permits (or carbon tax rebates) in the absence of cost pass-through would reduce overall electricity industry profits. As a result, ETS are sometimes designed with output-based allocation of free emissions permits, which in turn can reduce the effectiveness of a carbon price on changing the supply mix in electricity.

Effects of electricity market liberalization on emissions and interactions with carbon pricing

Moving from a regulated electricity system to a market-based system will usually affect the electricity supply mix as well as the amount of electricity used, and with it emissions. Whether power market liberalization in itself increases or decreases emissions depends on the particular circumstances.

Liberalizing electricity markets – and more generally energy markets, i.e. prices for fuels – in any respect will change the relative profitability of different types of power plants, and hence investment incentives. Changes in profitability can occur through lower or higher electricity prices (through lifting price controls), lower or higher input costs (if fuel costs are regulated), and lower or higher capacity utilization factors (through changes in dispatch systems).

Whether a move to market settings on balance puts high-emissions plants or low-emissions plants at an advantage depends on how the regulatory settings compare to the market outcomes. Thus partial or full electricity market liberalization by itself could result in higher emissions or in lower emissions. It will also affect overall system costs and the distribution of costs and revenue between electricity generators.

Where market liberalization by itself increases emissions but increases the effectiveness of carbon pricing, there could be a ‘break-even’ level of the carbon price required to keep emissions the same as without electricity market liberalization. Conversely, it is also possible that the two interventions both reduce emissions and the combination has an amplified effect on emissions.

3. China’s Power Industry: Pricing and Dispatch

Regulatory reform in China’s electricity sector began in the year 2002 starting from the separation of the monopoly State Power into five regional power generation companies and two transmission companies (Xu and Chen, 2006). After years of rapid growth, China’s electricity consumption growth has recently begun to slow down, also in the context of slowing economic growth. This has been considered as an opportunity to implement further reform measures in power market. In 2014, a new round of electricity reform started, focusing on the transmission and distribution sectors. The reform is characterized by two aspects: first, reform of transmission and distribution tariff based on principle of “cost plus reasonable profit”; second, opening up of electricity retail to non-state-owned companies. It is also proposed that a real time electricity market will be developed, and that large consumers will also be required to buy electricity directly in the market from power generators or retail electricity companies. However, currently the electricity sector is still under a fully regulated price and “equal generation hour” dispatch rules as detailed below.

Electricity Pricing

Although the ultimate objective of the new electricity market reform is to introduce competition in both wholesale and retail markets, and to gradually allow prices to be more responsive to supply and demand, the electricity pricing system is still highly regulated (Liu and Kong 2016).

In China, the electricity retail price consists of several parts: power purchase cost (wholesale generation price), charge for transmission and distribution losses, transmission and distribution tariff and government funds. Generally, power purchase costs account for about 65% to 70% of the electricity retail price. Both wholesale the generation price and the retail price are adjusted regularly. For most coal based generation units, their on-grid tariff is determined based on the province-specific benchmark tariff, which is estimated based on average investment and operating cost in each of China’s provinces.

Since the year 2005, the wholesale generation price has been linked with the coal price. The linking mechanism is designed to trigger adjustment of the wholesale generation price if the coal price reaches a predetermined threshold. Theoretically, the electricity retail price is also adjusted regularly on the basis of the wholesale generation price. But such price adjustments only apply to industrial and commercial consumers who are subject to a higher retail price than the national average. For household and agricultural consumers, the electricity retail price is relatively stable and lower than the average price. Thus both wholesale prices and retail prices in China are not in line with energy costs. This has led to erratic investment patterns and periodic shortages in electricity supply.

Dispatching system in China

In earlier times when the whole electricity sector was operated by the only state own company, State Power, dispatch of power stations was based on the least cost principle. After the market reform of separating generation assets from transmission and distribution, the dispatching system was largely constrained by contracts between generators and grid company that were signed in the early stage of market reform (Kahrl et al 2013). To give incentives to capacity expansion serving the fast growing load, grid companies signed fixed price and quota contracts with investors to reduce their risk and attract investment.

In this circumstance, the National Development and Reform Commission (NDRC), China's main economic management agency, began to stimulate the construction of power plants by publishing a dispatching rule which ensured approximately similar annual generation hours of similar kinds of generation units in each province. The so called "equal generation and utilization hours" dispatching model has been used up to now (Ding et al 2013, Gao and Yang 2010). In this dispatching system, the provincial dispatching authorities firstly allocate the annual generation quotas to different power plants[1] based on the equal utilization hours principle and demand estimation. The dispatching center then determines the monthly and daily generation schedule based on monthly and daily demand and physical constraints on grid operation.

Such "equal share dispatch" is not cost effective, as it means that the less efficient generation units will be operated as much as the most efficient ones. China has implemented pilot programs for energy-saving power dispatch since the end of 2007 (Gao and Yang 2010). Under energy-saving dispatch, the generation units are ranked according to their energy consumption and pollutant emission levels. The operator will then call on different generation units with a view to minimizing energy and resource consumption and emissions. The merit order of energy-saving power dispatch is as follows: renewables, nuclear, cogeneration, natural gas, coal and oil generators.

However, those energy saving dispatch pilots have not been successful in China. The major barrier is that the shift of dispatch rules reduces the profit of grid companies by prioritizing renewable energy. In addition, it changes the distribution of financial revenue among generators, so financial compensation is a key to the effective implementation of the energy saving power dispatch. Because of the lack of compensation plans, some pilot provinces such as Sichuan withdrew from energy saving dispatch and replaced it with "equal generation hour" dispatch.

[1] There are three categories of generation units in such allocation: renewable units, combined heat and power units and conventional thermal units.

4. Models and methodologies

The interaction between the carbon pricing and electricity market reform in China can be modeled as a two stage problem. In the first stage, the dispatching entities will determine the generation scheduling through dispatch rules. The dispatch rules determine the merit order, and in turn determine annual generation hours of different generation technologies. In the second stage, investors choose to invest in different generation technologies, based on relative costs and expected future revenues. Lower annual operating hours for a given generation technology will contribute to a reduction in their profitability and hence less investment. Due to the lack of a national dispatch model to analyze these effect, we use a simplified methodology to capture the effects of different dispatch regimes and a carbon price.

In the short term, approximated by the first stage of our analysis, a change of dispatching rules (and/or introduction of a price on carbon emissions) will change the utilization hours of different generation units. Under an "equal generation hours" dispatch rules, the utilization hours of the similar generation technologies are almost the same. The dispatch entities have incentives to abandon generation of renewables to minimize their power purchase cost, thus leadiing to higher curtailment of renewable power. U

nder the market reform scenario, we assume that an energy saving generation dispatch will be adopted giving priority to the most efficient fossil fuel based units and the zero-emissions generators. The impact on change of utilization hours can be estimated on the basis of existing estimates without the use of a dispatch model.

In the second stage, we consider a case where potential investors decide which power generation technologies to invest in. We use a logit model to represent the choices among various generation technologies. The approach differs from the traditional calculation of levelized cost of electricity (LCOE) which considers the cost of electricity generation technologies fixed and is the only indicator for technology choice. Logit models give recognition to a range of factors beyond the averaged expected cost in determining the specific investment decisions in generators of different technologies. This may include geographical factors differentially affecting the production possibilities and cost of different generation technologies, local investment opportunities and preferences, demand profiles, and so forth. These factors are often not adequately represented in models of electricity sector investment.

Logit models can capture in an aggregate way factors that influence the decision variables but are not directly observable, such as patterns of substitution across various generation technologies other than observed variables such as LCOE. For example, logit models have long been used successfully to model the choice of consumers in choosing between different brands of objectively similar products (eg Guadagni and Little 1983). We take this approach to create a quantitative representation of power mix choices. The logit model approach also assumes that unobserved factors affecting decisions are independent over repeated investment choices.

The traditional approach is to use dispatch models that incorporate technical and cost data for all power stations; and to couple this with a longer-term model of investment choices which should reflect different LCOEs, risk profiles, capital costs, demand profiles and so forth. However, reliable dispatch models at this point are not available for China, on account of data limitations; and the modelling of investment is fundamentally subject to assumptions about future market conditions.

In the logit model, we posit that the different primary fuels will compete for the generation of a secondary fuel or energy service. The price of each fuel is assumed to fall within a fuel-price range, while the related variance is captured in an energy price exponent (Clarke and Edmonds 1993). The market share of each competing technology is determined by the comparison of its own price and variance with others, and formally calculated by means of logit share equation. Hence, the share S_j of technology j allocated to a competitive market is expressed as Equation (1).

$$Share_j = \frac{b_j \times P_{fuel\ j}^{r_p}}{\sum_j b_j \times P_{fuel\ j}^{r_p}} \tag{1}$$

Here, P_j is the LCOE of technology j, r_p is the price exponent which stands for the rate that the implementation of this technology in response to a change in the cost, thus is also known as the elasticity, while b_j is the base share of technology j.

A standard formula to calculate the LCOE is shown in Equation (2), where $I_i(t)$, $OM_i(t)$, $F_i(t)$, $C_i^{CO_2}(t)$ and $EP_i(t)$ denote the investment cost, operation & maintenance cost, fuel costs, carbon costs due to emission quota or carbon tax, and the expected electricity production, while r denotes the discount rate.

$$LCOE_i(t) = \frac{\sum_{t=0}^{\tau_i} \frac{I_i(t)+OM_i(t)+F_i(t)+C_i^{CO_2}(t)}{(1+r)^t}}{\sum_{t=0}^{\tau_i} \frac{EP_i(t)}{(1+r)^t}} \tag{2}$$

We use the logit model as follows. Firstly, we calculate the LCOE of each generation technology. Then we calibrate the logit model to the IEA's Current Policy Scenario (CPS)[2], resulting in a set of parameters b_j and r_p [3]in equation 1. We then establish several policy scenarios on the market reform and carbon price which will change the LCOE accordingly (as explained in the previous section) but will not change the parameters on b_j and r_p.

The introduction of carbon pricing will change the $C_i^{CO_2}(t)$ component of LCOE for different generation technologies. The change of dispatch rules will change the $EP_i(t)$ component of generation technology i. We then run the model to estimate changes in market shares for different technologies under various scenarios.

[2] The current policies scenario (CPS) of the International Energy Outlook (IEA 2016) only takes into consideration policies which have been formally adopted.

[3] Similar with the GCAM model, we use a set of r_p for different generating technologies. Normally we use r_p=-3 for fossil fuel generating technologies and biomass, and r_p=-1 for other non fossil fuel generating technologies.

5. Scenarios and results

Scenarios Design

We consider four scenarios for the impact of market reform and introduction of a carbon price in China's electricity sector.

(1) The first scenario is a *base case scenario*. In this base case, we assume there is no carbon price in the electricity sector and the "equal generation hours" dispatch rules remain.

(2) The second scenario is the *market reform scenario*. We assume the power market will be liberalized in year 2020 and that dispatch will be changed from "equal generation hours" principle to energy saving generation dispatch, where the merit order is as follows: renewables, nuclear, cogeneration, natural gas, coal and oil generators. The implementation of energy saving generation dispatch will reduce energy consumption and carbon dioxide emissions.

The main effect will come from the substitution between large scale coal generation units and small scale generation units. For example, in the pilot of Jiangsu province, the annual utilization hours of coal fired generation units with capacity over 600 MW are 30% higher than without implementing the energy saving generation dispatch, while the annual utilization hours of coal fired capacity smaller than 200 MW – which are less efficient - are 25% lower than before.

The second effect comes from the reduction of curtailment of renewable energy. Abandoning the "equal generation hours" approach means that the shedding of renewable energy would be largely resolved. Another contribution to reduction of curtailment could come from the promotion of electricity trading across provinces, providing greater flexibility and further minimizing curtailment of energy from wind and solar power sources.

No studies are available to show to what extent market reform can resolve the issue of curtailment and increase the competitiveness of renewables by increasing its generation hours in the merit order. Based on the historical experience between 2012 and 2014, we assume a 10% improvement in absolute terms from current renewable power curtailment rates[4], which we believe to be a thoroughly conservative assumption.

(3) The third scenario is for *a carbon price in the electricity sector*. China has announced that the national ETS will start in 2017, however key design elements of the national ETS are still in progress. The electricity sector is to be included in the national ETS but the permit allocation scheme is still not clear, which can have impacts on the effectiveness of the scheme. It is also unclear what price levels may prevail in the Chinese national ETS. As an illustration of a low to moderate carbon price we model a carbon price of 25 RMB/tCO_2

[4] The curtailment rate was 15.4% for wind power and 11.1% for solar PV in year 2015. Between 2012 and 2014, there was no significant transmission expansion but the curtailment was reduced by 9.2%. This improvement was mainly achieved through government intervention on more stringent implementation of a principle of "full purchase of renewable electricity". Thus it appears reasonable to use 10% as a lower bound for the effect of market reform on the generation hours of renewables.

(around USD3.6/tCO_2) in the year 2020, and assume the carbon price increases by 8% per year from 2020 to 2040. It is assumed that the carbon price is additional to existing policy instrument, especially subsidies on renewables.

(4) The fourth scenario is a *combination of market reform and ETS*. Under this scenario, the power sector will be fully liberalized in year 2020, together with a carbon price of 25 RMB/tCO_2 at 2020 growing by 8% per year thereafter.

Under the assumptions made here about future costs, the LCOE of coal based electricity is still low in comparison with wind and solar power, even if there was a high coal price and high carbon price. To increase the share of renewables in the market share, market reform is likely to be effective because the energy saving generation dispatch will give priorities to renewables and the competition in the spot market will be determined by the variable cost, not the long-term average cost. The crucial insight is that without market reform on dispatch, the introduction of a low to moderate carbon price would only have limited effects on dispatch, and thus limited implication on the emission performance.

Technology Shares

The cost assumptions provide a general sense that coal will still be competitive over the coming decades compared with other alternatives but it is not clear how the technology portfolio will change, given specific circumstances. We then use the logit model – as described in the previous section - to model the impact on the investment decisions.

It should be noted that the logit model is only used to present the investment process and cannot represent the demand side (reductions in electricity consumption), which is also important as explained in the previous section. Thus of the three channels of effects of a carbon price on emissions levels discussed in section 3, only two are captured in our analysis.

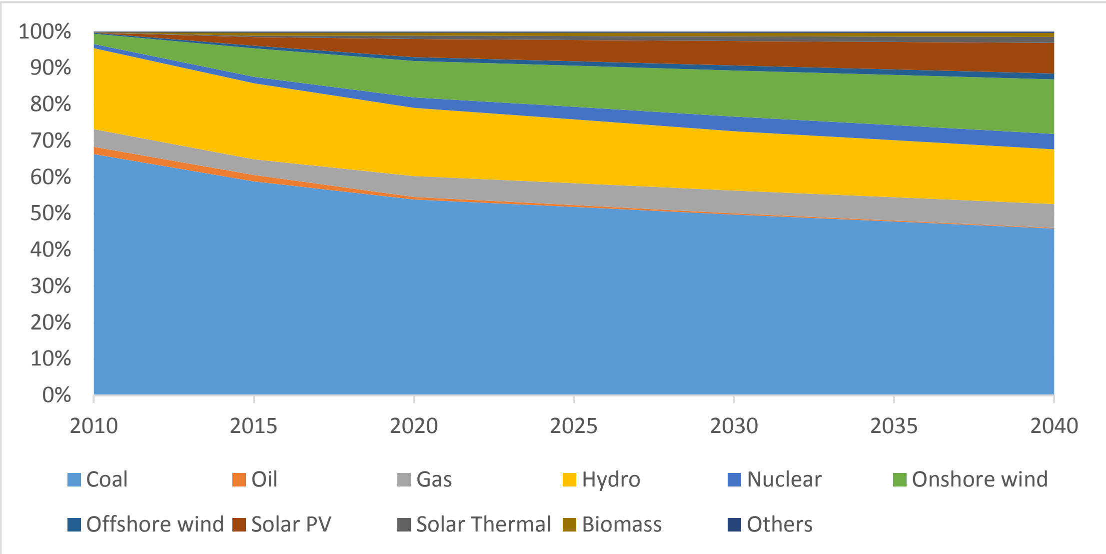
Table 2 Market share of various generation technologies in different scenarios

	2020				2030			
	(1) Reference	(2) Market Reform	(3) Carbon Price	(4) Combined	(1) Reference	(2) Market Reform	(3) Carbon Price	(4) Combined
Coal	54%	46%	50%	42%	50%	41%	42%	35%
Oil	1%	1%	1%	1%	0%	0%	0%	0%
Gas	6%	7%	6%	7%	6%	7%	7%	8%
Hydro	19%	21%	20%	22%	16%	18%	19%	20%
Nuclear	3%	3%	3%	3%	4%	4%	5%	5%
Wind	11%	14%	12%	15%	14%	17%	16%	19%
Solar	6%	8%	7%	9%	8%	11%	10%	12%
Others	1%	1%	1%	1%	1%	1%	2%	2%
Share of non-fossil fuel in	39%	47%	43%	50%	44%	52%	51%	57%

capacity								
Share of non-fossil fuel in generation (National target implies 30% at 2020, 40% at 2030)	28%	34%	30%	36%	31%	38%	37%	43%
Average emissions intensity of power generation ($kgCO_2/kWh$)	0.53	0.49	0.51	0.47	0.49	0.45	0.45	0.41

Under the reference scenario (1), the share of coal based technology capacity decreases from 66% in 2010 to less than 50% in year 2030 and about 46% in year 2040. The share of non-fossil fuel capacity (renewable plus nuclear) increases from 26.8% in year 2010 to 43.7% in year 2030 and 47.4% in year 2040 (Table 1, Figure 1). The share of non-fossil fuel technology is 27.5% in year 2020, 31% in year 2030 and 34.6% in year 2040 respectively.

Under the reference scenario, the share of non-fossil fuel generation is lower than the requirement in China's national target (NDC) which requires the share of non-fossil fuel generation to reach 30% in year 2020 and 40% in year 2030[5]. Thus China's non-fossil fuel target would not be achieved.



[5] China's NDC includes a target for the share of non-fossil fuel in the primary energy consumption, but no target specifically for the share of non-fossil fuel technologies in electricity generation. The target is to increase the share of non-fossil in primary energy consumption to 15% in year 2020 and 20% in year 2020. Given that the electricity consumption roughly accounts for 50% of China's primary energy consumption, and non fossil fuel is mainly used for electricity generation, those targets can be translated into a target on share of non-fossil fuel in electricity generation, which need to reach 30% in year 2020 and 40% in year 2030.

Figure 1: Share of various technologies in the reference scenario

In the *market reform scenario (2)*, we assume that the curtailment of renewable generation will be improved and the LCOE of renewables will be reduced due to the increasing generation hours. As a result, the share of renewable will be higher. Compared with the reference scenario, the share of renewables increases in the short term by avoiding the curtailment of wind and solar power. In 2020, the share of non-fossil fuel generation is 34%, compared to 28% in the reference scenario. By liberalizing the power market, the 2020 national target for the non fossil fuel share can be achieved. However, the 2030 non fossil fuel target is still not met – this would require a 40% non-fossil fuel share in generation, whereas only a 38% share is achieved.

In the *carbon price scenario*, in the short-term, the share of non-fossil fuel generation is lower than in the market reform scenario – the relatively low carbon price has less effect than the market reform. But together with the assumed rapidly growing carbon price over time, the long-run impact of carbon price begins to dominate. By 2030, the share of non-fossil fuel generation is 37% in the carbon price scenario, similar to that under the market reform scenario.

However, neither the carbon price scenario nor the market reform scenario can achieve the target of 20% non-fossil fuel in primary energy (which is equivalent to 41% percent of non fossil fuel generation in power sector). The only way to achieve this target, under our assumptions and model, is to combine market reform with a carbon price.

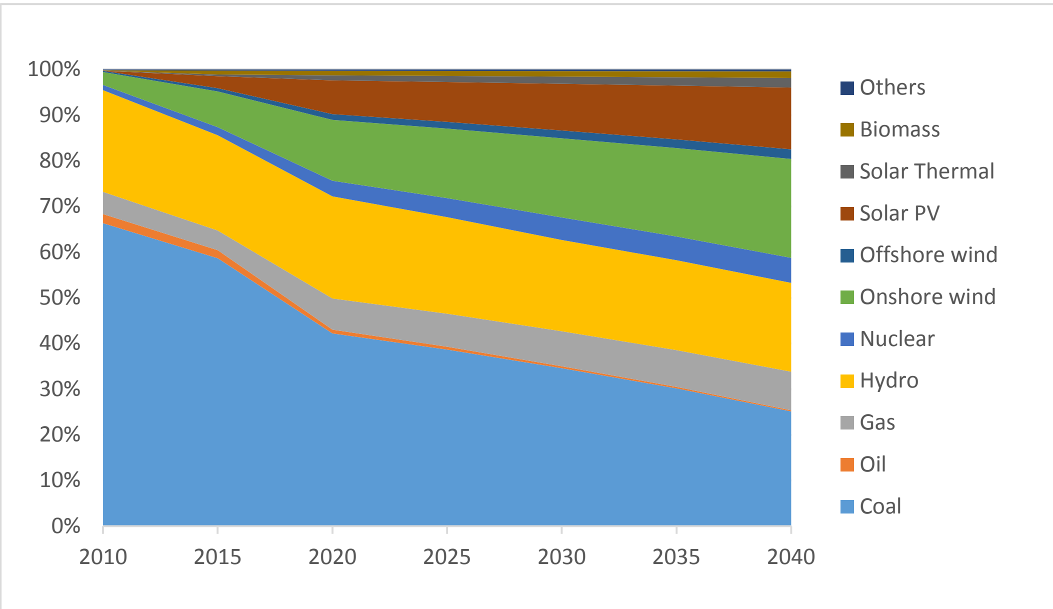


Figure 2: Share of various technologies in the combined scenario

With the combination of a liberalized power market and a growing carbon price through introduction of ETS (scenario 4), the share of non-fossil fuel generation is estimated at 43% in 2030 (see also Figure 2). This is consistent with the target of 20% non fossil fuel share in

China's NDC which support the peaking of China's emission around 2030.

If the power market cannot be liberalized, then the carbon price needs to be double at 2030 to ensure that the non fossil fuel energy target. But a higher carbon price may trigger greater concerns about competiveness in other sectors subject to international competition.

The resulting emission intensity of electricity generation is shown in Table 2 and Figure 3. The reduction of emission intensity is due to the combined effect of the increased share of non-fossil fuel generation and the improvement of efficiency in coal fired power plants. From 2010 to 2015, the annual decarbonization rate was about 3% per year as a result of the two effects combined. 40% of the contribution came from the increase of non-fossil fuel in the generation mix and 60% come from the improvement of efficiency in coal fired power plants.

Without further policy interventions, the decarbonization rate would reduce to around 1% per year by 2020 because the efficiency improvement of coal fired power plants seen in the past, including through replacement of old inefficient with more efficient plants, has been exhausted. To maintain the recent observed decarbonization rate, it is necessary to combine market reform and a carbon price. With the combination of those two effects, the decarbonization rate in electricity supply can be raised to 3.5% per year in 2030, under our assumptions.

Importantly, the impact of market reform by itself is a one-off effect on the decarbonization rate. The long term impact is relative small. By contrast, the carbon price can give a long-term impact on the decarbonization through its influence on investment patterns over time driven by a growing carbon price. However, market reform is a prerequisite for effectiveness of a carbon price.

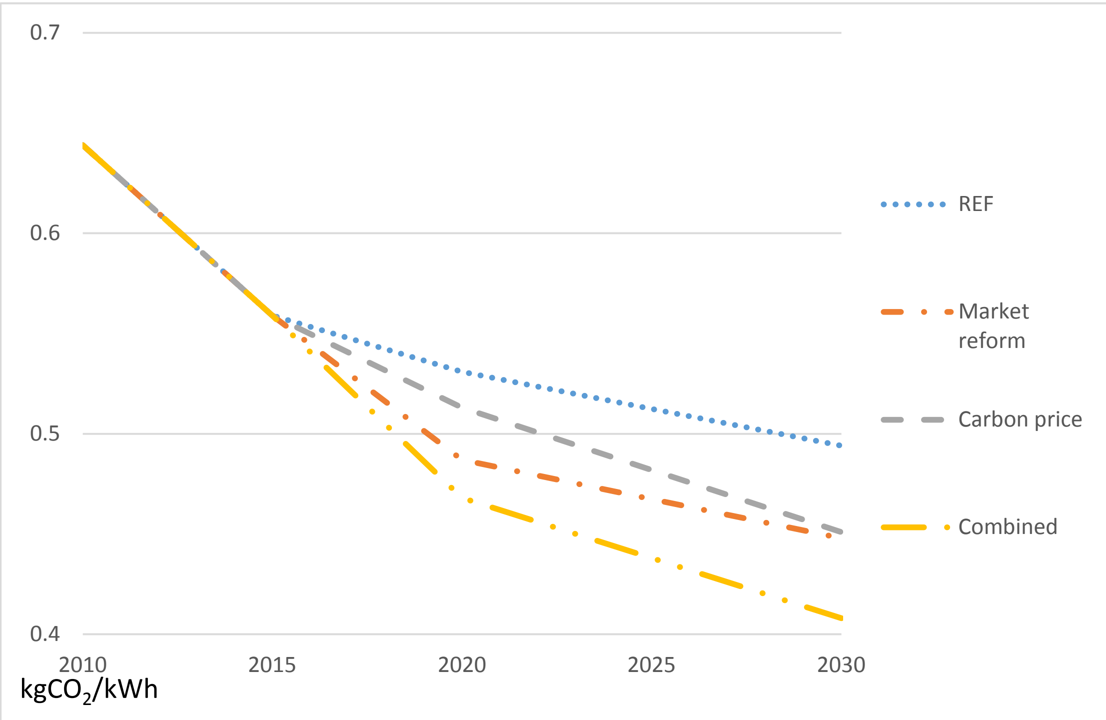


Figure 3: Trends of average emission intensity in China's electricity generation under different policy scenarios

6. Conclusions

China's goal to peak its national carbon dioxide emissions around 2030 requires a substantial shift towards decarbonization in the power sector. To achieve this requires policy intervention and market reform. The current power sector framework tends to lock in the operation of high-emissions power plants and would limit the effectiveness of a carbon price, as under China's national ETS planned for introduction in 2017.

Our quantitative analysis, using a logit model the power sector, indicates that market reform can deliver benefits including by reducing curtailment of renewable power. If China liberalized its power market, then this policy intervention under our assumptions and using our estimation methods can increase the share of non-fossil fuel generation to 34%, consistent with national targets at 2020 for non-fossil fuel in primary energy. Without market reform, to achieve the same level of incentive for development of non-fossil fuel technologies, a relatively low carbon price of around 25 RMB/tCO_2 in year 2020 would be needed.

However, neither market reform nor a relatively low carbon price individually would achieve the 2030 target. This can be achieved by combining a carbon price with market reform which can make carbon pricing in China's power sector more effective. We estimate that without market liberalization, in 2030 a carbon price needs to be twice as high than if a carbon price is applied with market reform, in order to achieve the same share of non-fossil fuel generation. By combining a low to moderate carbon price with market reform, significant rates of decarbonization of China's electricity supply could be achieved and maintained.

Market reform has a one-off benefit by itself, whereas the carbon price can give a long-term impact on the decarbonization through its influence on investment patterns over time driven by a growing carbon price. However, market reform is a prerequisite for effectiveness of a carbon price. Together, market reform and a carbon price signal can incentivize more investment in low carbon generation technologies, and to reduce the utilization hours of fossil fuel generating units.

The introduction of market reform and carbon price would have significant impacts on financial position of different electricity generation companies. The renewables generating units and large scale coal fired generation units would gain more utilization hours while the small scale inefficient generation unit would have lower capacity utilization. The transitional effects on generators' profitability can be addressed through appropriate design of ETS rules, including through time-limited allocation of free emissions permits.

In this paper, we have used a simplified methodology to capture the effects of change in dispatch rules and introduction of carbon price, allowing an illustrative analysis of the key interactions between a carbon price and market reform in China's electricity supply. In future research, the discrete choice model approach in this paper could be coupled with a generation scheduling model. Also, a more detailed analysis using provincial level data could be undertaken.

The limitations of the quantitative analysis in this paper notwithstanding, it appears a robust conclusion that a combination of market reform and a moderate carbon price is likely to be the most effective and arguably most feasibly policy package to significantly reduce emissions intensity, and to cut emissions in China's power sector.

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