China's Unconventional Nationwide CO_2 Emissions Trading System: Cost-Effectiveness and Distributional Impacts

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ABSTRACT

China is implementing what will be the world's largest CO_2 emissions trading system. To reduce emissions, the nation will employ a tradable performance standard (TPS), a rate-based instrument differing significantly from cap&trade (C&T) and a carbon tax, emissions pricing instruments used elsewhere. With matching analytically and numerically solved models, we assess the cost-effectiveness and distributional impacts of China's forthcoming TPS for reducing CO_2 emissions from the power sector.

The TPS implicitly subsidizes electricity output; this has significant consequences for cost-effectiveness and distribution. The subsidy disadvantages the TPS relative to C&T by causing power plants to make less efficient use of output-reduction to reduce emissions (indeed, it induces some generators to increase output) and by limiting the cost-reducing potential of allowance trading. In our central case simulations, TPS's overall costs are three times those of C&T. The TPS's distributional impacts also differ significantly from C&T's: the share of the overall economic burden borne by producers is much higher.

The use of customized rather than uniform benchmarks (maximal emission-output ratios consistent with compliance) compromises cost-effectiveness, but can help serve regional distributional objectives. We examine numerically the aggregate costs of customizing benchmarks in order to reduce the adverse profit impacts in particular regions.

1. Introduction

China has embarked on what promises to be the world's largest carbon dioxide (CO_2) emissions trading system (ETS). When fully implemented, this nationwide system will more than double the amount of CO_2 emissions covered worldwide by some form of emissions pricing.

China will rely on a tradable performance standard (TPS) as its emissions pricing instrument for reducing emissions. This mechanism differs in important ways from the emissions pricing instruments used in other countries, such as cap and trade and a carbon tax. A TPS is a rate-based instrument: the number of emissions allowances granted to a facility depends on the ratio of its emissions to output over the compliance period. Since compliance depends on a ratio, covered facilities can influence their allowance allocations by changing their output levels during the compliance period. In contrast, under cap and trade (C&T), a covered facility's allocation of allowances is not influenced by within-period production changes. The dependence under the TPS of the allowance allocation on within-period output decisions has important implications for incentives and associated system performance. It significantly affects production levels, overall emissions abatement, and the levels and distribution of costs.

This paper employs matching analytically and numerically solved models to evaluate China's new TPS, focusing on the impact on the nation's power (electricity) sector, the first sector to be covered by the TPS.[1] The power sector includes more than 2,000 coal-fired power plants and is critical to China's climate policy effort, as it accounts for over 40 percent of the country's total CO_2 emissions (Yang and Lin, 2016). The sector has been undergoing virtually continuous reform since 1985, when the state monopoly ended (Ho *et al.*, 2017). While electricity prices historically had been set by the government, recent reforms allow for considerable market-determination of electricity prices. The electricity output sold at market prices has grown steadily over the last decade and is now almost one third of the total.

We apply the two models to assess the TPS's impact on output levels, production costs and CO_2 emissions of power plants of differing technologies, as well as its implications for aggregate costs (lost producer and consumer surplus) and aggregate emissions reductions. We also examine how costs are distributed across different types of power plants and regions of the country.

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[1] Ultimately, the TPS is expected to cover nine major sectors. The cement and aluminum sectors are next in line to be covered, to be followed by iron & steel, nonferrous metals, petroleum refining, chemicals, pulp and paper, and aviation. China's TPS design calls for emissions trading across all facilities and all covered sectors.

Throughout, we compare the TPS's impacts with those of a C&T program with similar coverage and achieving the same economy-wide emissions reductions.

The TPS's rate-based approach, according to which compliance requires limiting emissions to a given ratio of emissions to output, contrasts with the mass-based approach of C&T, under which compliance requires avoiding exceeding a given level (mass). Under a TPS, the number of emissions allowances the regulator offers to a facility in each compliance period is the product of the maximum emissions-output ratio (or benchmark) assigned to the facility and the facility's output in that period.[2] Fischer (2001) showed that a rate-based system like the TPS implicitly subsidizes output while it taxes emissions. The implicit subsidy reflects the fact that, at the margin, additional output increases the number of (valuable) allowances a facility will receive from the regulator. Subsequent studies have indicated that, as a result of their implicit output subsidy, rate-based standards tend to be less cost-effective than a mass-based instrument like cap and trade.

Rate-based standards come in several varieties. In recent years, several studies have explored *input*-oriented rate-based standards, which impose floors on the ratio of "clean" (low-polluting) to "dirty" (high-polluting) inputs to production. Fuel standards and clean energy standards are important examples. Holland *et al*. (2009) and Holland *et al*. (2015) have explored the cost-effectiveness of clean fuel standards as part of climate policy in California and at the federal level, respectively. Fischer and Newell (2008), Parry and Krupnick (2011), and Goulder *et al.* (2016) have assessed the cost-effectiveness of clean energy standards imposed on purchases of renewable- and fossil-generated electricity by US utilities. As indicated in this literature, these input-oriented rate-based standards implicitly subsidize the cleaner input and tax the dirtier one. The subsidy component causes overall fuel prices to be too low in terms of efficiency; this compromises cost-effectiveness.

China's TPS is an example of an *output*-oriented rate-based standard – it imposes a limit on the ratio of a firm's CO_2 emissions to its output of electricity. Under an output-oriented standard, the implicit subsidy applies to output.[3] Fischer and Newell (2008), de Vries *et al.* (2014) and

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[2] More precisely, a rate-based system's benchmarks are the assigned emissions-output ratios that covered facilities must not exceed, after adjusting for any emissions credits purchased on the allowance trading market.

[3] The subsidy motivates all covered facilities to expand output beyond the first-best level. At the same time, the TPS tends to favor facilities with emissions-output levels below the applicable benchmark, as discussed in Section 4 below.

Zhang *et al*. 2018) find that, as a result of this subsidy, the TPS generally is less cost-effective than a mass-based alternative such as cap and trade.[4]

This paper extends the theory regarding the implications of a TPS relative to C&T. In addition, it offers what we believe is the first quantitative assessment of China's new nationwide TPS that closely considers the TPS's incentives along with a comparison with the prominent alternative, namely C&T.

One contribution of our analytical model is to focus sharply on the implications of multiple (i.e., varying) benchmarks. This is an important feature of China's planned TPS. Multiple benchmarks can help serve distributional goals, since higher (that is, less stringent) benchmarks can be assigned to facilities that otherwise would face especially high compliance costs. Our analytical model shows that greater variation of benchmarks, while addressing distributional goals, reduces cost-effectiveness (that is, raises the cost of achieving any given aggregate emissions-reduction target), other things equal. Greater variation increases costs because it alters the relative magnitudes of the implicit output subsidies across covered facilities and thereby distorts the relative outputs of these facilities. Cap and trade also can employ multiple benchmarks for determining the initial allocations of emissions allowances across covered facilities and thereby affect the distribution of policy costs. But in contrast with the TPS, the use of multiple benchmarks under C&T does not reduce cost-effectiveness. Because a typical C&T program does not include the output subsidy,[5] the extent of benchmark variation across facilities (holding total number of allocated allowances fixed) does not affect decisions at the margin; it only has distributional consequences.

A second contribution of the theoretical model is to reveal that the TPS's implicit subsidy reduces the gains from allowance trading. Under C&T, covered facilities minimize their costs by trading allowances until their marginal abatement costs equal the common allowance price. This

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[4] Other related studies include Davis and Knittel (2019), who assess the impacts of US Corporate Average Fuel Economy (CAFE) standards. CAFE standards are output-oriented rate-based standards: the denominator in the rate is miles. Such standards yield an implicit subsidy or tax to an automobile producer, depending on whether the fuel requirement per mile is below or above the standard. Burtraw *et al*. (2015) and Bushnell *et al.* (2017) analyze efficiency implications and coordination challenges related to US states' strategic choices between intensity standards and cap and trade as a way to comply with the Obama administration's Clean Power Plan. Strategic choices apply because a given state's choice is influenced by the choice made by a neighboring state. Fullerton and Metcalf (2001), Goulder and Parry (2008), Parry *et al.* (2016), and Metcalf (2019) survey the efficiency attractions and limitations of a wide range of climate policy instruments, including intensity standards and cap and trade.

[5] In Section 3 we address the case where C&T offers output-based allocation for certain covered facilities. In that case, the magnitude of a benchmark influences cost-effectiveness.

maximizes the cost-savings from trading, as it implies equality of marginal abatement costs across facilities. Under the TPS, in contrast, a facility will minimize its costs by trading until its marginal abatement costs equal the *net-of-subsidy* allowance price. We show that the net-of-subsidy price generally differs across facilities, as it depends on technologies that differ across facilities. Thus, allowance trading does not achieve equality of marginal abatement costs across facilities, and gains from trades are compromised. The analytical model shows that this compromise occurs even in the case where the TPS applies the same benchmark to all covered facilities.

In addition, the analytical model reveals that under the TPS, covered facilities with relatively low emissions-output ratios will tend to *increase* both electricity output and emissions relative to their business-as-usual levels. This contrasts with C&T, which generally motivates all covered facilities to reduce both output and emissions.[6] The TPS's more limited engagement of output-reduction (as opposed to reductions in emissions per unit of output) as a channel to reduce emissions underlies its lower cost-effectiveness compared with C&T.

Our numerical model yields results consistent with the analytical model's predictions, supplementing the qualitative results of the theoretical model with a unique quantitative assessment closely geared to China's power sector.[7] Key findings of the numerical model are as follows.

First, this model finds that the TPS involves considerably higher economy-wide costs than a C&T program of the same stringency and scope, a reflection of the TPS's implicit output subsidy.[8] Consistent with the analytical findings, in the numerical model the TPS causes some generating units to expand output, while C&T induces most or all units to reduce output. The less efficient use of the output-reduction channel contributes to the TPS's higher costs. In our central case simulation, under a 3-benchmark TPS (an option under consideration by Chinese policy planners)

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[6] There are exceptions. As discussed in Section 4, C&T generally leads to increases in electricity prices, and this exerts a positive influence on facilities' output and emissions. We show analytically that it is possible for this effect to be large enough to cause some facilities to increase output and emissions. Our numerical simulations indicate that this price effect generally is not strong enough to produce this outcome: nearly all facilities reduce output and emissions under C&T.

[7] This quantitative analysis complements a number of recent empirical studies of China's efforts to reduce CO_2 emissions through emissions trading. See, for example, Duan and Zhou (2017), Ho *et al.* (2017), Teng *et al.* (2017), Karplus and Zhang (2017), and Zhang *et al.*(2017). Our model differs from other numerical models of China's climate policy because of its sharp focus on the incentive effects of the TPS and its associated ability to yield a close comparison of the impacts of the TPS and C&T.

[8] Other factors can mitigate the potential disadvantages of rate-based approaches such as the TPS. Goulder, Hafstead, and Williams (2016) show that pre-existing distortionary taxes can reduce and sometimes eliminate the potential cost-disadvantage of a clean energy standard relative to cap and trade or an emissions tax.

the TPS would yield a 4.9 percent reduction in aggregate CO_2 emissions. This reduction could be achieved at 67 percent lower private cost under a C&T program with similar allowance allocations.

Second, the TPS's economy-wide costs rise substantially with the number and variability of benchmarks. A 3-benchmark TPS has 45 percent higher private cost per ton of reduced emissions, compared to a single-benchmark TPS with the same number of allowances allocated in the compliance period. Greater variation of benchmarks implies higher costs by distorting the relative contributions of different facilities to emissions reductions.

Third, the distributional impacts of the TPS differ significantly from those of C&T. One difference is in terms of the relative impact on producers and consumers. As discussed, reductions in electricity output contribute a much smaller share to overall emissions reductions under the TPS than under C&T. The TPS's less extensive reductions in output imply smaller increases in electricity prices[9] than under C&T. As a result, electricity producers (consumers) bear a larger (smaller) share of the overall economic burden under the TPS than under C&T. Indeed, in our central case, the sign of the producer surplus change differs between the TPS and C&T: it is negative under the TPS, positive under C&T.

Fourth, the TPS has very different cost-impacts across the Chinese provinces, reflecting differences in technologies and emissions intensities of the generators and the associated differences in compliance costs. Under the 3-benchmark central case specification for the TPS, among the generating units that experience the largest percentage losses in profit are those in provinces in the northern and northeastern provinces. We consider an alternative, 4-benchmark policy specification designed to avoid the large cost-impacts in these provinces. In this case, the technologies on which these regions disproportionately rely, and which involve especially high emissions intensities, are given less stringent benchmarks. We find that achieving the distributional objective lowers profits in other regions of the country and increases aggregate policy costs.

Although the TPS is less cost-effective than C&T, it has important offsetting attractions. One is that, compared to an equally stringent C&T program, the TPS likely would yield less "emissions leakage" – offsetting increases in emissions stemming from shifts in production across jurisdictions. To the extent that regulation of China's pollution raises the prices of China's outputs relative to foreign goods, consumers could shift toward imports, potentially offsetting the pollution-

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[9] As noted earlier and discussed further in Section 4, a considerable share of China's electricity prices is now market-determined. Our models account for both government-controlled and market-determined prices.

reduction goals of the domestic regulation. Similarly, higher electricity prices can cause a shift in demand away from the electricity sector and toward other domestic industries, causing leakage by increasing the emissions from those industries. Because of the implicit subsidy to output, a TPS induces smaller increases in electricity prices than does the equivalent C&T system. Thus, to the extent that the TPS yields smaller price increases than C&T, emissions leakage can be reduced.[10]

A second attraction is that the TPS's rate-based structure causes policy stringency to adjust automatically in response to current macroeconomic conditions. When the economy is booming, and demand for electricity is relatively high, the expanded output of electricity entitles generators to a larger number of allowances, since allowance allocations are a function of output. Cap-and-trade programs do not have this attribute.

A third attraction is familiarity. The TPS's rate-based structure matches that of several of the previous provincial- and regional-level pilot programs for reducing CO_2 emissions. The structure also is in line with other rate-based regulations with which China is familiar.

Our numerical model indicates that despite its higher overall economic costs relative to C&T, the TPS can generate significant aggregate gains once environmental benefits are accounted for. In our central case, the environmental benefits from the TPS (in terms of avoided climate-related damages) are 2.4 times the costs when emissions reductions are valued at 290 RMB (or about 44 U.S. dollars) per ton. Accounting for the health effects from associated reductions in air pollution would further increase the benefit-cost ratio.

These issues have significance in other contexts. In many countries, policy makers are making important choices that include whether to adopt a rate-based or a mass-based approach to pollution control. The results shown here for China are highly relevant to their choices.

The rest of the paper is organized as follows. The next section briefly describes key features of the power sector. Section 3 then presents the basic structure of China's TPS program. Subsequent sections examine analytically and numerically the potential impacts of the program. Section 4 develops and applies an analytical model to assess qualitatively the firm- and aggregate-

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[10] In China, relatively little electricity is imported. In 2016, imports represented about 0.1 percent of electricity consumed. Hence the smaller price increases from the TPS relative to the increases under C&T would not likely make much difference in terms of imports of electricity, at least in the first, power-sector-only, phase of the program. The issue of international emissions leakage is likely to be more important in the later phase of China's TPS program, when coverage is extended to eight industrial sectors, including sectors in which domestic production faces more competition from imports. Fowlie and Reguant (2018) address theoretical and empirical challenges associated with the measurement of leakage.

level impacts of the TPS, and compares these impacts with those under C&T. Section 5 lays out the structure, inputs, and solution method of the numerical model. Section 6 then applies the numerical model to assess the cost-effectiveness and distributional impacts of the TPS and C&T. Section 7 offers conclusions.

2. Key Features of the Electricity Sector

Almost 72 percent of electricity produced in China's power sector comes from its fossil-based plants.[11] In 2016 the sector contained 2,392 coal-fired, circulating fluidized bed, and natural-gas-fired generating units. Table 1 groups the units into three main technology categories – coal-fired units other than circulating fluidized be units, circulating fluidized bed units, and gas-fired units – and into 11 more specific technology classifications. In addition to numbers of units, the table provides information on outputs, costs and CO_2 emissions intensities for the different technologies.

Among these units, the 300 MW subcritical coal units account for the largest share of electricity production and CO_2 emissions. The 600 MW supercritical coal units, which operate at a slightly lower emissions intensity, are the second largest producers of electricity and CO_2 emissions. The quite limited gas-fired capacity has much lower emissions per mWh.

Regulations imposed by the central government affect electricity output decisions and pricing. For almost every generating unit, the pattern in recent years is that some of the unit's electricity output is sold at prices fixed by the government while some is sold at market prices. Generating units can choose levels of production, but a three-tiered system determines the prices at which the production can be sold.[12] The first tier applies to electricity output up to the amount associated with a government-assigned number of "guaranteed annual utilization hours" of operation. The second tier applies to production in excess of the guaranteed-hours (GH) level and up to another level set by the government. Electricity production within the first tier is sold locally at an administered price, while electricity production within the second tier is sold within a larger production zone, at a different administered price.

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[11] About 20 percent, 4 percent, 4 percent, and 1 percent of electricity production is hydropower, nuclear power, wind power, and solar power, respectively ("Annual Statistics of China Power Industry 2016," *China Electricity Council*, March 21, 2018, http://www.cec.org.cn/guihuayutongji/tongjxinxi/niandushuju/2018-03-21/178791.html).

[12] See Kahrl *et al.* (2016) and Ho *et al.* (2017).

We refer to third-tier production as electricity output beyond the second-tier level. This output is sold at market prices. The principal markets are a "residual local market," to which the generators in the unit's province are the main suppliers, and a "zonal" market, to which units in the several provinces in a given zone contribute. The main purchasers in the zonal market are grid companies.[13] As discussed further in Section 6, the market prices generally are below the fixed prices. Forward markets exist for both the residual local and the zonal markets.

A decade ago, nearly all production was in the first or second tier and therefore faced fixed prices. However, the situation has changed in recent years. By 2018, almost one-third of the electricity consumed in China was sold at market-clearing prices.[14] The increased importance of market prices reflects the gradual narrowing of the first and second tiers as well as the substantial growth in total electricity demand. These developments are consistent with the central government's efforts to expand the role of market-driven prices in the power sector.

Thus, individual generators are able to choose their production levels, and the chosen production levels influence the share of production that can be sold at market prices. These features are captured in our models.

3. Structure of the TPS

Allowance trading, a central feature of both tradable performance standards and cap and trade programs, promotes a reallocation of abatement activity, leading to greater effort by facilities that can reduce emissions at lower cost. This helps reduce the economy-wide cost of achieving aggregate emissions reductions. China's system allows for trading across regions in the power sector. It is expected that the system will allow for intersectoral trading as well once it is extended beyond the power sector.

During the first two trading periods (spanning the years 2005-12) of the European Union's Emissions Trading System (EUETS), free allowances were given to individual facilities on the

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[13] Starting in 2017, some provinces allow private power retailers and large electricity consumers to enter the residual local markets and zonal markets. And as of 2018, consumers from coal, steel, non-ferrous, and building material sectors can purchase all of their electricity in the markets.

[14] Department of Industrial Development and Natural Resources, "An Analysis of National Electricity Trading in 2018", *China Electricity Council,* March 4, 2018, http://www.cec.org.cn/guihuayutongji/dianligaige/2019-03-04/189190.html (accessed November 16, 2019).

basis of their historical emissions. More recently, the trading programs in California and Quebec, as well as the revised third-period program in the EUETS, have relied on benchmarking, according to which the number of allowances received by a facility is based on a technology- or industry-specific emissions-output ratio rather than on historical levels of emissions.

A key difference between C&T and China's TPS relates to the allocation of emissions allowances. Under C&T, in most cases each covered facility's allowance allocation at a given point in time is exogenous to the firm. The number of allowances a firm receives is the product of the pre-established benchmark emissions-output ratio and some fixed reference quantity (usually an historical level of production). To achieve compliance, a facility's emissions, minus any allowances it purchases from other facilities, must not exceed this product.[15]

In some exceptional cases, the allocation under C&T is endogenous. This occurs where C&T offers "output-based allocation" to certain facilities. Under output-based allocation, a facility's allocation in a given period is the product of the benchmark and the facility's output in the previous period. In this case, a firm's output choice in a given period affects its allocation in the next period. Thus, the allocation is endogenous to the firm, although the impact on the allowance allocation comes with a one-period lag. In the EUETS, California's C&T, and some other C&T systems, output-based allocation has been applied to certain firms in the industrial sector that are designated as the most "emissions-intensive trade-exposed" and thus especially vulnerable to import-competition. Output-based allocation is a way of helping these firms compete internationally: it effectively subsidizes output, since additional output leads to larger allocations of allowances.[16] In practice, output-based allocation tends to be applied only to a small subset of covered firms and generally not to the power sector.[17]

In contrast with most forms of C&T, under China's nationwide TPS the allocation of allowances to each covered facility is endogenous within each compliance period; it depends on the product of the benchmark β_i assigned to each generator i and the level of electricity output q_i

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[15] Some ETSs include provisions that allow entities to borrow the allowances that it has been promised for future compliance periods, or bank some of its current allowances for use in future periods. In this case, aggregate emissions can exceed (if there is net borrowing) or must fall short of (if there is net banking) the sum of currently issued allowances. When there are provisions for intertemporal borrowing or banking of allowances, the effective cap is on cumulative emissions, and this cap is equal to the sum of the allowances introduced over time.

[16] Haites (2003), Böhringer and Lange (2005), Fowlie (2012), Fischer and Fox (2012), Bushnell and Chen 2012) and Fowlie *et al.* (2016) offer discussions of output-based allocation.

[17] California's ETS does not apply output-based allocation to the power sector. The EU ETS applies such allocation to the power sector only in a few exceptional cases.

chosen by the generator in that period. Because the number of allowances allocated to each generator is endogenous, the aggregate emissions associated with the government-chosen benchmarks is endogenous as well. Thus, unlike C&T, with a TPS the regulator will not know the total number of allowances to be issued and the aggregate level of emissions until the end of the compliance period, after firms' production decisions over the period have been made.[18]

Reflecting the differences in structure, C&T systems are categorized as *mass-based*, since in each period the regulator sets the aggregate level (or total mass) of emissions, while the TPS is categorized as *rate-based*, since the regulator sets emissions intensities but not total emissions.

China plans to allocate allowances through a two-step process. At the start of the compliance period, a covered facility receives a number of allowances equal to the product of its designated benchmark emissions-output ratio, β, an "initial allocation factor," α, and some measure of output, q_0 (e.g., a recent level of production).[19] The second step in the process comes at the end of the compliance period, at which time a covered entity receives the quantity of additional allowances needed to bring its total allocation into conformity with the sector-specific benchmark emissions-output ratio.[20]

The extent to which China's program will reduce CO_2 emissions depends crucially on the choice of benchmarks. Currently, the planners are considering employing three benchmarks for the power sector. These benchmarks apply to the three technology *categories* identified in Table 1: coal-fired, circulating fluidized bed (CFB), and gas-fired units. We use the term "technology *class*"

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[18] In C&T systems that include some output-based allocation, the total number of allowances to be issued – the aggregate cap – is set in advance and remains exogenous. Although firms enjoying output-based allocations can affect their allocations through changes in output, these changes do not alter each period's total allocations. Increased allocations to firms enjoying output-based allocation correspond to reductions in allocations to other firms. Thus, the aggregate cap does not change.

[19] At the time of this writing, China has not yet specified the value it will employ for α, although a 0.6 value has been widely discussed. With a value of 0.6 for α, the facility would initially receive 60 percent of the allowances it would need to justify the emissions-output ratio β if its level of output did not change from q_0. It is theoretically possible for a facility to receive more allowances at the beginning of the period than the amount it is will be entitled to have received by the period's end. This happens when end-of-period output is lower than αq_0. This could put the government in an awkward position at the end of the compliance period of needing to take away from the facility some of the allowances it had given out at the beginning of the period. It appears that the program will utilize a value for α sufficiently below 1 to make it unlikely that the government would encounter this problem with any facility that remains in operation. As discussed below, any facility that shuts down during the compliance period must relinquish its allowances.

[20] In fact, each province has the option of reducing the allocation of allowances to facilities within the province if it wishes to make the program more stringent locally. The Ministry of Ecology and Environment sets national benchmark emissions-output ratios, but the provincial government can reduce them. It is also our understanding that the central government will also offer "reserve allowances" to governments in some low-income provinces, additional allowances that these governments can allocate according to their own chosen criteria.

to refer to more specific technology types. The Ministry of Ecology and Environment distinguishes the 11 technology classes and the three technology categories shown in Table 1. We use the same groupings in applying benchmarks in the numerical simulations below.

This section has emphasized three key aspects of the structure of China's forthcoming nationwide ETS. First, the program will authorize trading of emissions allowances across regions and (once it expands beyond the power sector) across industrial sectors. Second, in contrast with a C&T system, under the TPS the number of allowances allocated to a covered facility depends on the facility's chosen production level over the compliance period; hence the number of allowances allocated is endogenous to firms' production decisions and the aggregate number of allowances introduced in any given compliance period – the aggregate cap – is endogenous as well. Third, the planners seem to be focused on employing three benchmarks in the first (power-sector) phase of the program, one for each of three main technology categories. Differential benchmarking offers a channel for achieving distributional goals. At the same time, as examined further below, it can compromise cost-effectiveness.

The next section develops an analytical model to examine the impacts of the TPS in the power sector and to contrast these impacts with those of C&T. The subsequent two sections present the structure of and results from the corresponding numerical model.

4. Impacts of the TPS: An Analytical Treatment

In the presence of the TPS, managers of a generating unit need to make several interconnected decisions. One is whether to remain in operation or shut down. Generators that remain in operation also need to decide how much electricity to produce and how much to reduce the emissions intensity of production. These decisions depend on the stringency of the benchmark applied to the generating unit, the price of emissions allowances, and the administered and market prices of electricity.

The analytical model considers these elements. For transparency, this model does not distinguish between the tier 1 and tier 2 administered prices; it considers a single tier and "tier production" here refers to production on that tier. Also, this model does not separate the residual and zonal electricity markets. The key insights from this model are preserved in the results from the more disaggregated numerical model.

a. Net Revenue, Conditional on Remaining in Operation

Let:

q_{ij} ≡ total end-of-period electricity output of generator *i* in technology class *j*

$\bar{q}_{ij}$ ≡ guaranteed-hour electricity output of generator *i* in technology class *j*

e_{ij} ≡ CO_2 emissions by generator *i* in technology class *j*

C_{ij} ≡ total cost of production by generator *i* in technology class *j*

$\bar{p}_{ij}$ ≡ administered wholesale price applying to electricity output by generator *i* in technology class *j* below the generator's guaranteed-hour level

p_{ij} ≡ market equilibrium wholesale price applying to electricity output by generator *i* in technology class *j* at or above the generator's guaranteed-hour level

β_j ≡ benchmark emissions-output ratio assigned to generators in technology class *j*

t ≡ market price of emissions allowances

Consider first the choices of a generating unit conditional on its remaining in operation. The generator's[21] choice variables are *q* and *e*. Net revenue π for operating generator *ij* is given by:

$$\pi_{ij} = \bar{p}_{ij}\bar{q}_{ij} + p_{ij}\left(q_{ij} - \bar{q}_{ij}\right) - C\left(q_{ij}, e_{ij}\right) - t\left(e_{ij} - \beta_j q_{ij}\right) \tag{1}$$

The first right-hand term in (1) is the revenue from production of electricity up to $\bar{q}_{ij}$, the highest level of output subject to the administered price $\bar{p}_{ij}$. The second right-hand term is the revenue from electricity output in excess of $\bar{q}_{ij}$. The third and fourth terms refer to total production cost and the expense or revenue associated with allowance purchases or sales. We assume $\partial C_{ij} / \partial q_{ij} > 0$ and $\partial C_{ij} / \partial e_{ij} < 0$. We also assume that each generator's objective is to maximize net revenue.[22] For simplicity of exposition, equation (1) and subsequent equations in this section reflect the assumption that $q_{ij} > \bar{q}_{ij}$. This is the most frequent case in our data. In the infrequent cases where $q_{ij} < \bar{q}_{ij}$, $\bar{p}_{ij}$ replaces p_{ij} throughout.[23]

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[21] For brevity, we will let "generator" refer to both the physical unit and the unit's decision-maker (manager). The intended reference will be clear from the context.

[22] See Ho *et al.* (2017). This assumption seems reasonable for the approximately 50 percent of the generators that are privately owned.

[23] Thus, when $q_{ij} < \bar{q}_{ij}$, the equation for net revenue reduces to $\pi_{ij} = \bar{p}_{ij} q_{ij} - C\left(q_{ij}, e_{ij}\right) - t\left(e_{ij} - \beta_j q_{ij}\right)$. This squares with the fact that in this case $\bar{p}$, not the endogenous price, is the price that applies to each unit of electricity sold.

The endogeneity of q_{ij} in the far-right term in (1) is critical to the impact of the TPS. To be in compliance, the generating unit's ultimate (end-of period) allocation of allowances βq_{ij} , plus (minus) any allowances it purchases (sells) on the trading market, must be at least enough to justify it emissions during the period. The far-right term in (1) represents the additional needed purchases (or potential sales) of allowances consistent with compliance.

Let $u_{ij}(\equiv e_{ij} / q_{ij})$ represent the generator's end-of-period emissions-output ratio.[24] Then we can rewrite the far-right term as $t(u_{ij} - \beta_j)q_{ij}$. In the absence of purchases of additional allowances, a unit that produces output q will be in or out of compliance depending on whether its emissions-output ratio is less than or greater than β_j.

Let u_{ij0} represent the generator's beginning-of-period emissions-output ratio. A generator with $u_{ij0} > \beta_j$ can come into compliance by purchasing additional allowances, reducing its emissions rate, or both. A generator with $u_{ij0} < \beta_j$ will not need to purchase allowances[25] and will benefit from the sale of its excess allowances. Indeed, once a generator with an initial emissions ratio less than β_j has achieved its optimal emissions ratio, its best option is to sell its excess allowances, since such allowances have no other beneficial use for the facility; selling them involves no opportunity cost.[26]

This suggests some of the potential distributional implications of the TPS. Generators in the $u < \beta$ category can benefit from the TPS by selling their excess allowances, while generators in the $u > \beta$ category face compliance costs, as they will need to reduce emissions intensity and/or purchase additional allowances to come into compliance.[27] Below we explore further the distributional impacts.

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[24] By "end-of-period" emissions-output ratio we mean the ratio of cumulative emissions to cumulative output over the compliance period. This is the ratio relevant to ascertaining compliance.

[25] This assumes the generator does not increase its emissions-output ratio during the compliance period enough to cause its ratio to exceed β. There is no reason to expect this to occur, since the TPS gives all generators incentives to reduce their emissions-output ratios, as discussed below.

[26] The National Development and Reform Commission 2017 document, *Guidelines of National Carbon Emissions Trading System (Power Generation Sector),* did not include provisions for intertemporal banking or borrowing of emissions allowances. Correspondingly, the model assumes no such provisions. As a result, the allowances available to generators needing additional allowances are restricted to the excess allowances offered by the generators with $u_{ij}<\beta_j$. In China's pilot trading programs, intertemporal borrowing was not permitted, although intertemporal banking was an option.

[27] Although China's TPS does not cover renewable sources of electricity such as wind and solar, it will encourage production from these sources by increasing the cost of supplying fossil-based generated electricity. A further boost to renewables production would occur if the TPS were to cover these sources, since presumably these sources would have emissions-output ratios well below the benchmarks and thus could benefit significantly by selling excess allowances.

b. The Shutdown Decision

In considering whether to shut down, the generator will compare the revenue from continued operation with the revenue associated with shutting down. In the case of shutting down, the revenue consists solely of the liquidation value[28] of the abandoned capital. Note that the generator's owners cannot earn additional revenue by selling any of the allowances it was allocated at the beginning of the compliance period; the program requires that such allowances be returned to the government.

It is useful to rewrite (1) as:

$$\pi_{ij} = p_{ij}q_{ij} + (\overline{p}_{ij} - p_{ij})\overline{q}_{ij} - C(q_{ij,}e_{ij}) - t(e_{ij} - \beta_j q_{ij}) \tag{2}$$

This expression divides the gross revenue from electricity production into $p_{ij}q_{ij}$, a component that depends on the level of production q_{ij}, and $\left(\overline{p}_{ij} - p_{ij}\right)\overline{q}_{ij}$, a fixed component.[29] The fixed component is the revenue associated with output up to the maximal level to which the administered price applies. This revenue is inframarginal. It affects the level of profit and the shutdown decision, but because it is inframarginal it does not affect the optimal level of production for firms that do not shut down.[30]

From (2), a generator will remain in operation if and only if

$$pq + \left(\overline{p} - p\right)\overline{q} - C\left(q,e\right) - t\left(e - \beta q\right) > L \tag{3}$$

where L represents the liquidation value (subscripts have been suppressed for convenience).

We can rewrite (3) as

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[28] In discussions with the ETS planers, we have learned that the market for abandoned electricity generation capital is quite limited, so that the liquidation value is very low. Also, it should be noted that in this one-period model, the relevant "liquidation value" is the avoided one-period rental on the capital that is no longer employed.

[29] Note that p_{ij} as well as $\overline{p}_{ij}$ and $\overline{q}_{ij}$ are exogenous to the individual generator.

[30] Recall that the equations in this section assume $q_{ij} > \overline{q}_{ij}$. When $q_{ij} < \overline{q}_{ij}$, the corresponding profit equation is

$\pi_{ij} = \overline{p}_{ij}q_{ij} - C(q_{ij}, e_{ij}) - t(e_{ij} - \beta_j q_{ij})$ and $\overline{p}_{ij}$ is the price at the margin.

$$pq + (\bar{p} - p)\bar{q} - C(q,e) - L > te - t\beta q \tag{4}$$

Define $\hat{t}$ as the allowance price t that equates the left-hand and right-hand sides of (4):

$$\hat{t} = \frac{pq + (\bar{p} - p)\bar{q} - C(q,e) - L}{e - \beta q} \tag{5}$$

$\hat{t}$ is a critical value of t: the generator will shut down or remain in operation depending on whether the allowance price is above or below this value. Other things equal, $\hat{t}$ will be lower for generators facing a lower (more stringent) β: they will shut down first.[31]

c. Equilibrium Conditions

1. The Allowance Price

Let RP_j refer to the set of generators in technology class j that *remain* in operation and *purchase* allowances – the generators in technology class j with $u_{ij} > \beta_j$ (or equivalently, $e_{ij} > \beta_j q_{ij}$) for which condition (3) above is satisfied. Then the total market demand for allowances, $D(t)$, is expressed by:

$$D(t) = \sum_j \sum_{i \in RP_j} (u_{ij} - \beta_j)\, q_{ij} \tag{6}$$

Demand is a function of the allowance price t because this price influences the number of generators that remain in operation (the number for which t is below $\hat{t}$). The allowance price also affects demand through its influence on the output levels and emissions intensities of the generators that remain in operation.

The supply of allowances on the trading market comes from generators that remain in operation and have excess allowances to sell. Let RS_j represent the set of generators in technology

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[31] Under cap and trade, the expression for profit is $\pi = pq - C - t(e - a_0)$, where a_0 represents the facility's allocation of (free) allowances. From this it follows that under cap and trade, $\hat{t}$ is equal to $(pq - C - L) / (e - a_0)$. A larger initial allocation of free allowances raises $\hat{t}$.

group j that *remain* in operation and *sell* allowances – the generators in technology group j for which $u_{ij} < \beta_j$.[32] The total supply of allowances into the emissions trading market is:

$$S(t) = \sum_j \sum_{i \in RS_j} (\beta_j - u_{ij})\, q_{ij} \tag{7}$$

The allowance price affects allowance supply by influencing the electricity production levels of the generators with $u < \beta$: this affects the number of excess allowances they have to sell. This price also affects supply by influencing the emissions intensities of these generators.

The market equilibrium price of allowances is the price t that satisfies $D(t) = S(t)$.

2. Electricity Prices

Generators whose production does not exceed $\bar{q}$ face only the administered electricity price $\bar{p}$, while generators that produce more than $\bar{q}$ face both the administered price and the market price p for production beyond $\bar{q}$. In each province, the total demand for electricity is assumed to be a negative function of price. The equilibrium market price equates total supply with the total demand.

d. Cost-Effectiveness Considerations

1. TPS and C&T electricity outputs relative to the cost-minimizing output level

Consider the profit-maximizing choices made by an individual generating unit under the TPS. As indicated in expression (2) above, the profit function for a generating unit is $\pi = pq + (\bar{p} - p)\bar{q} - C(q,e) - t(e - \beta q)$, where subscripts are suppressed for simplicity. This function yields the following first-order conditions for the profit-maximizing levels of q and e, given the allowance price t and applicable benchmark β :

$$\partial \pi / \partial q : p - C_q = -\beta t \tag{8}$$

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[32] Recall that u_{ij} is endogenous. We assume that generating units in the group RS_j undertake expenditure on process change to the extent that this will increase net revenue (by increasing the number of excess allowances).

$$\partial \pi / \partial e : -C_e = t \tag{9}$$

where $C_q \equiv \partial C / \partial q$ and $C_e \equiv \partial C / \partial e$. The left-hand side of (8) is the marginal net revenue from output, excluding any change in costs of needed allowances. The right-hand side is the marginal cost of output in terms of the additional allowance costs associated with that increment to output since each unit of output raises allowance payments by βt (holding fixed the emissions-output ratio). Expression (8) states that a generator maximizes profit by equating the marginal net revenue with the marginal allowance cost.

To assess the cost-effectiveness of the TPS, we compare these first-order conditions with those from the following optimization problem:

$$max\, \Pi = \sum_i pq_i + (\bar{p} - p)\bar{q}_i - C(q_i, e_i) \tag{10}$$

$$s.t. \ \sum_i e_i \le \bar{E}$$

where Π represents the net surplus produced by the generators in the aggregate[33] and $\bar{E}$ is a given aggregate emissions target. The solution to (10) is the maximal surplus that can be obtained when emissions are kept within the given target or, equivalently, the minimum cost of reducing emission to the amount indicated by the target. The Lagrangian expression associated with (10) is

$$\mathcal{L}: \quad \sum_i pq_i + (\bar{p} - p)\bar{q}_i - C(q_i, e_i) - \lambda\left(\sum_i e_i - \bar{E}\right) \tag{11}$$

The first-order conditions associated with this expression are

$$\partial \mathcal{L} / \partial q_i : \ p - C_{q_i} = 0 \tag{12}$$

$$\partial \mathcal{L} / \partial e_i : \ -C_{e_i} = \lambda \tag{13}$$

$$\partial \mathcal{L} / \partial \lambda : \ \sum_i e_i \le \bar{E} \tag{14}$$

Equation (12) indicates that social costs are minimized when generators' production levels equate the marginal revenue (*p*) and the marginal private cost C_{q_i} of production. The difference between this first-order condition for *q* and the corresponding first-order condition under the TPS

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[33] This implicitly assumes no externalities or taxes, and pure competition. Under these conditions, social surplus (the sum of producer and consumer surplus) is maximized when the sum of net revenues to firms is maximized.

(equation (8)) is the source of the TPS's limitations in terms of cost-effectiveness. The difference, $-\beta t$, is the implicit subsidy to output under the TPS. From equation (2), other things equal[34] each unit of q under the TPS reduces by βt the cost of additional allowances needed for compliance. Thus, condition (8) means that the TPS leads generators to produce more output, for given output prices p, than would be the case if equation (12) applied.[35]

Equation (13) is the first-order condition associated with the choice of emissions levels consistent with minimizing the cost of achieving a given emissions-reduction target. The Lagrangian multiplier λ is the shadow value of the constraint on emissions; in an emissions trading market, this is the market price of allowances. Thus, we can interpret λ as equal to t. This means that the first-order condition (13) for cost-minimization matches equation (9), the first-order condition regarding emissions under the TPS. Both equations express the condition that the marginal benefit from emissions (or the negative of the marginal cost) should be equated to t. Note that the similarity of conditions (9) and (13) does not mean that the level of emissions under the TPS will match the first-best level. This is because C_e depends on the level of output, and output under the TPS differs from first-best output. For a given value of t, the level of emissions under the TPS will exceed (fall short of) the first-best level if $\partial C_{e_i} / \partial q_i$ is negative (positive).

Consider now the impacts under cap and trade. The expression for profit under C&T is:

$$\pi_{ij}^{C\&T} = pq + (\overline{p} - p)\overline{q} - C(q,e) - t(e - a_0) \qquad (15)$$

where a_0 is the initial allocation of (free) allowances and the superscript "C&T" designates the case of C&T. It is straightforward to show that the associated first-order conditions for a generator's optimal choice of q and e match expressions (12) and (13) for the planner's cost-minimization problem above. This implies that the output and emissions levels under C&T are such as to minimize the cost of achieving the specified aggregate emissions limit.[36] The cost-effectiveness advantage of C&T over the TPS reflects the absence of the output subsidy: the level of output does not appear in the far-right term in the C&T profit expression.

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[34] In keeping with the fact that (8) is a partial derivative, this condition is calculated holding e constant. In fact, the TPS affects both q and e. The connections between q and e are important for explaining the impacts of the TPS on levels of electricity supply and emissions relative to the business-as-usual case. We address these connections below.

[35] Generators with $u_0 > \beta$ will reduce output relative to the business-as-usual level, but the reduction will fall short of the optimal amount.

[36] Of course, this assumes the absence of transactions costs and other possible impediments to trading. Such limitations might well exist, but they could apply under the TPS as well.

The difference in the impacts of the TPS and C&T become smaller, the lower is the price elasticity of output supply. One way to see this is to compare the TPS first-order condition for optimal output (given by equation (8)) with the corresponding condition for C&T (which, as noted above, is the same as (12)). The former can be rewritten as $C_q = p - \beta t$, while the latter can be rewritten as $C_q = p$. The difference between these two conditions is βt. Note that C_q is inversely related to the supply elasticity, implying that as C_q approaches infinity the supply elasticity approaches 0. Suppose that q satisfies the TPS first-order condition. Since βt is a constant, as C_q approaches infinity (or as the supply elasticity approaches zero) the change in q needed to satisfy the C&T first-order condition becomes infinitely small. In the limiting case of a zero supply elasticity, optimal q is in the same for the TPS and C&T, and since the first-order conditions for optimal emissions are also the same, both policies are the same in terms of cost-effectiveness. A comparison of equations (2) (for the TPS) and (15) (for C&T) indicates that with a zero supply elasticity the two policies will also have identical distributional consequences so long as the initial allowance allocations $\beta_j q_{ij}$ (for the TPS) and a_0 (for C&T) are the same.

2. TPS and C&T electricity outputs relative to business-as-usual levels

Here we consider how outputs of the TPS and C&T differ from their baseline (business-as-usual) values. We will see that while C&T often induces all generators to reduce production relative to the baseline level, the TPS typically causes some generators to increase output relative to the baseline.

We start with a focus on the TPS. To determine the relationship with baseline output, we examine the *total* derivative[37] of the TPS profit expression (2):

$$d\pi = p\,dq - \frac{\partial C}{\partial e}de - \frac{\partial C}{\partial q}dq - t\,de + t\,\beta\,dq \qquad (16)$$

Dividing the above expression by dq yields:

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[37] In contrast with the partial derivative condition shown in expression (8), the total derivative considers at one time the impact of changes in both q and e on profit.

$$\frac{d\pi}{dq} = p - \frac{\partial C}{\partial e}\frac{de}{dq} - \frac{\partial C}{\partial q} - t\frac{de}{dq} + t\beta \tag{17}$$

Setting $d\pi / dq$ equal to 0 and rearranging give:

$$p = \frac{\partial C}{\partial q} + \frac{\partial C}{\partial e}\frac{de}{dq} + t\frac{de}{dq} - t\beta \tag{18}$$

The left-hand side is marginal revenue from output, while the right-hand side is the marginal cost, which includes the marginal emissions-related compliance cost. More specifically, the first two right-hand-side terms are the direct cost of an increase in output and the indirect cost via the output's impact on emissions, while the third and fourth right-hand-side terms represent the change in compliance costs associated with a marginal increase in emissions, net of the implicit subsidy $t\beta$. Expression (18) states that, to maximize profit, q must be chosen so that the "overall marginal cost of q" (first two terms) plus the marginal compliance cost (second two terms) equals marginal revenue (the electricity price).

It is convenient to rewrite (18) as:

$$p^{TPS} = A(q^{TPS}) + t\left(\frac{de}{dq} - \beta\right) \tag{19}$$

where $A(q^{TPS}) \equiv \frac{\partial C}{\partial q} + \frac{\partial C}{\partial e}\frac{de}{dq}$, and the superscript *TPS* is employed to make clear that this condition applies under the TPS.

Under business as usual, the allowance price t is zero, so the above optimality condition reduces to $p^{BAU} = A(q)$, where p^{BAU} is the business-as-usual electricity price. Assume for the moment (and counter to fact) that the TPS does not affect electricity prices, so that $p^{TPS} = p^{BAU}$. Under the TPS, satisfying (19) requires that the overall marginal cost $A(q)$ differ from its business-as-usual value, to offset the value introduced by the extra term $t(de / dq - \beta)$. The extra term is either positive or negative depending on whether de / dq is greater or lower than β. For an interior solution, overall marginal cost must increase with q.[38] Satisfying the profit-maximization condition

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[38] If $d(A(q)) / dq$ were negative throughout the relevant range, a facility with $u < \beta$ would forever increase its output, thereby augmenting without limit the excess allowances that it can sell. It is plausible to assume that at some point, an

(19) then requires the facility's electricity output to decline or increase, depending on the sign of $\frac{de}{dq}-\beta$. Since *de / dq* is the generator's emissions rate at the margin, a generator's electricity supply under the TPS is either below or above its baseline level of output, depending on whether its emissions rate at the margin is greater or less than β.

These results refer to a facility's marginal emissions rate; but compliance under the TPS depends on the facility's average rate. It is reasonable to expect significant correlation between marginal and average rates – that facilities with relatively high (low) marginal emissions rates will tend to have relatively high (low) average emissions rates. To the extent that this correlation applies, the TPS will tend to cause output reductions for the facilities that are out of compliance initially (because of their relatively high average emissions rates) and tend to cause output increases for the facilities that are in compliance initially (because of their relatively low average emissions rates).

The results are slightly different once account is taken of policy-induced changes in the electricity price that the facility faces. Define Δ^{TPS} as $p^{TPS}-p^{BAU}$. Applying equation (19) and the definition of Δ^{TPS}, we can write:

$$p^{BAU}=A(q^{TPS})+t\left(\frac{de}{dq}-\beta\right)-\Delta^{TPS} \qquad (20)$$

Thus the impact of the TPS on output is modified by the change in electricity prices. If the TPS causes an increase in electricity prices (as it usually does), Δ^{TPS} is positive and expression (20) is satisfied with a higher value of q (and higher overall marginal cost) than would be the case if the electricity price did not increase. It indicates that if Δ^{TPS} is sufficiently large, even the generators with initial emissions-output ratios above their benchmarks would maximize profits by expanding output. In our simulations, we find that the price increase under the TPS generally is not large enough to produce this result. Over the range of simulations we have performed, the TPS causes nearly every generator with initial emissions-intensity above its benchmark to reduce output.

Under C&T, the equation corresponding to (20) is:

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increase in q raises total marginal costs (that is, $d(A(q))/dq$ becomes positive), implying a limit to the extent that a facility will increase its output.

$$p^{BAU} = A(q^{C\&T}) + t\frac{de}{dq} - \Delta^{C\&T} \qquad (21)$$

where $\Delta^{C\&T}$ is the increase in the electricity price relative to the business-as-usual price. In contrast with equation (20) for the TPS, β does not appear in (21). As a result, the middle right-hand-side term is always positive. In the (counterfactual) case where C&T does not increase in electricity prices, in contrast with the TPS, C&T will induce *all* generators to reduce output relative to the business-as-usual levels. In the more realistic case where C&T leads to a higher electricity price, the higher electricity price counters the effect exerted by the allowance price (middle term), raising the possibility that some $u < \beta$ generators will increase output under C&T. As was the case under the TPS, our numerical simulations of C&T indicate that the electricity price effect is fairly small. Over the range of simulations performed, C&T causes nearly all generators to reduce output relative to the baseline levels, and in many simulations it causes every generator to reduce output.

To summarize: The TPS often induces some facilities to increase output relative to their BAU levels. These are the facilities whose initial emissions-output ratios are low relative to the benchmark. Other things equal, such facilities face smaller adverse profit impacts than facilities with higher initial emissions-output ratios. In contrast, C&T generally incentivizes all facilities to reduce output relative to BAU, although policy-induced increases in electricity can potentially cause some facilities to increase output relative to BAU.

It is important to recognize that the comparisons here are with BAU output levels, not with first-best levels. As indicated earlier, the TPS causes all facilities to produce output above the first-best levels, conditional on remaining in operation.

3. Gains from allowance trading

With a perfectly fluid market for allowance trading, managers of generating units will reduce emissions to the point where the private marginal costs of abatement equal the private marginal benefits. The two elements can be obtained from the total derivative of profit shown in equation (16) above. Dividing both sides by *de* yields:

$$\frac{d\pi}{de} = p\frac{dq}{de} - \frac{\partial C}{\partial e} - \frac{\partial C}{\partial q}\frac{dq}{de} - t + t\beta\frac{dq}{de} \qquad (22)$$

Setting $d\pi / de$ to 0 and rearranging yields:

$$\underbrace{p\frac{dq}{de}-\frac{\partial C}{\partial e}-\frac{\partial C}{\partial q}\frac{dq}{de}}_{MB_e^{pvt}} = \underbrace{t(1-\beta\frac{dq}{de})}_{MC_e^{pvt}} \tag{23}$$

The left-hand side, MB_e^{pvt}, is the marginal private benefit from emissions (or marginal private cost of abatement), while the right-hand side, MC_e^{pvt}, is the marginal private cost of emissions (or marginal private benefit from abatement). The gains from trading are maximized when the marginal costs of abatement (left-hand side) are the same for all producers. This is accomplished under C&T, since (under fluid trading) firms equate these marginal costs to a common value: the allowance price, *t*. However, under the TPS, the right-hand side (marginal benefit from emissions abatement) will generally differ, since the $\beta\frac{dq}{de}$ element differs. In particular, the right-hand side will be lower (higher) for firms for which this element is higher (lower). Thus, trading doesn't lead to equality of marginal abatement costs. After the allowance market has cleared, society's costs could be reduced further if the high $\beta\frac{dq}{de}$ units were compelled to sell more allowances to the low $\beta\frac{dq}{de}$ units (though such additional trading would not be in the firms' private interests).

Equation (23) indicates that the greater the variation in $\beta\frac{dq}{de}$ across firms, the greater the gap between the costs after trades and the costs that would result if the additional trading needed to equate society's marginal abatement costs took place. Note that even if all facilities were to face the same β, the benefits from allowance trading often will be compromised, since the gap depends on both β and dq/de, and the latter will often differ across generators. The implication of greater variation in the β's for this gap depends on the extent to which greater variation of the β's induces an increase or decrease in the variation of the dq/de's.

These considerations indicate that C&T has an advantage over the TPS in terms of the cost-reductions from allowance trading. Under C&T, the right-hand side element in the *MB=MC* expression (23) is simply *t*, which implies (in the absence of impediments to trading) that all units equate their marginal private benefits from emissions (marginal private costs of abatement) to the same value, leading to maximal trade-related cost-reductions.

The foregoing indicates that, under any given benchmark specification, the presence of the benchmarks limits the gains from allowance trading by preventing equality of marginal abatement costs. There is another connection between benchmarks and gains from trade: variation in benchmarks influences the importance of allowance trading. Consider, in particular, a likely difference between a uniform- and multiple-benchmark TPS. In general, a multiple-benchmark TPS "customizes" the benchmarks: for many generators (particularly those with relatively high or relatively low emissions-output ratios), the discrepancies between initial emissions-output ratios and the benchmarks will be smaller than what would be the case in a uniform-benchmark system. That is a key motivation for multiple benchmarks. This implies that in a single benchmark system, the ability of trades to bring a unit's emissions-output ratio closer to its benchmark ratio becomes especially important. As indicated with numerical simulations presented in Section 6, the gains from the presence of allowance trading, when measured as the percentage reduction in policy costs, can be considerably larger in a uniform-benchmark system than in a multiple-benchmark system.

e. Other Considerations

Maximal cost-effectiveness requires that the marginal cost of production equal marginal revenue, or price. Equation (8) shows that the TPS's benchmarks create a wedge between marginal cost and price. The equation can be rewritten as: $C_q = p + \beta t.$ Note that if producers face a common electricity price at the margin, then the use of multiple benchmarks can limit cost-effectiveness by causing the marginal net revenue ($p - C_q$) to differ across producers: C_q will be higher, and marginal net revenue lower, for producers facing higher benchmarks. Thus, relative to the uniform-benchmark case, the use of multiple benchmarks can compromise cost-effectiveness by distorting the generators' relative production levels. Uneven benchmarking can serve distributional goals, however. Higher (less stringent) benchmarks can be applied to generators that otherwise would suffer especially high costs of compliance or be forced to shut down. In Section 6 we consider numerically the cost-effectiveness implications of multiple benchmarks as well as the trade-offs between cost-effectiveness and the achievement of certain distributional goals.[39]

Some attractions of the TPS relative to C&T deserve mention. First, because of the TPS's implicit subsidy to output, the TPS leads to smaller increases in electricity prices than does a comparably stringent C&T system. This can help reduce emissions leakage.[40] Second, the TPS has an advantage in terms of adaptability to changes in macroeconomic conditions. In boom times, when electricity demand and production are high, the allowance allocations increase automatically. This prevents what otherwise could be very high abatement costs in a cap-and-trade program with a fixed cap on allowances. Likewise, the TPS's allowance allocation is lower in slack times, when electricity demand is likely to be lower and a fixed cap could have yielded excessive allowances. Finally, a possible additional attraction is that Chinese planners are more familiar with intensity-based regulations, of which the TPS is an example. This suggests that the administration of the TPS could be less costly and more effective than administration of a C&T program – at least in the nearer term.

f. Summary and Challenges

Key findings from this analysis are:

- A TPS generally is less cost-effective than an equivalently scaled C&T program. The difference in cost-effectiveness reflects the implicit subsidy to output under the TPS, which causes generators' electricity output levels to exceed the levels consistent with minimizing the costs of achieving a given aggregate emissions limit. This difference gains importance the higher the price elasticity of electricity supply.

- The TPS induces some covered facilities – in general, those with emissions-output ratios below their required benchmarks – to increase supply beyond their BAU levels. This contrasts with C&T, which tends to cause facilities to reduce production relative to their

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[39] Benchmarks can also be employed under C&T. The benchmark size affects a unit's allowance allocation. However, in contrast with the TPS, under C&T (and in keeping with the absence of the output subsidy) the magnitude of a given unit's benchmark does not affect the unit's marginal conditions. Holding fixed the number of allowances allocated in the aggregate, the variation in benchmarks across units only affects cost-effectiveness insofar as it affects shutdowns, which depend on profit levels rather than marginal conditions.

[40] This issue is particularly significant to industries that are especially import-competing and/or carbon-intensive. It is not a major issue for producers in China's power sector, since relatively little domestically produced electricity is sold internationally. The issue will be more important once the TPS expands to major industries in China's manufacturing sector.

BAU levels. As discussed, exceptions can arise with sufficiently large electricity price increases under C&T.

- The TPS usually does not lead to equality in marginal abatement costs across facilities that continue to operate, even when trading is perfectly fluid. This limits the aggregate cost-reductions from allowance trades.
- The use of multiple benchmarks distorts the relative output levels across generators. However, employing multiple benchmarks can help achieve distributional objectives. Thus, there is a trade-off between cost-effectiveness and distributional goals.

Each of these findings contrasts with the properties of C&T.

The results from our numerical model reinforce these analytically derived findings. They also provide estimates of the magnitudes of the analytical model's predicted qualitative impacts.

5. A Numerical Model

a. Overview

The model considers the 2,392 generating units and 11 technology classes of Table 1. Within each technology class, the model allows for heterogeneity in the cost functions and thus considers a large number of generation units in each class.

The numerical model's basic structure matches that of the previously described analytical model, although this model has more detail regarding elements of producer cost. The model also considers each generator's production capacity, which in some cases will constrain the unit's total production. We calibrate the numerical model so that its solution under baseline (status quo) conditions matches the data in terms of costs, production levels, emissions and electricity prices.

TPS policies are defined by the benchmark emissions-output ratios that are applied to different generators, while C&T policies are defined by assumed initial allocations of emissions allowances to the different generators. All generators within a given technology class receive the same benchmarks under the TPS and the same initial allowance allocations under C&T.

Under each policy, profit-maximizing managers of generating units determine whether to shut down or remain in operation and, conditional on continuing to operate, the optimal level of production, the extent of effort to reduce emissions intensity of production, and the number of allowances to purchase or sell. Under each policy, the model solves for the equilibrium allowance price and for the equilibrium prices of electricity in each provincial and zonal (regional) market. The equilibrium allowance price equates the aggregate supply of allowances with the aggregate demand. The equilibrium electricity prices pertain to the electricity produced in excess of the quantities facing administered prices. Such excess electricity is sold either to residual local electricity markets or to regional grid companies.[41]

The data show that a given generating unit will often sell its electricity in the local market and zonal market at different prices. Transactions costs help explain the difference in equilibrium prices of electricity, a homogenous product. As indicated in subsection 5b below, we model transaction costs as increasing in the quantity of electricity that a given generator sells to the zonal market. We calibrate the parameters of the transactions cost function so that sales to the zonal market in the baseline simulation match the observed data. In both baseline and policy simulations, the equilibrium market price of electricity in the local market equals the price in the relevant zonal market net of the marginal transactions cost.

b. Cost and Profit

Under business as usual, the cost of production is expressed by:

$$C(q,h) = p_f \frac{h}{\xi} q + (\phi_0 + \phi_1 q^{\phi_2}) \tag{24}$$

The choice variables determining cost are the output level q and the heat rate h. The heat rate is the required energy input (often measured in BTUs) per unit of electricity generated. The two terms on the right-hand side represent fuel costs and operation and maintenance costs, respectively. The fuel cost is the product of the unit price of fuel (p_f), the required amount of fuel per unit of output (h/ξ), and the level of output (q). ξ indicates the energy associated with a unit of fossil fuel input. Thus, dividing h by ξ yields the required fuel per unit of output. Per-unit fuel costs are an increasing function of the heat rate. ϕ_0, ϕ_1 and ϕ_2 are parameters of the operation and maintence cost function.

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[41] In a few unusual cases, the overall demand for electricity at the administered price is less than the GH level of output. In this case, the equilibrium quantity produced is less than the GH output level and all electricity is sold at the administered price.

The introduction of the TPS adds two compliance-related costs. One is the cost of purchasing any additional allowances needed to address the excess of the emissions-output ratio to the benchmark. This cost is equal to $t(u-\beta)q$, where t, u, and β are defined as in the analytical model. For the generators with $u < \beta$, this is a negative cost; such generators will sell allowances. Besides purchasing allowances, generators can come into compliance by increasing the efficiency of the generation unit; that is, by reducing the heat rate. Reducing the heat rate translates into a reduction in u based on the relationship $u\,(\equiv e/q) = h \cdot \psi$, where ψ represents emissions per unit of energy for the fuel used by the unit in question. The annualized cost of lowering the heat rate from its BAU value h_0 to the lower value h is given by the function $\gamma(\frac{\alpha}{1+\alpha})(h^{\frac{1+\alpha}{\alpha}} - h_0^{\frac{1+\alpha}{\alpha}})$, where α and γ are parameters. The costs of lowering the heat rate must be compared with the benefits in terms of reducing per-unit fuel costs.

Introducing these specific cost components into the general expression for profit (equation (2) yields:

$$\pi^{BAU} = pq + (\bar{p} - p)\bar{q} - p_f(h/\xi)q - (\phi_0 + \phi_1 q^{\phi_2}) \tag{25}$$

and

$$\pi^{TPS} = pq + (\bar{p} - p)\bar{q} - p_f(h/\xi)q - (\phi_0 + \phi_1 q^{\phi_2}) - t(u-\beta)q - \gamma(\tfrac{\alpha}{1+\alpha})(h^{\frac{1+\alpha}{\alpha}} - h_0^{\frac{1+\alpha}{\alpha}}) \tag{26}$$

where π^{BAU} and π^{TPS} represent profit under BAU and the TPS, respectively. p is the market price (which applies at the margin).

In the case of C&T, the profit function is

$$\pi^{C\&T} = pq + (\bar{p} - p)\bar{q} - p_f(h/\xi)q - (\phi_0 + \phi_1 q^{\phi_2}) - t(uq - a_0) - \gamma(\tfrac{\alpha}{1+\alpha})(h^{\frac{1+\alpha}{\alpha}} - h_0^{\frac{1+\alpha}{\alpha}}) \tag{27}$$

where a_0 is the number of allowances allocated to the generator.

c. Optimal Output and Emissions Choices

Producers choose q and h to maximize profit. Together, the choices of q and h determine emissions. Because the associated marginal revenues and marginal benefits are interdependent, the choices of q and h must be made simultaneously. The model takes account of each unit's production capacity, and the choice of *q* is subject to the constraint that *q* must not exceed the unit's capacity. Below we focus on interior solutions to the producer problem.

Differentiating the profit functions with respect to the choice variables *q* and *h* yields:

$$\partial\pi^{TPS} / \partial q : p = p_f(h/\xi) + \phi_1\phi_2 q^{\phi_2 - 1} + t(h\psi - \beta) \tag{28}$$

$$\partial\pi^{TPS} / \partial h : -\gamma h^{\frac{1}{\alpha}} = p_f(1/\xi)q + t\psi q \tag{29}$$

$$\partial\pi^{C\&T} / \partial q : p = p_f(h/\xi) + \phi_1\phi_2 q^{\phi_2 - 1} + t(h\psi) \tag{30}$$

$$\partial\pi^{C\&T} / \partial h : -\gamma h^{\frac{1}{\alpha}} = p_f(1/\xi)q + t\psi q \tag{31}$$

Expressions (28) and (30) equate the marginal benefit from *q* (left side) with its marginal cost. Expressions (29) and (31) equate the marginal cost of lowering *h* (left side) with the implied marginal benefit in terms of compliance and fuel cost reductions. Under each of the two policies, we solve simultaneously the two relevant first-order conditions to obtain the optimal values for *q* and *h*.[42]

The first-order conditions in expressions (28) and (30) hold when the capacity constraint is not binding under the optimal *q* solved from them. Otherwise, the optimal *q* is restricted to equal the maximum output level allowed by capacity constraint.

d. Producer Heterogeneity

Our data on production costs consist of *average* total costs for each of the 11 technology classes shown in Table 1. We allow for cost heterogeneity within technology classes by assuming that the parameter ϕ_0 in the operation and maintenance cost function differs across the units within a

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[42] The numerical model obtains the solution by the following iterative procedure. It first posits a value of *q* and uses equation (29) (or (31)) to solve for the optimal *h* conditional on the posited value. It then uses equation (28) (or (30)) to obtain a value for *q* that is optimal conditional on the derived value of *h*. If the derived *q* exceeds the maximum output level allowed by capacity constraint, we restrict *q* to equal to capacity level. If the derived *q* and original posited *q* do not match, the model posits another value for *q* based on gradient descent and repeats the procedure. This iterative procedure continues until the posited and derived values of *q* match, at which point both of the applicable first-order conditions are satisfied.

class according to a beta distribution. Since ϕ_0 is a constant term in that function, it does not affect the first-order conditions for optimal q or h. However, it does affect the level of profits and thus, under any given policy scenario, it influences whether profits for a given unit are positive and whether the unit shuts down. Because the values of ϕ_0 are distributed according to the (continuous) beta distribution, the number of units that shut down is a continuous function of policy parameters and the allowance price.[43]

e. Equilibrium Conditions

We adopt the following approach to solve for the market equilibria under the TPS and C&T policies. Let V represent a vector consisting of an allowance price and a set of province-level and zonal electricity prices. For any given V, the model calculates each generator's net-revenue-maximizing quantity of output and optimal heat rate (which determines emissions intensity), conditional on remaining in operation. For some units – particularly those with emissions-output ratios above the applicable benchmark – production costs can be sufficiently high to imply negative profits. These are the units with exceptionally high values of ϕ_0 within the distribution of this parameter for the technology class in question. These units will shut down.

The production decisions of individual generators determine the aggregate demand and supply of allowances and they affect the supply and demand for electricity in both the residual local market and the six zonal markets. The model's solution algorithm continually alters both the allowance price and the electricity prices in V until three sets of equilibrium conditions are satisfied: (1) the aggregate allowance supply equals the aggregate allowance demand; (2) for each province, the supply of electricity to the local market equals the demand in that market; and (3) for each zonal market, the sum of provinces' supplies to that market equals the electricity demand in that market. The equilibrium allowance and electricity prices are closely connected, since electricity prices affect allowance supply and demand through their impact on electricity production, and the allowance price affects electricity supplies through its impact on compliance costs.[44]

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[43] Using a continuous probability distribution function to incorporate heterogeneity within broad technology classes causes the model's aggregate demand functions for allowances to be continuous. This facilitates solving the model.

[44] The solution method obtains equilibrium electricity prices for 29 province-level residual electricity markets, equilibrium electricity prices for six zonal markets, and one equilibrium price for the national allowance market. We

f. Data and Calibration

Here we summarize the data and calibration methods; details are provided in Appendix A.

1. Data

The data are for the year 2016. Table 1, referred to previously, presented the data on generators' outputs, production cost, and emissions by technology class. We assume that, for a given technology class, the average total production costs and emission intensity are the same across provinces. Output levels are the total outputs over the year. Annual output is below the level that would apply if units operated at capacity at all times.[45]

Table 2 displays baseline administered and market electricity prices, organized by province. Overall, 68.3 percent of electricity is sold at administered price, 94.3 percent of which is coal-fired electricity. For coal-fired electricity, the generation-weighted administered price of guaranteed-hour electricity sold within the province is 0.364 RMB, which is 10.2 percent higher than the local market price. For gas-fired electricity, the generation-weighted admininistered price at the local level is 0.727 RMB, 120.2 percent above the local market price.

Table 3 indicates the sources of data for several other key variables. We obtain the heat rate for each unit as the ratio of the unit's emissions-output ratio and the emissions factor.

2. Parameters

In our central case, we assume a short-term wholesale-level price elasticity of demand for electricity equal to -0.202, based on results from the meta-analysis of Labandeira *et al.* (2017). As

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solve for the 36 equilibrium prices by minimizing the differences between supply and demand in each market through gradient descent.

[45] Output below capacity reflects several factors. First, units need to go offline during parts of the year for maintenance. In 2016, the average hours due to regular maintenance and unintended outage are 582 and 674 for coal-fired and gas-fired units in China, respectively. Second, some generation units that are used to meet peak and intermediate load do not produce at capacity at every hour of the day. Third, during some parts of the year, electricity prices and fuel prices might not justify capacity-level production. Fourth, to the extent that marginal production costs increase as production levels approach capacity, current electricity prices will not always justify production at capacity. Our model is unable to address each of these factors explicitly. Instead, as described in Appendix A, we adopt a reduced-form approach that aims to capture the overall difference between actual output and capacity-level production.

detailed in Appendix B, we first obtain the demand elasticities for electricity in each of the sectors: agriculture, commerce, resident, and industry. We then obtain the overall price elasticity of demand as an electricity-consumption-weighted average of the four demand elasticities.

Remaining parameters are obtained via calibration. We sketch the approaches here; details are in Appendix B.

For each technology class in each province, we identify the parameters ϕ_1, and ϕ_2 of the cost function, along with $\phi_{0\text{mean}}$, the mean value of the cost function's constant term ϕ_0, through a calibration procedure that imposes three requirements on the average generator in each technology class. The requirements are that, in the business-as-usual simulation: (1) at the baseline level of output in 2016, net revenue equals the net revenue from the data, (2) at the baseline level of output and price in 2016, the private marginal cost of output equals the marginal benefit, and (3) at the baseline level of output and price in 2019, the private marginal cost of output equals the marginal benefit. Details on the calibration method are provided in Appendix B. A further step is to specify the distribution of the constant term ϕ_0 in the cost function of each technology class. As mentioned, we employ a beta distribution, which involves finite bounds for the parameter, and we assume the distribution is symmetric. As detailed in Appendix B, we impose two conditions to identify the parameters of this distribution.

The parameters α and γ of the heat-rate cost function are obtained as follows. For coal-fired classes including circulating fluidized bed, we derive α from Linn *et al*. (2013), and calibrate γ such that the net-revenue maximizing level of heat rate matches h_0. For gas-fired classes, both α and γ are calibrated such that (1) the net-revenue-maximizing heat rate matches h_0, and (2) the cost of lowering the heat rate to a given level equals the cost from literature. Appendix B provides details.

6. Numerical Results

We consider a range of TPS and C&T policies. Our central case TPS policy involves three benchmarks: $\beta_{GF} = .382$, $\beta_{CF} = .848$, and $\beta_{CFB} = 1.002$, where the subscripts refer to the three technology categories indicated in Table 1 – gas-fired generators, coal-fired (other than circulating fluidized bed) generators, and circulating fluidized bed generators. These benchmarks are currently being considered by the Chinese government. We also introduce alternative benchmark specifications that differ in terms of the number, variation, and stringency of the benchmarks.

For comparability with the TPS policies, we distribute the initial C&T allowances in a way that matches the initial distribution under the TPS and leads to the same aggregate emissions (total number of allowances in circulation) as under the TPS.[46]

a. Central Case Results

-- *Prices, Costs, Emissions, and Outputs*

Table 4 displays the results in our central case. With the central-case benchmarks, the TPS prompts a reduction in emissions of 133.93 million tons, or 4.9 percent. An allowance price of 415 RMB (or about 62 U.S. dollars) brings the supply of excess allowances by the $u < \beta$ generators into balance with the demand for allowances by the $u > \beta$ generators. In the allowance market, the $u > \beta$ generators purchase 59.8 million tons of allowances from the $u < \beta$ generators.

The shutdown of some units accounts for an emisions-reduction of about 73 million tons, or about 55 percent of the overall reduction. The generators that remain in operation contribute to emissions-reductions through lowered emissions intensities and (for the $u > \beta$ units) through reduced electricity production. The units that increase electricity output increase emissions by 15 million tons.

The TPS causes aggregate electricity supply to decline by about 0.70 percent although, as expected, the $u < \beta$ units increase their output. The reduction in supply by $u > \beta$ units – those that shut down and those that remain in operation – exceeds the increase by $u < \beta$ units. The reduction in aggregate output squares with the fact that, under the TPS, emissions face a tax on emissions at the margin, in the form of the allowance price. (As indicated earlier, the TPS is a combination of subsidy to output and tax on emissions.) This marginal tax raises costs of production and underlies the aggregate reduction in electricity output. The reduction in aggregate supply gives rise to an increase of 1.06 percent in the output-weighted-average price of electricity. This increase reflects

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[46] The TPS and C&T policies lead to different adjustments in output, including different choices as to whether to shut down, in response to the policy implementation. As a result, the end-of-period distribution of allowances across units differs, although by construction the total number of allowances held at the end of the compliance period (which determines total emissions) is the same.

the higher market-clearing prices of electricity sold in the local residual and zonal markets. Administered electricity prices are constant.[47]

The private cost of this central case TPS policy, measured as the negative of the change in producer and consumer surplus, is about 15.90 trillion RMB, or 118.75 RMB per ton. Sixty-five percent of this cost is borne by consumers, a reflection of the policy-induced increase in electricity prices.

Although assessing the climate-related environmental benefits from emissions reductions involves great uncertainties, it is worth considering how climate-related benefits from the TPS might compare with these estimated costs. The Interagency Working Group on the Social Cost of Carbon (2016) arrived at a central value of about \$44 (2016\$) (or 290 RMB) per ton for the social cost of carbon. Applying this value to the estimated 133.93 million ton reduction in CO_2 emissions yields a climate-related benefit of 38.84 trillion RMB, approximately 2.4 times the estimated costs.

-- *Comparison with Cap and Trade*

Although both the TPS and C&T are examples of emissions trading policies, their impacts differ in important ways. As was noted, under the C&T policy (free) allowances are allocated to all of the generators in proportion to their initial allocations under the TPS. The allocations are scaled so that the number of allowances allocated over the compliance period matches the allocations over that period under the TPS. This assures that the aggregate emissions reduction is the same (133.93 million tons) under both policies. End-of-period allocations differ from initial allocations because of changes in output and shutdowns within the compliance period.

Table 4 includes results under C&T. The responses by generators under C&T are quite different. Very few units increase electricity supply, because the allowance allocation is exogenous and there is no implicit subsidy to increased electricity output. Under C&T, the generators that remain in operation and reduce output account for 137.2 million tons of emissons reductions; this is offset by 3.2 million tons in increased emissions by the few units that increase supply. This

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[47] The administered electricity prices for each province for each type of fuel (coal and gas) are constant, but since some units shut down in TPS and C&T, the weighted average administered prices under TPS and C&T are slightly different from BAU.

contrasts with the TPS, where the generators that remain in operation and reduce output contribute just 75.4 million tons of reductions; most of the additional needed reductions are due to shutdowns.

The two pie charts in Figure 1 further illustrate the significant differences between the TPS and C&T in terms of their reliance on the different channels for emissions reductions. The charts decompose the overall reductions into those due to changes in electricity production, changes in the relative outputs among generating units, and changes in emissions intensity.[48] Holding industry composition and emissions intensity fixed, changed electricity output contributes about 26 percent of the emissions reductions, as compared with about 74 percent under C&T. Because the TPS does not exploit the output channel as efficiently as C&T does, to achieve comparable emissions reductions this policy must rely more on reduced emissions intensities. Such reductions account for about 61 percent of the reductions under the TPS, as compared with about 18 percent under C&T. Under both policies, the changes in industry composition make the smallest contribution to the overall emissions reductions.

The greater reduction in electricity output under C&T yields larger increases in electricity prices than under the TPS: the national average electricity price (output-weighted, and encompassing all local and zonal prices) rises to .399 RMB/kWh, as opposed to .381 under the TPS (Table 4). The higher electricity prices under C&T moderate the profit losses. They also account for the absence of shutdowns under C&T. Shutdowns accounted for electricity supply reductions of 72.8 billion kWh under the TPS.

Table 5 shows that under both policies, the units that shut down are in technology classes C5, C6, and C7 (within the coal-fired category) and classes C9 and C11 (within the circulating fluidized bed and natural-gas categories, respectively). These are the units with original emissions intensities above the benchmarks for their categories. As we described in subsection 5d above, there is heterogeneity within each technology class in the costs of production, and it is only the highest-cost units within each class that shut down.

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[48] The decomposition in the pie charts was accomplished as follows. The contribution from reduced electricity output is the emissions reduction that would occur from the differences between output in the policy case and the baseline, if emissions intensities and sector composition remained the same as in the baseline. The contribution from lowered emissions intensities is the reduction that would occur if the emissions intensities changed but industry production levels remained at baseline levels. The contribution from changed sector composition is the reduction that would occur if the only change from the policy were in the shares of production from the different technology classes.

The equilibrium allowance price under C&T is 76 percent lower than under the TPS, a reflection of the signfiicantly lower electricity output and allowance demand associated with any given allowance price.

These differences between the TPS and C&T prices and outputs imply differences in overall costs as well as in the distribution of those costs between producers and consumers. In this central case, the overall private cost (measured as the sum of the losses in producer and consumer surplus) is 67 percent lower under C&T than under the TPS. As indicated in the analytical model, this reflects the absence of the implicit output subsidy under C&T and the associated more efficient exploitation under C&T of reductions in electricity output as a mechanism for reducing emissions.

The distribution of the costs between producers and consumers is quite different as well. Because electricity prices rise more under C&T, consumers experience a much larger share of the burden under this policy. Indeed, they bear over 100 percent of the burden, as the change in producer surplus is positive. This result is in keeping with earlier studies that show how 100 percent free allocation of emissions allowances can create large rents or windfalls for producers.[49] The basic mechanism is that the limited supply of allowances compels producers to reduce output as one channel for achieving compliance; this boosts electricity prices and creates economic rents for competitive producers in the same way that a cartel's restriction in output would do so.

-- *Regional Impacts*

The numerical model incorporates data on the geographical locations and electricity production levels of each technology class under business as usual. Using this information, the model calculates how the policy costs experienced by each technology class are distibuted across provinces and regions. While the available data include differences in costs across technology classes, we do not have information on how, within a given technology class, the costs might differ across regions. As a result, within a given technology class the model-generated differences in

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[49] See Bovenberg and Goulder (2001), Parry (2003), Burtaw *et al.*, (2007), Fullerton and Karney (2009), Goulder, *et al.* (2010), and Stavins (2019). In the present study, 100 percent of the allowances under C&T are given out free. Previous studies indicate that freely allocating a significantly smaller share of the allowances would be sufficient to prevent a loss of profit. See, for example, Goulder *et al.* (2010). Note also that if the government were to auction off rather than freely allocate the allowances, what otherwise would be rents to producers take the form of revenues to the government. The recognition that 100 percent free allocation is not needed to preserve profits partly explains the increased reliance on auctioning under the European Union's Emissions Trading System and California's cap-and-trade program over the past decade.

profit impacts are mainly due to regional differences in impacts on electricity prices rather than regional differences in production costs.[50]

Table 6 indicates how the costs to producers under the TPS are distributed across provinces and regions of the country. One key result is that three of the seven regional provincial categories in the table – East, South, and Northwest -- experience overall *increases* in producer surplus from the TPS. This reflects the rents stemming from the free allocation of allowances under the TPS. It is the North, Northeast, Central, and Southwest provinces that experience overall losses of producer surplus, with the largest losses in percentage terms applying to Shandong Province in the North and Heilongjiang Province in the Northeast. These provinces are especially reliant on coal-fired generation, and our results indicate that (under the benchmarks we have chosen) coal-fired generators experience the largest cost increases under the TPS.

These results might come as a surprise – some might expect the TPS to impose more widespread losses of profit. We do find that the TPS reduces profits of some generating units – indeed, it causes some units to shut down – but the scope of the profit-losses is much smaller than might have been expected. The losses would be larger if the TPS allocated allowances via an auction rather than offered them free (based on the magnitudes of the benchmarks).

b. Impacts under Alternative Benchmark Scenarios

Here we explore the sensitivity of policy impacts to alternative benchmark specifications.

-- *Impacts of Spread of Benchmarks*

We first consider how the benchmark "spread" – the range between the high and low benchmarks – affects the results. Figure 2 displays the overall costs under different specifications for the spread. The one-benchmark case, where the same benchmark applies to all 11 technology classes, is the limiting case of zero spread. The single benchmark is the output-weighted average of the three benchmarks, and it is scaled so that the number of allowances allocated matches the

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[50] For units in a given technology class, the calibration procedure described in Appendix B introduces differences in cost parameters across units in different provinces, reflecting provincial differences in benchmark prices. Hence the qualifier "mainly" above.

allowance total from the 3-benchmark case. In the other benchmark cases, the same three benchmark categories apply as in the central case, but the benchmark values are different. To obtain these values, we expand or shrink the spread across the three benchmarks while preserving the total end-of-period emissions.[51] This preserves overall stringency because it does not alter the total end-of-period emissions.

Figure 2 shows that the private cost per ton increases with spread. This is in keeping with the implication of equation (8) that greater spread increases the discrepancies across generators in the marginal net value of electricity output.

As shown in Table 7, in the most cost-effective case – the one-benchmark case -- the private cost per ton is about a third lower than in the central 3-benchmark case. The 3-benchmark case offered higher (less stringent) benchmarks to the coal-fired generators, whose emissions-intensities are higher than those of the other two catergories (circulating-fluidized-bed- and natural-gas-fired generators). In the 1-benchmark case, coal-fired generators face lower benchmarks, and their profits are reduced by considerably more.

Table 8 shows the extent to which allowance trading lowers costs relative to a scenario involving the same benchmarks but no provisions for trades. The presence of trading reduces policy costs by 77 percent in the 1-benchmark case and by 62 percent in the 3-benchmark central case. Recall that in the 1-benchmark case, the benchmark was set at the output-weighted average of the benchmarks in the 3-benchmark case. For many generators, the discrepancy between their BAU emissions-output ratios and the benchmark will be considerably higher in the 1-benchmark case than in the 3-benchmark case, where the benchmarks are customized to address differences in initial intensities. As a result, the potential gains from trade are especially high and the gains from trade in percentage terms are higher than in the 3-benchmark case. Table 8's results reflect such conditions.

-- *Impacts of Stringency of Benchmarks*

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[51] More specifically, for each of the three central-case benchmarks, we calculate the difference between the central-case benchmark and the benchmark in the 1-benchmark case. Let d_j denote the difference for technology category *j*. The new category-*j* benchmark is the value in the uniform-benchmark case plus the product of d_j and a scaling factor. We employ scaling factors of smaller than one and greater than one to produce benchmarks with less and more spread. Note that applying a scaling factor of 0 recreates the 1-benchmark case; applying a scaling factor of 1 reproduces the central-case benchmarks. After applying the scaler factor, we then scale up or down all benchmarks by the same percentage so that the total end-of-period emissions match the central case.

We also consider how the overall stringency of the benchmarks alters policy costs. Here we scale up or down each of the three central-case benchmarks by a common factor. This alters stringency while maintaining the relative sizes of the benchmarks. In the central case, the sum of the initial allocations is 4.2 percent below the aggregate level of emissions under BAU. In the two alternative stringency scenarios displayed in Figure 3, the overall stringency, as measured by policy-induced emissions reductions, is 60%, and 140% percent of the overall stringency in the central case. Costs increase with the stringency of the TPS, at an increasing rate.

-- *Subcategorization of Benchmarks to Achieve Distributional Objectives*

Above we considered alternative spread of the benchmarks while maintaining the number of benchmarks at 3 (except for the uniform-benchmark case). It is also useful to explore the implications of changes in the number of benchmarks, when spread among the benchmarks is not altered. Trade-offs apply here. While a larger number of benchmarks can help meet distributional objectives, this can sacrifice cost-effectiveness.[52] As noted, in the central case the Heilongjiang and Shandong provinces experience the largest percentage losses of producer surplus. These losses reflect the heavy reliance on coal-fired generation, along with the fact that the emissions-output ratios of the coal-fired generators in these provinces were significantly above the benchmark for that generation category.

In an alternative sensitivity analysis, we introduce a TPS policy involving four benchmarks, with the extra benchmark designed to reduce the cost-burden on the provinces that otherwise would experience the largest cost-impacts in percentage terms. Here we split the coal fired generation category into two sub-categories, with technology classes 1, 2, 3 and 5 in one and classes 4, 6 and 7 in the other.[53] In this alternative benchmark scenario, we increase (i.e., loosen) by a common factor the benchmark that applies to technology classes 4, 6 and 7, and reduce (i.e., tighten) by a common factor the benchmark applicable to technology classes 1, 2, 3 and 5. These changes were determined by the following two conditions: (1) the baseline-emissions-weighted average benchmark for the coal-fired generation category is unchanged, and (2) the increase in the

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[52] Pizer and Zhang (2018) point out that subcategorization can lead to shifts in production toward "dirtier" sectors and thereby cause emissions to increase in those sectors.

[53] The division of the coal-fired generation category was based on the capacity level of classes. The capacity level is 600-1000MW for classes 1, 2, 3 and 5, and 0-300 MW for classes 4, 6 and 7.

benchmark for the class 4, 6 and 7 sub-category is just large enough to limit profit losses to all provinces to no more than 11 percent. As noted, the central case benchmark for the coal-fired generators is .848 tCO_2/mWh. Meeting the two conditions requires changing the benchmarks for technology classes 1, 2, 3, 5 and 4, 6, 7 to 0.807 and 0.898, respectively. These changes reduce the burden on the Heilongjiang and Shandong provinces, for which an especially large share of production is by class 6 and 7 generators.

The right-hand pair of columns in Table 6 displays the results in this alternative "subcategorization" case. In this case, the percentage reduction in profit in Heilongjiang is 11 percent (the maximum allowed under this scenario), as compared with 18.73 percent in the central case. The percentage reduction in profits in Shandong Province is also reduced considerably. Several provinces that would experience profit increases in the central case have lower profits under this alternative TPS policy, a consequence of the tighter benchmarks applied to technology classes 1, 2, 3 and 5. As indicated in the final row of the table, the overall loss of profit is about 65 percent greater than in the 3-benchmark case. Also, the overall economic cost (not shown in the table) is 16,485 million RMB, as compared with 15,903 million RMB in the central case (Table 4).

c. Further Sensitivity Analysis

Table 9 indicates how alternative parameter values for generators' supply or demand elasticities affect the results. Changes in these parameter values affect total emissions reductions, since the central case benchmarks are retained.

Consider first the impact of alternative values for the supply elasticity. The analytical results from Section 4 indicate that the cost-effectiveness disadvantage of the TPS relative to C&T depends on the extent to which producers respond to the TPS's implicit subsidy to output. This disadvantage is muted, the lower the value of the supply elasticity. Table 9 shows that in the limiting case of zero for this elasticity, the results under the TPS match those of C&T. The differences across policies in the high-elasticity case are greater than in the central or zero-elasticity cases. In particular, the ratio of the economic cost per ton of the TPS to that of C&T is about 2.54 in the low elasticity case, as compared with 3.29 in the high elasticity case. With a lower supply elasticity, the TPS's implicit subsidy to output is less potent and does less to counteract the tendency of the regulation-induced higher production costs to cause a reduction in output. As a result, a lower supply elasticity causes the TPS to function more and more like C&T, occasioning larger reductions in electricity output, prompting larger increases in electricity prices, and shifting more of the policy burden to consumers.

A higher absolute value for the demand elasticity reduces the overall economic cost of both the TPS and C&T. Under both policies, a higher demand elasticity facilitates achieving emissions reductions through the output-reduction channel. This underlies the fact that the overall private costs of both policies are lower when the elasticity is higher. A higher demand elasticity also affects the relative costs of the two policies. With a more elastic demand, the essential difference beetween the TPS and C&T -- the output subsidy -- gains importance. Hence the cost-effectiveness disadvantage of the TPS expands and the difference in the total private costs of the two policies increases with the elasticity of demand.

Although the alternative parameter values affect the magnitudes of impacts, the fundamental differences between the policies in terms of their relative price impacts, relative costs, and distributional impacts are robust across these scenarios.

7. Conclusions

China's forthcoming nationwide CO_2 emissions trading system, which will take the form of a tradable performance standard, has the potential to make a very substantial contribution to the world's efforts to confront global climate change. This paper assesses the cost-effectiveness and distributional consequences of alternative designs of this TPS during its power-sector phase, using matching analytically and numerically solved models. It also compares the TPS's impacts with those of cap-and-trade program with the same coverage and stringency.

A key property of the TPS – inherent in its rate-based approach – is its implicit subsidy to production. The subsidy underlies important differences in the TPS's impacts relative to C&T. First, it causes the TPS to make less efficient use of electricity output reduction as a way of reducing emissions. While C&T induces nearly all covered power-generation facilities to reduce electricity output, the TPS causes covered facilities with relatively low emissions intensities to increase both electricity output and emissions relative to their levels under business as usual. In addition, the implicit subsidy reduces the extent to which emissions allowance trading can reduce costs. This arises from the fact that under the TPS, a cost-minimizing firm will aim to equate its marginal abatement costs with the net-of-subsidy allowance price applicable to that facility. Since the net-of-subsidy price generally differs across facilities, allowance trading will not bring about equality of marginal abatement costs across facilities; hence gains from trades are compromised. This limitation to the gains from trade does not occur under C&T.

The subsidy further compromises cost-effectiveness when multiple benchmarks are employed. Multiple benchmarks add to costs by affecting the relative strength of the subsidy across different covered facilities, thereby distorting the relative contributions of different facilities to emissions abatement. The TPS's costs are about 45 percent higher in our central case's 3-benchmark system than in an equally stringent single-benchmark system.

These channels combine to produce the higher overall costs of the TPS. In our central-case numerical simulation, the costs of the TPS are more than twice those of C&T. To our knowledge, this study is the first to identify these three channels and quantify their impact.

In addition to yielding different overall cost impacts, the TPS and C&T produce quite different distributional consequences. Because producers make less use of the output-reduction channel under the TPS, aggregate output is reduced less under the TPS than under C&T and electricity prices rise by a smaller amount. Hence electricity producers shift less of their compliance costs to consumers, and the share of the overall economic burden borne by consumers is smaller under the TPS than under C&T.

To address distributional concerns, China's TPS will apply different benchmarks to different power plants. The especially emissions-intensive coal-fired power plants will receive higher (less stringent) benchmarks in order to avoid what would be exceptionally high compliance costs if they faced the same benchmarks as other generators. The planners have been giving serious consideration to a 3-benchmark system. We find that although this system would reduce the TPS's regional cost-disparities significantly relative to a 1-benchmark system, quite significant disparities would remain, reflecting regional differences in the composition of generation technologies. We find that provinces in the northern and northeastern regions of the country would face the largest percentage reductions in profits. An alternative, 4-benchmark system that "customizes" the benchmarks successfully avoids exceptional cost-impacts in some areas. However, achieving this distributional objective lowers profits in other regions of the country and involves higher aggregate policy costs. Under central case parameter values, the increase in aggregate cost is 3.7 percent.

On cost-effectiveness grounds, economists have reason to applaud China's decision to reduce CO_2 through an emissions pricing instrument as well as its plan to move from a group of provincial or municipal pilot programs to an integrated nationwide program. The TPS may not be as cost-effective as C&T, but its reliance on emissions pricing and its wide geographical scope can help achieve emissions reductions on a broad scale at relatively low cost. Also, the TPS has certain attractions relative to C&T. Its rate-based structure implies that policy stringency adjusts automatically in response to changes in macroeconomic conditions. And the fact that it brings about smaller increases in electricity prices implies that it would cause less emissions leakage. The smaller price increases could also be an attraction in terms of fairness and political feasibility. Another potential attraction – at least to some interested parties -- is the fact that Chinese planners are more familiar with intensity-based regulation.

It is important to note that despite its higher costs than those of an equally stringent C&T system, the TPS can generate significant net gains once environmental benefits are counted. Our central case results indicate that the TPS's benefits in terms of avoided climate damages are about 2.4 times the policy costs when CO_2 emissions reductions are valued at 290 RMB (or 44 U.S. dollars) per ton. In addition to reducing CO_2 emisions, the TPS will also reduce several air pollutants whose emissions are correlated with CO_2 emissions. Accounting for the reductions in air pollution and associated health benefits would raise the benefit-cost ratio considerably.

Some caveats area in order. First, although we have been fortunate to gain access to important data through our contacts in China, we still faced some limitations in available data, and we have needed to calibrate or borrow others' estimates of important parameters rather than estimate them econometrically. Yet the robustness of our results leads us to believe that the key insights from this study would not change significantly with better data. Second, ours is a one-period model. Hence it does not capture investment decisions and associated changes to capital stocks, though it accounts for shutdowns. We would expect that in a multi-period model, the results would show a similar pattern but be amplified. Specifically, we would expect that the use of multiple benchmarks would imply larger sacrifices of cost-effectiveness, as multiple benchmarks would not only distort relative output decisions across units (as captured in the current model) but also distort the relative levels of investment across units. We would also expect that the differences between the costs of the TPS and C&T would be widened in a model with investment decisions, as the implicit output subsidy of the TPS would cause investment decisions to be less efficient than those under C&T.

At the time of this writing, the Chinese planners are continuing to make important decisions regarding the design of the TPS. We believe this study's findings can significantly help Chinese planners arrive at designs that achieve distributional goals with the least additional aggregate cost. This study brings out hitherto unrecognized channels of impact of the TPS, and offers unique quantitative estimates of the wide-ranging impacts of China's planned TPS system along with relevant comparisons with C&T.

The findings should be of value to the broader policy community as well. They reveal the key channels that cause the impacts of a TPS to differ from those of C&T, in terms of both cost-effectiveness and distribution. These results also should be useful to the many regional and national jurisdictions that making important choices as to whether to employ rate-based, mass-based, or other ways to achieve reductions in emissions of CO_2 and other pollutants.

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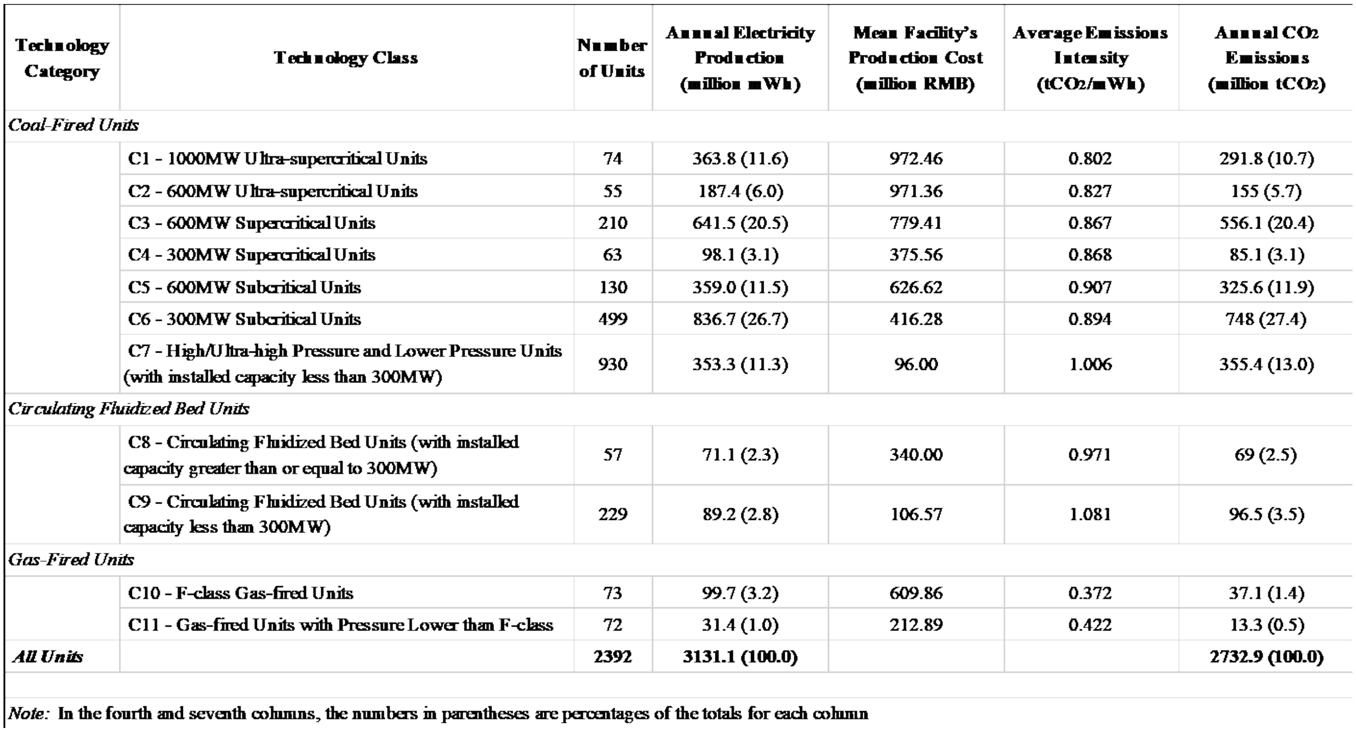
Table 1: Production Levels, Production Costs, Emissions Intensities and Emissions



Technology Category	Technology Class	Number of Units	Annual Electricity Production (million mWh)	Mean Facility's Production Cost (million RMB)	Average Emissions Intensity (tCO2/mWh)	Annual CO2 Emissions (million tCO2)
Coal-Fired Units						
	C1 - 1000MW Ultra-supercritical Units	74	363.8 (11.6)	972.46	0.802	291.8 (10.7)
	C2 - 600MW Ultra-supercritical Units	55	187.4 (6.0)	971.36	0.827	155 (5.7)
	C3 - 600MW Supercritical Units	210	641.5 (20.5)	779.41	0.867	556.1 (20.4)
	C4 - 300MW Supercritical Units	63	98.1 (3.1)	375.56	0.868	85.1 (3.1)
	C5 - 600MW Subcritical Units	130	359.0 (11.5)	626.62	0.907	325.6 (11.9)
	C6 - 300MW Subcritical Units	499	836.7 (26.7)	416.28	0.894	748 (27.4)
	C7 - High/Ultra-high Pressure and Lower Pressure Units (with installed capacity less than 300MW)	930	353.3 (11.3)	96.00	1.006	355.4 (13.0)
Circulating Fluidized Bed Units						
	C8 - Circulating Fluidized Bed Units (with installed capacity greater than or equal to 300MW)	57	71.1 (2.3)	340.00	0.971	69 (2.5)
	C9 - Circulating Fluidized Bed Units (with installed capacity less than 300MW)	229	89.2 (2.8)	106.57	1.081	96.5 (3.5)
Gas-Fired Units						
	C10 - F-class Gas-fired Units	73	99.7 (3.2)	609.86	0.372	37.1 (1.4)
	C11 - Gas-fired Units with Pressure Lower than F-class	72	31.4 (1.0)	212.89	0.422	13.3 (0.5)
All Units		**2392**	**3131.1 (100.0)**			**2732.9 (100.0)**

Note: In the fourth and seventh columns, the numbers in parentheses are percentages of the totals for each column

Table 2: Baseline Production and Prices by Province, 2016

Province	Number of Units	Administered-Price Production								Market-Priced Production				Total Production
		Coal-fired				Gas-fired				Coal-fired & Gas-fired				
		Provincial Administered Production	Provincial Administered Price	Zonal Administered Production	Zonal Administered Price	Provincial Administered Production	Provincial Administered Price	Zonal Administered Production	Zonal Administered Price	Provincial Marketed Production	Provincial Market Price	Zonal Marketed Production	Zonal Market Price	
Anhui	62	85.5	0.369	21.2	0.431	-	-	-	-	30.8	0.335	8.3	0.387	145.9
Beijing	16	1.1	0.352	0.3	0.395	9.2	0.732	2.3	0.709	1.0	0.324	0.3	0.350	14.1
Chongqing	24	25.9	0.380	6.4	0.445	1.0	0.644	0.3	0.759	10.0	0.369	2.7	0.400	46.3
Fujian	59	65.3	0.374	16.2	0.431	3.1	0.586	0.8	0.745	23.8	0.339	6.4	0.387	115.6
Gansu	44	20.1	0.298	5.0	0.391	-	-	-	-	30.7	0.304	8.3	0.346	64.1
Guangdong	214	128.1	0.451	31.8	0.414	28.7	0.657	7.1	0.728	85.4	0.326	23.0	0.369	304.1
Guangxi	24	1.4	0.414	0.4	0.414	0.7	0.695	0.2	0.728	33.4	0.364	9.0	0.369	45.0
Guizhou	46	51.7	0.336	12.8	0.414	-	-	-	-	22.9	0.335	6.2	0.369	93.5
Hainan	14	9.4	0.420	2.3	0.414	1.3	0.641	0.3	0.728	3.5	0.328	0.9	0.369	17.8
Hebei	134	91.6	0.357	22.7	0.395	0.3	0.695	0.1	0.709	33.1	0.345	8.9	0.350	156.7
Heilongjiang	77	28.2	0.372	7.0	0.414	-	-	-	-	10.2	0.363	2.7	0.369	48.1
Henan	120	89.4	0.355	22.2	0.445	2.1	0.628	0.5	0.759	46.4	0.345	12.5	0.400	173.0
Hubei	28	28.4	0.398	7.1	0.445	0.7	0.739	0.2	0.759	10.3	0.381	2.8	0.400	49.4
Inner Mongolia	191	126.7	0.290	31.4	0.414	-	-	-	-	72.3	0.266	19.4	0.369	249.9

Note: **Units for production data are millions of mWh. Units for price data are RMB/kWh**

Table 2: Baseline Production and Prices by Province, 2016, *continued*

Province	**Number of Units**	**Administered-Price Production**								**Market-Priced Production**				**Total Production**
		Coal-fired				**Gas-fired**				**Coal-fired & Gas-fired**				
		Provincial Administered Production	Provincial Administered Price	Zonal Administered Production	Zonal Administered Price	Provincial Administered Production	Provincial Administered Price	Zonal Administered Production	Zonal Administered Price	Provincial Marketed Production	Provincial Market Price	Zonal Marketed Production	Zonal Market Price	
Jiangsu	243	132.2	0.378	32.8	0.431	8.7	0.642	2.2	0.745	86.4	0.344	23.2	0.387	285.4
Jiangxi	28	33.2	0.399	8.2	0.445	-	-	-	-	12.0	0.395	3.2	0.400	56.7
Jilin	44	33.6	0.372	8.3	0.414	-	-	-	-	12.1	0.348	3.3	0.369	57.4
Liaoning	78	49.3	0.369	12.2	0.414	-	-	-	-	26.0	0.340	7.0	0.369	94.5
Ningxia	38	39.7	0.260	9.8	0.391	-	-	-	-	14.3	0.265	3.8	0.346	67.7
Qinghai	4	2.0	0.325	0.5	0.391	-	-	-	-	1.3	0.331	0.3	0.346	4.1
Shaanxi	75	48.8	0.335	12.1	0.391	1.3	0.695	0.3	0.705	24.7	0.341	6.6	0.346	93.9
Shandong	312	146.6	0.373	36.4	0.395	-	-	-	-	52.9	0.345	14.2	0.350	250.1
Shanghai	42	42.1	0.405	10.4	0.431	10.5	0.809	2.6	0.745	15.9	0.370	4.3	0.387	85.9
Shanxi	111	74.2	0.321	18.4	0.395	2.4	0.675	0.6	0.709	26.9	0.273	7.2	0.350	129.8
Sichuan	39	32.0	0.401	7.9	0.445	-	-	-	-	11.5	0.391	3.1	0.400	54.6
Tianjin	26	21.4	0.351	5.3	0.395	1.7	0.719	0.4	0.709	7.8	0.324	2.1	0.350	38.7
Xinjiang	72	45.4	0.262	11.2	0.391	0.7	0.695	0.2	0.705	16.4	0.268	4.4	0.346	78.2
Yunnan	33	31.2	0.336	7.7	0.414	-	-	-	-	11.3	0.181	3.0	0.369	53.2
Zhejiang	194	130.5	0.415	32.4	0.431	26.2	0.838	6.5	0.745	48.8	0.381	13.1	0.387	257.5
Total	**2392**	**1615.4**	**0.364**	**400.6**	**0.417**	**98.4**	**0.727**	**24.4**	**0.734**	**782.1**	**0.330**	**210.2**	**0.372**	**3131.1**

Note: Units for production data are millions of mWh. Units for price data are RMB/kWh

Table 3: Data sources

Variable	Source
Electricity output	Endcoal.org (accessed July 2020) Carbonbrief.org (accessed July 2020) China Electric Power Yearbook (2017)
Capacity	
Emissions-output ratio	
Production costs	Liu & Zhang (2018); Liu *et al.* (2016); Zhang (2013); Chen & Chen (2012); Zhang (2011); Zhu (1987)
Electricity prices	National Development and Reform Commission (2015) National Energy Administration (2018) Electric Power Development Research Institute (2018)
Fuel prices	China Coal Market (2016) National Development and Reform Commission (2015)
Emissions factors	Jiang *et al.* (2013) Intergovernmental Panel on Climate Change (2006)
Price elasticity of demand for electricity	Labandeira *et al.* (2017)

Table 4: Impacts of Tradable Performance Standard and Cap & Trade – The Central Case

	Baseline	**TPS**	**C&T**
Benchmarks (tCO_2/mWh)			
– Coal-fired (technology classes 1-7)		0.848	Allowance Allocations Matching TPS Allocations
– CFB (technology classes 8 and 9)		1.002	
– Gas-fired (technology classes 10 and 11)		0.382	
Emissions (million tCO_2)	2,732.88	2,598.95	2,598.95
– change from baseline		-133.93	-133.93
– change from units that shut down		-73.25	0.00
– change from units that remain and increase supply		14.73	3.24
– change from units that remain and reduce supply		-75.40	-137.17
– percentage change from baseline		-4.90	-4.90
Allowance Price (RMB)		414.84	101.11
Allowances Traded (million tCO_2)		59.80	46.87
Aggregate Electricity Supply (million kWh)	3,131,149	3,109,350	3,020,932
– change from baseline		-21,799	-110,216
– change from units that shut down		-72,832	0
– change from units that remain and increase supply		104,873	9,182
– change from units that remain and reduce supply		-53,839	-119,398
– percentage change from baseline		-0.70	-3.52
Electricity Price (RMB/kWh)			
Average Electricity Price	0.377	0.381	0.399
-- marketed electricity in intraprovincial market	0.331	0.341	0.400
-- administered electricity in intraprovincial market	0.385	0.386	0.385
-- marketed electricity in interprovincial market	0.372	0.384	0.440
-- administered electricity in interprovincial market	0.435	0.436	0.435
Private Cost (million RMB)		15,903	5,288
– change in Consumer Surplus		-10,351	-63,814
– change in Producer Surplus		-5,551	58,526
Private Cost per Ton of Reduced Emissions (RMB/tCO_2)		118.75	39.48
Environmental Benefit (million RMB)		38,840	38,840

Table 5: Impacts on Generators’ Market Status – The Central Case

Technology Category	**Technology Class**	**TPS**				**C&T**			
		Initially in Compliance?	**Policy Response** *(percentage of generators in each category)*			**Initially in Compliance?**	**Policy Response** *(percentage of generators in each category)*		
			Shut Down	*Operate and Purchase Allowances*	*Operate and Sell Allowances*		*Shut Down*	*Operate and Purchase Allowances*	*Operate and Sell Allowances*
Coal-Fired Units									
	C1	**Y**	**0**	**0**	**100**	**Y**	**0**	**0**	**100**
	C2	**Y**	**0**	**0**	**100**	**Y**	**0**	**0**	**100**
	C3	**N**	**0**	**0**	**100**	**N**	**0**	**0**	**100**
	C4	**N**	**0**	**0**	**100**	**N**	**0**	**0**	**100**
	C5	**N**	**0.64**	**99.36**	**0**	**N**	**0**	**100**	**0**
	C6	**N**	**0.21**	**99.79**	**0**	**N**	**0**	**85.37**	**14.63**
	C7	**N**	**17.53**	**82.47**	**0**	**N**	**0**	**100**	**0**
Circulating Fluidized Bed (CFB) Units									
	C8	**Y**	**0**	**0**	**100**	**Y**	**0**	**0**	**100**
	C9	**N**	**7.47**	**92.53**	**0**	**N**	**0**	**8.3**	**91.7**
Gas-Fired Units									
	C10	**Y**	**0**	**0**	**100**	**N**	**0**	**100**	**0**
	C11	**N**	**0.54**	**99.46**	**0**	**N**	**0**	**100**	**0**

Table 6: TPS Cost Impacts by Region and Province

Region/Province	3-Benchmarks (Central) Case		4-Benchmarks (Subcategorization) Case	
	Change in Profit (million RMB)	*Change as Pct of Baseline Profit*	*Change in Profit (million RMB)*	*Change as Pct of Baseline Profit*
East	**1,938**	**1.47**	**-2,501**	**-1.90**
Anhui	867	4.82	-436	-2.43
Shanghai	589	3.49	346	2.05
Jiangsu	122	0.32	-906	-2.40
Jiangxi	402	5.2	-126	-1.64
Zhejiang	-43	-0.08	-1,378	-2.68
North	**-5,693**	**-7.05**	**-4,122**	**-5.10**
Beijing	-10	-0.32	6	0.19
Tianjin	110	2.23	-44	-0.89
Shanxi	-566	-5.68	-389	-3.90
Shandong	-3,331	-10.93	-2,116	-6.94
Hebei	-1,141	-6.57	-259	-1.49
Inner Mongolia	-753	-5.11	-1,319	-8.95
Northwest	**313**	**1.55**	**875**	**4.33**
Shaanxi	-395	-4.26	-986	-10.64
Gansu	199	4.93	782	19.40
Ningxia	239	7.78	360	11.69
Qinghai	-34	-9.6	44	12.35
Xinjiang	304	8.84	674	19.57
Northeast	**-1,377**	**-5.88**	**-473**	**-2.02**
Heilongjiang	-1,153	-18.73	-678	-11.00
Jilin	-175	-2.52	203	2.92
Liaoning	-47	-0.46	1	0.01
Central	**-161**	**-0.56**	**-58**	**-0.20**
Hubei	-10	-0.14	105	1.37
Henan	-150	-0.72	-163	-0.78
South	**679**	**0.93**	**-899**	**-1.24**
Guangdong	401	0.79	-538	-1.06
Guangxi	-29	-0.57	-172	-3.33
Fujian	389	2.75	-458	-3.24
Hainan	-81	-3.01	269	9.96
Southwest	**-1,250**	**-4.29**	**-1,987**	**-6.82**
Chongqing	76	1.1	-59	-0.85
Sichuan	-536	-6.17	-637	-7.32
Guizhou	-556	-5.8	-1,003	-10.47
Yunnan	-234	-6.15	-286	-7.51
Total	**-5,551**	**-1.44**	**-9,167**	**-2.37**

Table 7: Impacts of Tradable Performance Standard – One Benchmark Case

	Baseline	TPS
Benchmarks (tCO_2/mWh)		
– Coal-fired (technology classes 1-7)		0.836
– CFB (technology classes 8 and 9)		
– Gas-fired (technology classes 10 and 11)		
Emissions (million tCO_2)	2,732.88	2,598.95
– change from baseline		-133.93
– change from units that shut down		-89.26
– change from units that remain and increase supply		24.63
– change from units that remain and reduce supply		-69.30
– percentage change from baseline		-4.90
Allowance Price (RMB)		266.62
Allowances Traded (million tCO_2)		113.24
Aggregate Electricity Supply (million kWh)	3,131,149	3,108,778
– change from baseline		-22,370
– change from units that shut down		-86,898
– change from units that remain and increase supply		114,711
– change from units that remain and reduce supply		-50,182
– percentage change from baseline		-0.71
Electricity Price (RMB/kWh)		
Average Electricity Price	0.377	0.381
– marketed electricity in intraprovincial market	0.331	0.341
– administered electricity in intraprovincial market	0.385	0.387
– marketed electricity in interprovincial market	0.372	0.383
– administered electricity in interprovincial market	0.435	0.436
Private Cost (million RMB)		10,968
– change in Consumer Surplus		-10,586
– change in Producer Surplus		-381
Private Cost per Ton of Reduced Emissions (RMB/tCO_2)		81.88
Environmental Benefit (million RMB)		38,840

Table 8: TPS Impacts with and without Allowance Trading

	3-Benchmarks Case		1-Benchmark Case	
	With Trading	Without Trading	With Trading	Without Trading
Percent Reduction in Emissions	-4.90	-7.20	-4.90	-10.38
Percent Increase in Average Electricity Price	1.06	3.77	1.09	6.34
Private Cost (million RMB)	15,903	61,422	10,968	99,431
-- change in Consumer Surplus	-10,351	-41,515	-10,586	-70,901
-- change in Producer Surplus	-5,551	-19,906	-381	-28,529
Private Cost per Ton of Reduced Emissions (RMB/tCO_2)	118.75	312.17	81.88	350.66
Gains from Trade				
-- value (million RMB)	193.42		268.78	
-- percent of no-trade private cost	61.96		76.65	

Table 9: Impacts under Alternative Supply and Demand Elasticities

	Supply Elasticity				Demand Elasticity		
	0	0.6134	1.2268 (central case)	1.8402	-0.101	-0.2020 (central case)	-0.303
TPS							
Percent Reduction in Emissions	-6.26	-5.08	-4.9	-4.78	-4.59	-4.9	-5.17
-- share from reduced emissions intensities (%)	58.31	64.25	61.29	58.79	65.34	61.29	58.21
-- share from compositional changes (%)	5.07	10.10	12.92	14.90	13.42	12.92	12.54
-- share from changed output (%)	36.62	25.65	25.79	26.31	21.25	25.79	29.25
Percent Increase in Average Electricity Price	3.40	1.38	1.06	0.90	1.11	1.06	1.03
Private Cost (million RMB)	18,760	16,751	15,903	15,263	15,927	15,903	15,882
-- change in Consumer Surplus	-36,098	-13,699	-10,351	-8,479	-11,412	-10,351	-9,409
-- change in Producer Surplus	17,337	-3,051	-5,551	-6,784	-4,514	-5,551	-6,472
Private Cost per Ton of Reduced Emissions (RMB/tCO_2)	109.64	120.6	118.75	116.77	127.08	118.75	112.47
C&T							
Percent Reduction in Emissions	-6.26	-5.08	-4.9	-4.78	-4.59	-4.9	-5.17
-- share from reduced emissions intensities (%)	58.31	20.01	17.94	16.92	27.79	17.94	14.22
-- share from compositional changes (%)	5.07	5.36	8.34	10.90	13.50	8.34	5.98
-- share from changed output (%)	36.62	74.63	73.71	72.18	58.71	73.71	79.80
Percent Increase in Average Electricity Price	3.40	6.05	5.84	5.68	9.79	5.84	4.19
Private Cost (million RMB)	18,760	6,598	5,288	4,640	7,003	5,288	4,717
-- change in Consumer Surplus	-36,098	-66,357	-63,814	-62,286	-111,714	-63,814	-44,052
-- change in Producer Surplus	17,337	59,759	58,526	57,646	104,711	58,526	39,334
Private Cost per Ton of Reduced Emissions (RMB/tCO_2)	109.64	47.47	39.48	35.48	55.92	39.48	33.42

Note: Supply elasticity is implied by parameters associated with cost function. It is the baseline weighted average supply elasticity over all units. The 0.6134 and 1.8402 supply elasticities are 50% lower and higher than the central case respectively. The -0.1010 and -0.3030 demand elasticity are the 50% lower and higher in absolute value than the central case respectively.

Figure 1: Sources of Emissions Reductions under the TPS and C&T

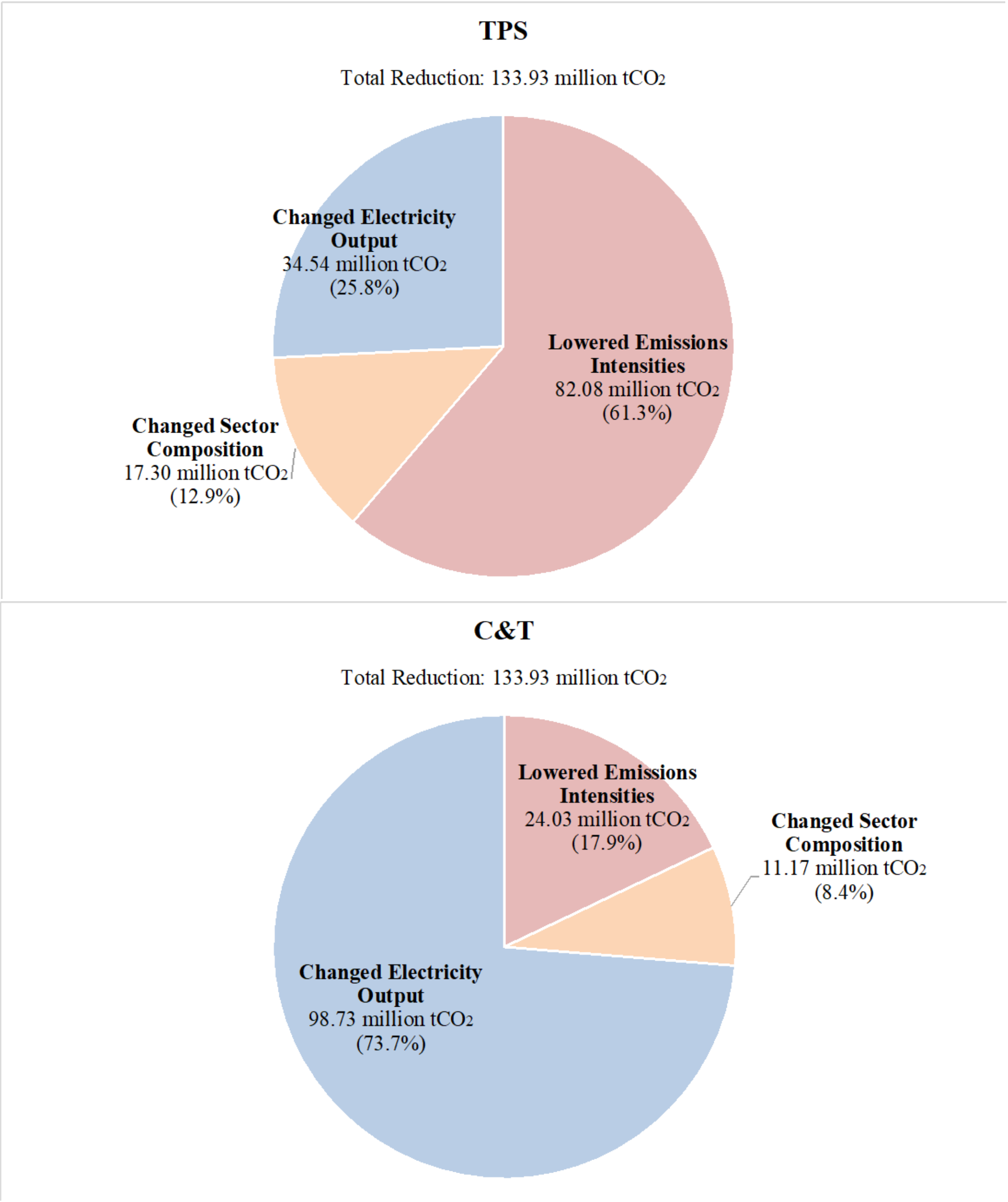


Figure 2: Benchmark Variation and Cost per Ton Reduction in Emissions under TPS

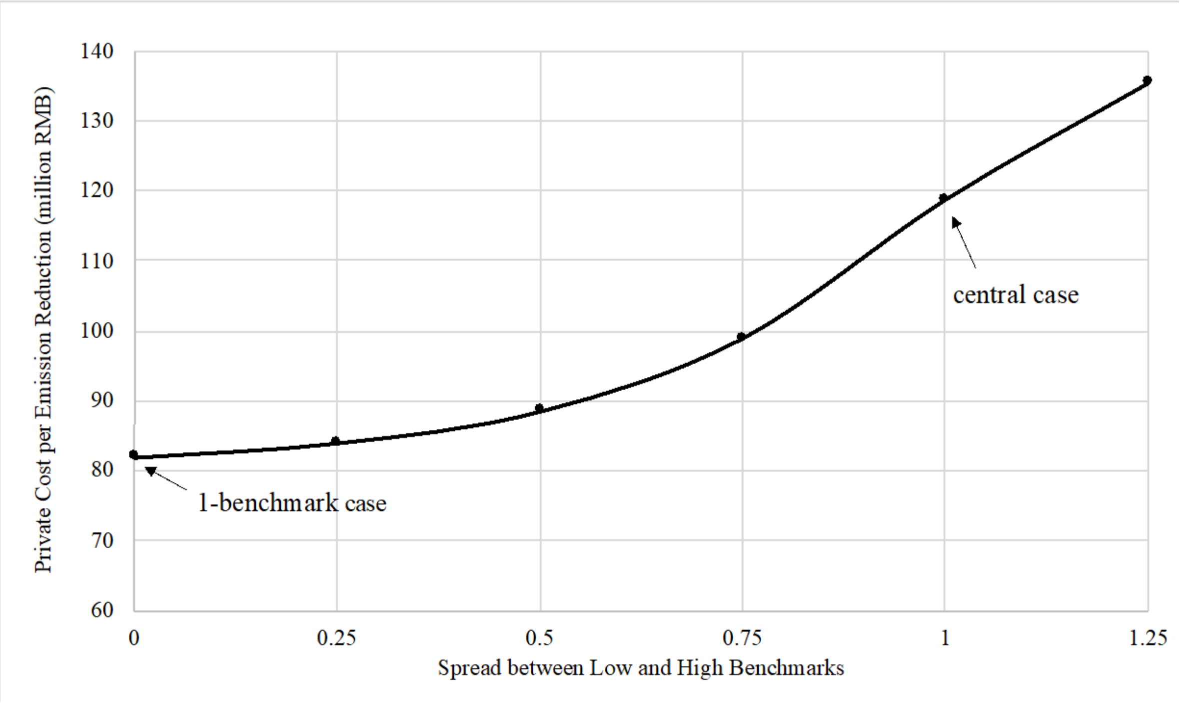
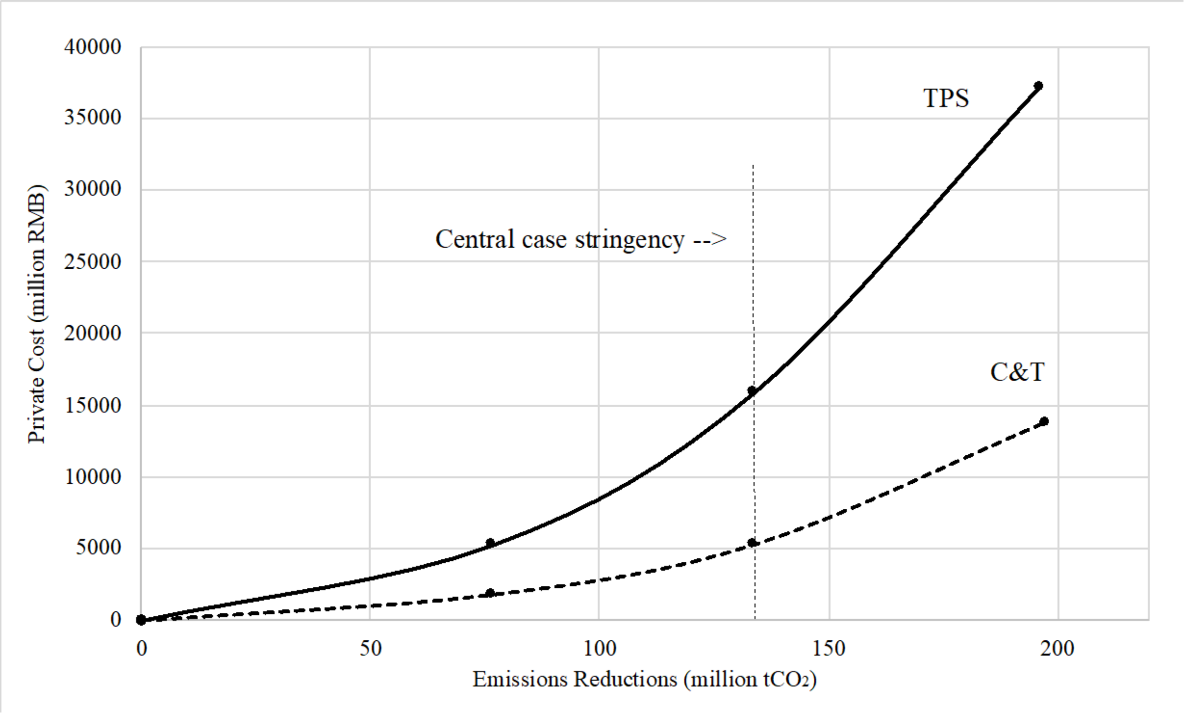


Figure 3: TPS and C&T Costs under Varying Policy Stringencies



Appendix A: Data on Electricity Prices, Production Levels, and Fuel Prices

1. Electricity Prices

Electricity produced in a given province divides into the following four categories:

- electricity sold in the province at administered prices
- electricity sold in the local (provincial) market
- electricity sold in the zonal market
- electricity sold outside the province at administered prices

For each province, we define the electricity prices p_1, p_2, p_3, and p_4 as the prices associated with the above four categories of electricity sold, respectively.

The administered prices p_1 for electricity sold in each of 29 provinces were obtained from China's National Development and Reform Commission and National Energy Administration. The coal electricity prices are inclusive of subsidies for desulfurization, denitrification, and soot removal.

Data on local and zonal market prices of electricity (p_2 and p_3) were collected from China's Electric Power Development Research Institute. For some provinces, these data were not available. In the cases where p_2 was not available,[54] we assumed that the difference between p_1 and p_2 in a missing province equals wt_diff_{12}, the output-weighted average difference between p_1 and p_2 in provinces with available p_2 within the same region. Thus, for the missing provinces we assigned to p_2 the value $p_1 + wt\_diff_{12}$. In the cases where p_3 was not available,[55] analogously to the procedure with p_2 we assumed the difference between p_2 and p_3 in these provinces equals wt_diff_{23}, the output-weighted average difference between p_3 and p_2 in other provinces within the same region. Thus, for the missing provinces, $p_3 = p_2 + wt\_diff_{23}$.

Data on p_4, the administered prices of electricity sold outside provinces, were not available. To construct these data, we assume that, for each province, the difference between the out-of-province administered price p_4 and the zonal market price p_3 is the same as the output-weighted average difference between the province-level prices p_2 and p_1 of provinces in the same region.

2. Electricity Production

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[54] Data on p_2 were unavailable for the following provinces: Beijing, Tianjin, Shanghai, Gansu, Qinghai, Ningxia, Xinjiang, Sichuan, Hainan and Yunnan.

[55] Data on p_3 were unavailable for the following provinces: Beijing, Tianjin, Shanxi, Shandong, Shanghai, Fujian, Hubei, Hunan, Jiangxi, Jilin, Heilongjiang, Inner Mongolia, Qinghai, Ningxia, Xinjiang, Sichuan, and Guizhou.

Data on electricity production were collected from China Electricity Council and National Energy Administration. Table A1 summarizes the two sets of data collected: (1) total electricity production by province in 2016 and the national electricity production by category in 2016; and (2) the ratios between administered and market prices of electricity at provincial and national levels in 2018.

Table A1: Available Data on Electricity Production

	Provincial	National
2016	$X_{TOT,P}^{2016}$	$X_{1,N}^{2016}$, $X_{2,N}^{2016}$, $X_{3,N}^{2016}$, $X_{4,N}^{2016}$, $X_{TOT,N}^{2016}$
2018	m_P^{2018}	m_N^{2018}

Notation:

The subscripts *P* and *N* indicate provincial and national levels, respectively.

X_1: quantity of electricity sold at the administered price within the province;
X_2: quantity of electricity sold in the provincial (local) market;
X_3: quantity of electricity sold in the zonal market;
X_4: quantity of electricity sold outside the province at the outside-of-province administered price;
X_{TOT} : total electricity sold;

m: ratio between administered electricity and marketed electricity, i.e., $m=(X_1 + X_4) / (X_2 + X_3)$.

For each of the 29 provinces, we obtained electricity production by technology category as follows. Using the national data for 2016, we computed

$$m_N^{2016} = (X_{1,N}^{2016} + X_{4,N}^{2016}) / \left(X_{2,N}^{2016} + X_{3,N}^{2016} \right)$$

This is the ratio of all administered electricity to all marketed electricity at the national level. From this we calculated the ratio of the 2018 value to the 2016 value for *m*:

$$ratiom = m_N^{2018} \,/\, m_N^{2016}$$

To obtain 2016 numbers at the provincial level, we assumed that the national-level percentage change in *m* from 2016 to 2018 applies in all provinces:

$$m_P^{2016} = m_P^{2018} \,/\, ratiom$$

This implies:

$$X_{1,P}^{2016} + X_{4,P}^{2016} = \frac{m_P^{2016}}{m_P^{2016} + 1} X_{TOT,P}^{2016}$$

$$X_{2,P}^{2016} + X_{3,P}^{2016} = \frac{1}{m_P^{2016} + 1} X_{TOT,P}^{2016}$$

Using the national-level data, we calculate, for the year 2016, the ratio of production between categories 1 and 4 and the ratio of production between categories 2 and 3:

$$r_{14} = X_{1,N}^{2016} / X_{4,N}^{2016}$$

$$r_{23} = X_{2,N}^{2016} / X_{3,N}^{2016}$$

We assume that these national-level ratios across the categories apply at the provincial level. This enables us to obtain the provincial-level production levels in each of the four categories:

$$X_{1,P}^{2016} = \frac{r_{14}}{r_{14} + 1}\left(X_{1,P}^{2016} + X_{4,P}^{2016}\right)$$

$$X_{4,P}^{2016} = \frac{1}{r_{14} + 1}\left(X_{1,P}^{2016} + X_{4,P}^{2016}\right)$$

$$X_{2,P}^{2016} = \frac{r_{23}}{r_{23} + 1}\left(X_{2,P}^{2016} + X_{3,P}^{2016}\right)$$

$$X_{3,P}^{2016} = \frac{1}{r_{23} + 1}\left(X_{2,P}^{2016} + X_{3,P}^{2016}\right)$$

3. Fuel Prices

We assume that the various electricity generation units in a province face the same prices for a given fuel (coal or natural gas). Data on fuel prices at fuel supply province and transportation between provinces where coal or gas fields locate and supply destinations were obtained from the China Coal Market, China Railway Yearbook (2017), China Bond Rating Co., Ltd. (2017), and Gan *et al*. (2020).

Appendix B: Demand and Supply Parameters

1. Short-term wholesale-level price elasticity of demand for electricity

The short-term wholesale-level price elasticity of demand for electricity was obtained based on results from the meta-analysis of Labandeira *et al.* (2017). That study's elasticity estimates were based on the following model

$$b_j = \alpha_0 + \sum_{k=1}^{K} \alpha_k Z_{jk} + \varepsilon_j \, (j = 1, 2, \ldots L)$$

where b_j is the estimated price elasticity of demand for electricity in the j^{th} study; $\boldsymbol{\alpha_0}$ is the constant term; Z_{jk} are the K categorical variables pertaining to characteristics of the j^{th} study; the α_k's are estimated coefficients; and $\boldsymbol{\varepsilon_j}$ is the error term.

To obtain the price elasticity of demand for China, we employed the above equation with the Labandeira study's estimated values for α_0 and the α_k's, while plugging in values for the categorical variables that applied to China or the type of study involved. The categorical values included dummy variables for whether the country is a net energy exporter (China is not) and whether it is a developing country (China is). They also included values that designated the following attributes of the study involved: the sample period (whether it was post-2008), the type of data (cross-section, time-series, or combination), the type of model (cointegration, AIDS, discrete-continuous, micro, or other), and type of journal (peer-reviewed or not).

In the Labandeira study, one of the Z_k 's pertains to the sector demanding the electricity. This categorical variable can take on four different values, depending on whether the study involved consumption from the residential, industrial, commercial, or agricultural sectors. To identify the price elasticity of demand associated with each of the four sectors, we applied the above equation four times, each time using dummy variables to indicate the sector to which the study in question applied. This produced four derived values $\hat{b}$ for the price elasticity. These four derived values yielded an electricity-consumption-weighted average price elasticity of demand of -0.202. This is the price elasticity we employ in our central case.

1. Cost function parameters and price elasticity of supply

a. Parameters for Heat Rate Cost Function

The heat rate cost function is:

$$C_h = \gamma(\frac{\alpha}{1+\alpha})h^{\frac{1+\alpha}{\alpha}}$$

For coal-fired classes including circulating fluidized bed, we derive the value for α from Linn *et al*. (2013). That study regressed the heat rate on the fuel price to obtain the value for α. They did the regression with multiple specifications (e.g., with or without fixed effects, observations unweighted or weighted by generation, including only 20 largest firms or all firms, observations in a single-year time period or five-years period). Their paper presents multiple estimates of α, one for each specification. We chose the estimate of –0.023 for α, which is from the specification with unit fixed effects, observations weighted by generation, and all firms included in five-year period. Then we calibrated γ such that for every generator, the net-revenue maximizing level of heat rate matches h_0, the value for the heat rate in the benchmark data.

For gas-fired generator classes, α and γ were obtained via calibration. We imposed two requirements in the calibration procedure: (1) the net-revenue maximizing level of heat rate matches h_0, and (2) the annualized cost of lowering the heat rate is consistent with prior literature.[56]

b. Parameters for Operating and Maintenance Cost; Price Elasticity of Supply

For each of the 11 technology classes, we specify the following functional form for the operating and maintenance cost function:

$$C_{O\&M} = \phi_0 + \phi_1 q^{\phi_2}$$

where ϕ_0, ϕ_1, and ϕ_2 are parameters. To identify ϕ_0, ϕ_1, ϕ_2 for each generator technology, we impose the following three restrictions at the baseline level of output:

(1) the operating cost function yields the observed total cost minus the observed fuel cost:

$$\phi_0 + \phi_1 q_{BAU}{}^{\phi_2} = C_{BAU} - p_f(h_{BAU} / \xi)q_{BAU}.$$

(2) marginal private cost of output equals the marginal private benefit in 2016:

$$p_{BAU2016} = p_f(h_{BAU} / \xi) + \phi_1\phi_2 q_{BAU2016}{}^{\phi_2 - 1}.$$

(3) marginal private cost of output equals the marginal private benefit in 2019:

$$p_{BAU2019} = p_f(h_{BAU} / \xi) + \phi_1\phi_2 q_{BAU2019}{}^{\phi_2 - 1}$$

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[56] For C10, we employed results from Li *et al*. (2019), in which the estimated the annualized cost of lowering heat rate by 103 kJ/kWh is 6.29 million RMB. For C11, we employed results from Luo *et al*. (2017), in which the estimated aanualized of lowering the rate by 4.8 percent is 20.86 RMB.

These three conditions yield an output-weighted average of the price elasticity of supply of 1.2206, 1.2152, and 1.3746 for coal-fired, circulating fluidized bed, and natural-gas-fired generators, respectively, under the benchmark levels of output.

c. Distribution of Costs within Each Technology Class

To incorporate cost heterogeneity within each technology class, we vary the parameter ϕ_0 that applies to each class. ϕ_0 is a constant term in the cost function for each class. We assume that this parameter is distributed according to a beta distribution. This is a bounded distribution. The probability density function (pdf) of beta distribution has the general form:

$$\frac{x^{\omega-1}(1-x)^{\delta-1}}{\int_0^1 v^{\omega-1}(1-v)^{\delta-1}\,dv}$$

We impose symmetry on this pdf by setting ω equal to δ.

i. Determining values for the maximal, minimal, and mean values of ϕ_0

For consistency with the data, we require that ϕ_{0mean}, the mean value of ϕ_0 from the distribution, be equal to the value obtained in the calibration procedure above for the representative generator in the given technology class.

Economic considerations imply that the upper bound of the distribution should have a value that makes profit just equal to zero for the generator with that value in the baseline. The generator with $\phi_0 = \phi_{0max}$ is a marginal producer. It makes zero economic profit and thus even a slight increase in cost implies negative profit and induces this unit to shut down. Thus ϕ_{0max} must have a value that makes profit equal to zero under business-as-usual (or baseline) conditions. Hence ϕ_{0max} satisfies:

$$pq_{BAU} + (\bar{p} - p)\bar{q}_{BAU} - p_f(h_{BAU} / \xi)q_{BAU} - (\phi_{0\max} + \phi_1 q_{BAU}{}^{\phi_2}) = 0$$

Hence,

$$\phi_{0max} = pq_{BAU} + (\bar{p} - p)\bar{q}_{BAU} - p_f(h_{BAU} / \xi)q_{BAU} - \phi_1 q_{BAU}{}^{\phi_2}$$

ii. Translating the Beta Distribution into a Distribution for ϕ_0.

In its standard form, the beta distribution is defined over the interval (0,1). We need to shift and scale the standard distribution to the interval (ϕ_{0min}, ϕ_{0max}) with mean value ϕ_{0mean}.

Let *a* and *b* denote the scale factor and the shift factors that translate the pdf's initial (0,1) distribution into the desired distribution for the model. And let *x* be the mean of the initial beta distribution. We choose *a* and *b* to satisfy:

$$\phi_0 = a(x-0.5)+b$$

s.t.

when x = 0.5, $\phi_0 = \phi_{0mean}$

when x = 1, $\phi_0 = \phi_{0\max}$

The solution is: $a = 2\cdot(\phi_{0\max} - \phi_{0mean})$ and $b=\phi_{0mean}$. Under the TPS or C&T, there will exist values of ϕ_0 that are critical in the sense that any generator with ϕ_0 greater than that value will have zero profit. This translation enables us to determine the fraction of generators in the technology class involved that have ϕ_0 above this value, and thus the number of generators that must shut down. This enables us to calculate the loss of profits to the generators that shut down. In addition, from the distribution of costs for the generators that remain in operation, we can calculate the changes in profit to the remaining generators.

The calculations rely on the pdf and cumulative distribution functions defined on the distribution of ϕ_0 . These distributions can be derived from the pdf for the *x* translation of ϕ_0. Because the translation is linear, the cdf for ϕ_0 is identical to the cdf for $x(\phi_0)$. The probability density functions $pdf_{\phi_0}(\phi_0)$ and $pdf_x(x)$ are not identical, however. The relationship between the two can be derived as follows. We start with the recognition that $cdf_{\phi_0}(\phi_0) = cdf_x(x)$. Then we take the full derivative with respect to *x* on both sides:

$$\frac{d}{d\phi_0} cdf_{\phi_0}(\phi_0) \frac{d\phi_0}{dx} dx = \frac{d}{dx} cdf_x(x) dx$$

$$pdf_{\phi_0}(\phi_0)\frac{d\phi_0}{dx} = pdf_x(x)$$

Since $\phi_0 = a\cdot(x-0.5)+b$, we have $\frac{d\phi_0}{dx} = a$. As a result,

$$pdf_{\phi_0}(\phi_0)a = pdf_x(x)$$

or

$$pdf_{\phi_0}(\phi_0) = \frac{pdf_x(x)}{a}$$

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