GENERATION PERFORMANCE STANDARDS IN THE US ELECTRIC SECTOR: LESSONS FOR CHINA

The Regulatory Assistance Project

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I. SUMMARY

Power plant emissions in the United States have been regulated largely on the basis of fuel-input standards. The input-based approach follows a tradition of regulating emissions according to industrial process, differentiating among activities such as cement and asphalt manufacturing, refining, and chemicals production. Such standards were primarily designed to reduce visible emissions, but did not necessarily create incentives for operational efficiency and technological innovation. In contrast, standards that relate pollutant emissions to the productive output of the process – for example, pounds of emissions per kilowatt-hour of electricity – encourage the most efficient production. Furthermore, if the standards are set on a uniform (i.e., fuel-neutral) output-basis, they remove any regulatory biases or unfair competitive advantages that might favor one technology over another or the dirtier plants over the cleaner. Limits of this type are called *output-based standards*.

Similar incentives for thermal efficiency will be created by "cap-and-trade" systems in which generators must have rights ("allowances") for the entire amount of the pollutants they emit. This is because efficiency improvements will reduce the number of allowances generators must have, thereby saving them money by reducing the number they must purchase or producing revenues by freeing up allowances that they can then resell. Two factors will affect the force of these incentives: one, the aggregate amount of allowances available in relation to the aggregate needed and, two, the manner in which the allowances are distributed, or allocated. These factors are related in that they affect the value of the allowances and, therefore, the value of alternatives to using ("retiring") the allowances. The first simply determines whether the overall supply of allowances is sufficient to meet overall demand, but the second determines who will need allowances and the amount of money that is at stake.

There are a number of ways in which allowances can be allocated to generators, and they differ in the incentives for efficiency that they create. One way is through free allocation on the basis of a generating unit's historic emissions, which is effectively the same as a fuel-input emissions standard. It will create incentives for efficiency improvements, or for purchases of additional

allowances, to the extent that the allocation is insufficient to cover the generator's need. In the longer run, however, free allocations, like fuel input-based standards, will do little to promote investment in more efficient technologies and cleaner fuels.

In contrast, an allocation on the basis of electrical output creates, in effect, a uniform output-based emissions standard. This *output-based allocation* creates both an incentive to improve efficiency and an incentive to invest in cleaner technologies, because it does not differentiate among technologies or fuels: all face the same generation performance standard. Generators are rewarded for reducing their emissions per unit of electricity, which they can do by becoming more thermally efficient or by investing in cleaner technologies and fuels. Moreover, depending on the overall amount of allowances allocated, it may happen that the cleaner generators will receive more allowances than they need. They will make money by selling their surpluses to the dirtier generators who will not have received enough.

A third approach to allocation is to *auction* the allowances. An auction is an output-based approach, since the amount of allowances that a generator needs is directly related to its emissions per unit of electrical output. The more efficient and lower-emitting generators will have lower costs of compliance than higher-emitting generators. But, perhaps more importantly, an auction, unlike any kind of free allocation, raises revenues that the government controls and can use for increased investment in clean energy resources, including end-use energy efficiency and renewables.

Output-based standards, output-based allocations of allowances, and allowance auctions comprise the broad category of electric sector emissions regulations that define performance (and evaluate compliance) in terms of the productive output (i.e., the electrical generation) of the affected facility. Such regulations are broadly referred to as *generation performance standards*, and they constitute an important evolution in air pollution regulation in the United States. It is an evolution that, in the last decade, has been driven, not by the federal government, but by states, who have recognized several virtues that such regulations have over the fuel input- and technology-based approaches:

- Generation performance standards do not prescribe the means of compliance, but instead give generators the freedom to discover the best way to meet the requirements, which means that
    - in the short run, they reward improvements in thermal efficiency; and
    - in the longer run, they reward investments in low- and non-emitting technologies – that is, they promote innovation – ;
    - which together will reduce the total costs of compliance;
- They are "polluter pays" policies – under them, the more one pollutes the more one pays – ; and
- They are equally compatible with both vertically integrated electric systems and competitive generation markets – indeed, their strong, resource-blind incentives for efficiency and innovation complement the workings of well-designed competitive markets.

China has already adopted policies whose compliance and implementation would be enhanced through the implementation of generation performance standards. Environmental dispatch relies on the use of continuous emissions monitors (CEMs). CEM data are transmitted to the regional transmission operators and used to dispatch generators with the cleanest emissions first. Adopting output-based standards will enhance environmental dispatch, since it internalizes the cost of emissions into the variable cost of production and thereby assures that the economically efficient outcomes will also be the environmentally preferred ones. This will improve the planning process as well, because such standards assign a monetary value to the emissions and reveal the enhanced benefits of alternative resources. This in turn will allow China to more fully integrate energy efficiency programs into government and business operations.

II. TERMINOLOGY

We begin by defining several terms.

- *Output-based emissions standards* are emissions limits based on the amount of electricity produced by an affected facility. Standards are typically expressed as pounds of pollutant per megawatt-hour (MWh) of electricity production. This encourages generation to be as thermally efficient as possible.
- *Uniform output-based emissions standards* set the same emissions level for all sources of generation, regardless of the fuel choice. This encourages both thermal efficiency and, in the longer term, increased investment in the cleanest generation options.
- An *output-based allocation* refers to a means by which emissions permits, or allowances, are distributed to affected sources. In criteria pollutant programs, such as the NO_X budget program in the Eastern US, and in greenhouse-gas trading programs, allowances have monetary value.[1] Some states allocate allowances based upon the generating output of an affected unit.
- *Input-based emissions standards* are emissions limits based on the amount of fuel used by a facility, typically expressed in terms of Btu (British Thermal Unit). By their very nature, they automatically differentiate among technologies and fuels and therefore dilute incentives for long-run efficiency and innovation.

Of course, regulation is never as simple as a choice between input- and output-based standards might imply. It is not unusual, for instance, that a jurisdiction will mix the means by which, one, regulatory compliance is determined and, two, allowances are allocated in an emissions trading program. A state may, for example, require generators to comply on the basis of fuel input-based emissions standards, but then distribute allowances for an emissions trading program on an output basis. The reasons for such hybrid approaches vary, but typically have to do with notions of fairness, desires for smooth transitions from an old regime to a new, and simple politics.

[1] *Criteria pollutants* are those for which the US Environmental Protection Agency has set legally binding air quality limits.

III. HISTORICAL CONTEXT

US state and local air quality control programs were first implemented during the 1950s and '60s, prior to those of the federal government. These early programs focused on visible emissions as a simple and direct way to reduce air pollution, without requiring measurement instrumentation (which wasn't available anyway) or extensive training for personnel. These programs were often administered by state and local public health agencies, which understood the health effects of air pollution, but which had little technical expertise on how to reduce such pollution. Early air pollution sampling techniques consisted of measuring the amount of soot that was deposited each day in buckets that the city agency placed in various locations around a metropolitan area. Today, sophisticated instrumentation packages are installed on each power plant smokestack and data are recorded and transmitted every 5-15 seconds.

These early state and local efforts were incorporated into the US Federal Clean Air Act, which went into effect in 1972. Also focusing on visible emissions, federal regulations were first applied to asphalt and cement plants and, later, to electric generating units, or EGUs. Like emissions from other industries, EGU emissions were regulated on a fuel-input basis, expressed in pounds per million Btus of heat input. Indeed, one early standard in the United States was 1.2 pounds of nitrogen oxides per million Btu (1.2 lbs NO_X/MMBtu),[2] which had been carried over to EGUs from 1970s regulations that applied to asphalt plants and cement production facilities. It was generally believed that output-based standards were not well suited to process-oriented industries such as cement manufacturing. Policymakers at the time felt that measuring output for non-electric generating facilities is more complex than determining input, which is calculated as a function of the weight of a pollutant contained in the fuel. So, when it came time to develop and apply federal emissions regulations to EGUs, the fuel input-based approach, developed for process-based industries, was merely extended to the electric sector. As explained below, the input-based approach was also favored by coal-fired generators, which were (and still are) the dominant means by which electricity is produced in the US.

An early axiom held that "dilution was the solution to pollution," meaning that plant operators could simply reduce the amount of visible pollution by injecting more air (from larger fans and blowers) just upstream of the entrance to the smokestack in order to reduce the visible effects of the emissions. However, while the opacity from the process was reduced, dilution did not change the mass of pollution emitted in a region or the effects of its eventual deposition. Many of coal-fired plants installed 300-meter tall stacks in the 1960s and 1970s to disperse their smoke and to mitigate the effects of sulfates and nitrates upon the immediate surrounding areas. The quantity of pollution and the height at which it was emitted meant that the plumes from these plants easily blended into air currents that transported the emissions very long distances from the Ohio River Valley, and caused increased acid deposition in the northeast. To this day, the effects of the tall stacks impede efforts by the northeastern states to improve their unhealthy air quality.

[2] Mid-1980s New Source Performance Standard, or NSPS, 40 CFR Subpart Db under the US Clean Air Act.

The influence of this transported air pollution was documented by the northeastern states during the 1980s. The 1990 Amendments to the Clean Air Act authorized the creation of a regional administrative agency, the Ozone Transport Commission (OTC), to focus on the science of air pollution transport and to develop policies to reduce its effects. The OTC is comprised of thirteen jurisdictions from Maine to Virginia (including the District of Columbia).

The NO_X Budget Program (NBP) was developed in the late 1990s by the OTC states (and later evolved into EPA's NBP). Specific NO_X budgets (i.e., tons for each state) were calculated as a function of generating output (in MWh) and an input-based emissions standard of 0.15 pounds NO_X per MMBtu.[3] Associated with each ton of the budget was an allowance – a permit to emit NO_X – which was tradable. The states were free to allocate their budget as they saw fit. Most states used the fuel-input standard as the basis for allocation, but other states, such as Massachusetts, allocated the tons of NO_X to generators using an output-based emission rate of 1.5 pounds NO_X per MWh.[4] But, within these general approaches, states took additional steps to address their own unique circumstances (geography, weather patterns, etc.). For example, some states gave preference to new sources in their states by allocating allowances first to these sources and giving them enough to cover their current compliance obligations. Other states included sources such as municipal waste burners and pulp and paper mills in the program, since they are also major emitters of NO_X and had contracts to sell electricity.

Factors that contributed to the decisions of most of the states on NBP to continue to regulate EGUs through input-based standards were:

- Regulators were most comfortable with the fuel-input methods that they had been using for many years;
- Regulators used the EPA's Acid Rain (SO_2) Program as a model for the NBP, which used a fuel-input method for allocating allowances;
- The utility industry was still a vertically integrated monopoly, and the costs of compliance could be passed along to customers through regulated prices;
- The technical tools and models that states and the EPA relied upon to assess the costs and potential reductions of policy measures were based upon large, central fossil fuel-fired generators. These tools could not accommodate energy efficiency, renewable energy, and alternative means to establish regulatory standards (such as output-based requirements); and

[3] The fuel-input standard of 0.15 lbs NO_X/MMBtu was computed as follows. A NO_X budget (i.e., total amount of acceptable emissions) for the affected region was determined. It was based on then-current ambient air quality standards, and it was significantly lower than the actual level of NO_X emissions in the region at the time. That budget was converted to a fuel-input standard that accounted for the region's generation mix – that is, its mix of fuels and heats rates. The standard was, in effect, a weighted average of the fuel-input rates necessary to meet that NO_X budget. See also Footnote 6.

[4] Other states, such as Connecticut, also allocated allowances based on output, but did so as a matter of internal agency policy, not as a requirement of state law.

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- Most importantly, electricity markets with hourly clearing prices had not yet been created and environmental regulators did not fully appreciate the implications of the shift to competitive generation.

As the OTC states began to implement the NO_X budget program, their allocation decisions led to further understanding about electricity production. Allocating emissions standards based on heat input continued to "grandfather" older plants and disadvantage newer power plants, as the following example demonstrates.[5] The example assumes that each plant emits 0.15 pounds of nitrogen oxides per million Btu.

Table 1: Example of Input-Based Allocation

Fuel Type	Heat Rate (Btu/kWh)	Emissions per Million MWh (tons NO_X at 0.15 lbs NO_X/MMBtu)[6]	Input-Based Allocation (tons NO_X per year)
Coal	12,000	900	900
Oil	10,000	750	750
Natural Gas	7,500	562.5	562.5

The example shows that, under a heat-input allocation, a coal plant would receive 337.5 more allowances than a natural gas plant, given an identical amount of electricity production. In the NO_X budget trading program, each state developed an emissions budget (in tons per year) based upon the applicable emissions standard (in this case 0.15 pounds per million Btu) and the sum of all in-state generating output (in MWh). Next, each state calculated the number of allowances that each EGU would need based upon the emissions standard and its individual generation output. This equaled the number of allowances that would be allocated to each EGU annually.

Owners of coal-fired plants argued that this allocation scheme was equitable, since emissions control equipment for coal plants was more expensive than that required for natural gas plants.[7] They argued that the proceeds from the sale of these extra allowances could then be used to pay for and maintain the control equipment. Owners of natural gas plants however argued that, in competitive electricity markets, all MWh are valued the same, and that, with a fuel-input allocation, coal units are being rewarded for their inefficient conversion of fuel to electricity by receiving more allowances for the same number of MWh of electricity generation than are provided to natural gas plants. Oil units in the above example are disadvantaged relative to coal, but advantaged in relation to natural gas.

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[5] *Grandfathering* is a term of art refers to the practice of exempting facilities that existed prior to the adoption of a particular regulation from compliance with that regulation.

[6] The mathematics are as follows: Tons emissions/million MWh = [0.15 lbs NO_X / ((MMBtu) / (X Btu/kWh))] * [(1000 kWh/MWh * 1,000,000 MWh) / (2000 lbs/ton)];

Where X = number of Btus required to produce a kWh by a given technology.

[7] Under the northeast states' NO_X budget program, allowances are given to generators at no cost. In turn, they can sell them (each allowance is worth roughly $1000-$2000) and use the proceeds to invest in control equipment. Typical coal plant emissions are higher than the 0.15 fuel-input standard, and newer natural gas plants can usually meet the 0.15 standard without the addition of controls.

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By way of comparison, Table 2 below shows what would happen if both the allowance allocation and regulatory compliance were determined using output-based methods. This table assumes that both emissions budgets and compliance are based upon an emissions rate of 1.5 pounds NO_x per MWh (this emissions rate is equal to the NO_x budget program input-based emissions rate of 0.15 pounds NO_x per MMBtu, using a heat rate of 10,000 Btu/kWh).

Table 2: Example of Output-Based Allocation

Fuel Type	Heat Rate (Btu/kWh)	Emissions per Million MWh (tons NO_X)	Output-Based Allocation (tons NO_X per year, assuming a rate of 1.5 lb NO_X/ MWh)
Coal	12,000	900	750
Oil	10,000	750	750
Natural Gas	7,500	562.5	750

In the above case, coal plants would have either have to improve their operating efficiency to reduce their heat rate and/or purchase 150 allowances from other generating facilities in order to cover their regulatory obligations. Natural gas plants can sell their extra 187.5 allowances to other generating facilities, and use the revenue to help recover capital and operating costs. This example also assumes annual allowance allocations.

IV. Rationale for Output-Based Allocations and Emissions Standards

Any argument in favor of determining compliance and allocating emissions allowances on a fuel input-basis disappeared when New England and many other eastern states restructured their electricity markets. Regional transmission organizations adopted rules aimed at assuring economic dispatch (as had also occurred under the previous fully regulated regime) through competitive bidding into a single-price auction market – that is, a market whose clearing price is determined by the bid of the marginal unit and is paid to all units that clear in the market and operate during the specified hour.

New England's electricity markets were restructured at around the same time that the OTC states began to implement their NO_X emissions trading program. Environmental regulators designed the trading program using the model developed for the EPA Acid Rain (SO_2) Program, assuming that electricity markets would continue to be vertically integrated and that the cost of air pollution controls could be recovered through the sale of allowances and through proceedings at state public utility commissions. The Acid Rain program allocated SO_2 allowances on the basis of fuel input, which, as Table 1 shows, has the effect of allocating them on the basis of units' historic emissions levels. By using the Acid Rain Program as a model, the OTC states continued this practice of fuel input-based allocations in NO_X trading program. Another factor in this decision was that most of the affected sources in the OTC program also were required to comply with the EPA Acid Rain Program, and had developed record-keeping and reporting systems to meet EPA's input-based requirements.

Natural gas units are disadvantaged under a regulatory scheme where compliance with air pollution regulations is based on heat input, and where electricity is dispatched based on the economics of each generating plant. Many natural gas plants have been built since the middle 1990s, anticipating potential market advantages in a competitive electricity market. Low fuel costs at the time aided decisions by developers to construct natural gas plants; their expected low operating costs would have ranked them among the first to be dispatched, they would have operated as base-load units, and they would have quickly recovered their capital costs. However, shortly after the first group of states restructured their electricity markets (circa 1998-1999), natural gas fuel prices increased and have since remained high, especially in relation to coal prices. As a result, the natural gas plants have higher operating costs than coal plants, and the plant owners have been unable to operate them as frequently as they had planned in order to fully recover the capital costs of their investment. Today, under the region's economic dispatch rules, gas plants operate as marginal units more than 75% of the hours in a year. The region's coal plants, with lower marginal costs, are dispatched in more hours than the gas plants. (This and that fact that they are older and more highly depreciated – i.e., have lower capital costs – means that they are also very profitable.) Exacerbating this economic distortion is the fuel-input allocation of allowances, which means that the natural gas plants receive fewer NO_X allowances per MWh of electrical output than do the coal and oil plants; consequently, in many case, natural gas plants are unable to fully recapture their now higher operating costs through sale of NO_X allowances. An output-based standard for allocating NO_X allowances would have avoided these problems.

Current and expected regulation of greenhouse gas (GHG) emissions further demonstrates the benefits of such output-based approaches. States that have completed climate change action plans recognize that the substantial majority of GHG reductions will be achieved indirectly, through investment in end-use energy efficiency, renewables, and clean, distributed generation. This is because there is currently nothing in the way of smokestack controls for CO_2, the primary GHG. Combustion efficiency improvements will produce some decreases in emissions, but it will be largely through demand reductions and alternative energy resources that the lion's share of emissions reductions will be achieved. Consequently, it is imperative to design GHG-reduction policies to both encourage improvements in thermal efficiency and facilitate increased investment in end-use efficiency, combined-heat-and-power (CHP) resources, and renewables.

One example of this is the Regional Greenhouse Gas Initiative (RGGI), a carbon cap-and-trade program among ten northeastern states in the US. The allowances will be auctioned off to the generators, and the auction revenues will be invested in end-use efficiency measures and renewable energy resources. The cleaner and more efficient generators will be rewarded because their cost of compliance, per unit of electrical output, will be lower than the less efficient and more polluting generators, but, more importantly, the monies raised through the sale of the allowances will be put to GHG-reducing uses.

V. Development of Output-Based Standards

Implementation of the NO_X budget program led the OTC states to think about ways to better achieve the region's energy and environmental goals (other US states also considered output-based standards, such as California). Air regulators favored construction of more natural gas plants, since this fuel is the least polluting of the fossil fuels and it would help to reduce the NO_X emissions that are precursors to the unhealthy ozone concentrations found in many urban areas. Natural gas generating units can also be constructed relatively quickly, in response to changing demand. However, reliance on natural gas as a primary fuel for electricity generation made energy regulators uneasy, due to supply volatility, and fuel price increases quickly diminished any price advantages that natural gas initially enjoyed over coal and oil.

The consideration of other means to regulate emissions from power plants emerged through consistent and routine communications between air and energy regulators (at both the state and federal levels), and between them and the operators of regional transmission organizations. An appreciation of the benefits of output-based standards for electric generating units emerged from these discussions. Those findings are listed in the SUMMARY, which opens this paper. In finer detail, environmental regulators discovered that such standards:

- Encourage more efficient generation of electricity and reduce fuel consumption;
- Connect the instrumentation (CEMS) at the smokestack to energy and capacity markets, to ensure that all MW and MWh are valued equally;
- Are a straight-forward means by which states can improve air quality and meet federal health-based standards for ozone and fine particulates;
- Can be adapted to multi-pollutant approaches to also reduce mercury and greenhouse gas emissions;
- Encourage clean distributed generation, such as combined heat and power, where the generation is installed and serves load at the same location (reducing line losses and helping to defer the need to install/upgrade transmission lines);
- Help states implement their climate change action plans, in which clean, efficient generation and energy efficiency rank consistently as the most cost-effective and significant policy measures to reduce greenhouse gases and other air pollutants;
- Complement other innovative policies, such as dynamic pricing and demand response programs, to discourage inefficient and more polluting generation from participating during peak electricity demand periods; and
- Help implement state statutes and policies that require the most cost-effective and efficient resources to be procured first.

Federal requirements also present opportunities to implement output-based emissions standards. Section 111 of the Clean Air Act requires the US EPA to assess New Source Performance Standards (NSPS) every five years, and to update them as appropriate to account for new technology and processes. During the late 1990s, the EPA completed such an evaluation of the NSPS for electric generating units, and convened a process that included state agency representatives. While the EPA ultimately decided to continue regulating electric generating plant emissions on a fuel-input basis, several state agencies subsequently adopted generation output-based policies and regulations. These efforts included:

- A Massachusetts regulation that established a compliance standard for electric generating units of 1.5 pounds NO_X per MWh;
- A Connecticut NO_X emissions allocation, implementing that state's NO_X budget program (part of the OTC program described earlier), to electric generating units of 1.5 pounds per MWh (2003 to present);
- New Jersey's Best Available Control Technology permit decisions based upon generation output; and
- The Distributed Resources Working Group, convened by the Regulatory Assistance Project (RAP) in 2001 and 2002, which developed a US national model rule that specifies output-based emissions standards for small-scale, distributed generating resources.

VI. What Jurisdictions Are Requiring Output-Based Standards?

Based on states' experiences with implementing the NO_X budget program, and with the growing cooperation and collaboration between state energy and environmental officials, Northeastern states have increasingly favored output-based emission standards as they adopt new, and revise existing, air regulations. As previously mentioned, the ten RGGI states have adopted regulations which call for allowances to be distributed on the basis of electrical output, specifically by auctioning them.

In addition, several states have adopted the model output-based emissions rule (mentioned above) for small-scale, distributed resources. The emission standards for NO_X, CO_2, CO, and particulates are expressed in pounds per MWh.[8] To date, Connecticut, Delaware, Rhode Island, Massachusetts, and Maine have adopted the model rule, either in whole or in part.

VII. The Future of Output-Based Emissions Standards

Implementation of EPA's Clean Air Interstate Rule (CAIR)[9] permits states to adopt regulations where NO_X allowances will be distributed on an output basis. This policy helps to codify efforts by Connecticut and Massachusetts, which have either formally or informally distributed allowances on an output basis as part of the earlier NO_X budget program.

Connecticut's program (RCSA 22a-174-22c) implements CAIR in two phases: Phase 1 (2009-11) allocates allowances first to industrial and cogeneration sources on a heat input basis. Existing electric generating units will receive allocations at a rate of 1.2 lbs NO_X /MWh; new EGUs receive

[8] SO_2 is dealt with through a low-sulfur fuel requirement.
[9] CAIR is a continuation of the late 1990s NO_X budget program, which applies to power plants located in a geographic area consisting of the 19 states east of the Mississippi River roughly north of 36 degrees latitude. CAIR was recently vacated by the US District Court (July 2008). EPA has yet to determine how it will address the Court's actions, but states with existing NO_X rules, such as the OTC states, will continue to implement their state programs.

allocations based on actual emissions rates. Phase 2, starting in 2012, continues to allocate allowances first to industrial and cogeneration sources based on heat input, but, all EGU allowances will be pooled. Allocations will then be based on each unit's *pro rata* share of the previous year's generation output.

New EGUs are expected to receive sufficient allocations to adequately cover their expected generation output. Existing EGUs are expected to receive 35-40% less than that which they would have received under previous input-based allocation schemes. Consider the example in Table 2: under an output-based allocation scheme, a coal plant would require 337.5 more allowances than a gas plant for each million megawatt-hours of generation, and natural gas plants would be expected to receive enough allowances to cover their predicted operations. Coal and oil plants will have to either purchase allowances or reduce generation, or do some combination of both, in order to comply with the post-2012 emissions standards.

States continue to lead in promulgating requirements for output-based emissions standards. A new approach has been to extend eligibility for participation in renewable portfolios to fossil fuel-fired resources whose thermal efficiency exceeds a specified amount (typically 50-55%). Combined heat-and-power projects are encouraged by this treatment, which is now an element of Connecticut's renewable portfolio standards (RPS) program.[10]

State climate change action plans, now completed or being drafted in 30 states, include policy measures to promote more efficient electricity generation. Recommendations in these plans include the adoption of output-based emissions standards, encouragement of CHP, and a greater integration of energy and environmental policies. As policy measures in the state action plans are developed into regulations and statutes, additional states will promulgate output-based emissions standards. The wisdom of New Jersey's output-based air pollution permitting decisions has prompted several other states to adopt similar policies. Massachusetts and New Hampshire have adopted output-based emissions standards for central station power plants; and California and Texas have adopted output-based standards for distributed generation.

The new capacity markets in the Northeast, whose development has been overseen by the Federal Energy Regulatory Commission (FERC), offer opportunities for all resources, whether supply or demand, to participate and to be valued fairly. Currently, the market in New England is farther advanced in this respect than those in New York and the mid-Atlantic region (PJM). Air and energy regulators, environmental and consumer advocates, and other interested parties actively participated in the process which led to the development of the rules governing the new capacity market. Energy efficiency and efficient generation, including combined heat and power, are now eligible to receive payments for the capacity these resources provide. Qualified resources can receive payments for as long as they provide capacity value. The capacity market offers an option that qualified resources can lock in the capacity price they receive for up to five years. Thereafter, resources can receive payments annually for as long as the resource performance persists. In the

[10] Public Act 05-01 (2005) established a class III RPS. Eligible resources include CHP and energy efficiency. The RPS began in 2007 at a level of 1% (based on annual MWh) and ramps up to 4% by 2010.

first auction, held by ISO-NE in February 2008, over 300 MW of energy efficiency programs qualified as resources in the capacity market, clearing the auction at a price of $4.25/kW-month. PJM, the largest RTO in the US, is considering similar rules now.

The relevance of these developments to output-based emissions standards lies in the compatibility of the one with the other: here are economic and environmental regulations that act to reinforce each other. Cleaner resources are no longer disadvantaged by rules that historically favored polluting central generation stations; uniform output-based standards reveal the true comparative values of the emissions from different facilities. This helps regulators identify the most effective and economical resources and policy options for reducing pollution. Demand-side measures and clean generation provide energy and capacity benefits to New England's electricity market. The quantity of benefits, measured in terms of MWh for energy and MW for capacity, is directly verified through replicable protocols. Translating the energy and capacity benefits of the demand-side and clean energy resources into environmental requirements is then determined by calculating the avoided emissions based upon applicable output-based standards and regulations.

Three states – Connecticut, Maryland, and New Jersey – have gone even further to integrate environmental and energy regulation by calculating the environmental benefits of demand-side measures and other clean energy resources and then accounting for those benefits (valued in tons per year of NO_x emissions) in their air quality plans. In this way, they take credit for the amount of emissions that will be avoided by these resources. California is now taking similar steps, so that it too can quantify the value of, and take credit for, the emissions avoided by demand-side measures and clean generation.

Output-based emissions standards will play an important role in the future, as US states implement their climate change action plans, and as the US federal government and Congress take up legislation to regulate greenhouse gases on a national scale. The same techniques described above that are helping states to determine the energy and NO_x emissions benefits can also be applied to calculate the greenhouse gas benefits from demand side measures and clean generation.

VIII. ADVANTAGES OF OUTPUT-BASED STANDARDS FOR CHINA

China is well positioned to take advantage of the lessons learned in the United States, to avoid the same costly mistakes, and to build upon the long-term thinking embedded in energy policies that China is considering or has already adopted. Among the potential advantages of implementing output-based emissions standards for China are that they:

- Fit with China's goals of increased use of competitive generation while fully reflecting environmental costs of those resources;
- Build upon the environmental dispatch policy already adopted;
- Are consistent with the "polluter pays" and clean production policies;
- Are compatible with energy efficiency and Clean Development Mechanism (CDM) projects, to monetize value of efficiency;

- Improve measurement and verification of energy and environmental benefits;
- Avoid the unintended environmental and energy consequences that can result from application of input-based emissions; and
- Complement emissions trading schemes that allocate allowances based on generating output

China's adoption of a policy to dispatch electric generating units according to their environmental attributes places China ahead of US states and the federal government in establishing links between environmental and energy policy. Utilizing output-based standards is a logical next step, and it will also facilitate compliance with China's new pollution tax infrastructure, which rewards the most efficient electricity generation through reductions in, or exemption from, the tax.

Output-based standards will also facilitate the adoption of policies that promote strategic long-range planning, and will help avoid the short-term mistakes, and the subsequent expensive mitigation efforts, that resulted from the environmental and energy policies that were initially adopted in the US. The minor economic advantage that the US initially enjoyed in the 1970s when the tall stacks/dilution approach was adopted was more than overwhelmed by the costs to retrofit controls on these power plants, the environmental and public health costs associated with acid deposition and smog, and the costs borne by consumers who were required to pay for correcting the mistakes of these short-sighted policies.

Adopting output-based standards in China will also enable technologies, such as combined heat and power, to achieve higher penetration rates. Improvements in process efficiency, which are measurable and verifiable, can also be included as part of an overall portfolio of supply- and demand-side resources, all of which will have measurable economic value, internationally through CDM and related programs and domestically as both energy and capacity resources.