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Emissions Trading Market Study

Report to the Ontario Ministry of Environment

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Executive Summary

One objective of this study is to provide details on existing emissions trading programs including their rules, their performance, and the administrative costs to both participants and governments. To this end we examine the RECLAIM program in California, the US Clean Air Act Title IV SO_2 trading program, the Canadian PERT program, NO_x trading in the US including the OTC budget program, the EPA's NO_x SIP Call, and two state NO_x trading programs: Pennsylvania and New Jersey. We also examine briefly the US refinery lead trading program and the EU's emerging $CO2_2$ trading program for implementing the Kyoto Protocol.

Emissions trading began in the 1970s and 1980s in the United States using mainly emission reduction credits (ERCs). However, beginning with Title IV in 1990, new US emissions trading programs have been predominantly of the cap-and-trade design without emission reduction credits or with very limited credits. But these more recent programs have included "opt-in" provisions under which sources that are not capped can enter the program bringing with them an entitlement to allowances according to a formula.

The cap in recent (post-1990) cap-and-trade programs has always involved a fixed cap specified in tons, rather than an activity-based limit. The capped Title IV utilities may emit 8.95 million tons of SO_2 no matter how many new facilities are constructed and no matter how much the demand for electricity grows. The NO_x budget does not increase as economic output increases; while the initial distribution of allowances to facilities is in terms of activity, the total of that distribution is scaled up or down until it equals the state budget. In both of these programs, however, year-to-year flexibility is afforded by allowing banking of unused allowances from one year to another. The RECLAIM limits do not vary with economic output and there is no banking, but recent revisions provide a mechanism to increase allowances if allowance prices exceed specified levels. Presumably there is value in promising that emissions will not exceed a specific level, and there is confidence that technology will progress so that the fixed cap will not unduly restrain economic growth. Indeed, the cost of controlling SO_2 under Title IV has been less than was feared by some when the program was proposed.

The distribution of allowances in cap-and-trade programs in the US has been based on historic activity and an emission factor. Heat input is the activity measure used for electricity generation and other boilers. There are a variety of ways in which Ontario could distribute allowances to facilities under an expanded trading program. We conclude that the least distorting distribution is based on fixed historic activity. Distribution according to recent activity introduces some distorting incentives, which are less if the basis is production activity rather than fuel use.

With respect to operational efficiency, emissions trading programs seem to have achieved considerable success in the United States. For example, trading volumes have been substantial in RECLAIM. The average price per ton of SO_2 Reduction Trading Credits (RTCs) from 1996 to 2000 ranged from US$1,500 to US$3,000. The average price of 1998 NO_x RTCs traded in 1999 was US$1,827 per ton of NO_x RTCs. There has also been extensive trading of allowances with respect to the US Clean Air Act Title IV SO_2 trading program. Actual number of trades reached 4,690 in 2000 and 4,900 in 2001. Since 1999 prices have stayed between US$130-200/ton. A significant volume of trading has occurred in the OTC budget program. While usually less than 40,000 allowances a month are traded, in peak months as many as 90,000 allowances have been traded. This trade occurs principally between utilities. From 1999 onwards, prices for OTC NO_x allowances were till recently, below US$2,000. However, the beginning of 2003 has witnessed a spike in NO_x prices in the US, reaching as high as $US 7,500.

We note that while emissions trading markets are "artificial" markets, they are still markets and their success depends on participant confidence that the market will be transparent, fair and predictable. Participants will look for assurances that investments that they make, whether purchasing allowances or installing emission controls, will not have their value arbitrarily debased by changes in the rules.

A significant contribution of this study is the quantification of transactions costs associated with Emissions Trading Programs. According to our estimates, transaction costs to participants in the SO_2 allowance trading program range from 0.5 per cent and 1.5 per cent of the value of an allowance. Transaction costs to participants in the newer NO_x trading program appear to be in the range of one per cent to five per cent of the value of allowances being transacted. But transactions costs have been higher in RECLAIM. Our research suggests that brokerage fees in that program today are still on the order of three per cent to five per cent on *both sides* of trades.

The allowance-trading portion of Ontario's new emissions trading program is similar to RECLAIM and the state NO_x trading programs in terms of the variety of sources included. Ontario's large sources are far less numerous than the sources in RECLAIM, but similar to the number of sources in some of the NO_x trading states. Provided that allowances are as homogeneous a commodity as allowances in US programs, overall, our transactions costs should be similar to those in RECLAIM or in state NO_x trading, but well above those in the much larger Title IV market. ERCs may involve added transactions costs at the time of creation and perhaps at the time of sale, because of rules that apply specifically to ERCS.

Based on the U.S. experience, we provide estimates on the likely magnitude of administrative costs related to the startup and implementation of a tradeable permits market. Our startup costs could range from CDN $1.5 million to $16 million, while operating costs could range from CDN $37,000 to $2.3 million.

The U.S. experience suggests that trading of emissions grows slowly as participants gain experience and understanding of how the market works and how to limit risks associated with trading. Some firms that can benefit from trading may be reluctant to do so in the first few years of market operation. Many of the U.S. programs have involved a staged reduction in the cap so that only a few firms would feel compelled to trade initially and others could join as the savings from trading grew in response to the cap reductions.

A final key contribution of this study is simulations aimed at predicting allowance and credit prices and the magnitude of trades in Ontario. Given the relative absence of large-scale emissions trading in Canada, simulations were conducted to evaluate possible cost savings from such a system. These simulations were accomplished through the use of abatement cost data from plants in seven industrial sectors. NO_X simulations included the Cement, Pulp and Paper, Petroleum, Iron & Steel, and Glass sectors, while the SO_2 simulations included the Cement, Pulp and Paper, Petroleum, Iron & Steel, Carbon Black, and Non Ferrous sectors. In addition, four coal-fired electricity generation (OPG) plants were included in both NO_X and SO_2 scenarios. The data were provided to LECG by the Ministry.

Several scenarios were compared to a base case in order to gain insights into the price and quantity ranges that might emerge from different market arrangements. Scenarios 1 & 2 are intended to show the benefits (if any) of trading when all facilities face the same emission reduction requirements (45% for NO_x and 50% for SO_2). The main difference between Scenarios 1 and 2 is that industrial plants cannot buy or sell credits among themselves but can sell to OPG under rules described in O. Reg. 397/01 in the former, while the same facilities receive allowances (equal to the 45/50 rule, i.e., 45% of 1990 NO_x emissions and 50% of 1994 SO_2 emissions) and are allowed to buy and sell allowances and buy credits from each other and OPG, in the latter case. Scenarios 3a and 3b are also intended to evaluate benefits to trading, but in this case, emission reductions requirements are tailored to each facility. But broadly speaking, the differences between Scenarios 3b and 3a correspond to Scenarios 1 and 2, in that Scenario 3b simulates a command-and-control regime, while Scenario 3a focuses on emissions trading.

Our results are of course sensitive to the scenario being modelled and the accuracy of the abatement cost data. In a scenario where all firms are permitted to trade both allowances and credits (Scenario 2), allowance prices range from CDN $144 to CDN $250 for SO_2 and between CDN $3,400 to CDN $4,360 for NO_x. These ranges are definitely consistent with above discussed trends in corresponding U.S. prices.

Further, our results suggest that emissions trading in Ontario will result in considerable savings in abatements cost for participants relative to a command-and-control regime. For example, in a command-and-control scenario (Scenario 1) with respect to SO_2, participants will collectively incur between CDN $230 million to CDN $242 million in abatement costs (roughly). In comparison, we find that a trading regime (Scenario 2) implies much lower abatement costs for firms; specifically, between CDN $31 million to CDN $45 million. Emissions trading also implies considerable cost savings for NO_x abatement. Our calculations suggest that firms will spend between CDN $27 million to CDN $139 million in abatement costs in a trading scenario (Scenario 2) compared to between CDN $74 million to CDN$ 127 million in a command-and-control scenario (Scenario 1). Although the scenario simulations suggest a higher upper bound, it is important to understand that this may be due to the fact that the abatement cost functions (ACFs) are often discontinuous.[1]

Similar results are obtained in scenarios where plant specific facilities receive specific allowances. Specifically, in the command-and-control scenario (Scenario 3b), firms will probably spend approximately CDN $162 million with respect to SO_2 abatement; but between CDN $32 million to CDN $49 million through emissions trading (Scenario 3a). With respect to NO_x abatement, firms are expected spend between CDN $67 million to CDN $89 million in a command-and-control regime (Scenario 3b), but from CDN $11 million to CDN $49 million through emissions trading (Scenario 3a).

[1] Some ACFs only contain data at the high and low end of the range of control options. The lack of data creates large, discrete steps in the functions. In reality, plants are likely to have access to more options covering the full range of control efficiencies and costs.

1. INTRODUCTION

The first part of this report describes existing emissions trading programs including their rules, their performance, and the administrative costs to both participants and governments. We examine the RECLAIM program in California, the US Clean Air Act Title IV SO_2 trading program, the Canadian PERT program; NO_X trading in the US including the OTC budget program, the EPA's NO_X SIP Call, and two state NO_X trading programs: Pennsylvania and New Jersey. We also examine briefly the US refinery lead trading program and the EU's emerging $CO2_2$ trading program for implementing the Kyoto Protocol. This report will lay the foundation for the evaluation of rules under which the existing Ontario emissions trading program may be expanded to include a number of industrial sectors. The text discussion gives an overview of each program, while tables summarise the main features of all but the lead and OTC programs. We also review the participation of major Ontario polluters in past emissions trading programs and evaluate the implications of alternative principles for distributing allowances to polluting facilities.

There are two basic types of emission trading systems. One imposes a cap on a specified set of pollution sources, distributes emission allowances to each source indicating its permitted discharge amount, and authorises the polluters to trade allowances with each other. This is referred to as a "cap and trade" or "allowance" system. The other begins with existing emission limits imposed on individual sources, or with their historical emissions, or with projected future emissions and authorises sources to create "emission reduction credits" or ERCs if they reduce their emissions below one or another of these amounts. The ERCs once created can be sold to other sources, which may use them to increase their emissions.

The difference between a cap and trade system and an emissions reduction credit system can be subtle, especially when in practice some elements of both may be included. The trading system promulgated in 2001 by the Ontario Ministry of Environment, and described below, is an example of such a hybrid system. However, the key distinction between the two systems is as follows. A cap and trade system starts from a designated total emission level that applies to specified sources and an initial allocation of "allowances" to these sources, the sum total of which does not exceed the cap. These sources can then trade the allowances and must keep their emissions in line with the allowances that they own. Changes in activity level in the sector do not affect the total amount of allowances distributed. Any new source of emissions, such as a newly formed company, must buy allowances from the specified sources or from a "holdback" of allowances from the distribution to the specified sources. This is sometimes referred to as a closed trading system.

An ERC system does not require an initial cap on total emissions. Instead, it starts from a level of emissions for each source (usually the lower of past emissions or a regulatory limit) against which reductions can be made and credit given. These emission reduction credits can then be sold to other sources that use them to meet a mandatory or voluntary limit. Under an ERC system, new emission sources have to meet all applicable emission regulations and standards. However, unlike a cap and trade system, they do not have to buy ERCs from existing sources so there is no automatic limit on total emissions. This is sometimes referred to as an open trading system, since trading is not limited to capped sources.

2. RECLAIM, SO_2 ALLOWANCE TRADING AND PERT

2.1 RECLAIM: Southern California NO_X and SO_2 Trading

California's South Coast Air Quality Management District (SCAQMD), created in October, 1983, a cap-and-trade approach to reducing emissions of NO_X and SO_2 within the South Coast Air Basin. The Regional Clean Air Incentives Market, or RECLAIM, began operating in January, 1984 in areas of Orange County and major portions of Los Angeles, San Bernardino and Riverside counties in Southern California. Prior to RECLAIM, the SCAQMD used source-specific emissions regulations to limit the emissions of NO_X, SO_2, and other pollutants.

RECLAIM applies to all facilities that emit more than 4 tons[2] of NO_X or SO_2 except for some essential public services that remain subject to command-and-control, such as landfills, public transit, restaurants, fire fighting facilities, etc. (SCAQMD, 2001, White Paper). For each source, the baseline for emissions allocations was defined as the highest year of reported emissions between 1989 and 1992, less reductions that were required by various regulations through 1993 (USEPA Experience, 2001, p. 94). The program began with 370 sources for NO_X and 40 sources for SO_2. The SCAQMD set out to reduce emissions from 1994 to 2003 by 8.3% for NO_X and 6.8% for SO_2 annually (USEPA, 2001). Emissions monitoring was accomplished by the use of Continuous Emissions Monitoring Systems (CEMS), where emissions are read into a central computer directly from the participating facilities.

RECLAIM Trading Credits (RTC) were allocated to participants on a declining basis from 1994 to 2003; thereafter allocations are constant. A single RTC allows for one pound of emissions. The original design provided no banking for future years, but it appears that the crisis of 2000 led to a relaxation of this rule. In Los Angeles, the breeze generally flows inland, and since it takes several hours for NO_X emissions to react to form smog, coastal emissions have a greater effect on the District's air quality than inland emissions. RECLAIM recognizes this by defining two trading regions: coastal and inland, and limiting the sale of inland RTCs to coastal sources. Penalties for exceeding emissions allocations may include an allocation reduction equal to the amount of emissions exceeding the allowable limit. Civil penalties of up to $500 per day or per 1000 pounds of excess emissions and loss of operating permit may also result.

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[2] Ton refers to the US short ton of 2000 pounds. Tonne refers to metric tonnes of 1000 kilograms, the standard measure outside the US. The benchmark emissions level of 4 tons does not distinguish among firms in terms of size.

At the start of RECLAIM, sources that acquired offsets from previous emissions trading programs were allowed to convert those offsets to RTCs. In addition, an existing program that created emission reduction credits from scrapping old cars was incorporated into RECLAIM, subject to a minimum of 100 cars and a maximum of 30,000 cars per year.[3] Sources not included in RECLAIM may choose to opt into the program, in which case they bring with them allowances calculated on the same basis as sources compelled to participate.[4]

New sources that were not in operation during the 1989-91 baseline period appear to receive no special allocation of RTCs, and must purchase offsets from existing facilities and trade them for RTCs. (Fromm and Hansjurgens, 1996, p. 373; Regulation XX, Rule 2005.) One exception to this rule is the provision of 91 tons of RTCs for 1997 to be allocated to new sources that meet a high employment low emissions (HILO) criterion intended to encourage growth in clean industries. However the permitting of new sources is easier under RECLAIM than it was under previous regulations which, because the District is a non-attainment area, required that any new source reduce emissions at an existing source (offsets) in a ratio of 1.5:1. Because the allocation of RTCs is based on historic activity, it appears that sources that reduce their activity or cease activity altogether should still receive their RTC allocation. However it also appears that as of May, 2001 RECLAIM rules explicitly prohibit production curtailment as a means of demonstrating compliance with a facility's allocation.[5]

Facilities involved in RECLAIM are placed into two cycles. The first cycle runs from January 1 to December 31 while the second cycle runs from July 1 to June 30. Facilities are randomly placed into one of the cycles. This structure is intended to create a liquid market for tradable permits and to reduce large price swings that could occur when all credits expire at the same time (SCAQMD, 2001, White Paper). Participants in both cycles can freely exchange credits.

In order to jumpstart the market of Reduction Trading Credits (RTC's), the SCAQMD held an auction on July 29, 1994. A total of 114,676 NO_X credits and 9,400 SO_2 credits were exchanged at the auction (USEPA Report, 2001). The utilities were the largest seller of NO_X credits because most had already installed new emission control equipment

For NO_X and SO_2, starting allowances were allocated on the following basis:[6]

Starting Allocation = $\sum$ [A X B1]+ERCs+External Offsets, where

A = the throughput for each NO_X and SO_2 source or process unit in the facility for the maximum throughput year from 1989 to 1992 inclusive

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3 AQMD Regulation XVI, Rule 1610; Regulation XX, Rule 2008.
4 AQMD Regulation XX, Rule 2001(f)
5 Rule 2009.1(b)(3)(A) cited in "Rule 2009.1 Implementation Guidance Document", July 27, 2001, Southern California Air Quality Management District, p. 11.
6 AQMD Regulation XX, Rule 2002. http://www.aqmd.gov/rules/html/tofc20/html

B1= an emissions factor depending on type of source

A similar calculation was made to determine year 2000 and 2003 starting allocations using stricter emissions factors. Once 1994, 2000, and 2003 allocations were calculated, a straight-line rate of reduction was used to calculate allocations for years 1995-1999, 2001, and 2002. After 2003, allocations are equal to the facilities' 2003 allocation.

The excess demand for RTCs during the electricity crisis of 2000 led to the creation of a mitigation reserve of RTCs that could be purchased by power producers who meet stringent requirements. The price of these additional RTCs is $3,000, $6,000 or $15,000 per ton depending on the circumstances.[7] This provides a safety valve to keep RTC prices within reasonable limits in years of high demand.

Sources were required to install continuous emission monitors on any boiler emitting more than 10 tons per year (or qualifying as a "major" NO_X source based on a list of size factors), at a cost of US $100,000 to $150,000. Sources who do not qualify as "major" sources are not required to install CEMS. Data from the CEMS are transmitted to an AQMD computer where they are analysed to determine compliance. The AQMD estimated that participating sources would have to spend $13 million to install emission monitoring equipment, and that operating costs would be negligible. (US EPA, 2001, Experience, p. 94.) Since the threshold for participating in RECLAIM is 4 tons/year from a facility, many smaller participants have not been required to install CEMS. These "large" (but not Major) facilities must install an approved fuel meter or meter on some other measure of activity and accept an emission estimate based on that activity and an emission factor, or they may install CEMS like the Major facilities.[8]

Trading volumes have been substantial. While they were low in the initial year, they jumped in 1995 and have fluctuated since then. For NO_X RTCs, on average one-quarter of all trades have been trades "with price," meaning that they are trades between distinct RECLAIM facilities. The remaining three-quarters of the trades are either internal trades or sales to or from a broker. For SO_2, the trades between facilities have averaged about 22% of all trades. It is interesting to note the difference in trade volumes with and without prices. In the first few years, trades without price dominated trading, while in later years they have been less dominant, as firms developed more experience and confidence in buying and selling RTCs with other firms without using a broker. Tables 1 and 2 below show the annual trading volumes.

7 AQMD Regulation XX, Rule 2020, section (h).
8 AQMD Regulation XX, Rule 2012, sections (c) and (d).

Table 1: Annual RECLAIM NO_X RTC Trading Volume

(number of trades)

Year	Trades with Price	Trades without price	Total trades
1994	2,210	5,769	7,979
1995	11,681	66,820	78,501
1996	5,595	41,691	47,286
1997	9,176	38,652	47,828
1998	26,003	19,072	45,075
1999	8,917	29,171	38,088
2000	8,316	11,667	19,983
Total	71,898	212,842	284,740

Table 2: Annual RECLAIM SO_2 RTC Trading Volume

(number of trades)

Year	Trades with Price	Trades without price	Total trades
1994	4	286	290
1995	3,052	14,105	17,157
1996	5,172	19,118	24,290
1997	5,077	15,614	12,969
1998	1,780	7,892	21,140
1999	1,548	19,360	3,775
2000	2,087	2,227	4,314
Total	18,720	78,602	83,935

Source: South Coast Air Quality Management District, 2001, White Paper.

The average price per ton of SO_2 RTCs from 1996 to 2000 ranged from $1500 to $3000. The average price of 1999 NO_X RTCs traded in 2000 was $15,377 per ton, but this was an aberration arising from the need to run fossil-fuelled electricity generators at high output because of a drought that reduced hydroelectric generation and a hot summer that caused demand to soar. In the more normal preceding year the average price was $1,827 per ton of NO_X RTCs. (SCAQMD, 2001, White Paper).

2.2 US Title IV SO_2 Allowance Trading

Title IV of the 1990 United States *Clean Air Act* set out to reduce sulphur dioxide emissions from coal-fired electricity plants by 10 million tones below 1980 levels, to about 8.95 million tons per year.[9] To reach these goals, a two-phase reduction scheme was implemented across the continental United States. Phase I began in 1995 while Phase II started in the year 2000. Phase 1 was focused on limiting emissions from the largest SO_2 emitting sources. Initially, this included 110 electrical utility plants (mostly coal-burning) with 263 emitting units. By the end of Phase I, an additional 182 units joined the program resulting in a total of 445 units. Phase II added all units larger than 25 megawatts and emitting more than 1.2 pounds per million Btu and ultimately covered approximately 2000 units including substitute, compensating, and opt-in units. The Phase II limit of 1.2 lbs/mmBTU is equal to the new source performance standard (NSPS) adopted back in 1970, so Title IV can be seen as finally applying the NSPS, on average, to every coal-fired power plant, old or new.

Under the legislation, each utility receives a free distribution of allowances every year for the number of tons of SO_2 emissions specified in the legislation.[10] The formula underlying the allocation in Phase 1 (1995-1999) is 2.5 pounds of SO_2 for every million Btu of coal burned on average during 1985-1987, and 1.2 pounds per million Btu in Phase II starting in 2000. This formula, however, is just the starting point, and Congress made a number of adjustments before arriving at the final allocations. The Phase I allocations are published in a table in the legislation, while the more complicated rules and adjustments for the Phase II allocations are set out in many pages of section 7651d of the U.S. Code. The legislation does not summarise the results in any table. (Ellerman, *et al.*, 2000, ch. 3,) A utility may sell its allowances, bank them for future use, or buy additional allowances from others. (US EPA, 2001, Experience, p. 76.) Allowances are assigned serial numbers and the "vintage" of the year in which they were issued. Utilities keep track of their SO_2 emissions and must retire one allowance for every ton of SO_2 discharged. In the first few years there was significant trading, but most of it was within corporations. By 1999, total trading had grown and it was about evenly divided between external and external trading. (US EPA, 2001, p. 80.)

In addition to the free distribution of allowances to units that operated in 1985-87, the EPA holds an annual auction to distribute allowances equivalent to a couple of percent of the free distribution. The auction was intended to ensure that generators, including new generators, were not prevented from securing access to necessary allowances if the market for allowances did not function well. The auction includes current year allowances and allowances for 7 years hence. There are additional provisions for distributing allowances as a bonus to units that reduce their emissions by 90% during Phase I, for Phase II units that enter Phase I as substitutes or as compensating units, and for industrial units that opt into the program voluntarily. (US EPA, 2001, p. 77.)

Title IV also provides that units not covered by the cap, such as small generators or industrial sources of SO_2, may opt in to the trading program.[11] The allowable emissions for such units are based on the unit's fuel use in 1985-87 multiplied by the

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[9] http://www.epa.gov/airmarkets/arp/overview.html
[10] See 42 U.S.C. 7651d.
[11] 42 U.S.C. 7651i.

emission factor (2.5 before 2000 or 1.2 thereafter) or by the unit's allowable emission rate, whichever is less. While this provision allows participation by units not under the cap, it is not an ERC provision because the unit becomes entitled to allowances based on its activity or emissions at a fixed time prior to the initiation of the program, not based on current activity. There has apparently been little use of this provision. (US EPA, 2001, p. 78.)

During Phase I, emissions were significantly less than the allowances distributed, so there was an accumulation of unused allowances in the "bank." This means that pollution emissions were reduced more rapidly than required under the law. Still, there has been concern that the geographic pattern of purchases and sales could lead to actual increases in pollution in some areas despite the overall decrease. New York State, among others, has tried to restrict the sale of allowances to upwind states where their use might increase air pollution in New York. (Nash and Revesz, 2001, 593-597.) It is not apparent whether these challenges will survive litigation. In any event, there are no restrictions in Title IV itself on the geographical distribution of purchases and sales. Neither does Title IV restrict the use of allowances that have been banked. There is no discount on banking or using banked allowances.

If a facility emits more than they are allowed with respect to allowances held, they are assessed a penalty.[12] The penalty began as a $2000 fine per ton, but it is indexed to inflation and is currently $2600/ton. In addition to the penalty, the source must submit allowances in the amount of the excess emissions. It does not appear that any facility has been assessed these penalties, indicating a high level of compliance under the program.

Utilities included in Phase I and Phase II must install continuous emissions monitors on their units and report emissions to the EPA. According to a survey conducted by the Centre for Energy and Environmental Policy Research (CEEPR) at the Massachusetts Institute of Technology, the capital cost of CEMS for 130 Phase 1 units was found to be US $709,000 per unit. Using an 11% "annualization factor" and adding annual operating costs of $50,000 bring the annualized cost to $125,000 per unit. With 2,100 units requiring CEMS, this monitoring cost alone may reach US $262 million/year, or 7% of the cost of compliance (Ellerman *et al*, 1997, p. 47). Record keeping for the program is the responsibility of the EPA. The EPA uses the Allowance Tracking System to keep a record of all trades and the amount of allowances available to each source and as its primary method of monitoring compliance. The EPA spent US $44 million to implement the Title IV program over five years and allocated $19 million to state and local governments to implement the program. (US EPA, 2001, Experience, p. 80.) It is not clear what proportion of this cost is a start-up cost and how much represents an ongoing cost of the program. Either way, the EPA cost is only a few percent of the cost savings from the program.

SO_2 allowance trading is open to everyone as long as they are registered with the EPA. Both regulated facilities and the general public can buy and sell. Environmental

[12] 42 U.S.C. 7651j.

groups often buy allowances and "retire" them so they can't be used to cover future emissions.

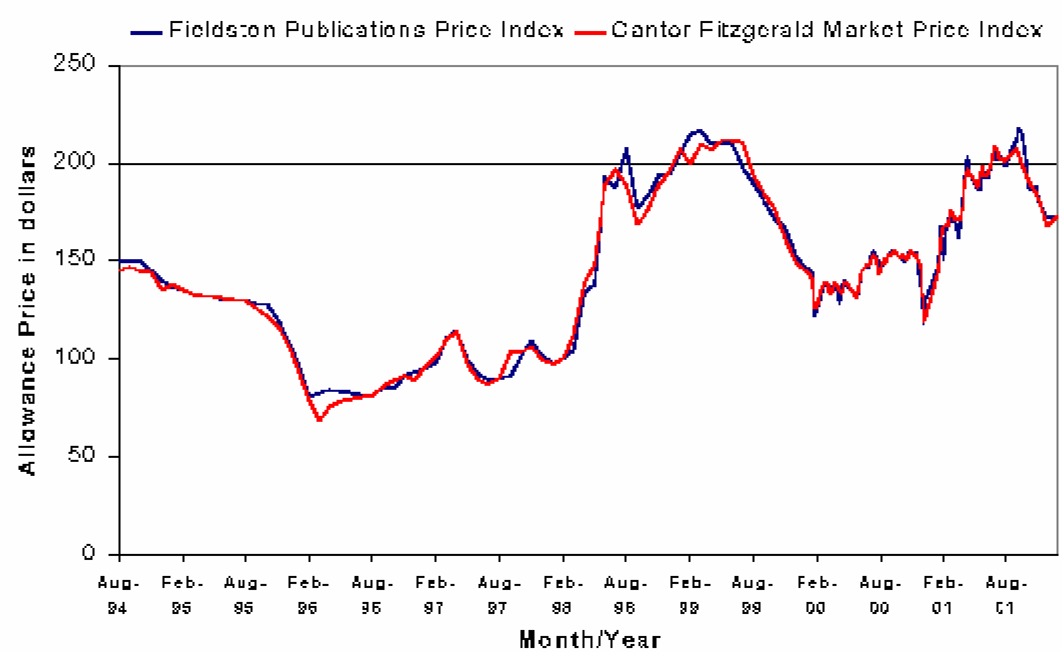
Prices began at about $300/ton (US$, short tons) but quickly dropped to $150 by the end of 1993. Prices steadily declined from 1993 to mid-1996. In 1996, prices remained less than $100/ton. Prices began to rise in spring 1998 and climbed to $200/ton until the end of 1999. Since then, prices have stayed between $130-200/ton. The relatively low cost of SO_2 allowances has been attributed to the following factors:

- Price of low sulphur western coal delivered to the mid-west and east has decreased due to extraction improvements, lower transport costs, and deregulation of rail rates

- Cost of operating scrubbers has decreased by approximately 50%. (US EPA, 2001, Compliance.)

- Early emission reductions arising from investments in scrubbers that were planned before the trading began reduced demand in the 1990s, allowing a surplus of allowances to accumulate under the banking provisions. It is expected that prices will rise over the next few years as the surplus is used up and output increases.

Figure 1: Monthly Average Price of Sulphur Dioxide Allowances



Source: US EPA Website – http://www.epa.gov/airmarkets/trading/SO2market/prices.html

The volume of trading under Title IV has grown steadily from 1994 to 2000. In 1994 there were 215 "private" trades, representing trades between separately owned utilities. In 1996 there were 1070 trades and in 1998 almost 1600. The number of trades reached 4,690 in 2000 and 4900 in 2001. The number of allowances transferred in the private market between separately owned utilities was a quarter million in 1993-4, 1.5 million in 1994-5, and 8.5 million in 1997-98, matching the growth in the number of trades themselves. As participant experience with the market increases, and as the need for allowances increases with the beginning of Phase II, trading has increased. In 1995, about 20% of Phase I units acquired additional allowances; two years later the proportion was 30%. (Ellerman, *et al.* 2000, ch. 6.) The majority of emissions trading under Title IV has been internal to a utility, as it moves allowances from one unit or facility to another or draws down its bank of saved allowances, but the volume of external trading has still been very large.

In terms of emission reduction, the program has been a great success. The cap of 8.95 million tons/year of SO_2 represents about a 50% reduction from previous emission levels, and emissions have been below that cap since Phase II took effect in 2000. Indeed, during 1995-97 23.6 million allowances were allocated and only 16.2 million were retired, so there was a considerable over-achievement of the Phase I goals. (Ellerman *et al.* 2000, p. 110.) It is unlikely that Congress could have agreed on an emission reduction this large without the trading provisions.

The most sophisticated study of the cost savings from using emissions trading to achieve the Title IV emission reduction is Ellerman, *et al.* (2000, ch. 10). To determine the savings from trading, it is necessary to describe the regulatory program that trading replaces. Ellerman assumed that the alternative to Title IV was to implement a regulation that would limit each of the units to the allowances it receives under Title IV. This yields the same total emissions, and is a more reasonable program than assuming the scrubbing and new source requirements that preceded Title IV. Even with this reasonable regulatory comparison, Ellerman concludes that the cost savings from trading averaged US $358 million/year during Phase I and $2,282 million during Phase II. (Ellerman, *et al.*, 2000, p. 282.) This represents a cost reduction of about 55% from the costs that would have been incurred had the regulatory alternative been enacted. These savings are large because the costs of control among the many participating units vary enormously, trading takes place over many units, and transactions costs are low enough that most trading opportunities are exploited.

2.3 PERT

Canada's Pilot Emission Reduction Trading (PERT) was a pilot credit trading program that operated between 1996 and 2001. PERT facilitated the voluntary registry of emission reduction credits in Ontario for industrial emissions reduction below that required by regulations or voluntary commitments. The purpose was to develop a working example of an open market emissions reduction trading program, produce relevant documentation that supports the program, create a trading rule, and provide recommendations based on findings of the multi-stakeholder Working Group and Executive Committee. The initial focus was NO_X and VOC emissions; in 1997, the program was expanded to include $CO2_2$, SO_2, and CO.

Any source, regardless of size or industry, could make voluntary reductions and participate in trading. For an emission reduction to qualify for credits creation the reduction must be real, quantifiable, surplus, verifiable, and unique. (PERT, 1999.) Credits are measured in metric tonnes of pollution. A multi-stakeholder group of government, industry, environmental, and health organizations was set up to manage the project. PERT participants paid an annual fee to pay for administrative and research costs. Clean Air Action Corporation volunteered their registry to track and monitor the flow of transactions throughout the life of PERT. The following formula was used to calculate the credits available in a creation period:

ERCs created = (BER - CER) * CA

where:

BER = baseline emission rate
CER = creation period emission rate
CA = creation period activity[13]

The baseline emission rate was selected as the lower of the actual historical emission rate, actual projected emission rate, or the allowable emission rate (any legislative limit that may be set for a facility).

Ownership of registered credits can be contractually transferred between parties. Credits could be banked for use in subsequent years. There was no discount on trading, so credits could be traded at a 1:1 ratio. Sources keep records of all analytical results, calculations made, and testing undertaken to quantify and verify emission baselines and emission reduction credits. If a facility emits more than they are able to cover with credits, they will be assessed a penalty by the Ministry. Penalties can take the form of requiring sources to retire 3 times the amount of credits that they are deficient in a given creation period, suspension from the PERT project, or suspension from any emissions trading program in Ontario in the future.[14] The unit of measurement for the PERT program is in metric tons. That is, one credit is equal to one metric ton of emissions.

With respect to trading, there were 121 total transfers registered on the Clean Air Action Corporation registry leading to a total of 4,537,904 credits changing hands. OPG was the only buyer of credits. The largest three sellers of credits were the following companies:

1) KMS Energy

[13] PERT Trading Rule – http://www.pert.org/respapers.asp .
[14] PERT Trading Rule 7

2) PG & E Generating
3) EP 2000 Conservation Inc.

Direct and indirect levels of $CO2_2$ were the largest pollutants traded in PERT. In terms of credit transfers, indirect $CO2_2$ made up 73% of the total transfers traded 38% of the number of trades (44 trades).

Unfortunately, we have not been able to locate any published price data with respect to PERT.

Table 3: RECLAIM, SO_2 Allowance Trading and PERT

Program name	RECLAIM	SO_2 Allowance Trading	PERT
Market Organization	Cap-and-Trade	Cap and Trade	Credit trading system
Pollutants traded	NO_X and SO_2	SO_2 emissions	NO_X and VOC, added $CO2_2$, SO_2, and CO in 1997.
Type and size of source required to participate	All sources of NO_X or SO_2 greater than 4 tons/year. [15]	Phase 1: Coal-burning electric utility plants >100 MW capacity Phase 2: Coal-burning electric utility plants > 25 MW and all new utility units[16]	Membership open to all interested parties PERT actively solicited new participants.
Geographic market area	Orange County and major portions of Los Angeles, San Bernardino and Riverside counties in S. California[17]	Phase 1: Mostly sources in 21 eastern and midwestern states Phase 2: continental U.S.	Canada: ON, QUE, Man, U.S. - MI, IL, OH, PA, WI and NY[18]
Allocation rules	1994 allocation = maximum activity (1989-1992)* an emission factor. Emission factors reduced annually from 1994-2003. [19]	Principle for annual allocation (subject to many variations): Phase 1: 2.5 lbs/mmBtu of heat input * 1985-87 baseline Phase 2: 1.2 lbs/mmBtu of heat input * 1985-87 baseline[20]	Not Applicable
Time trend of emission limit	Reduce emissions from 1994 to 2003 by 75% for NO_X and 60% for SO_2[21]	Reduce emissions by 10 million tons below 1980 levels.[22] 50% reduction in 10 yrs.	Voluntary pilot program, no timetable imposed
Tradable unit	One RTC = one pound of emissions	One allowance = One short ton of SO_2	Emission reduction credits measured in metric tonnes[23]
Banking	No	Yes	Yes
Discount on trading?	No	No	No
Geographic trading limit?	Limit sale of inland RTCs to coastal sources.	Sources: continental USA; buyers unlimited.[24]	None

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15 AQMD Regulation XX, Rule 2001 (http://www.aqmd.gov/rules/html/r2001.html)
16 The U.S. Experience with Economic Incentives for Protecting the Environment (USEPA1) 2001, pg 76.
17 AQMD Homepage – http://www.aqmd.gov
18 Clean Air Mechanisms and the PERT Project: A Five Year Report pg 8
19 AQMD Regulation XX, Rule 2002
20 42 U.S.C. 7651d
21 Nash and Revesz, 2001, p. 610.
22 EPA Website - http://www.epa.gov/airmarkets/arp/overview.html#phases
23 PERT Trading Rule 2.3

Program name	RECLAIM	SO_2 Allowance Trading	PERT
Credit creation?	Credits for scrapping old cars, an existing program, carried over to RECLAIM.[25] Also opt-in provision for non-capped sources.	No. Sources not required to participate may opt in, receiving allowances based on 1985 heat input and an emission factor. [26]	ERCs created=(BER-CER) * CA where: BER = baseline emission rate, CER = creation period emission rate, CA = creation period activity[27]
Provision for new sources	Purchase offsets from existing source and trade for RTCs. (Rule 2005)	New sources must purchase allowances from existing sources or from the EPA auction.	Any sources may create credits. Credit creation is voluntary.[28]
Provision for shutdowns	Can sell RTC's but must indicate reason is shutdown to administrator[29]	Affected sources continue to receive allowances regardless of activity or shutdown.[30]	Emission reductions from plant or process shutdown are not eligible for credits, unless shutdown source is shifted to a replacement source with lower emissions rate[31]
Emission measurement / estimation method	>10 tons/yr NO_X use continuous emissions monitoring. < 10 tons use activity monitor and emission factor or install CEMS.[32]	Utilities in Phase 1 and 2 must install Continuous Emissions Monitoring and submit Quarterly reports of hourly emissions to EPA	Method of monitoring differs among sources. It is agreed upon in the Protocol.[33]
Records required for sources	Sources must measure, record and report emissions. See AQMD Rules 2011-1 (SO_2) and 2012-1 (NO_X)[34]	Sources must file quarterly reports of their hourly emissions data to the EPA[35]	Sources keep records of analytical results, calculations, and testing to quantify emission baselines and emission reduction credits[36]
Program record keeping system	AQMD runs monitoring computer system District imposes penalties and determined baseline emissions rates	EPA uses the Allowance Tracking System (ATS) to ensure compliance from sources.	Clean Air Action Corporation (CAAC) volunteered the use of their registry. PERT registration stages: creation, transfers, use, and retirement[37]
Legislative authority	The South Coast Air Quality Management District, Regulation XX.	Title IV of the *1990 Clean Air Act Amendments* 42 U.S.C. 7651.	None
Dispute resolution mechanism	Hearings regarding administrative penalties.[38]	EPA Civil Enforcement Program;[39] Administrative procedure.	PERT Working Group

[24] EPA Website - http://www.epa.gov/airmarkets/arp/allfact.html#who
[25] AQMD Regulation XVI, Rule 1610; Regulation XX, Rule 2008.
[26] EPA Website - http://www.epa.gov/airmarkets/arp/optin/index.html#who
[27] PERT Trading Rule 2.5
[28] PERT Trading Rule 2.2
[29] AQMD Regulation XX, Rule 2007
[30] 42 U.S.C. 7651b.
[31] PERT Trading Rule 2.10
[32] AQMD Regulation XX, Rule 2012, sections (c) and (d).
[33] PERT Trading Rule 4.4
[34] AQMD Website - http://www.aqmd.gov/rules/html/tofc20.html
[35] US EPA, 2001, Experience, p 78.
[36] PERT Trading Rule 4.5
[37] Pert (1999) p 12.
[38] AQMD Regulation XX – Rule 2010
[39] http://www.epa.gov/compliance/civil/

Program name	RECLAIM	SO_2 Allowance Trading	PERT
Start-up timing and procedures	The RECLAIM program began January 1, 1994.	Phase I began in 1995 Phase II began in the year 2000	Established in early 1996. Participants must subscribe to the Registry in order to participate[40]
Number of sources covered	1994 – NO_X=370 sources, SO_2 = 40 Sources (approx. 70% of stationary source emissions)[41]	445 units end of Phase 1; Phase 2 - over 2000 units[42]	101 firms are registered under the CleanAir Canada Registry[43]
Number of firms trading			16 unique firms traded over the life of PERT[44]
Number of trades/year	20,000 to 80,000 NO_X RTCs traded per year; 4,000 to 24,000 SO_2 RTCs traded per year. More than $253 million of NO_X RTCs and more than $25 million of SO_2 RTCs traded by 2001.[45]	2000 - 4690 transfers in ATS 1999 – 2832 (18.7 m. tons) 1998 – 1584 (13.5 m. tons) 1997 – 1429 (15 m. tons) 1994 - 215[46]	121 trades over all years
Characteristics of most active trading firms	Buyers: Large refineries and Utilities Sellers: small refineries, glass container mfgrs, and facilities that shut down.[47]	Coal burning electrical utilities	OPG only buyer of credits in PERT. Based on tonnes traded, Toromont Energy was the largest seller over the life of PERT.
Allowance price trends	SO_2 RTCs 1996 to 2000: US $1500 to $3000/ton. NO_X RTCs 1999: US $1,827/ton.[48] Much higher during 2000.	Prices began at US $300/ton but dropped to $150 by end 1993, to US $100 by 1996. Prices rose 1998 to $200/ton end 1999. $130-200/ton since 1999.[49]	Not Available
Penalties for rule violations	1) Reduce RTC allocation next year to cover the deficit. 2) Revoke permit 3) Penalty up to $500 per violation, per day[50]	Number of excess tons emitted times $2000 adjusted for inflation plus allowances to cover the excess.[51]	Submit credits to cover deficit; removal from the Registry, or suspension from future ERC trading in Ontario. Pert Model Rule, sec. 7.
Abatement cost savings from trading	Estimated cost reduction of US $58 million: from $139 m down to $81 m.[52] Save 42%.	US $358m/yr Phase I US $2,282m/yr Phase II. Save 55% of cost of traditional regulation.[53]	Not Available

[40] PERT Trading Rule 4.1
[41] US EPA, 2001, Experience, p 95
[42] EPA Website - http://www.epa.gov/airmarkets/arp/overview.html#phases
[43] www.epregistry.com
[44] www.epregistry.com
[45] SCAQMD, 2001, White Paper
[46] EPA Website - http://www.epa.gov/airmarkets/trading/SO2market/cumchart.html
[47] US EPA, 2001, Experience, p 96
[48] SCAQMD, 2001, White Paper
[49] EPA Website - http://www.epa.gov/airmarkt/trading/SO2market/pricetbl.html .
[50] AQMD Regulation XX – Rule 2010
[51] EPA Website - http://www.epa.gov/fedrgstr/EPA-AIR/1997/October/Day-07/a26531.htm .
[52] US EPA, 2001, experience, p. 95.
[53] Ellerman *et. al.*, 2000, ch. 10, p. 282.

Program name	RECLAIM	SO_2 Allowance Trading	PERT
Administrative costs to participants	3% to 10% transaction cost + $200/contract cost + planning and research	½% to 1.5% transaction cost (up to 10% on small trades) + 1% "slippage" + planning and research	$10,000 (CDN) review fee + consultants + brokers' fees
Administrative costs to governments	Not available	Issues allowances, records trades, audits emissions records. No screening or pre-approval of trades required 2 junior staff needed to process allowance transactions on ATS[54] Estimate $38 million 1990-1995.	No government cost, but PERT record-keeping system cost $40,000 to set up.

3. EPA NO_X BUDGET TRADING

The programs described below have been designed to help meet the standard for tropospheric ozone under Title I of the United States *Clean Air Act.*[55] Title I creates a structure under which the federal Environmental Protection Agency (EPA) is responsible for setting ambient air quality standards and state environmental agencies are responsible for meeting those standards by controlling emissions. States are required to develop State Implementation Plans (SIPs), detailing the steps they will take in addition to the federal measures to attain the ambient standard. The EPA reviews SIPs and is able to force states to revise their plans by announcing a 'SIP Call' if necessary. (Farrell, 2001.)

The two programs outlined in this section have both evolved as part of the *Clean Air Act* process. The Ozone Transport Commission (OTC) budget program was made possible by amendments to the *Act* in 1990 that acknowledged the impossibility of north-eastern states to attain the ozone standards with in-state controls alone due to significant transport from 'upwind' states, in short, the failure of section 126 of the *Clean Air Act*. (Farrell, Carter and Raufer, 1999.) The NO_X SIP Call is a more recent attempt to meet specific NO_X emission targets across all states.

3.1 The OTC Budget Program

The 1990 Amendments to the Clean Air Act created the Ozone Transport Commission (OTC) to coordinate the planning to reduce air pollution in the twelve Northeastern states from Maine to the northern counties of Virginia and the District of Columbia.[56] These amendments recognised that ground level ozone is a regional problem not confined to state boundaries and established special provisions to address ozone non-attainment areas. In 1994, the OTC developed a Memorandum of Understanding requiring each state to achieve region wide NO_X emission reduction targets by 1999 and 2003 through a 'cap and trade' emissions trading program.[57] These reductions are in

[54] US EPA, 2001, Experience, p 79
[55] *Clean Air Act*. Pub. L. 89-675, title I, 1963, 79 Stat. 992.
[56] The OTC states are: Connecticut, Delaware, Massachusetts, Maryland, Maine, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont as well as the District of Columbia.
[57] Virginia did not adopt the MOU.

addition to previous OTC state efforts to control NO_X emissions, which included the installation of reasonably available control technology (RACT).[58]

The OTC states in collaboration with the US EPA, as well as representatives from industry, utilities, and environmental groups, developed a model rule that identified key elements that should be consistent among the regulations in all participating states so that an integrated interstate emissions trading program could be created.

The program affects all fossil fuel fired boilers or indirect heat exchangers with a maximum rated heat input capacity of 250 mmBtu/hour or more and all electric generating facilities with a rated output of 15 MW or more.

For the control period, or control season, of May through September 1999 – the start of the first phase of the program – the region-wide seasonal NO_X budget was 219,000 short tons. This cap remains in place until 2003 – the start of the second phase of the program – when the cap will be reduced to 143,000 tons.

The area covered by this program includes three geographic zones with different emission reduction targets. The inner zone includes the Atlantic coast from Northern Virginia to New Hampshire, to varying distances inland. The outer zone is adjacent to the inner zone, from western Maryland through most of New York State. The northern zone includes northern New York and New Hampshire, and all of Vermont and Maine. By 1999, NO_X emissions were to be reduced by 65 per cent from baseline in the inner zone and 55 per cent in the outer zone. In 2003, emissions are to be further reduced by 75 per cent from baseline for the inner and outer zones, and 55 per cent for the northern zone. The inner zone targets are higher initially because they have been judged as being in 'moderate', 'serious' or 'severe' non-attainment of the *Clean Air Act* ambient standards.

The EPA distributes NO_X allowances to each state, and the states then allocate allowances to the sources in their jurisdiction. Each source receives allowances equal to its restricted percentage of 1990 emissions, a fixed time prior to the initiation of the program. Each source must submit one allowance for each ton of NO_X emitted over the ozone season. Sources may buy, sell and bank allowances. While there are no geographic restrictions on trade, limits on banking mean that banked allowances are discounted when the level of banked emissions is high, a provision referred to as progressive flow control. If the total number of banked allowances in the program is less than 10 percent of the NO_X budget for the season, then banked allowances may be withdrawn and used at face value. However if the total in the bank exceeds 10 percent of the budget, the PFC ratio must be calculated as: 0.1*(NO_X budget)/banked allowances. When a source submits allowances, its current year allowances are taken at face value, but only the PFC fraction of banked allowances will be accepted at face value; the remaining fraction of banked allowances being accepted at 2:1 (that is, 2 banked allowances per ton of emissions). This flow control was applied in the year 2000 (PFC = 0.5) and 2001 (PFC = 0.36). (US EPA, 2000.)

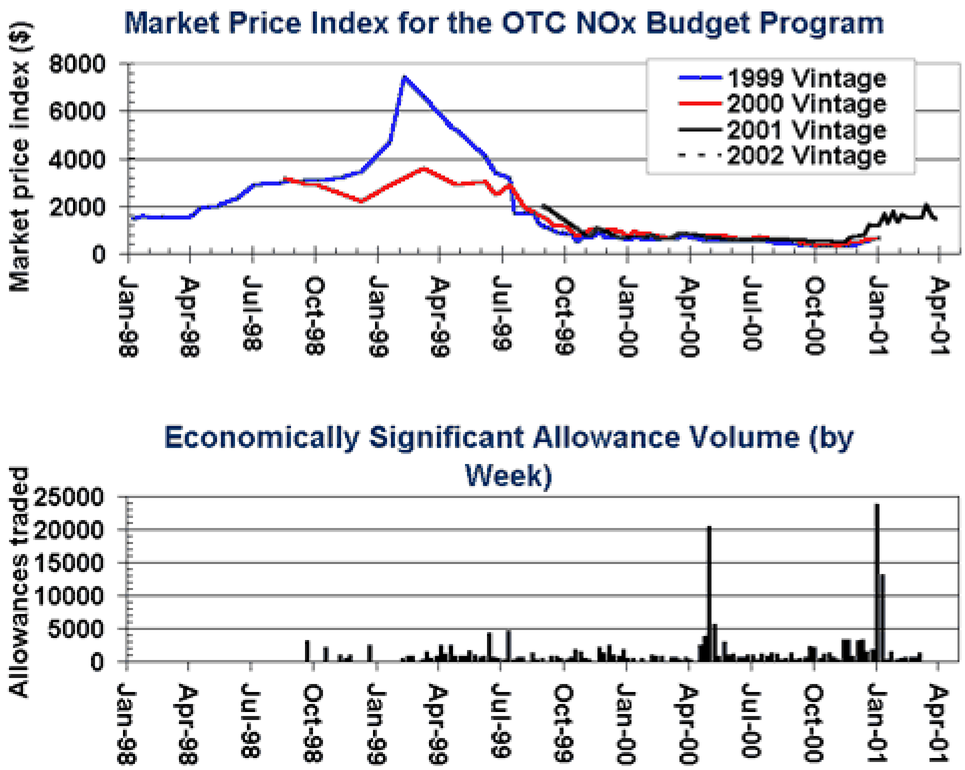
[58] *Clean Air Act*, Section 182 (42 U.S.C. § 7511(a)).

The 2001 compliance report found that NO_X budget sources emitted 12 per cent less than their allowable emissions level (similar to the 11 per cent below the allowable emissions level in 2000). (US EPA, 2002a). Because the number of banked allowances exceeded 10 per cent of the total regional NO_X budget for the year, only 36 per cent of the banked allowances could be used at a one to one ratio while the remaining 64 per cent could only be used at a two to one ratio.

A significant volume of trading has occurred. While usually less than 40,000 allowances a month are traded, in peak months as many as 90,000 allowances have been traded. This trade occurs principally between utilities.

Prices for OTC NO_X allowances were quite variable early in the program but they have begun to level off as the trading program becomes more established. Prices were relatively stable during 1998 at approx. $2,000-$3,000 per ton. As the first NO_X season approached, participants began to anticipate a shortage of NO_X allowances and the price rose to more than $7,000/ton. However, as operating data began to demonstrate that a surplus would be available, allowance prices began to drop and they have remained below $2000 ever since. As can be seen, there is considerable variation in prices across vintage, especially between the beginning and mid parts of 1999. This is probably because only NO_X allowances from the 1999 vintage were available at that time period. With the progression of time NO_X allowances from other vintages became available, hence driving down prices and permitting prices to converge across vintage. However, the past four months has witnessed a spike in NO_x prices in the US, reaching as high as $US 7,500.

Figure 2: Historical NO_X Allowance Prices



Source: EPA Website - http://www.epa.gov/airmarkets/trading/NOxmarket/pricetransfer.html .

3.2 NO_X SIP Call

While the EPA was assisting the OTC to develop its NO_X trading program it also sought to put in place a broader program into which the OTC scheme could eventually be merged. In October 1998, the EPA issued a SIP call and promulgated a NO_X SIP rule requiring upwind states to take action to ensure that the transport of NO_X would not contribute significantly to the non-attainment of the ambient air standards in downwind states. The EPA's Model Rule is not compulsory, it is only a model, and states may deviate from its provisions. Here we describe the Model Rule and then the actual rules of two states that developed their own rules following the Model Rule more (Pennsylvania) or less (New Jersey) closely.

Despite challenges from various states and industry groups the SIP call has been upheld and requires 22 eastern states and the District of Columbia to reduce NO_X emissions sufficiently to bring the majority of non-attainment areas into attainment with the air quality standards.[59] The EPA has since announced a model NO_X trading rule that states can adopt as part of their revised SIPs.[60]

As with the OTC trading program, the model program applies to large stationary sources (although other sources can opt into the program) and provides sources with provisions for the trading and banking of allowances. The design of the program is similar to the OTC program, with a control period, or season, running from May 1 to September 30. Limits have been placed on the use of banked allowances. The program has been designed to allow merger with the existing OTC NO_X trading program in the future.

The EPA's Model Rule begins with an allocation of NO_X allowances to a state for a particular year, which are divided between electric utility units with a capacity more than 25 megawatts (Part 96.4(a)(1)) and other boilers with a maximum design heat input greater than 250 mmBtu/hr (Part 96.4(a)(2)). For years through 2005, the heat input of a unit is defined as the average of the two highest years from among 1995, -96, -97. (Part 96.42(a)(1)(i).) For years 2006 and beyond, the heat input of a unit is defined as the heat input from four years earlier. (Part 96.42(a)(1)(i).) The electric utility units receive allowances in a year equal to their defined heat input multiplied by 0.15 lbs/mmBTU, **except** that if the sum of the allowances is not equal to 95% (98% in 2006 and beyond) of the allowances available for electric utility units, all allocations are increased or decreased by the same proportion until the sum equals the amount available. (Part 96.42(b)(1), (2).) The other boilers receive allowances in a year equal to their defined heat input multiplied by 0.17 lbs/mmBtu, **except** that if the sum of the allowances is not equal to 95% (98% in 2006 and beyond) of the allowances available for other boilers, all allocations are increased or decreased by the same proportion until the sum equals the amount available. (Part 96.42(c)(1), (2).) This system of allocation is equivalent to setting the cap for each of the two types of boiler and allocating that cap to the units in proportion to their defined heat inputs. Through 2005 the allocation is unchanging, based on a fixed time before the program began. Beginning in 2006 it is variable, depending on recent activity.

A source that closes down becomes exempt from the NO_X budget program thereby losing the right to receive allowances. (Part 96.5.) A unit that begins operation after May 1 of a control period may request allowances from the set-aside (5%, 2%) to cover the period from start-up until it can earn allowances under the 4-year rule. (Part 96.42(d).) The allowances will be based on the nameplate capacity of the unit multiplied by 0.15 or 0.17 lbs/mmBTU, as appropriate.

The Model Rule allows a unit that is not initially within the cap (not a NO_X Budget unit under 96.4) to opt in to the trading system. An opt-in unit will be given allowances in the amount of its defined heat input (based on a recent year or some other

[59] The states are: Alabama, Connecticut, Delaware, Georgia, Illinois, Indiana, Kentucky, Massachusetts, Maryland, Michigan, Missouri, North Carolina, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, Wisconsin and West Virginia.
[60] NO_X SIP Final Rule, Part 96, 63 Fed. Reg. 57,514 et. seq. [1998]

calculation) multiplied by an emission rate that is the lower of the unit's baseline emission rate or the most stringent federal or state emission limit applicable to the unit. (Part 96.88.)

The Model Rule allows banking of unused allowances. (Part 96.55.) If the sum of all banked allowances is less than 10% of the sum of the NO_X control budgets of the participating states the banked allowances may be used to cover current emissions. However if the total in the bank exceeds 10 percent of the budget, the PFC ratio must be calculated as: 0.1*(NO_X budget)/bank. When a source submits allowances, its current year allowances are taken at face value, but only the PFC fraction of banked allowances will be accepted at face value; the remaining fraction of banked allowances will be accepted at 2:1 (that is, 2 banked allowances per ton of emissions). (Part 96.55(b)(3).)

The EPA considered imposing geographic constraints on trading that either banned trade between certain regions or permitted some trades only with appropriate exchange rates. However, after asking for comments on the issue the feedback was overwhelmingly in support of unrestricted traded and so in its current form there are no geographical constraints to trade. (Nash and Revesz, 2001, p. 608.)

3.3 Pennsylvania Emissions Trading Program

Pennsylvania is an OTC state and showed early interest in the proposals to establish a regional emissions trading program to assist in meeting their ambient air quality standards. In 1997, Pennsylvania adopted a cap and trade program consistent with the Northeast Ozone Transport Commission's model rule. (Pennsylvania, 2000, p. 10.) That program is set out at 25 PA. Code, Chapter 123. The Chapter 123 program continued in effect through the 2002 control period, May 1 through Sept. 30. However it became apparent that this program would not achieve the NO_X reductions necessary to meet the EPA's section 110 NO_X SIP call, so Pennsylvania amended its State Implementation Plan in the year 2000 to further reduce its NO_X emissions.

The new interstate ozone trading program is set out in 25 *Pennsylvania Code*, Chapter 145 which will replace Chapter 123 in 2003. Subchapter A of Chapter 145 implements the EPA NO_X SIP Call, the portion of the Section 126 remedy applicable to Pennsylvania sources and *Clean Air Act* attainment requirements applicable to Pennsylvania. The method of determining the state budgets is summarised in Pennsylvania (2000, pp. 11-15). It consists of determining a 1995 base year emission inventory, projecting emissions from that inventory up to 2007 based on economic growth and anticipated emission reductions to get a base 2007 inventory, then assuming certain control levels (e.g. 0.15 pounds per mmBtu) to get the state budget.

The program is essentially a 'cap and trade' system covering two groups of NO_X emitters: electric generating units with capacities greater than 25 megawatts and other fossil fuel combustion units with a rated heat input capacity greater than 250 mmBTU per hour.[61] An exception excludes units whose control period NO_X emissions are less than

[61] 25 *Pennsylvania Code,* Chapter 145 'Interstate Ozone Transport Reduction' ss 4(a)(1) and 4(a)(2).

25 tons. The state is still considering incorporating two additional sources of emissions: internal combustion engines and cement kilns. Moreover there are provisions for NO_X emitters not included in the program to 'opt in'. (*Code,* Sections 145.80–88.)

The NO_X budget from 2003 to 2007 is 47,224 tons per control period for the electric generating sector and 3,619 tons for the other combustion units. (*Code*, s. 145.40) The control period is May 1 through September 30. Only 95 per cent of the allowances are allocated in any control period, leaving a 5 per cent set aside for new entrants or those choosing to 'opt in' to the program. (*Code*, s. 145.42(b)) The Pennsylvania program thus deviates from the Model Rule in applying only a 5% holdback, rather than 5% then 2%.

The formula for allocating allowances to units in each control period varies over time. For the years 2003 through 2007, allowances are allocated in each control period to units in the program based on the average of the two highest control period totals of heat input for the control periods in 1995 through 1998 multiplied by 0.15lb/mmBtu all divided by 2000lb/ton. (*Code*, s. 145.42) For the years 2008 through 2012, the allocation is based on the average control period heat input in years 2002 through 2004. Where the sum of these allocations exceeds 95 per cent of the available allowances they are all scaled back proportionally until they equal 95 per cent. Facilities allocated allowances under this provision that shut down (permanently retire) will become exempt from the program and thus will not be allocated permits. (*Code*, s. 145.5)

The formula for calculating allowances for new entrants and voluntary participants is similar to that for initial participants although the heat input is the minimum of either a pre-specified baseline or the monitored actual volume, and the emission rate is taken as the lesser of the baseline rate or the most stringent applicable state or federal limit. (*Code*, s. 145.42(d)) Where the sum of these special allocations in any control period exceeds the 5 per cent of total allowances available they are also scaled back proportionally.

Following the EPA's Model Rule, banking provisions have been incorporated into the trading program. Where banked allowances exceed 10 per cent of all allowances then a portion of any banked allowances used in a control period must be used in a two to one ratio applying the principles of progressive flow control set out in the Model Rule. (*Code*, s. 145.54(f).)

The new Pennsylvania trading program takes effect in 2003. It does, however, allow sources that reduced emissions in the 2001 or 2002 control periods to apply for "early reduction credits" which are allowances drawn from Pennsylvania's "compliance supplemental pool," a special allocation of the NO_X budget. If a NO_X budget unit reduces its emissions to less than 0.25lb/mmBTU **and** 80% of its emission rate in the 2000 control period, it may request early reduction credits in the amount of its heat input in the 2001 and/or 2002 control period multiplied by (0.25 lb/mmBtu-actual emission rate in the control period), converted to tons. (*Code* s. 145.43(a).) Thus qualifying reductions in 2001 and/or 2002 can be converted to allowances in 2003. The previous trading regulation, Chapter 123, can give rise to early reduction credits because of banked allowances or because of installing certain NO_X control technology, or for innovative control technology. (*Code* s. 145.43(b), (c), (d).) If the total of all requests for early reduction credits exceeds the supplemental pool, all allocations are reduced pro rata.

The trading program includes limited recognition of emission reduction credits (ERCs). (*Code*, s. 145.90) ERCs may be created under *Pennsylvania Code* Title 25, Chapter 127, which applies to the construction and modification of sources; Chapter 145 does not provide a new method of creating ERCs. Any ERCs created under Chapter 127 cannot be used to satisfy NO_X allowance requirements, so this is a cap-and-trade program, not a cap-and-trade-and-credit program. There are restrictions on the creation, transfer and use of ERCs that apply to NO_X budget units that do not apply to other units. For example, a NO_X budget unit may transfer NO_X ERCs to another NO_X budget unit if the recipient unit's ozone control period allowable emissions do not exceed the ozone control period portion of the baseline emissions that were used to generate the NO_X ERCs. (*Code,* section 145.90(b).) If a NO_X budget unit transfers ERCs to a non-NO_X budget unit, the former must retire allowances in the amount of the ERCs created. In other words, an emission reduction cannot create ERCs and release allowances at the same time. Furthermore there are geographic restrictions on trading; ERCs may not be sold into a non-attainment region, currently the greater Philadelphia area consisting of Philadelphia, Bucks, Chester, Delaware and Montgomery counties.

Overall the Pennsylvania program closely follows the EPA model rule.

The volume of NO_X trading involving Pennsylvania buyers and sellers has increased steadily since the program went into operation in 1999. In 1999 there were 98 private sales involving a Pennsylvania buyer and seller; by 2002 this number had more than doubled to 223. The number of transactions involving a Pennsylvania buyer and an out-of-state seller quadrupled from 77 in 1999 to 311 in 2002. Finally the number of transactions involving a Pennsylvania seller and an out-of-state buyer grew from 116 in 1999 to 307 in 2002, with a dip to 89 in 2001. See Table 4 below.

Table 4: Annual Number of Private NO_X Trades: Pennsylvania

Year	PA. Seller PA. Buyer	PA. Seller Other Buyer	Other Seller PA. Buyer
1999	98	116	77
2000	148	141	98
2001	179	89	177
2002 (as of 10/23/02)	223	307	311

Source: NATS

3.4 New Jersey Emissions Trading Program

New Jersey adopted a NO_X Budget Program in 1998 to take effect in 1999.[62] The program is set out at NJ Administrative Code Title 7, Chapter 27, subchapter 31. The program is closer to the OTC program than to the EPA Model Rule. It is a cap and trade program although there are interactions with the State's offsets program and its open market emissions trading program. (Subch. 31.5, 31.6.) The program applies to fossil fuel electric utility units with a rated capacity greater than 15 megawatts and to fossil fuel fired indirect heat exchangers rated at 250 mmBtu or greater. (Subch. 31.2.) Other sources may opt in to the program. (Subch. 31.4.)

The overall allocation of NO_X allowances to the State is 17,340 tons per control period from 1999 through 2002 and 13,022 tons per control period from 2003 forward. (Subch. 31.3(b).) The distribution of allowances takes place in April of each year and changes from 2002 to 2003. Up to 2002, the state begins by deducting from 17,340 reserves for new sources and for growth of existing sources. The New Source Reserve is determined as the product of each new source's allowed emission rate (but no more than 0.15 lbs/mmBtu) and its activity level. (Subch. 31.7(b)(1).) The Growth Reserve is determined only for sources with weighted average emission rates during the last three control periods less than 0.15 lbs/mmBtu and it equals the emissions that would result from a 50% increase in heat rate for the control period. (Subch. 31.7(b)(2).) The remainder of the budget is allocated to existing sources by multiplying the lesser of the actual emission rate or 0.15 lbs/mmBtu by the average of the two highest heat rates for the last three control control periods. (Subch. 31.7(b)(4).) If the total allocation for New Sources, Growth Reserve and existing sources exceeds the budget, then the allocation to sources that were in existence in 1990 will be divided in proportion to percentages specified in Table 1 of the Statute. (Subch. 31.(b)(5).)

For years 2003 and following, the distribution procedure differs in several ways. First, the state transfers 4,822 allowances to the attainment reserve, leaving 8,200 to be distributed. (Subch. 31.7(d).) Then it deducts allowances for energy conservation incentives. It calculates New Source Reserves based on the allowed emission rate and allowed activity for the new source, where the allowed emission rate may not be more than 0.15 lb/mmBtu for electricity generating units and 0.20 lb/mmBtu for industrial sources. (Subch. 31.7(d)1.) Then it calculates the Growth Reserve for generating units less than 0.15 lb/mmBtu and for industrial sources less than 0.20 lb/mmBtu, in both cases equal to 150% of the average heat input for the two highest heat input control periods of the last three control periods. (Subch. 31.7(d)2.) The state does a preliminary distribution of allowances to industrial boilers equal to 0.2 lb/mmBtu multiplied by the average of the two highest heat inputs of the last three control periods, or if the actual emission rate is less than 0.2 lb/mmBtu the emission rate used is the average of the actual emission rate and 0.2 lb/mmBtu. For electricity generating units, if the emission rate is greater than 0.15 lb/mmBtu, allowances are based on electricity output and steam output multiplied by factors that are equivalent to 0.15 lb/mmBtu; if the emission rate is less

[62] *New Jersey Administrative Code* Title 27, Chapter 27, subchapter 31, section 1.

than 0.15 lb/mmBtu, allowances equal the average of those calculated from 0.15 lb/mmBtu and those calculated from the actual emission rate. (Subch. 31.7(d)4.) If the total of allowances to be allocated exceeds those available for allocation, then the existing source allocations are all scaled back proportionally to fit the total available. (Subch. 31.7(d)5.)

As is apparent from the above, new sources receive an allocation of allowances based on their activity, and growing sources may receive extra allowances if their emission rate is below the threshold. Non-budget sources can opt into the program, bringing with them allowances equal to the lesser of their actual emissions or their allowed emissions. (Subch. 31.4.) Banking is allowed, but as with the model rule, if the total allowances in the bank exceed 10% of the current budget, then a portion of any banked allowances used in a control period must be used in a two to one ratio. (Subch. 31.11(d).)

Sources that reduced their emissions in the two years before the program began operating may be able to create credits for those reductions, which become allowances in the current program. (Subch. 31.12.) The trading program does not provide for emission reduction credits otherwise, but it does link to the offset credit program and to the State's Discrete Emission Reduction system. These things cannot be turned into allowances for the NO_X trading system. (Subchs. 31.5, 31.6.)

The penalty for having insufficient allowances to cover the source's emissions in a control period is to surrender three times the shortfall in the next control period. (Subch. 31.19.)

NO_X trading involving New Jersey sellers and buyers has varied since the program began in 1999. The number of private trades between New Jersey buyers and sellers has varied between 20 and 40. New Jersey sellers sold few NO_X allowances to outside buyers in the first two years, but 327 such trades have already been recorded in 2002. New Jersey purchases from outside sellers declined from 1999 to 2000 but tripled from 2001 to 2001. The total volume of in-state trading is far below that of Pennsylvania, but interstate trading is similar to that of Pennsylvania. See Table 5 for details.

Table 5: Annual Number of Private NO_X Trades: New Jersey

Year	NJ. Seller NJ. Buyer	NJ. Seller Other Buyer	Other Seller NJ. Buyer
1999	38	11	135
2000	20	8	94
2001	24	142	106
2002 (as of 10/23/02)	40	327	329

Source: NATS (NO_X Allowance Tracking System)

Table 6 summarizes the main features of the above discussed NO_X trading programs.

Table 6: NO_X Budget Trading

Program name	**NO_X SIP Call: Model Rule**	**NO_X Budget Prog.: New Jersey**	**NO_X SIP Call: Pennsylvania**
Market organization	Cap and trade	Cap and trade	Cap and trade
Pollutants traded	NO_X	NO_X	NO_X
Type and size of source required to participate	Fossil fuel electric utility units > 25 MW Fossil fuel boilers >250 mmBtu	Fossil fuel electric utility units > 15 MW[63] Fossil fuel heat exchangers >250 mmBtu;	Fossil fuel electric utility units > 25 MW[64] Fossil fuel combustion units >250 mmBtu;[65] unless < 25 t/yr NO_X[66]
Geographic market area	19 Eastern States and Washington DC: AL, CT, DC, DE, IL, IN, KY, MA, MD, MI, NC, NJ, NY, OH, PA, RI, SC, TN, VA, WV	New Jersey and SIP states[67]	Pennsylvania and other states allocated a NO_X budget
Allocation rules	US EPA sets state NO_X budget for both types of sources. State allocates to units in proportion to heat input – Until 2005 use 1995-97 heat input; After 2005, use heat input from 4 years previous	State deducts from NO_X budget reserves for new sources and growth and allocates remainder to units in proportion to heat input – in the highest 2 of the last 3 years x 0.15 or an average of the actual emission rate and 0.15 if actual is lower (99-02);[68] **Or** for 2003 +, heat input of the highest 2 of the last 3 years x 0.20 for non-EGUs, and x 0.15 for EGUs or a factor x electricity output, scaled back proportionally if budget is exceeded.[69]	State allocates 95% of NO_X budget to units in proportion to heat input – 2003-2007, use 1995-98 heat input base; 2008-2012, use 2002-2004 heat input base; 2013+ use 5-year average.[70]
Time trend of emission limit	By 2007 meet air quality goal	17,340 tons 1999-2002; 13,022 tons 2003 +.[71]	Steady 2003-2007: 50,843.[72]
Tradable unit	One allowance authorizes one ton of emissions	One allowance authorizes one ton of emissions	One allowance authorizes one short ton of emissions
Banking	Yes. But 2:1 discount if bank > 10% of budget.	Yes. But 2:1 discount if bank > 10% of budget.[73]	Yes. But 2:1 discount if bank > 10% of budget.

[63] *New Jersey Administrative Code*, Title 7, Chapter 27, Subchapter 31, (hereafter *NJAC*) s. 31.2.
[64] 25 *Pennsylvania. Code*, Ch. 145, (hereafter *Pa. Code*) s. 145.4(a)(1).
[65] *Pa. Code* s. 145.4(a)(2).
[66] *Pa. Code* s. 145.4(b).
[67] *NJAC* 31.10(b).
[68] *NJAC* 31.7(b), (c)
[69] *NJAC* 31.7(d), (e)
[70] *Pa. Code* 145.42. Calculation uses 0.15 and 0.17 lb/mmBTU, but reconciles.
[71] *NJAC* 31.3(b).
[72] *Pa. Code* 145.40.
[73] *NJAC* 31.11(d).

Program name	NO_X SIP Call: Model Rule	NO_X Budget Prog.: New Jersey	NO_X SIP Call: Pennsylvania
Discount on trading?	No	No	No
Geographic trading limit?	No	No	May not sell into non-attainment area: greater Philadelphia
Credit creation?	Not Applicable	Yes, but not to satisfy the NO_X trading system. Limited use for credits created.	Yes, but not to satisfy the NO_X trading system. Limited use for credits created.[74]
Provision for new sources	Allowances from set-aside	From set-aside based on 0.15 lb/mmBtu (max) x max activity[75]	From set-aside based on heat input and emission factor.[76]
Provision for shutdowns	Retirement ends allowance distribution	Retirement ends allowance distribution	Retirement ends allowance distribution
Emission measurement / estimation method	CEM for EGUs	See 40 CFR 75.72 & 75.76	See 40 CFR 75.72 & 75.76
Records required for sources	Sources record emissions	Sources record emissions.[77]	Sources record emissions
Program record keeping system	EPA database for allowance accounts, holdings, transactions, etc. (NATS: NO_X Allowance Tracking System)	NO_X Budget Administrator database for allowance accounts, holdings, transactions, etc. If state chooses, it could be EPA administered.	NO_X Budget Administrator database for allowance accounts, holdings, transactions, etc. If state chooses, it could be EPA administered
Legislative authority	US *Clean Air Act* sections 110, 126; 42 USC 7410(k)(5) and 42 U.S.C. 7426(b).	NJ *Administrative Code* Title 7, Chapter 27, Subchapter 31 (NJAC-7-27-31)	25 *Pa. Code*, Ch. 145
Dispute resolution mechanism	None specified.	Administrative procedures generally.	Administrative procedures generally.
Start-up timing and procedures	Initial compliance date is May 31,2004	Initial compliance date is May 31,2004.[78]	Initial compliance date is May 31,2004
Number of firms covered	Varies by state	13 companies listed in Table 1 of NJAC-7-27-31[79]	EGU: 64 firms Large Non-EGU's: 37 firms[80]
Number of firms trading	Varies by state		
Number of trades/year	Varies by state	2002 – 40 NJ/NJ trades; 327 sales to others; 329 purchases from others	2002 – 223 Pa/Pa trades; 307 sales to others; 311 purchases from others
Characteristics of most active trading firms	Varies by state	Public Service Electric & Gas contributed 2/3 of emissions or activity.	
Allowance price trends	Varies by state		
Penalties for rule violations		Allowance shortfall penalty: pay 3x shortfall allowances.[81]	Not in rule.

[74] *Pa. Code* 145.90.
[75] *NJAC* 31.7(b)1.
[76] *Pa. Code* 145.42(b). 0.15 or 0.17.
[77] *NJAC* 31.15.
[78] *NJAC* 31.12.
[79] *NJAC* 31.7.(b)5.
[80] *Pa. Code* 145.
[81] *NJAC* 31.19.

Program name	NO_X SIP Call: Model Rule	NO_X Budget Prog.: New Jersey	NO_X SIP Call: Pennsylvania
Other issues		Opt-in provision, bring actual and limit emission rate, last 5 years.[82] Allowance allocation provisions needlessly complex.	

4. European Union $CO2_2$ Trading

4.1 Overview

The proposed Commission of European Communities allowance scheme will be organized as a cap and trade system. Two concepts are central to the proposal. First, each installation covered by the scheme must hold a greenhouse gas permit. The permit sets an obligation to hold allowances equal to the actual emissions as well as requires adequate monitoring and reporting of emissions. Second, transferable greenhouse gas allowances, denominated in metric tonnes of carbon dioxide equivalent, entitle the holder to emit a corresponding quantity of greenhouse gases. If they do not have enough allowances, sanctions will be imposed on them. The holding and tracking of allowances will be done through an electronic register. The total quantity of allowances issued under the proposal would "be left essentially to the Member states".[83]

4.2 Participation

The proposal lists types of installations that will be required to participate in the program:

- Energy installations if they are a) burning fuel at a rate exceeding 20 MW; b) mineral oil refineries, or c) coke ovens.
- Installations that produce or process ferrous metals if they roast or sinter metal ore, or produce pig iron or steel at more than 2.5 tonnes per hour.
- Mineral installations that only a) produce cement clinker in rotary kilns at more than 500 tonnes per day or lime at more than 50 tonnes per day b) installations that manufacture glass with a melting capacity exceeding 20 tonnes per day, or c) installations that manufacture ceramic products by firing, at more than 75 tonnes per day, and/or with a kiln capacity exceeding 4 m^3 and with a setting density per kiln exceeding 300 kg/m^3.
- Other installations that produce a) pulp from timber or other fibrous materials or b) paper and board with a production capacity exceeding 20 tonnes per day.

[82] *NJAC* 31.4.
[83] Commission of the European Communities, Proposal for a Directive of the European Parliament and of the Council establishing a scheme for greenhouse gas emission allowance trading within the Community and amending Council Directive 96/61/EC, Brussels, October 23, 2001, p. 11.

4.3 Program Details

Each Member State (Belgium, Spain, Luxembourg, Finland, Denmark, France, Netherlands, Norway, Germany, Ireland, United Kingdom, Italy, Portugal, Greece, Austria, Sweden) will develop a national plan stating how it proposes to allocate the allowances. The total quantity of allowances to be allocated for the relevant period will be consistent with the Member State's obligation to limit its emissions pursuant to Decision xx/xxxx/EC and the Kyoto Protocol. For three years beginning Jan. 1, 2005, Member States shall allocate allowances free of charge. The Commission shall specify a harmonized method of allocation for the five-year period beginning Jan. 1, 2008.

Beginning on Jan. 1, 2005, installations required to participate in the program must possess a permit. Three years later the program begins officially and the air quality goal must be met. By 2010, approximately 4,000 to 5,000 installations will be covered by the program.

Measurement of emissions will use standardized or accepted methods, and will be corroborated by a supporting calculation of emissions. Calculations of emissions will be performed using the formula: (activity data) x (emission factor) x (oxidation factor).

Each Member state will establish and maintain a registry of the issue, holding, transfer, and cancellation of allowances. The registry will contain separate accounts to record the allowances held by each person to whom allowances are issued or transferred. A Central Administrator will be designated to maintain an independent transaction log recording the issue, transfer, and cancellation of allowances.

Member states will establish penalties and ensure that they are implemented. The penalties must be effective, proportionate and dissuasive.

Member states will publish the names of operators who are in breach of national provisions. Any operator which does not surrender sufficient allowances by March 31 of each year to cover its emissions during the previous year will be liable for the a penalty of EUR 100 or twice the average market price during the first quarter of that year for allowances valid for emissions during the preceding year, whichever is higher, for each excess tonne of carbon dioxide equivalent emitted. The operator must also surrender allowances equal to those excess emissions when surrendering allowances in relation to the following calendar year.

During the three-year period beginning January 1, 2005, the excess emissions penalty will be EUR 50 or twice the average market price.

The primary legislative authority is the Directive of the European Parliament and of the Council establishing a scheme for greenhouse gas emission allowance trading within the European Community, 23.10.2001. The secondary legislative authorities are the Burden Sharing Agreement (as contained in the Council Conclusions of 16 June 1998) and Council Directive 96/61/EC concerning integrated pollution prevention and control, OJ L 257, 10.10.1996.

The proposal allows for the unrestricted banking of allowances from one year to the next during the initial three-year period or within each subsequent five-year period. Member states are free to decide whether to allow the banking of allowances between the period ending in 2007 and that starting in 2008.

Table 7: Proposed EU Greenhouse Gas Emission Trading

Program name	**Proposed CEC GHG Emission Trading Allowance Scheme**
Market organisation	Cap and trade
Pollutants traded	$CO2_2$
Type and size of source required to participate	Energy activities: combustion installations with a rated thermal input > 20 MW; mineral oil refineries; coke ovens. Production and processing of ferrous metals: metal ore roasting or sintering installations; Installations for the production of pig iron or steel with a capacity > 2.5 tonnes per hour. Mineral industry: installations producing cement clinker in rotary kilns with capacity > 500 tonnes/day or lime in rotary kilns or furnaces with capacity > 50 tonnes/day; glass manufacture with a melting capacity > 20 tonnes/day; ceramic products manufacture by firing with capacity > 75 tonnes/day, and/or kiln capacity exceeding 4 m^3 and with a setting density per kiln exceeding 300 kg/m^3. Industrial plants for the production of: pulp from timber or other fibrous materials; paper and board with capacity > 20 tonnes per day
Geographic market area	15 countries comprising the European Union: Belgium, Spain, Luxembourg, Finland, Denmark, France, Netherlands, Norway, Germany, Ireland, United Kingdom, Italy, Portugal, Greece, Austria, Sweden.
Allocation rules	Each State will allocate allowances, the total quantity of which is consistent with the State's obligation under the Kyoto Protocol. For the three-year period beginning Jan 1, 2005, Member States shall allocate allowances free of charge. The Commission shall specify a harmonized method of allocation for the five-year period beginning Jan 1, 2008.
Time trend of emission limit	By 2008 meet air quality goal.
Definition of emissions for trading purposes	One allowance authorizes one tonne of emissions
Discount on trading?	Not specified.
Geographic trading limit?	Allowances can be traded within the European Community
Credit creation?	No
Provision for new sources	Left to member states.
Provision for shutdowns	Left to member states
Emission measurement / estimation method	Measurement: Standardized or accepted methods. Calculation: Emissions = Activity data x Emission factor x Oxidation

	factor
Program record keeping system	A central administrator shall maintain an independent transaction log recording the issue, transfer and cancellation of allowances
Legislative authority	Primary: Directive of the European Parliament and of the Council establishing a scheme for greenhouse gas emission allowance trading within the European Community, 23.10.2001 Secondary: Burden Sharing Agreement (as contained in the Council Conclusions of 16 June 1998) Council Directive 96/61/EC concerning integrated pollution prevention and control, OJ L 257, 10.10.1996
Start-up timing and procedures	Jan 1 2005 to Dec 31 3007: Installations require permits to undertake an activity listed above, but there are no legally binding targets. Jan 1 2008 to Dec 31 2012: The program begins officially. This gap in time is to enable countries to meet the requirements of the Kyoto Protocol.
Number of sources covered	Approximately 4,000 to 5,000 by 2010
Penalties for rule violations	To be set by member states. The penalties must be effective, proportionate and dissuasive. Member states shall publish the names of violators. Any operator that does not surrender sufficient allowances to cover its emissions during the year is liable for an excess emissions penalty equal to the higher of EUR 100 or twice the average market price, for each excess tonne emitted. The operator shall also surrender allowances equal to those excess emissions next year. During 2005-2007, Member States shall apply a lesser penalty of EUR 50 or twice the average market price.
Other issues	Banking, Permits

5. US Refinery Lead Trading

The purpose of the U.S. lead trading program, developed in the 1980's, was to allow gasoline refiners greater flexibility while reducing the average lead content of gasoline to 10 percent of its previous level. The US EPA set a limit of 1.1 grams of lead per gallon of gasoline beginning on November 1, 1982. This limit was reduced to 0.5 grams/gallon on July 1, 1985 and to 0.1 grams/gallon on January 1, 1986. Refiners, however, differed in their ability to modify their refineries to meet this schedule, so the EPA provided two types of flexibility. In 1982, the EPA authorized inter-refinery trading of lead credits, so that refiners that produced gasoline with a lower lead content that was required would earn lead credits, which they could sell to refiners that had not yet met the standard. Initially the rights that a refiner earned by producing gasoline in a quarter expired at the end of that quarter if not used. In 1985, the EPA allowed refiners to bank credits and use them until the end of 1987, which extended the life of credits that had already been created. Cumulative total lead emissions on any date could not be larger than they would have been in the absence of trading, but refinery costs were lowered and possible shutdowns averted.

The lead trading program created a homogeneous tradable commodity: grams of lead. Any refiner that produced gasoline with less lead than the current legal limit could record its production and lead content and compute the quantity of credits created. The creation of credits depended entirely on current production activity, which was easy to monitor. There was no need for pre-approval of credit creation or the sale of credits. The EPA audited records after the fact and discovered and punished a small amount of fraud, but the system was generally self-enforcing. (US EPA, 2001, Experience, p. 87.)

The lead program was successful in meeting its environmental targets (Anderson, Hofmann and Rusin, 1990). By 1987 the amount of lead traded exceeded 40% of total lead used. Initially 20% of refineries participated in trading but late in the program participation reached 60% of refineries. One-half of trades were between refineries owned by the same firm, and in the other half of the trades there was a tendency to trade with their normal trading partners. This pattern suggests that transactions costs were higher in dealing with strangers. (US EPA, 2001, Experience, p. 87.) Trading levels suggest that the program was cost effective (Kerr and Mare, 1997). The trading activity was higher than earlier environmental markets (U.S. General Accounting Office 1986). The EPA estimated savings from the lead trading program of approximately 20 percent over alternative schemes that did not provide for lead banking, a cost savings of about $250 million per year (U.S. EPA, Office of Policy Analysis 1985).

6. Transactions Costs in Emissions Trading Markets

Considerably more is known on a theoretical level about the likely effects of transaction costs on the performance of tradeable permit markets[84] than about the actual magnitude of these costs in previous or currently operating programs. This section of the report reviews what is known about the magnitude of these costs. The section is divided into three main sub-sections: sources of transaction costs; empirical evidence of the existence of transaction costs in tradeable permit markets; and quantitative empirical estimates. The final is a key contribution of this study as there exists very little in the way of quantitative estimates of transactions costs.

6.1 Sources of Transaction Costs in Tradeable Permit Markets

Transaction costs can arise from the transfer of property rights because parties to exchanges must find one another, communicate, and exchange information. There may be a necessity to inspect and measure; draw up contracts, consult with lawyers or other experts, and transfer title. Depending upon who provides these services, transaction costs can take one of two forms: inputs of resources — including time — by a buyer and/or a seller; and as a margin between the buying and selling price of a commodity in a given market.

[84] See, for example: Stavins (1995).

Three potential sources of transaction costs in tradeable permit markets can be identified: (1) search and information; (2) bargaining and decision; and (3) monitoring and enforcement.[85] The first source, search and information, may be the most obvious. Due to the public-good nature of some information, it can be under-provided by markets. Brokers step in, provide information about firms' pollution-control options and potential trading partners, and thus reduce transaction costs, while absorbing some as fees.[86] Although less obvious, the second source of transaction costs, bargaining and decision, is potentially as important. There are real resource costs to a firm involved in entering into negotiations (Kohn, 1991), including time and/or fees for brokerage, legal, and insurance services (Hahn and Noll, 1982; Dwyer, 1992). The first two types of transactions costs are borne by market participants, but the magnitude of these costs may be influenced by the design of the market and by the trading infrastructure, discussed in sections 6.2 and 6.3 below. The third source of transactions costs — monitoring and enforcement — are typically borne by governmental authorities rather than trading partners.

6.2 Empirical Evidence of Transaction Costs

There is considerable anecdotal evidence of significant transaction costs in tradeable permit markets. Atkinson and Tietenberg (1991) surveyed six empirical studies of emissions trading that found trading levels — and hence cost savings — in permit markets to be lower than anticipated by theoretical models. Liroff (1989) suggested that this experience with permit systems "demonstrates the need for ... recognition of the administrative and related transaction costs associated with transfer systems."[87] And Hahn and Hester (1989a) suggested that the Fox River water-pollutant trading program failed due to high transaction costs in the form of administrative requirements that essentially eliminated potential gains from trade. Similarly, under EPA's Emissions Trading Program for criteria air pollutants, there was no ready means for buyers and

[85] All three categories can be interpreted as representing costs due to lack of information (Dahlman, 1979). An alternative taxonomy is: direct financial costs of engaging in a trade; costs of regulatory delay; and indirect costs associated with uncertainty of completing a trade (Foster and Hahn, 1995).

[86] In the Title IV SO_2 allowance trading program, there is a substantial role for brokers for consulting with electricity generators to help them identify their options. Brokerage firms maintain computer models used to predict the supply and demand for permits to provide forecasting services for utilities. In local programs, such as EPA's early Emissions Trading Program, not discussed in this report, brokers may also carry out air-quality modeling required for trades between non-contiguous sources of non-uniformly mixed pollutants (Krupnick, Oates, and Van de Verg, 1983).

[87] Alternative explanations of low observed trading levels have been advanced: lumpy investment in pollution-control technology; concentration in permit or product markets; the sequential and bilateral nature of the trading process (in the context of a non-uniformly mixed pollutant) leading to some initial trades that then preclude better trades from being carried out subsequently (Atkinson and Tietenberg, 1991); and the regulatory environment (Hahn and Noll, 1983; Bohi and Burtraw, 1992). Some but not all of these "alternative explanations" of low trading levels can be viewed as special cases of transaction costs, broadly defined.

sellers to identify one another, and — as a result — buyers frequently paid substantial fees to consultants who assisted in the search for available permits (Hahn and Hester 1989b; Hahn 1989). In short, the analysis of early emissions trading programs in the US, many of which were emission reduction credit programs, suggests that high transactions costs reduced trading substantially compared to trading levels predicted by models that ignored transactions costs.

At the other extreme, the high level of trading that took place under the program of lead rights trading among refineries as part of EPA's leaded gasoline phasedown, has been attributed to the program's minimal administrative requirements and the fact that the potential trading partners (refineries) were already experienced at striking deals with one another (Hahn and Hester 1989a). Hence, it has been argued that transaction costs were kept to a minimum and there was little need for intermediaries. Similarly, Tripp and Dudek (1989) claimed that the success of the New Jersey Pinelands transferable development rights program was due to its design, which minimized transaction costs (by government taking on a feeless brokerage role). The New Jersey Pinelands, an environmentally sensitive area of about one million acres, was targeted for protection through The New Jersey Pinelands Protection Act of 1979. The Pinelands Commission, the regional land use authority, established a transferable development rights program in 1980, which had protected 5,300 acres by 1991.

Likewise, some observers have suggested that the high level of activity currently observed in the SO_2 allowance trading market — activity which seems to be associated not only with regulatory compliance, but with conventional market exchange — is indicative of low transactions costs

Another source of indirect evidence of the prevalence of transaction costs in permit markets comes from the bias in actual trading toward "internal trading" within firms, as opposed to "external trading" among firms. It has been suggested that the crucial difference favouring internal trades and discouraging external trades has been the existence of transaction costs that arise once trades are between one firm and another (U.S. General Accounting Office 1982; Hahn and Hester 1989b). Finally, of course, the existence of commercial brokers charging significant fees to facilitate transactions is another body of evidence.

6.3 Quantitative Empirical Estimates

Empirical estimates of transaction costs are unavailable in the published literature. Hence, in order to develop rough estimates of the magnitude of transaction costs in previous and existing tradable permit markets, contact was made with officials at the U.S. Environmental Protection Agency, six brokerage firms, two emissions traders at U.S. companies, and three economists who have carried out research on the performance of tradable permit programs. In addition, the limited scholarly literature on quantitative estimates of transaction costs was reviewed.

There is some disagreement among market participants about what constitutes legitimate transaction costs. Four components frequently described are:

(1) search and brokerage costs;

(2) contracting costs;

(3) movement along the bid-offer spread when large quantities are traded (so-called "slippage"); and

(4) planning and research activities in firms engaged in trading.

The first two — search, brokerage, and contracting costs — are clear, but the second two are somewhat problematic, as explained below. Under these four headings, we consider active trading programs. Results for the lead trading program and PERT are reported separately because the decomposition is not possible in that case.

(1) Search and Brokerage Fees

Most existing tradeable permit markets in the United States have highly developed brokerage systems. Brokers implement searches for trading partners, and charge for this service. These brokers generally provide internally consistent estimates of transaction costs but they may have an incentive to understate transaction costs to avoid criticism of the impediment that these costs could offer to trading or to avoid drawing unwanted attention to their revenues. Official fee schedules that would provide unambiguous information regarding volume discounts and the like simply do not exist.

According to most brokers involved in the SO_2 allowance trading program, they frequently provide their services in regard to allowance transactions *at no cost*, essentially as a means of retaining clients that may generate substantial revenues in other areas. This does not imply that transaction costs are non-existent, but that they may be hidden.

According to one environmental economist who has studied the SO_2 allowance trading system, Dallas Burtraw (of Resources for the Future), transaction costs in the program range from 0.5% and 1.5% of the value of an allowance. Economists at MIT's Center for Energy and Environmental Policy Research who have also studied that same system in great detail agree.[88] For small trades, brokerage costs are greater, perhaps US$10 to US$20 per ton traded, that is, up 10% of the value of a trade. This applies only

[88] Joskow and Schmalensee (1998) analysed data on trades from 1992 to 1997, concluding that "a relatively efficient private market developed in a few years' time…. In 1993, third-party intermediaries developed transparent, standardized transaction procedures, and the cost of commissions fell to a fraction of that previously charged. Commissions per allowance per trade averaged $3.50 in mid-1994, $2.00 in late 1995, and $1.50 in September 1996. The latter (sic) figure was less than 2 percent of the prevailing spot price. Reported bid-ask spreads have also declined: from nearly $20 in August 1994….to $1.50 in January 1997. All of this points to the emergence of an efficient, competitive allowance market."

to small lots, however. Anything above 5,000 tons usually trades for free. Having observed that transactions costs have fallen, Joskow and Schmalensee (1998) noted that "it is plausible to expect that efficient markets for emission rights will be the norm as long as the government does not restrict when and how those rights can be traded on the private market."

Transaction costs in the newer NO_X trading program appear to be in the range of 1% to 5% of the value of allowances being transacted (US$600 presently). All brokers contacted expect these transaction costs to become minimal as the market matures and becomes more efficient (although, again, the transaction costs may show up as hidden costs in other transactions firms carry out with the same brokers). No one contacted thought that transaction costs would be different in Pennsylvania and New Jersey.

In the case of the Los Angeles-based RECLAIM program, Cason and Gangadharan (1996) report that in 1996, some brokers charged a minimum fee on the order of US$200, while others charged a one-time fee of US$100 plus about 3% of transaction value on successful trades. According to one broker, brokerage fees in the program today are still on the order of 3% to 5% on *both sides* of trades.

One difference between RECLAIM and the Title IV sulphur dioxide market that may contribute to the greater transaction costs in the former is that RECLAIM is a decentralized market system where facilities are expected to search for partners on their own without the help of centralized auctions arranged by the regulatory authority. (Gangadharan, 2000.) Apparently, RECLAIM does not utilize the internet or electronic bulletin board systems to help traders find each other. In contrast, Title IV trading includes a centralized auction as a small component of the market, and the EPA established a computerized allowance tracking system to keep track of allowance allocations, to record reallocations of allowances between generating units over time (via banking), and to mach emissions from a specific source in each year with the allowances it possesses. (Joskow and Schmalensee, 1998.) Moreover, Title IV allows banking, which facilitates trading, and RECLAIM does not.

EPA emphasizes that RECLAIM's administrative costs to the Agency have been enormous. This is significant, since it implies that were an environmental agency to take on the brokerage function for new tradable permit markets, this could involve significant costs.

(2) Contracting Costs

Numerous interviews with market participants produced only very general statements about contracting costs, that is, the cost of writing the contract. Frequently, market participants have special clauses in contracts, especially in the case of intertemporal trades, and it is because of this that contacting costs arise. Brokers generally confirm the intuition that for standard spot trades on the SO_2 allowance market, this cost is essentially zero, while according to one broker, it amounts to approximately

$100 per contract for even slightly nonstandard contracts. These contract costs appear to average about US$200 per contract for the SIP NO_X market and the RECLAIM program.

(3) Bid-Offer Spread

Some argue that the bid-offer spread does not represent transaction costs, while others argue that since the spread is a measure of how easy or difficult it is to change market position, it does constitute transaction costs from the firms' perspectives.[89] If a firm looks at bids and offers and sees a spread of US$10/ton, it may restrict its trading, fearing that any excess purchased (or sold) may have to be sold (purchased) later at a price that is unfavourable to the extent of the spread. This is not merely definitional; it has an effect on how one evaluates market liquidity and the allocative role of the market. The effect that trading has on market price — an effect some traders refer to as "slippage" — is usually minimal for quantities typically traded. For SO_2 and NO_X, most transactions are executed in the mid-range of the bid-offer spread (US$3-US$5 for SO_2). Slippage may turn out to be a major transaction cost when a firm greatly increases volume, driving the price to the limits of the existing spread and overwhelming the savings from decreasing per-unit contracting costs or decreasing per unit brokerage costs (volume discounts). For the RECLAIM program, the bid-offer spread is wider because of the lower liquidity of the market (with low liquidity keeping transaction costs high). No useful numerical estimates are available, however.

(4) Planning and Research Activities

No one contacted was willing or able to provide a numerical estimate in this area. The one statement on which everyone seems to agree is that planning costs are smallest for the SO_2 allowance trading program (essentially nil in most cases), but substantial for the NO_X program. Clearly, where a complicated dynamic programming problem needs to be set up and solved, the true transaction costs involve making decisions, not the act of trading *per se*. This is relevant for policymaking, because it implies that the fact that transaction costs have generally been small in existing markets does not necessarily imply that new markets will exhibit the same degree of active trading and associated cost savings (gains from trade).[90]

(5) The Lead Market

The relatively modest numerical estimates of transaction costs above are self-reported statistics of easily measurable costs, such as brokerage fees and the like. Interestingly, in the one case, where transaction costs have been estimated *indirectly* by

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[89] Parties that wish to purchase a commodity submit a "bid" for the product, while those interested in selling make an "offer". The difference between them is the bid-offer spread. The spread should converge in a well-functioning, frictionless market.

[90] The most fundamental determinant of the potential gains from trade from use of market-based instrument in a new market is the degree of heterogeneity of abatement costs in the affected sector (Newell and Stavins, 2003).

scholars, the estimates have been considerably greater, although the results are not directly comparable.

In the case of lead-rights trading program that was active in the United States in the 1980's when leaded gasoline was being phased out of the market, Kerr and Maré (2002) estimate that average transaction costs were around 30% of average surplus (gains from trade). But if the gains from trade are only a fraction of the market price of the permits (e.g. seller's cost = $100, buyer's cost = $150, gain from trading = $50), the transactions costs might be on the order of 11 % (($150-100)*0.3/$150 = 0.1).[91]

One of the authors of the lead phasedown study estimated that the observed loss reported above arises from a combination of people not trading, and thereby foregoing the savings from trading, and people trading but having to bear transaction costs. Richard Newell (Resources for the Future) confirms this intuition. However because the potential surplus from trading depends not only on the divergence of the refinery's marginal value from the market price of lead permits if trading does not take place, but also on the marginal product of lead use (the savings in refining costs from using lead to avoid further refining), these cost estimates from lead trading cannot be used to calculate total transactions costs for the lead market. From a policy perspective, the numerical estimates do indicate, however, that if transaction costs are large enough, their impact includes both expenditures on transactions and the failure to achieve the savings from transactions not made because of the transactions costs.

(6) PERT

Canadian experience with emissions trading is far less than in the USA. Nonetheless, some information on transactions costs is available from PERT.[92]
Details of the PERT Review Process are included as Appendix C in Butters (2000).

Two fees were charged to creators of emission reduction credits:

- A fee of $7,000 paid to PERT on application to have a proposal to create emission reduction credits reviewed by a panel of experts against the PERT criteria and approved.[93] The experts were drawn from the PERT membership. This application was known as a 'protocol report', and its purpose was to establish what the proponent was going to do. Reviews would typically take 4-6 weeks,

[91] In the Kerr and Maré econometric analysis, the proxy variables for transaction costs are: refinery size (proxy for on-site legal and accounting capacity); total capacity of firm (proxy for skill of traders); number of refineries in the firm (to measure the refinery's access to internal trading); and a time dummy (to account for learning and the development of relationships that reduce transaction costs).

[92] Mike Butters, Director of PERT until March 2002, provided information on some components of the transaction costs in this pilot project.

[93] Sunil Kumar of MacViro Engineering reported that for some projects, e.g. those that presented an interesting aspect that PERT wanted to explore, a lower fee might be charged.

though some took much longer owning to their complexity, lack of data and sometimes difficulty for the experts to reach agreement.

- Once approved , the protocol report was followed by annual 'creation reports' for the duration of the project. In these reports data was provided to PERT showing what actually transpired. Submission of this report was accompanied by a payment of $3,750.

The fees covered honoraria for the panels of experts, which reviewed the information. According to Butters (2000) the fees were "well below market rates." Members participated because they shared a desire to promote emissions trading and because they could benefit from the system as and when they submitted proposals. PERT had identified 21 areas of expertise required to review the documentation and was working with a model of 7 experts per area drawn from companies, NGOs and government. Panels for 3 areas were established before PERT ceased operations.

A third category of report included in the PERT process was the 'verification report', prepared by third party auditors who made site visits to ensure that the results in the creation reports were accurate. (Protocol reviewers did not make site visits.) Apparently there was no payment to PERT for these verification reports.

PERT also established an electronic registry at an estimated development cost of about $40,000 to track the creation and transfer of reduction credits. This registry has been further enhanced and is now operated by Clean Air Canada Inc. No additional fee was charged for posting an approved ERC on the registry. (The proponent did the posting but only the PERT system coordinator could change the posting.) After a trade was completed, the proponent was responsible for notifying the system coordinator who would record the transaction. Brokers were just starting to use the registry when the Ministry of the Environment introduced its trading system in January 2002.

In addition to the fees charged by PERT, companies would usually employ consultants, typically from small to medium sized engineering firms, to complete their protocol report and creation reports. The fees were highly dependent on the complexity of the emissions reductions under consideration. Sunil Kumar, Project Engineer in MacViro consulting had considerable experience in preparing PERT reports and he provided the following estimates of the fees:

- Protocol report – consultant fees typically ranged from $10,000 to $20,000. The low end applied when the methodology for estimating the reduction in emissions was well known and the data were readily available.

- Creation report – usually no more than $5,000 per year

- Verification report – a range of $5,000 to $10,000 was typical, including the costs of the site visit.

Under unusual circumstances, fees could go above the upper end of the above ranges.

6.4 Conclusions Regarding Transactions Costs

It appears possible to establish a cap and trade system in which the costs for participants to make trades is relatively small, perhaps only a one or two percent of the value of the allowances traded. Achieving low costs requires that the item traded be a perfectly standardized good – an allowance of a particular vintage, and that there be minimal restrictions on trading to minimise the cost of participants determining whether the trade will be legitimate. There must be no requirement for government pre-approval of trades. Low costs also require that it be easy for participants to identify potential trading partners. In the case of Title IV SO_2 trading, the participants are all members of a single sector and many of them probably knew many others well before the trading program was established, so it would be easy to enquire about trading possibilities. Moreover the predominance of trading within corporate entities speaks to the advantage of dealing with a party about whom one has confidence that they will uphold the bargain without problems or litigation. Finally, trading is facilitated by having a large number of potential participants and a central registry that provides information about the holdings of each participant, to reduce search costs.

The allowance trading portion of Ontario's new emissions trading program is similar to RECLAIM and the state NO_X trading programs in terms of the variety of sources included. Ontario's large sources are far less numerous than the sources in RECLAIM, but similar to the number of sources in some of the NO_X trading states. Ontario's allowances should be as homogeneous a commodity as the allowances in the US programs. Overall, our transactions costs should be similar to those in RECLAIM or in state NO_X trading. Because our market is far smaller than the Title IV market, we should not expect transactions costs as low as in that market.

Emission reduction credit systems seem to have inherently higher costs. Under a system like the EPA's emission credit program for criteria pollutants or under PERT, every project must be reviewed and approved before it can create credits. Instead of a standard commodity like allowances issued by the government, the thing being traded is custom-created with every project. Since every ERC system requires that the credits meet some sort of quality standard, review of the project and the proposed credits will be costly. The limited trading of credits under the EPA's early emissions trading, formalised in the EPA's 1986 "Final Emissions Trading Policy Statement" and the attached "Emissions Trading: Technical Issues Document"[94] suggests that we should expect higher transactions costs for such programs than for cap-and-trade programs. There were trades, saving considerable control costs, but they were relatively few in number and a large proportion were within corporate entities. (Hahn and Hester, 1989.)

Under the Ontario emissions trading system the first project of a particular type will require the preparation and submission of a new Standard Method, likely a costly undertaking. Subsequent projects that can use an existing Standard Method will not have

[94] Federal Register, 51: 233, December 4, 1986, pp. 43829-43859.

to repeat that expense, but they will still have to follow the procedure for creation spelled out in the *Code* including securing approval by the Director through a Notice of Creation. (*Code*, s. 2.2.6.)

Once the credits are created and approved, trading may still be more expensive than for allowances to the extent of any risk that the approval would be challenged. The *Code* provides for very limited challenges to the approval of creation, so this risk may be small. Whatever the risk, it may result in a discount on the price, one form of transaction cost discussed above.

Since credit creation depends on activity, the buyer of a stream of credits from a project faces some uncertainty that the stream will continue to be produced for the promised life of the project. Since the parties are in an ongoing relationship, as the credits are created every year, they must know more about each other than in a cap and trade situation. Allowances, unlike credits, are a homogeneous commodity issued to a number of sources under the program every year and bankable from one year to the next. If Ontario's emissions trading market is successful, it should always be possible to purchase allowances, at some price. Thus the problem of uncertain credit creation could be solved, in a multi-year purchase if the buyer is promised credits from the project or the equivalent in allowances, thereby allowing the seller to provide the latter if the project fails to create the former in a given year.

7. Administrative Costs in Tradeable Permit Markets

This review of what is known about administrative costs in tradeable permit markets in the United States is divided into four sections: background and methodology; administrative costs of programs operated by the U.S. Environmental Protection Agency (EPA); state-level administrative costs of the OTC NO_X Budget Program; and administrative costs of independent state trading programs.

7.1 Background and Methodology

We have collected information on the administrative costs of two categories of tradeable permits programs in the United States: (1) Federal (i.e., U.S. government) programs that operate at the national level, such as the SO_2 allowance trading program, or at the state level, such as the NO_X Budget Program (operated under the Ozone Transport Commission (OTC) NO_X Budget Program and the NO_X SIP Call);[95] and (2) independent state programs, such as the RECLAIM program of the South Coast Air Quality Management District (SCAQMD), the Michigan Air Emission Trading Program, and the Emissions Reduction Market System (ERMS) of the Illinois EPA Bureau of Air.

[95] The OTC NO_X Budget Program and the NO_X SIP Call have both Federal and state administrative costs because they are implemented at the state level, but much of the administrative work is performed by EPA.

To gather information regarding administrative costs for the EPA national programs, officials at the EPA Clean Air Markets Division were contacted. To determine the state-level administrative costs of the NO_X Budget Program, air quality divisions from all participating states were contacted. Also, officials were contacted at the SCAQMD, the Michigan Department of Environmental Quality, and the Illinois EPA Bureau of Air.

Through these contacts, we endeavoured to obtain estimates of administrative costs for specific tradeable permit programs. When hard numbers were not available, we asked for rough estimates, using a variety of measures that might be estimated — share of full-time equivalents (FTE's), number of person-hours, number of employees to run particular programs, and administrative budgets). When officials did not have data that would allow them to quantify costs, qualitative estimates were requested.

7.2 Federal Administrative Costs of EPA Programs

The total administrative costs of developing and implementing the SO_2 allowance trading program over its first five years — 1990 to 1995 — appear to have been on the order of US $38 million (McLean 1997),[96] accounting for the lion's share of the total administrative costs of EPA's acid rain program over those years — US $44 million. No breakdown is available of the US $38 million, but McLean (1997) offers the following breakdown of the total administrative costs of the acid rain program:

Table 8: US Title IV SO_2 Administration Costs

Program Development and Support	$19.9 million
Data System Development · Emissions Tracking System · Allowance Tracking System	$9.9 million
Program Operations · Applicability Determinations · Monitoring Plan Review · Certification · Review of Emissions Reports	$10.8 million

[96] Brian McLean is the Director of EPA's Clean Air Markets Division.

· Permit Review and Issuance · Recording of Allowance Transfers	
Other · Benefit-Cost Analyses, Program Evaluation · Outreach and Communication · U.S.-Canada Air Quality Agreement	$3.5 million
Total	**US $43.5 million**

Source: McLean (1997)

In addition to these direct Agency costs, EPA awarded US $18.9 million to state and local governments to implement the Acid Rain Program. Because the trading program is run completely though EPA, however, a reasonable estimate of the administrative costs of the SO_2 allowance trading program over its first five years is US $38 million. McLean (1997) maintains that "approximately one third of the cost of developing and supporting the allowance trading program, or about US $1.4 million" can be attributed to the complicated process of allocating allowances, with its "special considerations for special situations." Simpler methods of allocating allowances would have significantly lowered these administrative costs.

Among the most reliable estimates of *ongoing* administrative costs were those received from EPA officials in the form of Information Collection Requests (ICR's) that were provided to us and that include estimates of administrative costs of the SO_2 allowance trading program and the NO_X SIP Call program.

In the SO_2 allowance trading ICR (U.S. Environmental Protection Agency 2002), administrative costs for the acid rain program were estimated to be US $460,722 in 2003 and US $456,873 in subsequent years. Exhibit 19 of the ICR is included as Table 9. It provides a breakdown of costs.

Table 9: US Title IV SO_2 Trading

AGGREGATE ANNUAL EPA BURDEN AND COST OF COLLECTIONS

Program	Total Burden (person-hours)		Total Costs[a] ($US)	
	2003	Subsequent Years	2003	Subsequent Years
Allowance transfers	1,500	1,500	$71,280	$71,280
Energy conservation and renewable energy Allowances	57	57	$2,709	$2,709
Permits				
Permitting Authority	2,710	2,710	$128,792	$128,792
EPA	593.5	593.5	$28,202	$28,202
Emissions reporting	21,760	21,760	$1,034,035	$1,034,035
Auctions	80	80	$3,802	$3,802
Opt-in	117	36	$5,560	$1,711
Annual compliance certification	1,375	1,375	$65,340	$65,340
NO_X permitting	106	106	$5,037	$5,037
Operation & Maintenance of data systems[b]	NA	NA	$150,000	$150,000
TOTAL	28,298.5	28,217.5	$460,722	$456,873

Source: US Environmental Protection Agency, 2002, Information Collection Request, Exhibit 19.
[a] 2001 US dollars.
[b] Average annual operation and maintenance costs associated with running electronic data systems are assumed to be incurred by an EPA contractor. Therefore, EPA will not incur any labour burden for these activities

Estimates of cumulative administrative costs of the NO_X SIP Call program between 2000 and 2002 were US $3.83 million for EPA and US $1.72 million for state agencies (total of US $5.55 million), based on the NO_X SIP Call ICR, completed in 2000.[97] Agency officials expect future administrative costs to be similar to those experienced in 2002. Hence, future administrative costs are expected to be on the order of US $1.4 million per year for EPA and US $1 million per year for all 22 state agencies.

[97] Calculations of these cost estimates are detailed in Table 6-1, 6-2, 6-3, and 6-8 of U.S. EPA (2000).

EPA officials indicate that administrative costs of the OTC NO_X Budget Program — while less certain, due to the lack of ICR requests — are probably not unlike those experienced for the acid rain program and the NO_X SIP Call program. It is believed that the administrative costs for the OTC program may be slightly less than the SIP Call program because of the smaller number of sources involved. This was confirmed by several Agency officials.

7.3 State-Level Administrative Costs of the NO_X Budget Program

All state officials contacted insisted that the ongoing administrative costs of the NO_X budget program were minor, due to the fact that EPA absorbs the bulk of the costs (allocations, emissions tracking, etc. are performed by EPA). Estimates of costs varied widely across states, however, largely because the number of regulated sources varies widely across states. Most cost estimates were for the OTC NO_X Budget program, because states are just beginning to perform activities under the NO_X SIP Call.

First, an official from the Massachusetts Department of Environmental Protection noted that the OTC NO_X Budget program had been running in Massachusetts for three years, and estimated development costs to have been 2.5 to 3 FTEs per year at roughly US $35 per hour. At 2,000 hours per year, this amounts to between US $175,000 and US $210,000 annually. On-going costs of testing continuous emissions monitors (CEMs), permitting new sources, and other activities were estimated to be equivalent to only 0.5 FTEs per year. With the same calculation as above, this amounts to about US $35,000 of annual administrative cost.

By way of contrast, a knowledgeable official with the Vermont Air Pollution Control Division estimated that the total time spent on the NO_X budget program by state government staff over the past seven years amounted to between 60 and 100 person-hours of activity. Note, however, that Vermont has only one source. Similarly, an official from the Air Resources Division of the New Hampshire Department of Environmental Services said that their annual costs did not exceed US $10,000. Their costs are relatively small because they only have three sources. They initially had full-time staff to work on regulations for the NO_X Budget Rule, but no longer.

Another official from the air quality division of a small state with few NO_X Budget Program sources provided a rough estimate of US $17,000 per year for all tasks related to the NO_X Budget program. These estimates are for an ongoing program. Considerably more time was spent on outreach, monitoring system certification, and regulation writing during the initial implementation of the program.

An official from the air quality division in another state provided the following rough estimates for the implementation of the NO_X SIP Call program: initial requirements of three to four full-time personnel, with five to six full-time personnel required once the program was implemented. It was also noted that the program raised additional computer hardware and software needs, as well as on-going training requirements. Staff are required to maintain familiarity with on-going allowance trading and markets, track receipt of funds, monitor Agency costs and redistribution of funds, and review compliance status of CEMs.

7.4 Independent State Trading Program Administrative Costs

One air quality official with an independent state trading program estimated that administrative costs of the program amounted to five full-time employees. This team performs all allowance and emissions tracking activities, develops computer programs for tracking, and coordinates rule-making, engineering, permitting, and enforcement. Over the five to six years of the program's operation, it was estimated that US $1 million had been spent on developing computer programs for tracking permits. Inspectors already existed for the 50,000 permitted facilities under Title V of the Clean Air Act, and so the implementation of the emissions trading program added very little cost to permitting.

State officials from Illinois could not provide any estimate for their ERMS program, but rough estimates were available for the Michigan Air Emission Trading Program. An official from the Michigan Department of Environmental Quality's Air Quality Division indicated that the trading program was originally designed to have a minimum of three FTEs for its administration. The positions and responsibilities were: data coding operator (inputs data to the database and maintains all electronic records); administrator (oversees program objectives); and reviewer (review of documents submitted). Because of very low trading volumes, however, only one position is currently devoted to the program. As a result, it is estimated that current administrative costs of the trading program are less than US $85,000 per year.

7.5 PERT

Doug Harper of the MOE, who co-ordinated the Ministry of Environment's role in reviewing PERT documents until early 1999, provided the following information. It would normally require 1 to 2 days of MOE staff time (i.e. his own and any additional MOE experts he would call on for input), to review a protocol report. The time could be less for simple applications and more for more complicated ones. Mr. Harper noted that the MOE did not 'give any kind of approval' to the protocol document since PERT operated on the principle of 'buyer beware'. As a member of a PERT review panel, his concern, as with the other members, was to check if the assumptions and data were reasonable. The MOE seems to have played no role, and incurred no costs, in relation to the creation and verification reports. But the PERT record-keeping system cost CDN $40,000 to set up.

7.6 Conclusions Regarding Administrative Costs

These data on administrative costs provide only rough guidance as to the administrative costs that might be incurred in establishing an emissions trading program in Ontario. The US emissions regulations involve both state and federal agencies, while here only Ontario will be involved. The US programs generally have far more sources to contend with, at least at the federal level, than will be involved in the Ontario program. The design of the programs is quite different. Still, we suggest the following analysis to give some order of magnitude of the costs that might be incurred here.

Some program costs are likely proportional to the number of sources in the program because of the need to interact separately with each source. Other program costs may be required to establish and maintain a program regardless of the number of sources. We will look at two models. In the first, we assume that program costs are strictly proportional to the number of sources. In the second, we assume that half of the program costs must be incurred regardless of the number of sources, while the remainder of the costs are proportional. We will also separate startup costs and operating costs.

The US Title IV program has about 2000 units participating. We do not know the number of sources participating in the EPA's NO_X trading programs but our data show 64 firms in Pennsylvania and 13 in New Jersey, implying over 100 participating sources in those two states together. This suggests that the total number of sources in the programs may exceed 500. We assume that Ontario may have 100 sources participating in the program. Thus the Ontario sources would represent 5% of the number of Title IV sources and 20% of the number of NO_X SIP call sources.

Looking first at Title IV, we will assume that half of the startup costs were one-time costs for developing a cap-and-trade program that would not be incurred by future agencies who carefully studied the Title IV experience and learned from it. This leaves startup costs of US$19 million. Operating costs are $460,000. If Ontario has 5% as many sources and we use the proportional cost model, our startup costs could be US $0.95 million with operating costs of US $23,000. If half of the costs are independent of the number of sources, our startup costs could be US $9.97 million and our operating costs US $241,500.

Turning to the NO_X trading experience, we have startup costs of US $5.5 million and operating costs of US $2.4 million. If Ontario has 20% as many sources, and we use the proportional cost model, our startup costs could be US $1.1 million with operating costs of US $480,000. If half of the costs are independent of the number of sources, our startup costs could be US $3.3 million and our operating costs US $1.44 million.

These data provide a wide range of possible costs for Ontario. If we multiply by 1.6 to convert US to Canadian dollars, our startup costs could range from CDN $1.5 million to $16 million. Our operating costs could range from CDN $37,000 to $2.3 million. See Table 10. Where in this range we end up will depend on many factors including the complexity of the implementation of our programs and differences in administrative procedure in the two countries.

Table 10: Possible Administrative Costs in Ontario
(millions of $ Canadian)

	Costs Proportional to Number of Sources	Costs Half Fixed, Half Proportional
Based on US Title IV		
Startup	1.5	16.
Operations (per year)	0.037	0.39
Based on US NO_X Budget		
Startup	1.8	5.3
Operations (per year)	0.8	2.3

Assumptions:
Title IV: 2000 sources, startup $38 million US, operations $0.46 million/yr.
NO_X Budget: 500 sources, startup $5.5 million US, operations $2.4 million/yr.
Ontario: 100 sources. Exchange rate 1.6.

8. Dispute Resolution Mechanisms

Disputes may arise between the agency responsible for the emissions trading system and a pollution source or a buyer or seller of marketable permits, or between buyers and sellers. In the absence of specific provisions in the emissions trading law disputes between the agency and private parties will be handled under the usual administrative law procedures. In Canada and the United States administrative law determines the rights of a party interacting with the agency to be told the reasons for an administrative decision, the right to a hearing of his grievance or complaint, and the right to seek judicial review of an agency decision.

In Ontario, the *Environmental Protection Act* provides in Part XIII that certain decisions of the Director must be made in writing, supported by written reasons. Part XIII gives the person a right in some cases to request a hearing on the matter before the Environmental Review Tribunal. Section 144 of the *Act* sets out the powers of the Tribunal and provides that any party to a hearing has the right to appeal from the decision or order to a court. Since the emissions trading regulation is made under the *Environmental Protection Act*, the administrative law procedures of Part XIII will apply to disputes between the Ministry and parties affected by decisions under the Regulation and Code unless substitute procedures are provided.

Disputes between private parties regarding the purchase and sale of credits and allowances or the creation and use of credits would normally be settled according to the common law and statutory law of commercial transactions unless the emissions trading regulation provides alternative dispute resolution mechanisms. An extreme example of such dispute resolution has just arisen in California where a buyer of NO_X credits sued a broker that allegedly sold non-existent NO_X credits. The broker settled the claim for US $7 million. While this is a private lawsuit, the District has charged the broker with false reporting under the RECLAIM rules, which will lead to an administrative law proceeding arising out of the same facts. (Gallon, 2002). More generally, parties may seek legal remedies if they do not receive the payment agreed upon or if the product purchased, whether allowances or credits, is not delivered or is not of the quality or characteristics that were promised.

We review here the dispute resolution mechanisms found in the trading systems that we considered earlier in this report. We focus on administrative law provisions, since few systems seem to provide mechanisms for resolving disputes among parties.

8.1 RECLAIM

RECLAIM provides for administrative penalties for sources that discharge greater amounts of pollution than they can cover with their RTCs. (Rule 2010.) The administrative penalty may be a fine of up to $500 per violation per day, a reduction of the next year's allocation to offset the excess, and ultimately revocation of the Facility Permit. The formal rules do not indicate the basis for determining the penalties to be assessed for specific violations. If RECLAIM seeks to impose an administrative penalty, it must provide the subject with the right to a hearing within 30 days. While the hearing is not subject to the formal rules of evidence, it does provide for sworn testimony and cross-examination. If RECLAIM seeks to cancel a Facility Permit[98], which is similar to a Certificate of Approval in Ontario, it can do so only through the process of a Hearing Board. Other rules allow a client to submit a request to the Hearing Board for adjudication. (Rule 2004.) In short, RECLAIM appears to provide a traditional administrative process for handling disputes between the agency and its clients.

During the design of RECLAIM, disputes arose over the pollutants to be included, the sources to be included and the baseline for determining the distribution of allowances. We have not found clear indications of how these disputes were resolved, but it seems likely that they were resolved through the same sorts of political and administrative steps as any disputes that may arise during the development of pollution control regulations.

8.2 US Title IV SO_2

The development of the legislation establishing Title IV consumed a number of years and involved conflicts over the extent of the emission reduction, the use of emissions trading, and the distribution of allowances to individual sources. The disputes took place in the US congress and were handled in the usual way for the Congress,

[98] A Facility Permit incorporates pre-existing Permits to Operate and Permits to Construct and includes all conditions and limitations of operation. AQMD Regulation XX, Rule 2006, section (b)7.

including lobbying, argument and negotiation. An excellent analysis is presented in Ellerman, *et al.* (2000, chs. 2, 3).

To the extent that the EPA developed rules and regulations to implement Title IV, it would have to follow the US federal procedure for rule-making, including issuing a notice of proposed rule-making, perhaps submitting a Regulatory Impact Analysis to the Office of Management and Budget, inviting comments, and publishing a final rule with responses to the comments received. (Menell and Stewart, 1994, ch. 7.) This process allows affected parties to comment on all aspects of the proposed rule or regulation and requires the agency to consider those comments.

Title IV provides numerous requirements for owners of pollution sources and spells out consequences and penalties for failing to comply with these requirements. We have found no specific mechanisms within Title IV for handling disputes between the EPA and sources over any of these matters, although the *Clean Air Act* does specify the courts to which citizen suits challenging agency actions must be brought. Citizens, including corporations, can challenge agency actions in court, under the procedures of the US *Administrative Procedure Act,* which applies to all federal administrative actions. Prior to going to court, decisions could be appealed by the polluter to an administrator at the EPA. It is not clear whether there exists an administrative hearing board that could hear and adjudicate the dispute if it is not resolved at the first step.

8.2 PERT

PERT does not appear to have had a specific dispute resolution mechanism. Since trading is voluntary and participation in PERT is voluntary, there may have been less need for dispute resolution than in other situations. With no legislative or regulatory framework defining the need to reduce emissions or the type of reductions that would qualify, the opportunity for conflict was mainly limited to potential buyers and sellers of credits. Furthermore the PERT Working Group, consisting of stakeholders, was available to discuss issues relating to proposed trades.

8.3 NO_X: EPA Model Rule

The Model Rule addresses disputes between private parties by specifically providing that the EPA will not adjudicate such disputes regarding the actions of authorized account representatives, especially regarding transfers of allowances.[99] (Sec. 96.14.) A similar disclaimer is provided regarding private disputes over NO_X tracking system accounts. (Sec. 96.51(b)(5)(iii).) The Model Rule does not appear to contain any specific dispute resolution mechanisms of its own, either for disputes between parties or

[99] "Neither the permitting authority nor the Administrator will adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any NO_X authorized account representative, including private legal disputes concerning the proceeds of NO_X allowance transfers." Model Rule, section 96.14(c).

for disputes with the EPA. This means that the former are governed by commercial law and the latter by the administrative law that applies generally to the administration of the *Clean Air Act* by the EPA. In support of this proposition is the NESCAUM Model Rule of 1996, which provides that with respect to appeals of decisions on enforcement actions and penalties "state and federal administrative procedures are applicable."[100]

8.5 Pennsylvania

The Pennsylvania NO_X Budget Trading Program contains the two disclaimers regarding adjudicating private disputes that are found in the EPA's Model Rule. (*Pennsylvania Code* chapter 145.14; 145.51.) There is no other reference to dispute resolution or appeals in the Pennsylvania law, so as with the Model Rule, state and federal administrative procedures would apply.

8.6 New Jersey

The New Jersey NO_X Budget Program does not refer to disputes or appeals at all. This means that in disputes with the agency, state and federal administrative procedures would apply, while private disputes would be handled under commercial law principles.

9. Participation by Major Polluters in other Trading Programs

In order to explore the potential interest of Ontario pollution sources in emissions trading, this section reports and discusses participation by major Ontario polluters (excluding the electricity sector) in other previous emissions trading programs.[101]

9.1 Pilot Trading Programs

Two joint private-public emissions credit trading pilot programs have been implemented in Canada to evaluate emissions trading as a cost-effective way for industry to reduce emissions of various pollutants. The Ontario Pilot Emissions Reduction Trading (PERT) Project, a voluntary, industry-led, multi-stakeholder initiative, was established in 1996 and applied to GHGs and other air pollutants emitted in the Windsor - Québec City corridor.[102] Members received credits and recognition from the Ontario Ministry of Environment for emissions reduced over and above what was required by regulation. This program has already been discussed in some detail in section 2.3 above.

[100] NESCAUM/MARAMA NO_X Budget Model Rule, May 1, 1996, section 16, Prepared for: the NESCAUM/MARAMA NO_X Budget Task Force, the NESCAUM/MARAMA NO_X Budget Ad Hoc Committee and the Ozone Transport Commissions Stationary and Area Source Committee.

[101] Following the definition given to us by the Ministry, we define a major polluter as a firm, which emitted 200 or more tons of either NO_X or SO_2 in 2000.

[102] http://www.pert.org/pert.html

The Greenhouse Gas Emission Reduction Trading (GERT) Pilot, initiated in 1998 as a voluntary joint initiative between the federal government, provinces, industry, labour and environmental groups, reviews emissions reduction projects to ensure that credits generated for trades reflect additional[103], measurable and verifiable emission reductions.[104] GERT received projects for evaluation until December 2001.[105]

As GERT handles trading in most cases by firms located in Western Canada, we will focus on participation in PERT, which is more likely to attract emissions trading by Ontario firms. Table 11 lists firms with major Ontario air discharges, classified by type of industry. Participation in PERT by major emitters, shown in Column 1 of Table 11, has been quite limited.[106] Specifically, while both Imperial and Shell have participated, there has been only one participant from the pulp and paper (Domtar) and manufacturing industries (St. Lawrence Cement).

9.2 Private Sector Initiatives and Training

In addition to participating in pilot trading programs (above), a number of Canadian companies are actively engaged in bilateral trades and/or international emissions trading organizations. For example, Manitoba Hydro, Ontario Power Generation and Suncor Energy are participating in the design phase of a voluntary emissions trading scheme through the Chicago Climate Exchange.[107] Another company, TransAlta, is actively engaged in the International Emissions Trading Association (IETA), which has the objective of establishing a marketplace for buying and selling greenhouse gas emission offsets.[108] An example of actual trading is the 1999 OPG purchase of 55,000 tonnes of $CO2_2$ emission reduction credits from CHI Energy Inc. of Stanford, Connecticut and another 75,000 tonnes from CHI Canada Inc. and Abitbi-Consolidated of Montreal, P.Q.[109]

Available evidence also suggests Shell Canada as a likely and vigorous participant in an emissions trading program. This belief is premised on the launching of the Shell Tradable Emissions Permits System (STEPS) by Shell in January 2000. STEPS is a voluntary cap and trade system in which permits are to be traded between 2000 and 2002 towards a 2% emission reduction target from 1998 levels. Both $CO2_2$ and methane (CH4) are covered in the system. Permits are allocated (grandfathered) to participating branches of the company for each of the 3 years to promote long-term compliance strategies and forward trading. Participation in the system is voluntary and is limited to

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103 Over and above what is required by law.
104 http://www.gert.org/
105 http://www.gert.org/links/documents/pdf/GERT%20Newsletter%20No.2.pdf
106 Participation in this case is defined as broadly as possible, to include all ERC creations (applications: reviewed and registered, reviewed but not registered, and applications under review).
107 http://www.chicagoclimatex.com/html/about.html
108 http://ieta.org/IETA2/Index_New.htm.
109 Canada NewsWire, June 9, 1999, Wednesday.

branches of the company that operate in industrialized countries. So far six business units have committed to participate, representing about a third of Shell's GHG emissions and over half of its industrialized-country emissions.[110] Shell also participates in the World Bank's international emissions trading program.[111]

A number of Canadian companies, including Epcor, Ontario Power Generation, BC Hydro and Nova Scotia Power, are members of the Greenhouse Emissions Management Consortium (GEMCo). This is a not-for-profit Canadian corporation formed by the private sector to demonstrate leadership in developing voluntary and market-based approaches to greenhouse gas emissions management.[112]

The Voluntary Challenge and Registry (VCR) program is another joint public-private initiative, which was launched in 1995 to encourage Canadians to make commitments to reduce greenhouse gas emissions.[113] A key component of this program is persuading firms to join the Registry, which records the actions planned and executed by registrants, and hence chronicles all efforts at GHG emissions reductions. The Registry also provides members with the opportunity to exchange information and to share best practices with their peers. Column 2 of Table 11 shows that many major Ontario emitters are members of the Registry, including all firms that took part in PERT.

Finally, in the United States the EPA and the Department of Energy have established the Climate Wise Program to seek voluntary reductions by the cement industry. Because many of the measures to reduce greenhouse gas emissions involve improved energy efficiency, U.S. companies have signed on with Climate Wise to document historical carbon dioxide emissions and implement action plans for reductions. Among the companies voluntarily preparing and documenting their action plans and greenhouse gas reductions, is Essroc.

Table 11 summarizes our understanding of the participation in prior emissions trading by major Ontario emitters. Apart from membership in the VCR Registry, such participation has been limited.

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[110] http://www.iht.com/articles/23595.html

[111] Climate Change: World Bank to Expand Emissions Trading Program (John J. Fialka, Wall Street Journal, April 24 2000).

[112] http://www.gemco.org/

[113] For further details see http://www.vcr-mvr.ca/vcr-013.cfm.

Table 11: Participation in Previous Programs by Major Ontario Emitters

	1 Active in PERT	2 Member of VCR Registry	3 Other Initiatives or Programs
A. REFINERIES			
Imperial Oil Ltd.	YES	YES	
Shell Canada	YES	YES	STEPS
Nova Chemicals (Canada) Ltd	NO	YES	
B. PULP and PAPER			
Bowater Pulp and Paper Canada Inc.	NO	YES	
Abitibi-Consolidated Incorporated	NO	YES	Emissions Credit Trading with OPG
Marathon Pulp Inc.	NO	YES	
Domtar Inc.	YES	YES	
Kimberly-Clark Corporation	NO	YES	
Weyerhaeuser Company Limited	NO	YES	
Norampac Inc.	NO	NO	
Tembec Inc.	NO	NO	
C. MANUFACTURING			
St. Marys Cement	NO	NO	
St. Lawrence Cement	YES	YES	
PPG Canada Inc.	NO	YES	
Federal White Cement Ltd.	NO	NO	
Lafarge Canada Inc	NO	YES	
Essroc Canada Inc	NO	YES	Climate Wise

10. Implications of Allocating Allowances

One of the advantages of using emissions trading for pollution control is that the decision regarding allowable pollution discharge from a source can be separated from the decision on the degree of pollution control to be undertaken by each of those sources. Under traditional regulation, if a facility is limited to 100 tonnes/day or 258 ng/Joule, it has no choice but to reduce its emissions to comply with that regulation or permit. With emissions trading, a facility may be allocated 100 tonnes/day of allowances but it can discharge more if it purchases additional allowances from other sources and if it discharges less it can sell allowances to other sources. The distribution of allowances does not determine any individual source's final emission rate.

Most economic literature on emissions trading asserts that the distribution of allowances has little or no effect on the efficiency of the final emission reduction allocation among facilities, since facilities will reduce their emissions until the marginal cost of pollution control equals the market price of the allowances. Once the price of allowances can be predicted, so can the abatement by each facility, regardless of its initial allocation. (Tietenberg, 1985, p. 97.) However recent literature has recognised that trading of allowances is not costless. If trading is costly, the distribution will have an effect on the abatement by each facility. (Stavins, 1995.) Facilities will tend to reduce emissions to match their allocation of allowances unless the savings from trading outweigh the transactions costs of trading, so the higher the cost of trading, the more the distribution will be like setting emission limits for the individual facilities.

The distribution of allowances where transactions costs are not insignificant therefore has two consequences. One is to affect the final emission rates, since firms will tend to reduce emissions to match their allowances. If the Ministry wants to minimise the cost of pollution control it should try to distribute allowances as closely as possible to the quantities reflecting efficient pollution control by the facilities. The other effect is that allowances will be valuable assets, so distributing them is like distributing money – a special money that can only be traded in a special market. Firms will be very interested in how much of this valuable asset they receive. The Ministry may wish to make the allocation meet accepted criteria of fairness and equity, however those may be defined.

Most emissions trading systems employ a cap-and-trade structure in which the cap is a fixed quantity set by regulation or legislation. Such a "fixed cap" does not let total emissions increase with industrial growth. With a fixed cap, the total quantity of allowances distributed to all sources in a year is determined in advance, regardless of sector activity. The remaining issue is the basis on which those allowances are distributed, which is discussed below. There are several possibilities, in all of which activity levels play a part.

Another possibility is to set an emission factor in relation to some measure of activity and let total emissions depend on industrial activity. This is essentially the method used in the US during the phase-down of lead in gasoline in the 1980's. This approach works with a single sector or product such as lead in gasoline, and with a program that reduces the emission factor so drastically that growth in activity cannot significantly offset the reduction. In the lead case, the reduction was 90% in five years. We are not aware of any program using this approach for general air pollution. We do, however, discuss how such a program might work in section 10.2 below.

10.1 Fixed Cap

The fixed cap sets an annual distribution of allowances that is fixed for each year regardless of economic activity. The cap of 157.5 kilotonnes of SO_2 per year in MOERT, the cap of 8.95 million tons of SO_2 in *CAAA* Title IV, and the US NO_X budgets under the NO_X SIP call and OTC process are examples of fixed caps. The fixed cap has the advantage that the total discharge to the environment cannot increase. Even if economic activity doubles, air pollution may not grow. If facilities are allowed to bank allowances from one year to the future, then reductions below the cap this year may lead to emissions above the cap in future years. While banking may allow total emissions to vary from one year to another there is no upward trend in emissions. And if a decline in emissions is desired, the cap may be reduced from time to time. The disadvantage of the fixed cap is that if economic activity expands over time, sources have to find increasingly effective (and costly) means of controlling their emissions. Furthermore, if banking is not allowed a burst of activity in one year will require short-run controls (e.g. fuel switching) or activity limits (limited output) by the capped sources in order to avoid exceeding the cap.

Once the fixed cap has been set, how can it be allocated among the capped sources? The economics literature extols the virtue of auctioning allowances to polluters, and indeed an auction solves several problems including both startups and shutdowns. However in fact, a free distribution has been used almost universally. If the distribution is to be free, what should be the basis of the distribution? Again almost universally the distribution is based on some measure of activity: fuel burned, inputs to the production process, product output, or pollution discharge. The first issue is whether this activity basis is fixed in time or variable over time. The second issue is what activity measure to use. We will use as examples actual distribution systems described in sections 2 and 3 above.

10.1.1 Fixed Historic Activity

Fixed historic activity allocation means that the basis for each year's allocation is some activity measure that took place before the trading system began operation. The allocation does not change as activity levels change over time.

The Title IV SO_2 trading system in the US distributes allowances (approximately) on the basis of the annual average heat input of coal burned by each power plant in 1985-1987. Every year starting in 2000, each plant receives 1.2 pounds of allowances for each million Btu of coal burned in the historic period. If a plant closes down, it continues to receive the same annual allocation, which it will presumably sell to other plants that are still operating. New plants receive no allocation and must purchase allowances from existing facilities, or from a "hold-back" which some systems such as Title IV auction off to all comers including new facilities. See section 2.2 above.

RECLAIM is an example of a fixed historic allocation. The allocation of "RTCs" in 1994 was based on the facility's maximum activity during 1989-1992 multiplied by an emission factor. The allocation is reduced over time according to a pre-announced timetable by reducing the emission factor for each source. New sources after 1993 must purchase RTCs from sources entitled to an allocation from the AQMD. See section 2.1 above.

The EPA's Model Rule for the NO_X SIP call provides for fixed historic allocation through 2005, based on 1995-1997 heat input. The EPA's Model Rule sets aside 5% or 2% of the allowances each year to be distributed to new sources on the basis of their nameplate heat input capacity multiplied by 0.15 or 0.17 lbs/mmBTU. The Pennsylvania NO_X rule is similar to the Model Rule, using 1995-98 heat input as the basis for allocations through 2007. See section 3 above.

Under Title IV, the measure of activity is the heat content of coal burned. Other activity measures that could be used include the heat content of fuel of any type, the quantity of product output (electricity, cement) or process input (ore smelted). The RECLAIM system in California covered sources in a variety of industries, so it used different activity measures for different industries. Rule 2002(c)(2) specifies that the facility must use an activity measure (throughput) that is included in its operating permit, but does not specify what that activity measure is. The EPA Model Rule, which covers only fossil-fuel fired electricity generation units or other boilers, uses heat input as the activity measure. The expansion of MOERT to eight industrial sectors would require the use of several activity measures, as in RECLAIM.

The advantage of using fixed historic activity as the basis of allocation is that it avoids distorting the incentives of facilities with regard to choosing their activity level, and their choice of fuel. (Dewees, 2001.) Facilities will not increase their activity in order to increase their allocation. Nor will it discourage switching to a cleaner fuel. A plant can convert from coal to natural gas and still receive the allowances under Title IV. Fixed historic allocation avoids distorting incentives regardless of the activity measure used, since current behaviour does not affect the quantity of allowances. Expanding facilities will have to purchase increasing quantities of allowances, just as they buy more labour, office space and energy, while declining facilities will be able to sell increasing quantities of allowances.

10.1.2 Recent or Current Activity

The second method of allocating a fixed cap is according to recent or current activity. One example of a recent activity-based allocation is the distribution of NO_X allowances under the US EPA Model Rule after 2005. Beginning in 2006, NO_X Budget units receive allowances in proportion to their heat input four years earlier. Thus even when the rule moves away from the fixed historic basis, it still looks back in time by four years rather than looking at the most recent year. The Pennsylvania NO_X trading rules also use past activity after 2007, from six or more years previous: 2002-2004 is used as the basis for allocation for 2008 through 2012. New Jersey comes closer to current allocation with its NO_X distribution based on heat input during the average of the highest two of the last three years. See section 3 above.

Ontario's emissions trading program comes the closest to using current activity with its allocation of SO_2 allowances to SO_2 facilities beginning in 2004 on the basis of each facility's share of last year's electricity generation by SO_2 facilities. The NO_X allowance distribution is also based on the facility's share of electricity generated by NO_X facilities in the previous year.

The advantage of using recent activity as the basis of allowance distribution is that it adapts the distribution of allowances to the fluctuating activity levels of different industries and facilities. Facilities that expect to expand their activity will prefer recent activity to fixed historic distribution, while facilities expecting not to expand or to contract their activity will prefer fixed historic. Unfortunately recent activity distribution has a distorting effect on the incentives of facilities, since more activity is a means of earning a larger share of the fixed allowance pie. The degree of this problem depends on the type of activity measure.

10.1.3 Choice of Activity Measure

Keeping in mind the above discussion of distortions, how should the activity measure be chosen? If the distribution is to be based on fixed historic data, then no distortion arises because current operating decisions do not affect the facility's right to receive allowances. The facility can switch from coal to gas without losing the right to allowances regardless of the basis for determining the historic distribution. However if recent activity is to be the basis for distribution, then the choice of activity matters because the distribution of allowances is essentially a subsidy to that activity. If the distribution is to coal-burning facilities, facilities will be discouraged from switching to other fuels because they will lose the right to allowances. If the activity is heat input, facilities will be discouraged from switching from fossil fuel to wind power or hydroelectric, since they will lose the right to allowances. If the activity is heat input, facilities will be discouraged from engaging in energy conservation projects because they will lose the right to allowances. If it is to minimise the distortion of facility incentives, the activity measure should be as far from the pollution emissions as possible.

If we want to give polluters an incentive to consider all possible ways to reduce their pollution and if we also want to avoid giving them any incentive to continue to use polluting production methods, then we should not tie allowance distribution to specifically polluting activities. For electricity generators, the ranking of last year's activity measures that might be used for distribution of SO_2 allowances, from most to least distorting, is as follows:

Most distorting
- SO_2 discharged
- coal burned (mmBTU)
- fossil fuel burned (mmBTU)
- electricity generated by sources of the pollutant in question (MWh)
- electricity generated by all generators (MWh)

Least distorting

The current regulation, using electricity generated by facilities that discharge the pollutant in question would be classified in the fourth category in the list above, and therefore involves relatively low distortion. Distortion could be further reduced by amending the existing regulation so that the distribution of allowances was to all generators, not just those discharging the pollutant in question. This would reduce the incentive to continue using a polluting fuel. It would, of course, also greatly increase the amount of emissions trading, since nuclear and hydroelectric generators would ultimately sell all of their allowances to fossil generators. Whether the reduced distortion is worth the increased transactions cost is an empirical question.

The US NO_X trading programs all use fossil fuel heat input as the activity measure, an easy choice since the programs apply only to fossil fuel generators and boilers. But RECLAIM, which involves many industries, uses many activity measures, referred to generally as “throughput”. RECLAIM, however, uses a fixed historic allocation method, not recent activity.

Ontario has no choice but to use a variety of activity measures, given the variety of industries and processes being considered. Heat input has been most widely used elsewhere and is probably the best choice for fuel-burning activities. For other activities, the choice will depend on available data.

10.1.4 Choice of Distribution Policies for a Fixed Cap

To evaluate alternative distribution policies, we require some definitions and mathematical notation.

For each sector (except electricity) an activity measure is identified, based on data reported on certificates of approval. The baseline data, from 1999 or 2000 (or some other baseline year) are used to determine the activity. For boilers, heat input is probably the best activity. For other sources, other activities would have to be chosen; non-ferrous smelting might use tonnes of ore smelted. Assume that we know, for each facility the activity level and the total emissions for the base year. We will use the following notation:

A_{ij} = activity by facility i in sector j, per year
AS_j = total activity by all facilities in sector j, per year

E_{ij} = emissions by facility i in sector j, tonnes/year
ES_j = total emissions by all facilities in sector j, tonnes per year
SUM_iES_j = ET = total emissions by all facilities in all industries, tonnes per year
F_{ij} = emission factor for facility i in sector j.
L_{ij} = allowances distributed to facility i in sector j
The superscript ^{B} indicates data from the base year
The superscript ^{t} indicates data from year t.
The superscript ^{C} indicates the level of an emission cap

We can calculate the total emissions from all facilities i in each sector j in the base year as:

1) $$SUM_iE^B_{ij} = ES^B_j$$

Similarly, we can calculate total activity in each sector j in the base year as:

2) $$SUM_jA^B_{ij} = AS^B_j$$

We can calculate an emission factor for a sector in the base year as the aggregate baseline emissions of that sector divided by the aggregate baseline activity for that sector:

3) $$F^B_j = AS^B_j / ES^B_j$$

Having established these definitions, we identify three alternatives for distributing allowances. The first is the least distorting on private sector decisions, the third is the most distorting.

Option 1: Least Distorting – Fixed Historic Activity, Facility Level

This option is modelled on the RECLAIM system. A simple emission cap system would reduce the allowable emissions for each sector by a specified percentage, say 45%. In this case the cap for sector j, at least for the part of sector j that is subject to this regime, would be:

4) $$ES^C_j = ES^B_j * (1\text{-}0.45)$$

Each facility in sector j would receive a share of this cap. In RECLAIM the share is based on the facility's baseline activity as a share of the sector's baseline activity:

5) $$L^B_{ij} = (A^B_{ij} / AS^B_j) * ES^C_j$$

This allocation formula uses fixed historic activity data to determine each facility's allocation of allowances in any year. An alternative would be to use the facility's historic emissions as a proportion of sector emissions to allocate the allowances. We believe that activity is preferable because it does not give more allowances to the facility with the high baseline emission rate, nor does it reduce the allowances given to the facility with the low baseline emission rate. That is, using activity offers "baseline protection" to the facility that engages in early emission reductions before the baseline year.

Some firms may argue that equation 5 is unfair in that it fails to respond to differences in the inherent difficulty of emission control among facilities. We believe that adjudicating such arguments would be difficult. If the MOE chooses to respond to these concerns it could replace equation 5 with the following fixed historic emission basis:

6) $L^B_{ij} = (E^B_{ij} / ES^B_j) * ES^C_j$

Here each facility receives a share of the sector's emission cap in proportion to its historic baseline emissions. Some firms may object to this because it fails to recognise early reductions; it fails to provide baseline protection.

Option 2: Recent Activity by Facility, Fixed Sector Share

This option is modelled loosely on a combination of RECLAIM and MOERT. Activity is calculated as the average of the two highest activity levels from a recent 3-year period (e.g. for 2006 allowances, average the highest two of years 2002-2004; call this period t-3.) For each sector, determine the appropriate activity measure, preferably having to do with product throughput rather than fuel (i.e. tonnes of cement produced, barrels of oil refined, tonnes of copper matte smelted). Emission data from the baseline year are used along with activity data from period t-3 to determine allowable emissions.

As before, we can calculate the total emissions for each sector in the base year and reduce the allowable emissions for each sector by a specified percentage, say 45% to get the sector cap $ES^C_j = ES^B_j * (1-0.45)$. Each facility in sector j would receive a share of this cap in year t based on the facility's recent (t-3) activity as a share of the sector's recent (t-3) activity:

7) $L^t_{ij} = (A^{(t-3)}_{ij} / AS^{(t-3)}_j) * ES^B * (1-0.45)$

This allocation formula uses recent facility and sector activity to re-allocate the baseline sector emissions reduced by the emission reduction factor. However there is no re-allocation between sectors.

Option 3: Recent Activity by Facility, and by Sector

This option is similar to option 2 except that each sector share of allowances varies over time as that sector's share of total activity varies over time. This is like a distribution to sectors based on recent activity followed by a distribution to facilities within the sector based on their relative activity. The problem with this concept is that different activity measures are used in different sectors; they cannot be added to each other. You cannot add mmBtu and tonnes of ore to get a total activity measure. You can, however, say that sector #1 has increased in activity by 50% while sector #2 has decreased its activity by 50% and adjust their emissions accordingly. This option would require identifying a baseline year in which sectoral activity would be measured along with sectoral emissions. The initial distribution of allowances to each sector would be in proportion to sectoral emissions in that baseline year. In subsequent years, changes in the relative activity of the sectors would be calculated and the total emission cap would be allocated among the sectors in proportion to their new relative activity compared to their baseline activity. We have not worked out the algorithm in detail, but this option seems feasible in principle, so long as all sectors accept the full set of activity measures being used.

Evaluation of Options

When dealing with a single sector with a single activity measure, such as MWh of electricity generated, or a single function such as fossil fuel burning which can be measured by heat input, it is not much more difficult to administer a distribution of allowances that varies from year to year in accordance to a recent activity measure than it is to make a fixed historic distribution. However when dealing with many sectors, each with its own activity level, the problems with adjusting the distribution every year or every few years become greater. One needs reliable activity data each year. If the fixed historic system leads to arguments over the data, the recent activity system will repeat some of those arguments every year when the data are constantly changing.

The Fixed Historic allocation therefore has several advantages. It eliminates the distortion of incentives for firms to choose fuels or emission rates. It simplifies administration. It reduces disputes. For these reasons, we recommend the fixed historic distribution, as in Title IV. If this is not acceptable for some reason, we believe that the allocation based on recent facility activity but with fixed sector shares (option 2) may be less problematic than option 3.

10.2 Floating Cap

If one wanted the distribution of allowances to respond to activity in each sector, with no protection against pollution increasing as economic output grows, one could devise a distribution in which the allocation to each facility was based on recent activity multiplied by an emission factor. The emission factor could be determined from the sector's baseline emission factor reduced by a percentage, *i.e.* (1-0.45). No clawback would be used. Two problems arise with such a system. First it is not really cap, it is just an emission reduction with trading. There is no guarantee that total emissions in any year would not exceed any pre-set target. The system loses the ability to claim that environmental harm has been capped, or that progress toward a specific reduction target such as 45% has been made. Second, it invokes all of the problems of measuring recent activity discussed under options 2 and 3 above. All the arguments about the measurement of emissions will be repeated every year in arguments about activity and its measurement.

There are several variations on this distribution, described below.

Option 4A: Floating "Cap"

In this option, the distribution of allowances to a facility in year t would be based on the baseline emission factor for the sector of which that facility was a member multiplied by a reduction factor (1-0.45) multiplied by the facility's activity in a recent year (t-3).

8) $L^{t}_{ij} = F^{B}_{j} * (1-0.45) * A^{(t-3)}_{ij}$

Here the reduction factor reduces emissions per unit of activity from the baseline, but total emissions will vary with activity. Total emissions may be greater or less than any predetermined cap. No claim of firm environmental protection may be made. Indeed, with robust economic growth in a sector, there may be no reduction at all in total emissions. We are aware of no existing emission trading systems using this approach.

Option 4B: Floating "Cap" with Clawback

The solution to the absence of a real cap is the "clawback". All the individual facility allowances can be added up; if they exceed some pre-determined cap then each facility's allocation can be reduced proportionally until the total equals the pre-determined cap. This is similar to one proposal made in the Ministry's Discussion Paper. This yields a result similar to that in Option 3 above. The sector shares will vary with their activity, but the total emissions will be no greater than the cap. The difference from Option 3 is that if the sum of individual facility allowances falls short of the pre-determined cap, no adjustment is made. This is good for the environment, since emissions in that year will be reduced, but bad for industry because it reduces the total quantity of allowances and thereby raises their price as compared to Option 3. For a given announced cap, industry should prefer Option 3, while environmental groups should prefer option 4B. However if the Ministry recognises that Option 3 should yield higher emissions on average, it should be prepared to set a more ambitious reduction target, perhaps 50% for Option 3 compared to 45% for Option 4B.

Option 4C: Floating Cap with 2-way Clawback

The final variation on this system would be to calculate the facility allowances as in option 4A and compare the total allowances to a predetermined cap. If the total did not exactly equal the cap, the allowances due to each facility would be reduced or increased proportionally such that the total just equalled the cap. This would provide an environmental guarantee and would allow sector allocations to vary depending on recent activity. This would render the floating cap "fixed"; it would in fact be similar to Option 3 above. It would be equivalent to the distribution in the US NO_X trading Model Rule. The advantages and disadvantages of Option 3 would apply here.

11. Conclusions

Emissions trading began in the 1970's and 1980's in the United States using emission reduction credits to escape the rigidity of air pollution regulations. Beginning with Title IV in 1990, new US emissions trading programs have been predominantly of the cap-and-trade design without emission reduction credits or with very limited credits. These more recent programs have, however, included "opt-in" provisions under which sources that are not capped can enter the program bringing with them an entitlement to allowances according to a formula.

The cap in recent (post-1990) cap-and-trade programs has always involved a fixed cap specified in tons, rather than an activity-based limit. The capped Title IV utilities may emit 8.95 million tons of SO_2 no matter how many new facilities are constructed, no matter how much the demand for electricity grows. The NO_X budget does not increase as economic output increases; while the initial distribution of allowances to facilities is in terms of activity the total of that distribution is scaled up or down until it equals the state budget. In both of these programs, however, year-to-year flexibility is afforded by allowing banking of unused allowances from one year to another. The RECLAIM limits do not vary with economic output and there is no banking, but recent revisions provide a mechanism to increase allowances if allowance prices exceed specified levels. Presumably there is value in promising that emissions will not exceed a specific level, and there is confidence that technology will progress so that the fixed cap will not unduly restrain economic growth. Indeed, the cost of controlling SO_2 under Title IV has been less than was feared by some when the program was proposed.

The distribution of allowances in cap-and-trade programs in the US has been based on historic activity and an emission factor. In Title IV and RECLAIM the distribution is fixed by history, 1985-87 for Title IV and 1989-1992 for RECLAIM. In NO_X trading it begins with an historical base, then moves to activity from several years prior to the distribution. Heat input is the activity measure used for electricity generation and other boilers. Various other measures are used for non-electricity sources covered by RECLAIM

The formula for allowance distribution has been vigorously contested in all market developments, with stakeholders arguing for variations that recognize their unique circumstances. The design of the allocation process seems to work best when the total cap is fixed so that bargaining is a zero-sum game – increases for one source mean decreases for another.

Banking has been important for stabilising allowance prices from one year to another as activity levels fluctuate. RECLAIM did not allow banking and encountered massive price increases in 2000 when electricity generation was unusually high, after which an emergency supply of allowances was added. Even the NO_X SIP Call trading program, designed to deal with a seasonal ozone problem, allows banking, while using "progressive flow control" to limit withdrawals in any year.

Emissions trading has succeeded in reducing pollution control costs, sometimes dramatically. The cost savings are greatest when pollution control costs vary widely among sources in the program. Even though emission reduction credit trading was limited under the early EPA trading programs, savings of tens of millions of dollars were reported. Title IV emissions trading appears to save US $2.5 billion per year, about half of the expected cost of control with traditional regulations and no trading.

Trading works well with low transactions costs when there are many sources in a single sector, as in Title IV. It seems to work well, although with higher transactions costs, when there are fewer sources or multiple industries, as with RECLAIM and NO_X trading. Trading has been most attenuated in programs with emission reduction credits requiring approval of each project and facilities in many industries, although even these programs have given rise to many trades and considerable cost savings.

There are a variety of ways in which Ontario could distribute allowances to facilities under an expanded trading program. The distribution is important because it is a distribution of valuable rights. The distribution also may have incentive effects that can distort economic decisions. The least distorting distribution is based on fixed historic activity. Distribution according to recent activity introduces some distorting incentives, which are less if the basis is production activity rather than fuel use. A fixed cap is most commonly used as the basis for distribution. With a fixed cap and distribution according to recent activity, there are arguments for both fixed and flexible sector shares.

12. The Emissions Trading Simulations: Implications for Ontario

Experience with emissions trading in the United States has shown considerable variation in the prices at which allowances and credits for SO_2 and NO_x have been traded. (See sections 1 to 5 of this report.) This variation is due to a variety of factors including the structure and scope of the markets, the range and cost of available emission reduction technologies, the number of allowances issued and the terms under which they can be traded, rules governing the creation and use of emission reduction credits, as well as the general state of the economy and the specific circumstances of the industries involved in trading.

The simulations that were conducted in the present study were designed to throw light on how some of these factors might play out in an expanded emissions trading market in Ontario. These simulations were accomplished through the use of abatement cost data from plants in seven industrial sectors. NO_X simulations included the Cement, Pulp and Paper, Petroleum, Iron & Steel, and Glass sectors, while the SO_2 simulations included the Cement, Pulp and Paper, Petroleum, Iron & Steel, Carbon Black, and Non Ferrous sectors. In addition, four coal-fired electricity generation (OPG) plants were included in both NO_X and SO_2 scenarios. We shall refer to all of these non-OPG facilities as CAPI (Clean Air Plan for Industry) plants.

The Ministry of the Environment provided the data to LECG. Several scenarios were compared to a base case and each other in order to gain insights into the price and quantity ranges that might emerge from different market arrangements.

Before discussing the simulation results in detail, the main limitations of the simulations should be noted:

1. The abatement cost functions, which were provided by the Ministry of the Environment, do not cover the full range of emission reduction options available to each of the sources. As a result, the reductions included in the simulations are lumpy'- in the sense that small changes in regulatory standards can result in sharp and discrete changes in abatement levels, when in reality they are likely to be far less so. Also, under these circumstances the difference between average and marginal costs begins to break down as they converge.

2. The abatement cost functions likely overstate the cost of abatement because not all abatement options are included.

3. The simulated market in Ontario includes OPG, Inco, Falconbridge ('Non-Ferrous Industrial Plants') and twenty-two 'Other Industrial' Plants. In most scenarios the participants in the market are only a sub-set of these companies and the conditions for competitive market behaviour do not apply. We did not adjust the data to reflect the missing Non-Utility Generators (NUGs) or other sectors due to the arbitrary nature of necessary assumptions. The strategic behaviour of the participants will have a major impact on the price/quantity outcomes that emerge from trading and the volatility of the

market. As a result, it is possible that the simulations will predict higher (lower) trading prices (quantities), than will actually occur.

In light of the above, the results of the simulations are most useful for putting bounds around the likely trading outcomes rather than for predicting specific prices and quantities of allowances and/or credits or the time path by which market equilibria might be reached.

Another caveat is in order. Simulations were performed according to various scenarios that were outlined by the Ministry. The objective of these scenarios, is to isolate possible gains from an emissions trading system. We assume that each scenario has an emissions target, which participating facilities must achieve. For scenarios in which facilities face a regulatory cap on emissions, the target is the emission reduction the facilities must implement to achieve the cap. For scenarios that allow for trading, the relevant target is the emission reductions the plants must implement to avoid having emissions exceed the number of allowances received.

12.1 The Scenarios

Table 12 summarizes the assumptions and features of each scenario.

Table 12

BASE CASE: No Additional Regulation
This is the current Ontario regulatory system including Regulation 397/01, and investigates the extent to which CAPI facilities will create credits to sell to electricity sector. However, only OPG receives allowances and can buy credits.
SCENARIO ONE: Command and Control (Uniform Targets)
There are uniform limits on identified industrial facilities (i.e., 45% of 1990 NO_x emissions and 50% of 1994 SO_2 emissions). CAPI facilities cannot buy or sell credits among themselves but can create and sell credits to OPG under rules described in O. Reg. 397/01. All other conditions as in the Base Case.
SCENARIO TWO: Emissions Trading (Uniform Targets)
CAPI facilities receive allowances equal to the 45/50 rule (i.e., 45% of 1990 NO_x emissions and 50% of 1994 SO_2 emissions). OPG gets allowances through O.Reg. 397/01. OPG and CAPI facilities are allowed to buy and sell allowances and credits.

SCENARIO THREE: (a) Emissions Trading (Plant Specific Targets)[114]
CAPI facilities receive allowances according to the Ministry proposal. OPG gets allowances through O.Reg. 397/01. OPG allowances based on 2010 projected energy output. OPG & CAPI are both allowed to buy and sell allowances and credits.
SCENARIO THREE: (b) Command and Control (Plant Specific Targets)
CAPI facilities face emission limits at levels in the CAPI proposal. CAPI facilities receive no allowances, but can create credits. OPG gets allowances through O.Reg. 397/01 and can purchase credits.

The difference between abatement costs in a command-and-control regime (Scenario One) and an emissions trading system (Scenario Two) should shed some light on whether industry participants would gain from emissions trading. Central to both these scenarios is the achievement of a uniform target for each industrial facility (45% of 1990 NO_x emissions and 50% of 1994 SO_2 emissions). In contrast, scenarios 3 (a) and (b) are concerned with meeting plant specific targets. Scenario 3(a) studies the consequences of emissions trading while 3 (b) focuses on the effects of meeting these targets through command-and-control.

Tables 13 and 14 summarize our simulation results for SO_2 and NO_x emissions respectively. They give the upper and lower bounds to equilibrium prices and trades in terms of *allowances*. The motivation for converting credits into allowances is because in some scenarios, CAPI facilities generate credits by exceeding their abatement requirements. These credits can be sold to OPG plants, but OPG plants can apply only 90% of the value of a Credit against their own abatement requirements. This implies that a credit earned by a CAPI plant for abating one tonne of emissions can be converted to an allowance, which allows an OPG plant to emit an additional .9 of a tonne. In order to compare simulation results across scenarios, we convert the tonnage embodied in a credit to its equivalent tonnage value as an allowance. The supply of credits by CAPI facilities is therefore multiplied by a factor of 0.9 to convert the tonnage embodied in credits to allowances. Hence, the net demands reported in the Tables and discussed in this narrative are allowance equivalents. To convert the tonnage in allowances back to credits, the former must be divided by 0.9 (ie. Credits = Allowances/0.9). Similarly, the prices reported in the Tables and in this narrative are prices for Allowances. Finally, according to O.Reg 397, OPG faces a limit on credit use of 33 per cent of the allowances it retires. Although this is not explicitly modeled due to the inherent complexities, the constraint was never violated at the aggregate level.

Equilibrium trades in Tables 13 and 14 are embodied by net demand and supply of allowances (all in tonnes) by OPG, Non-Ferrous and Other Industrial facilities for SO_2,

[114] Allocations are based on a hypothetical distribution of allowances that are different for each facility. They are based on the most recent discussions of potential allocations with stakeholders.

and for OPG and Other Industrial facilities for NO_x.[115] We present the figures in terms of net demand; hence figures in parentheses imply that facilities are net *suppliers*. If figures are not within parentheses then they are net *purchasers*. The results are broken down according to the above different scenarios outlined by the Ministry. These are further segregated according to "Low Nuclear" and "High Nuclear" Scenarios, which correspond to different types of electricity generation and hence levels of Business As Usual (BAU) emissions and allowances for OPG. As suggested by the labels, "Low Nuclear" refers to a higher proportion of electricity generated by OPG's coal fired generators and hence a requirement for more abatement, while "High Nuclear" indicates more electricity produced by nuclear plants (and hence less pollution and need for abatement).[116] Finally, these tables also contain estimates of abatement (in tonnes) by OPG and CAPI facilities as well as corresponding abatement costs. Technical details regarding the simulations are contained in the appendix.

The objective of emissions trading is to minimize abatement costs for participants. However, it is also important to note that some participants may also earn some revenue from the sale of credits, while others incur expenditure purchasing them. However, the tables do not consist of explicit estimates of such revenue or expenses because they are simply transfers and will be netted out across firms.

12.2 Base Case

As mentioned above, the base case is a depiction of existing emissions trading in Ontario. Industrial Plants can generate credits and sell them to OPG. Only OPG receives allowances and can buy credits.

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[115] NO_x specific abatement cost functions for Non-Ferrous plants are not available, and hence we could not include INCO and Faclonbridge in the NO_x simulations.

[116] Specifically, we were given separate abatement cost functions for OPG, corresponding to Low and High Nuclear Scenarios.

- SO_2

Table 13.1: SO_2 Base Case[117]

			Low Nuclear		High Nuclear	
Price		($/tonne)	ZERO	$175	NO MARKET	
Net Demand		(tonnes)				
	OPG		24,467			
	Other Industrials		-			
	Non-Ferrous Industrials		(32,522)			
	TOTAL		(8,056)			
Abatement		(tonnes)				
	OPG		-			
	Other Industrials		-			
	Non-Ferrous Industrials		90,100			
	TOTAL		90,100			
Abatement Cost		($ 000's)				
	OPG		-			
	Other Industrials		-			
	Non-Ferrous Industrials		$11,547			
	TOTAL		11,547			

In the *low- nuclear* base case, Non-Ferrous plants automatically generate SO_2 credits and are willing to supply 32,522 tonnes. This is probably due to the fact that in order to comply with their control orders, INCO and Falconbridge have to install abatement equipment that reduces their emissions well beyond the levels mandated in the control orders. Other Industrial Plants do not generate any SO_2 credits. The Non-Ferrous facilities can reduce their emissions by 90,100 tonnes if they are operating at peak capacity. Readers should note, however, that recent history indicates that companies in this sector rarely utilize all their smelting capacity, and therefore the forecast supply of 35,522 tonnes may be overstated. It may be considered an upper bound on the number of excess allowances that this sector could sell in the SO2 market.

In a situation where OPG is dealing with one or two large companies in the Non-Ferrous metals industry, the trading outcome depends very much on their respective bargaining strategies and negotiating skills, which are not known and have not been simulated. If there were no other participants in the market the price of credits could range from zero to well over CDN $100/tonne of SO_2 in the base case. An upper bound of CDN $175/tonne is quite consistent with prices for SO_2 allowances under the US Clean Air Act Title IV SO_2 trading program since 1999 (see above pages 7 and 8).

For the *high- nuclear* case, the simulation results suggest that there would be no market for SO_2 credits because OPG can meet its SO_2 target by replacing electricity generated from coal combustion with electricity from its nuclear plants. This suggests that if OPG gets its nuclear plants back on stream it will be receiving many more allowances than it needs to meet its requirements.

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[117] No Market implies that there is no demand for credits because OPG switches from fossil fuel generation to nuclear generation.

- NO_x

Table 13.2: NO_x Base Case

			Low Nuclear		High Nuclear	
Price		($/tonne)	$2,578	$2,589	$233	$244
Net Demand		(tonnes)				
	OPG		11,376	11,376	874.8	874.8
	All Industrials		(11,371)	(11,666)	(506)	(1,577)
	TOTAL		5	(290)	369	(702)
Abatement		(tonnes)				
	OPG		-	-	-	-
	All Industrials		12,634	12,962	562	1,752
	TOTAL		12,634	12,962	562	1,752
Abatement Cost		($ 000's)				
	OPG		-	-	-	-
	All Industrials		$65	$321	$65	$321
	TOTAL		65	321	65	321

OPG and the Other Industrial Plants are significant sources of NO_x emissions. The Non-Ferrous Industrial Plants are not and are therefore not included in the analysis of the base case or any of the scenarios.

In the *low-nuclear* variant of the base case, the price of a NO_x allowance of one tonne is bracketed between CDN $2,578 and $2,589/tonne of NO_x emissions. At the lower price the Other Industrial Plants would find it profitable to create 11,371 tonnes of NO_x allowances, which is essentially the same as the 11,376 tonnes of allowances that OPG requires to meet its NO_x reduction target. At the slightly higher price the quantity of credits created would exceed this quantity by a few hundred tonnes. As with SO_2, OPG does not abate and Other Industrials abate between 12,634 to 12,962 tonnes.

These prices per tonne of NO_x emissions are higher than the equivalent price in the US over the past few years (see above page 16) but they are not out of line given the likelihood that actual abatement costs are lower than the cost information used in the simulation might suggest because of the limited range of options included in the simulations.

As with SO_2, OPG's NO_x emissions decline dramatically in the *high-nuclear* version of the base case though not quite to the point where OPG meets its NO_x target. Consequently, the simulation results indicate that there will be a small number of NO_x allowances traded (875 tonnes) at a price in the range of CDN $233 to $244/tonne of NO_x. These prices are well below typical prices in the US largely because the projected demand for NO_x credits by OPG in this case is so modest. Finally, it is also important to note that OPG does not abate while abatement by Other Industrials is much lower than in the *low- nuclear* case (562 to 1,752 tonnes).

12.3 Scenario 1: Command and Control – Uniform Targets

This scenario differs from the above primarily because all plants now have to reduce emissions by 45% of 1990 levels for NO_x , and to 50% of 1994 levels with respect to SO_2. In other words, we are evaluating the effects of a command-and-control regime.

- SO_2

Table 13.3 SO_2 Scenario 1: Command and Control – Uniform Targets

			Low Nuclear		High Nuclear	
Price		($/tonne)	$142	$143	NO MARKET	
Net Demand		(tonnes)				
	OPG		24,467	24,467		
	Other Industrials		(12,211)	(12,211)		
	Non-Ferrous Industrials		(10,202)	(91,292)		
	TOTAL		2,053	(79,037)		
Abatement		(tonnes)				
	OPG		-	-		
	Other Industrials		70,087	70,087		
	Non-Ferrous Industrials		141,120	231,220		
	TOTAL		211,207	301,307		
Abatement Cost		($ 000's)				
	OPG		-	-		
	Other Industrials		$135,434	$135,434		
	Non-Ferrous Industrials		95,248	106,795		
	TOTAL		230,682	242,229		

In the *low-nuclear* case the imposition of SO_2 targets on Other Industrial Plants has the effect of increasing the supply of SO_2 credits at zero cost because the technologies they are assumed to employ, reduce their SO_2 emissions by more than the required amount. Compared with the base case there exists even more downward pressure on the price of SO_2 credits. Recall that SO_2 prices are already expected to be low in the base case because Non-Ferrous Industrial Plants may generate credits by complying with control orders.

As in the base case, OPG's net demand is at 24,467 tonnes and it does not abate. Given this and the fact that Industrial Plants are willing to supply credits, it is unsurprising that upper bound equilibrium prices are lower than in the base case. Non-Ferrous Industrials abate between 141,120 to 231,220 tonnes, while Other Industrial Plants abate by 70,087 tonnes.

Similar to the base case scenario, the simulation results for the *high- nuclear* case suggest that there would be no market for SO_2 credits because OPG can meet its SO_2 target by replacing electricity generated from coal combustion with electricity from its nuclear plants.

- NO_x

Table 13.4 NO_x Scenario 1: Command and Control – Uniform Targets

			Low Nuclear		High Nuclear	
Price		($/tonne)	$4,344	$4,356	ZERO	$5,113
Net Demand		(tonnes)				
	OPG		7,728	1,320	874.8	-
	All Industrials		(5,197)	(5,197)	(2,366)	-
	TOTAL		2,531	(3,877)	(1,491)	-
Abatement		(tonnes)				
	OPG		6,388	13,690	-	-
	All Industrials		26,701	26,701	23,555	
	TOTAL		33,089	40,391	23,555	
Abatement Cost		($ 000's)				
	OPG		$21,777	$53,572	-	-
	All Industrials		73,908	73,908	73,908	73,908
	TOTAL		95,685	127,480	73,908	73,908

In the *low-nuclear* variant of Scenario 1, the core industrial plants must reduce their NO_x emissions to meet their own targets before creating credits that they can sell to OPG. As a result, their supply of NO_x credits is less than in the base case and the price is correspondingly higher between CDN $4,344 and $4,356/tonne of NO_x emissions. At the lower price there is a slight short-fall between the quantity of allowances demanded by OPG and the quantity supplied by the core industrial plants. At the higher price an additional abatement technology becomes cost-competitive for OPG, which reduces its demand for NO_x emissions well below the amount available.

These prices per tonne of NO_x emissions are much higher than the equivalent price in the US over the past few years (see above page 16), likely due to the combination of a much smaller market in Ontario (only one buyer) and the possibility that there are additional abatement options that have not yet been defined. This could also be a result of less stringent U.S. standards.

In the *high-nuclear* case, the introduction of NO_x targets on Other Industrial Plants creates a supply of NO_x allowances (2,366 tonnes) in excess of the quantity required by OPG to meet its NO_x targets (875 tones). This is because the technologies available to the core industrial plants included in the simulations, over achieve their NO_x targets. Consequently, the lower bound for the price of NO_x credits in this scenario is zero. However, the simulations also show that OPG will have to pay an average of CDN $5,113/tonne to meet their NO_x target if they do this entirely on their own. Hence, the upper bound of the price of a NO_x allowance could be very high. The actual price will depend on the bargaining strength and skills of Other Industrial plants, (specifically those actually involved in trading), and OPG.

12.4 Scenario 2: Emissions Trading – Uniform Targets

We now derive the implications of a trading scenario. As opposed to specific targets, emission levels are achieved by distributing allowances to OPG and all Industrial Plants. In this scenario OPG and all Industrial Plants receive allowances and are able to buy credits and allowances from each other.

- SO_2

Table 13.5 SO_2 Scenario 2: Emissions Trading – Uniform Targets

			Low Nuclear		High Nuclear	
Price		($/tonne)	$250	$251	$144	$145
Net Demand		(tonnes)				
	OPG		(33,917)	(48,387)	(11,090)	(46,874)
	Other Industrials		28,665	28,665	37,578	37,578
	Non-Ferrous Industrials		5,728	5,728	5,728	5,728
	TOTAL		476	(13,994)	32,216	(3,568)
Abatement		(tonnes)				
	OPG		58,384	72,854	11,090	46,874
	Other Industrials		35,466	35,466	26,553	26,553
	Non-Ferrous Industrials		118,563	118,563	118,563	118,563
	TOTAL		212,412	226,883	156,206	191,990
Abatement Cost		($ 000's)				
	OPG		$8,946	$12,968	$1,230	$6,389
	Other Industrials		3,689	3,689	1,978	1,978
	Non-Ferrous Industrials		28,385	28,385	28,385	28,385
	TOTAL		41,020	45,042	31,593	36,752

The price of an allowance in the *low-nuclear* case is roughly CDN $250/tonne. OPG is now a supplier while Industrial Plants are purchasers. Hence, it is intuitive that OPG abates more while the Industrial Plants abate more in this scenario relative to Scenario 1. It is possible that increased demand from the Industrials has driven prices up. And unlike previous scenarios, a market does exist in the *high-nuclear* scenario.

As can be seen, the price of a tonne of SO_2 in the *high-nuclear* variant of this scenario is lower than in the *low-nuclear* variant. Specifically, the price falls to $144 - $145/tonne from the *low* to *high-nuclear* scenarios. This could occur if some OPG plants reduce their demand for allowances and that offsets any increased demand on the part of Other Industrials. In both cases OPG is a net supplier, while both Non-Ferrous and Other Industrial Plants are purchasers. Abatement by both Non-Ferrous and Other Industrial Plants drop considerably from Scenarios 1 to 2.

It is now appropriate to examine the differences in total abatement and corresponding costs according to scenarios 1 and 2. We focus on the “Low-Nuclear” Scenario, as there is no trading in the “High-Nuclear” case. Scenario 1 (command-and-control) results in total abatement costs ranging from CDN $231 million to CDN $ 242 million (roughly). On the other hand, results from Scenario 2 simulations suggest that similar abatement targets can be achieved through emissions trading for only CDN $41 to

CDN $45 million. Hence, trading results in significant abatement cost savings for participants. Looking at just the *low-nuclear* case, industry participants abate between 211,207 -301,307 tonnes in Scenario 1 and between 212,412-226,883 tonnes in Scenario 2. Hence, there exists potential for significant *over-abatement* by firms in a command-and-control regime.

- NO_x

Table 13.6 NO_x Scenario 2: Emissions Trading – Uniform Targets

			Low Nuclear		High Nuclear	
Price		($/tonne)	$4,350	$4,360	$3,400	$3,410
Net Demand		(tonnes)				
	OPG		4,988	(14,484)	875	(5,513)
	All Industrials		2,923	2,923	4,224	4,224
	TOTAL		7,911	(11,561)	5,099	(1,289)
Abatement		(tonnes)				
	OPG		6,388	25,860	-	6,388
	All Industrials		19,399	19,399	18,098	18,098
	TOTAL		25,787	45,259	18,098	24,486
Abatement Cost		($ 000's)				
	OPG		$21,777	$106,564	-	$21,777
	All Industrials		32,680	32,680	27,631	27,631
	TOTAL		54,457	139,244	27,631	49,408

The price of a tonne of NO_x in this scenario is between $3,400 to $4,360/tonne in the high and low nuclear variations. While there isn't much difference between Scenario 1 and 2 prices in the *low-nuclear* case, the upper bound for the *high-nuclear* case is definitely higher in Scenario 1. In both *high* and *low-nuclear* cases, the level of abatement by the core industrial plants could potentially be the same (6,388 tonnes). What changes dramatically is OPG's demand and supply of allowances. In the low nuclear case at a price of $4,350/tonne NO_x OPG wants to buy 4,988 tonnes of NO_x allowances, but there is no supply. At a price only $10/tonne higher, OPG finds it profitable to increase its abatement of NO_x and becomes a supplier of allowances (14,484 tonnes) to the core industrial plants. Many factors, including cost, govern these decisions. Of course, the scope of this study limits the number of factors we can consider to one – cost.

Similarly, in the *high-nuclear* variant of this scenario, OPG is a purchaser of allowances at the low price but a supplier at the high price.

Other Industrial Plants abate less across both *high* and *low-nuclear* cases in Scenario 2, relative to Scenario 1.

Abatement costs across both *low* and *high-nuclear* cases are in most cases much lower with trading (Scenario 2) relative to command-and-control (Scenario 1). This is with the exception of the upper bound of the *low-nuclear* case, which is higher in

Scenario 2 than in Scenario 1. However, too much weight should not be put on this, as it is likely an artifact of discontinuous cost functions, and in reality will probably not occur.

12.5 Scenario 3a: Emissions Trading – Plant Specific Targets

This scenario also evaluates possible benefits from trading. The difference from Scenario 2 is that the allowances given to industrial plants are based on different percentage reductions for each facility rather than a 45/50 blanket reduction (45% of 1990 NO_x emissions and 50% of 1994 SO_2 emissions).

- SO_2

Table 13.7 SO_2 Scenario 3a: Emissions Trading –Plant Specific Targets

			Low Nuclear		High Nuclear	
Price		($/tonne)	$505	$506	$434	$435
Net Demand		(tonnes)				
	OPG		(56,150)	(56,150)	(77,844)	(80,617)
	Other Industrials		9,197	9,197	9,696	9,696
	Non-Ferrous Industrials		68,694	43,078	68,694	68,694
	TOTAL		21,741	(3,875)	546	(2,227)
Abatement		(tonnes)				
	OPG		80,617	80,617	77,844	80,617
	Other Industrials		37,325	37,325	36,826	36,826
	Non-Ferrous Industrials		90,100	118,563	90,100	90,100
	TOTAL		208,042	236,505	204,770	207,543
Abatement Cost		($ 000's)				
	OPG		$16,202	$16,202	$14,863	$16,202
	Other Industrials		4,339	4,339	4,101	4,101
	Non-Ferrous Industrials		11,547	28,385	11,547	11,547
	TOTAL		32,088	48,926	30,511	31,850

At a range of CDN $434 to 506, prices per tonne of SO_2 are higher in this scenario than in Scenario 2, possibly because demand by all Industrials is higher than corresponding supply from OPG. However, as in Scenario 2, OPG remains a net supplier, while Other Industrial and Non-Ferrous plants are purchasers. With the exception of the lower bound of the *high-nuclear* case, there doesn't seem to be great differences in overall abatement between Scenarios 3a and 2. But it is interesting to note that abatement is a bit higher, which is unsurprising given the slightly higher prices relative to Scenario 2. In most cases, total abatement costs are a bit lower in Scenario 3a relative to 2.

- NO_x

Table 13.8 NO_x Scenario 3a: Emissions Trading – Plant Specific Targets

			Low Nuclear		High Nuclear	
Price		($/tonne)	$3,400	$3,410	$2,070	$2,080
Net Demand		(tonnes)				
	OPG		11,376	4,988	875	875
	All Industrials		(6,563)	(6,563)	(695)	(920)
	TOTAL		4,813	(1,575)	180	(45)
Abatement		(tonnes)				
	OPG		-	6,388	-	-
	All Industrials		18,098	18,098	12,230	12,455
	TOTAL		18,098	24,486	12,230	12,455
Abatement Cost		($ 000's)				
	OPG		-	$21,777	-	-
	All Industrials		27,631	27,631	10,985	11,453
	TOTAL		27,631	49,408	10,985	11,453

The prices per tonne of NO_x are much lower in this scenario than in Scenario 2, and the direction of the trades has changed. OPG is now consistently the buyer of allowances, which are supplied by other plants. This is interesting because it illustrates how a modest change in the allocation of allowances can have a significant change in how the market functions.

Given the lower prices (relative to Scenario 2), it is unsurprising that actual abatement and corresponding costs are correspondingly lower.

12.6 Scenario 3b: Command and Control – Plant Specific Targets

Scenario 3b was conceived to evaluate the costs incurred by CAPI participants assuming similar emissions levels to Scenario 3a, but within a command-and-control regime.

- SO_2

Table 13.9 SO_2 Scenario 3b: Command and Control – Plant Specific Targets

			Low Nuclear		High Nuclear	
Price		($/tonne)	ZERO	$158	NO MARKET	
Net Demand		(tonnes)				
	OPG		24,467			
	Other Industrials		(14,059)			
	Non-Ferrous Industrials		(53,942)			
	TOTAL		(43,534)			
Abatement		(tonnes)				
	OPG		-			
	Other Industrials		61,634			
	Non-Ferrous Industrials		226,363			
	TOTAL		287,997			
Abatement Cost		($ 000's)				
	OPG		-			
	Other Industrials		$54,876			
	Non-Ferrous Industrials		106,795			
	TOTAL		161,671			

It is interesting that the simulation results for SO_2 bears some similarities to Scenario 1, which only included credits. The reason for this is that the restrictions on the purchase and sale of allowances in Scenario 3b largely eliminate trade in allowances leaving trade in credits the main mechanism for flexibility as in Scenario 1.

Prices in the low nuclear case (CDN $ 0-158) are quite similar to Scenario 1. As in Scenario 1 there is no market in the *high-nuclear* case. In terms of total abatement costs, Scenario 3b is much more expensive than 3a, but lower than Scenario 1.

- NO_x

Table 13.10 NO_x Scenario 3b: Command and Control – Plant Specific Targets

			Low Nuclear		High Nuclear	
Price		($/tonne)	$3,400	$3,410	ZERO	$4,602
Net Demand		(tonnes)				
	OPG		11376	4988	875	
	All Industrials		(10,994)	(10,994)	(4,286)	
	TOTAL		382	(6,006)	(3,411)	
Abatement		(tonnes)				
	OPG		-	6,388	-	
	All Industrials		23,162	23,162	14,472	
	TOTAL		23,162	29,550	14,472	
Abatement Cost		($ 000's)				
	OPG		-	$21,777	-	
	All Industrials		67,375	67,375	67,375	
	TOTAL		67,375	89,152	67,375	-

Scenario 3b displays the same prices as in Scenario 3a in the low nuclear case and quite similar prices to Scenario 1 in the high nuclear case. But the total abatement costs are much higher in Scenario 3b. Hence, trading seems to offer a significant gain over command and control.

12.7 Conclusions

The first point to note that an emissions trading system should result in lower abatement costs relative to a command-and-control regime. However, the magnitude of cost savings is impacted by the amount of electricity generated at Ontario's nuclear power plants. The simulations show that under a wide range of different situations, the SO_2 prices that clear the markets do not exceed CDN $500/tonne and could be much less. For NO_x the situation is a rather different. The market clearing prices are between CDN $2,000 - $4,000/tonne. Another important result is that participants seem to abate more in command-and-control scenarios (Scenarios 1 and 3b) relative to trading cases (Scenarios 2 and 3a).

The conclusion to draw from these results is that there are two main influences on how an expanded emissions trading system in Ontario is likely to function: the first is whether Ontario will have a low or high nuclear electricity generating regime over the next several years and the second is the design of the trading system itself.

The Ministry of the Environment has little influence over whether and at what rate the nuclear units currently off-line will be brought back on line. However, the impact of increasing the amount of nuclear generated electricity on the market clearing price for NO_x credits and allowances is very considerable in most of the scenarios. In preparing for an expanded emissions trading system, the Ministry of the Environment should ensure that stakeholders understand that the way the market will perform is highly dependent on the fate of Ontario's nuclear units largely because it affects OPG's likely demand for NO_x credits or allowances. The impact on SO_2 credits and allowances is similar but far less severe.

The second influence on how an expanded trading system will function is the design of the system itself. This is something over which the Ministry of the Environment does have some control. The scenarios show that not only do the prices of allowances and credits depend on the market design but so does the amount of abatement. In the low nuclear cases all of the scenarios with some form of trading generate significantly greater reductions (greater abatement) in SO_2 and NO_x emissions than the base case. The same applies to the high nuclear cases but only when a market in credits or allowances exists.

The suggestion that in comparison to command-and-control, emissions trading results in reduced abatement, may be counterintuitive since the theory of emissions trading is that trading itself does not reduce emissions but only ensures that it happens in the least cost manner. The reason why substantial reductions in emissions arise in the various scenarios is that the abatement activities included in the simulations are "lumpy". To reduce emissions by x tonnes, sources are obliged to reduce by x + y tonnes because of the limited abatement options assumed to be available. For reasons given earlier, this effect is likely to be over-stated in the simulations but not to the point where it can be ignored without further inquiry.

Finally, the simulations show that even with a comparatively limited number of participants and allowing for the possibility of strategic behaviour, an expanded emissions trading market for SO_2 and NO_x in Ontario can be expected to yield results and cost savings similar to those already achieved in the United States. As discussed earlier, the average price per ton of SO_2 Reduction Trading Credits (RTCs) from 1996 to 2000 in RECLAIM ranged from US$1,500 to US$3,000. In comparison, prices have stayed between US$130-200/ton in the US Clean Air Act Title IV SO_2 trading program since 1999. With respect to NO_x, the average price of 1998 NO_x RTCs traded in 1999 was US$1,827 per ton of NO_x RTCs. From 1999 onwards, prices for OTC NO_x allowances were till recently, below US$2,000.

13. Technical Appendix- Simulations

13.1 Definitions

Non-Ferrous Industrial Plants: Inco (Sudbury) and Falconbridge (Sudbury).

Other Industrial Plants: 22 in five industrial sectors for NO_x (Cement, Pulp and Paper, Petroleum, Iron & Steel, and Glass) and six industrial sectors for SO_2 (Cement, Pulp and Paper, Petroleum, Iron & Steel, Carbon Black, and Non Ferrous).

Ontario Power Generation ('OPG') Plants: Four coal-fired electricity generation facilities.

13.2 Notes

Abatement Cost Functions ('ACFs') are available for all Non-Ferrous and Other Industrial Plants, and OPG Plants.

No adjustments are made for emitters, in addition to those above, that may receive emissions allocations or be subject to other emissions requirements.

Business As Usual ('BAU') emissions levels (which were provided by the Ministry) are assumed to be the levels of emissions by plants in the absence of any abatement activity resulting from the introduction of an emissions trading mechanism.

The simulations were performed according to different scenarios defined by the Ministry and separately for SO_2 and NO_x. The objective of these scenarios, are to isolate possible gains from an emissions trading system. We assume that each scenario has an emissions "target", which participating facilities must achieve. For scenarios in which facilities face a regulatory cap on emissions, the target is the emission reduction the facilities must implement to achieve the cap. For scenarios that allow for trading, the relevant target is the number of allowances that facilities receive from the government.

We derive equilibria for four sub-cases for each SO_2 and NO_x simulation, for each of the five Scenarios described below. The sub-cases account for lower and upper equilibrium values and differences in OPG plant emissions resulting from different assumptions about generation from OPG's nuclear facilities (*High-Nuclear* and *Low-Nuclear* sub-cases).

13.3 Base Case Scenario

Summary: Non-Ferrous Plant emission levels are subject to caps. All Industrial Plants can create credits, but cannot purchase them to meet targets. OPG plants receive allowances through O.Reg. 397/01 and can purchase credits to meet targets, but cannot sell them. Credits are created for abatement activities that reduce emissions below either BAU levels or regulatory levels, whichever is lower:

Credits available for sale = Actual Abatement

Supply Schedules for Industrial Plants:

Other Industrial Plants can sell one tonne of credits for every tonne of abatement of emissions. At every price, p, of credits, plant *i* chooses its abatement level, B_i, to maximize the following profit function:

$$\text{Profit}_i\ (p) = pB_i - C_i(B_i)$$

Since no abatement targets are imposed on Other Industrial Plants in this case, the amount of actual abatement, B_i = tonnes of credits available for sale and $C_i(B_i)$ is plant *i*'s cost of abating B_i.

Our program derives, for each Other Industrial Plant, the profit-maximizing level of abatement for all prices in the range \$1-\$1,000, in increments of \$1, for SO_2. For NO_x, profit-maximizing levels of abatement are derived for all prices in the range \$10-\$10,000, in increments of \$10.

The Total net supply of credits for Other Industrials Plants is the sum of individual plant net supplies.

Non-Ferrous Plants maximize a slightly different objective function because they face a 'cap'.

$$\text{Profit}_i(p) = p(B_i - B_i^*) - C_i(B_i)$$

subject to the constraint $B_i \geq B_i^*$,

where

B_i = plant *i*'s quantity of abatement;

$C_i(B_i)$ = plant *i*'s cost of abating B_i, and;

B_i^* = plant *i*'s cap or target abatement level.

$B_i - B_i^*$ is the amount of credits created through the abatement of B_i tonnes of emissions when the target level of abatement is B_i^*. The constraint $B_i \geq B_i^*$, is imposed to ensure that each plant abates at least its requirement.

As with Other Industrial Plants, our program derives, for each regulated industrial plant, the profit-maximizing level of abatement for all prices in the range \$1-\$1,000, in increments of \$1, for SO_2. For NO_x, profit-maximizing levels of abatement are derived for all prices in the range \$10-\$10,000, in increments of \$10.

The Total net supply for Regulated Industrial Plants is the sum of individual net supplies. NO_x abatement cost functions for these plants were not made available to us, and consequently, we did not derive their NO_x supply functions.

Demand Schedules for OPG Plants:

OPG Plants are the only buyers of credits created by the industrial sector. Each plant is assumed to have an initial allocation of allowances from O.Reg. 397/01. When a plant's BAU emissions exceed its allocations, it must either purchase credits or abate to make up the difference:

Purchased Credits + Abatement = BAU emissions – Allocation

Rather than directly deriving OPG's demand for Credits, we derive the demand for Allowances and convert this into a demand for Credits by dividing by .9. This reflects the fact that only 90% of the purchased credits are effective credits for the purpose of meeting emissions requirements.

OPG plant *i* minimizes the cost of meeting its requirements:

$$\text{Cost} = C_i(A_i) + p\,[(A_i^* - A_i)/.9]$$

subject to the constraint $A_i. \leq A_i^*$.

where

A_i = the amount of abatement performed in OPG's plant *i*

$C_i(A_i)$ = plant *i*'s cost of abating A_i, and;

A_i^* = BAU_i emissions – Allocation, which is OPG plant i's target abatement.

$(A_i^* - A_i)$ represents plant *i*'s residual required credits from industrial sources. The cost of purchasing each of these credits is p/.9. The division by .9 reflects the fact that only 90% of the purchased credits are effective credits for the purpose of meeting the emission requirements.

The constraint $A_i. \leq A_i^*$ is imposed because in the Base Case Scenario, OPG plants cannot sell credits or allowances, and therefore have no incentive to abate more than their target levels. (This constraint is eliminated in Scenario 2, where OPG plants can buy credits *and* sell allowances).

13.4 Scenario 1: Command and Control –Uniform Targets

Summary: As in the Base Case, Industrial Plants can create credits, but cannot purchase them to meet targets. OPG plants receive allowances from O.Reg. 397/01 and can purchase credits to meet targets, but cannot sell them. All Industrial Plants are now subject to target abatement levels (command-and-control). They can create and sell credits only if abatement levels exceed targets.

Both *Non-Ferrous Core Industrial Plants* are assumed to be endowed with allocations for emissions (50% of 1994 levels for SO_2 and 45% of 1990 levels for NO_x). Credits are created for abatement activities that reduce emissions to levels below Allocation levels.

Credits available for sale = Actual Abatement – [BAU - [1 - (X/100)] x E^{ref}

where is E^{ref} is the 'reference' year for emissions: 1990 for NO_x and 1994 for SO_2.[118]

Each *Non-Ferrous* and *Other Industrial Plant* can sell one tonne of credits for every tonne of abatement of emissions in excess of target abatement levels. At every price, p, of credits, plant *i* maximizes the profit function:

$Profit_i(p) = p(B_i - B_i^*) - C_i(B_i)$

subject to the constraint $B_i \geq B_i^*$,

where

B_i = plant *i*'s quantity of abatement;

$C_i(B_i)$ = plant *i*'s cost of abating B_i, and;

B_i^* = plant *i*'s target abatement level. In this scenario, B_i^* = BAU - [1 - (X/100)] x E^{ref}.

$B_i - B_i^*$ is the amount of credits created through the abatement of B_i tonnes of emissions when the target level of abatement is B_i^*. The constraint $B_i \geq B_i^*$ ensures that each plant abates at least its requirement.

OPG Plants are assumed to be subject to the same trading restrictions as in the Base Case Scenario.

13.5 Scenario 2: Emissions Trading –Uniform Targets

Summary: All *Industrial Plants* and *OPG Plants* are provided with emissions allocations. They can purchase allowances if emissions exceed allocations, and they can sell allowances if emissions are less than allocations.

118 In Scenario 1, all Industrial Plants are required to reduce emissions by 45% from 1990 levels in the case of NO_x, and by 50% of 1994 levels for SO_2. We interpreted this to imply that these plants are permitted to emit 55% of 1990 levels for NO_x and 50% of 1994 levels for SO_2 in the model year. This interpretation yields the equation for Credits above.

All *Industrial Plants* are assumed to be endowed with allocations for emissions (50% of 1994 levels for SO_2 and 45% of 1990 levels for NO_x). Each plant can buy allowances to meet its emissions targets or sell allowances generated by abatement activities that exceed requirements. *OPG Plants* are also assumed to be endowed with allocations for emissions (OPG allocations were provided by the Ministry). Each plant can buy or sell Allowances.

For every Industrial Plant and for every OPG plant:

1. Allowances are created and can be sold if abatement activities reduce emissions by at least (BAU – Allocation):

Allowances available for sale = Actual abatement – [BAU – Allocation]

if Actual abatement > [BAU – Allocation]

2. Allowances must be purchased if abatement activities reduce emissions by less than (BAU – Allocation):

Purchase of Allowances = [BAU – Allocation] – Abatement

if Actual abatement ≤ [BAU – Allocation]

<u>Net Demand and Supply Schedules for every Industrial Plant and OPG plant</u>:

Each Industrial Plant and OPG Plant maximizes the following profit function:

$\text{Profit}_i(p) = p(B_i - B_i^*) - C_i(B_i)$

where

B_i = plant *i*'s quantity of abatement;

$C_i(B_i)$ = plant *i*'s cost of abating B_i, and;

B_i^* = plant *i*'s BAU level of emissions less its allocation of allowances.

If $B_i > B_i^*$, or after rearranging, B_i + Allocation > BAU, then the plant has created excess allowances, in the amount $B_i - B_i^*$, which it can sell on the market. If, on the other hand, $B_i < B_i^*$, then B_i + Allocation < BAU, and the plant purchases allowances in the amount $B_i^* - B_i^*$ to cover its deficit.

13.6 Scenario 3a: Emissions Trading – Plant Specific Targets

Same as Scenario 2 except that *Core Industrial Plants* have different allocation levels.

13.7 Scenario 3b: Command and Control – Plant Specific Targets

All *Industrial Plants* emissions are capped at levels that corresponding to allocations in Scenario 3a, so that in this case, they can only create credits and cannot buy allowances to meet their targets.

Credits available for sale = Actual Abatement – [BAU – Cap]

= Cap – Actual Emissions.

OPG Plants are assumed to be subject to the same trading restrictions, and have the same BAU levels and allocations as in Scenario 3a.

13.8 Allocations and Caps

The below tables summarize allocations and caps by sector and scenario.

Table 14: NOx Industry Allocations

	Base Case	Scenario 1	Scenario 2	Scenario 3a	Scenario 3b
	Cap for Industry, Allowances for OPG	Cap for Industry, Allowances for OPG	Allowances for Industry and OPG	Allowances for Industry and OPG	Cap for Industry, Allowances for OPG
Core Industrials	-	32,303	32,303	43,013	43,013
OPG					
Low Nuclear	22,855	22,855	22,855	22,855	22,855
Hi Nuclear	25,745	25,745	25,745	25,745	25,745

Table 15: SOx Industry Allocations

	Base Case	Scenario 1	Scenario 2	Scenario 3a	Scenario 3b
	Cap for Industry, Allowances for OPG	Cap for Industry, Allowances for OPG	Allowances for Industry and OPG	Allowances for Industry and OPG	Cap for Industry, Allowances for OPG
Core Industrials	-	63,497	63,497	84,720	84,720
Other Industrials	241,000	182,500	182,500	91,000	91,000
OPG					
Low Nuclear	99,921	99,921	99,921	99,921	99,921
Hi Nuclear)	121,646	121,646	121,646	121,646	121,646

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