Electricity and the Environment

An Article 13 Initiative of the North American Commission for Environmental Cooperation

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Working Paper

Estimating Future Air Pollution from New Electric Power Generation

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Commission for Environmental Cooperation Secretariat

Date: 21 November 2001

This working paper was prepared by the CEC Secretariat in support of the "Electricity and Environment" initiative undertaken pursuant to Article 13 of the North American Agreement on Environmental Cooperation. These background materials are intended to stimulate discussion and elicit comments from the public, as well as the Electricity and Environment Advisory Board, in addition to providing information for the 29–30 November 2001 Symposium on the "Environmental Challenges and Opportunities of the Evolving North American Electricity Market." The opinions, views or other information contained herein do not necessarily reflect the views of the CEC, Canada, Mexico or the United States. Following receipt of comments and observations on these materials, the Secretariat will prepare a report to Council, with recommendations, early in 2002.

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Estimating Future Air Pollution from New Electric Power Generation

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The generation of electricity from the burning of fossil fuels is a significant source of air pollutants and greenhouse gases in North America. For example, the electricity generation sector in Canada and the United States during 1998 had the greatest total reported toxic releases, on- and off-site, among all industry sectors reporting in the two countries.[1] The purpose of this report is to estimate the future emissions of four key pollutants from the electricity generation sector in North America based on projections of future electricity generation capacity changes. In doing this, we seek to discern where the greatest activity is occurring in terms of new power plant projects in North America, and what emission changes might occur due to these projects relative to historical power plant emissions during a representative "recent" year. We place these emissions in a local context (province or state) and at the national level as well.

The four pollutants we consider in this study are nitrogen oxides (NOx), sulfur dioxide (SO_2), mercury (Hg), and carbon dioxide (CO_2). These pollutants all arise from the combustion of fossil fuels by the electricity generation sector. Nitrogen oxides contribute to ground-level ozone (smog) on an urban and regional scale. Both NOx and SO_2 contribute to acidic deposition, commonly called acid rain. Emissions of NOx and SO_2 from fossil fuel combustion also are sources of fine particles in the atmosphere that are a major public health concern because of their links to lung damage and premature mortality. Toxic mercury deposited in lakes and streams has led to fish consumption advisories across North America. Carbon dioxide is an important greenhouse gas that contributes to global climate change. In addition to these pollutants, the electricity generation also gives rise to a host of toxics, such as hydrochloric acid, sulfuric acid, hydrogen fluoride, and heavy metals.

As a significant source of a number of air pollutants, the future evolution of the electricity generation sector in an integrated North American energy market will have a profound effect on air quality and climate change. In order to assess changes in environmental quality (both good and bad) arising from an integrated North American energy market, policy makers and the public will need a common frame of reference as a starting point. One conceivably straightforward approach is to establish a baseline of air emissions from the North American electricity generation sector for a common reference year, and track changes in emissions over time from the reference year as new sources of electricity are built and old sources are retired or refurbished.

While conceptually simple, there are obstacles to tracking changes in emissions from the electricity generation sector on the North American scale. At the most basic level, air pollution information is not uniformly available on a comparable basis in all three

[1] Commission for Environmental Cooperation, "Taking Stock 1998 Summary," (July 2001), p. 15.

countries, especially at the level of individual power plants. The information, when available, may not be for the same year across the three countries. Each country may also compile emissions data using different methods, such as directly measuring air pollutants through continuous emissions monitoring on smoke stacks as opposed to estimating pollution indirectly through the application of mathematical equations using standard emission factors, fuel usage information, and other parameters. The equations and parameters themselves may differ in each country.

These differences not only affect the ability of policy makers and the public to track changes in environmental quality due to changes in the electricity sector, they also affect the potential application of policy tools such as international emission allowance trading programs. If there is inadequate comparability, transparency or confidence in North American emissions data at the level of individual power plants, then there will be little confidence that an allowance trading regime involving sources in different countries will produce emission reductions that are real, permanent and enforceable. This diminishes the public appeal for such approaches, thus hampering the viability of policy tools that hold great promise for cost-effective and flexible pollution reductions achievable through international cooperative efforts.

The following sections describe our approach to putting some perspective on air pollution arising from new electricity generation capacity in North America through 2007. We first estimate a reference case inventory for four air pollutants: carbon dioxide, sulfur dioxide, nitrogen oxides, and mercury. We then develop two boundary cases that estimate future emissions in 2007 associated with electricity capacity changes contained in the NEWGen dataset from Resource Data International (RDI)/Platts. This is not, however, an estimation of 2007 emissions from the entire North American electricity generation sector as it does not attempt to account for potential reduction measures at existing sources. Estimating emissions from announced generation capacity changes is done to place some perspective on the potential emissions arising from announced capacity changes in relation to the reference case inventory. This analysis also serves to identify key areas where access to improved information will help policymakers better evaluate the potential environmental consequences of an increasingly integrated electricity market.

Estimating Emissions in North America from Electricity Generation

For this report, we have attempted to assess the amount of air pollution for four key pollutants emitted by the electricity generation sector during a recent year as a starting reference point. We use this starting reference point to compare reasonably foreseeable future levels of air pollution due to power plant capacity changes through the year 2007 using a publicly available database of announced new generation projects.[2]

There are obstacles in this approach that limit our ability to predict future emission changes that will affect public health and the environment due to an increasingly integrated North American energy market. The obstacles include a lack of available information at the power plant-level for the air pollutants of concern, and the lack of a

[2] RDI/Platts NEWGen Database, August 2001 issue (Boulder, Colorado, USA).

single common year for which air emissions data are available on a comparable basis in all three countries. These obstacles, however, appear surmountable although in some cases they will require changes in domestic legislation or regulation to make air pollutant information more openly available.

The four air pollutants considered here are NOx (expressed as NO_2 mass), SO_2, mercury, and CO_2. In the United States, the year 1998 is the most recent year at the time of this writing for which emissions information on all four pollutants are available at the individual power plant level. Because the U.S. power plants dominate North American emissions, this will give the broadest coverage for a relatively recent year for use as a reference scenario under the current circumstances of data availability in each country. While we are able to obtain individual power plant emissions information for U.S. plants in 1998, we were unable to obtain individual power plant emissions in 1998 for Mexico and some Canadian provinces. Therefore, while we developed a "reference inventory" emissions scenario, it is not based on a single year, rather it is a best approximation using the most relevant information available where 1998 data are lacking.

Of the three NAFTA countries, the Canadian provincial emissions data are the least comparable in terms of the most recent reporting year and public availability of individual power plant emissions information. We were able to obtain 1998 power plant emissions from some provinces in Canada, although we had to rely on older information (1995 or 1996) for others. In some cases, we could only obtain emissions information aggregated at the provincial level, but not at the individual power plant level. For example, Saskatchewan treats individual power plant emissions as confidential business information. Therefore, we had to use 1995 information aggregated at the provincial level in these situations. In other provinces, such as Ontario and Nova Scotia, we were able to obtain 1998 power plant emissions upon request from the provincial environmental agencies. Ontario Power Generation (OPG) also reports annual emissions of CO_2, SO_2 and NOx from its power plants in annual company reports.

For Mexico, we estimated emissions based on 1999 fuel consumption by the electricity generation sector. We obtained 1999 emissions of mercury in Mexico at the power plant level from an earlier study prepared for the Commission for Environmental Cooperation (CEC) by Gildardo y Asociados.[3] The information developed in the mercury report served as our basis for estimating emissions of NOx, SO_2 and CO_2 in Mexico during 1999. While this is more recent than the 1998 U.S. information, the one-year difference is not likely to significantly affect conclusions about projected future emission changes compared to the reference emissions scenario.

We discuss the details of developing emissions information for each of the three countries in the accompanying sections.

[3] Acosta y Asociados, "Preliminary Atmospheric Emissions Inventory of Mercury in Mexico," prepared for the Commission for Environmental Cooperation (2001, in press).

Canada

Emissions information for NOx, SO_2, CO_2 and mercury from the electricity generation sector in Canada is currently not available on a national basis for all four pollutants on a comparable basis. Environment Canada has compiled preliminary estimates of 1998 greenhouse gas emissions from Canada's electricity generating sector aggregated at the provincial level.[4] The most recent national inventory at the provincial level for NOx and SO_2 emissions is 1995. Individual provinces in some cases, however, have more recent information that they make available at the individual power plant level upon request. Alberta has individual power plant information for 1996. The provinces of New Brunswick, Nova Scotia, Ontario, and Quebec have power plant information for 1998 available upon request, and Ontario Power Generation (OPG) provides NOx, SO_2 and CO_2 annual emissions from its power plants in annual company reports.[5] British Columbia makes publicly available individual plant emissions information for the year 1995. Saskatchewan treats individual plant emissions data as confidential business information, so the only publicly available information is for 1995 aggregated at the provincial level. Emissions information on mercury from individual power plants is not publicly available at this time. Environment Canada has estimated mercury emissions at the provincial level for the year 1995, and is updating its inventory for 2000.

Table 1 presents the annual emissions of CO_2, SO_2, and NOx from the electricity generation sector for Canada's provinces and territories. Note that not all emissions are for the same year. The table presents emissions in 1998 when possible, but relies on older information if no 1998 data are publicly available. We do not include mercury emissions at this time due to a pending update by Environment Canada. The information will be added as soon as Environment Canada releases the new inventory.

[4] Environment Canada, Greenhouse Gas Division, Preliminary 1998 Electricity Emissions, April 2001.
[5] Ontario Power Generation, "Toward Sustainable Development 2000 Progress Report," (2001) (available along with earlier annual reports from OPG at http://www.opg.com/envComm/E_annual_report.asp).

Table 1. Province and territory annual emissions of CO_2, SO_2, NOx and mercury (Hg) from the electricity generation sector in Canada (in metric tonnes or kilograms).

Province/Territory	Annual CO_2 equiv. (tonnes)	Annual SO_2 (tonnes)	Annual NOx (tonnes)	Annual Hg (kg)
Alberta	51,400,000	124,632	84,931	
British Columbia	1,840,000	369	4,172	
Manitoba	962,000	1,361	907	
New Brunswick	9,210,000	99,070	27,250	
Newfoundland	1,020,000	15,704	3,690	
Northwest Territories	326,000	317	5,675	
Nova Scotia	7,800,000	143,546	24,620	
Ontario	33,100,000	143,061	85,511	
Prince Edward Island	10,200	294	141	
Quebec	1,400,000	11,475	4,140	
Saskatchewan	15,100,000	108,536	47,509	
Yukon	33,100	46	591	
National Total	**122,000,000**	**648,411**	**289,137**	

Notes on table entries:
CO_2 equivalent emissions are 1998 data from Environment Canada, Greenhouse Gas Division, Preliminary 1998 Electricity Emissions, April 2001.
Alberta SO_2 and NOx (NO_2) emissions are 1996 data from "Alberta Electric Industry, Annual Statistics for 1996," Alberta Energy and Utilities Board, Statistical Series 28, Vol. XVII (November 1997).
New Brunswick SO_2 and NOx (NO_2) emissions are 1998 data from New Brunswick Department of Environment and Local Government.
Nova Scotia SO_2 and NOx (NO_2) emissions are 1998 data from Nova Scotia Department of Environment and Labour.
Ontario SO_2 and NOx (NO_2) emissions are 1998 data from Ontario Ministry of the Environment.
Quebec SO_2 and NOx (NO_2) emissions are 1998 data from Québec Ministère de l'Environnement.
British Columbia, Manitoba, Newfoundland, Northwest Territories, Prince Edward Island, Saskatchewan and The Yukon SO_2 and NOx (NO_2) emissions are 1995 data from Environment Canada, 1995 Criteria Air Contaminants inventory.
Mercury emissions data are omitted from table because Environment Canada is currently revising and updating its estimates. Environment Canada may make its estimates available by Nov. 15, 2001.

Mexico

No complete national inventory for all four air pollutants considered here exists for Mexico's electricity generation sector for a common year. Therefore, we had to make our own estimates of air emissions from the Mexico electricity generation sector, rather than obtaining information directly from reports by the government, states, or electricity generators. We describe our methodology in more detail in the following text.

Mexico has a 1990 greenhouse gas inventory that includes emissions from the electricity sector aggregated at the national level.[6] The Instituto Nacional de Ecologío (INE) provided 1995 NOx and SO_2 emissions information at the individual power plant level based on 1995 fuel consumption by power plants. For this study, we have updated the

[6] INE, Secretaría Medio Ambiente y Recursos Naturales, "México Primera Comunicación Nacional ante la Convención Marco de las Naciones Unidas sobre el Cambio Climático," (1st edition, 1997). A copy can be obtained at http://www.unfccc.de/resource/country/mexico.html.

1990 and 1995 information using fuel consumption information from 1999. The 1999 information was collected as part of a previous study for the CEC to assess mercury air emissions in Mexico.[7]

To develop estimates of NOx, SO_2, and CO_2 emissions in Mexico, we start with 1999 fuel consumption by Mexico's electricity generation sector. We take mercury air emissions from the previous CEC study that used the same 1999 fuel consumption information. We estimate NOx, SO_2, and CO_2 emissions at the power plant level by applying emission factors in combination with fuel use data for natural gas, diesel, fuel oil ("*combustóleo*"), and coal. We use the 1995 emissions information from INE to help determine the choice of NOx and SO_2 emission factors and sulfur content for each of these fuel types, with the exception of coal and diesel. For coal, we use a sulfur content based on a published analysis of coal samples taken from local coal mines in the State of Coahuila.[8] For diesel sulfur content, we use a value provided by Petróleos Mexicanos (PEMEX). We base CO_2 emission factors on the relevant factors given in the U.S. Environmental Protection Agency's AP-42 guidelines (hereinafter referred to as "EPA AP-42).[9] For natural gas, diesel and *combustóleo,* we use INE's emission factors for NOx and SO_2. We note that INE's NOx and SO_2 emission factors are virtually identical to the results we would have obtained if we used factors from EPA's AP-42 manual. We use EPA's AP-42 SO_2 and NOx emission factors for coal combustion in Mexico as we did not have information from Mexico on these at the time of this report.

We describe below the manner in which we estimate SO_2, NOx and CO_2 emissions for each fossil fuel type used by the Mexico electricity generation sector. As mentioned previously, we obtain mercury emissions from recent work performed by Gildardo y Asociados for the CEC. We present the results in Table 2, which shows the state-level and national emission estimates of each of the four air pollutants from the Mexico electricity generation sector in 1999.

<u>Coal</u>

In 1999, there were two coal power plants in Mexico, both in the State of Coahuila.[10] The Coahuila power plants are commonly referred to as Carbón I (José Lopez Portillo plant) and Carbón II, and are 1,200 MW and 1,400 MW in capacity, respectively. Much of the coal consumed by the Coahuila plants comes from local mines, which are generally rated as bituminous or lignite coals with high ash content.[11] In 1999, the power plants

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[7] Acosta y Asociados, "Preliminary Atmospheric Emissions Inventory of Mercury in Mexico," prepared for the Commission for Environmental Cooperation (2001, in press).

[8] J.D. Miller, J.R. Parga, J. Drelich, and C.L. Lin, "Coal Cleaning Opportunities for SO2 Emission Reductions in the Border Region," Southwest Center for Environmental Research and Policy (SCERP) 1996 Final Report, CX 821924-01-0.

[9] U.S. EPA, "Compilation of Air Pollutant Emission Factors AP-42," Fifth Edition, Vol. I Stationary Point and Area Sources, (January 1995, with updates).

[10] In 2001, the 2,100 MW Petacalco power plant in the State of Guerrero began burning coal from Asia and Australia (David Shields, "Unfashionable Fuel Finds a Market," The News Mexico (August 29, 2001)). Only its 1999 *combustóleo* emissions are considered in the 1999 reference year.

[11] J.D. Miller, J.R. Parga, J. Drelich, and C.L. Lin, "Coal Cleaning Opportunities for SO2 Emission Reductions in the Border Region," Southwest Center for Environmental Research and Policy (SCERP) 1996 Final Report, CX 821924-01-0, p. 139.

also used imported coal from Colorado, but we were unable to determine the type or amounts. As will be seen in the following section, we lacked complete information on the various types, quantities, and physical properties of coal consumed by the Carbón power plants. Therefore, in the absence of definitive information, we use our best judgment based on published coal analyses and government information (not all of which were consistent) to estimate emissions from coal combustion in Mexico. Because we did not have emission factors for coal in Mexico at the time of this report, we relied on EPA's AP-42 factors for bituminous coal as we felt these were most consistent with the available information. As the potential for coal use appears to be increasing in Mexico based on recent new project announcements, this is an area in need of further refinement to more accurately assess current and future emissions.

SO_2 emissions
Emissions of SO_2 will depend upon the sulfur content of the coal consumed, but we did not have consistent information on sulfur content. Emissions of SO_2 also depend on the level of control at the power plant. Based on available information, we believe that neither Carbón I nor II had SO_2 controls in 1999.

INE indicates that in 1995, the power plants consumed three types of coal: oil coal with a 3% average sulfur content, local coal with around a 4% average sulfur content, and coal imported mostly from Texas with an unknown sulfur content. The Comisión Federal de Electricidad (CFE) gave an average coal sulfur content of about 1.45%, which is significantly lower than that given by INE. A laboratory analysis of coal samples by Miller, et al. from local coal mines in Coahuila indicates a range of sulfur content from 1.3-2.5% dry weight, depending upon the mine location. This range indicates the coal is of a low to moderate sulfur content type.[12] The sulfur contents in the majority of coal samples were generally at the low end of the range (1.3-1.6%). Based on this and lacking specific information on the quantities of coal consumed from different mines, we have chosen to use the CFE sulfur weight content of 1.45% as it appears consistent with the majority of coal sample measurements given by Miller, et al. We note, however, that this could result in a lower estimation of SO_2 emissions from coal by more than a factor of two from estimations based on INE's sulfur content information.

For calculating SO_2 emissions, we use an SO_2 emission factor of 38S lb/ton from EPA AP-42 for an uncontrolled combustion boiler burning bituminous coal where S is 1.45, the weight % sulfur content of coal as fired, resulting in an emission factor of 55.1 lb/short ton (27.6 kg/metric tonne). Using this emission factor with 1999 coal consumption information from INE gives an estimate of 260,850 metric tonnes of SO_2 emissions in Mexico from the burning of coal by the electricity generation sector in 1999.

NOx emissions
For NOx emissions, we use two different emission rates depending on the power plant. Based on information from CFE, we believe Carbón I is equipped with low-NOx burners,

[12] J.D. Miller, J.R. Parga, J. Drelich, and C.L. Lin, "Coal Cleaning Opportunities for SO2 Emission Reductions in the Border Region," Southwest Center for Environmental Research and Policy (SCERP) 1996 Final Report, CX 821924-01-0 (Table 2).

whereas Carbón II does not have NOx controls.[13] The NOx emission factors will depend upon the type of boiler at the power plants, but we could not definitively confirm the types of boilers in use at Carbón I or II for this report. Based on partial information, we feel the best candidate for boiler type is a wet bottom, wall-fired boiler burning bituminous coal, and use the appropriate NOx emission factor for this boiler type given by EPA AP-42 Table 1.1-3.[14] For Carbón I, we use a NOx emission rate of 15.5 lb/short ton (7.75 kg/metric tonne), which assumes a 50% reduction in emissions from the use of low-NOx burners. For Carbón II, we use the EPA AP-42 factor of 31 lb/short ton (15.5 kg/metric tonne) for uncontrolled NOx emissions. Using 1999 fuel consumption information from INE, we estimate NOx emissions to be 110,207 metric tonnes from coal combustion by the Mexico electricity generation sector in 1999.

CO_2 emissions

The EPA AP-42 guidelines recommend using measured carbon content from coal samples in lieu of default emission factors given in EPA AP-42 Table 1.1-20 unless coal content information is lacking. The coal sample analyses by Miller, et al. does provide carbon content information in Table 1 of about 60% averaged across the coal samples. We choose to use this lower estimate rather than the default 75.9% carbon content for high-volatile bituminous coal given in EPA AP-42. Using this carbon content with the EPA AP-42 conversion factor of 72.6[15] gives us an estimated emission factor of 4,356 lb of CO_2 per ton of coal combusted (2,178 kg/metric tonne). Applying this emission factor gives in an estimate of 20,621,802 metric tonnes of CO_2 from coal combustion by the Mexico electricity generation sector in 1999.

We note that using an average carbon content from the coal samples assumes all coal mines contribute equally to the amount of coal burned at the power plants. This is unlikely as some mines will provide more coal on a tonnage basis than others. Therefore, a more accurate carbon content average would weight the samples on a proportional basis based on their contribution to total coal consumed at the power plants. For example, the Minera Carbonífera Rio Escondido (Micare) company is the largest coal producer in Coahuila,[16] with a production capacity of 6-7 million tonnes per year.[17] This could supply about 70-80% of the coal consumed by the Carbón I and II power plants. The Micare coal samples had carbon contents of about 50%, which is at the low end of the range from all coal samples. Thus, if the Micare coal is the dominate source of coal for the Carbón I and II power plants, which appears likely, then the CO_2 emission estimate obtained here overestimates CO_2 emissions from coal combustion by the two coal power

[13] G. Acosta, personal communication (September 23, 2001).
[14] U.S. EPA, "Compilation of Air Pollutant Emission Factors AP-42," Fifth Edition, Vol. I Stationary Point and Area Sources, (January 1995) (Section 1.1 "Bituminous and Subbituminous Coal Combustion," September 1998 update).
[15] U.S. EPA, "Compilation of Air Pollutant Emission Factors AP-42," Fifth Edition, Vol. I Stationary Point and Area Sources, (January 1995) (Section 1.1 "Bituminous and Subbituminous Coal Combustion," September 1998 update).
[16] U.S. Department of Energy (DOE), "An Energy Overview of Mexico," http://www.fe.doe.gov/international/mexiover.html (September 5, 2001 update).
[17] J.D. Miller, J.R. Parga, J. Drelich, and C.L. Lin, "Coal Cleaning Opportunities for SO2 Emission Reductions in the Border Region," Southwest Center for Environmental Research and Policy (SCERP) 1996 Final Report, CX 821924-01-0.

plants in Mexico, perhaps by about 15%. This is a situation in which more accurate information on coal consumption by Mexico power plants will be useful.

Natural Gas

SO_2 emissions

Natural gas has low SO_2 emissions relative to the other fossil fuels used for electricity generation. We use an SO_2 emission rate of 9.6 kg/10^6 cubic meters (m^3) as provided by INE. This is equivalent to the EPA AP-42 factor of 0.6 lb/10^6 dry standard cubic feet (scf) for natural gas combustion boilers.[18] With this emission factor, we estimate total SO_2 emissions to be 73 metric tonnes from the combustion of natural gas by the Mexico electricity generation sector in 1999.

NOx emissions

For natural gas NOx emissions, we use two different emission factors from INE that depend on boiler size. We did not have information on the level of NOx control from individual boilers, so we assumed no control of NOx emissions at all power plants. This, of course, will overestimate NOx emissions from natural gas units in Mexico if NOx controls exist on any power plant. For boilers with a heat input rate greater than 100 mmBtu/hr, we use a NOx emission factor of 3,760 kg/million cubic meters (MMm^3). For boilers with a heat input rate less than 100 mmBtu/MMm^3, we use a NOx emission rate of 1,600 kg/MMm^3. Using these emission factors, we estimate total NOx emissions to be 28,395 metric tonnes from the combustion of natural gas by the Mexico electricity generation sector in 1999.

CO_2 emissions

We use a CO_2 emission rate from natural gas combustion of 120,000 lb/10^6 scf (1,920,000 kg/10^6 m^3) given by EPA AP-42.[19] This gives an estimate of 14,497,514 metric tonnes of CO_2 from the combustion of natural gas by the Mexico electricity generation sector in 1999.

Diesel

SO_2 emissions

Diesel combustion contributes a relatively small portion of electricity produced in Mexico, so uncertainties in diesel fuel sulfur content have a relatively small impact on overall SO_2 emissions from the electricity generation sector. This is important as there is some discrepancy in determining sulfur content in diesel burned to produce electricity in Mexico. The SO_2 emission factor found in Mexico's stationary source combustion regulation assumes 0.5% sulfur content in diesel.[20] INE provides an emission factor of 17.04S kg/m^3 for diesel (No. 2 oil) where S is the weight percent of sulfur. The INE emission factor is consistent with the EPA AP-42 factor for distillate oil, which would

[18] U.S. EPA, "Compilation of Air Pollutant Emission Factors AP-42," Fifth Edition, Vol. I Stationary Point and Area Sources, (January 1995) (Section 1.4 "Natural Gas Combustion," Table 1.4-2, July 1998 update).
[19] U.S. EPA, "Compilation of Air Pollutant Emission Factors AP-42," Fifth Edition, Vol. I Stationary Point and Area Sources, (January 1995) (Section 1.4 "Natural Gas Combustion," Table 1.4-2, July 1998 update).
[20] Norma Oficial Mexicana, NOM-085-ECOL-1994, Tabla 3.

include diesel fuels.[21] INE uses S = 0.3% as the diesel sulfur content. Information provided by the national oil company Petróleos Mexicanos (PEMEX), however, gives a sulfur content of 0.5% for its diesel. Therefore, we use the INE emission factor of 17.04S kg/m^3 from INE, but with a sulfur content of S = 0.5% which is consistent with information provided by PEMEX. This results in an estimate of 3,042 metric tonnes of SO_2 emitted from the combustion of diesel by the Mexico electricity generation sector in 1999. While the difference in assumed sulfur content introduces a relatively large uncertainty in the absolute value of SO_2 emissions from diesel combustion, the diesel contribution to total SO_2 emissions from electricity generation on a national basis is small so that the uncertainty does not significantly affect the national total.

NOx emissions

For the NOx emission factor for diesel (No. 2 oil), INE uses 2.88 kg/m^3. Applying this factor to diesel fuel consumption gives a NOx emissions estimate of 1,017 metric tonnes from the Mexico electricity generation sector in 1999.

CO_2 emissions

For CO_2 emissions from diesel, we use the EPA AP-42 emission rate for No. 2 oil of 22,300 lb/10^3 gal (2,659 kg/m^3).[22] This gives a CO_2 emissions estimate of 938,509 metric tonnes from diesel combustion by the Mexico electricity generation sector in 1999.

Oil (*Combustóleo*)

SO_2 emissions

In Mexico, fuel oil used for electricity generation is called *combustóleo*. INE's SO_2 emission factor for *combustóleo* combustion is 18.84S kg/m^3 where S is the weight % of sulfur in the oil. INE uses a sulfur content of S = 3.6%. INE uses the same emission factor and sulfur content for *combustóleo ligero* (No. 5 oil) and *combustóleo pesado* (No. 6 oil). The SO_2 emission rate used by INE is the same as that in EPA AP-42 for No. 5 and No. 6 oil. Using a sulfur content of 3.6% gives a SO_2 emission rate of 68 kg/m^3 for oil combustion. This gives a SO_2 emissions estimate of 1,419,235 metric tonnes from *combustóleo* combustion by the Mexico electricity generation sector in 1999.

NOx emissions

The NOx emission factor used by INE for *combustóleo* combustion is 5.64 kg/m^3. INE uses the same NOx emission factor for both *combustóleo* types (*combustóleo ligero* and *combustóleo pesado*). This emission factor gives a NOx emissions estimate of 104,761 metric tonnes from *combustóleo* combustion by the Mexico electricity generation sector in 1999.

[21] U.S. EPA, "Compilation of Air Pollutant Emission Factors AP-42," Fifth Edition, Vol. I Stationary Point and Area Sources, (January 1995) (Section 1.3 "Fuel Oil Combustion," Table 1.3-1, September 1998 update).

[22] U.S. EPA, "Compilation of Air Pollutant Emission Factors AP-42," Fifth Edition, Vol. I Stationary Point and Area Sources, (January 1995) (Section 1.3 "Fuel Oil Combustion," Table 1.3-12, September 1998 update).

CO_2 emissions

The EPA AP-42 CO_2 emission factor for high sulfur No. 6 oil is 24,400 lb/10^3 gal (2,910 kg/m^3). We use this for both types of *combustóleo*. This gives a CO_2 emissions estimate of 54,038,057 metric tonnes from *combustóleo* combustion by the Mexico electricity generation sector in 1999.

Table 2. State-level 1999 annual emissions for CO_2, SO_2, NOx and mercury (Hg) from the Mexico electricity generation sector (in metric tonnes or kilograms).

State	Annual CO_2 (tonnes)	Annual SO_2 (tonnes)	Annual NOx (tonnes)	Annual Hg (kg)
Aguascalientes	0	0	0	0
Baja California	2,017,209	39,550	3,866	3
Baja California Sur	436,305	5,486	704	1
Campeche	0	0	0	0
Chiapas	0	0	0	0
Chihuahua	4,803,048	60,603	9,301	9
Coahuila	20,648,732	260,893	110,241	994
Colima	7,953,680	164,758	15,437	12
Distrito Federal	60,686	98	92	0
Durango	2,337,322	36,010	4,522	4
Guanajuato	4,186,747	86,727	8,126	6
Guerrero	761,261	177,183	1,475	10
Hidalgo	8,636,347	143,440	16,753	15
Jalisco	0	0	0	0
Mexico	3,726,303	75,403	7,193	6
Michoacan	0	0	0	0
Morelos	0	0	0	0
Nayarit	0	0	0	0
Nuevo Leon	3,402,462	46,576	6,566	6
Oaxaca	0	0	0	0
Puebla	0	0	0	0
Queretaro	959,426	1,408	1,756	3
Quintana Roo	230,855	371	345	1
San Luis Potosi	2,616,144	54,193	5,077	4
Sinaloa	3,900,585	80,608	7,566	6
Sonora	4,875,056	98,303	9,401	8
Tabasco	0	0	0	0
Tamaulipas	4,978,888	103,097	9,661	7
Tlaxcala	0	0	0	0
Veracruz	11,963,481	224,759	23,214	19
Yucatan	1,601,345	23,734	3,085	3
Zacatecas	0	0	0	0
National Total	**90,095,882**	**1,683,199**	**244,380**	**1,117**

United States

Air emissions information in the United States for the electricity generation sector was the most straightforward to obtain among the three North American countries. The U.S. Environmental Protection Agency maintains a number of databases with power plant emissions data, such as the National Emissions Trends Inventory (NET 1996) (http://www.epa.gov/ttn/rto/areas/emisdata.htm) and the Acid Rain Program Emissions Scorecard (http://www.epa.gov/airmarkets/). For purposes of this report, we obtained information from E-GRID2000, version 2.0, an integrated database available from the U.S. EPA (http://www.epa.gov/airmarkets/egrid/). This database contains information on NOx, SO_2, CO_2, and mercury emitted to the air by individual power plants in the U.S. It also contains emissions information aggregated in several ways, including by State, electric generating company, power control area, North American Electric Reliability Council region, and the country as a whole. Table 3 presents the E-GRID2000 pollutant information aggregated at the State level and converted to metric units.

Table 3. State-level 1998 annual emissions for CO_2, SO_2, NOx and mercury (Hg) from the United States electricity generation sector based on E-GRID2000 data (in metric tonnes or kilograms).

State	Annual CO_2 (tonnes)	Annual SO_2 (tonnes)	Annual NOx (tonnes)	Annual Hg (kg)
Alabama	74,861,586	522,690	186,200	1,967
Alaska	3,676,226	9,333	16,362	2
Arizona	41,200,149	92,766	82,470	504
Arkansas	26,970,863	69,204	43,509	399
California	40,860,065	28,820	32,047	2
Colorado	36,930,002	90,413	74,163	217
Connecticut	12,107,117	45,596	19,992	30
Delaware	7,381,963	42,488	15,525	110
District of Columbia	273,803	1,150	598	N/A
Florida	128,603,544	748,774	329,586	872
Georgia	73,031,860	587,982	177,387	1,140
Hawaii	7,502,354	22,464	28,144	3
Idaho	208,468	271	208	N/A
Illinois	86,954,445	747,820	272,878	2,364
Indiana	127,893,690	889,450	343,226	1,988
Iowa	36,995,042	160,294	79,163	815
Kansas	32,918,290	105,985	77,099	590
Kentucky	89,615,814	565,524	289,680	1,487
Louisiana	49,872,092	169,307	94,798	401
Maine	3,788,867	19,284	6,969	9
Maryland	33,463,395	263,732	110,823	794
Massachusetts	28,715,838	138,727	41,733	112
Michigan	78,009,126	385,746	200,218	1,181
Minnesota	36,417,840	97,406	98,104	519
Mississippi	22,022,624	137,981	56,004	251
Missouri	67,167,616	273,709	196,277	1,122
Montana	18,914,392	21,153	38,719	407

Nebraska	20,492,677	52,857	45,938	347
Nevada	21,808,144	45,132	47,509	153
New Hampshire	5,172,474	50,390	13,166	16
New Jersey	18,086,751	43,292	32,107	78
New Mexico	32,130,910	73,476	77,023	630
New York	62,453,146	287,571	97,043	505
North Carolina	71,122,679	454,100	239,353	1,258
North Dakota	35,180,102	183,507	91,917	1,108
Ohio	126,546,805	1,292,181	474,748	3,145
Oklahoma	45,315,438	101,400	98,645	693
Oregon	6,610,524	11,732	10,033	62
Pennsylvania	116,474,466	962,565	245,319	4,263
Rhode Island	3,387,013	71	1,088	N/A
South Carolina	32,888,769	186,926	89,973	415
South Dakota	3,528,670	19,894	21,571	36
Tennessee	54,097,987	427,783	216,224	887
Texas	238,729,252	624,270	430,736	4,083
Utah	35,405,316	31,070	72,703	181
Vermont	56,835	102	485	N/A
Virginia	40,240,789	219,224	110,307	531
Washington	11,988,063	68,575	23,603	223
West Virginia	85,738,536	610,119	273,075	1,942
Wisconsin	47,579,689	210,488	108,119	871
Wyoming	50,566,709	96,310	93,415	531
National Total	**2,331,958,813**	**12,291,107**	**5,825,982**	**39,241**

Estimating Emissions from Future Electricity Generation Capacity

Projecting future emissions from new electricity generation capacity on the scale of North America is a formidable challenge. As seen with the retrospective look at the FERC Order 888 environmental impact assessment of the future evolution of the U.S. electricity sector, numerous scenarios are possible depending on the basic assumptions made in the forecasting model.[23] In this report, we do not attempt to model future electricity generation scenarios in North America. Instead, we use a database called NEWGen maintained by the consulting firm RDI/Platts.[24] The NEWGen database contains announced capacity changes in Canada and the United States (additions and reductions) with more limited information for Mexico. We were able to supplement NEWGen with more comprehensive national information from Mexico. Using generation information from the supplemented NEWGen database, we estimate potential future air emissions (CO_2, SO_2, NOx, and mercury) associated with announced capacity changes in North America. Because it is unlikely that all announced capacity additions contained in the

[23] Woolf, T., G. Keith, D. White, and F. Ackerman, "A Retrospective Review of FERC's Environmental Impact Statement on Open Transmission Access," prepared for the Commission for Environmental Cooperation (October, 2001).
[24] RDI/Platts NEWGen Database, August 2001 issue (Boulder, Colorado, USA).

NEWGen database will occur, we present two possible future emission scenarios to reflect upper and lower boundaries of possible generation capacity changes.

By looking at planned expansion in new generating facilities based on the NEWGen database, we gain insight into where markets and investors are going *at the moment:* the NEWGen database we use in this analysis is updated to August 2001. The data, however, do not reflect changes in investment following the 11 September 2001 tragedy, which is likely to be at least of the order of magnitude of economy-wide effects following that date.

Included in the NEWGen database are planned electricity generating projects comprising 2,063 separate generating units falling into one of six phases: projects that are tabled, proposed, are in early development, advanced development, under construction, and operating. (The reason for the inclusion of operating plants is that the baseline year for the analysis is 1998.) As noted, the data include planned electricity expansion to 2007. We chose this cut-off year for two reasons.

First, after 2007, the data become increasingly thin. The electricity sector is characterized by a slow capital stock turn-over rate, coupled with lengthy licensing and approval processes, environmental assessments, permitting, construction, links with the grid, decommissioning and other stages. As a result, data beyond 7-8 years are increasingly speculative. Hence, a six-year window provides valuable insights as to where the sector may be heading.

Second, 2007 is the final year prior to the first 2008 to 2012 implementation period under the Kyoto Protocol of the United Nations Framework Convention on Climate Change. While Canada is the sole North American country that is a signatory to the Protocol as an Annex One country, there are growing expectations that climate-related policies – in particular some kind of emissions trading regime, joint implementation, or measures taken pursuant to the general goals of the Clean Development Mechanism – will begin before 2008. We also expect that as the Kyoto Protocol implementation period begins, some changes could occur in new electricity generation plans.

<u>Future electricity generation scenarios</u>

The NEWGen database includes all potential merchant plants, independent power projects with contracts for output, utility-built capacity additions, return of off-line capacity, and re-rates of existing capacity. The database also includes details such as the proposed site, total planned capacity, technology employed, primary and secondary fuels, and projected on-line date. NEWGen contains only limited information on electricity capacity changes in Mexico. For a more comprehensive picture we obtained information from three separate sources. NEWGen contained some information on planned new power plants mainly in northern Mexico. We supplemented this with national information from two federal agencies in Mexico, the Comisión Reguladora de Electricidad (CRE) and the Comisión Federal de Electricidad (CFE).[25]

[25] The Mexico federal agency information was collected and provided to the CEC by Miguel Breceda, Consultant, Mexico City.

By using the NEWGen database supplemented with information from Mexico, we base our estimates on announced plans for future capacity changes over the near to mid-term, rather than attempting to empirically model future capacity changes using assumed economic growth or other factors. This has its own limitations in that not all announced capacity changes in the database will occur, the database may not be comprehensive for North America, and it will not capture planned capacity changes that have not yet been announced. It also will not necessarily provide information on emission reduction measures at existing plants where no capacity changes occur. This is a problem in attempting to project future SO_2 and NOx emission changes for the entire electricity generation sector because we cannot account for control measures that are currently being implemented due to ongoing regulatory programs in each country. This is less of a problem with CO_2 and mercury emissions as no country currently has regulatory requirements to reduce these emissions from power plants. Recognizing these limitations, we use the supplemented NEWGen database as a basis for estimating emissions associated with announced capacity changes rather than for estimating emissions from the entire electricity generation sector. While this may not provide a national picture of future total emissions from the electricity generating sector, it does indicate the relative "cleanliness" of new capacity additions in specific regions of North America.

One of the largest areas of uncertainty using the supplemented NEWGen database is attempting to assess the likelihood of announcements of new capacity additions leading to actual generation of electricity. Past experience in the United States suggests that less than half of proposed capacity additions will occur.[26] For the United States, the announced fossil fuel capacity changes that are contained in the NEWGen database would result in a 53% increase in fossil fuel generating capacity by 2007 above existing 1999 capacity. For Mexico, the increase is even greater, with a projected doubling in national generating capacity by 2007 over 1999 levels. Canada's projected increase, by contrast, is only about 10%. We do not include non-fossil fuel capacity additions, such as hydropower, wind or solar, in the projected increase, but these make up only a relatively small fraction (<2%) of the overall announced capacity changes.

The projected Mexico and U.S. capacity increases appear unrealistically large, although we might expect the actual capacity increases in Mexico to be large due to the country's relatively small current generating capacity, high domestic demand growth, and incentives to locate new power plants in northern Mexico to service U.S. demand, particularly in California. Nevertheless, we take the large projected increases in generating capacity based on the supplemented NEWGen database to be an upper limit for capacity changes as we believe a number of the included projects are not likely to be accomplished by 2007. To estimate an alternative scenario of a lower increase in capacity, we screen new generation projects using development status codes in the NEWGen database. For the supplemented information on Mexico projects not included in the NEWGen database, we used status information from the Mexico federal agencies

[26] Report of the National Energy Policy Development Group (May, 2001) *National Energy Policy: eliable, Affordable, and Environmentally Sound Energy for America's Future,* Washington, DC.

to assign a status code best conforming with the NEWGen criteria. The NEWGen status codes and their criteria are:[27]

- OPERATING: Indicates that a new unit has begun operation, or that a re-rate or retirement has become effective.
- UNDER CONSTRUCTION: Signifies that construction is currently underway for a new unit or a re-rate.
- ADVANCED DEVELOPMENT: Indicates that two or more of the following criteria are met:
  - A power purchase agreement for a large portion of the output has been signed with a marketer that is not an affiliate of the developer.
  - Financing has closed or notification of an expected closing in three months has been received.
  - Turbines for the project have been secured.
  - The siting permit and the air permit have been obtained, or the acquisition of these licenses is imminent.
  - Strong local support is indicated or there is no visible local opposition.
  - The project involves repowering with no emissions increases.
- EARLY DEVELOPMENT: Indicates a range of projects, from those that have been recently announced to those that have taken beginning steps in the permitting process.
- TABLED: Indicates that a developer is not actively pursuing the project at a specific site, but maintains applications with regulatory agencies or otherwise keeps a stake in the project.
- CANCELED: Applies to projects that have been canceled by the developer.

The upper boundary includes all announced fossil fuel projects in the supplemented NEWGen database. For the lower boundary, we only include projects with status codes of ADVANCED PLANNING, UNDER CONSTRUCTION, and OPERATING. In either to upper or lower boundary cases, we do not include any projects with a CANCELED status code. The upper boundary case is a high limit for new capacity additions as it includes all announced new generation plans, of which a number are likely not to be completed. On the other hand, the lower boundary case is likely an underestimate of future capacity because it includes only plants already in operation, being built, or fairly far along in the planning stage. While it's likely a number of plants even in the advanced planning stage will not be completed, it's also likely a number of projects in the early development or proposed stages will be built. There are a little over 200 projects in the advanced planning stage, while there are over 900 projects in the early development or proposed stages. Therefore the advanced planning projects that do not reach completion are likely to be off-set to some extent by projects in the early development or proposed stages which are not included in the lower boundary case.

[27] RDI/Platts NEWGen Database, NEWGen User Guide, August 2001 issue (Boulder, Colorado, USA), pp. 13-14.

On a North American basis, it appears likely that substantially less than half of the proposed capacity additions will actually occur. Even so, a review of proposed locations for capacity additions can shed some light on possible "targets of opportunity" that power developers see in making planning decisions. For example, the U.S. Department of Energy suggests that Mexico, because of its lower environmental standards relative to California, may be an attractive location for new power plants that want to sell to the California market.[28] If this is the case, one might expect to see greater interest in the northern Mexico border states as a location for new planned capacity additions.

Tables 4 through 9 show the total projected 2007 capacity changes by fuel type for the two boundary cases in each country.

Table 4. High boundary case projected 2007 electricity generation capacity changes by fuel type in Canada (in Megawatts).

Province/Territory	Natural Gas	Coal	Oil	Distillate	Total
Alberta	3,116	1,750	0	0	4,866
British Columbia	795	0	0	0	795
Manitoba	0	0	0	0	0
New Brunswick	180	-60	0	0	120
Newfoundland	0	0	0	0	0
Northwest Territories	0	0	0	0	0
Nova Scotia	800	0	0	0	800
Ontario	2,330	0	0	0	2,330
Prince Edward Island	0	0	0	0	0
Quebec	800	0	0	0	800
Saskatchewan	603	0	0	0	603
Yukon	0	0	0	0	0
National Total	**8,624**	**1,690**	**0**	**0**	**10,314**

In the high boundary case, the top five provinces with planned capacity additions are, in decreasing order, Alberta, Ontario, Nova Scotia tied with Quebec, and British Columbia. On a national basis, most new fossil fuel capacity plans are for natural gas, and New Brunswick would retire coal capacity. Alberta is the only province with planned new coal capacity.

[28] U.S. Department of Energy (DOE), "An Energy Overview of Mexico," http://www.fe.doe.gov/international/mexiover.html (Sept. 5, 2001 update) (*stating* "Mexico's less stringent environmental regulations have provided an incentive for companies to locate their power plants in Mexico to produce electricity for export to California.").

Table 5. High boundary case projected 2007 electricity generation capacity changes by fuel type in Mexico (in Megawatts).

State	Natural Gas	Coal	Oil	Distillate	Total
Aguascalientes	0	0	0	0	0
Baja California	4,387	0	0	0	4,387
Baja California Sur	579	0	0	61	640
Campeche	900	0	0	1	901
Chiapas	121	0	10	12	142
Chihuahua	1,724	0	0	7	1,731
Coahuila	1,057	92	0	10	1,159
Colima	0	0	0	0	0
Distrito Federal	4	0	0	0	4
Durango	722	0	10	8	740
Guanajuato	1,282	0	0	0	1,282
Guerrero	0	0	0	0	0
Hidalgo	2,468	0	129	0	2,597
Jalisco	0	0	40	0	40
Mexico	284	0	10	0	294
Michoacan	40	0	27	0	67
Morelos	0	0	9	5	14
Nayarit	0	0	6	0	6
Nuevo Leon	4,125	0	64	11	4,200
Oaxaca	115	0	14	0	129
Puebla	66	0	0	0	66
Queretaro	138	0	12	0	150
Quintana Roo	115	0	70	43	227
San Luis Potosi	2,074	260	6	0	2,340
Sinaloa	0	0	16	14	30
Sonora	2,134	0	37	2	2,172
Tabasco	218	0	3	99	319
Tamaulipas	7,271	0	0	0	7,271
Tlaxcala	12	0	0	0	12
Veracruz	5,399	0	66	10	5,474
Yucatan	1,056	0	0	0	1,056
Zacatecas	0	0	0	0	0
Unknown location	0	700	0	0	700
National Total	**36,289**	**1,052**	**527**	**282**	**38,149**

Note: This table does not include the use of coal at the 2,100 MW Petacalco power plant in the State of Guerrero that began during 2001. We had insufficient information at the time of this study on the extent of new coal combustion at the facility.

In Mexico, the five states with the largest planned new capacity in the high boundary case are, in decreasing order, Tamaulipas, Veracruz, Baja California, Nuevo Leon, and Hidalgo. Tamaulipas, Baja California, and Nuevo Leon are northern states bordering the U.S., which could indicate an interest in exporting to the U.S. market although domestic demand growth in the region is also strong. The new capacity in these states would come largely from the use of natural gas, with small amounts of oil and distillate (diesel). For the country as a whole, new fossil fuel capacity would come mostly from natural gas, with lesser amounts from coal, oil, and distillate (diesel). We note, however, that the 2,100 MW Petacalco power plant in the State of Guerrero began burning an unknown amount of coal during 2001, which is not included in the table. Also, there is a 700 MW new coal project of unknown status appearing in the government information provided to us, but lacking location details. We are unsure if this is the Petacalco facility or another planned coal project.

Table 6. High boundary case projected 2007 electricity generation capacity changes by fuel type in the U.S. (in Megawatts).

State	Natural Gas	Coal	Oil	Distillate	Total
Alabama	12,083	1,500	0	0	13,583
Alaska	0	0	0	0	0
Arizona	16,526	760	0	0	17,286
Arkansas	8,202	3,100	0	0	11,302
California	25,582	0	0	95	25,677
Colorado	3,865	1,280	0	0	5,145
Connecticut	2,810	0	0	0	2,810
Delaware	646	228	0	0	873
District of Columbia	0	0	0	0	0
Florida	29,119	-517	-914	0	27,688
Georgia	14,754	1,100	80	0	15,934
Hawaii	0	0	0	0	0
Idaho	1,955	0	0	0	1,955
Illinois	26,552	631	240	0	27,423
Indiana	13,940	942	0	0	14,882
Iowa	1,340	0	56	0	1,396
Kansas	817	600	57	0	1,474
Kentucky	7,366	5,734	75	0	13,175
Louisiana	12,116	1,450	0	0	13,566
Maine	2,664	0	0	0	2,664
Maryland	4,182	180	0	0	4,362
Massachusetts	8,209	0	-451	0	7,758
Michigan	13,398	0	79	0	13,477
Minnesota	1,508	675	16	0	2,199
Mississippi	13,840	440	0	0	14,280
Missouri	4,976	1,440	0	0	6,416
Montana	1,040	1,370	19	0	2,429
Nebraska	510	400	0	0	910
Nevada	9,476	0	0	0	9,476
New Hampshire	1,945	0	0	0	1,945
New Jersey	7,117	0	-430	0	6,687
New Mexico	1,240	0	0	0	1,240
New York	18,613	0	-340	0	18,273
North Carolina	6,694	0	0	0	6,694
North Dakota	0	500	0	0	500

Ohio	17,699	94	143	0	17,936
Oklahoma	12,088	800	0	0	12,888
Oregon	4,418	0	0	0	4,418
Pennsylvania	11,426	420	0	0	11,845
Rhode Island	1,137	0	0	0	1,137
South Carolina	6,070	364	0	0	6,434
South Dakota	0	2,000	0	0	2,000
Tennessee	5,943	0	0	0	5,943
Texas	39,758	0	0	0	39,758
Utah	895	3,900	0	0	4,795
Vermont	1,350	0	0	0	1,350
Virginia	13,087	0	170	0	13,257
Washington	7,561	249	0	40	7,850
West Virginia	5,511	527	0	0	6,038
Wisconsin	8,873	1,879	0	0	10,752
Wyoming	130	1,830	0	0	1,960
National Total	**409,029**	**33,875**	**-1,199**	**135**	**441,840**

In the high boundary case, the five states in the U.S. with the greatest amounts of announced new fossil fuel capacity are, in decreasing order, Texas, Florida, Illinois, California, and New York. The fossil fuel of choice on a national basis is natural gas. Coal is the second most popular, but is only 8% of the announced new natural gas. Oil capacity would decrease on a national basis. The small amount of distillate is for a few small gasoline projects in Oregon and Washington.

Table 7. Low boundary case projected 2007 electricity generation capacity changes by fuel type in Canada (in Megawatts).

Province/Territory	Natural Gas	Coal	Oil	Distillate	Total
Alberta	2013	0	0	0	2,013
British Columbia	295	0	0	0	295
Manitoba	0	0	0	0	0
New Brunswick	180	0	0	0	180
Newfoundland	0	0	0	0	0
Northwest Territories	0	0	0	0	0
Nova Scotia	0	0	0	0	0
Ontario	1450	0	0	0	1,450
Prince Edward Island	0	0	0	0	0
Quebec	0	0	0	0	0
Saskatchewan	453	0	0	0	453
Yukon	0	0	0	0	0
National Total	**4,391**	**0**	**0**	**0**	**4,391**

In the low boundary case for Canada, the five provinces with the greatest fossil fuel capacity increases are, in descending order, Alberta, Ontario, Saskatchewan, British Columbia, and New Brunswick. No new coal capacity occurs in the low boundary case, reflecting the less advanced planning status of the projects. Even without the planned new coal capacity, Alberta remains the province with the largest planned capacity expansion in Canada.

Table 8. Low boundary case projected 2007 electricity generation capacity changes by fuel type in Mexico (in Megawatts).

State	Natural Gas	Coal	Oil	Distillate	Total
Aguascalientes	0	0	0	0	0
Baja California	3,005	0	0	0	3,005
Baja California Sur	559	0	0	41	600
Campeche	900	0	0	1	901
Chiapas	121	0	10	12	142
Chihuahua	1,456	0	0	7	1,463
Coahuila	1,057	92	0	10	1,159
Colima	0	0	0	0	0
Distrito Federal	4	0	0	0	4
Durango	0	0	10	8	18
Guanajuato	1,143	0	0	0	1,143
Guerrero	0	0	0	0	0
Hidalgo	2,468	0	129	0	2,597
Jalisco	0	0	40	0	40
Mexico	27	0	10	0	37
Michoacan	40	0	27	0	67
Morelos	0	0	9	5	14
Nayarit	0	0	6	0	6
Nuevo Leon	4,125	0	64	11	4,200
Oaxaca	115	0	14	0	129
Puebla	66	0	0	0	66
Queretaro	5	0	12	0	17
Quintana Roo	115	0	70	43	227
San Luis Potosi	4	260	6	0	270
Sinaloa	0	0	16	14	30
Sonora	1,581	0	37	2	1,619
Tabasco	218	0	3	99	319
Tamaulipas	3,087	0	0	0	3,087
Tlaxcala	12	0	0	0	12
Veracruz	3,277	0	66	10	3,352
Yucatan	532	0	0	0	532
Zacatecas	0	0	0	0	0
National Total	**23,915**	**352**	**527**	**262**	**25,055**

Note: This table does not include the use of coal at the 2,100 MW Petacalco power plant in the State of Guerrero that began during 2001. We had insufficient information at the time of this study on the extent of new coal combustion at the facility.

In the low boundary case, the five states with the largest fossil fuel capacity increases are, in descending order, Nuevo Leon, Veracruz, Tamaulipas, Baja California, and Hidalgo. On a national basis, natural gas remains the overwhelming fossil fuel of choice, with lesser amounts of oil, coal, and distillate (diesel). Once again, the table does not include the recent use of coal at the Petacalco power plant in the State of Guerrero or a 700 MW coal plant of unknown status and location.

Table 9. Low boundary case projected 2007 electricity generation capacity changes by fuel type in the U.S. (in Megawatts).

State	Natural Gas	Coal	Oil	Distillate	Total
Alabama	8,357	0	0	0	8,357
Alaska	0	0	0	0	0
Arizona	8,813	0	0	0	8,813
Arkansas	4,644	0	0	0	4,644
California	11,334	0	0	0	11,334
Colorado	2,383	0	0	0	2,383
Connecticut	2,810	0	0	0	2,810
Delaware	427	228	0	0	654
District of Columbia	0	0	0	0	0
Florida	15,290	-517	-914	0	13,859
Georgia	8,987	0	80	0	9,067
Hawaii	0	0	0	0	0
Idaho	360	0	0	0	360
Illinois	15,325	40	240	0	15,605
Indiana	5,405	0	0	0	5,405
Iowa	0	0	56	0	56
Kansas	313	0	32	0	345
Kentucky	4,032	524	0	0	4,556
Louisiana	7,265	0	0	0	7,265
Maine	1,664	0	0	0	1,664
Maryland	2,801	180	0	0	2,981
Massachusetts	7,863	0	-451	0	7,412
Michigan	7,278	0	79	0	7,357
Minnesota	1,258	-75	16	0	1,199
Mississippi	8,888	440	0	0	9,328
Missouri	2,871	540	0	0	3,411
Montana	80	0	0	0	80
Nebraska	100	0	0	0	100
Nevada	2,751	0	0	0	2,751
New Hampshire	1,245	0	0	0	1,245
New Jersey	3,967	0	-430	0	3,537
New Mexico	690	0	0	0	690
New York	2,971	0	60	0	3,031
North Carolina	3,586	0	0	0	3,586
North Dakota	0	0	0	0	0
Ohio	5,804	94	143	0	6,042
Oklahoma	6,478	0	0	0	6,478
Oregon	1,331	0	0	0	1,331
Pennsylvania	4,596	420	0	0	5,015
Rhode Island	787	0	0	0	787

South Carolina	2,620	-136	0	0	2,484
South Dakota	0	0	0	0	0
Tennessee	3,198	0	0	0	3,198
Texas	31,724	0	0	0	31,724
Utah	293	0	0	0	293
Vermont	0	0	0	0	0
Virginia	1,857	0	170	0	2,027
Washington	2,915	0	0	40	2,955
West Virginia	1,410	77	0	0	1,487
Wisconsin	2,445	0	0	0	2,445
Wyoming	130	330	0	0	460
National Total	**209,344**	**2,144**	**-918**	**40**	**210,610**

In the U.S. low boundary case, the five states with the greatest planned increase in fossil fuel capacity are, in descending order, Texas, Florida, Illinois, California, and Mississippi. New York, which was among the top five in the high boundary case, drops to 22nd in the low boundary case, reflecting a number of new projects in less advanced planning stages relative to the other top five states. It is somewhat surprising that Mississippi is now in the top five when considering its lower population and industrial base relative to the other top five states. Mississippi includes new coal capacity that would not fall under the NOx emissions cap of the NOx SIP Call found in many of its neighboring states, although it would be subject to some level of control under New Source Review (NSR) requirements. On a national basis, natural gas continues to maintain a dominant share of planned new fossil fuel capacity additions. Interestingly, the share of coal drops from 8% in the high boundary case to only 1% in the low boundary case. This could indicate a rising interest in the use of coal that the low boundary case does not reflect because it doesn't include a number of coal projects in the less advanced planning stages.

Future emissions

The upper and lower boundary cases described above serve as the basis for estimating emissions from changes in North American electricity generating capacity, which we describe in this section. Once again, this exercise highlights the need for comparable and readily available information across North America in order to place an integrated electricity generation market into a North American environmental context.

In estimating future emissions, we made a number of approximations and assumptions regarding pollution from future or existing sources. A number of capacity change announcements in the NEWGen database were multiple entries for the same project that included negative (decreases) as well as positive (increases) changes in planned generation capacity. For these entries, we calculated the decreases and increases in emissions using the same assumptions for all to obtain a "net" emission change for the project. There were some exceptions to this, however. In some cases of announced decreases in U.S. generation capacity, the projects appeared to be retirements of existing fossil fuel capacity, or conversions to a new fuel such as natural gas. For these situations, we directly subtracted the existing facility's 1998 emissions as they appear in Egrid2000. In cases where only a portion of the total plant capacity was being retired, we subtracted an equivalent portion of its 1998 emissions. This likely does not completely reflect the change in emissions as the capacity reduction isn't necessarily of the same proportion as the emission reduction, but these cases are few in the NEWGen database so will not greatly effect the total.

Natural gas is the fuel of choice for most announced new fossil fuel electricity generation across North America. We assume that natural gas plants below 500 MW are peaking plants with a capacity factor of 0.20. For natural gas combined cycle power plants with an announced capacity of 500 MW or greater, we assume a capacity factor of 0.75 as we believe these larger plants are less likely to be used for peaking only.[29] For all new natural gas plants, we assume an efficiency factor of 50% based on new plant efficiencies used by the International Energy Administration (IEA).[30] For any retirements of existing natural gas capacity where we did not have information on historical emissions from the specific power plant, we assume a lower efficiency of 40%.

For fuels other than natural gas, the next most popular fuel choices for new generation are coal and oil, with much of the announced new oil in Mexico. There are much smaller amounts of new generation using diesel and gasoline. For new capacity not using natural gas, we assume a generation efficiency of 40% based on IEA information.[31] For retirements of existing capacity where we did not have historical emissions information from the specific plant, we assume an efficiency of 0.35%. We assume new non-natural gas fossil fuel generation will be for base load, and assign it a capacity factor of 0.75.

There was a 700 MW coal project in Mexico for which we have no information on its location or status, but it would be a significant new source of pollution. Therefore, we estimate its emissions for its contribution to Mexico's national total, but could not assign the emissions to any individual state.

CO_2 emissions

We assume no CO_2 will be captured at any new fossil fuel generation project in North America through 2007. For natural gas combustion, we use the EPA AP-42 emission factor for CO_2 of 112,200 lb/10^6 scf (1.92 kg/m^3) assuming all new generation by natural gas combustion is from stationary gas turbines.[32] For new oil (including *combustóleo*), we use the EPA AP-42 high sulfur No. 6 oil CO_2 emission factor of 24,400 lb/10^3 gal (2,910 kg/m^3). This emission rate is 2.4% lower than that for low sulfur No. 6 oil, so it

[29] For example, a recent announcment of a proposed 800 MW natural gas combined cycle power plant in Québec stated it would generate up to 6.5 TeraWatt-hours (TWh) annually. This corresponds to a capacity factor well over 0.75. Source: Hydro Québec Communiqué, *Le premeir ministre dévoile le nouveau projet d'Hydro-Québec: une centrale à cycle combineé au gaz naturel*, (Oct. 2, 2001).

[30] International Energy Adminstration Greenhouse Gas R&D Programme (Gloucestershire, United Kingdom), "Greenhouse Gas Emissions from Power Stations," http://www.ieagreen.org.uk/sr1p.htm (accessed Oct. 17, 2001).

[31] International Energy Adminstration Greenhouse Gas R&D Programme (Gloucestershire, United Kingdom), "Greenhouse Gas Emissions from Power Stations," http://www.ieagreen.org.uk/sr1p.htm (accessed Oct. 17, 2001).

[32] U.S. EPA, "Compilation of Air Pollutant Emission Factors AP-42," Fifth Edition, Vol. I Stationary Point and Area Sources, (January 1995) (Section 3.1 "Stationary Gas Turbines," Table 3.1-2a, April 2000 update).

will slightly bias CO_2 emissions low for sources burning low sulfur oil. For new diesel and gasoline, we use the EPA AP-42 No. 2 oil (distillate) CO_2 emission factor of 22,300 lb/10^3 gal (2,660 kg/m^3).[33] For new coal in the United States and Canada, we use an emission rate of 3,664 lb of CO_2 per short ton of coal combusted (1,832 kg/metric tonne) based on a coal heat content that assumes most new coal generation will use western low sulfur subbituminous coal.[34] In the case of Canada, this is particularly appropriate as all proposed new coal generation is in Alberta. In the U.S., it is less clear, but an alternative would be to use the 1998 national average CO_2 emission rate for coal based on information reported by electricity generators to the U.S. Energy Information Administration (EIA) in EIA 767 forms. The 1998 national average CO_2 emission rate for coal was 211 lb/mmBtu, which is close to the 210.7 lb/mmBtu emission rate we use in assuming western subbituminous coal,[35] so the difference between the choice of CO_2 factors is small. For new coal generation in Mexico, we use the same CO_2 emission rate of 2,178 kg/metric tonne as we used in estimating Mexico's 1999 emissions. This assumes new coal power plants in Mexico will burn mainly local coal. This, however, already is not the case, as the 2,100 MW Petacalco power plant in the State of Guerrero began burning coal during 2001 imported from Australia and Asia.[36] A more refined estimate will require better information on the properties of coal that will be burned at new plants in Mexico.

SO_2 emissions

As opposed to estimations CO_2 emissions, projecting SO_2 emissions from the electricity generation sector has the additional complication of evolving control measures on existing sources in the near future and differing control requirements within an individual country depending on location. In Canada, a number of eastern provinces have announced intentions to reduce SO_2 emissions by about 50% beyond current levels. In the United States, the Clean Air Act SO_2 emissions cap places an upper limit on future emissions growth although banked allowances in 2000 amounted to about 10,380,000 short tons, which leaves room for emissions growth in the near to mid-term.[37] Nevertheless, some states, such as New York, have announced plans to reduce SO_2 emissions from power plants beyond Clean Air Act requirements. Furthermore, alleged "New Source Review" violations by existing power plants could lead to additional reductions should the U.S. EPA, as well as several states and environmental groups, prevail in on-going litigation. Power plant owners themselves may adopt additional controls, such as a recent announcement by the Tennessee Valley Authority (TVA) of plans to reduce SO_2 emissions from its coal power plants by over 200,000 short tons

[33] U.S. EPA, "Compilation of Air Pollutant Emission Factors AP-42," Fifth Edition, Vol. I Stationary Point and Area Sources, (January 1995) (Section 1.3 "Fuel Oil Combustion," Table 1.3-12, September 1998 update).

[34] The western subbituminous coal CO_2 emission rate is for coal from the Powder River, Green River, and Hannah Basins, and is based on information given by U.S. Department of Energy, EIA, "Assumptions to the Annual Energy Outlook 2001," Table 76, http://www.eia.doe.gov/oiaf/aeo/assumption/tbl76.html (accessed Oct. 10, 2001).

[35] U.S. Department of Energy, EIA, "Assumptions to the Annual Energy Outlook 2001," Table 76, http://www.eia.doe.gov/oiaf/aeo/assumption/tbl76.html (accessed Oct. 10, 2001).

[36] David Shields, "Unfashionable Fuel Finds a Market," The News Mexico (August 29, 2001).

[37] U.S. EPA, "Acid Rain Program: Annual Progress Report, 2000," EPA-430-R-01-008 (August, 2001).

annually sometime after 2003.[38] Therefore, estimates of future SO_2 emissions growth due to capacity changes in the electricity generation sector should be placed in the context of evolving control measures on existing sources. Anticipating near to mid-term SO_2 reductions from existing sources is beyond the scope of this study, but we recognize that anticipated SO_2 emissions growth from new or re-powered sources could be offset by likely additional control measures on existing sources. If, however, current allowable emissions are too high from an environmental and public health viewpoint as suggested by continuing acid rain damage and the public health threat from fine particles, then assessing SO_2 emission changes from proposed generating capacity additions can help indicate whether the generation trends are in a favorable or unfavorable direction for achieving additional reductions beyond current requirements. Furthermore, while total SO_2 emissions may decline when considered on a national or North American basis, local increases from new generation capacity could still be significant.

To estimate SO_2 emissions from generation capacity changes in the electricity generation sector, we make varying assumptions for each country. For natural gas in Canada, Mexico, and the United States, we do not have sulfur content information for use with the AP-42 factor of 0.94S for stationary gas turbines, where S equals the percent sulfur content. In the absence of sulfur content information, AP-42 recommends a factor of 0.0034 lb/mmBtu.[39] This, however, appears high as the U.S. national average in 1998 based on FERC 767 forms was about 0.001 lb/mmBtu. We believe that with newer natural gas plants, SO_2 emissions are likely to be below the national average. Therefore, in the absence of specific information, we use the same EPA AP-42 SO_2 factor as we used in the estimations of SO_2 emissions from natural gas in Mexico, which is 0.6 lb/10^6 scf (10 kg/10^6 m^3), or 0.0006 lb/mmBtu.

In Canada, all proposed new coal generation is in Alberta, and we used Alberta's regulatory SO_2 limit for new coal of 18 x 10^{-5} kg/MJ (0.42 lb/mmBtu). There were no proposed new oil or diesel projects for Canada in the NEWGen database.

For generation in Mexico using heavy and light oil (both considered in this study as *combustóleo*), diesel, and coal, we use the same SO_2 emission factors as used in the estimates for the 1999 Mexico emission inventory previously described. These emission rates are respectively 68 kg/m^3, 8.52 kg/m^3, and 27.6 kg/metric tonne. The factor for coal assumes it will come from domestic mines in the State of Coahuila, but this does not appear to be the case for new coal combustion at the Petacalco power plant in the State of Guerrero, as previously mentioned. Nevertheless, we have no information on the physical properties of coal in Mexico other than that from the State of Coahuila.

There are a small number of announced projects in the United States using gasoline. To calculate projected SO_2 emissions from these, we use the EPA AP-42 factor for distillate oil (No. 2) and assume a low sulfur content of 0.005% to get an emission rate of

[38] Tennessee Valley Authority press announcement (Oct. 4, 2001).
[39] U.S. EPA, "Compilation of Air Pollutant Emission Factors AP-42," Fifth Edition, Vol. I Stationary Point and Area Sources, (January 1995) (Section 3.1 "Stationary Gas Turbines," Table 3.1-2a, April 2000 update).

0.71 lb/10^{-3} gal (0.085 kg/m^3). There were no announced diesel projects for the U.S. in the NEWGen database. For new coal generation in the U.S., we assume the sources must install Best Available Control Technology (BACT) with an SO_2 emissions limit in the range of 0.12 to 0.25 lb/mmBtu. We choose 0.2 lb/mmBtu (90 kg/10^6 MJ) as a midrange estimate, noting that this is consistent with a recent new power plant in Wyoming.[40] We use the same factor for new oil generation in the U.S. as used for coal on the assumption that new oil generation will have to meet a BACT SO_2 emission limit at least as stringent as for new coal. Our assumed SO_2 emission factor is six times lower than the national average for 1998 oil combustion derived from EIA's 767 forms.

NOx emissions

Estimating NOx emissions from future generation capacity changes in North America has similar challenges as with SO_2 in regards to pending NOx control measures and a patchwork of differing regulatory requirements within countries. For example, in the U.S., new power plants located in ozone nonattainment areas are subject to more stringent NOx controls than in attainment areas, including the need to obtain "offsets" of any NOx emissions from existing sources in the area. The revised eight-hour ozone and fine particulate health standards in the U.S. would expand the number and geographical scale of nonattainment areas, but the timing of their implementation and the extent of any additional controls they may bring are uncertain. Furthermore, the U.S. EPA promulgated a regional ozone strategy in the eastern United States (the "NOx SIP Call") that will reduce NOx emissions in a number of eastern states.[41] While the principal targets for control in many of these states would appear to be existing fossil fuel power plants, the application and extent of controls at specific sources is at the discretion of the states and not all planning is complete. In addition, the recently signed Ozone Annex to the U.S.-Canada Air Quality Agreement includes commitments to reduce NOx emissions on both sides of the border, but the details of how this will be implemented are unknown. As a result, the projections for NOx emissions associated with announced generation capacity changes is probably best viewed as an indicator of regions where energy developers find more or less attractive for power projects, but the NOx emissions associated with those projects may be offset, at least on a national basis, from ongoing NOx control measures that are not included in this study. Local or regional increases, on the other hand, could still be significant, particularly outside of U.S. ozone nonattainment areas.

[40] Pembina Institute Backgrounder, "New Alberta standards for emissions from coal-fired power plant less stringent than other jurisdictions," http://pembina.piad.ab.ca/news/press/2001/2001-06-18bg.php (Sept. 11, 2001).

[41] The NOx SIP Call is for attainment of the existing one-hour ozone standard in the U.S., and at the time of this writing currently encompasses the District of Columbia and the entire states of Connecticut, Delaware, Illinois, Indiana, Kentucky, Maryland, Massachusetts, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, and West Virginia. The NOx SIP Call will also cover portions of Alabama, Georgia, Michigan, and Missouri. EPA is currently revising its methodology for calculating the NOx reduction obligations as the result of a court order. If the EPA revisions are upheld, we would expect a reduction in NOx emissions from eastern U.S. electricity generating units of roughly 600,000 short tons by the 2007 five-month ozone season.

As with the previous SO_2 estimates, we make varying assumptions for the NOx emission rates associated with generation capacity changes for each country. For natural gas in Canada and Mexico, we use the uncontrolled NOx emission factor from EPA AP-42 for natural gas turbines of 0.32 lb/mmBtu (140 kg/10^6 MJ).[42] For the United States, we take a different approach. There are a large number of proposed U.S. natural gas generation projects in the NEWGen database. A significant number of these would be located in current one-hour ozone nonattainment areas where NOx limits are likely to be more stringent. A number of ozone nonattainment areas, however, received waivers by EPA granting them exemptions from applying more stringent NOx controls on sources in their areas. For nonattainment areas without NOx waivers, we adopt a more stringent NOx limit of 0.01 lb/mmBtu (4 kg/10^6 MJ) for new natural gas combustion sources. Outside of nonattainment areas without NOx waivers, we assume Best Achievable Control Technology will apply, which is in the range of 0.04 to 0.10 lb/mmBtu in the U.S.[43] We take the mid-point as 0.07 lb/mmBtu (30 kg/10^6 MJ) and apply this to all natural gas projects outside of ozone nonattainment areas not having NOx waivers.

In Canada, all proposed new coal generation in Alberta (the only province with announced coal projects in the NEWGen database) were given Alberta's regulatory NOx limit for new coal of 12.5 x 10^{-5} kg/MJ (0.29 lb/mmBtu). Canada had no proposed new oil or diesel projects appearing in the NEWGen database.

For generation in Mexico using heavy and light oil (both considered in this study as *combustóleo*), diesel, and coal, we use the same NOx emission factors as used in the estimates for the 1999 Mexico emission inventory previously described. These emission rates are respectively 5.64 kg/m^3, 3.00 kg/m^3, and 15.5 kg/metric tonne. The NOx factor for coal assumes the same dry bottom, cell burner fired, bituminous coal combustion as assumed for the Carbón I and II power plants in the 1999 emissions inventory. We have no information at this time on the actual combustion technologies at planned new coal plants in Mexico.

For new coal generation in the United States, we assume the new coal projects will meet the equivalent of the NOx emission rate used by EPA to calculate state-level NOx budgets under the NOx SIP Call. The assumed NOx rate is 0.15 lb/mmBtu (64 kg/10^6 MJ). We apply the same NOx factor for new oil and gasoline generation in the U.S. as with new coal on the assumption that these fuel types will have to meet at a minimum the same NOx limit as new coal. Our assumed NOx emission factor for oil and gasoline is 25% lower than the national average for 1998 oil combustion derived from EIA's 767 forms. The NEWGen database contained no announced diesel projects for the U.S.

Mercury emissions

For estimating mercury emissions, we assume no controls specifically intended to reduce mercury at the combustion source. We use EPA AP-42 mercury emission factors for all

[42] U.S. EPA, "Compilation of Air Pollutant Emission Factors AP-42," Fifth Edition, Vol. I Stationary Point and Area Sources, (January 1995) (Section 3.1 "Stationary Gas Turbines," Table 3.1-1, April 2000 update).
[43] Communication from Amy Stillings, M.J. Bradley and Associates, Concord, MA (Sept. 17, 2001).

fuel types in all three countries. The factor for natural gas is 2.6 x 10^{-4} lb/10^6 scf (4.15 x 10^{-3} kg/10^6 m^3).[44] For new oil, we use the mercury emission factor for uncontrolled No. 6 oil of 1.13 x 10^{-7} lb/gal (1.35 x 10^{-5} kg/m^3).[45] With new diesel and gasoline, we apply the factor for distillate fuel of 3 lb/10^{12} Btu (1.29 picogram/Joule (pg/J)).[46] For coal, we assume some level of combustion control for emissions other than mercury, and apply the EPA AP-42 mercury emission factor for controlled coal combustion of 8.3 x 10^5 lb/ton (4.2 x 10^5 kg/metric tonne).[47]

The following tables contain the results for the estimated emissions from the planned capacity changes in each country for the upper and lower boundary cases. We also compare these emissions to the reference emissions given in Tables 1, 2, and 3. This gives us some indication of the localities where planned capacity changes may have the biggest impact on current emissions.

Table 10. Canada high boundary case: Changes in emissions associated with planned electricity projects in Canada through 2007. This includes all announced projects in the supplemented NEWGen database (see text).

Province/Territory	Annual CO_2 (tonnes)	Annual SO_2 (tonnes)	Annual NOx (tonnes)	Annual Hg (kg)
Alberta	12,091,059	18,582	20,931	218
British Columbia	481,682	3	1,401	1
Manitoba	0	0	0	0
New Brunswick	-307,682	-22,539	-583	-13
Newfoundland	0	0	0	0
Northwest Territories	0	0	0	0
Nova Scotia	1,817,668	10	5,288	4
Ontario	2,494,749	13	7,257	6
Prince Edward Island	0	0	0	0
Quebec	2,252,505	12	6,553	5
Saskatchewan	365,351	2	1,063	1
Yukon	0	0	0	0
National Total	**19,195,332**	**-3,917**	**41,910**	**221**

In the high boundary case, the ordering of the top five provinces in terms of pollution associated with new fossil fuel capacity is the same for all four pollutants. These are, in descending order, Alberta, Ontario, Quebec, Nova Scotia, and British Columbia. A significant portion of emissions in Alberta is from added coal capacity. For Quebec, the

[44] U.S. EPA, "Compilation of Air Pollutant Emission Factors AP-42," Fifth Edition, Vol. I Stationary Point and Area Sources, (January 1995) (Section 1.4 "Natural Gas Combustion," Table 1.4-4, July 1998 update) There was no mercury factor for natural gas turbines in AP-42, so we use as a default the factor for natural gas combustion boilers.

[45] U.S. EPA, "Compilation of Air Pollutant Emission Factors AP-42," Fifth Edition, Vol. I Stationary Point and Area Sources, (January 1995) (Section 1.3 "Fuel Oil Combustion," Table 1.3-11, September 1998 update).

[46] U.S. EPA, "Compilation of Air Pollutant Emission Factors AP-42," Fifth Edition, Vol. I Stationary Point and Area Sources, (January 1995) (Section 1.3 "Fuel Oil Combustion," Table 1.3-10, September 1998 update).

[47] U.S. EPA, "Compilation of Air Pollutant Emission Factors AP-42," Fifth Edition, Vol. I Stationary Point and Area Sources, (January 1995) (Section 1.1 "Bituminous and Subbituminous Coal Combustion," Table 1.1-18, September 1998 update).

entire projected emissions increase is associated with an 800 MW natural gas plant recently proposed by Quebec Hydro with a high capacity factor that would export electricity to the U.S. Pollution in New Brunswick could decrease for all four pollutants due to a reduction in coal capacity.

Ontario has much greater announced fossil fuel capacity additions than Quebec or Nova Scotia, yet its estimated emissions from the new capacity additions are only marginally greater than the other two provinces. This is because only one of Ontario's planned natural gas projects exceeds 500 MW in size, so we used a lower capacity factor of 0.2 for most Ontario natural gas plants on the assumption these would be peaking plants. Quebec and Nova Scotia both had announced projects of 800 MW, which we gave capacity factors of at least 0.75 to reflect baseload service (we used a higher capacity factor in Quebec than Nova Scotia based on a Hydro Quebec press announcement stating its planned annual generation). It is possible that the planned Ontario plants could operate at higher capacity factors than 0.2 for either domestic production or export to U.S. markets. Certainly, the "potential to emit" pollution would be higher in Ontario due to its greater planned capacity additions than in Quebec and Nova Scotia. We note also that pollution reductions may occur at existing power plants in Ontario that could offset emissions associated with new capacity additions. There are intentions of fuel switching from coal to natural gas at some power plant boilers in Ontario, as well as installation of selective catalytic reduction (SCR) to reduce NOx emissions at other boilers using coal. The extent of these reductions, however, is uncertain at this point.[48]

[48] Communication from OPG, October 15, 2001.

Table 11. Mexico high boundary case: Changes in emissions associated with planned electricity projects in Mexico through 2007. This includes all announced projects in the supplemented NEWGen database (see text).

State	Annual CO_2 (tonnes)	Annual SO_2 (tonnes)	Annual NOx (tonnes)	Annual Hg (kg)
Aguascalientes	0	0	0	0
Baja California	6,988,952	37	20,331	16
Baja California Sur	1,529,476	799	4,009	8
Campeche	548,581	14	1,590	1
Chiapas	163,157	1,201	349	1
Chihuahua	1,154,185	97	3,307	3
Coahuila	1,158,949	6,176	5,307	11
Colima	0	0	0	0
Distrito Federal	2,666	0	8	0
Durango	514,210	1,198	1,395	2
Guanajuato	2,536,264	14	7,378	6
Guerrero	0	0	0	0
Hidalgo	5,879,406	14,119	16,548	15
Jalisco	178,650	4,399	346	1
Mexico	216,575	1,093	587	1
Michoacan	142,241	2,906	299	1
Morelos	58,425	1,004	97	1
Nayarit	24,400	601	47	0
Nuevo Leon	7,314,836	7,176	20,921	18
Oaxaca	129,567	1,475	319	0
Puebla	39,746	0	116	0
Queretaro	136,969	1,311	347	0
Quintana Roo	553,873	8,219	1,000	5
San Luis Potosi	5,261,294	17,826	19,360	35
Sinaloa	128,187	1,940	202	1
Sonora	1,461,381	4,015	4,082	4
Tabasco	544,935	1,562	859	8
Tamaulipas	14,870,794	80	43,260	34
Tlaxcala	7,174	0	21	0
Veracruz	10,981,293	7,380	31,592	27
Yucatan	2,398,185	13	6,977	6
Zacatecas	0	0	0	0
Location unknown	3,640,845	46,054	25,911	69
National Total	**68,565,216**	**130,708**	**216,565**	**275**

In the Mexico high boundary case, the five states with the greatest potential emissions of CO_2 from new fossil fuel capacity additions are, in decreasing order, Tamaulipas, Veracruz, Nuevo Leon, Baja California, and Hidalgo. The five states with highest SO_2 emissions are San Luis Potosi, Hidalgo, Quintana Roo, Veracruz, and Nuevo Leon. For NOx, the five highest are Tamaulipas, Veracruz, San Luis Potosi, Nuevo Leon, and Baja California. For mercury, the five highest are San Luis Potosi, Tamaulipas, Veracruz, Nuevo Leon, and Baja California. The presence of San Luis Potosi in three of the four pollutant categories is due to a planned 260 MW coal plant that is relatively more polluting than planned natural gas projects. The entry "Location unknown" corresponds to an individual 700 MW coal plant of unknown status and location. The individual plant by itself would rank seventh in CO_2 emissions, first in SO_2 and mercury, and third in

NOx among the states, so it likely would alter the relative rankings if we knew its state location.

Table 12. United States high boundary case: Changes in emissions associated with planned electricity projects in U.S. through 2007. This includes all announced projects in the supplemented NEWGen database (see text).

State	Annual CO_2 (tonnes)	Annual SO_2 (tonnes)	Annual NOx (tonnes)	Annual Hg (kg)
Alabama	32,972,154	7,728	21,640	239
Alaska	0	0	0	0
Arizona	30,116,097	3,984	19,148	152
Arkansas	28,970,542	15,757	19,186	403
California	40,177,138	222	3,595	103
Colorado	10,139,512	6,498	6,929	162
Connecticut	3,936,962	21	351	9
Delaware	2,386,433	1,158	973	30
District of Columbia	0	0	0	0
Florida	46,201,965	-53,037	7,433	71
Georgia	30,612,452	6,102	20,109	191
Hawaii	0	0	0	0
Idaho	3,350,567	18	2,090	8
Illinois	46,113,390	-8,531	27,862	174
Indiana	31,042,500	-2,987	20,120	180
Iowa	2,908,456	298	2,170	7
Kansas	3,947,733	3,331	3,077	75
Kentucky	41,125,763	29,463	28,438	718
Louisiana	29,662,599	7,456	19,241	226
Maine	5,046,451	26	3,148	12
Maryland	7,952,056	948	1,958	38
Massachusetts	9,192,284	-7,173	-394	24
Michigan	23,307,840	521	14,999	55
Minnesota	5,314,766	2,902	1,847	87
Mississippi	27,821,222	2,361	17,565	112
Missouri	13,423,831	7,321	8,997	187
Montana	8,826,934	7,041	6,279	169
Nebraska	2,441,199	2,027	1,712	49
Nevada	17,779,493	93	11,093	41
New Hampshire	4,398,094	23	392	10
New Jersey	14,039,395	17	1,174	33
New Mexico	1,617,724	8	1,009	4
New York	33,028,891	-2,016	7,588	79
North Carolina	9,910,833	52	6,183	23
North Dakota	2,665,244	2,531	1,899	60
Ohio	31,704,106	1,364	20,150	85
Oklahoma	27,040,979	4,170	17,312	149
Oregon	7,077,241	37	4,415	16
Pennsylvania	24,033,793	-14,558	12	98
Rhode Island	1,558,650	8	139	4
South Carolina	13,227,037	-3,185	6,932	73
South Dakota	10,660,978	10,125	7,594	241
Tennessee	11,895,121	62	7,421	28
Texas	59,705,611	314	31,207	138
Utah	22,334,228	19,753	15,773	474

Vermont	2,617,442	14	1,546	6
Virginia	27,691,697	168	17,306	68
Washington	15,233,746	1,338	9,672	65
West Virginia	14,412,310	2,729	9,240	91
Wisconsin	25,578,989	-1,187	15,756	273
Wyoming	9,833,560	9,265	6,998	221
National Total	**875,036,007**	**64,580**	**459,286**	**5,762**

For the U.S. high boundary case, the five states with the greatest projected amount of CO_2 emissions associated with new capacity additions are, in decreasing order, Texas, Florida, Illinois, Kentucky, and California. Kentucky was not among the five states with the greatest fossil fuel capacity increases, but has a high ranking for CO_2 emissions due to its relatively high amount of planned coal capacity additions. For SO_2 emissions, the five top states are Kentucky, Utah, Arkansas, South Dakota, and Wyoming. All these states have relatively large amounts of announced new coal capacity. For NOx, the five top states are Texas, Kentucky, Illinois, Alabama, and Ohio. Interestingly, four of the five top states for potential NOx emissions in the high boundary case are states partly or entirely within the NOx SIP Call region. Only the top state, Texas, is outside the area subject to a NOx cap. Presumably, the new sources in the NOx SIP Call region will have to reduce NOx emissions at the planned facilities beyond what we assume in our estimates and obtain any needed additional offsetting reductions from existing NOx sources in order to comply with the state NOx budgets. For mercury, the top five states are Kentucky, Utah, Arkansas, Wisconsin, and South Dakota. As with SO_2, the dominant source of additional mercury pollution will be from new coal capacity.

Table 13. Canada low boundary case: Changes in emissions associated with planned electricity projects in Canada through 2007. This includes only projects having advanced planning, under construction, or operating status (see text).

Province/Territory	Annual CO_2 (tonnes)	Annual SO_2 (tonnes)	Annual NOx (tonnes)	Annual Hg (kg)
Alberta	1,219,655	7	3,548	3
British Columbia	178,737	1	520	0
Manitoba	0	0	0	0
New Brunswick	109,060	1	317	0
Newfoundland	0	0	0	0
Northwest Territories	0	0	0	0
Nova Scotia	1,817,668	10	5,288	4
Ontario	1,961,566	10	5,706	5
Prince Edward Island	0	0	0	0
Quebec	0	0	0	0
Saskatchewan	274,468	1	798	1
Yukon	0	0	0	0
National Total	**5,561,154**	**30**	**16,178**	**13**

In the low boundary case for Canada, the ordering of the top five provinces in terms of emissions associated with planned new fossil fuel capacity additions are the same for all four pollutants. These are, in descending order, Ontario, Nova Scotia, Alberta, Saskatchewan, and British Columbia. The ordering reflects the amount of planned natural gas capacity at the advanced planning or higher status level, as well as the size of the projects, which determines our assumed capacity factor. Nova Scotia rates high because of an 800 MW project that we assume will have a higher capacity factor than smaller projects in other provinces. On a national basis, we project SO_2 emissions to not change in the low boundary case due to the absence of new coal capacity. As suggested in the high boundary case, this will not be the situation if new coal capacity becomes available in Alberta and no coal capacity is retired in New Brunswick. Additional reductions in SO_2 from existing sources in eastern Canada, however, may occur through application of new control measures.

Table 14. Mexico low boundary case: Changes in emissions associated with planned electricity projects in Mexico through 2007. This includes only projects having advanced planning, under construction, or operating status (see text).

State	Annual CO_2 (tonnes)	Annual SO_2 (tonnes)	Annual NOx (tonnes)	Annual Hg (kg)
Aguascalientes	0	0	0	0
Baja California	5,151,896	28	14,987	12
Baja California Sur	1,436,329	539	3,882	6
Campeche	548,581	14	1,590	1
Chiapas	163,157	1,201	349	1
Chihuahua	910,617	96	2,598	3
Coahuila	1,158,949	6,176	5,307	11
Colima	0	0	0	0
Distrito Federal	2,666	0	8	0
Durango	76,758	1,196	123	1
Guanajuato	2,452,046	13	7,133	6
Guerrero	0	0	0	0
Hidalgo	5,879,406	14,119	16,548	15
Jalisco	178,650	4,399	346	1
Mexico	60,861	1,092	134	0
Michoacan	142,241	2,906	299	1
Morelos	58,425	1,004	97	1
Nayarit	24,400	601	47	0
Nuevo Leon	7,314,836	7,176	20,921	18
Oaxaca	129,567	1,475	319	0
Puebla	39,746	0	116	0
Queretaro	56,386	1,311	112	0
Quintana Roo	553,873	8,219	1,000	5
San Luis Potosi	1,382,845	17,805	9,685	26
Sinaloa	128,187	1,940	202	1
Sonora	1,126,324	4,013	3,107	3
Tabasco	544,935	1,562	859	8
Tamaulipas	6,189,159	33	18,005	14
Tlaxcala	7,174	0	21	0
Veracruz	6,159,930	7,354	17,567	16
Yucatan	1,207,613	6	3,513	3
Zacatecas	0	0	0	0
National Total	**43,085,556**	**84,278**	**128,876**	**153**

In the Mexico low boundary case, the top five states with the highest CO_2 emissions associated with new capacity additions are, in descending order, Nuevo Leon, Tamaulipas, Veracruz, Hidalgo, and Baja California. For SO_2 emissions, the top five are

San Luis Potosi, Hidalgo, Quintana Roo, Veracruz, and Nuevo Leon. For NOx emissions, the states are Nuevo Leon, Tamaulipas, Veracruz, Hidalgo, and Baja California. For mercury, they are San Luis Potosi, Nuevo Leon, Veracruz, Hidalgo, and Tamaulipas.

Table 15. United States low boundary case: Changes in emissions associated with planned electricity projects in U.S. through 2007. This includes only projects having advanced planning, under construction, or operating status (see text).

State	Annual CO_2 (tonnes)	Annual SO_2 (tonnes)	Annual NOx (tonnes)	Annual Hg (kg)
Alabama	17,090,015	91	10,662	40
Alaska	0	0	0	0
Arizona	12,885,790	69	8,039	30
Arkansas	4,645,202	22	2,548	11
California	15,522,640	84	1,392	36
Colorado	1,443,834	8	901	3
Connecticut	3,936,962	22	351	9
Delaware	1,471,098	1,153	887	28
District of Columbia	0	0	0	0
Florida	20,756,616	-53,167	-8,442	12
Georgia	12,851,370	472	8,480	31
Hawaii	0	0	0	0
Idaho	218,120	1	136	1
Illinois	24,360,757	-11,618	14,012	60
Indiana	9,463,233	51	5,936	22
Iowa	248,602	284	479	1
Kansas	333,164	165	395	1
Kentucky	8,235,273	2,682	5,385	76
Louisiana	12,405,479	67	7,775	29
Maine	2,774,367	15	1,731	6
Maryland	5,405,806	935	1,080	32
Massachusetts	8,982,646	-7,173	-412	24
Michigan	13,301,580	470	8,756	32
Minnesota	1,165,427	-896	-1,096	-4
Mississippi	19,655,653	2,320	12,471	93
Missouri	5,401,569	2,748	3,568	71
Montana	48,471	0	30	0
Nebraska	60,589	0	38	0
Nevada	4,299,214	23	2,682	10
New Hampshire	2,828,745	15	252	7
New Jersey	7,715,426	-15	610	18
New Mexico	1,284,485	7	801	3
New York	3,865,463	323	2,199	10
North Carolina	4,465,404	24	2,786	10
North Dakota	0	0	0	0
Ohio	9,501,598	1,249	6,298	34
Oklahoma	11,349,517	61	7,081	26
Oregon	1,699,519	9	1,060	4
Pennsylvania	10,731,495	-14,627	-1,174	67
Rhode Island	1,346,589	7	120	3
South Carolina	2,723,100	-5,757	143	-5
South Dakota	0	0	0	0

Tennessee	6,099,790	33	3,806	14
Texas	46,344,749	248	24,846	107
Utah	177,526	1	111	0
Vermont	0	0	0	0
Virginia	3,301,429	40	2,089	11
Washington	3,893,771	25	2,480	12
West Virginia	3,114,228	404	1,979	16
Wisconsin	4,103,658	22	2,577	10
Wyoming	1,837,827	1,671	1,302	40
National Total	**333,347,795**	**-77,433**	**147,150**	**1,039**

In the U.S. low boundary case, the five states with the highest projected CO_2 increases associated with new capacity additions are, in descending order, Texas, Illinois, Florida, Mississippi, and Alabama. For SO_2, the five highest states are Missouri, Kentucky, Mississippi, Wyoming, and Ohio, which reflects planned additions of both coal and oil. On a national basis, however, we project SO_2 emissions to decline in the low boundary case due to overall reductions in relatively less controlled existing coal and oil capacity. For NOx emissions, the top five states are Texas, Illinois, Mississippi, Alabama, and Michigan. For mercury, the top five are Texas, Mississippi, Kentucky, Missouri, and Pennsylvania. For the top ranking states with relatively low planned capacity increases, their relatively higher ranking in terms of air emissions is a reflection of a proportionally larger planned use of coal or oil.

Tables 16 through 21 present the percent change in emissions for the various provinces, states, and territories of North America in the two boundary cases, along with a national summary in Table 22. This gives an idea of where some of the largest relative changes in emissions associated with planned generation capacity may occur. We note, however, that some of the largest changes in terms of percent increases or decreases may occur in localities with relatively low emissions at present, while other locations with relatively smaller percent changes could have larger absolute increases or decreases in emissions.

Table 16. Projected percentage changes in emissions in Canada between historical reference emissions inventory (Table 1) and the high boundary scenario (Table 10).

Province/Territory	**%CO_2-high**	**%SO_2-high**	**%NOx-high**	**%Hg-high**
Alberta	24	15	25	
British Columbia	26	1	34	
Manitoba	0	0	0	
New Brunswick	-3	-23	-2	
Newfoundland	0	0	0	
Northwest Territories	0	0	0	
Nova Scotia	23	0	21	
Ontario	8	0	8	
Prince Edward Island	0	0	0	
Quebec	161	0	158	
Saskatchewan	2	0	2	
Yukon	0	0	0	
National Total	**16**	**-1**	**14**	

Note this is only a comparison between the projected 2007 emissions from announced new projects in Canada and the historical reference inventory, and does not take into account potential emission decreases from existing electricity generators that may occur by 2007.

Table 17. Projected percentage changes in emissions in Canada between historical reference emissions inventory (Table 1) and the low boundary scenario (Table 13).

Province/Territory	%CO_2-low	%SO_2-low	%NOx-low	%Hg-low
Alberta	2	0	4	
British Columbia	10	0	12	
Manitoba	0	0	0	
New Brunswick	1	0	1	
Newfoundland	0	0	0	
Northwest Territories	0	0	0	
Nova Scotia	23	0	21	
Ontario	6	0	7	
Prince Edward Island	0	0	0	
Quebec	0	0	0	
Saskatchewan	2	0	2	
Yukon	0	0	0	
National Total	**5**	**0**	**6**	

Note this is only a comparison between the projected 2007 emissions from announced new projects in Canada and the historical reference inventory, and does not take into account potential emission decreases from existing electricity generators that may occur by 2007.

Table 18. Projected percentage changes in emissions in Mexico between historical reference emissions inventory (Table 2) and the high boundary scenario (Table 11).

State	**%CO_2-high**	**%SO_2-high**	**%NOx-high**	**%Hg-high**
Aguascalientes	0	0	0	0
Baja California	346	0	526	511
Baja California Sur	351	15	569	780
Campeche	---	---	---	---
Chiapas	---	---	---	---
Chihuahua	24	0	36	34
Coahuila	6	2	5	1
Colima	0	0	0	0
Distrito Federal	4	0	8	3
Durango	22	3	31	44
Guanajuato	61	0	91	94
Guerrero	0	0	0	0
Hidalgo	68	10	99	101
Jalisco	---	---	---	---
Mexico	6	1	8	11
Michoacan	---	---	---	---
Morelos	---	---	---	---
Nayarit	---	---	---	---
Nuevo Leon	229	15	319	287
Oaxaca	---	---	---	---
Puebla	---	---	---	---
Queretaro	14	93	20	17
Quintana Roo	240	2214	290	719
San Luis Potosi	201	33	381	896
Sinaloa	3	2	3	24
Sonora	30	4	43	52
Tabasco	---	---	---	---
Tamaulipas	299	0	448	465
Tlaxcala	---	---	---	---
Veracruz	92	3	136	140
Yucatan	150	0	226	190
Zacatecas	0	0	0	0
National Total	**76**	**8**	**89**	**25**

Note this is only a comparison between the projected 2007 emissions from announced new projects in Mexico and the historical reference inventory, and does not take into account potential emission decreases from existing electricity generators that may occur by 2007.
“---“ indicates states with no reported emissions from electricity generation in the historical reference scenario.

Table 19. Projected percentage changes in emissions in Mexico between historical reference emissions inventory (Table 2) and the low boundary scenario (Table 14).

State	%CO_2-low	%SO_2-low	%NOx-low	%Hg-low
Aguascalientes	0	0	0	0
Baja California	255	0	388	377
Baja California Sur	329	10	551	621
Campeche	---	---	---	---
Chiapas	---	---	---	---
Chihuahua	19	0	28	28
Coahuila	6	2	5	1
Colima	0	0	0	0
Distrito Federal	5	0	3	3
Durango	4	0	8	19
Guanajuato	59	0	88	91
Guerrero	0	0	0	0
Hidalgo	68	10	99	101
Jalisco	0	0	0	0
Mexico	2	1	2	4
Michoacan	---	---	---	---
Morelos	---	---	---	---
Nayarit	---	---	---	---
Nuevo Leon	215	15	319	287
Oaxaca	---	---	---	---
Puebla	---	---	---	---
Queretaro	6	93	6	10
Quintana Roo	240	2214	290	719
San Luis Potosi	53	33	191	665
Sinaloa	3	2	3	24
Sonora	23	4	33	42
Tabasco	---	---	---	---
Tamaulipas	124	0	186	193
Tlaxcala	---	---	---	---
Veracruz	51	3	76	82
Yucatan	75	0	114	96
Zacatecas	0	0	0	0
National Total	**48**	**5**	**53**	**14**

Note this is only a comparison between the projected 2007 emissions from announced new projects in Mexico and the historical reference inventory, and does not take into account potential emission decreases from existing electricity generators that may occur by 2007.
"---" indicates states with no reported emissions from electricity generation in the historical reference scenario.

Table 20. Projected percentage changes in emissions in the U.S. between historical reference emissions inventory (Table 3) and the high boundary scenario (Table 12).

State	%CO_2-high	%SO_2-high	%NOx-high	%Hg-high
Alabama	44	1	12	12
Alaska	0	0	0	0
Arizona	73	4	23	30
Arkansas	107	23	44	101
California	98	1	11	6492
Colorado	27	7	9	75
Connecticut	33	0	2	31
Delaware	32	3	6	27

District of Columbia	0	0	0	0
Florida	36	-7	2	8
Georgia	42	1	11	17
Hawaii	0	0	0	0
Idaho	1607	6	1004	---
Illinois	53	-1	10	7
Indiana	24	0	6	9
Iowa	8	0	3	1
Kansas	12	3	4	13
Kentucky	46	5	10	48
Louisiana	59	4	20	56
Maine	133	0	45	135
Maryland	24	0	2	5
Massachusetts	32	-5	-1	22
Michigan	30	0	7	5
Minnesota	15	3	2	17
Mississippi	126	2	31	45
Missouri	20	3	5	17
Montana	47	33	16	42
Nebraska	12	4	4	14
Nevada	82	0	23	27
New Hampshire	85	0	3	63
New Jersey	78	0	4	42
New Mexico	5	0	1	1
New York	53	-1	8	16
North Carolina	14	0	3	2
North Dakota	8	1	2	5
Ohio	25	0	4	3
Oklahoma	60	4	18	22
Oregon	107	0	44	27
Pennsylvania	21	-2	0	2
Rhode Island	46	12	13	---
South Carolina	40	-2	8	18
South Dakota	302	51	35	676
Tennessee	22	0	3	3
Texas	25	0	7	3
Utah	63	64	22	262
Vermont	4605	13	318	---
Virginia	69	0	16	13
Washington	127	2	41	29
West Virginia	17	0	3	5
Wisconsin	54	-1	15	31
Wyoming	19	10	7	42
National Total	**38**	**1**	**8**	**15**

Note this is only a comparison between the projected 2007 emissions from announced new projects in the U.S. and the historical reference inventory, and does not take into account potential emission decreases from existing electricity generators that may occur by 2007.

"---" indicates states with no reported emissions from electricity generation in the historical reference scenario.

Table 21. Projected percentage changes in emissions in the U.S. between historical reference emissions inventory (Table 3) and the low boundary scenario (Table 15).

State	%CO_2-low	%SO_2-low	%NOx-low	%Hg-low
Alabama	23	0	6	2
Alaska	0	0	0	0
Arizona	31	0	10	6
Arkansas	17	0	6	3
California	38	0	4	2278
Colorado	4	0	1	2
Connecticut	33	0	2	31
Delaware	20	3	6	25
District of Columbia	0	0	0	0
Florida	16	-7	-3	1
Georgia	18	0	5	3
Hawaii	0	0	0	0
Idaho	105	0	65	---
Illinois	28	-2	5	3
Indiana	7	0	2	1
Iowa	1	0	1	0
Kansas	1	0	1	0
Kentucky	9	0	2	5
Louisiana	25	0	8	7
Maine	73	0	25	74
Maryland	16	0	1	4
Massachusetts	31	-5	-1	21
Michigan	17	0	4	3
Minnesota	3	-1	-1	-1
Mississippi	89	2	22	37
Missouri	8	1	2	6
Montana	0	0	0	0
Nebraska	0	0	0	0
Nevada	20	0	6	7
New Hampshire	55	0	2	40
New Jersey	43	0	2	23
New Mexico	4	0	1	0
New York	6	0	2	2
North Carolina	6	0	1	1
North Dakota	0	0	0	0
Ohio	8	0	1	1
Oklahoma	25	0	7	4
Oregon	26	0	11	6
Pennsylvania	9	-2	0	2
Rhode Island	40	10	11	---
South Carolina	8	-3	0	-1
South Dakota	0	0	0	0
Tennessee	11	0	2	2
Texas	19	0	6	3
Utah	1	0	0	0
Vermont	0	0	0	---
Virginia	8	0	2	2
Washington	32	0	11	5
West Virginia	4	0	1	1
Wisconsin	9	0	2	1

Wyoming	4	2	1	8
National Total	**14**	**-1**	**3**	**3**

Note this is only a comparison between the projected 2007 emissions from announced new projects in the U.S. and the historical reference inventory, and does not take into account potential emission decreases from existing electricity generators that may occur by 2007.
"---" indicates states with no reported emissions from electricity generation in the historical reference scenario.

Table 22. Summary of national emission totals in the reference inventory case and the high and low boundary future projections (percent of reference inventory case shown in parenthesis). CO_2, SO_2, and NOx amounts are in metric tonnes. Mercury (Hg) amounts are in kilograms.

Country scenario	Annual CO_2	Annual SO_2	Annual NOx	Annual Hg
Canada reference inventory	122,000,000	648,411	289,137	---
Canada high boundary 2007	19,195,332 (+16%)	-3,917 (-1%)	41,910 (+14%)	221 n/a
Canada low boundary 2007	5,561,154 (+5%)	30 (0%)	16,178 (+6%)	13 n/a
Mexico reference inventory	90,095,882	1,683,199	244,380	1,117
Mexico high boundary 2007	68,565,216 (+76%)	130,708 (+8%)	216,565 (+89%)	275 (+25%)
Mexico low boundary 2007	43,085,556 (+48%)	84,278 (+5%)	128,876 (+53%)	153 (+14%)
U.S. reference inventory	2,331,958,813	12,291,107	5,825,982	39,241
U.S. high boundary 2007	875,036,007 (+38%)	64,580 (+1%)	459,286 (+8%)	5,762 (+15%)
U.S. low boundary 2007	333,347,795 (+14%)	-77,433 (-1%)	147,150 (+3%)	1,039 (+3%)

The percent value given in parentheses is the relative size of the new 2007 emissions in the boundary case compared to the reference inventory. For example, in the Canada 2007 high boundary case, the estimated emissions from projected electricity capacity changes would be equivalent to 16% of the reference inventory emissions. This provides a relative sense of the scale of potential emissions changes.