**Environmental Challenges and Opportunities of the Evolving North American Electricity Market**

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Working Paper

# Estimating Future Air Pollution from New Electric Power Generation

**Prepared by:** Paul Miller, Zachary Patterson and Scott Vaughan
CEC Secretariat

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Commission for Environmental Cooperation of North America
393, rue Saint-Jacques Ouest, Bureau 200
Montréal (Québec) Canada H2Y 1N9
Tel: (514) 350-4300; Fax: (514) 350-4314
E-mail: info@ccemtl.org
http://www.cec.org

# Estimating Future Air Pollution from New Electric Power Generation

By Paul J. Miller, Zachary Patterson and Scott Vaughan
Commission for Environmental Cooperation
Montréal, Québec, Canada

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 ($NO_x$), 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 $NO_x$ and $SO_2$ contribute to acidic deposition, commonly called acid rain. Emissions of $NO_x$ 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 Volume* (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 that we supplemented with information obtained from Mexico. The supplemented database contains publicly announced power plant capacity changes (new additions and existing closures) in North America. The emissions we estimate from the capacity changes are then put into the context of total electricity sector emissions from a recent “representative year” as reflected in the reference case inventory. We do this to gain a relative sense of the potential pollution from new power plants at the state and provincial levels in North America.

It is important to point out what this analysis does not estimate. We do not estimate total emissions from the entire North American electricity generation sector in 2007. Our analysis only estimates emissions associated with proposed changes (additions and closures) in electricity generation capacity in North America projected to 2007. It does not estimate emissions from existing sources that may still operate in 2007. For example, we do not account for potential pollution reductions at existing sources due to pending regulations, such as regional controls on emissions of nitrogen oxides in the eastern United States. We also do not estimate potential pollution reductions associated with reductions in electricity generation from existing sources where that generation may be displaced by newer, cleaner sources. This would require forecasting of demand growth and dispatch modeling that is beyond the scope of the analysis. Fuel switching at existing sources to relatively cleaner fuels, such as natural gas, also may not be completely captured in this analysis. In Mexico, for example, the *Comisión Federal de Electricidad* estimates $CO_2$ and $SO_2$ emissions to decline through 2006, and $NO_x$ to stabilize, due to increased use of natural gas with higher efficiency (combined cycle) plants in the electricity sector.[2]

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 electricity sector's emissions from a recent year in North America (the reference case inventory). This also provides initial indications of what regions in North America may appear the most attractive to new energy developers, as reflected in the amount of new power plant capacity or emissions. This can lead to future lines of inquiry as to why developers deem these regions attractive, either because of greater local demand growth, access to transmission lines, differing regulatory requirements, availability of tax or other financial incentives, or other reasons. Furthermore, by developing a reference case emissions inventory for the North America electricity sector (the first of its kind), this analysis identifies 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.[3]

There are obstacles in this approach that limit our ability to predict future emissions 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 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 $NO_x$ (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 US 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 US 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"

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[2] Communication from Semarnat, April 2002.

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

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 $NO_x$ 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 Acosta y Asociados.[4] The information developed in the mercury report served as our basis for estimating emissions of $NO_x$, $SO_2$ and $CO_2$ in Mexico during 1999. While this is more recent than the 1998 US information, the one-year difference is not likely to significantly affect conclusions about projected emissions from future capacity changes relative to the reference emissions scenario.

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

**Canada**

Emissions information for $NO_x$, $SO_2$, $CO_2$ 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.[5] The most recent national inventory at the provincial level for $NO_x$ 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 Manitoba, New Brunswick, Nova Scotia, Ontario, and Quebec have power plant information for 1998 available upon request, and Ontario Power Generation (OPG) provides $NO_x$, $SO_2$ and $CO_2$ annual emissions from its power plants in annual company reports.[6] British Columbia makes publicly available individual plant emissions information for the year

[4] Gildardo Acosta y Asociados, "Preliminary Atmospheric Emissions Inventory of Mercury in Mexico," prepared for the Commission for Environmental Cooperation (2001, in press).
[5] Environment Canada, Greenhouse Gas Division, Preliminary 1998 Electricity Emissions, April 2001.
[6] 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>).

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 available for 2000 from Environment Canada's National Pollutant Release Inventory (NPRI).

Table 1 presents the annual emissions of $CO_2$, $SO_2$, $NO_x$, and mercury 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. The mercury emissions data are for 2000, the first year that power plants reported their mercury emissions to the NPRI in Canada.

*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 $NO_x$ (tonnes) | Annual Hg (kg) |
|---|---|---|---|---|
| Alberta | 51,400,000 | 124,632 | 84,931 | 725 |
| British Columbia | 1,840,000 | 369 | 4,172 | 0 |
| Manitoba | 962,000 | 3,145 | 1,981 | 23 |
| New Brunswick | 9,210,000 | 99,070 | 27,250 | 156 |
| Newfoundland | 1,020,000 | 15,704 | 3,690 | 0 |
| Northwest Territories | 326,000 | 317 | 5,675 | 0 |
| Nova Scotia | 7,800,000 | 143,546 | 24,620 | 267 |
| Ontario | 33,100,000 | 143,061 | 85,511 | 529 |
| Prince Edward Island | 10,200 | 294 | 141 | 0 |
| Quebec | 1,400,000 | 11,475 | 4,140 | 0 |
| Saskatchewan | 15,100,000 | 108,536 | 47,509 | 274 |
| Yukon | 33,100 | 46 | 591 | 0 |
| **National Total** | **122,000,000** | **650,195** | **290,211** | **1,975** |

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 $NO_x$ ($NO_2$) emissions are 1996 data from "Alberta Electric Industry, Annual Statistics for 1996," Alberta Energy and Utilities Board, Statistical Series 28, Vol. XVII (November 1997).
Manitoba $SO_2$ and $NO_x$ ($NO_2$) emissions are 1998 data from Manitoba Conservation.
New Brunswick $SO_2$ and $NO_x$ ($NO_2$) emissions are 1998 data from New Brunswick Department of Environment and Local Government.
Nova Scotia $SO_2$ and $NO_x$ ($NO_2$) emissions are 1998 data from Nova Scotia Department of Environment and Labour.
Ontario $SO_2$ and $NO_x$ ($NO_2$) emissions are 1998 data from Ontario Ministry of the Environment.
Quebec $SO_2$ and $NO_x$ ($NO_2$) emissions are 1998 data from *Québec Ministère de l'Environnement.*
British Columbia Newfoundland, Northwest Territories, Prince Edward Island, Saskatchewan and The Yukon $SO_2$ and $NO_x$ ($NO_2$) emissions are 1995 data from Environment Canada, 1995 Criteria Air Contaminants inventory.
Mercury emissions are 2000 data from the National Pollutant Release Inventory (NPRI), Environment Canada <http://www.ec.gc.ca/pdb/npri/>.

**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.[7] The Instituto Nacional de Ecología (INE) provided 1995 $NO_x$ 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 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.[8]

To develop estimates of $NO_x$, $SO_2$, 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 $NO_x$, $SO_2$, 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 $NO_x$ 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.[9] 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 US Environmental Protection Agency's AP-42 guidelines (hereinafter referred to as "EPA AP-42").[10] For natural gas, diesel and *combustóleo*, we use INE's emission factors for $NO_x$ and $SO_2$. We note that INE's $NO_x$ 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 $NO_x$ 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 $SO_2$, $NO_x$ 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 Acosta y Asociados for the CEC. We present the results in Table 2, which shows the

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[7] 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>.

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

[9] J.D. Miller, J.R. Parga, J. Drelich, and C.L. Lin, "Coal Cleaning Opportunities for $SO_2$ Emission Reductions in the Border Region," Southwest Center for Environmental Research and Policy (SCERP) 1996 Final Report, CX 821924-01-0.

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

state-level and national emission estimates of each of the four air pollutants from the Mexico electricity generation sector in 1999.

Coal

In 1999, there were two coal power plants in Mexico, both in the State of Coahuila.[11] The Coahuila power plants are commonly referred to as Rio Escondido (José López 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.[12] In 1999, the power plants also used imported coal from Wyoming and 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 coal power plants in Mexico. 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 Rio Escondido nor Carbón II had $SO_2$ controls in 1999.[13]

INE indicates that in 1995, the power plants consumed three types of coal: oil coal with a 3 percent average sulfur content, local coal with around a 4 percent 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 percent, 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 percent dry weight, depending upon the mine location. This range indicates the coal is of a low to moderate sulfur content type.[14] The sulfur contents in the majority of coal samples were generally at the low end of the range (1.3–1.6 percent). Based on this and lacking specific information on the quantities of coal

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

[12] J.D. Miller, J.R. Parga, J. Drelich, and C.L. Lin, "Coal Cleaning Opportunities for $SO_2$ Emission Reductions in the Border Region," Southwest Center for Environmental Research and Policy (SCERP) 1996 Final Report, CX 821924-01-0, p. 139.

[13] Communication from Dr. Eduardo Arriola, 8 February 2002.

[14] J.D. Miller, J.R. Parga, J. Drelich, and C.L. Lin, "Coal Cleaning Opportunities for $SO_2$ Emission Reductions in the Border Region," Southwest Center for Environmental Research and Policy (SCERP) *1996 Final Report,* CX 821924-01-0 (Table 2).

consumed from different mines, we have chosen to use the CFE sulfur weight content of 1.45 percent 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 percent 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.

*$NO_x$ emissions*
For $NO_x$ emissions, we do not believe Rio Escondido nor Carbón II are equipped with $NO_x$ controls.[15] The $NO_x$ 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 Rio Escondido or Carbón 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 $NO_x$ emission factor for this boiler type given by EPA AP-42 Table 1.1-3.[16] We use the EPA AP-42 factor of 31 lb/short ton (15.5 kg/metric tonne) for uncontrolled $NO_x$ emissions. Using 1999 fuel consumption information from INE, we estimate $NO_x$ emissions to be 146,758 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 percent averaged across the coal samples. We choose to use this lower estimate rather than the default 75.9 percent 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[17] 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,

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[15] Communication from Dr. Eduardo Arriola, 8 February 2002.
[16] US 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).
[17] US 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).

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,[18] with a production capacity of 6-7 million tonnes per year.[19] This could supply about 70–80 percent of the coal consumed by the Rio Escondido and Carbón II power plants. The Micare coal samples had carbon contents of about 50 percent, which is at the low end of the range from all coal samples. Thus, if the Micare coal is the dominant source of coal for the Rio Escondido and Carbón 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 plants in Mexico, perhaps by about 15 percent. 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. 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.

*$NO_x$ emissions*

For natural gas $NO_x$ emissions, we use two different emission factors from INE that depend on the size of the unit. We did not have information on the level of $NO_x$ control from individual power plants, so we assumed no control of $NO_x$ emissions at all power plants. This, of course, will overestimate $NO_x$ emissions from natural gas units in Mexico if $NO_x$ controls exist on any power plant. For natural gas units with a heat input rate greater than 100 mmBtu/hr, we use a $NO_x$ emission factor of 3,760 kg/million cubic meters ($MMm^3$). For plants with a heat input rate less than 100 mmBtu/hr, we use a $NO_x$ emission rate of 1,600 kg/$MMm^3$. Using these emission factors, we estimate total $NO_x$ 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.[20] 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*

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[18] US Department of Energy (DOE), "An Energy Overview of Mexico," <http://www.fe.doe.gov/international/mexiover.html> (5 September 2001 update).

[19] J.D. Miller, J.R. Parga, J. Drelich, and C.L. Lin, "Coal Cleaning Opportunities for $SO_2$ Emission Reductions in the Border Region," Southwest Center for Environmental Research and Policy (SCERP) 1996 Final Report, CX 821924-01-0.

[20] US 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).

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 percent sulfur content in diesel.[21] 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 include diesel fuels.[22] INE uses S = 0.3 percent as the diesel sulfur content. Information provided by the national oil company Petróleos Mexicanos (Pemex), however, gives a sulfur content of 0.5 percent 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 percent 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.

*$NO_x$ emissions*
For the $NO_x$ emission factor for diesel (No. 2 oil), INE uses 2.88 kg/$m^3$. Applying this factor to diesel fuel consumption gives a $NO_x$ 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/$m^3$).[23] This gives a $CO_2$ emissions estimate of 938,509 metric tonnes from diesel combustion by the Mexico electricity generation sector in 1999.

<u>Oil (*Combustóleo*)</u>
*$SO_2$ 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 percent of sulfur in the oil. INE uses a sulfur content of S = 3.6 percent. 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 percent 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.

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[21] *Norma Oficial Mexicana,* NOM-085-ECOL-1994, Tabla 3.
[22] US 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).
[23] US 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).

*$NO_x$ emissions*
The $NO_x$ 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 $NO_x$ emissions estimate of 104,761 metric tonnes from *combustóleo* combustion by the Mexico electricity generation sector in 1999.

*$CO_2$ 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 $CO_2$, $SO_2$, $NO_x$ and mercury (Hg) from the Mexico electricity generation sector (in metric tonnes or kilograms).

| State | Annual $CO_2$ (tonnes) | Annual $SO_2$ (tonnes) | Annual $NO_x$ (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 | 146,791 | 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 |
| Michoacán | 0 | 0 | 0 | 0 |
| Morelos | 0 | 0 | 0 | 0 |
| Nayarit | 0 | 0 | 0 | 0 |
| Nuevo León | 3,402,462 | 46,576 | 6,566 | 6 |
| Oaxaca | 0 | 0 | 0 | 0 |
| Puebla | 0 | 0 | 0 | 0 |
| Querétaro | 959,426 | 1,408 | 1,756 | 3 |
| Quintana Roo | 230,855 | 371 | 345 | 1 |
| San Luis Potosí | 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 |
| Yucatán | 1,601,345 | 23,734 | 3,085 | 3 |
| Zacatecas | 0 | 0 | 0 | 0 |
| **National Total** | **90,095,882** | **1,683,199** | **280,931** | **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 US 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 US

EPA (http://www.epa.gov/airmarkets/egrid/). This database contains information on $NO_x$, $SO_2$, $CO_2$, and mercury emitted to the air by individual power plants in the US. 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 $CO_2$, $SO_2$, $NO_x$ 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 $NO_x$ (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** |

We note that the 1998 annual $NO_x$ emissions from E-GRID2000 are about 20 percent lower than the annual emissions given in EIA Electric Power Annual reports. The difference is due in large part to differing methods for estimating emissions between the two databases. E-GRID2000 uses hourly monitoring data from continuous emissions monitoring (CEM) for virtually all large power plants equipped with CEM. The EIA inventory does not use CEM data. Instead, EIA calculates emissions using information on fuels and combustion sources coupled with the relevant emission factors. Some preliminary evaluations at specific power plants indicate that $NO_x$ emission rates are highly variable depending on operating conditions. Therefore, applying a single emission factor would not capture this variability. Furthermore, there may be insufficient information about installed $NO_x$ controls and how they are used at power plants, which could produce overestimates of $NO_x$ emissions in the EIA data. Finally, based on $CO_2$ CEM data, there may be an upward bias in the CEM $NO_x$ data, although if such a bias exists in the 1998 $NO_x$ data, it would narrow the difference with the EIA estimates, rather than increase it. Work is ongoing at EPA to better understand the differences between the two approaches.

**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 US electricity sector, numerous scenarios are possible depending on the basic assumptions made in the forecasting model.[24] In this report, we do not attempt to model future electricity

[24] 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).

generation scenarios in North America. Instead, we use a database called NEWGen maintained by the consulting firm RDI/Platts.[25] 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 ($CO_2$, $SO_2$, $NO_x$, and mercury) associated with announced capacity changes in North America.

Not all announcements of new power plants are likely to result in new power plants, as changes in demand projections, available financing, economic downturns, or other circumstances can cause construction plans to be cancelled. Because it is unlikely that all announced capacity additions contained in the 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 2007 as the 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 has announced plans to ratify 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.

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

Future electricity generation scenarios

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 Mexico, we used national information from two federal agencies in Mexico, the Comisión Reguladora de Energía (CRE) and the Comisión Federal de Electricidad (CFE).[26]

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 in that it may not include all plants that have been constructed or announced since 1998,[27] 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 $NO_x$ emission changes for the entire electricity generation sector because we do not account for control measures that are currently being implemented due to ongoing regulatory programs in each country. In the case of $CO_2$ and mercury emissions, no country currently has regulatory requirements to reduce these emissions from power plants. There are preliminary indications, however, that coal-fired power plants equipped with selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) for $NO_x$ control coupled with wet fluid gas desulfurization (FGD) for $SO_2$ control may have an added "co-benefit" by significantly enhancing mercury removal. Preliminary pilot tests on bituminous coals suggests greater than 90 percent mercury removal from a combination of SCR and wet FGD control technologies, so it is possible there may be significant mercury reductions at power plants if equipped with these controls. Currently, however, the mercury reduction results are preliminary and it is not known how broadly applicable the initial pilot tests are to all coal types and actual operating conditions.[28] Therefore, we do not include potential mercury reductions in this analysis that may occur as a "co-benefit" from required $NO_x$ and $SO_2$ controls, but note that these may be significant if preliminary results are borne out under actual operating conditions at coal-fired 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

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

[27] For example, the province of Alberta has commented that the NEWGen database may underestimate the amount of new generation capacity in Alberta (primarily natural gas) constructed between 1998 and 2001. Comments from Alberta Environment, Policy Secretariat (26 February 2002).

[28] US EPA, "Performance and Cost of Mercury Emission Control Technology Applications on Electric Utility Boilers," EPA-600/R-00-083, National Risk Management Research Laboratory, Research Triangle Park, NC (Sept. 2000).

estimating emissions from the entire electricity generation sector. While this may not provide a continental 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.[29] For the United States, the announced fossil fuel capacity changes that are contained in the NEWGen database would result in a 53 percent increase in fossil fuel generating capacity by 2007 above existing 1999 capacity. For Mexico, the increase is even greater, with a projected increase of 62 percent in national generating capacity by 2007 over 1999 levels. Canada's projected increase, by contrast, is only about 10 percent. 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 percent) of the overall announced capacity changes.

The projected Mexico and US 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 US 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 to assign a status code best conforming with the NEWGen criteria. The NEWGen status codes and their criteria are:[30]

- 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.

[29] Report of the National Energy Policy Development Group (May 2001) *National Energy Policy: Reliable, Affordable, and Environmentally Sound Energy for America's Future,* Washington, DC.
[30] RDI/Platts NEWGen Database, NEWGen User Guide, August 2001 issue (Boulder, Colorado, USA), pp. 13–14.

- 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 offset to some extent by projects in the early development or proposed stages which are not included in the lower boundary case.

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 US 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.[31] 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.

[31] US Department of Energy (DOE), "An Energy Overview of Mexico," <http://www.fe.doe.gov/international/mexiover.html> (5 Sept. 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 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[32] | 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.

[32] Note that the province of Alberta has commented that the NEWGen database may underestimate the amount of new generation capacity in Alberta (primarily natural gas) constructed between 1998 and 2001. Comments from Alberta Environment, Policy Secretariat (26 February 2002).

*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 | 2,324 | 0 | 0 | 0 | 2,324 |
| Baja California Sur | 41 | 0 | 0 | 95 | 136 |
| Campeche | 261 | 0 | 0 | 8 | 269 |
| Chiapas | 0 | 0 | 0 | 0 | 0 |
| Chihuahua | 1,281 | 0 | 0 | 0 | 1,281 |
| Coahuila | 256 | 0 | 0 | 0 | 256 |
| Colima | 0 | 0 | 0 | 0 | 0 |
| Distrito Federal | 0 | 0 | 0 | 0 | 0 |
| Durango | 905 | 0 | 0 | 0 | 905 |
| Guanajuato | 519 | 0 | 0 | 0 | 519 |
| Guerrero | 0 | 1,750 | -1,750 | 0 | 0 |
| Hidalgo | 0 | 0 | 0 | 0 | 0 |
| Jalisco | 0 | 0 | 0 | 0 | 0 |
| Mexico | 251 | 0 | 0 | 0 | 251 |
| Michoacán | 0 | 0 | 0 | 0 | 0 |
| Morelos | 0 | 0 | 0 | 5 | 5 |
| Nayarit | 0 | 0 | 0 | 0 | 0 |
| Nuevo León | 1,430 | 0 | 0 | 0 | 1,430 |
| Oaxaca | 0 | 0 | 0 | 0 | 0 |
| Puebla | 0 | 0 | 0 | 0 | 0 |
| Querétaro | 342 | 0 | 0 | 0 | 342 |
| Quintana Roo | 115 | 0 | 104 | 0 | 218 |
| San Luis Potosí | 2,675 | 0 | 510 | 0 | 3,185 |
| Sinaloa | 0 | 0 | 0 | 0 | 0 |
| Sonora | 1,635 | 0 | 0 | 0 | 1,635 |
| Tabasco | 0 | 0 | 0 | 0 | 0 |
| Tamaulipas | 4,293 | 0 | 0 | 0 | 4,293 |
| Tlaxcala | 5 | 0 | 0 | 0 | 5 |
| Veracruz | 4,019 | 0 | 0 | 0 | 4,019 |
| Yucatán | 1,046 | 0 | 0 | 0 | 1,046 |
| Zacatecas | 0 | 0 | 0 | 0 | 0 |
| **National Total** | **21,397** | **1,750** | **-1,136** | **108** | **22,119** |

In Mexico, the five states with the largest planned new capacity in the high boundary case are, in decreasing order, Tamaulipas, Veracruz, San Luis Potosí, Baja California, and Sonora. Tamaulipas, Baja California, and Sonora are northern states bordering the US.. Much of the new capacity in Baja California is being built to service US demand, whereas the new capacity in the other border states are for local demand growth.[33] The new capacity in these states would come largely from the use of natural gas, with a smaller amount of oil. 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). There

[33] Communication from Dr. Eduardo Arriola, 8 February 2002.

is a projected net decrease in oil capacity due to a conversion from oil to coal at the 2,100 MW Petacalco power plant in the State of Guerrero. In 2001, the Petacalco plant began burning coal in half its boilers (1,050 MW), and plans to convert an additional 700 MW from oil to coal by 2003.[34] The additional 510 MW in oil capacity in San Luis Potosí is from oil-derived petroleum coke.[35]

*Table 6.* High boundary case projected 2007 electricity generation capacity changes by fuel type in the US (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 |

[34] Communication from Miguel Breceda, 15 February 2002.
[35] Communication from Dr. Eduardo Arriola, 8 February 2002.

| | | | | | |
|---|---|---|---|---|---|
| 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 US 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 percent 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[36] | 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, which is based on the NEWGen database updated as of August 2001. Since August 2001, however, several Alberta coal projects have advanced in planning with about 1400 MW having gone through public hearings, of which 450 MW received approval from the Alberta Electric Utilities Board.[37] Even without this planned new coal capacity, Alberta remains the province with the largest planned capacity expansion in Canada in the low boundary scenario.

[36] Note that the province of Alberta has commented that the NEWGen database may underestimate the amount of new generation capacity in Alberta (primarily natural gas) constructed between 1998 and 2001. Comments from Alberta Environment, Policy Secretariat (26 February 2002).
[37] Comments from Alberta Environment, Policy Secretariat (26 February 2002).

*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 | 1,786 | 0 | 0 | 0 | 1,786 |
| Baja California Sur | 41 | 0 | 0 | 0 | 41 |
| Campeche | 261 | 0 | 0 | 8 | 269 |
| Chiapas | 0 | 0 | 0 | 0 | 0 |
| Chihuahua | 579 | 0 | 0 | 0 | 579 |
| Coahuila | 256 | 0 | 0 | 0 | 256 |
| Colima | 0 | 0 | 0 | 0 | 0 |
| Distrito Federal | 0 | 0 | 0 | 0 | 0 |
| Durango | 0 | 0 | 0 | 0 | 0 |
| Guanajuato | 519 | 0 | 0 | 0 | 519 |
| Guerrero | 0 | 1,750 | -1,750 | 0 | 0 |
| Hidalgo | 0 | 0 | 0 | 0 | 0 |
| Jalisco | 0 | 0 | 0 | 0 | 0 |
| Mexico | 7 | 0 | 0 | 0 | 7 |
| Michoacán | 0 | 0 | 0 | 0 | 0 |
| Morelos | 0 | 0 | 0 | 5 | 5 |
| Nayarit | 0 | 0 | 0 | 0 | 0 |
| Nuevo León | 1,430 | 0 | 0 | 0 | 1,430 |
| Oaxaca | 0 | 0 | 0 | 0 | 0 |
| Puebla | 0 | 0 | 0 | 0 | 0 |
| Querétaro | 342 | 0 | 0 | 0 | 342 |
| Quintana Roo | 115 | 0 | 104 | 0 | 218 |
| San Luis Potosí | 0 | 0 | 510 | 0 | 510 |
| Sinaloa | 0 | 0 | 0 | 0 | 0 |
| Sonora | 933 | 0 | 0 | 0 | 933 |
| Tabasco | 0 | 0 | 0 | 0 | 0 |
| Tamaulipas | 1,179 | 0 | 0 | 0 | 1,179 |
| Tlaxcala | 5 | 0 | 0 | 0 | 5 |
| Veracruz | 1,451 | 0 | 0 | 0 | 1,451 |
| Yucatán | 500 | 0 | 0 | 0 | 500 |
| Zacatecas | 0 | 0 | 0 | 0 | 0 |
| **National Total** | **9,403** | **1,750** | **-1,136** | **13** | **10,030** |

In the low boundary case, the five states with the largest fossil fuel capacity increases are, in descending order, Baja California, Veracruz, Nuevo León, Tamaulipas, and Sonora. On a national basis, natural gas remains the fossil fuel of choice, with lesser amounts of oil, coal, and distillate (diesel). There is a projected net decrease in oil capacity due to a planned conversion of 1,750 MW in capacity from oil to coal at the Petacalco plant in Guerrero.

*Table 9.* Low boundary case projected 2007 electricity generation capacity changes by fuel type in the US (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 US 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 $NO_x$ emissions cap of the $NO_x$ 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 percent in the high boundary case to only 1 percent 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 US 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 E-GRID2000. 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.[38] 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 more likely for baseload than peaking.[39] For all new natural gas plants, we assume an efficiency factor of 50 percent based on new plant efficiencies used by the International Energy Administration (IEA).[40] 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 percent.

For fuels other than natural gas, the next most popular fuel choice for new generation is coal. There are much smaller amounts of new generation using diesel and gasoline (distillate). There is a net decrease in future oil generation capacity. For new capacity not using natural gas, we assume a generation efficiency of 40 percent based on IEA information.[41] For retirements of existing capacity where we did not have historical emissions information from the specific plant, we assume an efficiency of 0.35 percent. We assume new non-natural gas fossil fuel generation will be for base load, and assign it a capacity factor of 0.75.

*$CO_2$ 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.[42] 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

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[38] We have been informed by Dr. Eduardo Arriola, former director of programming at the *Comisión Federal de Electricidad* (CFE), that all new combined cycle natural gas plants in Mexico may serve as baseload. To maintain a consistent approach for all three countries, however, we continue to treat proposed natural gas plants in Mexico of less than 500 MW capacity as peaking units with a 0.2 capacity factor, but note that if these plants are used as baseload with a higher capacity factor, projected emissions of $CO_2$ and $NO_x$ in Mexico would be higher by about 10–20%. The difference in capacity factors has less of an effect on projected emissions of $SO_2$ and mercury as natural gas is a relatively small contributor of these pollutants.

[39] 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 premier ministre dévoile le nouveau projet d'Hydro-Québec: une centrale à cycle combineé au gaz naturel*, (2 Oct. 2001).

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

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

[42] US 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).

(2,910 kg/$m^3$). This emission rate is 2.4 percent lower than that for low sulfur No. 6 oil, so it 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/$m^3$).[43] For new coal in the United States, 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.[44] 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 US Energy Information Administration (EIA) in EIA 767 forms. The 1998 US 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,[45] so the difference between the choice of $CO_2$ factors is small. For new coal generation in Canada (Alberta), we use an emission rate of 1,760 kg/tonne that was provided by Alberta Environment.[46] 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.[47] 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 percent 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.[48] 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 US EPA, as well as several states and environmental groups, prevail in ongoing litigation. Power plant owners themselves may adopt additional controls, such as a recent announcement by the Tennessee Valley Authority (TVA) of

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[43] US 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).

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

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

[46] Comments from Alberta Environment, Policy Secretariat (26 February 2002).

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

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

plans to reduce $SO_2$ emissions from its coal power plants by over 200,000 short tons annually sometime after 2003.[49] In Mexico, the *Comisión Federal de Electricidad* estimates total $SO_2$ emissions to decline through 2006, due to increased use of natural gas with higher efficiencies (combined cycle).[50] 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.[51] This, however, appears high as the US 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 is not 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 this coal.

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[49] Tennessee Valley Authority press announcement (4 Oct. 2001).

[50] Communication from Semarnat, April 2002.

[51] US 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).

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 percent to get an emission rate of 0.71 lb/$10^{-3}$ gal (0.085 kg/$m^3$). There were no announced diesel projects for the US in the NEWGen database. For new coal generation in the US, 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.[52] We use the same factor for new oil generation in the US 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.

*$NO_x$ emissions*

Estimating $NO_x$ emissions from future generation capacity changes in North America has similar challenges as with $SO_2$ in regards to pending $NO_x$ control measures and a patchwork of differing regulatory requirements within countries. For example, in the US, new power plants located in ozone nonattainment areas are subject to more stringent $NO_x$ controls than in attainment areas, including the need to obtain "offsets" of any $NO_x$ emissions from existing sources in the area. The revised eight-hour ozone and fine particulate health standards in the US 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 US EPA promulgated a regional ozone strategy in the eastern United States (the "$NO_x$ SIP Call") that will reduce $NO_x$ emissions in a number of eastern states.[53] 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 US-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. In Mexico, the *Comisión Federal de Electricidad* estimates $NO_x$ emissions will stablize between 2004 and 2006, due to greater use of natural gas with high efficiency (combined cycle).[54] As a result, the projections for $NO_x$ 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 $NO_x$ emissions

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[52] 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> (11 Sept. 2001).

[53] The $NO_x$ SIP Call is for attainment of the existing one-hour ozone standard in the US, 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 $NO_x$ SIP Call will also cover portions of Alabama, Georgia, Michigan, and Missouri. EPA is currently revising its methodology for calculating the $NO_x$ reduction obligations as the result of a court order. If the EPA revisions are upheld, we would expect a reduction in $NO_x$ emissions from eastern US electricity generating units of roughly 600,000 short tons by the 2007 five-month ozone season.

[54] Communication from Semarnat, April 2002.

associated with those projects may be offset from ongoing $NO_x$ control measures on existing plants that are not included in this study. Therefore, total $NO_x$ emissions from the electricity generation sector could decrease due to ongoing control programs that would more than offset $NO_x$ emissions from new power plants in 2007. Local or regional increases, on the other hand, could still occur, particularly outside of US ozone nonattainment areas.

As with the previous $SO_2$ estimates, we make varying assumptions for the $NO_x$ emission rates associated with generation capacity changes for each country. For natural gas in Canada and Mexico, we use the uncontrolled $NO_x$ emission factor from EPA AP-42 for natural gas turbines of 0.32 lb/mmBtu (140 kg/$10^6$ MJ).[55] For the United States, we take a different approach. There are a large number of proposed US natural gas generation projects in the NEWGen database. A significant number of these would be located in current one-hour ozone nonattainment areas where $NO_x$ 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 $NO_x$ controls on sources in their areas. For nonattainment areas without $NO_x$ waivers, we adopt a more stringent $NO_x$ limit of 0.01 lb/mmBtu (4 kg/$10^6$ MJ) for new natural gas combustion sources. Outside of nonattainment areas without $NO_x$ waivers, we assume Best Achievable Control Technology will apply, which is in the range of 0.04 to 0.10 lb/mmBtu in the US.[56] 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 $NO_x$ 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 $NO_x$ 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 $NO_x$ 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 $NO_x$ factor for coal assumes the same dry bottom, cell burner fired, bituminous coal combustion as assumed for the Rio Escondido and Carbón 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 $NO_x$ emission rate used by EPA to calculate state-level $NO_x$ budgets under the $NO_x$ SIP Call. The assumed $NO_x$ rate is 0.15 lb/mmBtu (64 kg/$10^6$ MJ). We apply the same $NO_x$ factor for new oil and gasoline generation in the US as with new coal on the assumption that these fuel types will have to meet at a minimum the same $NO_x$ limit as new coal. Our assumed $NO_x$ emission factor for oil and gasoline is 25 percent

[55] US 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).
[56] Communication from Amy Stillings, M.J. Bradley and Associates, Concord, MA (17 Sept. 2001).

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 US.

*Mercury emissions*
For estimating mercury emissions, we assume no controls specifically intended to reduce mercury at the combustion source. As noted previously, however, some preliminary results suggest the potential for substantial mercury reductions as a "co-benefit" from the application of certain $NO_x$ and $SO_2$ controls.[57] As these are still considered preliminary results, we do not include an assumption of additional mercury reductions from the application of $NO_x$ and $SO_2$ controls other than what is already assumed by the developers of the EPA AP-42 mercury emission factors. We note that if a significant mercury co-benefit is borne out by more research, our mercury emission projections could be significantly overestimated.

We use EPA AP-42 mercury emission factors for all fuel types in all three countries. The factor for natural gas is $2.6 \times 10^{-4}$ lb/$10^6$ scf ($4.15 \times 10^{-3}$ kg/$10^6$ $m^3$).[58] For new oil, we use the mercury emission factor for uncontrolled No. 6 oil of $1.13 \times 10^{-7}$ lb/gal ($1.35 \times 10^{-5}$ kg/$m^3$).[59] With new diesel and gasoline, we apply the factor for distillate fuel of 3 lb/$10^{12}$ Btu (1.29 picogram/Joule (pg/J)).[60] 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 $8.3 \times 10^5$ lb/ton ($4.2 \times 10^5$ kg/metric tonne).[61]

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: Emissions associated with planned electricity projects in Canada through 2007. This includes all announced projects in the supplemented NEWGen database (see text).

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[57] US EPA, "Performance and Cost of Mercury Emission Control Technology Applications on Electric Utility Boilers," EPA-600/R-00-083, National Risk Management Research Laboratory, Research Triangle Park, NC (Sept. 2000).

[58] US 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.

[59] US 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).

[60] US 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).

[61] US 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).

| Province/Territory | Annual $CO_2$ (tonnes) | Annual $SO_2$ (tonnes) | Annual $NO_x$ (tonnes) | Annual Hg (kg) |
|---|---|---|---|---|
| Alberta | 11,724,264 | 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** | **18,828,537** | **-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 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 US.[62] Pollution in New Brunswick could decrease for all four pollutants due to a proposed 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 US 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 $NO_x$ emissions at other boilers using coal. The extent of these reductions, however, is uncertain at this point.[63]

[62] Lalonde, Michelle, "Economy before emissions," *Montreal Gazette*, 4 October 2001 (quoting Quebec Environment Minister André Boisclair as saying that the 800 MW of power is needed to fill rising demand in the US).
[63] Communication from OPG, 15 October 2001.

*Table 11*. Mexico high boundary case: 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 $NO_x$ (tonnes) | Annual Hg (kg) |
|---|---|---|---|---|
| Aguascalientes | 0 | 0 | 0 | 0 |
| Baja California | 3,182,718 | 17 | 9,259 | 7 |
| Baja California Sur | 410,018 | 1,234 | 507 | 7 |
| Campeche | 189,681 | 102 | 496 | 1 |
| Chiapas | 0 | 0 | 0 | 0 |
| Chihuahua | 776,144 | 4 | 2,258 | 2 |
| Coahuila | 155,108 | 1 | 451 | 0 |
| Colima | 0 | 0 | 0 | 0 |
| Distrito Federal | 0 | 0 | 0 | 0 |
| Durango | 548,330 | 3 | 1,595 | 1 |
| Guanajuato | 1,165,592 | 6 | 3,391 | 3 |
| Guerrero | 8,467,729 | -32,518 | 63,547 | 165 |
| Hidalgo | 0 | 0 | 0 | 0 |
| Jalisco | 0 | 0 | 0 | 0 |
| Mexico | 151,799 | 1 | 442 | 0 |
| Michoacán | 0 | 0 | 0 | 0 |
| Morelos | 20,272 | 65 | 23 | 0 |
| Nayarit | 0 | 0 | 0 | 0 |
| Nuevo León | 2,540,960 | 14 | 7,392 | 6 |
| Oaxaca | 0 | 0 | 0 | 0 |
| Puebla | 0 | 0 | 0 | 0 |
| Querétaro | 207,335 | 1 | 603 | 0 |
| Quintana Roo | 530,262 | 11,348 | 1,095 | 2 |
| San Luis Potosí | 8,340,340 | 55,738 | 22,066 | 25 |
| Sinaloa | 0 | 0 | 0 | 0 |
| Sonora | 990,629 | 5 | 2,882 | 2 |
| Tabasco | 0 | 0 | 0 | 0 |
| Tamaulipas | 9,492,467 | 51 | 27,614 | 22 |
| Tlaxcala | 3,151 | 0 | 9 | 0 |
| Veracruz | 8,649,978 | 46 | 25,164 | 20 |
| Yucatán | 2,376,601 | 13 | 6,914 | 6 |
| Zacatecas | 0 | 0 | 0 | 0 |
| **National Total** | **48,199,112** | **36,131** | **175,707** | **270** |

In the Mexico high boundary case, the five states with the greatest potential emissions of $CO_2$ from new fossil fuel capacity changes are, in decreasing order, Tamaulipas, Veracruz, Guerrero, San Luis Potosí, and Baja California. The five states with highest $SO_2$ emissions are San Luis Potosí, Quintana Roo, Baja California Sur, Campeche, and Morelos. For $NO_x$, the five highest are Guerrero, Tamaulipas, Veracruz, San Luis Potosí, and Baja California. For mercury, the five highest are Guerrero, San Luis Potosí, Tamaulipas, Veracruz, and Baja California.

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

| State | Annual $CO_2$ | Annual $SO_2$ | Annual $NO_x$ | Annual Hg |
|---|---|---|---|---|

| | (tonnes) | (tonnes) | (tonnes) | (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 US 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 $NO_x$, the five top states are Texas, Kentucky, Illinois, Alabama, and Ohio. Interestingly, four of the five top states for potential $NO_x$ emissions in the high boundary case are states partly or entirely within the $NO_x$ SIP Call region. Only the top state, Texas, is outside the area subject to a $NO_x$ cap during the five month ozone season. Presumably, the new sources in the $NO_x$ SIP Call region will have to reduce $NO_x$ emissions at the planned facilities beyond what we assume in our estimates and obtain any needed additional offsetting reductions from existing $NO_x$ sources in order to comply with the state $NO_x$ 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: 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 $NO_x$ (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 | 0 | 0 | 0 | 0 |
| 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** | **3,743,487** | **20** | **10,890** | **9** |

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, Alberta, Saskatchewan, British Columbia, and New Brunswick. 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. On a national basis, we project $SO_2$ emissions to not change significantly in the low boundary case due to the absence of new coal capacity.

As suggested in the high boundary case, the size of the emission increases in the low boundary case, in particular the relative small changes in $SO_2$ and mercury emissions, will not be the result if new coal capacity becomes available in Alberta. The NEWGen database of capacity additions that we use in this analysis was updated as of August 2001. Since that time, Alberta Environment informed us that about 1400 MW in expanded coal capacity has advanced through public hearings.[64] If this expanded coal capacity was included in the low boundary case of Table 13, the estimated $CO_2$ emissions would increase by about an additional 700,000 tonnes, $SO_2$ by about 14,000 tonnes, $NO_x$ by 9,900 tonnes, and mercury by about 160 kilograms. Clearly, if the expanded coal capacity in Alberta was included in Table 13, the potential emissions would be significantly higher in Canada than shown here. Additional reductions in $SO_2$ and $NO_x$ from existing sources in eastern Canada, however, may occur through application of new control measures so that the increase in at least some of the pollutants in the low boundary case could be offset by future reductions from existing sources.

*Table 14*. Mexico low boundary case: 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 $NO_x$ (tonnes) | Annual Hg (kg) |
|---|---|---|---|---|
| Aguascalientes | 0 | 0 | 0 | 0 |
| Baja California | 2,856,750 | 15 | 8,311 | 7 |
| Baja California Sur | 24,841 | 0 | 72 | 0 |
| Campeche | 189,681 | 102 | 496 | 1 |
| Chiapas | 0 | 0 | 0 | 0 |
| Chihuahua | 350,810 | 2 | 1,021 | 1 |
| Coahuila | 155,108 | 1 | 451 | 0 |
| Colima | 0 | 0 | 0 | 0 |
| Distrito Federal | 0 | 0 | 0 | 0 |
| Durango | 0 | 0 | 0 | 0 |
| Guanajuato | 1,165,592 | 6 | 3,391 | 3 |
| Guerrero | 8,467,729 | -32,518 | 63,547 | 165 |
| Hidalgo | 0 | 0 | 0 | 0 |
| Jalisco | 0 | 0 | 0 | 0 |
| Mexico | 3,963 | 0 | 12 | 0 |
| Michoacán | 0 | 0 | 0 | 0 |
| Morelos | 20,272 | 65 | 23 | 0 |
| Nayarit | 0 | 0 | 0 | 0 |
| Nuevo León | 2,540,960 | 14 | 7,392 | 6 |
| Oaxaca | 0 | 0 | 0 | 0 |
| Puebla | 0 | 0 | 0 | 0 |
| Querétaro | 207,335 | 1 | 603 | 0 |
| Quintana Roo | 530,262 | 11,348 | 1,095 | 2 |
| San Luis Potosí | 2,262,513 | 55,706 | 4,385 | 10 |
| Sinaloa | 0 | 0 | 0 | 0 |
| Sonora | 565,295 | 3 | 1,644 | 1 |
| Tabasco | 0 | 0 | 0 | 0 |
| Tamaulipas | 2,417,195 | 13 | 7,032 | 6 |
| Tlaxcala | 3,151 | 0 | 9 | 0 |
| Veracruz | 2,815,264 | 15 | 8,190 | 7 |
| Yucatán | 1,136,042 | 6 | 3,305 | 3 |

[64] Comments from Alberta Environment, Policy Secretariat (26 February 2002).

| | | | | |
|---|---|---|---|---|
| Zacatecas | 0 | 0 | 0 | 0 |
| **National Total** | **25,712,762** | **34,779** | **110,978** | **212** |

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, Guerrero, Baja California, Veracruz, Nuevo León, and Tamaulipas. For $SO_2$ emissions, the top five are San Luis Potosí, Quintana Roo, Campeche, Morelos, and Baja California. For $NO_x$ emissions, the states are Guerrero, Baja California, Veracruz, Nuevo León, and Tamaulipas. For mercury, they are Guerrero, San Luis Potosí, Baja California, Veracruz, and Nuevo León.

*Table 15*. United States low boundary case: Emissions associated with planned electricity projects in US 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 $NO_x$ (tonnes) | Annual Hg (kg) |
|---|---|---|---|---|
| Alabama | 17,090,015 | 90 | 10,662 | 40 |
| Alaska | 0 | 0 | 0 | 0 |
| Arizona | 12,885,790 | 68 | 8,039 | 30 |
| Arkansas | 4,645,202 | 22 | 2,548 | 11 |
| California | 15,522,640 | 82 | 1,392 | 36 |
| Colorado | 1,443,834 | 8 | 901 | 3 |
| Connecticut | 3,936,962 | 21 | 351 | 9 |
| Delaware | 1,471,098 | 1,153 | 887 | 28 |
| District of Columbia | 0 | 0 | 0 | 0 |
| Florida | 20,756,616 | -53,170 | -8,442 | 12 |
| Georgia | 12,851,370 | 471 | 8,480 | 31 |
| Hawaii | 0 | 0 | 0 | 0 |
| Idaho | 218,120 | 1 | 136 | 1 |
| Illinois | 24,360,757 | -11,621 | 14,012 | 60 |
| Indiana | 9,463,233 | 50 | 5,936 | 22 |
| Iowa | 248,602 | 284 | 479 | 1 |
| Kansas | 333,164 | 165 | 395 | 1 |
| Kentucky | 8,235,273 | 2,681 | 5,385 | 76 |
| Louisiana | 12,405,479 | 65 | 7,775 | 29 |
| Maine | 2,774,367 | 15 | 1,731 | 6 |
| Maryland | 5,405,806 | 935 | 1,080 | 32 |
| Massachusetts | 8,982,646 | -7,174 | -412 | 24 |
| Michigan | 13,301,580 | 468 | 8,756 | 32 |
| Minnesota | 1,165,427 | -896 | -1,096 | -4 |
| Mississippi | 19,655,653 | 2,318 | 12,471 | 93 |
| Missouri | 5,401,569 | 2,747 | 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 | -16 | 610 | 18 |
| New Mexico | 1,284,485 | 7 | 801 | 3 |
| New York | 3,865,463 | 323 | 2,199 | 10 |
| North Carolina | 4,465,404 | 23 | 2,786 | 10 |
| North Dakota | 0 | 0 | 0 | 0 |
| Ohio | 9,501,598 | 1,248 | 6,298 | 34 |

| | | | | |
|---|---|---|---|---|
| Oklahoma | 11,349,517 | 59 | 7,081 | 26 |
| Oregon | 1,699,519 | 9 | 1,060 | 4 |
| Pennsylvania | 10,731,495 | -14,628 | -1,174 | 67 |
| Rhode Island | 1,346,589 | 7 | 120 | 3 |
| South Carolina | 2,723,100 | -5,758 | 143 | -5 |
| South Dakota | 0 | 0 | 0 | 0 |
| Tennessee | 6,099,790 | 32 | 3,806 | 14 |
| Texas | 46,344,749 | 244 | 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** | **-77,468** | **147,150** | **1,039** |

In the US 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 $NO_x$ 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*. New emissions in the Canada high boundary scenario (Table 10) relative to the historical reference emissions inventory (Table 1).

| Province/Territory | %$CO_2$-high | %$SO_2$-high | %$NO_x$-high | %Hg-high |
|---|---|---|---|---|
| Alberta | 23 | 15 | 25 | 30 |
| British Columbia | 26 | 1 | 34 | --- |
| Manitoba | 0 | 0 | 0 | 0 |
| New Brunswick | -3 | -23 | -2 | -9 |
| Newfoundland | 0 | 0 | 0 | --- |
| Northwest Territories | 0 | 0 | 0 | --- |
| Nova Scotia | 23 | 0 | 21 | 2 |
| Ontario | 8 | 0 | 8 | 1 |
| Prince Edward Island | 0 | 0 | 0 | 0 |
| Quebec | 161 | 0 | 158 | --- |
| Saskatchewan | 2 | 0 | 2 | 0 |
| Yukon | 0 | 0 | 0 | --- |
| **National Total** | **15** | **-1** | **14** | **11** |

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

*Table 17*. New emissions in the Canada low boundary scenario (Table 13) relative to the historical reference emissions inventory (Table 1).

| Province/Territory | %$CO_2$-low | %$SO_2$-low | %$NO_x$-low | %Hg-low |
|---|---|---|---|---|
| Alberta | 2 | 0 | 4 | 0 |
| British Columbia | 10 | 0 | 12 | --- |
| Manitoba | 0 | 0 | 0 | 0 |
| New Brunswick | 1 | 0 | 1 | 0 |
| Newfoundland | 0 | 0 | 0 | --- |
| Northwest Territories | 0 | 0 | 0 | --- |
| Nova Scotia | 0 | 0 | 0 | 0 |
| Ontario | 6 | 0 | 7 | 1 |
| Prince Edward Island | 0 | 0 | 0 | 0 |
| Quebec | 0 | 0 | 0 | --- |
| Saskatchewan | 2 | 0 | 2 | 0 |
| Yukon | 0 | 0 | 0 | --- |
| **National Total** | **3** | **0** | **4** | **0** |

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

*Table 18*. New emissions in the Mexico high boundary scenario (Table 11) relative to the historical reference emissions inventory (Table 2).

| State | %$CO_2$-high | %$SO_2$-high | %$NO_x$-high | %Hg-high |
|---|---|---|---|---|
| Aguascalientes | 0 | 0 | 0 | 0 |
| Baja California | 158 | 0 | 239 | 233 |
| Baja California Sur | 94 | 23 | 72 | 746 |
| Campeche | --- | --- | --- | --- |
| Chiapas | --- | --- | --- | --- |
| Chihuahua | 16 | 0 | 24 | 19 |
| Coahuila | 1 | 0 | 0 | 0 |
| Colima | 0 | 0 | 0 | 0 |
| Distrito Federal | 0 | 0 | 0 | 0 |
| Durango | 23 | 0 | 35 | 30 |
| Guanajuato | 28 | 0 | 42 | 43 |
| Guerrero | 1112 | -18 | 4309 | 1604 |
| Hidalgo | 0 | 0 | 0 | 0 |
| Jalisco | --- | --- | --- | --- |
| Mexico | 4 | 0 | 6 | 6 |
| Michoacán | --- | --- | --- | --- |
| Morelos | --- | --- | --- | --- |
| Nayarit | --- | --- | --- | --- |
| Nuevo León | 229 | 0 | 113 | 92 |
| Oaxaca | --- | --- | --- | --- |
| Puebla | --- | --- | --- | --- |
| Querétaro | 22 | 0 | 34 | 19 |
| Quintana Roo | 230 | 3057 | 318 | 340 |
| San Luis Potosí | 319 | 103 | 435 | 631 |
| Sinaloa | 0 | 0 | 0 | 0 |
| Sonora | 20 | 0 | 31 | 31 |
| Tabasco | --- | --- | --- | --- |
| Tamaulipas | 191 | 0 | 286 | 297 |
| Tlaxcala | --- | --- | --- | --- |
| Veracruz | 72 | 0 | 108 | 105 |
| Yucatán | 148 | 0 | 224 | 188 |
| Zacatecas | 0 | 0 | 0 | 0 |
| **National Total** | **53** | **2** | **63** | **24** |

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*. New emissions in the Mexico low boundary scenario (Table 14) relative to the historical reference emissions inventory (Table 2).

| State | %$CO_2$-low | %$SO_2$-low | %$NO_x$-low | %Hg-low |
|---|---|---|---|---|
| Aguascalientes | 0 | 0 | 0 | 0 |
| Baja California | 142 | 0 | 215 | 209 |
| Baja California Sur | 6 | 0 | 10 | 6 |
| Campeche | --- | --- | --- | --- |
| Chiapas | --- | --- | --- | --- |
| Chihuahua | 7 | 0 | 11 | 9 |
| Coahuila | 1 | 0 | 0 | 0 |
| Colima | 0 | 0 | 0 | 0 |
| Distrito Federal | 0 | 0 | 0 | 0 |
| Durango | 0 | 0 | 0 | 0 |
| Guanajuato | 28 | 0 | 42 | 43 |
| Guerrero | 1112 | -18 | 4309 | 1604 |
| Hidalgo | 0 | 0 | 0 | 0 |
| Jalisco | --- | --- | --- | --- |
| Mexico | 0 | 0 | 0 | 0 |
| Michoacán | --- | --- | --- | --- |
| Morelos | --- | --- | --- | --- |
| Nayarit | --- | --- | --- | --- |
| Nuevo León | 229 | 0 | 113 | 92 |
| Oaxaca | --- | --- | --- | --- |
| Puebla | --- | --- | --- | --- |
| Querétaro | 22 | 0 | 34 | 19 |
| Quintana Roo | 230 | 3057 | 318 | 340 |
| San Luis Potosí | 86 | 103 | 86 | 269 |
| Sinaloa | 0 | 0 | 0 | 0 |
| Sonora | 12 | 0 | 17 | 18 |
| Tabasco | --- | --- | --- | --- |
| Tamaulipas | 49 | 0 | 73 | 76 |
| Tlaxcala | --- | --- | --- | --- |
| Veracruz | 24 | 0 | 35 | 34 |
| Yucatán | 71 | 0 | 107 | 90 |
| Zacatecas | 0 | 0 | 0 | 0 |
| **National Total** | **29** | **2** | **40** | **19** |

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*. New emissions in the US high boundary scenario (Table 12) relative to the historical reference emissions inventory (Table 3).

| State | %$CO_2$-high | %$SO_2$-high | %$NO_x$-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 US 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*. New emissions in the US low boundary scenario (Table 15) relative to the historical reference emissions inventory (Table 3).

| State | %$CO_2$-low | %$SO_2$-low | %$NO_x$-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 US 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 parentheses). $CO_2$, $SO_2$, and $NO_x$ amounts are in metric tonnes. Mercury (Hg) amounts are in kilograms.

| Country scenario | Annual $CO_2$ | Annual $SO_2$ | Annual $NO_x$ | Annual Hg |
|---|---|---|---|---|
| Canada reference inventory | 122,000,000 | 650,195 | 290,211 | 1,975 |
| Canada high boundary 2007 | 18,828,537 (+15%) | -3,917 (-1%) | 41,910 (+14%) | 221 (+11%) |
| Canada low boundary 2007 | 3,743,487 (+3%) | 20 (0%) | 10,890 (+4%) | 9 (0%) |
| Mexico reference inventory | 90,095,882 | 1,683,199 | 280,931 | 1,117 |
| Mexico high boundary 2007 | 48,199,112 (+53%) | 36,131 (+2%) | 175,707 (+63%) | 270 (+24%) |
| Mexico low boundary 2007 | 25,712,762 (+29%) | 34,779 (+2%) | 110,978 (+40%) | 212 (+19%) |
| US reference inventory | 2,331,958,813 | 12,291,107 | 5,825,982 | 39,241 |
| US high boundary 2007 | 875,036,007 (+38%) | 64,580 (+1%) | 459,286 (+8%) | 5,762 (+15%) |
| US low boundary 2007 | 333,347,795 (+14%) | -77,468 (-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 $CO_2$ emissions from projected electricity capacity changes would be 15 percent of the reference inventory emissions. This provides a relative sense of the scale of potential emission changes. This, however, is not a projection of the total emissions increase from all electric power generation, as emissions from existing sources could decrease due to potential generation displacement by newer power plants or the installation of new pollution controls.