Impacts of Canadian Electricity and Gas Exports in the United States for Natural Resources Canada

Prepared by Ziff Energy
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# NRC GREENHOUSE IMPACT

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EXECUTIVE SUMMARY

A large share of Canadian hydroelectricity and more than half of Canadian gas production are exported to the United States. Because hydroelectricity and natural gas are low greenhouse gas emission energy sources, Canadian electricity and natural gas exports contribute to reducing U.S. greenhouse gas emissions. Natural Resources Canada has retained Ziff Energy Group to assess alternatives that the United States would have to electricity and natural gas exports from Canada.

Electricity Trade

While net Canadian exports of electricity equal only about 1% of total U.S. electricity sales in 2000, they play a much larger role in the Northeast and Midwest United States. The U.S. Northeast is the most heavily dependent U.S. region on Canadian electricity exports, and the U.S. West the least dependent of the major importing regions. In fact, through the first six months of 2001, the U.S. West has been a net exporter of electricity to Canada.

An ending of net Canadian electricity exports to the United States can be accommodated by increased generation of electricity from existing U.S. power plants. In the Northeast, this would principally be increased use of oil-fired generation. For oil-fired generation to totally offset net Canadian electricity exports to the U.S. Northeast, about 40,000 barrels per day (bpd) of additional residual fuel oil would have to be consumed.

In the Midwest, increased use of existing nuclear or coal-fired capacity could offset net Canadian electricity exports to the Midwest. However, almost all Canadian exports go to Minnesota and the available nuclear capacity is in Michigan. As a result, the extent to which nuclear could offset an ending of Canadian electricity exports to the Midwest would be strongly affected by the availability of electricity transmission capacity within the Midwest.

Electricity trade between the United States and Canada appears to principally reflect the economic and environmental attractiveness of Canadian electricity exports relative to the generation of that electricity from existing coal or oil-fired power plants in the Midwest or Northeast. As a result, an ending of net Canadian electricity exports to the United States could be accommodated by heavier utilization of existing electricity generation capacity, although at higher economic and environmental costs. Sufficient electricity generation capacity exists in the Midwest and Northeast to allow new nuclear or more “environmentally friendly” coal-fired capacity to be brought on line in the medium to long term to meet long-term growth.

Gas Trade

Net Canadian gas exports to the United States (9.5 Bcf/d) only account for about 15% of total U.S. gas supply, but they play a much larger role in the principal importing regions. About 30% of the gas consumed in the Northeast, Midwest, and California comes from Canada. Almost all of the gas consumed in the Pacific Northwest comes from Canada.
While various forecasts expect that Canadian gas exports will grow in the coming decade, this growth will be much smaller than in the previous 15 years. An ending of Canadian gas exports would pose significant challenges to the U.S. energy market, particularly in the Pacific Northwest. The major alternative source of new gas supply to the United States would be liquefied natural gas (LNG) from other countries or, towards the end of the period, Alaska. However, LNG is not a near-term alternative.

While LNG currently provides only about 1% of U.S. gas supply, that share is expected to grow in the future. The United States has four existing LNG terminals, but only two are currently operating. All four existing LNG terminals should be operating by mid-2002. The capacity of the four existing terminals (including proposed expansions) is 3.4 Bcf/d, and future expansions could bring their capacity to more than 4 Bcf/d.

Ten new terminals are currently proposed for the United States and Mexico. The initial capacity of the proposed new terminals is 6 Bcf/d, but this capacity could probably be expanded to approach 10 Bcf/d. Most of these proposed terminals have expected operation dates in the 2005-2007 timeframe. In addition, LNG deliveries from Alaska could develop towards the end of the decade (2008+) and provide an additional 2-3 Bcf/d to Pacific Coast gas markets.

An ending of Canadian gas exports would create strong pressure to bring these proposed terminals into operation and to develop additional terminal sites as well. As a result, LNG deliveries to U.S. gas markets could grow substantially in the coming decade to offset the ending of Canadian gas exports, potentially reaching 12 Bcf/d by 2010. Under this scenario, an ending of Canadian gas exports could be mostly offset by increased LNG imports by the end of the decade. The remainder of the “lost” Canadian exports would be offset by increased coal consumption and conservation.

While LNG exports might be able to offset an ending of Canadian gas exports to the United States in the long term, an ending of Canadian gas exports would have significant short-term and mid-term effects on U.S. gas supply and demand. Because U.S. gas production has only grown modestly, despite record gas rig activity, U.S. gas supply (65 Bcf/d) might not return to its 2000-2001 levels until about 2005, when LNG supply from new terminals begins to surge. This would probably lead to significant surges in near-term gas prices, which could make alternative sources of electricity generation more economic than new gas-fired combined cycle plants. Because such an ending of Canadian gas exports would be driven primarily by greenhouse gas concerns, this would probably make nuclear and integrated gas combine cycle (IGCC), coal gasification into a combined cycle plant, the more attractive alternatives, but not until after 2005.

An ending of Canadian gas exports to the United States would remove 9.5 Bcf/d of gas supply from the U.S. energy mix. In the near-term, 4 BcfE/d could be replaced by increased oil imports and about 1 Bcf/d by increased nuclear or coal-fired electricity generation. An additional one Bcf/d each would be replaced by increased efficiency in California electricity generation as combined cycle plants displace steam plants and the return of more normal hydroelectric outputs. The remaining 2.5 Bcf/d would need to be met by conservation.

The increase of about 4 BcfE/d of oil imports (700,000 bpd) would probably remain through 2005 before it would begin to decline noticeably. The decline would reflect continued growth in LNG
imports and U.S. production and large scale displacements of steam-fired electricity generation by combined cycle in the Gulf Coast that free up Gulf Coast gas supplies for other regions. By 2007, increased oil imports due to an ending of Canadian gas exports would be largely over.

The absence of Canadian gas exports would also lead to increased coal and oil consumption to meet increased energy demand that would have been met by gas in the coming decade. The main impact would be in electricity generation, where coal-based generation would be the principal alternative. Although interest in nuclear has revived in the United States, it has not revived to the point of new plant orders. Because of the strong concerns about global warming, IGCC technology would be a more likely option for new coal-based electricity generation to replace new gas-fired combined cycle capacity.

Under the scenario of an ending of Canadian gas exports, coal consumption could grow almost two quads between 2000 and 2010 to replace new gas-fired generation that would have developed with the availability of Canadian gas exports to the United States. In a scenario where LNG supplies would grow to offset most of an ending of Canadian gas exports to the United States by 2010, most of the growth in coal consumption would occur by 2005. However, because of the lower incremental costs of coal-based generation from an existing plant, this new coal consumption is likely to be long term, despite a recovery of U.S. gas supplies as a result of increased LNG imports.

Some increased oil consumption could also develop in this scenario, but it would be largely confined to the Atlantic Coast, and would be less than 100,000 barrels per day (bpd). With the growth in U.S. gas supplies due to increased LNG imports, the incremental demand for oil would probably largely end by 2010.
INTRODUCTION

A large share of Canadian hydroelectricity and more than half of Canadian gas production are exported to the United States. Because hydroelectricity and natural gas are low greenhouse gas emission energy sources, Canadian electricity and natural gas exports contribute to reducing U.S. greenhouse gas emissions. Natural Resources Canada has retained Ziff Energy Group to assess alternatives that the United States would have to electricity and natural gas exports from Canada.

U.S. alternatives to Canadian electricity and natural gas exports over the next ten years would be affected by near-term or longer-term considerations. In the near term, the critical issue will be the availability of alternative electricity or gas supply sources. In the longer term, new investments can be made in new alternative sources, such as new coal-fired or nuclear power plants or LNG facilities. Because current industry investment plans envision natural gas as the major source of new electricity generation capacity, an ending of or even a reduction in net gas exports from Canada to the United States would also affect U.S. electricity generation.

ELECTRICITY

Canadian electricity exports to the United States set a new record level in 2000 of \(48.5\) terawatt hours (TWh), \(8\%\) of total Canadian electricity generation. While this was only \(1\%\) of total U.S. electricity sales, Canadian electricity exports played a much larger role in some areas of the United States. For example, net Canadian electricity exports to the U.S. Northeast in 2000 equaled \(6\%\) of electricity sales in that region.

The U.S. market also plays an important role in Canadian electricity generation activity. Electricity exports from New Brunswick and Manitoba were about one fourth of electricity generation in those provinces in 2000. Electricity exported from Quebec (including Labrador) and British Columbia was in the \(9-15\%\) range of electricity generation in those provinces. Exports from Ontario were less than \(3\%\) of electricity generation in that province. Exports from the remaining provinces were less than \(1\%\) of their electricity generation.
Canada-U.S. Electricity Trade

Canada-U.S. electricity trade is a two-way street. Figure 1 shows Canada-U.S. electricity trade since 1985. Electricity trade in 2001 is estimated based on data for the first six months of 2001. Canadian electricity exports tailed off in the late 1980s, but recovered in the mid-1990s. Despite the record level of exports in 2000, Canadian electricity exports have been quite stable since 1994, averaging 42.9 TWh per year with a standard deviation of less than 7%.

Figure 1
Canadian Electricity Trade with United States

Canadian imports of electricity from the United States, however, have grown during the 1990s, and are on a pace to set a record in 2001. Because imports have grown since the mid-1990s, net Canadian exports of electricity have declined since the mid-1990s. In 2001, they may be the lowest since 1991.
Canada-U.S. electricity trade is concentrated in the Northeast, where Canadian electricity plays an important role in electricity supply. In the Midwest and Western states, Canadian electricity plays a very modest role, accounting for only about 1% of regional electricity supply. Figure 2 presents Canada-U.S. electricity trade by region for 2000 and as estimated for 2001 based on the first six months of data. Net exports of Canadian electricity to the U.S. Northeast in 2001 appear to be running at their 2000 levels. Net exports to the Midwest states may be slightly lower in 2001.

The greatest change is in the West. Canadian exports of electricity to the Western United States have declined, while imports of U.S. electricity in the West have surged. If Canada-U.S. electricity trade remains at their six-month trend for the rest of 2001, Western Canada will be a net importer of electricity from the United States in 2001.

**Figure 2**

*Canadian Electricity Trade with United States*

The impact of Canada-U.S. electricity trade on U.S. electricity generation is significant. In 2001, net Canadian electricity exports to the United States are even more heavily concentrated in the U.S. Northeast. Exports to the Midwest are eroding, and exports to West have ended. If net exports of electricity from Canada to the United States were to end after 2001, this would reduce electricity supplies in the Northeast and Midwest United States, but slightly increase supplies in the Western United States. The critical issue is what are the options to replace net deliveries of Canadian electricity to the Northeast and Midwest United States.
1. Northeast United States

The Northeast United States is comprised of New England and the Middle Atlantic States, nine states in all (Figure 3). Net Canadian electricity exports to the Northeast have grown noticeably in the late 1990s. About two thirds of the net exports goes to New England, and the remaining one third to the Middle Atlantic states.

![Figure 3: U.S. Northeast](image)

In 2000, net Canadian electricity exports to New England were 14.3 TWh, 12% of New England electricity sales. Net exports to the Middle Atlantic States were 8.7 TWh, less than 3% of Middle Atlantic electricity sales. Because of the strong electricity links between New England and the Middle Atlantic States, the assessment of alternatives to net Canadian electricity exports will treat the U.S. Northeast as a whole.
Existing nuclear and coal-fired electricity generation capacity is utilized quite heavily in the Northeast. In 2000, the capacity factor of nuclear power plants averaged almost 89%. As a result, prospects for increased generation from nuclear plants in the U.S. Northeast would depend on upgrading the capacity of existing plants. Some upgradings have begun in the United States, adding up to 5% to the capacity of existing nuclear plants (e.g. Browns Ferry 2, Browns Ferry 3, Perry1).

Coal-fired power plants are also highly utilized in the U.S. Northeast. In 2000, their capacity factor averaged 73%. However, in many U.S. regions, capacity factors for coal plants currently average well above 80%. As a result, some potential for increased coal-fired generation of electricity exists in the U.S. Northeast.

The U.S. Northeast has a third option, oil-fired electricity. While oil-fired generation has declined substantially in the 1980s and 1990s, most oil-fired capacity is still available (34,635 MWe). If net Canadian electricity exports were to end in 2002, oil-fired generation would be a critical near-term option to maintain electricity supplies in the U.S. Northeast.

Table 1 summarizes electricity generation options in the U.S. Northeast if net Canadian electricity exports were to end. The table includes reported nuclear, coal-fired, and oil-fired electricity generation capacity. (Data are from the 1999 U.S. Department of Energy, Energy Information Administration (EIA) electricity capacity reports. Heat rates are estimated from historical averages.)

<table>
<thead>
<tr>
<th>Category</th>
<th>Incremental Supply</th>
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<tbody>
<tr>
<td>Net Exports from Canada (2001 est)</td>
<td>22.0</td>
</tr>
<tr>
<td>1996-2000 average electricity growth (TWh/yr)</td>
<td>3.7</td>
</tr>
<tr>
<td>Available Electricity Supplies</td>
<td></td>
</tr>
<tr>
<td>Nuclear (22.4 GWe capacity)</td>
<td></td>
</tr>
<tr>
<td>@85% average c.f.</td>
<td>0.0</td>
</tr>
<tr>
<td>@88% average c.f.</td>
<td>0.0</td>
</tr>
<tr>
<td>With 2% capacity upgrade</td>
<td>3.9</td>
</tr>
<tr>
<td>Coal-Fired Plants (27.4 GWe capacity)</td>
<td></td>
</tr>
<tr>
<td>@75% average c.f.</td>
<td>8.1</td>
</tr>
<tr>
<td>@80% average c.f.</td>
<td>20.1</td>
</tr>
<tr>
<td>Heat rate = 10,200 Btu/kWh</td>
<td></td>
</tr>
<tr>
<td>Oil-Fired Plants (34.6 GWe)</td>
<td></td>
</tr>
<tr>
<td>@33% c.f.</td>
<td>60.8</td>
</tr>
<tr>
<td>Heat rate = 10,500 Btu/kWh</td>
<td></td>
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</table>
Nuclear is not a likely option for near-term incremental electricity generation in the U.S. Northeast unless existing capacity is increased via power upgrades. A 2% power upgrade could add only 4 TWh to New England electricity supply, not even 20% of estimated net electricity exports from Canada in 2001.

Coal-fired capacity can provide much more incremental supply, but could not offset net Canadian electricity exports unless coal-fired capacity factors average more than 80% during the year.

Table 1 suggests that ending net electricity exports from Canada to the Northeast United States is likely to lead to a large jump in oil-fired electricity generation. The potential incremental electricity supply showed in Table 1, which is almost three times net Canadian exports, would entail the consumption of an additional 100,000 barrels per day (bpd) of residual fuel oil. For oil-fired generation to totally offset net Canadian exports to the U.S. Northeast, about 40,000 bpd of additional residual fuel oil need to be burned to generate the required electricity.

The demand for electricity in the U.S. Northeast has grown 3.7 TWh per year between 1996 and 2000. If the average oil-fired capacity factor reached the 33% level indicated in Table 1, the Northeast might be able to meet its entire growth in electricity demand for much of the coming decade using existing capacity. If gas is not available to generate increased electricity in the Northeast, Table 1 indicates that the U.S. Northeast may have sufficient electricity capacity available to meet electricity demand until alternative coal-fired or nuclear capacity is constructed, if electricity generation from existing oil-fired capacity can be increased in the Northeast.
2. Midwest

The Midwest United States is comprised of the East North Central and West North Central states, 12 states in all (Figure 4). Because of the strong interconnections among midwestern states, the assessment of alternatives to net Canadian electricity exports will treat the U.S. Midwest as a whole.

Net Canadian electricity exports to the Midwest declined in the late 1990s. In 2000, net Canadian electricity exports to the West North Central States were 7.5 TWh, 3% of West North Central electricity sales in 2000. Almost all (99.6%) of these exports were to Minnesota from Manitoba. Net exports to the East North Central States were less than 0.1 TWh, not even 0.01% of East North Central electricity sales in 2000. The negligible level of net exports to the East North Central states reflects the offsetting effects of electricity imports from Michigan by Ontario. Through the first six months of 2001, Ontario has been a net importer of electricity from Michigan.
With the exception of Michigan, existing nuclear electricity generation capacity is currently utilized very heavily in the Midwest. In 2000, the capacity factor of nuclear power plants averaged almost 94% outside of Michigan. In Michigan, the capacity factor averaged 55%, largely because Cook 1 only began operating during summer 2000. As a result, prospects for increased generation from existing nuclear plants in the Midwest outside of Michigan would depend on upgrading the capacity of existing plants.

Coal-fired power plants are not as highly utilized as Northeast coal-fired capacity. In 2000, the capacity factor for coal-fired plants in the Midwest averaged only 62%, below average utilization in the United States as a whole. Substantial potential exists for increased coal-fired generation of electricity in the U.S. Midwest.

Table 2 summarizes electricity generation options in the U.S. Midwest if net Canadian electricity exports were to end. The table includes the reported nuclear and coal-fired generation capacity. (Data are from the 1999 U.S. Department of Energy, Energy Information Administration (EIA) electricity capacity reports. Heat rates are estimated from historical averages.)

| Table 2 | Near-Term Electricity Generation Options |
| U.S. Midwest (TWh) |
| Category | Incremental Supply |
| Net Exports from Canada (2001 est) | 6.6 |
| 1996-2000 average electricity growth (TWh/yr) | 15.3 |
| Available Electricity Supplies |
| Nuclear (22.8 GWe capacity) |
| @85% average c.f. (Michigan only) | 10.2 |
| @88% average c.f. (Michigan only) | 11.3 |
| With 2% capacity upgrade | 15.3 |
| Coal-Fired Plants (27.4 GWe capacity) |
| @75% average c.f. | 142.0 |
| @80% average c.f. | 194.9 |
| Heat rate = 10,600 Btu/kWh |

The potential for increased nuclear generation in Michigan exceeds net exports from Canada to the Midwest. Because the net exports are almost all to Minnesota and the available nuclear capacity is in Michigan, the electricity transmission network within the Midwest will affect the extent to which Michigan nuclear power could offset the need for electricity exports from Manitoba to Minnesota. To the extent that the transmission grid cannot accommodate a nuclear/export “transfer,” coal-fired capacity would have to be utilized to replace the net exports from Canada.
Table 2 shows that existing capacity could also be able to meet the growth in Midwest electricity demand over the next decade, even with limited growth in gas-fired electricity generation. This reflects the large amount of unused coal-fired capacity in the Midwest.

**Electricity Observations**

The electricity trade between the United States and Canada appears to be driven principally by the fact that Canadian electricity exports are more economically or environmentally attractive than the generation of that electricity from existing coal or oil-fired power plants in the Midwest or Northeast. As a result, an ending of net Canadian electricity exports to the United States could be accommodated by heavier utilization of existing electricity generation capacity. Sufficient capacity exists in the Midwest and Northeast to allow new nuclear or more environmentally friendly coal-fired capacity to be brought on line to meet long-term growth. As will be seen in the following discussion on Canadian gas exports, an ending of Canadian gas exports to the United States may make these non gas-fired alternatives economically attractive.

**NATURAL GAS**

The United States receives natural gas from three general sources: U.S. production, Canada, and LNG. In 2000, net exports from Canada provided 15% of U.S. gas supply, and LNG provided 1%. U.S. production provided the remaining 84%. Most forecasts expect Canadian gas exports to continue to grow, although at a slower rate. While LNG provides only 1% of U.S. gas supply, that share is expected to grow substantially in the next decade as two existing terminals resume operation by 2002 and new terminals are constructed.

As in the case of net electricity exports, Canadian natural gas exports play a much larger role in U.S. regional gas markets. About 30% of the gas consumed in the Midwest, Northeast, and California comes from Canada. In the Pacific Northwest states of Oregon and Washington, almost all gas supplies come from Canada.
Overall U.S. Gas Supply Scenarios

The most recent U.S. Department of Energy, Energy Information Administration (EIA) long-term forecast (AEO 2001) expects that U.S. gas supply will grow to almost 29 Tcf by 2010. Figure 5 shows that most of the growth in U.S. gas supply will come from U.S. production. The EIA forecast expects that U.S. gas production will grow about 1 Bcf/d per year between 2000 and 2010, reaching 23.1 Tcf in 2010. Almost half of this growth occurs in the Gulf Coast (offshore and onshore), reflecting growing production from the Deepwater Gulf and deeper sediments (onshore and offshore). About one fourth of the growth occurs in the Rocky Mountains.

Figure 5
U.S. DOE U.S. Gas Supply Forecast
(AEO 2001)

Canadian gas exports grow, but at a much slower rate than in the previous decade. By 2010, net Canadian gas exports reach 4.8 Tcf, more than one third higher than in 2000. While LNG imports more than double, these imports would not fully use the capacity (actual plus planned expansions) at the Everett, Massachusetts, and Lake Charles, Louisiana, terminals (2 Bcf/d) by 2010. Given that the two terminals at Elba Island, Georgia, and Cove Point, Maryland, will re-open in the next 12 months and interest in new LNG terminals is surging, LNG imports will probably be much larger than expected in AEO 2001.

If net Canadian gas exports were to end in 2002, total U.S. gas supply would decline 15% in that year. Under the prices of the AEO 2001 reference case, U.S. gas supply would not return to its 2000 level of 22.8 Tcf until 2010. While gas prices would surge if Canadian gas exports ended, their impact on U.S. gas production is uncertain. The recent surge in gas prices and gas drilling activity
has not been followed by a comparable surge in U.S. gas production. Company reports through the first two quarters of 2001 suggest that U.S. gas production in 2001 has only increased about one Bcf/d, despite the record level of gas rig activity. This suggests that LNG may have to play the dominant role in offsetting any decline in Canadian gas exports while also providing increased gas supply to meet a growing U.S. demand for gas.

Figure 6 shows existing and currently proposed LNG terminal sites in the United States. The United States has four existing LNG terminals, two of which (Everett and Lake Charles) are operating. Elba Island is planned to resume operation in late 2001, and Cove Point in 2002. The total capacity of these four terminals (including proposed expansions at Everett and Lake Charles) is 3.4 Bcf/d. Both Cove Point and Elba Island could be expanded, which would probably bring capacity at all four terminals to more than 4 Bcf/d.

**Figure 6**
North American LNG Terminals

**Existing Terminals**
- a. Everett, MA: 0.45 Bcf/d, exp. 0.7 Bcf/d (Tractebel)
- b. Cove Point, MD: 0.75 Bcf/d, 2002 (Williams)
- c. Elba Island, GA: 0.67 Bcf/d, late 2001 (El Paso)
- d. Lake, Charles, LA: 0.7 Bcf/d, possible expansion to 1.3 Bcf/d (CMS)

**Proposed Terminals**
1. Radio Island, NC: 0.25 Bcf/d, 2005+ (El Paso)
2. Bahamas: 0.5 Bcf/d, 2005 (Enron/El Paso)
3. Tampa, FL: 0.5 Bcf/d, 2005+ (BP)
4. Hackberry, LA: 0.75 Bcf/d, 2003 (Dynegy)
5. Gulf of Mexico: 1 Bcf/d, 2005 (Texaco)
6. Freeport, TX: 0.55 Bcf/d, 2005+ (Cheniere LNG Partners)
7. Brownsville, TX: 0.55 Bcf/d, 2006 (Cheniere LNG Partners)
8. Altamira, Tamulipas: 0.5-1 Bcf/d, 2004 (El Paso)
9. Baja California: 0.7 Bcf/d, 2005 (El Paso)
10. California: 0.5 Bcf/d, 2005 (Chevron)

The initial capacity of the currently proposed ten terminals is 6 Bcf/d, but this capacity can probably be expanded. For example, the Hackberry LNG terminal proposed by Dynegy has an announced initial capacity of 0.75 Bcf/d, but could expand capacity to 1.5 Bcf/d. As a result, the final capacity of the currently proposed terminals could approach 10 Bcf/d, about the level of current net Canadian gas exports to the United States. If Canadian gas exports to the United States fell off significantly,
these terminals or comparable ones would probably begin operation in the coming decade. If Canadian gas exports remain near current levels, only about 3 Bcf/d of this proposed capacity would likely begin operation in the coming decade.

Most of the proposed terminals have expected operation dates in the 2005-2007 time frame. The earliest announced operation date of a new terminal is late 2003 for the Hackberry facility proposed by Dynegy. Thus, these proposed terminals are not a near-term option to offset a decline in net Canadian gas exports to the United States. Over the medium to longer term, they are a serious option.

If net Canadian gas exports tail off significantly, particularly to the West Coast, Alaska could become a source for LNG deliveries to Pacific Coast gas markets. This might provide an additional 2-3 Bcf/d of gas supply to Pacific Coast gas markets by 2008-2010 over and above the potential in Figure 6.

Figure 7 presents the U.S. gas supply outlook under the scenario that net Canadian gas exports end in 2002. LNG exports grow substantially, reaching 12 Bcf/d (4.4 Tcf) by 2010. More than 40% of this volume would probably be imported through the four existing (but expanded) terminals. The critical uncertainty is whether liquefaction capacity will develop in exporting countries or Alaska to fill this demand.

Figure 7
U.S. Gas Supply Scenario
in Absence of Canadian Exports
Despite the surge in LNG imports and near-term growth of U.S. gas production on the order of one Bcf/d per year, U.S. gas supply would not return to its 2001 level until 2005. The large growth in LNG imports, however, would not bring U.S. gas supply back to 29 Tcf by 2010, the level expected by EIA in its reference case forecast for 2010 (AEO 2001). The “lost” gas supply would be replaced by increased coal consumption to generate electricity or conservation as a result of the higher prices that would develop upon an ending of Canadian gas exports.

**Near-Term Impacts**

An ending of Canadian exports to the United States would be regionally concentrated. In the **U.S. Northeast**, net Canadian gas exports were almost 3 Bcf/d in 2000, 32% of Northeast gas supply. The volume of Canadian gas exports is comparable to gas sales (utility and non-utility) to generate electricity in the U.S. Northeast. In the near term, most of this loss would be offset by increased oil consumption and the capacity expansion planned for the Everett, Massachusetts, LNG terminal (250 MMcf/d). If Canadian gas exports were totally offset by increased oil consumption, this would imply that an additional 500,000 bpd of distillate and residual fuel oil would have to be imported in the Northeast for a few years until LNG capacity expands or alternative electricity generation capacity is constructed.

In the **U.S. Midwest**, net Canadian gas exports were 3.5 Bcf/d in 2000, 31% of Midwest gas supply in 2000. Because of the surplus coal-fired capacity available in the Midwest, an ending of Canadian gas exports to the Midwest would be reflected first in a displacement of gas-fired electricity generation (about 0.9 Bcf/d). About one third of the remaining 2.6 Bcf/d of gas supply might be replaced by oil, but the remaining two thirds would have to be obtained from U.S. production and LNG. If this additional supply is not available, Midwest gas demand could fall below 3 Tcf.

In **California**, net Canadian gas exports were 1.8 Bcf/d, 30% of California gas supply in 2000. California gas consumption was at a record 2.2 Tcf (6.1 Bcf/d) in 2000, but about 1 Bcf/d of this demand reflects low hydroelectric production. Exclusive of variations in hydroelectric output, California consumes about 3 Bcf/d of gas to generate electricity. The opening of the more than 8,000 MWe of combined cycle capacity in the state offers an opportunity to reduce gas demand by replacing less efficient gas-fired steam generation. Coupled with the strong conservation in electricity demand that has occurred in California during 2001 (electricity demand down 6% through June), a return to more normal water flows, and displacement of steam-fired generation by combined cycle generation, California might be able to weather an ending of net Canadian gas exports. However, if water flows remain low, then additional gas would be needed to generate electricity or electricity supplies would suffer a shortfall.

The **Pacific Northwest states** of Washington and Oregon are the most vulnerable to an ending of Canadian gas exports because of their location. The gas market in these states has grown 50% since 1995, reaching 1.5 Bcf/d in 2000, and almost all of this gas comes from Canada. In the near term, there is no gas alternative to Canadian gas in the Pacific Northwest. Even if U.S. production were available, new pipeline capacity would be needed before that gas could reach the Pacific Northwest. While the Northwest Pipeline can deliver gas to the Pacific Northwest from Wyoming, gas markets in Idaho and Northern Nevada currently “use” almost all of this capacity. The only near-term alternatives to gas would be large imports of oil to replace gas where it could be replaced, but this...
would be limited to about 20-30% of total Pacific Northwest gas demand in the near term. This suggests that oil imports might increase about 50,000 bpd.

**Longer-Term Impacts**

The fall-off in U.S. gas supply between 2002 and 2005 indicates that gas prices would be under severe pressure during much of the decade. The upward pressure will be particularly severe through the middle of the decade, but that pressure should ease off as LNG imports continue to grow. Because the growth in U.S. gas demand in the coming decade depends heavily on price-sensitive industrial and electricity generation sales, the near-term price surge will probably reduce U.S. gas demand below the levels expected in the EIA reference case for 2000.

Current, longer-term NYMEX strip prices are approaching US$4 per MMBtu. This implies a burnertip price to electricity generators near or above US$4.50 per MMBtu. This is about the price at which alternative fuels become economically attractive relative to gas-fired technology. Figure 8 shows the costs of electricity generation for new nuclear, coal-fired, integrated gas combined cycle (IGCC), which is coal gasification plus a combined cycle plant, and gas-fired combined cycle plants (selected gas prices). Because of the time frames to construct new coal-based or nuclear generation capacity, new coal-based or nuclear plant orders are not likely to begin operation before 2006 unless they have already been ordered.

**Figure 8**

Nominal Busbar Costs (80% c.f.)

If exports from Canada were to end in 2002, near-term gas prices could surge well above the point at which alternative fuels would become attractive electricity generation options. Because this scenario
would be driven by greenhouse gas concerns, nuclear and IGCC technologies would probably be the more attractive alternatives. Interest in nuclear power has revived in the United States. However, because no new nuclear plants have yet been ordered and nuclear plants are likely to not be available until towards the end of this decade, nuclear will not be considered an alternative to gas-fired combined-cycle generation plants in the next 5-7 years.

Interest in IGCC technology picked up during the winter 2000-2001 gas price spike. The IGCC technology can be used as a new plant, or the gasifier component could be added to an existing gas-fired combined cycle plant if gas prices were thought to remain high for a sustained period of time. As a result, coal gasifiers added to gas-fired combined cycle plants provide a reasonable near-term option to provide electricity generation if Canadian gas exports were to end.

The AEO 2001 expects that U.S. gas consumption to generate electricity would grow 3 Tcf (8.2 Bcf/d) between 2000 and 2010. Because the time frame to construct a new coal-based generation plant is on the order of 4-5 years, near-term substitutions of coal for new gas-fired generation would involve construction of gasifiers to attach to the front end of new gas-fired combined cycle power plants fired or increased utilization of existing coal-fired capacity. In this a scenario, coal use to generate electricity could increase almost 2 quads by 2010, with more than three fourths of that growth occurring by 2005. As new LNG deliveries bring U.S. gas supply back to its expected growth path in AEO 2001, a growing share of new electricity generation capacity could once again become gas-fired.

Oil consumption could also increase to offset limited gas supplies to non electricity generation customers on the Atlantic coast, but this substitution would be modest and would not last the entire decade. Based on AEO 2001 trends, oil consumption could increase 100,000 bpd by 2005. However, as gas supplies continue to grow after 2005, gas could back out most of this increased oil consumption.

**Gas Observations**

An ending of Canadian gas exports to the United States would have significant effects on some parts of the Midwest and Pacific Northwest, but much less effects on the Northeast and California. This is because the Northeast and California have sufficient alternatives to minimize near-term disruptions due to an ending of Canadian gas exports until longer-term options, such as increased U.S. gas production and new LNG capacity, allow gas supplies to grow once again in these regions. Problems in the Midwest would last longer, but would probably be largely over by the middle of the decade. Problems in the Pacific Northwest would be quite severe and probably long term because of its effectively total dependence on Canadian gas.

Overall, an ending of Canadian gas exports to the United States would remove 9.5 Bcf/d, about 15% of gas supply from the U.S. energy mix. In the near-term, 4 BcfE/d could be replaced by increased oil imports and about 1 Bcf/d by increased nuclear or coal-fired electricity generation. An additional one Bcf/d each would be replaced by increased efficiency in California electricity generation as combined cycle plants displace steam plants and the return of more normal hydroelectric outputs. The remaining 2.5 Bcf/d would need to be met by conservation.
The increase of about 4 BcfE/d of oil imports would probably remain through 2004 before it would begin to decline noticeably. The decline would reflect continued growth in LNG imports and U.S. production and large scale displacements of steam-fired electricity generation by combined cycle in the Gulf Coast that free up Gulf Coast gas supplies for other regions. By 2007, the increased oil imports due to an ending of Canadian gas exports should be largely over.

Under the scenario of an ending of Canadian gas exports, coal consumption could grow almost two quads between 2000 and 2010 to replace new gas-fired generation that would have developed with the availability of Canadian gas exports to the United States. In a scenario where LNG supplies grow to offset an ending of Canadian gas exports to the United States by 2010, most of the growth in coal consumption would occur by 2005. However, because of the lower incremental costs of coal-based generation from an existing plant, this new coal consumption is likely to be long term, despite the recovery of U.S. gas supplies as a result of increased LNG imports.

Some increased oil consumption could also develop in this scenario, but it would be largely confined to the Atlantic Coast, and would be less than 100,000 bpd. With the growth in U.S. gas supplies due to increased LNG imports, the incremental demand for oil is likely to largely end by 2010.