Summary of Key Findings

The following information supplements the conclusions and recommendations with an overview of the findings from the three task groups. Additional detail on the findings, assumptions, sensitivities, and model output can also be found in the task group reports.

The various projections and sensitivities presented in this report were prepared using market simulation models developed by Energy and Environmental Analysis, Inc. (EEA). The oil and gas supply projections were prepared using the GRI Hydrocarbon Supply Model, which was integrated with the gas demand, storage, and transportation elements of EEA’s Gas Market Data and Forecasting System.

The GRI Hydrocarbon Supply Model was originally developed by EEA for the Gas Research Institute (GRI) in the early 1980s and was the basis for the gas supply projections and scenario analysis for the 1992 NPC Study on natural gas. The model characterizes oil and gas exploration, development, and production in nineteen U.S. and five Canadian regions. Each region is further broken down into four to eight subareas, usually representing drilling depths on onshore regions or water depths for offshore regions. Proved reserves and undiscovered resources for gas are divided into associated-dissolved gas, conventional high permeability gas, tight gas, shales, and coalbed methane. The Hydrocarbon Supply Model provides the user with a wide range of options for selecting assumptions for resource base, drilling and development cost, technological improvements, upstream environmental compliance costs, land access, and financial parameters.

The Hydrocarbon Supply Model’s projection of future natural gas deliverability by region was used in the Gas Market Data and Forecasting System to solve for monthly gas production, storage activity, pipeline flows, end-use consumption, and prices at locations in the United States, Canada, and the Mexico/U.S. border. This model was used to project gas demand in the United States and Canada and to determine the pipeline and storage infrastructure that would be economically justified in the various cases developed for this report. Key inputs to the model that can be varied among cases include a wide variety of drivers to gas demand and infrastructure-related parameters such as the cost of new pipeline and storage facilities.

Each task group established key assumptions and identified the variables that could significantly influence the model in their study area. Some of the key assumptions used in the 1999 Study for the 1999–2015 period are listed in Table 1. As indicated in Table 1, the model uses a U.S. GDP growth rate of 2.5% per year throughout the study period. This rate is below the rate at which GDP has grown in recent years. However, history has shown that recessions have interrupted periods of significant growth and resulted in a lower average growth over an extended period. The
Council concluded that a 2.5% growth rate was reasonable, but sensitivity analyses were conducted to test the effects of both higher and lower rates. The Canadian GDP growth rate was assumed to be 2.2%, or 0.3% lower than the U.S. rate, reflecting a relative value that has prevailed over the last 10 years.

The crude oil prices used in the model were selected to approximate the average real prices experienced in the 70 years from 1929 to 1998. These crude oil prices affect the outcome of the model by determining the wellhead values of crude oil and natural gas, thereby setting the price of fuel oils that compete with natural gas in end-use markets. The oil prices also strongly influence the amount of capital that producers have available for reinvestment in exploration and production development. Sensitivity analyses were run to test the effect of both higher and lower oil prices.

Findings of the Demand Task Group

Demand Finding 1: Rapid growth exceeded expectations of the 1992 Study.

Consumption of natural gas grew much faster in the 1990-98 period than was anticipated. Despite the warmer-than-normal weather that prevailed in 1998, demand grew over that nine-year period in all end-use categories. The various studies of natural gas demand that have been conducted in the past decade have consistently underestimated actual growth in demand. The 1992 NPC Study was no exception, as shown in Figure 2. The High Reference Case in the 1992 Study projected that total demand could grow from 19.3 TCF in 1990 to 24.8 TCF in 2010, with 1998 projected at 20.9 TCF. Actual demand in 1998 was 22 TCF (including net storage fill), or about 1 TCF ahead of the level forecast for 1998 in the 1992 Study.

Several factors caused the 1992 Study to underestimate actual growth in gas demand. Growth in GDP was assumed to be 2.4% annually and actual growth for the 1990-98 period was 2.6%. Although energy intensity measured by Btu per unit of growth declined between 1990 and 1998, it declined at a much slower rate than the 1992 Study had anticipated. Most of the increased gas demand occurred because of an increase in total energy demand.

Gas demand grew during this period, even as the market was restructured significantly. In 1990, prior to the restructuring, over 90% of the gas moving in interstate pipelines was owned by the pipeline companies. FERC actions in the early 1990s have transformed interstate pipelines from sellers and transporters to solely open-access transporters. Many state regulatory agencies and LDCs are moving toward the same type of transformation.

In addition, major consolidations have occurred within the gas industry in anticipation of and response to the restructuring of the gas and electric industries. Numerous combinations of energy service providers have occurred within and across industry segments, as evidenced by the combinations of gas and electric companies. In most cases, mergers have been driven by the need to improve competitive position through economies of scale, greater geographic spread, more diversified services, and acquisition of expertise. These actions, along with increasing competition, have resulted in services that are generally more responsive to customer needs and are provided at lower prices.

The gas delivery system has remained the safest form of transport and continues to provide reliable service despite these massive
changes. Natural gas consumption has grown to a degree that its most ardent supporters would have found amazing at the time the 1992 NPC study was prepared.

U.S. natural gas consumption is projected to grow from 22 TCF in 1998 to 29 TCF in 2010 and could increase beyond 31 TCF in 2015 (see Table 2). Canadian gas demand is expected to rise from 2.8 TCF in 1998 to 3.5 TCF in 2010 and 3.8 TCF in 2015.

The most significant growth in gas demand is projected to be for electricity generation. In the 1992 Study, increased penetration of the electricity generation market was an expectation. Today—as result of dramatic improvements in heat rate for combined-cycle gas/oil generating equipment, the relatively low capital cost of such plants, the relatively short construction time required to bring them on line, tighter emission standards for electricity generation, and the deregulation of the electricity industry—gas is the preferred choice of the electricity generation industry for new generating plants. Currently, 98% by capacity of the 243 electricity generating plants that have been announced for construction in the next five years are to be gas-fired; the remaining 2% by capacity will be fueled by coal, oil, wastewood, wood, wind, and other.1

A number of key assumptions were made concerning electricity generation. One assumption was that 113 gigawatts of gas/oil combined-cycle and gas-fired combustion turbine capacity would be operating by 2010 (an increase from 25 gigawatts in 1998) and a total of 140 gigawatts by 2015 to satisfy incremental electricity demand. The 1999 Study determined that, through 2010, the cost of electricity generated from new coal plants (including capital costs) would not be competitive with electricity from new gas units, but that after 2010 an estimated 20 gigawatts of new coal capacity would be built. Heat rates for all classes of electricity generation are assumed to improve 3 percentage points between 1998 and 2015. Seventy percent of

---

1 Source: Online data base at Resource Data International, Inc. (July 1999).

### Table 2: U.S. Natural Gas Consumption (Trillion Cubic Feet)

<table>
<thead>
<tr>
<th>Year</th>
<th>Residential</th>
<th>Commercial</th>
<th>Industrial</th>
<th>Electric</th>
<th>Total</th>
<th>Net Output/Fuel Balancing</th>
</tr>
</thead>
<tbody>
<tr>
<td>1998</td>
<td>5.6</td>
<td>3.0</td>
<td>2.6</td>
<td>3.2</td>
<td>14.4</td>
<td>0.6</td>
</tr>
<tr>
<td>2005</td>
<td>6.6</td>
<td>3.7</td>
<td>2.6</td>
<td>5.1</td>
<td>18.0</td>
<td>0.1</td>
</tr>
<tr>
<td>2010</td>
<td>7.0</td>
<td>3.8</td>
<td>2.8</td>
<td>5.5</td>
<td>21.1</td>
<td>0.1</td>
</tr>
<tr>
<td>2015</td>
<td>7.5</td>
<td>3.9</td>
<td>2.8</td>
<td>6.0</td>
<td>22.2</td>
<td>0.0</td>
</tr>
</tbody>
</table>

Historical data include all gas use, for industrial cogeneration and independent power producers. All gas for new power plants except cogeneration is included in the electricity generation sector.

combined-cycle plants are assumed to be capable of burning either gas or oil and would therefore switch fuels depending on cost. Coal capacity utilization was assumed to increase 11 percentage points from 64% in 1997 to 75% by 2015, continuing the trend observed in the last 10 years (Figure 15). However, this continuing increase in capacity utilization is recognized as a significant challenge for those facilities. Adding to this concern is the legal action taken in November 1999 by the EPA against several large utility companies, charging that their coal-fired plants had effectively added to their capacity during maintenance without installing new pollution control equipment. This recent action could have the impact of lowering coal capacity utilization, thus increasing demand for natural gas.

No new nuclear capacity was projected to be developed in the timeframe of this study and an estimated 15 gigawatts of nuclear generation capacity is projected to retire by 2015 as some licenses expire. The Demand Task Group projected that 15 gigawatts of nuclear capacity would be relicensed, and that a total nuclear capacity of approximately 80 gigawatts would remain in operation in 2015. The electricity generation industry has increasingly relied on its nuclear generation capacity, as seen in Figure 16. With the resumption of service at the Clinton, LaSalle, and Millstone units in the spring of 1999, nuclear capacity utilization reached an unprecedented peak of 96.5% in August 1999. This compares to the previous peak capacity utilization of 86% in July 1998 and the historical average of approximately 75%. The average annual capacity utilization of nuclear generating capacity is assumed to increase from 75% to 80% over the study period. Nuclear retirements beyond the few projected in this study could significantly increase natural gas demand in the 2010–2015 time frame.

Hydroelectric and renewable generation are assumed to remain nearly constant throughout this case, although hydroelectric generation could diminish due to environmental concerns about the adverse impact of dams on anadromous fish populations, espe-

![Figure 15. U.S. Central Utility Coal-Fired Electricity Generation Capacity Utilization](image-url)
Figure 16. Total U.S. Daily Nuclear Capacity Utilization

![Graph showing historical nuclear capacity utilization](image)


cially in the Pacific Northwest. However, such declines are assumed to be nearly offset by increased generation from renewable energy such as wind and solar. Increases in renewable capacity are evident because of existing and growing demand for "green power," and state-level legislation calling for renewable portfolio standards.

The Demand Task Group recognized that assumptions for key variables have a significant impact on ultimate demand. As discussed, assumptions were made for the Reference Case about the rate of increase in GDP, prices of competitive fuels (e.g., fuel oil and coal), construction of new gas-fired generating plants, the retirement of nuclear plants, and utilization rates of gas, coal, and nuclear plants. The highest-impact variables were tested with sensitivity analyses. GDP growth and oil prices proved to be significant drivers of gas demand. For example, if GDP growth were to average 3.0% per year rather than 2.5%, demand could increase by 0.6 TCF in 2010. An average GDP growth of 2.0% could result in 0.9 TCF lower demand in 2010. If oil prices were $3.50 higher than assumed in the Reference Case, demand could increase by 0.7 TCF. Conversely, if oil prices were $3.50 lower, demand could be 1.0 TCF lower than the Reference Case.

The assumptions regarding other fuels that are used for electricity generation can also have a large impact on demand. For example, if the capacity utilization factor of coal-fired plants is 65% rather than the 75% assumed in this study, gas demand could increase by 1.7 TCF. If an additional 15 gigawatts of nuclear retirements were to occur, demand
could increase as much as 0.7 TCF. Further detail on these sensitivities is included in the Demand Task Group Report.

The potential 29 TCF demand projected for 2010 does not include the effect of environmental and other regulations that are not currently scheduled for implementation. New legislation or policy initiatives that might be implemented to address global climate change could substantially increase gas demand. For example, the Energy Information Administration (EIA) and the Edison Electric Institute (EEI) have conducted separate studies of the impact of meeting the U.S. target under the Kyoto protocol. These studies, which are discussed in the Demand Task Group Report, confirm that substantial reductions in coal and oil consumption would be required with a concomitant increase in gas demand. These studies examine various scenarios and indicate an increase in gas demand of 2-12% in the case of EIA, and 10-22% in the case of EEI above their respective reference cases.

While the 1999 NPC Study did not specifically analyze the effect of new environmental regulation, correlations can be made with other factors that affect demand and price. For example, the sensitivity analysis that examined a decrease in the utilization rate of coal-fired electricity generation capacity—which could easily occur with new environmental regulation—indicated that a significant corresponding increase in demand would occur.

Findings of the Supply Task Group

The estimated resource base of 1,466 TCF for the lower-48 states in the 1999 Study represents a 171 TCF increase from the 1,295 TCF used in the 1992 Study (see Figure 4 and Table 3). In addition, Canada's resource base is estimated at 667 TCF. Canada's resource base is approximately 73 TCF lower than determined in the 1992 Study due to depletion and reassessment of nonconventional resources.

The Supply Task Group's team of industry experts on resource assessment conveys a high level of confidence in the robustness of the U.S. resource base. This team notes that the 171 TCF increase in the resource base has occurred despite production in the lower-48 states of 124 TCF of reserves from 1991 through 1997. The increase in the estimated resource base is primarily derived from technology improvements. For example, advances in computer technology have yielded breakthroughs in data processing, integration, and imaging, which have in turn vastly improved reservoir modeling. This information enables better projections of the size and location of hydrocarbon deposits. Technology has also played a significant role in improving drilling and completion techniques, thus improving access to the resource base. The major contributors to increases in the resource base are:

- **Old Field Reserve Appreciation.** The application of new technology has helped in the assessment of hydrocarbons in known fields. The new information has resulted in an increase of 69 TCF in the estimates of the resource base in "Old Fields."

- **New Fields Primarily in the Deepwater Gulf of Mexico.** New information and improved interpretations have also yielded increases in projections for New Fields—fields that are theoretically in place but are yet to be discovered. For example, estimates of New Fields resources in deepwater Gulf of Mexico have increased to 140 TCF, a 145% increase from the 57 TCF estimate in the 1992 Study.

Figures 17a and 17b show the U.S. and Canadian assessment regions and the "Assessed Additional Resources" for each region, which is the sum of Old Field growth, New Field discoveries, and unconventional gas sources. Two areas, the Rocky Mountain Foreland and the Central and Western Gulf of...
<table>
<thead>
<tr>
<th></th>
<th>1992 NPC Study*</th>
<th>1999 NPC Study</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(1-1-91)</td>
<td>(1-1-98)</td>
</tr>
<tr>
<td><strong>LOWER-48 RESOURCES</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Proved Reserves</td>
<td>160</td>
<td>157</td>
</tr>
<tr>
<td>Assessed Additional</td>
<td>1,135</td>
<td>1,309</td>
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<tr>
<td>Resources</td>
<td></td>
<td></td>
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<tr>
<td>Old Fields (Reserve</td>
<td>236</td>
<td>305</td>
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<tr>
<td>Appreciation)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>New Fields</td>
<td>493</td>
<td>633</td>
</tr>
<tr>
<td>Nonconventional</td>
<td>406</td>
<td>371</td>
</tr>
<tr>
<td>**Total Remaining</td>
<td>1,295</td>
<td>1,466</td>
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<tr>
<td>Resources (Proved +</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Assessed Additional)</td>
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<td></td>
</tr>
<tr>
<td><strong>Cumulative Production</strong></td>
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<td>881</td>
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<td>**Total All-Time</td>
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<td>2,347</td>
</tr>
<tr>
<td>Recovery**</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>ALASKAN RESOURCES†</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Proved Reserves</td>
<td>9</td>
<td>10</td>
</tr>
<tr>
<td>Assessed Additional</td>
<td>171</td>
<td>303</td>
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<tr>
<td>Resources</td>
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<td></td>
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<tr>
<td>Old Fields (Reserve</td>
<td>30</td>
<td>32</td>
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<tr>
<td>Appreciation)</td>
<td></td>
<td></td>
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<tr>
<td>New Fields</td>
<td>84</td>
<td>214</td>
</tr>
<tr>
<td>Nonconventional</td>
<td>57</td>
<td>57</td>
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<tr>
<td>**Total Remaining</td>
<td>180</td>
<td>313</td>
</tr>
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<td>Resources (Proved +</td>
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<td></td>
</tr>
<tr>
<td>Assessed Additional)</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Cumulative Production</strong></td>
<td>5</td>
<td>9</td>
</tr>
<tr>
<td>**Total All-Time</td>
<td>185</td>
<td>322</td>
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<tr>
<td>Recovery**</td>
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<td></td>
</tr>
<tr>
<td><strong>CANADIAN RESOURCES</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Proved Reserves</td>
<td>72</td>
<td>64</td>
</tr>
<tr>
<td>Assessed Additional</td>
<td>668</td>
<td>603</td>
</tr>
<tr>
<td>Resources</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Old Fields (Reserve</td>
<td>24</td>
<td>22</td>
</tr>
<tr>
<td>Appreciation)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Discovered Undeveloped</td>
<td>47</td>
<td>35</td>
</tr>
<tr>
<td>New Fields</td>
<td>379</td>
<td>384</td>
</tr>
<tr>
<td>Nonconventional</td>
<td>218</td>
<td>162</td>
</tr>
<tr>
<td>**Total Remaining</td>
<td>740</td>
<td>667</td>
</tr>
<tr>
<td>Resources (Proved +</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Assessed Additional)</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Cumulative Production</strong></td>
<td>65</td>
<td>103</td>
</tr>
<tr>
<td>**Total All-Time</td>
<td>805</td>
<td>770</td>
</tr>
<tr>
<td>Recovery**</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*Assessed Additional Resources from the 1992 Study reflect re-allocation of tight gas resources among categories consistent with 1999 Study allocations.

†Old Fields resource includes 25 TCF for Prudhoe Bay; New Fields resource is based on 1995 USGS/MMS assessment; and Nonconventional resource is PGC coalbed methane resource.

Obtained and made public by the Natural Resources Defense Council, March/April 2002
Alaskan resources were not assessed in this study.
Figure 17b. Assessed Additional Resources by Region

TRILLION CUBIC FEET

A: Appalachia
B: Eastern Gulf Onshore
C: North Central
D: Arkla - East Texas
E: South Louisiana
G: Texas Gulf Onshore
WL: Williston Basin
FR: Rocky Mtn. Foreland
SJB: San Juan Basin
CV: Overthrust Belt
JN: Mid-Continent
JS: Permian Basin
L: West Coast Onshore
BO: Eastern Gulf of Mexico
EGO: Cent. & West. Gulf of Mex.
LC: West Coast Offshore
AO: Atlantic Offshore
ASM: Alberta, Sas., Man.
BC: British Columbia
NWC: Northwest Canada
EC: Eastern Canada
ART: Arctic Canada

UNITED STATES

CANADA
Mexico, contribute almost half of the U.S. total. In Canada, the Western Sedimentary Basin (model region ASM) will provide a significant amount of the additional resource.

U.S. gas production is projected to increase from 19 TCF in 1998 to 25 TCF in 2010 and could approach 27 TCF in 2015. Canadian imports to the United States are projected to increase from 3 TCF in 1998 to 3.8 TCF in 2010 and could reach 4.4 TCF by 2015 (Table 4). Approximately 13–14% of U.S. gas supply will continue to come from Canada. LNG imports will reach 0.9 TCF using an average of 75% of existing U.S. capacity. No additional import facilities are projected in this study. Exports to Mexico are projected to increase in the near term to 0.4 TCF and remain at that level throughout the study period.

Future production will be from deeper wells, deeper water, and more nonconventional sources. As Table 5 demonstrates, lower-48 production will gradually increase from deeper wells. Onshore production from depths below 10,000 feet is projected to increase from 33% in recent years to over 40% by 2010. The industry's ability to achieve production from deeper horizons will be dependent on the appropriate amount of deep drilling infrastructure and the continued evolution of technology.

In the Gulf of Mexico, production from deeper waters will be the driving force in future supply growth, as demonstrated in Table 6. Production from water depths of more than 200 meters is projected to increase from 0.8 TCF in 1998 to over 4.5 TCF in 2010 and maintain approximately that level.

---

**TABLE 4**

U.S. GAS SUPPLY
(Trillion Cubic Feet)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>U.S. Gas Production</td>
<td>19.0</td>
<td>22.6</td>
<td>25.1</td>
<td>26.6</td>
</tr>
<tr>
<td>Net Imports from Canada</td>
<td>3.0</td>
<td>3.7</td>
<td>3.8</td>
<td>4.3</td>
</tr>
<tr>
<td>LNG Imports</td>
<td>0.1</td>
<td>0.4</td>
<td>0.6</td>
<td>0.9</td>
</tr>
<tr>
<td>Exports to Mexico and Japan</td>
<td>-0.1</td>
<td>-0.4</td>
<td>-0.5</td>
<td>-0.5</td>
</tr>
<tr>
<td>Total Supply</td>
<td>22.0</td>
<td>26.3</td>
<td>28.0</td>
<td>31.3</td>
</tr>
<tr>
<td>Canada as a % of Total</td>
<td>14%</td>
<td>14%</td>
<td>13%</td>
<td>13%</td>
</tr>
</tbody>
</table>

*Historical data from Energy Information Administration, Natural Gas Monthly, September 1998. Data include synthetic natural gas.

---

**TABLE 5**

ONSHORE LOWER-48 GAS PRODUCTION
BY DEPTH INTERVAL

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>0–5,000 ft</td>
<td>28%</td>
<td>27%</td>
<td>25%</td>
<td>25%</td>
</tr>
<tr>
<td>5–10,000 ft</td>
<td>39%</td>
<td>37%</td>
<td>34%</td>
<td>32%</td>
</tr>
<tr>
<td>10–15,000 ft</td>
<td>26%</td>
<td>20%</td>
<td>29%</td>
<td>32%</td>
</tr>
<tr>
<td>&gt; 15,000 ft</td>
<td>7%</td>
<td>10%</td>
<td>12%</td>
<td>11%</td>
</tr>
</tbody>
</table>

*Energy and Environmental Analysis, Inc., estimates adapted from Pl/Dwights production reports.
through 2015. Conversely, Gulf of Mexico shelf production is projected to decrease from 4.5 TCF in 1998 to 3.5 TCF in 2010 and around 3.0 TCF in 2015.

Growth in production from nonconventional sources will be especially pronounced in the Rocky Mountain region. Nonconventional production in this region is projected to increase from 1.9 TCF in 1998 to 2.9 TCF in 2010 and as much as 3.4 TCF in 2015. Production in the lower-48 states from nonconventional sources (i.e., the sum of tight gas, shales, and coalbed methane) accounted for 4.4 TCF of total production in 1998. This volume is projected to increase to 6.8 TCF in 2010 and could reach 8.5 TCF in 2015 (Table 7).

All of these new sources of gas require that significant technology hurdles be

| TABLE 6 |
| GULF OF MEXICO PRODUCTION BY WATER DEPTH |

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Gulf of Mexico Production (TCF/Year)</td>
<td>5.3</td>
<td>7.4</td>
<td>8.0</td>
</tr>
<tr>
<td>Conventional Production (%)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Shelf 0-40 meters</td>
<td>49%</td>
<td>27%</td>
<td>20%</td>
</tr>
<tr>
<td>Shelf 40-200 meters</td>
<td>35%</td>
<td>24%</td>
<td>20%</td>
</tr>
<tr>
<td>Slope 200-1,000 meters</td>
<td>14%</td>
<td>28%</td>
<td>25%</td>
</tr>
<tr>
<td>Slope 1,000-1,500 meters</td>
<td>10%</td>
<td>9%</td>
<td>13%</td>
</tr>
<tr>
<td>Slope &gt;1,500 meters</td>
<td>11%</td>
<td>8%</td>
<td>15%</td>
</tr>
<tr>
<td>Subsalt Production (%)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Shelf 40-200 meters</td>
<td>12%</td>
<td>3%</td>
<td>4%</td>
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<tr>
<td>Slope 200-1,000 meters</td>
<td>2%</td>
<td>2%</td>
<td>2%</td>
</tr>
<tr>
<td>Slope &gt;1,000 meters</td>
<td>0%</td>
<td>1%</td>
<td>1%</td>
</tr>
</tbody>
</table>

*Energy and Environmental Analysis, Inc., estimates adapted from PI/Dwights production reports.

| TABLE 7 |
| LOWER-48 PRODUCTION FROM CONVENTIONAL VS. NONCONVENTIONAL SOURCES |

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Associated Gas</td>
<td>14%</td>
<td>13%</td>
<td>14%</td>
</tr>
<tr>
<td>High Permeability Gas</td>
<td>60%</td>
<td>62%</td>
<td>59%</td>
</tr>
<tr>
<td>Tight Gas &amp; Shale Gas</td>
<td>20%</td>
<td>20%</td>
<td>21%</td>
</tr>
<tr>
<td>Coalbed Methane</td>
<td>6%</td>
<td>5%</td>
<td>6%</td>
</tr>
</tbody>
</table>

*Energy and Environmental Analysis, Inc., estimates adapted from PI/Dwights production reports.
addressed and overcome in order to deliver cost-competitive supply. Two sensitivity cases were developed to determine the impact on price and demand if technology develops at either a slower rate or a faster rate. When technology improvements developed more slowly than in the Reference Case, demand in 2010 fell by 0.7 TCF and price increased by $0.27 per MMBtu. Conversely, when the rate of technology improvements increased, demand increased by 0.7 TCF, and price decreased $0.32 per MMBtu.

Sensitivity analyses were also run on the size of the resource base to evaluate the impact of learning more about the resource base. An increase of 250 TCF in the economically recoverable resource base, beyond the 1,466 TCF Reference Case estimate, resulted in a decrease in gas price of $0.96 per MMBtu. Conversely decreasing the estimate of the resource base by 250 TCF from the 1,466 TCF estimate, increased the price by $0.56 per MMBtu. The sensitivity analyses indicated that the assumption on the size of the estimated resource base has the highest impact on the ability to produce competitively priced natural gas. This sensitivity analysis provides some insight into the impact of access issues since access restrictions remove potential supply from the available resource base.

Access issues limit the ability to reach known resources, slow down development in certain areas, and impede the construction of needed pipelines required to deliver natural gas to markets. For the purposes of the 1999 Study, the following assumptions were made with regard to access: (1) all scheduled lease sales will continue on time (including MMS Lease Sale 181 in the eastern Gulf of Mexico); (2) all existing regulatory requirements and restrictions on—and all current rights to drill on—public lands are honored; and (3) rights-of-way will be obtained for constructing and expanding any necessary pipeline infrastructure. If any of these assumptions fall short, the ability to explore for, produce, and deliver adequate supply will be hampered. Enabling access beyond that assumed in the Reference Case is necessary to improve availability and cost-competitiveness of gas supply in the time period of the 1999 Study.

Two areas that will significantly contribute to future gas supply are the Rocky Mountain region and the Gulf of Mexico, both of which have significant access restrictions. For example, approximately 9% of resource-bearing lands in the Rockies are completely inaccessible due to "no leasing" and "no surface occupancy" restrictions. Another 32% of resource-bearing lands are specifically subject to restrictions that delay development activity by an average of two years and add measurably to the cost of drilling wells on these properties. These restrictions mean that over 137 TCF of resources are subject to prohibitions or impediments. Another 76 TCF of resources are estimated for restricted offshore areas in the eastern Gulf of Mexico, the Atlantic, and the Pacific. Regardless of the lack of specific stipulations, nearly all public-lands acreage otherwise accessible for development regularly becomes encumbered to some degree in disputes among stakeholder groups and inconsistent application of regulatory policy by the governmental group(s) charged with managing these lands. These issues result in similar delays and added costs for offshore areas.

The 1999 Study assumes access to those tracts in planned MMS Lease Sale 181, but not the resources in the eastern Gulf of Mexico beyond the Norphlet Trend areas off Mississippi and Alabama. These areas have not been opened up and no plans to do so are currently in progress. Similarly, the Destin Dome area off the Panhandle of Florida was not assumed to be available for development in the Reference Case because the regulatory approval process was taking place during the time of this study.

Two sensitivity cases were developed to evaluate the impact of access on natural gas production. As seen in Table 8, the reduced access case assumed that further restrictions in the Rocky Mountain region would increase development costs and reduce the area that can be leased under standard terms. This case also assumed that the scheduled MMS Lease Sale 181 would not occur. The reduced access case resulted in a price increase of $0.16 per
TABLE 8
SUMMARY OF NPC FEDERAL LANDS AND WATERS ACCESS SENSITIVITIES

<table>
<thead>
<tr>
<th>Rocky Mountains</th>
<th>Reference Case</th>
<th>Increased Access Case</th>
<th>Reduced Access Case</th>
</tr>
</thead>
<tbody>
<tr>
<td>Standard Lease Terms</td>
<td>59%</td>
<td>59%</td>
<td>22%</td>
</tr>
<tr>
<td>Off Limits</td>
<td>9%</td>
<td>9%</td>
<td>14%</td>
</tr>
<tr>
<td>High Cost</td>
<td>32%</td>
<td>6%</td>
<td>64%</td>
</tr>
<tr>
<td>High Cost Penalty per Well Costs</td>
<td>0%</td>
<td>0%</td>
<td>6%</td>
</tr>
<tr>
<td>High Cost Delay</td>
<td>2 Years</td>
<td>None</td>
<td>2 Years</td>
</tr>
</tbody>
</table>

Eastern Gulf of Mexico

<table>
<thead>
<tr>
<th>Destin Dome</th>
<th>No Development</th>
<th>Production by Lease Sale in 2002</th>
<th>No Development</th>
</tr>
</thead>
<tbody>
<tr>
<td>MMS Lease Sale 181 Non-Sale 181</td>
<td>Lease Sale in 2001</td>
<td>Lease Sale in 2004</td>
<td>No Sale or Development</td>
</tr>
</tbody>
</table>

Other Offshore U.S.

<table>
<thead>
<tr>
<th>Pacific</th>
<th>No Development</th>
<th>Lease Sale in 2004</th>
<th>No Development</th>
</tr>
</thead>
<tbody>
<tr>
<td>Atlantic</td>
<td>No Development</td>
<td>Lease Sale in 2004</td>
<td>No Development</td>
</tr>
</tbody>
</table>

MMBtu in 2010 and a decrease in U.S. production of 0.5 TCF. The declines in production occurred primarily in the Rockies and the eastern Gulf of Mexico. The decrease in production in 2015 was 0.2 TCF, with a decrease in price of $0.08 per MMBtu. The changes that occurred in the reduced access sensitivity case were not pronounced, primarily because the access assumptions in the Reference Case were already very restrictive.

The second sensitivity case assumed that access restrictions would be relaxed in the Rockies, resulting in the elimination of high-cost delays. Currently restricted offshore areas were assumed to be open to leasing in 2004 and production from the area opened in MMS Lease Sale 181 would begin in 2002. This increased access case resulted in an increase in U.S. production of 0.5 TCF in 2010, 95% of which was in the Rockies and the eastern Gulf of Mexico. A corresponding increase in price of $0.21 per MMBtu accompanied this production increase. More importantly, a dramatic shift occurred in the Extended View period with an increase in U.S. production in 2015 of 1.6 TCF. This increase continued to be primarily from the Rockies and the Eastern Gulf of Mexico, with some Atlantic offshore production beginning in this time frame. Prices in 2015 decreased by $0.45 per MMBtu.
Supply Finding 3:
A healthy oil and gas industry is critical for natural gas supply to satisfy expected increases in demand.

Adequate financial performance must be demonstrated to compete for and attract financial investment.

The growth in gas demand projected in the 1999 Study will require approximately $658 billion (constant 1998 dollars) in upstream capital expenditures from 1999 through 2015. This figure includes all exploration, development, production, and gathering capital expenditures. A summary of the capital investment requirements projected by the Reference Case in the 1999 to 2015 study period is shown in Figure 9.

This supply growth will require an increased annual average capital expenditure of $39 billion per year from 1999 through 2015, versus an annual average of $27 billion from 1991 through 1998. However, these needed levels of investment will take place only if investors have confidence that competitive rates of return will be earned. In recent years, this has not been the case as the U.S. upstream sector has earned very modest rates of return. According to the Financial Reporting System, the 23 largest producers reported an average return on assets of just 5.4% over the 12-year period from 1986 through 1997.

The assumption for future oil prices in the 1999 Study does not take into account the price volatility that has been experienced and that has caused difficulty in maintaining steady levels of upstream investments. The strong direct correlation between commodity prices and upstream investment means that investments drop rapidly following a significant downturn in oil or gas prices and confidence returns slowly. The historical low rates of return and the degree of volatility jeopardize the steady flow of capital that is needed to achieve the large projected increases in gas production required to meet growing demand.

Aggressive pro-active workforce planning is essential.

Without immediate action, impending shortages of qualified personnel are expected to hinder the ability of the supply sector to find and develop the required gas supply. Three major shocks to employment prospects in the producing sector have occurred in the last 20 years. Each of these shocks (1982, 1986, and 1998) was caused by drastic declines in the world market price of crude oil and resulted in significant reductions in expenditures and jobs. At the same time, companies dramatically decreased hiring rates. As a result, the producing sector now suffers from a very slim "bench" of mid-career workers between the ages of 30 and 40 and is facing a large wave of retirements.

In the aftermath of precipitous declines in crude oil prices in 1981, enrollments in key disciplines that support the producing sector began to decline drastically and gained momentum with the equally devastating oil price drop in 1986. The "farm clubs"—college and university petroleum-related degree programs—continue to have great difficulty attracting promising high school seniors. Enrollments in undergraduate petroleum engineering and geoscience programs have declined by 77% and 60%, respectively, between 1985 and 1998 (see Figure 18).2

The oilfield service/supply sector faces similar challenges in meeting engineering and operations requirements. Volatility in the drilling industry has caused many toolpushers and other key supervisory personnel to leave the industry in search of more stable careers. Industry contractors will be challenged to find and train adequate numbers of skilled laborers, such as machinists, electricians, pipeliners, and welders. Higher wage scales are likely to be required to attract workers back into the industry.

Beginning immediately, aggressive pro-active workforce planning is a necessity for producers and contractors to achieve staffing levels that are necessary to meet the challenge of the projected demand increase.

---

New drilling rigs must be built.

In order to supply the volume of natural gas needed through this study period, the total number of wells drilled annually must increase from 24,000 in 1998 to 37,000 in 2010 and as high as 48,000 by 2015. The well counts include both gas and oil wells because approximately 14% of natural gas produced in the United States is associated gas. In 1998, an average of just over 1,250 onshore rigs of the 1,700 rigs available have been active. While rig efficiency (footage drilled per rig, see Figure 19) has improved since 1985 and is expected to continue to improve over time with technology advancements, increased well depth requirements will likely cause the current number of actual wells drilled each year per active rig to remain relatively constant. Thus, to drill 48,000 wells annually by 2015 an average of 2,100 onshore rigs and 180 offshore rigs will be required to actively drill each month of the year.

With this increased level of drilling, the availability of drilling rigs becomes a primary concern. Over the 1999–2015 time frame, the number of onshore rigs that will be retired or lost to attrition is estimated at 90% of the current fleet. In order to meet estimated rig demand, over 1,125 onshore rigs would need to be constructed by 2010 and as many as 1,894 by 2015. Onshore rig construction will be needed as early as 2001. Capital requirements for onshore rig construction is projected at $12 billion.

Additional offshore drilling rigs will also be needed in this time frame, as shown in
Figure 19. Annual Average Footage Drilled Per Rig

Source of historical data: American Petroleum Institute, Quarterly Completion Report; and Baker Hughes, Inc., Rotary Rigs Running.

Table 5
GULF OF MEXICO DRILLING RIG INVENTORY

<table>
<thead>
<tr>
<th>Type</th>
<th>Total</th>
<th>Marketed</th>
<th>Contracted</th>
<th>Not Marketed</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jack-up</td>
<td>170</td>
<td>119</td>
<td>105</td>
<td>20</td>
</tr>
<tr>
<td>Stacks</td>
<td>159</td>
<td>94</td>
<td>27</td>
<td>4</td>
</tr>
<tr>
<td>Drillships</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>0</td>
</tr>
<tr>
<td>Submersibles</td>
<td>7</td>
<td>1</td>
<td>1</td>
<td>6</td>
</tr>
<tr>
<td>Total Mobile</td>
<td>137</td>
<td>157</td>
<td>136</td>
<td>30</td>
</tr>
<tr>
<td>Platform</td>
<td>28</td>
<td>57</td>
<td>37</td>
<td>21</td>
</tr>
<tr>
<td>Jack-up Barges</td>
<td>35</td>
<td>70</td>
<td>34</td>
<td>25</td>
</tr>
<tr>
<td>All Offshore</td>
<td>90</td>
<td>284</td>
<td>297</td>
<td>76</td>
</tr>
</tbody>
</table>

Source: Offshore Data Services, Rig Locator, September 24, 1999.
Table 9. As of September 24, 1999, the offshore fleet actively drilling in the Gulf of Mexico numbered 207, with 30 of those working in deepwater. Included in that total were 76 rigs that were not being marketed. Some of the rigs in this category might not be returned to service due to the costs that would be associated with meeting U.S. Coast Guard certification requirements and classification society standards. Since offshore drilling rigs are mobile, improved market conditions in the Gulf of Mexico could potentially attract rigs to relocate from foreign waters. Taking into account increasing drilling efficiencies as well as annual attrition rates of 5% for deepwater rigs and 7% for all others, the 1999 Study projects that 72 additional rigs—either reactivated, new construction, or relocations—will be needed by 2015 for the increased offshore activity. This total includes 10 deepwater rigs, 32 platform rigs, and 30 jack-up rigs and barges. If all of these additions were met by new construction, capital requirements would be approximately $7 billion.

Supply Finding 4: Investment in research and development is needed to maintain the pace of advancements in technology.

As stated earlier, technology advancement has played a major role in the increase of the North American resource base by:

- Improving efficiency of drilling, equipment, operating, and other costs
- Increasing recovery factors of discovered oil and gas in place
- Improving success rates (i.e., reducing the number of dry holes)
- Revealing new areas and types of resources for exploitation through innovative geologic and engineering concepts.

The above improvements occurred mainly due to advances in 3D seismic, directional drilling, and improved completion techniques.

Information and communications technology also has had a widespread impact on all facets of the natural gas producing sector. The persistent improvement of computing power at consistently decreasing prices has placed increasingly powerful information technology tools in the hands of even the smallest producers, improving efficiency and reducing cost structures. Processing power is growing and allowing applications to be moved from mainframes to high-efficiency workstations. The advent of object-based and improved data storage technologies have allowed greater access to data with a high level of access in user friendly interfaces. Connectivity has been enhanced by the use of high-capacity networks, fiber, and satellite communication links, and the Internet (intrarets, extrarets, etc.). More importantly, these types of system advances support new paradigms of multi-disciplinary teaming.

One consideration in this constantly changing environment and workstyle is the manner in which people can adapt, modify work processes, and comfortably utilize these tools. These changes challenge management to ensure that training is constantly updated to match the fast pace of technology growth.

Advances in technology do not happen in a vacuum. All industry stakeholders will have to support continued investment in technology research and development—from the producer who must apply the newest tools/techniques to the next opportunity, to the investor who must at times be willing to sacrifice immediate gains for longer-term viability. Continued and increased funding of research and development is required for the North American resource base to live up to its potential. Cooperative measures by all parties will be required. With continued emphasis and investment, new technologies such as those listed below could have a significant impact on future gas production:

- Improved Seismic Techniques. Time-lapse seismic reservoir monitoring, commonly known as 4D seismic, is the comparison of 3D seismic surveys acquired at two or more points in time. This allows scientists to study the movement of fluids in the reservoir. Another technique, multi-component technology, provides a more detailed picture of a subsurface reservoir's internal architecture. The combination of these two technologies
with visualization technology allows geoscientists to “see” reservoir events such as a gas cap enlarging as oil is produced. In the future, real-time reservoir models will use these techniques to allow quick updating as new data are available, thus enabling drilling and field development decisions to be made quickly to enhance production.

- **Deep Wireline Measurements.** Deep measurements of gravity and electromagnetic forces provide information that complements the seismic data. Wireline-based deep measurements typically have higher resolution than seismic and can provide enhanced detail about gas location and movement.

- **Integrated Well Planning.** Integrated well planning is the process of effectively and accurately planning for optimum wellbore placement in the reservoir, determining suitable equipment/systems for completion and production, and maximizing reservoir output and economics.

- **Drilling Systems.** A major focus on drilling systems will continue, because drilling time is a major component of rig cost and thus the total cost of the well. Significant strides have been made in the last several years with regard to rates of penetration, equipment dependability, downhole data gathering, and drilling dynamics. The ability to steer and extend the wellbore both vertically and horizontally to zones of interest has increased significantly with the advent of extended reach wells, horizontal drilling, and multi-laterals.

- **Deepwater Technology.** As exploration and production activities move deeper into the ocean, new technology will be essential for advancing offshore production systems. Traditional platforms are being replaced with new designs and subsea completions are becoming common place. New systems such as Floating Production Systems may have the potential to significantly extend producing systems to the ultra-deepwater areas if technology and cost challenges can be met.

The 1999 Study presumes that these technology advances and many others will form the basis for new innovations that increase exploratory success and optimize well production capability. Should technology advancements materialize at a slower rate, or should these technologies prove less valuable to producers than expected, the availability of future supply and the cost at which it is delivered could be impacted.

**Findings of the Transmission & Distribution Task Group**

**Transmission/Distribution Finding 1:** Significant expansion and enhancements to the delivery system are required to serve the growing demand.

Substantial changes are expected in natural gas supply and consumption patterns by 2015, which creates a need for enhancements to the existing delivery system and construction of new transmission and storage facilities. By 2015, annual requirements are projected to increase beyond 31 TCF, which equates to 88 BCF per day. Peak-day requirements will grow from approximately 111 BCF per day in 1997 to over 152 BCF per day in 2015, as shown in Figure 20. A significant investment in pipeline facilities will be necessary to meet the new demand requirements and shifts in supply locations to deepwater Gulf of Mexico, Rockies, western Canada, and the Canadian Atlantic. These frontier supply basins will have increased pipeline costs because of their more distant location from markets, mitigation of potential environmental impacts, and harsher environments for construction, maintenance, and operation. However, the annual average expenditures projected in this study are consistent with historical trends.

The consumption of natural gas in the United States previously peaked in 1972 at 22.1 TCF. Since then, geographic shifts in supply and demand (such as the decline of the industrial Midwest and increases in supply...
from the Rockies and Canadian imports) has caused the transmission and storage system to expand more slowly than otherwise expected. Today there are more than 270,000 miles of gas transmission pipelines and approximately 3.2 TCF of working gas storage capacity (Figures 21 and 22). The U.S. delivery system also includes another 952,000 miles of gas lines owned by the distribution segment of the industry. Through 2015, approximately 38,000 miles of transmission pipeline and 255,000 miles of distribution mainlines are projected to be needed to meet the requirements of the projected market. This rate of growth is comparable to the expansion experienced in the last few years. In addition, working gas storage will increase by 0.8 TCF.

The existing transmission and storage system is capable of meeting its existing firm requirements on an annual and peak-day basis. Analysis indicates that the system had a 1997 annual capacity of 45 TCF and a daily capacity of 131 BCF. This additional capacity above the 1998 annual consumption of 22 TCF, and estimated firm peak-day demand of 111 BCF per day, allows non-firm customers to use this capacity on peak days, provides necessary redundancy, adds reliability, and enables the system to support a growing U.S. gas market.

Peak-day requirements represent the sum of all loads on a system on the day of highest demand (as measured by volume). Any particular system must have the ability to meet its customers' firm requirements on design peak days. Gas utility systems use a combination of flowing gas and storage gas to meet their customers' firm requirements on these days.
The space-heating load is highly dependent on the impact of unpredictable winter weather. For this reason, almost all U.S. gas pipelines and distribution companies experience their peak day during the winter months. During the remaining months of the year, these utilities have unutilized capacity beyond that needed to meet market requirements and to refill storage.

In general, the increased demand projections for 2010 and 2015 in the residential, commercial, and industrial sectors will also increase peak-day requirements and thus necessitate construction of additional pipeline and storage facilities. Contracts with some customers, principally industrials and electricity generators, may limit consumption on peak days and allow (or require) them to switch to another fuel. Some customers are unable to switch fuels due to restrictions from environmental regulations. This is becoming more common, particularly for the new electricity generation facilities, as fuel-switching capabilities are becoming more difficult to permit in some areas of the United States. Thus, the new electricity generation load will likely have a higher impact on peak-day requirements than in the past. However, some level of fuel-switching capability is necessary to handle overall energy needs on peak days and to lessen pipeline and storage expansion needs.

Figure 21. U.S. Natural Gas Pipeline Cumulative Mileage

Two shifts in the flows on the transmission system have developed recently. The first is the decrease in Gulf Coast and Mid-Continent supply moving to the Midwest (i.e., Chicago area). This was caused by slow market growth in the Midwest and displacement of Gulf Coast and Mid-Continent supply by Rockies and Western Canadian supply as additional pipeline infrastructure has come online. The second is the increase in Gulf Coast supply to the Southeast that was caused by the large increase in market demand. Supply increases from the Rockies and western Canada will be landing in the Midwest area, turning Chicago into a supply hub at some point in the near future. The Reference Case shows that significant new or incremental transmission capacity will be built from the Rockies to California, Canadian Atlantic to New England, Gulf of Mexico to Florida, western Canada to the Pacific Northwest, and the Mackenzie Delta to Alberta.

The anticipated shifts in supply regions and regional growth patterns will require building pipelines to tap new supply sources, expanding infrastructure along existing corridors, building laterals to attach new markets, and attaching new storage facilities to the pipeline grid. A fundamental requirement to develop this infrastructure is access to land for attaching, gathering, and processing the natural gas and then transporting the natural gas...
to market or to storage fields for eventual delivery to market.

Issues related to access have become more prominent for the transmission and distribution sectors of the industry. Access issues arise from urban sprawl encroaching on potential and existing rights-of-way and eliminating potential pipeline routes, heightened public resistance to providing easements, and increasingly restrictive government policies and regulations. Some of these issues are exemplified by public protest to recently proposed pipeline projects from the Midwest to serve Northeast markets. Both industry and government have taken action to address the public's concerns. For example, FERC recently amended regulations by adding landowner notification requirements and also issued orders to help facilitate pipeline projects. However, the following examples of proposed policy/regulatory changes demonstrate a movement toward additional requirements for the building and maintenance of pipelines.

- The U.S. Fish & Wildlife Service (FWS) has developed a “Draft Compatibility Policy Pursuant to the National Wildlife Refuge System Act of 1997” that would significantly impact the ability to obtain permits from the FWS for non-wildlife-dependent activities.
- On July 21, 1999, the Corps of Engineers proposed to modify Nationwide Permits in certain areas, which if implemented could affect the ability to obtain permits in a timely and cost-effective manner.
- On September 15, 1999, the Federal Energy Regulatory Commission issued a Statement of Policy (Docket No. PL99-3-000) that it will use in deciding whether to authorize the construction of major new pipeline facilities. The change in policy now requires that an applicant demonstrate that the economic benefits to the public outweigh adverse impacts. Only when the benefits outweigh the adverse effects on economic interests will the Commission proceed to complete the environmental analysis and consider other interests. Prior to this policy change the economic test was much simpler, relying on the percentage of long-term contracts as the measure of demand for a proposed project.

Careful consideration must be given to these and similar issues in order to balance the myriad of interests that exist. The consequences of conflicting policy and regulations within and across government agencies will lead to higher costs, either directly or via delays. Natural gas has its own environmental benefits that should be taken into account when formulating policy so that an appropriate balance can be achieved.

**Transmission/Distribution Finding 3:**

*New services are needed to serve a changing market.*

The evolving competitive nature of the natural gas industry requires new mechanisms for existing and new customers to gain access to transportation services at competitive prices. As the LDCs' requirements to hold interstate pipeline capacity decline, marketers, producers, and other end-users will be contracting for the capacity. Many of these customers use capacity differently than the LDCs, because their individual load requirements and physical capabilities differ from the aggregated load and system capabilities of the LDCs.

The current delivery system was built and optimized over decades to meet the design peak-day requirements of firm service customers that are primarily residential, commercial, and to a lesser extent, industrial and electricity generation customers. To date, the “seasonal slack or off-peak slack” in the delivery system has been adequate to meet the levels of demand placed on this system by electricity generators. Looking ahead, the anticipated tremendous growth in electricity generation demand for natural gas will require the delivery system to be re-optimized to meet larger off-peak swing loads as well as growing peak-day requirements. For example, electricity generators (using high-efficiency combustion turbines) require significantly higher inlet pressures and higher hourly flow rates than other end-use customers (and previous generation turbines). In addition, the loads for peaking generators are volatile and of relatively short duration, thereby requiring...
greater flexibility and quicker responses by the natural gas delivery system. Meeting these requirements, as well as the increasing peak-day requirements of the other sectors, on a significantly larger scale will entail changes in physical capabilities, operational procedures, communications, contracting (supply and transportation), and tariffs.

While the capital required for transmission and distribution infrastructure expansions is not of the same magnitude as for the upstream sectors, investment issues are just as critical. The Reference Case shows that transmission and distribution companies will need to make capital investments of approximately $123 billion through 2015. This total includes $35 billion for transmission pipelines, $84 billion for distribution facilities, and $4 billion for storage. Clearly, companies will need to make considerable investments in infrastructure to serve new customers, manage seasonal and peak-day demand swings, and replace aging facilities. The magnitude of the expenditures is in line with historical averages, but restructuring has introduced new risks associated with investments.

The primary question that looms in this segment of the industry is about who will accept the risk of financing and constructing major new facilities. In the past, downstream investments in gas pipelines and storage fields were heavily regulated. LDCs, as franchise holders, had principal access to the end-use market and thus had a level of certainty that supported the investment in new facilities. The industry restructuring over the last two decades has led to changing roles and obligations—as well as new risks and different risk profiles—for all the industry participants. Many pipeline shippers now attach little value to holding contracts for firm service of more than three years. The shippers’ need to limit long-term exposure does not align with the pipelines’ need for long-term contract commitments to justify investment risk. In addition, industry restructuring can impose a myriad of challenges/risks to gas utilities that should be considered in the regulatory process. Faced with these changing conditions, it is not clear who will be willing to accept the risks for building the infrastructure needed to support the growth in natural gas demand.
The Secretary of Energy
Washington, DC 20585
May 6, 1998

Mr. Joe B. Foster
Chair
National Petroleum Council
1625 K Street, N.W.
Washington, D.C. 20006

Dear Mr. Foster:

In 1992, the National Petroleum Council released a study entitled, "Potential of Natural Gas in the United States." That study was critical in identifying natural gas as an abundant domestic resource that can make a significantly larger contribution to both this Nation’s energy supply and its environmental goals.

Since the release of the study, the Nation has experienced five years of sustained growth in the use of natural gas. In addition, the study did not anticipate at least two major forces that are beginning to take shape, which will profoundly affect energy choices in the future -- the restructuring of electricity markets and growing concerns about the potentially adverse consequences that using higher carbon-content fuels may have on global climate change and regional air quality. These issues offer opportunities and challenges for our Nation’s natural gas supply and delivery system. For a secure energy future, Government and private sector decision makers need to be confident that industry has the capability to meet potentially significant increases in future natural gas demand.

Accordingly, I am requesting that the Council reassess its 1992 study taking into account the past five years’ experience and evolving market conditions that will affect the potential for natural gas in the United States to 2020 and beyond. Of particular interest is the Council’s advice on areas of Government policy and action that would enable natural gas to realize its potential contribution toward our shared economic, energy, and environmental goals.

Given the significance of this request, Deputy Secretary Elizabeth Moler will co-chair the study committee. I offer my gratitude to the Council for its efforts since our meeting in December 1997, to assist the Department in defining a more concise study scope. The breadth of issues related to natural gas supply and demand is vast and I recognize that further refinements in scope may be necessary once the study is underway to address the most significant concerns about future natural gas availability.

Sincerely,

Federico Peña

2973

DOE006-0330

Obtained and made public by the Natural Resources Defense Council, March/April 2002
Mr. Joe B. Foster  
Chair  
National Petroleum Council  
1625 K Street, N.W.  
Washington, D.C. 20006

Dear Mr. Foster:

This is to convey my approval to establish a Committee on Natural Gas and to appoint industry members as proposed in your letter of October 6, 1998. I also approve the establishment of a coordinating subcommittee and the appointment of subcommittee members identified in your letter.

The Deputy Secretary will serve as the Government co-chair of the committee; the Assistant Secretary for Fossil Energy will co-chair the coordinating subcommittee. Staff involved in this study will be from the Office of Fossil Energy and the Office of Policy and International Affairs. In addition, the Energy Information Administration has expressed an interest in providing technical and analytic support. The Deputy Assistant Secretary for Natural Gas and Petroleum Technology will serve as the alternate for the Government co-chair of the subcommittee.

I agree that it would be appropriate for a representative of the Department of the Interior to be a member of the coordinating subcommittee, and we are pursuing this issue.

For a secure energy future, Government and private sector decision-makers need to be confident that industry has the capability to meet the significant increases in natural gas demand forecasted for the twenty-first century. I am pleased that the National Petroleum Council recognizes the challenge facing the domestic natural gas industry and has agreed to conduct a study of natural gas supply availability. I look forward to the study’s results.

Yours sincerely,

Bill Richardson

Bill Richardson
Description of the National Petroleum Council

In May 1946, the President stated in a letter to the Secretary of the Interior that he had been impressed by the contribution made through government/industry cooperation to the success of the World War II petroleum program. He felt that it would be beneficial if this close relationship were to be continued and suggested that the Secretary of the Interior establish an industry organization to advise the Secretary on oil and natural gas matters.

Pursuant to this request, Interior Secretary J. A. Krug established the National Petroleum Council on June 18, 1946. In October 1977, the Department of Energy was established and the Council was transferred to the new department.

The purpose of the NPC is solely to advise, inform, and make recommendations to the Secretary of Energy on any matter, requested by the Secretary, relating to oil and natural gas or the oil and gas industries. Matters that the Secretary of Energy would like to have considered by the Council are submitted in the form of a letter outlining the nature and scope of the study. This request is then referred to the NPC Agenda Committee, which makes a recommendation to the Council. The Council reserves the right to decide whether it will consider any matter referred to it.

Examples of recent major studies undertaken by the NPC at the request of the Secretary of Energy include:

- The Strategic Petroleum Reserve (1984)
- U.S. Petroleum Refining (1986)
- Factors Affecting U.S. Oil & Gas Outlook (1987)
- Integrating R&D Efforts (1988)
- Petroleum Storage & Transportation (1989)
- Industry Assistance to Government (1991)
- Short-Term Petroleum Outlook (1991)
- The Potential for Natural Gas in the United States (1992)
- U.S. Petroleum Refining—Meeting Requirements for Cleaner Fuels and Refineries (1993)
- The Oil Pollution Act of 1990—Issues and Solutions (1994)
- Marginal Wells (1994)
- Research, Development, and Demonstration Needs of the Oil and Gas Industry (1995)

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A-7

2979

DOE006-0336

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2980

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2984

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B-4

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B-9

2991

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