Attachment D-2 "Fossil Fuel Industry" Excerpted from:

Appendix D
New Mexico Greenhouse Gas Inventory and Reference Case Projections, 1990-2020

Prepared for the:
New Mexico Environment Department

By the:
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November 2006[1]

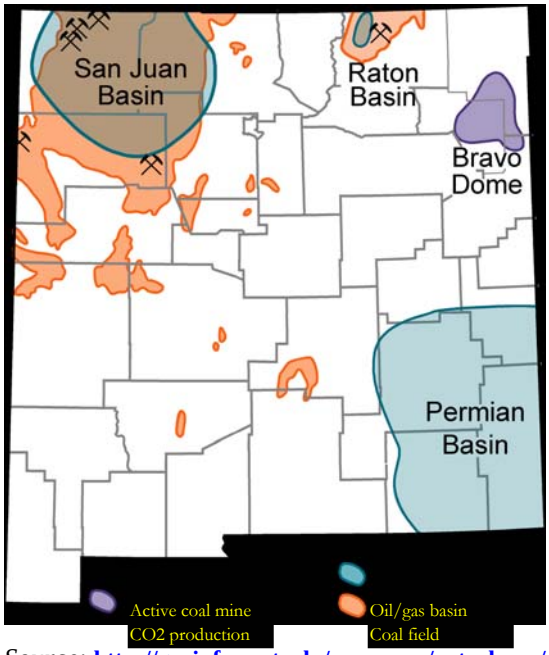
[1] Original draft completed July 2005. Second draft completed February 2006. Final technical changes completed November 2006.

Attachment D-2. Fossil Fuel Industry Emissions[32]

The oil and gas industry has played an instrumental role in New Mexico's economy and livelihoods for more than 70 years. Oil and gas revenues currently provide about 20% New Mexico's General Fund -- down from historic highs of nearly 90% -- and the industry provides employment for about 10,000 New Mexicans.[33] The State currently ranks second in the nation in natural gas production and fifth in crude oil production.[34] It is also a leader in both the production and reserves of carbon dioxide, which is used largely for enhanced oil recovery.

Natural gas production is concentrated in the northwestern corner of the State (San Juan Basin), while oil production occurs predominantly in the southeast (Permian Basin). (See Figure D-12) As of 2002, over 700 oil and gas industry-related companies operated in the State, working 21,771 oil wells, 23,261 gas wells, 456 CO2 wells, 4,097 enhanced recovery injection wells and 597 salt water disposal wells.[35] In response to expectations of strong US natural gas demands and firm prices, it is expected that another nearly 10,000 gas wells may be drilled in the San Juan Basin in coming years.[36] In addition, there are over 4,500 inactive, non-plugged oil and gas wells that could potentially be returned to production.[37]

Figure D-12. Fossil Fuel and CO2 Producing Regions of New Mexico



Source: **http://geoinfo.nmt.edu/resources/petroleum/**

While coalbed methane (CBM) supplies less than 10% of total US natural gas production, it accounts for nearly a third of New Mexico's natural gas production: 487 of the 1625 billion cubic feet (BCF) produced in 2002.[38] Coalbed methane is found throughout the Rocky Mountain Region, including the Raton and San Juan Basins that span both Colorado and New Mexico. The Fruitland Coal formation of the San Juan Basin is the largest CBM source in the US.

CBM production from the New Mexico portion of the San Juan Basin peaked in 1999 at over 610 Bcf (billion cubic feet), and has since dropped under 500 BCF annually since 2002. At the same time, increased drilling in response to

[32] The Energy Supply Technical Working Group reviewed and accepted the assumptions and results shown in this section.
[33] EMNRD, 2003. *New Mexico's Natural Resources 2003* http://www.emnrd.state.nm.us/Mining/resrpt/default.htm
[34] US DOE Energy Information Agency website. www.eia.gov
[35] ENMRD, 2003.
[36] Bureau of Land Management, 2003. Farmington Resource Management Plan with Record of Decision, December 2003. Farmington Field Office.
[37] EMNRD, 2003
[38] EMNRD, 2003 and data provided separately by the Oil Conservation Division.

expected high demand and prices for natural gas could postpone further decreases in CBM production. Overall, future oil and gas production levels remain highly uncertain, dependent on prevailing oil and gas prices and the potential development of new reserves.

Oil and Gas Industry Emissions

The sheer number and wide diversity of oil and gas activities in New Mexico present a major challenge for greenhouse gas assessment. Emissions of carbon dioxide and methane occur at many stages of the production process (drilling, production, and processing/refining), and can be highly dependent upon local resource characteristics (pressure, depth, water content, etc.), technologies applied, and practices employed (such as well venting to unload liquids which may result in the release of billions of cubic feet of methane annually). With over 40,000 oil and gas wells in the State, three oil refineries, several gas processing plants, and tens of thousands of miles of gas pipelines in the State – and no regulatory requirements to track CO_2 or CH_4 emissions – there are significant uncertainties with respect to the State's GHG emissions from this sector.

At the same time, considerable research – sponsored by the American Petroleum Institute, the Gas Research Institute, US EPA, and others – has been directed towards developing relatively robust GHG emissions estimates at the national level. For the national GHG inventory, US EPA uses a combination of top-down and detailed bottom-up techniques to estimate national emissions of methane from the oil and gas industry (USEPA, 2005). As noted earlier, US EPA has also developed a tool (SGIT) that enables the development of state-level GHG estimates, whereby emissions-related activity levels (numbers of wells, and amount of oil and gas produced) can be multiplied by aggregate emission factors to yield rough estimates of total CH4 emissions. Furthermore, EIA provides estimates of fuel used in New Mexico for natural gas production, processing, and distribution, which enables the estimation of CO2 emissions.

These sources provide a starting point for analysis of New Mexico's oil and gas industry emissions. Additional data and insights have been solicited from industry sources, including the New Mexico Oil and Gas Association (NMOGA) and individual facility managers, US EPA staff, and State agency experts. These sources provided "ground truthing" on several aspects related to State emissions. For example:

- Oil refiners and NMED provided access to permit data that includes estimated fuel consumption. These sources suggest that refinery gas use is over twice the level suggested by EIA data.
- USEPA staff remarked that methane emissions from well venting activities in New Mexico, especially at low pressure CBM sites where the build up of liquids may require venting, appear to be quite significant, perhaps on the order of 40 BCF annually (1.6 million $MMtCO_2eq$).[39]

[39] Personal communication, Roger Fernandez. (It also appears that that some producers have been able modify practices to reduce well venting emissions by about 50%, suggesting a potentially significant source of emission reductions.) This is only one of several significant sources of methane emissions from gas production. The preferred USEPA (SGIT) approach for estimating natural gas production emissions, which involves multiplying national aggregate per well CH4 emissions by the number of New Mexico wells, yields total methane emissions

- NMOGA provided separate estimates for several emissions sources, including carbon dioxide emissions from gas well site equipment (gas combustion in engines, tank heaters, and field separators), and methane and carbon dioxide emissions from venting and flashing activities at field sites. While these data only cover gas production activities in the San Juan Basin, they suggest rates of field gas use (carbon dioxide) and methane emissions that are 50% to 70% higher than the above (EPA-based) estimates. We consider these rates below in a sensitivity analysis.
- Raw gas that emerges from gas and oil wells often contains "entrained" CO_2 in excess of pipeline specifications. This CO_2 is typically separated at gas processing plants and vented to the atmosphere (except in some other states, such as Wyoming and Texas, where it is compressed and transported for enhanced oil recovery).[40] In the case of New Mexico, the CO_2 concentrations of Fruitland CBM are known to be quite significant (currently around 18%), and these concentrations have been rising over time. Data provided by the Oil Conservation Division of EMNRD and NMOGA enable estimates of entrained CO_2 emissions. Though these estimates cover only Fruitland CBM, which accounts for less that a third of New Mexico gas production, it is thought that this is the most significant source of entrained CO2 in the State.
- CO_2 from enhanced oil recovery – In New Mexico, carbon dioxide is extracted from natural formations (Bravo Dome), piped to oil fields, and injected into wells in order to increase yields. Any release of this CO2 during the extraction, transmission, injection, or oil production processes would lead to net emissions to the atmosphere. At the national level, USEPA currently excludes any such emissions from the national inventory, since they are not well understood. In the case of New Mexico practices, NMED is currently looking into available information to assess where any estimates are possible.

Table D-12 provides an overview of the methods used to estimate and project GHG emissions from the various oil and gas sector activities. As shown, a variety of methods were used, in general relying upon local data and guidance from industry and other experts wherever possible.

Several factors will drive future GHG emissions from New Mexico's oil and gas sector, among them:

- Future oil and gas production activity. This is perhaps the most important, yet most uncertain variable that will affect future GHG emissions. One assessment suggests that barring further discovery or development of new reserves, coalbed methane production will remain level for one or two more years, and then begin declining at rate of 13% annually as the fields are depleted.[41] Conventional gas production in the San Juan Basin, under this assessment, would remain flat through the end of the decade, and similarly

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estimates that are significantly less than the national average (per unit natural gas produced), which does not appear justified. Based on discussions with USEPA staff, it was felt that their alternative (SGIT) method – using the New Mexico production-weighted share of national natural gas production methane emissions – would be a better approach for developing initial methane emissions estimates.

[40] On a national level, the USEPA GHG inventory suggests that these entrained CO_2 emissions are quite significant (about 25 MMtCO2in 2002). However, USEPA is still working to systematically incorporate this emissions source into the national inventory, given concerns about double counting emissions in locations (outside New Mexico) where this CO_2 may be used for enhanced oil recovery.

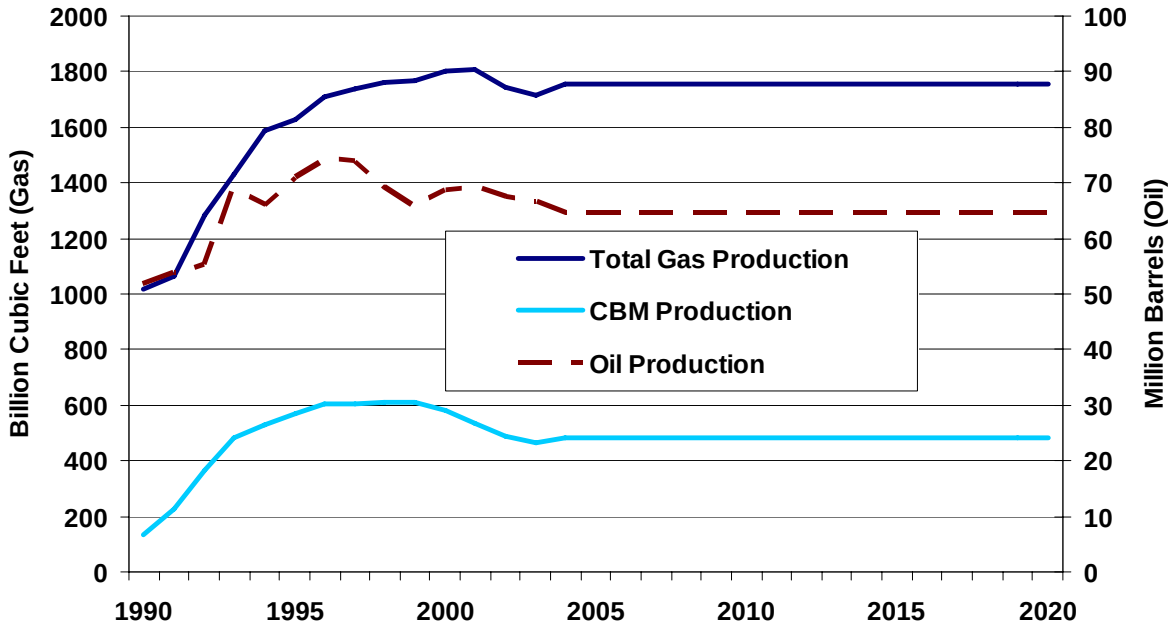
[41] Bernstein Research Call, May 27, 2005.

begin declining at 13% per year. (This assessment covered only the San Juan Basin)

Not surprisingly, there are many competing views on the future of oil and gas production, and prognostications of declining production have been made in the past. Total statewide natural gas production has been relatively steady from 1997 to 2004, varying by less than 6% over this 8-year time period. Thus another possible scenario is that additional reserves are found and exploited such that production remains constant through 2020. The Energy Supply Technical Working Group evaluated the differing views on future oil and gas production and came to the conclusion that the most likely was that emissions remain constant in the sector, and this assumption was used in preparing this inventory.

The implications of this assumption in terms of oil and gas production are depicted in Figure D-13 below.

Figure D-13. Future Oil and Gas Production



- Number of operating wells. As many of the oil and gas fields play out, more operating wells may be needed to maintain production levels. Some emissions, fugitive methane in particular, may depend on the number of operating wells as much as on total oil and gas production. The projected increase in the number of operating wells is based on the estimates contained in the BLM's Resource Management Plan for the San Juan Basin. Note that this estimate will likely need to be adjusted to correspond to the oil and gas production scenario chosen above.

- Changes in production, processing, and pipeline technologies and practices. In response to industry and USEPA emission reduction initiatives (e.g. GasStar), as well as

technological advancements, progress has been made in lower GHG emissions per unit of oil and gas produced and delivered. Further improvements are likely, but have not been estimated for this initial analysis.

Key assumptions are noted in Table D-11.

Table D-11. Key Assumptions for the Oil and Gas Sector Projections

Parameter	Assumption
Natural Gas and Oil Production	Flat oil and gas production through 2020 See text for details
Oil Refinery Production	No changes in refinery activities (or emissions) are presently assumed.
GHG emissions per unit input/output	Potential emissions savings particularly for methane could be considerable, but are not considered here due to lack of information.

Coal Production Emissions

Methane occurs naturally in coal seams, and is typically vented during mining operations for safety reasons. This methane is typically referred to as "coal mine methane" in contrast coal bed methane, which is associated with coal seams (such as Fruitland) that are not expected to be mined.

Historical coal mine methane emissions were estimated using the EPA SGIT tool, which multiplies coal production times an average emission factor, depending on the mine type. Coal mine methane emissions are considerably higher, in general, per unit of coal produced, from underground mining than from surface mining.

As of 2003, six surface mines were operation in New Mexico. In 2001, underground operations commenced at the San Juan coal mine, and since then surface operations at one other mine (Ancho) has been significantly curtailed. The increasing share of underground coal in recent years has led to an increase in estimated coal mine methane emissions from about 0.2 MMtCO2e to 0.7 MMtCO2e.

Future coal mine methane emissions will depend on the extent to which operations continue to move underground (which could increase emissions significantly) and/or new coal mining operations change in response to demands from the power market. No effort has yet been made to estimate these potential changes.

Table D-12. Emissions Sources and Estimation Methods for the Oil and Gas Sector

Activity	Emissions Source	Approach to Estimating Historical Emissions	Projection Approach
Natural Gas Drilling and Field Production	CO_2 from field use of natural gas	EIA data	Changes with number of operating wells. (CH_4 emissions savings due to further NG Star activity not considered).
	CH_4 from leaks, venting, upsets, etc.	NM share of national emissions (based on total production). EPA staff separately estimate 40 BCF CH_4 (1.6 MMtCO2e) could result from well venting alone.	
Natural Gas Processing	CO_2 from fuel use in gas processing	EIA data	Changes with total statewide gas production or for the case of entrained CO2, with Fruitland gas production. CO_2 concentrations of Fruitland CBM are assumed to increase based on recent trends.
	CO_2 released fro entrained CO_2	Based on NMOGA estimates of CO2 concentration, and NM Oil Conservation Division estimates of gas production, for the Fruitland CBM field. No estimates made for other gas production sources.	
	CH_4 from leaks, venting, upsets, etc.	NM share of national emissions (based on state vs. US production)	
Natural Gas Transmission and Distribution	CO_2 from fuel use (pumps, compressors)	EIA data	Distribution emissions grow with state gas consumption. No changes currently assumed for transmission-related emissions. Could decrease due to further NG Star activity.
	CH_4 from leaks, venting, upsets, etc.	NM share of transmission & distribution national emissions, based on NM share of national transmission line mileage (transmission) and natural gas consumption (distribution)	
Oil Production	CO_2 from fuel use	EIA data	Grows with state oil production.
	CH_4 from leaks, venting, upsets	SGIT tool.	
Oil Refining	CO_2 from on-site fuel use (refinery gas and natural gas)	Based on fuel use and capacity as reported to NMED in permit data. No annual variations considered.	Grows with oil refinery output.
	CH_4 from leaks and combustion	SGIT tool (included with production above)	
Oil Transport	CO_2 from field use of natural gas	No estimates available	Grows with state oil production.
	CH_4 from combustion	SGIT tool (included with production above)	
Carbon Dioxide Production	CO_2: Fugitive Losses	Not included/no information available.	n/a
	CO_2: Enhanced Oil Recovery	Not yet estimated	n/a
	CO_2: Other uses (shown with industrial process emissions)	Production data. Assume only 1% is for non-oil recovery applications (EMNRD as cited in USEPA, 2005).	No changes assumed.

Overall Results

The resulting emissions estimates for the fossil fuel industry are shown in Table D-13 below. As shown, total fossil fuel industry emissions are quite significant, increasing from 15 to nearly 20 MMtCO2e during the 1990s, largely as the result of increased gas production, and in particular of coalbed methane, which led to an increase in the release of entrained carbon dioxide by over 4 MMtCO2. As shown in this table, GHG emissions would likely remain near 2000 levels through 2020, assuming no new and major efforts to reduce fuel use and/or emissions.

Table D-13. Emissions Estimates for the Oil and Gas Sector, by Source and Gas, 1990-2020 (Scenario A)

(Million Metric Tons CO2e)	1990	2000	2010	2020	Explanatory Notes for Projections
Fossil Fuel Industry	**15.2**	**19.5**	**20.3**	**20.7**	
Natural Gas Industry	**12.7**	**17.0**	**17.3**	**17.7**	
Production					
Fuel Use (CO2)	1.8	2.0	1.9	1.9	grows with gas production
Methane Emissions (CH4)	1.9	3.4	3.7	3.7	grows with gas production
Processing					
Fuel Use (CO2)	1.9	2.1	2.0	2.0	grows with gas production
Methane Emissions (CH4)	0.8	0.8	0.9	0.9	grows with gas production
Entrained Gas (CO2)	0.8	5.0	5.2	5.6	grows with CBM prod & CO2 concentration
Transmission					
Fuel Use (CO2)	4.2	2.3	2.3	2.3	no change assumed from 2003 on
Methane Emissions (CH4)	1.0	0.9	0.9	0.9	no change assumed from 2003 on
Distribution					
Fuel Use (CO2)					included in transmission (above)
Methane Emissions (CH4)	0.4	0.4	0.3	0.4	grows with gas consumption
Oil Industry	**2.3**	**2.3**	**2.3**	**2.3**	
Production					
Fuel Use (CO2)					included in industrial oil use (above)
Methane Emissions (CH4)	0.7	0.7	0.7	0.7	grows with oil production
Refineries					
Fuel Use (CO2)	1.6	1.6	1.6	1.6	assumes no major changes
Methane Emissions (CH4)					included in oil production (above)
Coal Mining (Methane)	**0.2**	**0.2**	**0.7**	**0.7**	no change assumed from 2003 on

These results as noted earlier are highly sensitive to several assumptions, most notably emissions rates associated with natural gas production activities and future trajectories for oil and gas production. If the emissions rates estimated by NMOGA for oil and gas activities in the San Juan Basin (in 2002) are assumed to apply for all gas production activities in the State, then natural gas production emissions would be about 3 to 4 MMtCO2e higher than shown in Table D-13.[42]

[42] Estimated emissions for 2002 (not shown) would be 2.5 MMtCO2e higher for methane, and 0.9 MMtCO2e higher for carbon dioxide.

Major Uncertainties and Other Issues

The uncertainties in emissions for the fossil fuel industry are perhaps more significant than in any sector other than forestry. Methane emissions and entrained carbon dioxide emissions in gas production and processing represent over half of these emissions. However, these emissions are not directly monitored and can only be estimated using industry assumptions. Field practices can vary considerably, e.g. with respect to flashing and venting, depending on the operator and the resource involved, and there is no monitoring of these practices. There are also significant with respect to methane emissions in transmission and distribution systems, since there is no systematic monitoring and emissions from venting and leaks can vary considerably from site to site.

In addition, significant uncertainties remain with respect to:

- The quality of historical data on field, processing, and pipeline use of natural gas.
- CO2 emissions from enhanced oil recovery, which have not been estimated.
- Refinery fuel use. EIA indicates less than half the refinery fuel use as indicated by refinery permit data.
- Coal mine methane. More accurate estimates would require mine-specific measurements.

Description of Sources of Methane emissions in the Oil and Gas Industry
Excerpted from the US national GHG inventory (USEPA, 2005)

Petroleum Systems

- *Production Field Operations*. Production field operations account for over 95 percent of total CH_4 emissions from petroleum systems. Vented CH_4 from field operations account for approximately 83 percent of the emissions from the production sector, fugitive emissions account for six percent, combustion emissions ten percent, and process upset emissions barely one percent. The most dominant sources of vented emissions are field storage tanks, natural gas-powered pneumatic devices (low bleed, high bleed, and chemical injection pumps). These four sources alone emit 79 percent of the production field operations emissions. Emissions from storage tanks occur when the CH_4 entrained in crude oil under pressure volatilizes once the crude oil is put into storage tanks at atmospheric pressure.
- *Crude Oil Transportation.* Crude oil transportation activities account for less than one percent of total CH_4 emissions from the oil industry.
- *Crude Oil Refining*. Crude oil refining processes and systems account for only three percent of total CH_4 emissions from the oil industry because most of the CH_4 in crude oil is removed or escapes before the crude oil is delivered to the refineries.

Natural Gas Systems

- *Field Production*. In this initial stage, wells are used to withdraw raw gas from underground formations. Emissions arise from the wells themselves, gathering pipelines, and well-site gas treatment facilities such as dehydrators and separators. Fugitive emissions and emissions from pneumatic devices account for the majority of emissions. Emissions from field production accounted for approximately 34 percent of CH_4 emissions from natural gas systems in 2003.
- *Processing*. In this stage, natural gas liquids and various other constituents from the raw gas are removed, resulting in "pipeline quality" gas, which is injected into the transmission system. Fugitive emissions from compressors, including compressor seals, are the primary emission source from this stage. Processing plants account for about 12 percent of CH_4 emissions from natural gas systems.
- *Transmission and Storage*. Natural gas transmission involves high pressure, large diameter pipelines that transport gas long distances from field production and processing areas to distribution systems or large volume customers such as power plants or chemical plants. Compressor station facilities, which contain large reciprocating and turbine compressors, are used to move the gas throughout the United States transmission system. Fugitive emissions from these compressor stations and from metering and regulating stations account for the majority of the emissions from this stage. Pneumatic devices and engine exhaust are also sources of emissions from transmission facilities. Natural gas is also injected and stored in underground formations, or liquefied and stored in above ground tanks, during periods of low demand (e.g., summer), and withdrawn, processed, and distributed during periods of high demand (e.g., winter). Compressors and dehydrators are the primary contributors to emissions from these storage facilities. Methane emissions from transmission and storage sector account for approximately 32 percent of emissions from natural gas systems.
- *Distribution*. Distribution pipelines take the high-pressure gas from the transmission system at "city gate" stations, reduce the pressure and distribute the gas through primarily underground mains and service lines to individual end users. Distribution system emissions, which account for approximately 22 percent of emissions from natural gas systems, result mainly from fugitive emissions from gate stations and non-plastic piping (cast iron, steel). An increased use of plastic piping, which has lower emissions than other pipe materials, has reduced the growth in emissions from this stage.