<u>HIGHWOOD GENERATING STATION</u>
FINAL ENVIRONMENTAL IMPACT

JANUARY 2007

MT DEQ & USDA – RURAL UTILITIES SERVICE

CLIMATE CHANGE SECTION OF EIS

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negative effects may be acute or chronic, and from sub-lethal to lethal. While mercury contamination is widespread, indeed global, cases involving serious human health impacts have arisen from specific point source discharges to water or accidental food contamination rather than dispersed emissions to air.

3.3.6 GLOBAL CLIMATE CHANGE

In recent decades climatologists and other earth scientists have expressed growing concern that the earth's climate appears to be warming as a result of an accumulation of greenhouse gases (GHGs) in the atmosphere. The earth's surface temperature has risen by about one degree Fahrenheit over the last century, and the warming process has accelerated during the past two decades (Figure 3-25) (EPA, 2000c).

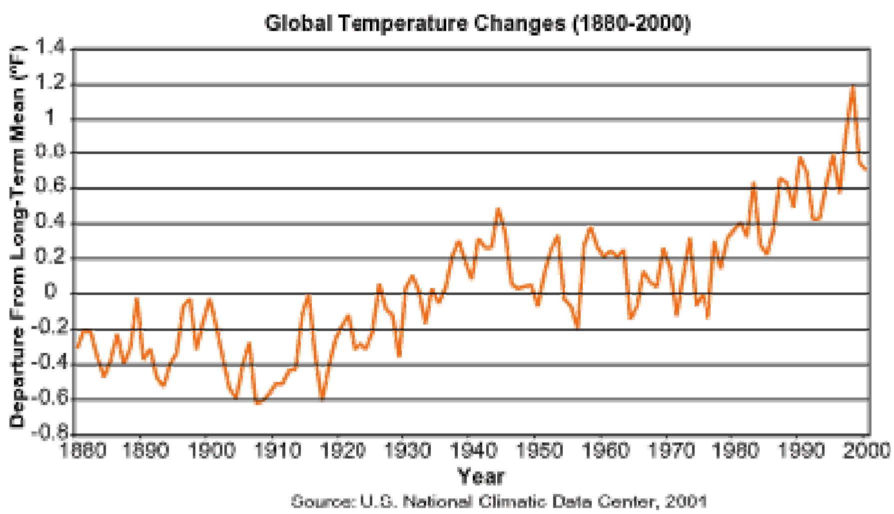

Figure 3-25. Average Global Temperature Trend from 1880 to 2000
Source: EPA, 2000c

Some GHGs occur naturally in the atmosphere, while others result from human activities (EPA, 2005h). Naturally occurring GHGs include water vapor, carbon dioxide, methane, nitrous oxide, and ozone. Certain GHGs are being released in growing quantities by expanding human populations and economic activities, particularly the combustion of fossil fuels (oil, natural gas, and coal) and the clearing/burning of forests, all of which emit carbon dioxide, the principal greenhouse gas, adding to the levels of this naturally occurring gas. Another important greenhouse gas – methane – escapes to the atmosphere from cattle flatulence and rice paddies, as well as from natural gas pipeline leaks and decomposition in landfills; in other words, methane levels in the atmosphere are rising due to expanding food and energy production and waste generation. Still other greenhouse gases include nitrous oxide emitted during combustion and chlorofluorocarbons (or CFCs, which also attack the stratospheric ozone layer), now banned as a result of the Montreal Protocol and other international agreements (EPA, 2000c).

In 1997, DEQ inventoried GHG emissions in Montana for 1990, during which approximately 40 million tons of CO_2 equivalent were emitted in the state. Carbon dioxide was the major GHG emitted in Montana, comprising 74 percent of 1990 emissions. Methane was next, accounting for approximately 14 percent of emissions, followed by halocarbons at 9.5 percent, and nitrous oxide at 2.5 percent.

Fossil fuel consumption was the major source of GHGs released in Montana, accounting for 71 percent of emissions. Petroleum comprised 53 percent of fossil fuel-related GHG emissions, coal 35 percent, and natural gas 12 percent. Emissions of halogenated fluorocarbons from Montana aluminum production made up 11 percent of total state emissions in 1990, while methane emissions from livestock were responsible for 10 percent. Overall, energy-related emissions accounted for 72 percent of GHGs, industrial production and agriculture each accounted for approximately 12.5 percent, and waste-related facilities accounted for three percent (DEQ, 1997). In 1999, funded by a grant from EPA, DEQ prepared a draft "Foundation for an Action Plan" to control GHGs emissions in the state; among other emissions sectors it considered, this document investigated strategies to reduce or offset utility industry GHG emissions (DEQ, 1999).

Energy from the sun heats the earth's surface and drives the earth's weather and climate; in turn, the earth radiates energy back out to space (Figure 3-26). GHGs are transparent to incoming solar radiation but trap some of the outgoing infrared (heat) energy, retaining heat rather like the glass panels of a greenhouse. Without this natural "greenhouse effect," temperatures would be much lower than they are now, and life as we know it would not be possible. Because of greenhouse gases, the earth's average temperature is a more hospitable 60 degrees Fahrenheit (EPA, 2000c).

Since the beginning of the Industrial Revolution, atmospheric concentrations of carbon dioxide have increased nearly 30 percent, methane concentrations have more than doubled, and nitrous oxide concentrations have risen by about 15 percent. These increases have enhanced the heat-trapping capability of the earth's atmosphere. Sulfate aerosols, common air pollutants, cool the atmosphere by reflecting light back into space; however, sulfates are short-lived in the atmosphere and vary regionally (EPA, 2000c). Also, with national and worldwide efforts to curb emissions of these pollutants, their offsetting influence is believed to be diminishing.

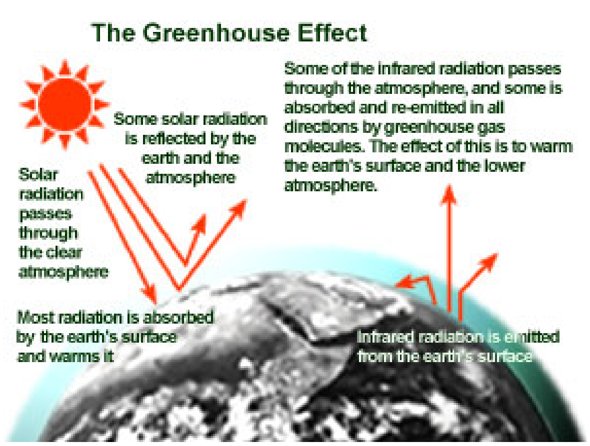

Figure 3-26. The Greenhouse Effect

Source: EPA, 2000c

The National Research Council of the National Academy of Sciences concluded in 2001 that the "warming process has intensified in the past 20 years, accompanied by retreating glaciers, thinning arctic ice, rising sea levels, lengthening of the growing season in many areas, and earlier arrival of migratory birds" (NRC, 2001). Among the predicted changes in the United States are "potentially severe droughts, increased risk of flood, mass migrations of species, substantial shifts in agriculture and widespread erosion of coastal zones" (NAST, 2000). While U.S. agricultural production could increase, due to "fertilization" of the air with carbon dioxide, "many long-suffering ecosystems, such as alpine meadows, coral reefs, coastal wetlands and Alaskan permafrost, will likely deteriorate further. Some may disappear altogether" (Suplee, 2000; Anon., 2000).

In 2001, the Intergovernmental Panel on Climate Change (IPCC) released *Climate Change 2001: Impacts, Adaptation and Vulnerability*, a report prepared by Working Group II (which included approximately 50 lead authors from more than 20 countries). The report concludes:

> *The stakes associated with projected changes in climate are high* [emphasis in original]. Numerous Earth systems that sustain human societies are sensitive to climate and will be impacted by changes in climate…Impacts can be expected in ocean circulation; sea level; the water cycle; carbon and nutrient cycles; air quality; the productivity and structure of natural ecosystems; the productivity of agricultural, grazing, and timber lands; and the geographic distribution, behavior, abundance, and survival of plant and animal species, including vectors and hosts of human disease. Changes in these systems in response to climate change, as well as direct effects of climate change on humans, would affect human welfare, positively and negatively. Human welfare would be impacted through changes in supplies of and demands for water, food, energy, and other tangible goods that are derived from these systems; changes in opportunities for nonconsumptive uses of the environment for recreation and tourism; changes in non-use values of the environment such as cultural and preservation values; changes in incomes; changes in loss of property and lives from extreme climate phenomena; and changes in human health (IPCC, 2001).

While climate change is the ultimate global issue – with every human being and every region on earth both contributing to the problem and being impacted by it to one degree or another – it does manifest itself in particular ways in specific locales like Montana. During the past century, the average temperature in Helena increased 1.3°F and precipitation has decreased by up to 20 percent in many parts of the state (EPA, 1997h).

Over the next century, Montana's climate may change even more. In this region and state, concerns have been expressed by scientists and conservationists over a range of potential impacts, including:

- glaciers melting and disappearing in Glacier National Park and elsewhere in the Rocky Mountains (ABC News, 2006; NWF, 2005);
- a potential decline in the northern Rockies snowpack and stressed water supplies both for human use and coldwater fish (USGS, 2004; ENS, 2006; NWF, 2005; Farling, no date);
- survival of ski areas receiving more rain and less snow (Gilmore, 2006), drying of prairie potholes in eastern Montana and a concomitant decline in duck production (NWF, 2005);
- an increase in the frequency and intensity of wildfires as forest habitats dry out, and perhaps a conversion of existing forests to shrub and grasslands (NRMSC, 2002; NWF, 2005; Devlin, 2004);
- loss of wildlife habitat (USGS, 2004; NWF, 2005);
- possible effects on human health from extreme heat waves and expanding diseases like Western equine encephalitis, West Nile virus, and malaria (EPA, 1997h; RP, 2005);
- possible impacts on the availability of water for irrigated and dryland crop production alike (EPA, 1997h; RP, 2005)

emission limits, an activated carbon injection control system or, at SME-HGS's request and as approved by DEQ, an equivalent technology (equivalent in removal efficiency).

With the IECS in place, annual mercury emissions from the HGS would be approximately 34.5 lbs. (15.7 kg), slightly less than its 2010-2014 allotment of 36.4 lbs (16.5 kg) under Montana's mercury rules. Currently operating coal fired power plants in Montana have emitted as much as 1,042 lbs. (474 kg.) of mercury in a year (DEQ, 2006b). However, as seen in Table 4-12, by 2018, combined statewide mercury emissions are projected to decrease by 72 percent, from 1,042 lbs. to 290 lbs. annually, as a result of implementing the CAMR and Montana's mercury limits. Under Montana's mercury rules, each Montana coal-fired power plant, including SME-HGS, would have to reduce the rate of mercury emissions to 0.9 lb./TBtu by 2018 (DEQ, 2006b).

Due to low chlorine levels in its source sub-bituminous coal, stack mercury emissions from the HGS would be primarily in the form of elemental mercury rather than ionic mercury. Ionic mercury is more easily "scavenged" from the air by attaching to particles or through precipitation, and would therefore tend to be deposited closer to the HGS. In contrast, as explained in Section 3.3.5, the elemental mercury species in the form of mercury vapor does not tend to fall out nearby and is readily transported long distances through the atmosphere. Thus, mercury emissions from the HGS would likely cause a minor change in the local deposition of mercury, while contributing 0.0003 percent to the global stock of atmospheric mercury – estimated at 5,200 metric tons (UNEP, 2002) – and distributed around the world due to air currents.

In conclusion, the HGS, by meeting Montana's mercury emission limits, would likely have minimal impact on environmental mercury levels both locally and in Montana as a whole.

4.5.2.2.5 Greenhouse Gas Emissions

The greenhouse effect and the potential implications of global climate change are summarized in Chapter 3 (Section 3.3.6). This section focuses on carbon dioxide and other greenhouse gas emissions from the proposed HGS as well as the potential for mitigation and offsets.

The potential facility-wide CO_2 emission rate of the HGS is 2.1 million tons (1.9 million metric tons) per year. In addition, the HGS would release methane and nitrous oxide, two other greenhouse gases. Per molecule, both of these gases have a higher global warming potential than carbon dioxide and their emissions are often quantified in terms of CO_2 equivalents. The potential facility-wide, CO_2 equivalents emission rate of these gases is 0.67 million tons (0.61 million metric tons) per year. Total GHG emissions from the HGS are 2.8 million tons (2.5 metric tons) per year.

HGS carbon dioxide emissions would constitute 0.033 percent of U.S. annual emissions of 5,843 million metric tons and 0.007 percent of global yearly emissions of 26,000 million metric tons in 2002 (Marland et al., 2005). As such, HGS's emissions would represent a very small but tangible, incremental contribution to this cumulative global issue. At the present time, U.S. emissions of greenhouse gases from all sources are unregulated and uncapped, since the U.S. is not a signatory to the Kyoto Protocol and not bound by its mandatory national reductions.

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DC = Deposition Concentration (ppm) = 21.5 * (N/d)X

Where:

N =Lifetime of facility in years = 40 years

d =depth of soil for deposited material = 3 cm

X = maximum annual average concentration

The results of the calculations are compared with screening levels from the screening document and presented in Table 4-15.

Table 4-15 Screening Analysis for Heavy Metal Deposition in Soils

Metal	Maximum Annual Average Concentration (μg/m³)	Deposited Concentration (ppm)	Screening Values (ppm)		
			Soil	Plant	Animal
Arsenic	$3.30x10^{-5}$	$9.46x10^{-3}$	3	1.8	21
Cadmium	$1.45x10^{-5}$	$4.16x10^{-3}$	2.5	0.28	1.4
Chromium	$6.12x10^{-5}$	$1.75x10^{-2}$	8.4	50	---
Cobalt	$2.70x10^{-5}$	$7.74x10^{-3}$	1,000	280	180
Fluoride	$6.62x10^{-3}$	1.90	400	10,300	3,300
Manganese	$2.33x10^{-4}$	$6.68x10^{-2}$	2.5	6,100	7,600
Mercury	$6.55x10^{-5}$	$1.88x10^{-2}$	455	--	--
Nickel	$7.55x10^{-5}$	$2.16x10^{-2}$	500	1,300	22,000
Lead	$1.14x10^{-4}$	$3.27x10^{-2}$	1,000	280	180
Selenium	$6.98x10^{-4}$	0.20	500	1,300	22,000

Source: Bull Mountain Development Company LLC., 2002b

Since the deposited concentrations are below the screening values, it is presumed that heavy metal deposition during the proposed life of the Project would have low impacts to soils, plants, and animals.

Greenhouse Gas Estimates

This section provides information on emissions that could increase the concentration of greenhouse gases that contribute to the "greenhouse effect" in the atmosphere. The greenhouse effect is described in the "Introduction to Estimating Greenhouse Gas Emissions"(EPA, 1999) as:

> The Earth naturally absorbs and reflects incoming solar radiation and emits longer wavelength terrestrial (thermal) radiation back into space. On average, the absorbed solar radiation is balanced by the outgoing terrestrial radiation emitted to space. A portion of this terrestrial radiation, though, is itself absorbed by gases in the atmosphere. The energy from this absorbed terrestrial radiation warms the Earth's surface and atmosphere, creating what is known as the "natural greenhouse effect." Without the natural heat-

trapping properties of these atmospheric gases, the average surface temperature of the Earth would be about 34 degrees Celsius (93 degrees Fahrenheit) lower.

The greenhouse effect is primarily a function of the concentration of water vapor, carbon dioxide, and other trace gases in the atmosphere that absorb the terrestrial radiation leaving the surface of the Earth. Changes in the atmospheric concentrations of these greenhouse gases can alter the balance of energy transfers between the atmosphere, space, land, and the oceans. A gauge of these changes is called radiative forcing, which is a simple measure of changes in the energy available to the Earth-atmosphere system. Holding everything else constant, increases in greenhouse gas concentrations in the atmosphere would produce positive radiative forcing.

The United Nations Environment Programme has established the Intergovernmental Panel on Climate Change (IPCC) to "assess the scientific, technical and socio-economic information relevant for the understanding of the risk of human-induced climate change" (IPCC 2002). The IPCC has developed a global warming potential (GWP) factor for most of the direct greenhouse gases. The GWP is defined as the cumulative radiative forcing—both direct and indirect—over a 100-year period.

Direct effects occur when the gas itself is a greenhouse gas. Indirect radiative forcing occurs when chemical transformations involving the original gas produce a gas or gases that are greenhouse gases, or when a gas influences the atmospheric lifetimes of other gases. The forcing is measured relative to a reference gas, carbon dioxide (CO_2), and is expressed in terms of metric tons of carbon equivalent. GWP factors have not been established for the indirect greenhouse gases because there is no agreed-upon method to estimate the contributions of the gases to radiative forcing.

A quantitative emissions inventory of the greenhouse gas emissions from the Project is provided in this section, based on EPA guidance and calculation methodologies. Direct greenhouse gases, including CO_2, methane (CH_4), and nitrous oxide (N_2O), are formed during the combustion of fossil fuels. The indirect greenhouse gases that are emitted from the combustion of fossil fuels include NO_X, CO, and non-methane volatile organic compounds (NMVOCs). Other direct greenhouse gases, which are not products of coal combustion, include chlorofluorocarbons (CFCs), hydrochlorofluorocarbons (HCFCs), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).

The primary greenhouse gas emitted from coal burning is CO_2. Most of the carbon contained in fossil fuels is emitted as CO_2 during the fuel combustion process. The remainder is emitted as CO, CH_4, or NMVOCs, all of which oxidize to CO_2 in the atmosphere within a time range of a few days to about 11 years. Table 4-16 lists the estimated greenhouse gas emissions from the Project in several different units of measure.

Table 4-16 Estimated Roundup Power Project Greenhouse Gas Emissions

Gas	Emissions (ton/yr)	Emissions (lb/MWh)	Emissions (metric tons/yr)	Emissions (kg/MWh)
CO_2	8,199,803	2,496	7,454,366	2,269
CH_4	65.96	0.020	60	0.018

Gas	Emissions (ton/yr)	Emissions (lb/MWh)	Emissions (metric tons/yr)	Emissions (kg/MWh)
N_2O	49.56	0.015	45	0.014
CO	4,917	1.50	4,470	1.36
NO_X	2,329	0.709	2,117	0.645
NMVOC	99.45	0.030	90	0.028

Source: Bull Mountain Development Company, LLC., 2002a.

Table 4-17 summarizes the Project greenhouse gas emissions relative to the US (year 2000) trends for greenhouse gasses. The table also lists the total greenhouse gasses from electric generation and transportation in US. The greenhouse gas emissions from the Project are calculated to be approximately 0.12 % of the total greenhouse gas emissions in the US.

Table 4-17 Estimated Greenhouse Gases in US and from the Project

	Emissions (million tpy)	% of Total US Greenhouse Gases
US Trends for all Greenhouse Gases	7001	--
Electric Generation for all Greenhouse Gases	2376	33.94%
Transportation for all Greenhouse gases	1877	26.81%
Roundup Power Project	8.2	0.12%

Source: EPA Specific Emission Inventory, 2002.

The data in Table 4-16 and Table 4-17 provide information needed to compare the greenhouse gas emissions from the Project to nationwide greenhouse gas emissions. No basis exists for determining the severity of greenhouse gases impacts on global warming; therefore, an impact level cannot be assigned.

161kV Transmission System

No impacts to existing air quality are expected from the 161kV Transmission System except during construction activities. Fugitive dust emissions would be expected during construction but would cease after construction has ended. As such, adverse effects to air quality are expected to be low from the 161kV Transmission System.

4.2.3 Action Alternatives

Landfill Alternative

No significant increase of fugitive emission impacts is expected from an expansion of the landfill for waste disposal. Fugitive emissions may slightly increase and/or change location for this alternative. New fugitive emissions would also occur during the construction of the landfill and

KEYSTONE XL PROJECT
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Full EIS document available on request from MT DEQ steel production, electricity generation, and oil refineries, among others. The gases covered by the rule are CO_2, CH_4, N_2O, HFC, PFC, SF_6, and other fluorinated gases, including nitrogen trifluoride (NF_3) and hydrofluorinated ethers (HFE). The first annual report would be submitted to EPA in 2011 for the calendar year 2010, except for vehicle and engine manufacturers, which would begin reporting for model year 2011.

According to the preamble of the rule, the U.S. petroleum and natural gas industry encompasses hundreds of thousands of wells, hundreds of processing facilities, and over a million miles of transmission and distribution pipelines. Crude oil is commonly transported by barge, tanker, rail, truck, and pipeline from production operations and import terminals to petroleum refineries or export terminals. Typical equipment associated with these operations includes storage tanks and pumping stations. The major sources of CH_4 and CO_2 fugitive emissions include releases from tanks and marine vessel loading operations. EPA does not propose to include the crude oil transportation segment of the petroleum and natural gas industry in this rulemaking due to its small contribution to total petroleum and natural gas fugitive emissions (accounting for much less than 1 percent) and the difficulty in defining a facility. The responsibility for reporting would instead be placed on the processing plants and refineries.

On June 2, 2010, the EPA issued a final rule that establishes an approach to addressing GHG emissions from stationary sources under the CAA permitting programs. These stationary sources would be required to obtain permits that would demonstrate they are using the best practices and technologies to minimize GHG emissions. The rule sets thresholds for GHG emissions that define when the CAA permits under the NSR/PSD and the Title V Operating Permits programs are required for new or existing industrial facilities. The rule “tailors” the requirements to limit which facilities will be required to obtain NSR/PSD and Title V permits and cover nearly 70 percent of the national GHG emissions that come from stationary sources, including those from the nation’s largest emitters (e.g., power plants, refineries, and cement production facilities).

For sources permitted between January 2, 2011 and June 30, 2011, the rule requires GHG permitting for only sources currently subject to the PSD permitting program (i.e., those that are newly-constructed or modified in a way that significantly increases emissions of a pollutant other than GHG) and that emit GHG emissions of at least 75,000 tpy. In addition, only sources required to have Title V permits for non-GHG pollutants will be required to address GHG as part of their Title V permitting (note: the 75,000 tpy CO_2-e limit does not apply to Title V). For sources constructed between July 1, 2011 and June 30, 2013, the rule requires PSD permitting for first-time new construction projects that emit GHG emissions of at least 100,000 tpy even if they do not exceed the permitting thresholds for any other pollutant. In addition, sources that emit or have the potential to emit at least 100,000 tpy CO_2-e and that undertake a modification that increases net emissions of GHG by at least 75,000 tpy CO_2-e will also be subject to PSD requirements. Under this scenario, operating permit requirements will for the first time apply to sources based on their GHG emissions, even if they would not apply based on emissions of any other pollutant. Facilities that emit at least 100,000 tpy CO_2-e will be subject to Title V permitting requirements. EPA plans further rulemaking that would possibly reduce the permitting thresholds for new and modified sources making changes after June 30, 2013.

On December 2, 2010, the EPA released its guidance for limiting GHG emissions based on the CAA requirement for new and modified emission sources to employ BACT to limit regulated air pollutants. As a result, the guidance focuses on the process that state agencies will use as they are developing permits for individual sources to determine whether there are technologies available and feasible for controlling GHG emissions from those sources. The guidance is not a formal rulemaking and does not establish regulations, but it provides permitting authorities more detail on EPA expectations for the implementation of its new GHG permitting requirements.

On April 1, 2010, the EPA and USDOT finalized a new joint regulation for GHG emissions and fuel economy for model years 2012 through 2016 light duty vehicles. The EPA regulates GHG emissions from passenger vehicles up to 8,500 pounds gross vehicle weight rating (plus medium-duty SUVs and passenger vans up to 10,000 pounds). The program sets standards for CO_2 emissions on the U.S. federal test procedure. Equivalent Corporate Average Fuel Economy (CAFE) regulations, measured in miles per gallon of fuel consumed, were simultaneously established by the USDOT National Highway Traffic and Safety Administration (NHTSA).

State Programs

Programs for GHG emissions are being adopted by some states along the proposed Project corridor. Montana is a member of the Western Climate Initiative (WCI). The WCI is a collaborative effort of seven U.S. states and four Canadian provinces to identify, evaluate, and implement measures to reduce GHG emissions in participating jurisdictions. The WCI has a regional GHG target of 15 percent below 2005 levels by 2020 to be met through a regional market-based multi-sector mechanism, as well as other policies. The recommended cap-and-trade program has a broad scope that includes six GHG (CO_2, CH_4, N_2O, HFC, PFC, and SF_6) and will cover 90 percent of GHG emissions from the region when fully implemented. The cap-and-trade program will begin January 1, 2012.

The Governor of Nebraska, along with 10 other midwestern Governors and 1 Canadian province Premier, is a member of the Energy Security and Climate Stewardship Platform for the midwest. The Platform lists goals for energy efficiency improvements, low-carbon transportation fuel availability, renewable electricity production, and carbon capture and storage development. In addition to goals related to energy efficiency, renewable energy sources, and biofuel production, the Platform lays out objectives with respect to carbon capture and storage (CCS). Members agreed to have in place a regional regulatory framework for CCS by 2010, and by 2012 to have sited and permitted a multi-jurisdiction CO_2 transport pipeline and have in operation at least one commercial-scale coal-powered integrated gasification combined cycle (IGCC) power plant with CCS, with additional plants to follow in succeeding years. By 2020, all new coal plants in the region will capture and store CO_2 emissions. Numerous policy options are described for states to consider as they work towards these goals. The Platform also lays out 6 cooperative regional agreements. These resolutions establish a Carbon Management Infrastructure Partnership, a Midwestern Biobased Product Procurement System, coordination across the region for biofuels development, and a working group to pursue a collaborative, multi-jurisdictional transmission initiative. States adopting all or part of the Platform include Wisconsin, Minnesota, South Dakota, Illinois, Indiana, Iowa, Kansas, Michigan, Missouri, Nebraska, North Dakota, and Ohio, as well as the Canadian Province of Manitoba.

Kansas, on November 15, 2007, joined 5 other states and one Canadian province to establish the Midwestern Regional Greenhouse Gas Reduction Accord. Under the Accord, members agree to establish regional GHG reduction targets, including a long-term target of 60 to 80 percent below current emissions levels, and to develop a multi-sector cap-and-trade system to help meet the targets. Participants also establish a GHG emissions reductions tracking system and implement other policies, such as low-carbon fuel standards, to aid in reducing emissions.

In South Dakota, on February 21, 2008, Governor Mike Rounds signed into law HB 1272, which established a voluntary Renewable Portfolio objective of 10 percent by 2015. Oklahoma and Texas currently do not have state initiatives addressing the reduction in GHG, although Senate Bill 184 required the Texas Commission on Environmental Quality (TCEQ) to develop and present a report to the legislature by December 31, 2010, recommending strategies to reduce the GHG emissions by businesses and consumers of the state.

Low Carbon Fuel Standard

The first low carbon fuel standards (LCFS) were enacted in California in 2007. Since then, other jurisdictions (e.g., British Columbia and the European Union) have enacted similar standards. These standards generally require that overall carbon values life-cycle GHG emissions for transportation fuels decrease by 10 percent over the next decade, although the definition of fuels and the percent reduction over time differ across jurisdictions. More carbon-intensive fuels include those derived from crude oil sources in the WCSB, Venezuela, Nigeria, the Middle East, and California (IHS CERA 2010). The impact of LCFS on U.S. market demand for oil sands crude oil is speculative at this time since few jurisdictions have implemented these standards.

One concern regarding the adoption of LCFS in certain jurisdictions is that GHG-intensive crudes will simply be routed to other markets through "emissions leakage" or "shuffling". Barr (2010) analyzed the potential for the implementation of an LCFS policy to actually result in an increase in GHG emissions (rather than the intended decrease) because of a "shuffling," where the fuels sector would support the most inexpensive avenues to comply with the LCFS, thereby shuffling production and sales that may double GHG emissions resulting from crude oil transport to and from areas affected by the LCFS policy. Barr (2010) suggests that an approved LCFS would result in increased GHG emissions based on a reduction of crude oil imported from Canada and subsequent rerouting of crude imports and exports to account for this displacement. If LCFS were increasingly required in the U.S., this would be expected to discourage overall U.S. imports of oil sands crude from Canada, and in turn would encourage importing of crude oil to the U.S. from areas that produce light sweet crude, likely the Middle East. Canadian crude sources would be diverted to other countries not affected by LCFS, and supplies in the U.S. negatively affected by LCFS requirements would be replaced with supplies from more distant parts of the world. The term "emissions leakage" refers to the phenomenon where consumers and producers can purchase or produce fuels at lowest cost by shifting consumption and production to unregulated markets (Yeh and Sperling 2010). In contrast to the Barr's (2010) finding that emissions leakage through fuel shuffling would result in increased GHG emissions, Yeh and Sperling (2010) note that "studies examining the effectiveness of a regional carbon policy or an LCFS suggest that in the case of extreme leakage, the marginal benefits of a carbon policy can be close to zero", but nonetheless they did not project a net increase in GHG emissions.

The avoidance of emissions leakage through fuel shuffling is a challenge of implementing any climate policy that focuses on the energy sector, including LCFS policies, since transport fuels are internationally traded commodities (Yeh and Sperling 2010). To some extent, leakage could be mitigated if similar standards are adopted throughout the world (Sperling and Yeh 2009). LCFS policies have already been adopted in California, British Columbia, the United Kingdom, and the European Union, and are in development in Oregon and Washington, nine states in the Midwest, and 11 states in the Northeast, according to the Pew Center on Global Climate Change (2011). Adoption of LCFS policies in U.S. and international markets would help mitigate the effect of crude shuffling and emissions leakage.[4] An additional factor that will minimize crude shuffling is the oil refinery sectors' varied processing arrangements designed to process a specific composition of crude oil feedstocks (EPA 1995). The refineries' process optimization for different crude oil feedstocks hinders the ability of fuel refineries to

[4]According to Sperling and Yeh (2009), "a major challenge for the LCFS is avoidance of 'shuffling' or 'leakage.' Companies will seek the easiest way of responding to the new LCFS requirements. That might involve shuffling production and sales in ways that meet the requirements of the LCFS but do not actually result in any net change. For instance, a producer of low-GHG cellulosic biofuels in Iowa could divert its fuel to California markets and send its high carbon corn ethanol elsewhere. The same could happen with gasoline made from tar sands and conventional oil. Environmental regulators will need to account for this shuffling in their rule making. This problem is mitigated and eventually disappears as more states and nations adopt the same regulatory standards and requirements."

switch crude oil feedstocks from light to heavy blends without incurring additional costs for process modifications.

An additional objective of LCFS policies is to stimulate innovation in the transportation and fuels sectors that would minimize fuel shuffling. For example, a study by the University of California indicates that LCFS "requires innovation in fuel and/or vehicle technologies. Because innovation in the transportation sector is necessary to achieve long-term climate stabilization in any case, the fact that the LCFS will stimulate innovation in the near term is an advantage, not a problem" (Farrell and Sperling 2007). Even in cases where fuel shuffling causes an increase in the GHG emissions resulting from crude oil transport, it is unlikely that overall life-cycle GHG emissions would increase significantly because crude and fuel transportation emissions have a small to moderate effect on well-to-wheel GHG emissions. Jacobs (2009) and NETL (2008) found that crude and fuel transportation emissions make up less than one to four percent of total well-to-wheels (WTW) emissions.

Finally, a goal of LCFS is to promote the development of ultra-low carbon fuels such as advanced biofuels, transportation electricity, biomethane, and hydrogen, and thus to provide an incentive to shift the transportation sector away from fossil fuels. As noted by Sperling and Yeh (2009), as compared to traditional fossil fuels, advanced low- or zero-carbon fuel sources are currently competing on a "very uneven playing field: the size, organization, and regulation of these industries are radically different." They argue that as LCFS creates a need for the transportation sector to greatly reduce their GHG emissions, these new fuels and vehicles have the opportunity to become more economical and increase their market share.

Cumulative Effects of GHG

Neither the federal government nor states crossed by the proposed Project have established thresholds for determining the significance of GHG emissions. While no final thresholds currently exist, this assessment of the direct and indirect contributions of the proposed Project to global GHG emissions was conducted in accordance with CEQ draft guidance for GHG (CEQ 2010) that established a draft threshold for NEPA purposes of 25,000 metric tpy for CO2-e. There is a general scientific consensus that the cumulative effects of GHG have influenced climate change on a global scale, which is considered a significant cumulative effect.

Construction and Operation Emissions

As discussed in Section 3.12, the GHG emissions during construction of the proposed Project would total approximately 236,978 tpy of CO_2-e over the construction period and direct GHG emissions during proposed Project operation would total approximately 85 tpy of CO2-e. Indirect GHG emissions associated with electrical generation for the proposed Project pump stations are estimated at approximately 2.6 to 4.4 million tons of CO2 per year for a proposed initial capacity of 700,000 bpd and a potential capacity of 830,000 bpd, respectively, as calculated using EPA AP-42 emission factor for large diesel engines and assuming 30 pump stations with 79 to 132 pumps rated at 6,500 hp. This contribution to cumulative GHG impacts from proposed Project construction and operation is very small compared to total GHG emissions for the United States (CO2 equivalents from anthropogenic activities) which totaled 7,054 million tons in 2006, and global CO2 emissions which totaled 28,193 million tons in 2005 (CO2 equivalents from fuel combustion) (EPA 2008). Construction activities associated with the proposed Project for each year represent less than 0.003 percent and 0.0008 percent of the national and global GHG emissions, respectively. While the EPA has released proposed regulations that would require approximately 13,000 facilities nationwide to monitor and report their CO2 and other GHG emissions, the proposed Project would not satisfy the definition of these regulated facilities and there are no federal regulations or guidance to definitively identify the significance of the GHG emissions associated with operation of the Project. Although the GHG emissions associated with construction of the proposed Project would be greater than the CEQ draft threshold of 25,000 tpy of CO2-e that is suggested as a useful presumptive threshold for disclosure during NEPA review, the overall contribution to cumulative GHG impacts from proposed Project construction and operation would not constitute a substantive contribution to the U.S. or global emissions.

Indirect Cumulative Impacts and Life Cycle Greenhouse Gas Emissions

The following discussion on GHG life cycle emissions associated with oil sands is provided in response to comments on the draft EIS and supplemental draft EIS. DOS is providing this information as a matter of policy, although the proposed Project would not substantively influence the rate or magnitude of oil extraction activities in Canada, or the overall volume of crude oil transported to the U.S. or refined in the U.S. (EnSys 2010). To assist in addressing concerns relative to GHG, the DOS third party contractor requested that ICF International LLC (ICF) a detailed review of key studies in the existing literature that address life-cycle GHG emissions of petroleum products, including petroleum products derived from Canadian oil sands, and a comparison of life cycle GHG emissions reported in the literature for Canadian oil sands derived crude oil and refined products with those of reference crude oils. A summary of the ICF report is presented in the following sections and the full report is presented in Appendix V.

Introduction

The EnSys (2010) report commissioned by DOE evaluated potential influences of the proposed Project on global, U.S., and regional oil demand; the effect of that demand on continued or expanded development of Western Canadian Sedimentary Basin (WCSB) oil sands crude oil sources; and assessments of global life-cycle GHG impacts under 14 separate crude oil transportation scenarios (Appendix V). As a part of that analysis, EnSys estimates the changes in life-cycle GHG emissions resulting from these scenarios, including a “no expansion” scenario (i.e., a scenario in which no additional pipelines beyond those in operation as of late 2010 are constructed to transport crude oil from WCSB). The GHG emissions estimated for each scenario are related to quantities of specific WCSB oil sands derived crude oils produced and their respective life-cycle GHG intensity. The EnSys (2010) analysis relied on the life-cycle GHG emission factors developed by the DOE National Energy Technology Laboratory (NETL 2008 and NETL 2009).[5] NETL’s estimates address a range of the world crude oils consumed in the United States, including the WCSB oil sands crude oils as well as the “average crude” consumed in the United States in 2005.[6] Because the NETL-developed emission factors were selected to be a key input to the EnSys (2010) analysis and to EPA’s renewable fuel regulations, they serve as an important reference case for evaluating life-cycle emissions for different crude sources. Thus, while this section provides an assessment of the differences between the life-cycle GHG emissions associated with Canadian oil sands derived crudes that may be refined in the United States versus reference crudes, it also specifically compares results from other literature against the NETL studies’ base case. A more detailed description of the ICF review is provided in Appendix V.

Life-Cycle Carbon Overview

Evaluating life-cycle emissions provides a method to assess the relative GHG emissions between various sources of crude oil. The life-cycle assessment (LCA) methodology attempts to identify, quantify and track carbon emissions arising from the development and use of a hydrocarbon resource. It is helpful to

[5] EnSys used factors from the “NETL: Petroleum-Based Fuels Life Cycle Greenhouse Gas Analysis – 2005 Baseline Model,” which were applied for each scenario within the DOE version of the Energy Technology Perspective (ETP) model.
[6] This 2005 average serves as the baseline in the U.S. Renewable Fuel Standard Program (EPA 2010).

characterize carbon emissions into what can be considered primary and secondary flows. The primary carbon emissions are associated with the various stages in the life cycle from the extraction of the crude from the reservoir to refining to combustion of the refined fuel products (typically referred to as a "well-to-wheels" analysis). The secondary carbon emissions are associated with activities (e.g., land use impacts) not directly related to conversion of the hydrocarbon resource into useful product fuels.

Most of the GHG emissions from hydrocarbon resource development results from three primary steps in the LCA: production of the crude oil, refining of the crude oil, and combustion of the refined products. Transportation of the crude oil to the refinery and transportation of the products to market also contribute to GHG emissions. The primary objective of refining crude oil is to produce three premium refined products: gasoline, diesel, and kerosene/jet fuel (i.e., gasoline and distillates). These primary GHG emissions associated with fuel production drive the economics and engineering of the oil business. In addition to the primary emissions arising from the production, transportation, refining, and combustion steps of the LCA, there is a range of secondary carbon emissions to be considered. For example, extracting crude can influence secondary GHG emissions, such as changes in biological or soil carbon stocks resulting from land-use change during mining. In addition to premium fuels, typically 5 to 10 percent of the carbon in the petroleum resource ends up in co-products, such as petroleum coke, that are often (but not always) combusted and converted to CO_2. As discussed in greater detail below, these secondary flows are treated differently across the LCA literature and estimates of specific process inputs and emission factors vary according to the underlying methods and data sources used in each LCA.

The GHG emission factors modeled by NETL are based on a well-to-wheels (WTW) LCA. WTW assessments for petroleum-based fuels focus on the GHG emissions associated with extraction of the crude oil from reservoirs, transportation of crude oils to refineries, refining of the crude oil, distribution of refined product (e.g., gasoline, diesel, and jet fuel) to retail markets, and combustion of these fuels in vehicles or planes. For some WCSB oil sands crude oils, the assessment also addresses upgrading of the extracted crude oil (i.e., partial refining of some oil sands crude oils to produce synthetic crude oil). Other analyses (e.g., well-to-tank [WTT] analyses) establish different life-cycle boundaries and evaluate only the emissions associated with the processes prior to combustion of the refined products. Inclusion of the combustion phase allows for a more complete picture of crude oil contribution to GHG emissions because this phase represents between approximately 70 to 80 percent (depending on crude source) of the WTW emissions (CERA 2010). As a result, a WTW analysis reduces the percent differential in total GHG emissions between different crude oil sources. Because a WTT analysis focuses on pre-combustion processes, it highlights the differences in upstream life-cycle GHG emissions associated with the extraction, transportation, and refining of crude oils from different sources, as illustrated in a comparison of Figures 3.14.3-1 and 3.14.3-2.

Scope of Review of Life-cycle Studies

A list of the reports reviewed for this assessment is presented in Table 3.14.3-8. The primary studies and additional supplemental reports for the assessment were selected on the following basis:

- The reports evaluate WCSB oil sands crude oils in comparison to crude oils from other sources;
- The reports focus on GHG impacts throughout the life-cycle of crude oils and their related products;
- The reports were published within the last 10 years, and most were published within the last five years;

- The reports represent the perspectives of various stakeholders, including industry, governmental organizations, and non-governmental organizations; and
- The reports originate from research bodies within the United States, Canada, and international locations.

TABLE 3.14.3-8
Primary and Additional Studies Evaluated[a]

	Type
Primary Studies Analyzed	
NETL. 2008. Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels.	Individual LCA
NETL 2009. An Evaluation of the Extraction, Transport and Refining of Imported Crude Oils and the Impact of Life Cycle Greenhouse Gas Emissions.	Individual LCA
IEA. 2010. World Energy Outlook.	Meta-analysis
IHS CERA. 2010. Oil Sands, Greenhouse Gases, and U.S. Oil Supply: Getting the Numbers Right.	Meta-analysis
NRDC. 2010. GHG Emission Factors for High Carbon Intensity Crude Oils ver. 2.	Meta-analysis
Energy-Redefined LLC for ICCT. 2010. Carbon Intensity of Crude Oil in Europe Crude.	Individual LCA
AERI/Jacobs Consultancy. 2009. Life Cycle Assessment Comparison of North American and Imported Crudes.	Individual LCA
AERI/TIAX LLC. 2009. Comparison of North American and Imported Crude Oil Lifecycle GHG Emissions.	Individual LCA
Charpentier, et al. 2009. Understanding the Canadian Oil Sands Industry's Greenhouse Gas Emissions.	Meta-analysis
Additional Studies/Models Analyzed	
RAND Corporation. 2008. Unconventional Fossil-Based Fuels: Economic and Environmental Trade-Offs.	Individual LCA
Pembina. 2005. Oil Sands Fever: The Environmental Implications of Canada's Oil Sands Rush.	Partial LCA
Pembina. 2006. Carbon Neutral 2020: A Leadership Opportunity in Canada's Oil Sands. Oil sands issue paper 2.	Partial LCA
McCann and Associates. 2001. Typical Heavy Crude and Bitumen Derivative Greenhouse Gas Life Cycles.	Individual LCA
Pembina. 2011. Life cycle assessments of oil sands greenhouse gas emissions: A checklist for robust analysis.	White Paper
GHGenius. 2010. GHGenius Model, Version 3.19. Natural Resources Canada.	Model
GREET. 2010. Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model, Version 1.8d.1. Argonne National Laboratory.	Model

[a] See Appendix V for more information on each study.

For WCSB oil sands crude oils, the assessment focused on those that could be transported through the proposed Project. Based on this criterion, the solid, raw bitumen from oil sands was eliminated except to the extent that it is included within averaged results (e.g., NETL provides a single WCSB oil sands estimate that represents a weighted average of 43 percent crude bitumen from *in situ* production and 57 percent SCO from mining).

This assessment addresses three types of WCSB oil sands crude oils that are extracted either by mining or the *in-situ* thermal processes. Conventional strip-mining methods are used to extract oil sands deposits that are less than about 75 meters below the surface.[7] To recover deeper deposits of oil sands, *in situ* methods are used. *In situ* recovery methods typically involve injecting steam into an oil sands reservoir to heat – and thus decrease the viscosity of – the bitumen, enabling it to flow out of the reservoir sand matrix to collection wells. Steam is injected using cyclic steam stimulation (CSS), where the same well cycles between periods of steam injection and bitumen production, or by steam-assisted gravity drainage (SAGD), where a pair of horizontal wells is drilled; the top well is used for steam injection, and the bottom well for bitumen production. Due to the high energy demands for steam production, steam injection *in situ* methods are generally more GHG-intensive than mining operations. The WCSB crude oil types assessed in this study are described briefly below:

- Synthetic crude oil (SCO) − SCO is produced from bitumen via a refinery conversion of heavy hydrocarbons to lighter hydrocarbons. While SCO can be sour, it is usually a light, sweet crude oil without heavy fractions.
- Dilbit (diluted bitumen) − Dilbit is bitumen blended with a diluent, usually a natural gas liquid such as condensate, to create a "lighter" product and to reduce viscosity so the dilbit can be transported via pipeline. Dilbit feedstock processing requires more heavy oil conversion capacity than most crude oils.
- Synthetic bitumen (synbit) – Synbit is usually a combination of bitumen and SCO. The properties of synbit blends vary greatly, but blending lighter SCO with heavier bitumen results in a product more similar to conventional crude oil than SCO or dilbit alone.

The reference crudes evaluated in the literature reflect a range of sources and GHG emissions and include:

- The average U.S. barrel consumed in 2005 (from NETL 2008). This reference was selected because it provides a baseline for fuels produced from the average crude consumed in the United States.
- Venezuela Bachaquero and Mexico Maya, which are representative of heavy crudes currently refined in PADD III refineries. It is assumed that these crude oils would be displaced or replaced by the WCSB oil sands crude oil that would be transported by the proposed Project, although it is likely that they would find markets elsewhere and would still be produced.
- Saudi Light (i.e., Middle East Sour), which was taken to be the balancing grade for world crude oil supplies in the *Keystone XL Assessment* (EnSys 2010). This is the crude that may ultimately be backed out of the world market if additional supply of WCSB oil sands crudes is produced.

Evaluation of Key Factors Influencing the GHG Results

There are many differences in the **study design factors** and **input assumptions** for life-cycle GHG analyses of WCSB oil sands crude oils relative to the four reference crude oils.

Study design factors relate to how the GHG comparison is structured within each study. These factors include the overall purpose and goal of the study, the types of crudes and refined products that are compared to each other, the timeframe over which the results of the study are applicable, the life-cycle boundaries established to make the comparison, the functional units or the basis used for comparing the life-cycle GHGs for crudes or fuels to each other (e.g., expressing GHG emissions per unit of crude, SCO,

[7] Mining accounts for roughly 48 percent of total bitumen capacity in the WCSB oil sands as of mid-2010 (IEA 2010, p. 152).

all refined products, or specific refined products such as gasoline or diesel, in terms of volume, energy, or distance units), and the treatment of co-products other than gasoline, diesel, and jet fuels (e.g., asphalt, petroleum coke, liquefied refinery gases, and lubricants). Some studies allocate a fraction of the GHG emissions from refining to these co-products and exclude these emissions from the life-cycle boundary (i.e., they are not included within the studies' life-cycle results). Other studies include these emissions but assign credits for GHG emissions from other sources that are offset by combustion of the co-products (e.g., electricity exported from a refinery replaces natural gas-fired power generation, and petroleum coke from a refinery replaces coal).

Key design factors across the studies identified through this assessment are summarized in Table 3.14.3-9. In general, the studies reviewed are consistent in their treatment of some factors (e.g., generally excluding emissions associated with land-use changes) but vary in their treatment of other factors (e.g., emissions from petroleum coke and electricity cogeneration). Most studies exclude land-use change and the emissions arising from the construction of capital infrastructure. Importantly, only a few studies modeled the effect that upgrading SCO has on downstream GHG emissions at the refinery. Several (but not all) studies include the following:

- Upstream production of purchased fuels and electricity used to power machinery in the oil fields and at refineries;
- Flaring and venting;
- Fugitive emissions; and
- Methane emissions from oil sands mining and tailings ponds.

Input assumptions impact life-cycle analysis results and assumptions are input at each life-cycle stage. Due to limited data availability and the complexity of and variation in the practices used to extract, process, refine, and transport crude oil, studies often use simplified assumptions to model GHG emissions. For example, for both WCSB oil sands crude oils and reference crude oils, assumptions about how much petroleum coke is produced, stored, and combusted at the upgrader or refinery, and how much is sold to other users, are key drivers of GHG emission estimates. Transportation assumptions have a more limited effect, but vary across the studies. Key input assumptions for WCSB oil sands derived crude oils include:

- Type of extraction process (i.e., mining or *in situ* production);
- Steam-oil ratio assumed for *in situ* operations;
- Efficiency of steam generation, and thus its energy consumption; and
- Upgrading processes modeled for SCO and whether or not estimated refinery GHG emissions account for upgrading.

For the reference crudes, key input assumptions include the oil-water and gas-oil ratios that are used to estimate reinjection and venting or flaring requirements, and whether and what type of artificial lift is considered for extracting crude oil.

Life-cycle GHG emissions for gasoline produced from WCSB oil sands crude oils relative to other reference crude oils consumed in the United States, as reported by NETL (2009) are summarized in Table 3.14.3-10. The results are subject to several input assumptions that influence the results of the analysis. These assumptions and their estimated scale of impact on the WTW results are summarized in the last two columns of Table 3.14.3-10.

TABLE 3.14.3-9
Summary of Key Study Design Features that Influence GHG Results

Estimated Relative WTW Impact:[a]		High					Medium				Low
Source	**Data Reference Year(s)**	**Petroleum coke combustion[b]**	**Cogeneration credit[c]**	**Upstream production of fuels incldued[d]**	**Flaring/ venting GHG emissions included**	**Capital equipment included[e]**	**Methane emissions from tailing ponds included**	**Fugitive leaks included**	**Local and indirect land use change included**	**Refinery emissions account for upgrading[f]**	**Methane emissions from mine face**
NETL, 2008	2005	No	NS	Yes	Yes	No	NS	Yes	No	No	NS
NETL, 2009	2005	No	NS	Yes	Yes	No	NS	NS	No	No	NS
IEA, 2010	2005-2009	NS	NS	Yes	NS	NS	Yes	NS	No	NA	NS
IHS CERA, 2010	~2005-2030	V	V	No	NS	NS	V	NS	No	NA	V
NRDC, 2010	2006-2010	NS[g]	NS[g]	P	NS	NS	NS	NS	No	NA	NS
ICCT, 2010	2009	NS	No	P	Yes	No	NS	Yes	No	No	NS
AERI/Jacobs, 2009	2000s	Yes	Yes	Yes	Yes	No	No	No	No	Yes	No
AERI/TIAX, 2009	2007-2009	P	P	Yes	Yes	No	Yes	Yes	No	Yes	Yes
Charpentier, et al., 2009	1999-2008	NS[g]	NS[g]	V	NS	V	NS	NS	No	NA	NS
RAND, 2008	2000s	NS	NS	NS	Yes	No	Yes	Yes	No	No	Yes
Pembina Institute, 2005	2000, 2004	NS	NS	NS	P	No	NS	P	No	No	NS
Pembina Institute, 2006	2002-2005	NS	NS	No	P	No	Yes	Yes	No	No	Yes
McCann, 2001	2007	P	NS	Yes	NS	No	NS	NS	No	NS	NS
GHGenius, 2010	Current	Yes	No	Yes	Yes	No	Yes	Yes	Local	NS	Yes
GREET, 2010	Current	NS	NS	Yes	Yes	No	NS	Yes	No	NS	NS

Notes: Yes = included in life-cycle boundary; No = not included; P = partially included; NS = not stated; NA = not applicable; V = varies by study addressed in meta-study.

[a] High impact = greater than 3% change in WTW emissions. Medium impact = 1 – 3% change in WTW emissions. Low impact = less than 1% change in WTW emissions.

[b] "Yes" indicates that GHG results for products such as gasoline, diesel, and jet fuel do include petroleum coke production and combustion. "No" indicates that GHG emissions from petroleum coke production and combustion were not included in the system boundary for gasoline, diesel, or jet fuel. The effect of including petroleum coke depends on how much is assumed to be stored at oil sands facilities versus sold or combusted, and whether a credit is included for coke that offsets coal combustion.

[c] "Yes" indicates that the study applied a credit for electricity exported from cogeneration facilities at oil sands operations that offsets electricity produced by other power generation facilities. "No" indicates a credit was not applied. Including a credit for oil sands will reduce the GHG emissions from oil sands crudes relative to reference crudes.

[d] Indicates whether studies included GHG emissions from the production of fuels that are purchased and combusted on-site for process heat and electricity (e.g., natural gas).

[e] Indicates whether the study included GHG emissions from the construction and decommissioning of capital equipment such as buildings, equipment, pipelines, rolling stock.

[f] Indicates whether refinery emissions account for the fuel properties of SCO relative to reference crudes. Since SCO is upgraded before refining, it requires less energy and GHG emissions to refine into gasoline, diesel, and jet fuel products.

[g] Not discussed in the meta-study; may vary by individual studies analyzed.

TABLE 3.14.3-10
GHG Emissions for Producing Gasoline from Different Crude Sources from NETL 2009 and Estimates of the Impact of Key Assumptions on the Oil Sands-U.S. Average Differential

	GHG Emissions (g CO2e/MJ LHV gasoline)[a]					Findings on Key Assumptions Influencing Results	
Life-Cycle Stage	**2005 U.S. Average**	**Canadian Oil Sands**	**Venezuela Conventional**	**Mexico**	**Saudi Arabia**	**Description**	**Estimated Ref Crude WTW Impact[b]**
Crude Oil Extraction	6.9	20.4[c]	4.5	7.0	2.5	Oil sands estimate assumes a weighted average of 43% crude bitumen (not accounting for blending with diluent to form dilbit) from CSS *in situ* production and 57% SCO from mining, based on data from 2005 and 2006	NA
Upgrading	NA	IE	NA	NA	NA		
Crude Oil Transport	1.4	0.9	1.2	1.1	2.8	Relative distances vary by study	Low increase or decrease
Refining	9.3	11.5[d]	11.0	12.9	10.4	Did not evaluate impact of upgrading SCO prior to refinery; only affects oil sands crudes	Medium decrease
Finished Fuel Transport	1.0	0.9	0.9	0.9	0.9	Transportation excluded co-product distribution	Low increase
Total WTT	**18.6**	**33.7**	**17.6**	**22.0**	**16.7**		
Fuel Combustion	72.6	72.6	72.6	72.6	72.6	Fuel combustion excluded combustion of petroleum coke and other co-products	Low to high increase[e]
Total WTW	**91.2**	**106.3**	**90.2**	**94.6**	**89.3**		
Difference from 2005 U.S. Average	**0%**	**17%**	**-1%**	**4%**	**-2%**		

Notes: IE = Included Elsewhere; NA = Not Applicable. LHV = Lower Heating Value. WTT = Well-to-Tank; WTW = Well-to-Wheels.

[a] NETL 2009 values converted from kgCO_2e/MMBtu using conversion factors of 1,055 MJ/MMBtu and 1000 g/kg.

[b] Estimated impact on the WTW GHG emissions for reference crudes, except where noted (i.e., refining assumption affects oil sands crudes), as result of addressing the key assumptions/ missing emission sources. High = greater than approximated 3% change, Medium = approximated 1 – 3% change, and Low = less than approximated 1% change in WTW emissions.

[c] Included within extraction and processing emissions.

[d] Calculated by subtracting other process numbers from WTT total; report missing this data point.

[e] The effect that including petroleum coke combustion has on WTW results depends upon assumptions about the end-use of petroleum coke and whether it is used to offset coal in electricity generation.

For example, NETL (2009) developed its weighted-average GHG emission estimate for oil sands extraction (including upgrading) from data on mining and CCS in situ operations in 2005 and 2006. The estimate that the NETL study used for mining oil sands was based on a 2005 industry report that estimates higher values than more recent estimates of surface mining GHG emissions (TIAX 2009, Jacobs 2009). The *in situ* GHG estimate is based on a CSS operation which—while CSS operations tend to be more GHG intensive than SAGD processes—is generally in the range of *in situ* estimates in other studies (e.g., TIAX 2009, Jacobs 2009). The NETL study, however, did not account for the fact that natural gas condensate is blended with crude bitumen to form dilbit, which is transported via pipeline to the United States. Since condensate has a lower GHG intensity than crude bitumen, per-barrel GHG emissions from dilbit are less than per-barrel emissions from crude bitumen.

The NETL study only considered combustion emissions from gasoline, diesel, and kerosene-type jet fuel and allocated the refinery emissions from co-products other than gasoline, diesel, and jet fuel to the co-products themselves. This approach removes the GHG emissions associated with producing and combusting co-products from the study's life-cycle boundary. This approach is consistent with DOE/NETL's objective of estimating the contribution of crude oil sources to the 2005 baseline GHG emissions profile for three transportation fuels (gasoline, diesel, and kerosene-type jet fuel). A portion of the petroleum coke produced from partial refining (upgrading) of WCSB oil sands crudes is stockpiled (sequestered) in Alberta and does not contribute to GHG emissions, whereas virtually all of the petroleum coke produced at U.S. refineries is ultimately combusted. As explained in more detail in the appendix on GHG emissions, if petroleum coke produced from refineries is assumed to offset coal combustion, however, the net emissions from coke combustion will be much smaller (Appendix V). As a result, the effect of including petroleum coke combustion depends upon study assumptions about the end use of petroleum coke at both the refinery and upgrader, and whether petroleum coke use offsets other fuels, such as coal.

Additionally, the NETL study used linear relationships to relate GHG emissions from refining operations to specific crudes based on API gravity and sulfur content. The study notes that these relationships do not account for the fact that bitumen blends (dilbits and synbits) and SCO in particular will produce different fractions of residuum and light ends than "full-range" crudes. Accounting for the variable properties of these crude oil types and resulting refinery GHG emissions would change the differences between WTW GHG emissions for premium fuels refined from WCSB oil sands derived crude oils relative to reference crude oils.

GHG Intensity of WCSB Crudes

The wide variation in design and input assumptions within the various studies leads to a wide divergence in calculated GHG emissions. Based on an extensive review of information provided in the studies reviewed, the WTW and WTT GHG emissions of gasoline produced from WCSB oil sands derived crude oils were compared to similar emission estimates from four reference crude oils (see Figures 3.14.3-1 and 3.14.3-2). Additional information on the data sources and assessment is available in Appendix V.

As shown in Figure 3.14.3-2, the NETL WTW GHG emission estimates from gasoline produced from WCSB oil sands derived crude oils are 17 percent higher than that the GHG emission estimates for gasoline produced from the average mix of crude oils consumed in the United States in 2005, and are approximately 19, 13, and 16 percent higher than GHG emission estimates for Middle East Sour, Mexican Heavy (i.e., Mexican Maya), and Venezuelan[8] crude oils, respectively (NETL 2009).

The WTW emission estimates for gasoline produced from SCO via *in situ* methods of oil sands extraction (i.e., SAGD and CSS) in general are higher than the GHG emission estimates for mining extraction methods (Figure 3.14.3-1). This difference is primarily attributable to the energy requirements of producing steam as part of the *in situ* extraction process.

Gasoline produced from dilbit generally has lower estimated GHG life-cycle emissions than gasoline produced from SCO extracted by mining and *in situ* methods. This is a result of blending raw bitumen with a diluent (e.g., gas condensate) for transport via pipeline. Diluent produces fewer GHG emissions than bitumen, so blending the two together results in lower WTW GHG emissions. This assessment

[8] NETL uses Venezuelan Conventional as a reference crude rather than Venezuelan Bachaquero.

evaluates the refining of both bitumen and diluent at the refinery, since diluent will not be separated from the dilbit blend and recirculated by the proposed Project. WTW GHG emission estimates from gasoline produced from synbit, a blend of SCO and bitumen, are similar to WTW GHG emission estimates for gasoline produced from SCOs produced from bitumen extracted by either mining or *in situ* methods.

Similar trends were evident in the WTT GHG analyses (see Figure 3.14.3-3). The percentage increase in WTT GHG emission estimates for gasoline produced from WCSB oil sands derived crude oils as compared to gasoline produced from reference crudes (Figure 3.14.3-3) is much larger than the percent increases for WTW GHG emission estimates (Figure 3.14.3-2). Most of the gasoline life-cycle WTW GHG emissions occur during the combustion stage irrespective of the feedstock (i.e., reference crude or oil sands). Because WTT GHG emission estimates do not include the combustion phase, the differences in GHG life-cycle emissions associated with crude oil extraction and refining are emphasized; when expressing the comparison in terms of percentage increases, the same incremental differences in the numerator are divided by a smaller denominator.

The GHG emissions associated with different oil sands extraction, processing, and transportation methods vary by roughly 25 percent on a WTW basis. Life-cycle GHG emission estimates for fuels produced from WCSB oil sands crude oils are higher than emission estimates for fuels produced from lighter crude oils, such as Middle East Sour crudes and the 2005 U.S. average mix. Compared to heavier crude oils from Mexico and Venezuela, WTW emission estimates associated with fuels derived from WCSB oil sand-derived crude oils are 37 percent higher than for SAGD SCO (petroleum coke burned at the upgrader) and 2 percent lower for mining-derived SCO (including storing or selling the petroleum coke).

Incremental GHG Emissions from Oil Sands Crudes Potentially Transported by the Proposed Project Compared to Reference Crudes

As noted earlier in this chapter, based on the EnSys (2010) analysis, under most scenarios the proposed Project would not substantially influence the rate or magnitude of oil extraction activities in Canada, or the overall volume of crude oil transported to the United States or refined in the United States. Thus, from a global perspective, the decision whether or not to build the Project will not affect the extraction and combustion of WCSB oil sands crude on the global market. However, on a life-cycle basis and compared with reference crudes refined in the United States, the reliance on oils sands crudes for transportation fuels would likely result in an increase in incremental GHG emissions.[9] Although a life-cycle analysis is not strictly necessary for purposes of evaluating the potential environmental impacts attributable to the proposed Project under NEPA, it is relevant and informative for policy-makers to consider in a variety of contexts. For illustrative purposes, this section provides information on the incremental life-cycle GHG emissions (in terms of the U.S. carbon footprint) from WCSB oil sands crudes likely to be transported by the proposed Project (or any transboundary pipeline). The incremental emissions are a function of: (i) the throughput of the pipeline, (ii) the mix of oil sands crudes imported, and (iii) the GHG-intensity of the crudes in the pipeline compared to the crudes they displace. Acknowledging the methodological differences in GHG-intensity estimates between the studies, the weighted-average GHG emissions for selected studies were calculated to estimate the incremental GHG emissions from WCSB oil sands relative to displacing an equivalent volume of reference crudes in U.S. refineries.

[9] Note that a substantial share of these emissions would occur outside of the United States. Also note that the U.S. National Inventory Report, like other national inventories, only characterizes emissions within the national border, rather than using a life-cycle approach. If the United States used a life-cycle approach, upstream emissions from other imported crudes would be attributed to the United States.

Jacobs (2009), TIAX (2009), and NETL (2009) formed the sub-set of studies used to develop weighted averages for purposes of the carbon footprint analysis. These studies are independent analyses of WTW GHG emissions from oil sands and reference crudes that utilize consistent functional units for comparison with each other. The other studies included in this assessment either did not look at the full WTW fuel life-cycle, did not evaluate emissions on a consistent functional unit basis for comparison, or are meta-analyses that include the results of the Jacobs and TIAX studies. Despite the underlying differences in study assumptions, the comparisons illustrated below are internally consistent and make comparisons between crudes from the same study.

For illustrative purposes, Figure 3.14.3-4 shows the percent change in weighted-average GHG emissions from the mix of WCSB oil sands crude oil likely to be transported in the proposed Project relative to each of the four reference crudes on a gasoline basis. The change in GHG emissions is calculated for the Jacobs (2009) and TIAX (2009) values by weighting the WTW GHG intensity of oil sands crudes by the composition of crudes that could be transported in the proposed Project. For purposes of this assessment, it is assumed that 50 percent of pipeline throughput would be SCO, and 50 percent would be dilbit. All WCSB dilbit is currently produced using in situ production and 12 percent of SCO is produced via in situ methods (ERCB 2010), yielding a final mix of 50 percent *in situ*-produced dilbit, 44 percent mining-produced SCO, and six percent *in situ*-produced SCO.[10] The results are representative of near term expected WCSB oil sands composition and GHG-intensities.

The Canadian oil sands average from NETL (2009) is also plotted on Figure 3.14.3-4 for comparison with Jacobs (2009) and TIAX (2009), although the NETL result assumes a mix of 43 percent crude bitumen and 57 percent SCO. The results show a 2 to 19 percent increase in WTW GHG emissions from gasoline produced from the weighted-average mix of oil sands crudes potentially transported in the proposed Project relative to the reference crudes in the near term. Heavier crudes generally take more energy to produce and emit more GHGs than lighter crudes, and in particular, the weighted-average WCSB oil sands crude is currently more energy- and carbon-intensive than lighter crudes like Middle Eastern Sour.

For illustrative purposes, Table 3.14.3-11 shows the incremental annual WTW GHG emissions associated with displacement of 100,000 barrels of each reference crude oil per day with WCSB oil sands crude oil using the weighted-average estimate for the mix of WCSB oil sands crudes likely to be transported in the proposed Project. The incremental GHG emissions were calculated by first multiplying the WTW GHG emission intensities per barrel of gasoline and distillates (i.e., gasoline, diesel, and kerosene/jet fuel) for WCSB and reference crudes from each study by the volume of premium fuel products produced by 100,000 barrels of WCSB oil sands crude. WTW GHG emissions from each reference crude were then subtracted from the WTW GHG emissions from the equivalent volume of WCSB oil sands crude to estimate incremental GHG emissions. We converted the 100,000 barrels of crude to an equivalent volume of gasoline and distillate products using yield data provided in each respective study. As previously noted, these incremental GHG estimates provide an example of the potential effect, on a life-cycle basis, resulting from displacement of reference crude oils in PADD III refineries; on a global scale, the decision whether or not to build the Project will not affect the extraction and combustion of WCSB oil sands crude on the global market (EnSys 2010).

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[10] Of *in situ* WCSB oil sands production from SAGD and CSS facilities, CSS accounts for 47 percent of production, and SAGD accounts for 53 percent. This ratio was used to calculate an average for *in situ*-produced dilbit for TIAX, which provided separate estimates for CSS and SAGD dilbit. Primary *in situ* production of WCSB bitumen (i.e., using conventional oil production techniques) was not included since estimates were not provided in the studies included in the scope of this assessment. Primary production currently accounts for 32.9 thousand cubic meters per day, or 14 percent of total oil sands production (ERCB 2010).

TABLE 3.14.3-11 Incremental Annual GHG Emissions of Displacing 100,000 Barrels Per Day of Each Reference Crude with WCSB Oil Sands (MMTCO2e) by Study			
Reference Crude	Jacobs, 2009	TIAX, 2009[a]	NETL, 2009[a]
Middle Eastern Sour	1.3	2.0	2.5
Mexican Maya	0.5	1.6	1.7
Venezuelan[b]	0.4	0.5	2.4
U.S. Average (2005)	NA	NA	2.3

Note: The incremental annual GHG emissions presented here are calculated using internally consistent comparisons for each reference crude and the weighted average WCSB oil sands crude using information from each respective each study. The incremental annual GHG emissions estimates for displacing the U.S. average (2005) reference crude is only provided for NETL (2009) because only NETL included a U.S. average reference. NA = Not Applicable.

[a] The NETL and TIAX studies allocate a portion of GHG emission to co-products other than gasoline, diesel, and jet fuel products, which are not accounted for in these estimates. As a result, incremental GHG emissions are underestimated for those studies.

[b] Venezuelan conventional crude values for NETL refer to a medium crude, not the heavy crude Venezuelan Bachaquero.

The incremental GHG emissions in Table 3.14.3-7 are compared against four different reference crude oils. To the extent that Middle Eastern Sour is the world balancing crude, as assumed as a model input in EnSys (2010), it may ultimately be the crude that is backed out of the world market by WCSB oil sands crudes. From another perspective, if the proposed Project is built and the PADD III refineries continue using about the same input mix of heavy crudes as they currently use, Venezuelan Bachaquero or Mexican Mayan are likely to be displaced by WCSB oil sand crudes. Finally, NETL (2009) estimated the GHG emissions intensity of the average barrel of crude oil refined in the United States in 2005. The Jacobs and TIAX studies are not compared to this reference crude because they did not include a U.S. average estimate.

The three studies referenced in Table 3.14.3-7 used different methods to allocate GHG emissions between premium fuels (e.g., gasoline, diesel, and jet fuel) and other co-products (e.g., light and heavy ends, petroleum coke, sulfur). Jacobs (2009) attributes all GHG emissions associated with extracting, refining, and distributing other co-products to premium fuels;[11] thus, the incremental GHG emissions shown for Jacobs (2009) in Table 3.14.3-7 take into account the production and use of these co-products.

As noted elsewhere in the EIS, the near-term initial throughput of the proposed Project is projected to be 700,000 barrels of crude per day with a potential capacity of 830,000 barrels per day.[12] Based on the results in the Jacobs study, incremental GHG emissions from the proposed project would be 9 million metric tons of CO_2 equivalent ($MMTCO_2e$) annually at the initial pipeline capacity, and 11 $MMTCO_2e$ annually at the potential capacity, if the oil sands crude oil transported by the proposed Project offset an equivalent amount of Middle Eastern Sour crude oil. Incremental emissions would be 3.7 to 4.4 $MMTCO_2e$ annually at initial and potential capacities, respectively, if oil sands crude oil offset Mexican Maya crude oil, and 3.1 to 3.7 $MMTCO_2e$ annually if Venezuela Bachaquero crude oil were offset.

Unlike the Jacobs study, the TIAX and NETL studies allocate a portion of GHG emissions to co-products other than gasoline, diesel, and jet fuel products, and these emissions are not included in the studies'

[11] Jacobs (2009) also applies a substitution credit for offsetting other products that are replaced by each of the co-products. For example, the production and use of petroleum coke is assumed to offset GHG emissions from coal-fired electricity production.

[12] It was assumed that the pipeline would be operating 365 days a year at an *initial* capacity of 700 thousand barrels per day and a *potential* capacity of 830 thousand barrels per day.

WTW GHG results. As a result, the incremental GHG emissions estimates for TIAX and NETL in Table 3.14.3-7 may underestimate total incremental GHG emissions.[13]

TIAX (2009, p. 34; Appendix D, p. 42) found that the change in refinery energy use associated with an incremental barrel output of co-products other than gasoline, diesel, and jet fuel contributed to less than one percent of energy use and GHG emissions per barrel of refined product at the refinery, so any error introduced by the underestimate of GHG emissions attributed to co-products is negligible. According to the results of the TIAX study, incremental GHG emissions would be 14 $MMTCO_2e$ at the initial project capacity and 17 $MMTCO_2e$ annually at the proposed project capacity if oil sands crude oil offset an equivalent amount of Middle Eastern Sour crude oil. Incremental emissions would be 11 to 13 $MMTCO_2e$ and 3 to 4 $MMTCO_2e$ annually if oil sands crudes offset Mexican Maya and Venezuelan Bachaquero crude oil, respectively, at the initial and potential project capacities.

Based on the results of NETL (2009), incremental emissions would be 18 to 21 $MMTCO_2e$ annually if oil sands crude oil offset an equivalent amount of Middle Eastern Sour crude oil at the initial and potential project capacities. Incremental emissions would be 12 to 14 MMTCO2e and 17 to 20 $MMTCO_2e$ annually if oil sands crudes offset Mexican Maya and Venezuelan Bachaquero crude oil, respectively, at the initial and potential project capacities. Compared to the average barrel of crude refined in the United States in 2005, incremental emissions from oil sands crudes would be 16 to 19 $MMTCO_2e$ annually at initial and potential project capacities. The effect of allocating a portion of the life-cycle GHG emissions of refining crude oils to other, non-premium co-products was larger in the NETL study than in either of the studies by Jacobs (which did not allocate any emissions to other co-products) or TIAX (which allocated less than 1 percent of GHG emissions at the refinery to other co-products). To estimate the magnitude of this effect, the NETL results for WCSB oil sands and the 2005 U.S. average crude oils were adjusted to include other product emissions modeled in NETL's analysis. The lead NETL study author was contacted to vet the approach used to make this adjustment in order to ensure that it was made consistently with the NETL study framework (Personal communication, Timothy Skone, 2011). Adjusting the NETL results to include other product emissions could increase the differential between WCSB oil sands and the 2005 U.S. average crude oils by roughly 30 percent.

The full range of incremental GHG emissions estimated across the reference crudes and sub-set of studies is 3 to 17 $MMTCO_2e$ annually at the near term initial throughput or 4 to 21 $MMTCO_2e$ annually at the potential throughput. This overall range of 3 to 21 $MMTCO_2e$ is equivalent to annual GHG emissions from the combustion of fuels in approximately 588,000 to 4,061,000 passenger vehicles or the CO_2 emissions from combusting fuels used to provide the energy consumed by approximately 255,000 to 1,796,000 homes for one year.[14] The differentials presented here are based on life-cycle emission estimates for current or near-term conditions in the world oil market, as can be seen from the reference years used in each report. Over time, however, the GHG emission estimates for fuels derived from both WCSB oil sands crude oils and the reference crude oils are likely to change.

GHG emissions from the production phase for reference crude oils may become more energy-intensive over time due to the need to extract oil from deeper reservoirs by using more energy-intensive secondary

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[13] Adjusting the TIAX and NETL GHG emission estimates to include co-products other than gasoline, diesel, and kerosene/jet fuel would require two pieces of information: (i) the GHG intensity of the other products, for both WCSB crudes and reference crudes, and (ii) the yield of the other products, for both WCSB crudes and reference crudes. TIAX (2009) and NETL (2008) do not provide explicit emissions intensity factors or product yields in a format that enables separate emissions estimates to be developed for these products. These products largely comprise the remaining fractions of the input crude that cannot be converted into premium products.

[14] Equivalencies based on EPA's GHG Equivalency calculator available at: http://www.epa.gov/cleanenergy/energy-resources/calculator.html

and tertiary recovery techniques, such as CO_2 flood. Many of the reference crude oil reservoirs are one to two miles (or more) underground or under the ocean floor. In contrast, the WCSB oil sands deposits are much shallower and can be extracted using either surface mining or near-surface *in situ* methods. Exploration efforts for new deep oil reservoirs will continue as known reservoirs continue to deplete.

In contrast, the extent of the WCSB oil sands deposits is well understood and defined. In the future, *in situ* extraction methods are projected to represent a larger share of the overall oil sands production, increasing from about 45 percent of 2009 oil sands production to an estimated 53 percent by 2030 (ERCB 2010). In particular, the share of SAGD *in situ* extraction methods are projected to rise from roughly 15 percent in 2009 to 40 percent of oil sands production in 2030 (CERA 2010).[15] The GHG profile of this more energy-intensive oil sands extraction method may be reduced by new technologies and innovations to reuse steam onsite and/or improve thermal recovery. However, surface mining is projected to remain a dominant extraction method for WCSB crude oils for the next 20 years (CERA 2010). In consideration of these factors, GHG intensity for future reference crude oils may trend upward while the GHG intensity for WCSB oil sands derived crude oils may be relatively constant to slightly upward. If this is the case, the differential in life-cycle GHG emissions for fuels refined from these crude oils may decrease.

Conclusions

The studies show conclusively that combustion (i.e., tank-to-wheels) phase of the fuel life cycle dominates the total GHG life-cycle emissions under all scenarios. Overall, it is clear that comparisons of GHG life-cycle emission estimates for fuels derived from different sources are sensitive to the choice of boundaries, consistent application of boundary conditions within studies, and to key input parameters. In particular, the results depend on assumptions regarding the use of petroleum coke at oil sands facilities, and upon the weighted-average mix of WCSB oil sands crude transported to the United States by the proposed Project or some other transboundary pipeline. SAGD and CSS *in situ* production methods are generally more GHG-intensive than mining, and while SCO requires upgrading prior to pipeline transport, bitumen blends such as dilbit and synbit require additional refining emissions and do not produce an equivalent amount of premium fuel products per barrel input.

Despite the differences in study design and input assumptions, it is clear that WCSB crudes, as would likely be transported through the proposed Project, are on average somewhat more GHG-intensive than the crudes they would displace in the U.S. refineries. Although EnSys (2010) reported that there would be no substantive change in global GHG emissions and, as explained in Section 4.1.2, there would likely be no substantial change in WCSB imports to PADD III with or without the proposed Project in the medium to long term, the life-cycle GHG emissions associated with transportation fuels produced in U.S. refineries would increase if WCSB crude oils replace existing heavy crude oil sources for PADD III.

We also note that the GHG intensity of reference crudes may increase in the future as more of the world crude supply requires extraction by increasingly energy intensive tertiary and enhanced oil recovery techniques[16]. The energy intensity of surface mined Canadian crudes will likely be relatively constant while higher energy intensive in-situ production may increase somewhat; the proportion of in situ extraction is forecast to increase relative to the less energy-intensive surface mining. Although there is

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15 Although the balance of mining and *in situ* extraction will change in the future, there are incentives for producers to keep GHG intensity as low as possible. For example, Alberta's climate policy requires that oil sands producers and other large industrial GHG emitters reduce their emissions intensity by 12 percent from an established baseline.
16 As with the producers of oil sands, however, in some cases producers of reference crudes are likely to face regulatory pressures or other incentives to lower the GHG intensity of their production process. Such a dynamic could counter the trend towards higher GHG intensities.

some uncertainty in the trends for both reference crude oils and oil sands derived crude oils, on balance it appears that the gap in GHG intensity may decrease over time.

Climate Change

Over the past 30 years, changes in the U.S. climate have included an increase in average temperature, an increase in the proportion of heavy precipitation events, changes in snow cover, and an increase in sea level (CCSP 2008). Climate change can exacerbate stresses on ecosystems through high temperatures, reduced water availability, and altered frequency of extreme precipitation events and severe storms (CCSP 2008). However, climate change can also ameliorate stresses on ecosystems through warmer springs, longer growing seasons and related increased productivity (CCSP 2008).

Anticipated impacts from climate change in North America applicable to the regions crossed by the proposed Project include:

- Stream temperatures are likely to increase and are likely to have effects on aquatic ecosystems and water quality;
- Proliferation of exotic grasses and increased temperatures are likely to cause in increase in fire frequency in arid lands; and
- Decreased streamflow, increased water removal, and competition from non-native species are likely to negatively affect river ecosystems in arid lands (CCSP 2008).

While there are uncertainties in the future of climate change, the response of ecosystems and the effects of management should allow ecosystem adaptations that would reduce anticipated damages or enhance beneficial responses associated with climate variability and change (CCSP 2008). Throughout development of the proposed Project, efforts to reduce overall Project-related impacts have been incorporated into the proposed Project. The proposed CMR Plan (Appendix B) includes construction procedures that would apply directly to the reduction of anticipated climate change-related induced impacts described above, including:

- Restoration of riparian habitats at stream crossings (Sections 3.3 and 3.7);
- Prevention of the spread and establishment of noxious and invasive weeds (Section 3.5);
- Prevention of the spread of aquatic invasive species (Section 3.7); and
- Limiting water withdrawal rates to less than 10 percent (or lower depending on permit requirements) of the base flow and returning water used for hydrostatic testing to the same drainage (Sections 3.3 and 3.7); and
- Avoid, minimize, and mitigate impacts to wetlands, including depressional wetlands (Section 3.4) that may decrease in abundance due to increased evaporation with increased temperature.

A variety of technologies are currently or potentially available in the oil sands sector to mitigate GHG emissions during production. The oil sands industry is exploring technologies that increase energy efficiency and reduce the industry's dependence on fossil fuel resource consumption, which in turn decrease GHG emissions during production. Notable GHG mitigation technologies or practices currently employed include:[17]

- *In situ* extraction improvements such as improved well configuration and placement, low-pressure SAGD, flue gas reservoir re-pressurization, new artificial lift pumping technologies, use of electric submersible pumps, and overall improvements in energy efficiency which can reduce the steam to oil ratios (SOR) of *in situ* production processes (Government of Alberta 2011a, Bergerson & Keith 2010, CAPP 2011);
- Incorporation of solvents such as ethane, propane, or butane (in addition to heat, in the case of thermal solvent processes) to lower the viscosity of bitumen extracted using vaporized extraction (VAPEX) processes during *in situ* production (Government of Alberta 2011a, RAND 2008, Bergerson & Keith 2010, CAPP 2011);
- Expanded use of cogeneration to produce electricity and steam during the upgrading stages of oil sands production, particularly for *in situ* production (IHS CERA 2010, Bergerson & Keith 2010, CAPP 2011); and
- Use of lower-temperature water to separate bitumen from sand during extraction to reduce the energy required (CAPP 2011).

Emerging technologies that would reduce the use of fossil fuel energy resources (and therefore GHG emissions), but that are not yet widely employed in the oil sands include:

- Steam solvent processes, which use solvents to reduce the steam required for bitumen extraction. Steam solvent processes include solvent-assisted processes (SAP), expanding solvent steam-assisted gravity drainage (ES-SAGD), and liquid addition to steam for enhanced recovery (LASER) (Government of Alberta 2011a, Bergerson & Keith 2010, IEA 2010, CAPP 2011);
- Additional *in situ* bitumen production technologies include *in situ* combustion, where the heavy portion of petroleum is combusted underground (Government of Alberta 2011a, Bergerson & Keith 2010, CAPP 2011), and electrothermal extraction, where electrodes are used to heat the bitumen in the reservoir (Government of Alberta 2011a, Bergerson & Keith 2010, CAPP 2011);[18]
- Use of natural gas or bio-based fuels such as biodiesel or bioethanol in mine and tracking fleets and equipment (Pembina 2006, Bergerson & Keith 2010);
- "Bio-upgrading", a future upgrading technology in development that includes the use of microbes to remove sulfur compounds and impurities (Pembina 2006);
- Use of offgas processing from oil sands facilities through the extraction of natural gas liquids and olefins to provide pipeline-specification natural gas. The net result is fewer overall emissions because the offgas is used as petrochemical feedstock rather than combusted (Government of Alberta 2011a);

[17] The degree to which the GHG emission estimates from LCA studies reviewed in the "Indirect Cumulative Impacts and Life-Cycle Greenhouse Gas Emissions" section incorporated these technologies varies based on the timeframe and facility-level data used to inform the estimates. None of the studies evaluated solvent-based *in situ* extraction methods. Jacobs (2009), TIAX (2009), and IHS CERA (2010) evaluated the effect of cogeneration systems and electricity export on life-cycle GHG emissions.
[18] Keith and Bergerson (2010, p. 6011) note that the GHG emissions from these technologies may depend upon their implementation. For instance, electrothermal *in situ* extraction may reduce GHG emissions if coupled with a source of low-GHG intensity electricity.

- Carbon capture and storage (CCS) technologies to store CO_2 produced from point sources. CCS technologies have existed for years and are currently being employed in the conventional oil and natural gas sectors. The oil sands sector has an opportunity, bolstered by significant Alberta government funding, to employ a variety of CO_2 capture technologies available including pre-combustion, post-combustion, and oxy-fuel systems in order to significantly reduce life-cycle GHG emissions from WSCB oil sands derived crude (Pembina 2006, Bergerson & Keith 2010, RAND 2008, Royal Society of Canada 2010, CAPP 2011);
- Similarly, CO_2 could be sequestered by injecting the gas into oil sands tailings, which has the co-benefit of improving settling rates. A version of this technology is expected to be commercially available in the next three to four years (Royal Society of Canada 2010); and
- Use of Metal Organic Frameworks (MOFs), which could be used to separate CO_2 from low concentration gaseous mixtures like flue gas. MOFs have the potential to absorb CO_2 effectively while requiring less energy to regenerate than other sorbent materials (CAPP 2011).

The Government of Alberta has worked to mitigate the GHG emissions associated with oil sands production through three main policy initiatives. First, the Climate Change and Emissions Management Act, enacted in 2003, establishes mandatory annual GHG intensity reduction targets for large industrial GHG emitters (Government of Alberta 2009a). Those emitters that fall short can either purchase credits from other companies that have reduced their emissions, or pay $15 for every metric ton of CO_2e above their target into a government-run clean energy technology fund (Government of Alberta 2010). Second, the Government of Alberta has dedicated $2 billion to fund four large-scale CCS projects. Of these four projects, two involve oil sands producers. These two projects are together expected to reduce 15.2 million metric tons of CO_2e per year beginning in 2015 (Government of Alberta 2011b). Third, the funds collected as part of the Climate Change and Emissions Management Act are placed in the Climate Change and Emissions Management Fund, which is dedicated to investing in clean energy projects (Government of Alberta 2011c). Several projects selected for funding in 2010 focus on energy efficiency improvements and cleaner energy production at oil sands production facilities (CCEMC 2010a, 2010b).

Other GHG mitigation policy proposals could establish some form of broad fiscal or regulatory national GHG reduction policy that would incentivize or regulate lower GHG emissions from oil sands operations and other sectors of the economy. MK Jaccard and Associates (2009) analyzed the cost and feasibility of meeting a target of a 20 percent reduction from 2006 levels by 2020, and a more aggressive target of a 25 percent reduction from 1990 levels by 2020 though a cap and trade or carbon tax system.[19] For both targets the largest reductions came from petroleum extraction (including, but not limited to the oil sands), accounting for roughly 10 to 20 percent of total reductions of the 20% reduction policy and 25% reduction policy, respectively. Under the 20% reduction policy target, the analysis found that 57 percent of the hydrogen produced for synthetic oil would be made using CCS, while 4 percent of the steam and process heat for oil sands extraction would be made using CCS by 2020. Under the 25% reduction policy target, the shares of each produced using CCS increased to 88 and 50 percent, respectively.[20]

[19] The study examined a policy package that would achieve each target by establishing a CO_2 emissions price and implementing other complementary measures. The 20% reduction policy had a target price that started at $40 per metric ton of CO_2 in 2011, increasing to $100 per metric ton in 2020. The 25% reduction policy had a target price that started at $50 and increased to $200 per metric ton CO_2 in 2020.

[20] The 25% reduction policy required CCS at all new sources of formation CO_2 from natural gas processors, process CO_2 from hydrogen plants, and combustion CO_2 from coal-fired power plants, oil sands facilities, and upgraders starting in 2016.

MEIC v. Department of Environmental Quality and Continental Energy Services, Inc.
Cause No. BDV-2002-474, 1st Judicial District
Judge Sherlock
Decided 2002

This case involved an administrative appeal by the Montana Environmental Information Center to the BER for the DEQ approval of an air quality construction permit for a proposed 500 megawatt gas fired power plant. The petition for the appeal charged that the permit was approved in violation of the state and federal Clean Air Acts and MEPA. The petition challenged the adequacy of the EIS that was produced for the project. The petition requested that the BER stay the approval of the permit until it either holds a contested case hearing on the appeal or assigns the case to an hearing examiner.

Judge granted defendant's motion to dismiss.

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Before the Board of Environmental Review,
Department of Environmental Quality,
State of Montana.

In Re: Permit Applicant Continental Energy Services, Inc. Silver Bow Generation Plant (Permit No. 3165-00) Montana Environmental Information Center	**AFFIDAVIT AND PETITION FOR HEARING AND FOR STAY OF PERMIT ISSUANCE**

STATE OF MONTANA)
):ss
COUNTY OF LEWIS AND CLARK)

This matter arises from the proposed issuance by the Montana Department of Environmental Quality ("DEQ") of Air Quality Permit #3165-00 to Continental Energy Service, Inc. Silver Bow Generation Plant to construct a natural gas fired power plant outside Butte, Montana. The permit will become effective March 30, 2002, unless a party requests a hearing and challenges the permit. The undersigned individual on behalf of Montana Environmental Information Center ("MEIC"), having first been duly sworn, deposes and says the following, in support of his challenge to the Permit and request for hearing pursuant to § 75-2-211, M.C.A.:

MEIC'S STANDING

1) Petitioner MEIC is a Montana non-profit public benefit corporation pursuant to 35-2-101, *et. seq.*, MCA, with over 4,000 members state - and nation-wide, and at all times pertinent hereto has had its principal office in Helena, Lewis and Clark County, Montana. MEIC has been in existence for over twenty eight years, and strives to protect the air, water and lands of Montana from pollution and to preserve Montana's quality of life. MEIC has been active in lobbying the legislature and executive branch agencies and educating the citizens of Montana about protection of Montana's air quality.

This action is brought on MEIC's own behalf and on behalf of its members. Members reside and work in Silver Bow and Deer Lodge Counties in the vicinity of Continental Energy's proposed Silver Bow Generation Plant. MEIC members use and enjoy the area because of its aesthetic qualities, lifestyle opportunities, and environmental amenities and have an interest in preserving them. MEIC and its members are actively involved in environmental issues in the Butte area and throughout the state, including issues relating to energy development, power generation and air quality. MEIC and its members are thus directly and adversely affected by the issuance of Air Quality Permit # 3165-00 by the DEQ and will sustain actual injury if the proposed action is carried forth without adequate environmental review, testing and disclosure and compliance with all existing laws. MEIC and its members have a further interest in participating in governmental decisions, in disseminating relevant information about those decisions to the general public and in insuring that all laws and procedures are complied with. Those interests are directly and adversely affected by the failures of the Department as alleged herein. MEIC and individual members of MEIC commented in, or otherwise participated in, the environmental review and permitting process for the Silver Bow Generation Project.

REQUEST FOR A HEARING

2) **MEIC requests a hearing pursuant to 75-2-211 (10)** M.C.A., in that MEIC represents individuals who are adversely affected by the Department's decision. Said persons, as well as MEIC, participated in the public comment process.

ALLEGATIONS AND BASIS FOR REQUESTED RELIEF

3) As set forth in the following paragraphs, MEIC alleges that the Permit was approved in violation of the Clean Air Act of Montana and regulations promulgated thereunder, the federal Clean Air Act and regulations promulgated thereunder, and the Montana Environmental Policy Act ("MEPA") and regulations promulgated thereunder. The decision to issue the permit was not in accordance with the procedures required by law, was arbitrary, capricious and an abuse of discretion.

4) Continental proposes to construct, and has sought an air quality permit for, a 500 megawatt (MW) electrical power generation facility to be located approximately 6 miles west of Butte, Montana. The facility will consist of two nominal 175 MW combined cycle natural gas combustion turbines (with two associated heat recovery steam generators including duct burners) and a 150 MW matched steam turbine (and associated power generator). In addition to the turbines and generators, the plant will have two emissions stacks, nine cooling towers, an electrical interconnection with transformers, and other equipment.

5) On July 20, 2001, DEQ received Continental's application for an air quality permit. In December, 2001, DEQ issued a draft air quality permit, along with a

draft environmental impact statement ("EIS"). The final EIS was issued in February, 2002. On March 12, 2002, DEQ issued its record of decision ("ROD") stating its intent to issue the permit.

6) Both the EIS and the ROD disclose that the plant will result in an increase in air pollution in the area, with adverse impacts to environmental quality. Importantly, on page 9 of the ROD, DEQ states:

> "**The No Action alternative,** which would be the denial of the air quality and MPDES permits and narrative standard authorizations, **is the environmentally preferred alternative.** Without the permits, the Silver Bow Generation Plant could not operate and likely would not be built. The environmental impacts associated with the Silver Bow Generation Plant and with the pipeline expansion would not occur."

The pollutants to be released into the Montana atmosphere include, but are not limited to, the following:

a) **Particulate matter: 235 tons per year; 227 tons per year at PM-10 (ten microns or less in diameter).** These fine particulates are of special concern because of their ability to penetrate deep into the lungs. Such "inhalable" particles can lodge deep in the lungs for months or years. Particulates can lead to cancer, cause and aggravate cardiopulmonary problems, and have been linked to increases in Sudden Infant Death Syndrome. In addition to their health effects, particulates have aesthetic effects such as impaired visibility and coating of surfaces. Natural visual ranges of 80 to 100 miles have been reduced by pollution to averages of less than 20 miles in the eastern United States and 50 to 70 miles in the west.

Table 4-31 of the EIS shows that the regional background concentration of particulate matter is currently 30 micrograms per cubic meter. Modeling results indicate that the Silver Bow Generation Plant could increase this level to 100 micrograms per cubic meter bringing the area substantially closer to the 150 microgram standards. This is especially disturbing given the plant's proximity to the Class I airsheds of Yellowstone National Park and the Anaconda-Pintler Wilderness Area (just 25 miles to the west), as well as to the Butte PM Non-Attainment Area just six miles away. In its comments on the draft EIS, MEIC stated its concern that the EIS had failed to incorporate Butte PM monitoring data in its analysis. In responding to that concern, DEQ stated in the final EIS "The CES facility is proposed to be located approximately 6 miles west of Butte, Montana. The predominant winds in this area are from the Northwest. Thus, the majority of the time CES would have little influence on the PM10 nonattainment area." It is common meteorological knowledge that prevailing Northwesterly winds could easily impact an area located just 6 miles to the east. By failing to consider and account for the available monitoring data, neither the EIS nor Continental's air quality permit properly reviews and assesses the air quality impacts of the facility and fails to meet the requirements of state and federal law.

b) **Sulfur oxides (SOx): 10.7 tons per year.** SO2 contributes to particulate levels through the formation of sulfate particles and acid aerosols and is the primary cause of acid precipitation. Acid rain is harmful to both terrestrial and aquatic environments (particularly forests, lakes, and streams) and can damage buildings, monuments, and other structures as well. In addition to tree and fish mortality, human health, livestock, crops, and wildlife can all suffer adverse effects from acid rain.

c) **Nitrogen oxides (NOx): 168 tons per year.** Nitrogen oxides (NOx) include both nitric oxide (NO) and nitrogen dioxide (NO2). NO2 is a brownish gas that reacts with volatile organic compounds (VOC) in the presence of sunlight to create photochemical smog (of which the main component is ground-level ozone). While ozone is critically important in the upper atmosphere as a shield against the sun's high-energy ultraviolet radiation, it is itself a very reactive and harmful gas, both for humans and vegetation (including crops). Like SO2, NOx leads to higher particulate levels (nitrate particles) and contributes to acid rain.

d) **Volatile organic compounds (VOCs): 94.2 tons per year.** Volatile organic compounds are carbon containing compounds that can contribute to the formation of smog.

e) **Carbon monoxide (CO): 732 tons per year.** CO is an odorless and colorless gas which is released into the atmosphere when carbon in fuels doesn't burn completely. The gas can become dangerous if it is inhaled excessively.

f) **Ammonia (NH4): 272 tons per year.** Ammonia is a toxic gas that can be carried many miles before being deposited in lakes or streams. As a form of nitrogen, ammonia can act as a nutrient precursor that can lead to algal blooms, eutrophication, and fish kills.

DEQ failed to adequately disclose and evaluate the health and environmental effects of the discharge of the foregoing pollutants in both the permit and the EIS. DEQ has provided no site-specific monitoring data to justify its contention that existing ambient air quality is below NAAQS and MAAQS. Instead, the department states merely "It is ... believed that typical Montana background data is representative of the site with the possible exception of particulate and VOC." The basis for the department's belief is an unsubstantiated statement as to the levels of industrialization and population in the area. If the baseline is incorrectly estimated, then the conclusions as to the compatibility with state and federal standards may be incorrect.

7) In addition, the EIS discloses that the plant will discharge approximately **2,375,720 tons of carbon dioxide (CO2)** into the air each year. The Permit and EIS provide no analysis of the health, environmental, and economic impacts of global climate change and provide no analysis to justify the statement that an additional release of 2,375,720 tons per year of CO2 is insignificant. CO2 is the most significant greenhouse gas emission caused by humans, and power plants are the leading source of CO2 emissions globally, nationally, and in Montana. DEQ's own "Montana Greenhouse Gas Emissions Inventory" report (issued January 1997) states there is "virtual certainty" (defined as "nearly unanimous agreement among scientists, with no credible alternative views existing") that "Greenhouse gas concentrations in the atmosphere are increasing due to human activities" and that "Added greenhouse gases cause added heating." According to the same document, Montana's 1990 estimated total emission of CO2 was 21,982,000 tons. Projected emissions from the Silver Bow Generation Plant represent an increase of 11% over that figure.

In addition to potentially severe economic, social, and political dislocations, global warming caused by greenhouse gases poses numerous environmental and public health concerns including increases in insect populations and the spread of infectious tropical diseases, a greater frequency of El Niño and extreme weather events (such as floods, droughts, and fires), the melting of glaciers and polar ice caps, rising sea levels, desertification, and general ecosystem disruption and extinctions caused by the rapid rate of change. Some of these effects, such as the disappearance of glaciers in Glacier National

Park in northwestern Montana, (which may be left "glacier-less" in as few as 33 years), are already dramatically evident.

In its comments on the draft EIS, MEIC noted that the amount of pollution issued from the Silver Bow Generation Plant would be not only absolutely but proportionately greater than the amounts released by NorthWestern's permitted "Montana First Megawatts" power plant in Great Falls. DEQ responded in the final EIS that the two plants were of different design and that the NorthWestern facility should be considered a 160 MW, not 240 MW plant. DEQ's response ignores NorthWestern's stated plans to convert the facility from simple cycle to combined cycle and to increase its final capacity to 240 MW (see page 4 of the Application of NorthWestern Generation I, LLC for Comment and Findings on a Power Purchase and Sales Agreement with the Montana Power Company on file with the Montana Public Service Commission). Given that capacity, the release of pollutants by Silver Bow Generation Plant will significantly exceed the release of pollutants from the NorthWestern plant both in absolute terms and also relative to the amount of electrical energy produced. DEQ failed in its analysis of Best Available Control Technology by stating, for example, that carbon monoxide catalysts or other controls were cost-prohibitive / economically unfeasible despite NorthWestern's commitment to incorporate such technology in its Great Falls plant. The Silver Bow Generation Plant should not be given a competitive advantage because of less stringent pollution controls.

8) MEPA, § 75-1-101, *et seq*, MCA, and DEQ's implementing regulations require that the final EIS be based on complete and accurate information and to fully inform the public and the decision maker of the potential effects, including cumulative effects, of the proposed action. In this case, DEQ's failure to conduct

such a review and its failure to follow procedures as required by law was arbitrary, capricious, an abuse of discretion and a violation of MEPA and its implementing regulations. In particular, the shortcomings of the EIS include, but are not limited to the following:

a. As mentioned above, the EIS failed to discuss or evaluate the impact of increased greenhouse gase emissions caused by the proposal, and may have incorrectly modeled the impacts of other air pollutants.

b. The EIS failed to adequately analyze reasonable alternatives to the proposed action, in violation of MEPA and A.R.M. 17.4.617 (5). According to the final EIS, "The purpose of the Proposed Action is to permit activities that provide additional electricity to meet increased demand for power within the western United States." DEQ dismissed "alternative sources of energy" as an alternative to the proposal, despite the enormous potential for renewable energy development in Montana at prices competitive with gas turbine technology. The draft EIS listed "alternative sources of energy" as one of six alternatives to the generation plant that were considered but eliminated from detailed study. It was the only alternative that was dismissed without explanation. MEIC noted in its comments to DEQ that given the selection criteria listed in the draft EIS, renewable energy should have qualified as a legitimate alternative for analysis. In the final EIS, DEQ responded that an alternative energy source does not bear a logical relationship to a gas-fired power plant. In fact, alternative energy sources can be employed to fulfill the same purpose as the proposed action and have been shown to be feasible, cost-effective, and environmentally-preferred. By "alternative energy sources," MEIC means not only supply-side renewable resources such as wind power, but also demand-side resources such as energy conservation and energy efficiency. Since the EIS was deficient in its analysis of alternatives, the decision maker had no means of making a reasoned and fully informed decision about the proposed project and the issuance of the air quality permit.

c. The final EIS also failed to conduct any analysis of the "upstream" environmental impacts associated with the plant's fuel requirements. The plant's **natural gas demand of 85 million cubic feet per day represents an increase of 55% over the total current consumption in the state of Montana.** Such a massive demand for natural gas cannot be met without impacts to the environment. As stated by MEIC in its comments, some of North America's most prized wild areas such as Montana's Rocky Mountain Front are continually threatened by the prospect of oil and gas exploration and drilling. The final EIS argues that an analysis of potential impacts to these sensitive areas would be speculative, because the source of gas for the plant has yet to be definitively determined. DEQ is itself speculating by considering impacts about which it currently has no information to be non-existent. DEQ cannot legally abdicate its responsibility to study the full range of impacts associated with the project. **To the contrary, until the source of gas has been selected and the impacts analyzed, the EIS remains incomplete.** MEPA requires DEQ to fully analyze the environmental impacts associated with its decision to grant an air quality permit to Continental. As acknowledged in the Record of Decision, without the granting of such permits, the Silver Bow Generation Plant would not become operational and the environmental impacts associated with the plant would be avoided. Therefore, the decision to grant the air quality permit is directly responsible (a necessary condition) for the power plant's need to acquire 31 billion cubic feet of natural gas per year.

The final EIS also erroneously dismisses the likelihood of development along the Rocky Mountain Front because of a current, temporary moratorium. But recent statements and proposals made at the federal level by President George W. Bush, Senator Conrad Burns, USDA Secretary Ann M. Veneman, and others indicate that the Rocky Mountain Front is a high priority for additional exploration and development (see, for example, "Veneman says Rocky Mountain Front not off limits to oil and gas exploration," Great Falls Tribune, March 29, 2002).

9) MEIC incorporates by reference the public comments submitted by MEIC as well as all written comments and issues raised by the public and other materials in the agency file. MEIC reserves the right to add additional grounds for appeal during the contested case hearing requested herein, if additional issues or information become available during that process.

RELIEF REQUESTED BY MEIC

MEIC requests the following relief:

a) That the Board order an in-person contested case hearing before the Board of Environmental Review in Helena, Montana, or a duly appointed hearing examiner, for purposes of challenging the validity of the Permit.

b) That the Board stay the Department's decision pending the hearing and adoption of a final decision by the Board of Environmental Review as required by law.

c) That the Board provide any and all other relief that the it determines to be appropriate in this case.

Dated this 29th day of March, 2002.

Peter Michael Meloy
Attorney for MEIC

James D. Jensen
on behalf of Montana Environmental Information Center

STATE OF MONTANA)
):ss
COUNTY OF LEWIS AND CLARK)

On this 29th day of March, 2002, before me the undersigned Notary Public, personally appeared James D. Jensen, known to me to be the person whose name is subscribed to the within instrument, and acknowledged to me that he executed the same.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my official seal the day and year first above written.

Notary Public for the State of Montana
Residing at: Helena, MT
My Commission Expires: AP 21, 2002

CERTIFICATE OF SERVICE

This is to certify that a true and correct copy of the foregoing was mailed, first class, this 29 day of March, 2007, to:

CHAIRMAN
BOARD OF ENVIRONMENTAL REVIEW
P.O. BOX 200901
HELENA, MT 59601

and was hand delivered, on the same date, to:

CHAIRMAN
BOARD OF ENVIRONMENTAL REVIEW
1520 6TH AVE.
HELENA, MT 59601

BY. [signature]

Mt. Environmental Center v. Dept. of Environmental Quality
Decided Dec. 17, 2002
Ju Sherlock
First Judicial District
Docket No. BDV-2002-474
2002 ML 3836 (1st Jud. Dist.)

MONTANA FIRST JUDICIAL DISTRICT COURT
LEWIS AND CLARK COUNTY

MONTANA ENVIRONMENTAL INFORMATION
CENTER,
Plaintiff,
v.
MONTANA DEPARTMENT OF ENVIRONMENTAL
QUALITY, and CONTINENTAL ENERGY
SERVICES, INC.,
Defendant.

Cause No. BDV-2002-474
ORDER ON MOTION TO DISMISS

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1 Before the Court is the Defendants' motion for dismissal.

Background

2 laintiff Montana Environmental Information Center (MEIC) brought this action to permanently enjoin the onstruction of a 500 megawatt energy facility, known as the Silver Bow Generation Plant (the Plant), approximately six niles west of Butte, Montana. MEIC claims that the Air Quality Permit issued by Defendant Department of Environmental Quality (DEQ) to Defendant Continental Energy Services (Continental) to build the Plant was issued in iolation of the Montana constitutional right to a clean and healthful environment.

3 In its complaint, MEIC claims that the Plant, if built, is expected to produce significant quantities of air pollution inked to cancer, acid rain, harmful gasses and other deleterious effects on the environment. MEIC's members who live nd work in the area will be harmed by the pollution caused by the Plant. Furthermore, MEIC alleges that there are easonable alternatives to building the Plant which would provide the advantages of the Plant without the adverse nvironmental effects.

Standard of Review

4 A complaint should not be dismissed for failure to state a claim unless it appears beyond doubt that the claimant can rove no set of facts which would entitle the claimant to relief. *Dubray v. Farmers Ins. Exch.*, 2001 MT 251, ¶ 8, 307 Mont. 134, ¶ 8, 36 P.3d 897, ¶ 8. A motion to dismiss pursuant to Rule 12(b)(6), M.R.Civ.P., has the effect of admitting ll wellpleaded allegations in the complaint. *Id.* In considering the motion, the complaint is construed in the light most avorable to the claimant, and all allegations of fact contained therein are taken as true. *Id.*

Discussion

5 Plaintiff's complaint consists of the following two counts:

6 1. That Defendant DEQ violated the right to a clean and healthful environment found in Article II, Section 3 and e IX, Section 1 of the Montana Constitution by issuance of the permit to build the Plant.

2. That Continental's proposed construction and operation of the Plant violates the right to a clean and

healthful environment in Article II, Section 3 and Article IX, Section 1 of the Montana Constitution. MEIC does not allege that the issuance of the permit was in violation of the Montana Clean Air Act or any other Montana statute. Further, MEIC does not allege that the Montana Clean Air Act is unconstitutional on its face or as applied in the issuance of this permit.

7 Defendants brought this motion to dismiss the complaint for failure to state a claim upon which relief can be granted ith the following two arguments:

8 1. Count One, for failure to state a claim upon which relief can be granted because the relief, if granted, would iolate the separation of powers mandated by Article III, Section I of the Montana Constitution.

9 2. Count Two, for failure to state a claim upon which relief can be granted because there is no private right of action y a non-governmental party against another seeking to enforce the constitutional right to a clean and healthful nvironment. Implicit in each of these arguments is the dispositive issue, which the Court will address. Specifically, hether Plaintiff has properly alleged a violation of the Montana Constitution.

10 As noted above, MEIC is not alleging that the permit for the Plant was issued in violation of the Clean Air Act or ny other statute. Furthermore, MEIC does not claim that the Clean Air Act violates the Montana Constitution. All egislative enactments, including the Clean Air Act, are presumed constitutional by the courts. The party challenging the onstitutionality of a statute bears the burden of proving the statute unconstitutional beyond a reasonable doubt. Henry v. tate Compensation Ins. Fund, 1999 MT 126, ¶ 11, 294 Mont. 449, ¶ 11, 982 P.2d 456, ¶ 11. Therefore, unless MEIC lleges otherwise, the Court must presume that the Clean Air Act is constitutional.

11 Furthermore, DEQ, as an arm of the executive branch, is required to faithfully execute the laws of Montana. Merlin Myers Revocable Trust v. Yellowstone County, 2002 MT 201, ¶ 25, 311 Mont. 194, ¶ 25, 53 P.3d 1268, ¶ 25. MEIC does not allege that DEQ did anything other than execute the provisions of the Clean Air Act and its implementing egulations.

12 Plaintiffs have not alleged that DEQ's actions in issuing the permit violated the Clean Air Act or its implementing egulations, and have not alleged that the act or its regulations are unconstitutional facially or as applied. It is clear that laintiffs have not properly alleged a constitutional violation.

13 MEIC suggests that it is the province of this Court to determine whether the agency's actions violate the constitutio n a permit by permit basis while ignoring statutes duly enacted by the legislature. The system, they suggest, would be raught with inconsistencies with no one able to determine whether they are acting within the laws of this state without a ull fledged lawsuit. Furthermore, all decisions would be made by judges in courtrooms, rather than in an open process ith public comment and expert input. If Plaintiffs believe that a permit can be issued without violating the Montana lean Air Act but still be unconstitutional, the appropriate action is to challenge the statute or its implementing egulations as unconstitutional. They have not done so.

14 Therefore, Defendants motion to dismiss is hereby GRANTED.

ATED this 17th day of December, 2002.

EFFREY M. SHERLOCK
istrict Court Judge

MEIC to sue over Butte plans

BG 6/18/02

BUTTE (AP) — A lawyer representing the Montana Environmental Information Center says the group plans to sue to stop Continental Energy Project's power plant on constitutional grounds.

"It is MEIC's position that the issuance of the (state) permit violates the guarantee of a clean and healthful environment," attorney Mike Meloy said Friday.

A lawsuit could mean further delays on the $300 million, 500-megawatt gas-fired facility planned near Butte. Company officials said previously they hoped to break ground this fall.

The project won permit approval from the Department of Environmental Quality following an environmental impact analysis.

The MEIC initially stated its opposition to the project with an appeal of an air-quality permit to the Board of Environmental Review, but that appeal has been dropped in favor of a suit in District Court, Meloy said.

Jim Jensen, director of the MEIC, said he is hopeful an agreement with the company can be reached without going to court.

"We believe that MEIC has chosen to ignore work done by countless experts and proceed with their own agenda, which appears determined to stifle development that would otherwise provide new employment opportunities," said Dan Rapkoch, spokesman for Continental Energy Services.

Butte-Silver Bow Chief Executive Judy Jacobson said the city has tried to work with the environmental group, as it did previously with Trout Unlimited and the Clark Fork Coalition on water issues, but failed.

"It sounds to me like they are using this as a test case," she said.

Jensen scoffed at suggestions MEIC is holding back the project or thwarting economic development.

"In fact, exactly the opposite is true," he said. Montana is hampered by its leaders' abilities and the way it conducts its affairs, he said.

MEIC has continually criticized the Butte facility, saying that it is unneeded, will pollute the environment and will generate electricity for out-of-state interests, not Montanans.

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Power plant's MEIC lawsuit tossed out

By Leslie McCartney of The Montana Standard

Environmental group may appeal

A Helena District Court judge has dismissed a lawsuit brought by the Montana Environmental Information Center against the Silver Bow Project, a 500-megawatt, $350 million electrical generation facility planned west of Butte.

In his order, Judge Jeffrey Sherlock released both Continental Energy Services Inc. and the Department of Environmental Quality from the lawsuit by siding with their motion to dismiss.

In July, Helena-based MEIC filed suit alleging that the gas-fired facility, which has enjoyed broad support in the Butte community, would violate the state Constitution's guarantee to a clean and healthful environment.

The judge disagreed, saying `` it is clear that plaintiffs (MEIC) have not properly alleged a constitutional violation."

Sherlock went further, saying that the MEIC has suggested that the court should determine if the state's action violated the Constitution on a permit-by-permit basis while ignoring statutes enacted by the Legislature.

`` The system, they suggest, would be fraught with inconsistencies with no one able to determine whether they are acting within the laws of this state without a full-fledged lawsuit," Sherlock wrote. If that were to be the case, judges in courtrooms would make all decisions, rather than in an open process with pub lic comment and expert opinions, he con tinued.

Dismissal of the lawsuit paves the way for Continental, which has been stymied by the lawsuit and its uncertain outcome. All along, the Butte-based company has maintained that it has met all state requirements -- and gone beyond with a full-fledged environmen tal review which was not required -- in permitting the plant.

`` Continental has demonstrated its commitment to the environment throughout the permitting process," said Dick Cromer, president of

Continental. `` We performed an environ mental impact statement to extensively evaluate all impacts associated with the Silver Bow Project. Our study resulted in air-quality permits that confirm the project will meet all state and federal laws."

The MEIC's Jensen, who is away for a month, was unavailable for comment Wednesday. However, MEIC Program Director Anne Hedges said the group will study the order and talk with its lawyers about how to proceed.

Calling Sherlock's decision `` odd," she said it is unclear what he means in the three-page order.

`` This case is of fundamental impor tance to Montanans and deserves to be reviewed at the highest level," Hedges said, referring to the state Supreme Court.

She added that the Constitution is fairly new, saying that it's common for a court to be uncertain how to proceed. `` It isn't a huge shock, but I doubt it's the end of it either," she said.

Butte officials hope the matter has been decided.

`` This is great news for Butte, assum ing MEIC does not want to pursue an appeal. We hope they'll see the light and error of their ways and let this impor tant project proceed," Butte Local Development Executive Director Evan Barrett said.

Butte-Silver Bow has spent many hours working with environmental groups in reference to issues such as water to be supplied to the plant. Those issues, brought by the Clark Fork Coalition and Trout Unlimited, have been successfully negotiated.

Continental officials pointed out that the plant employs the best available technology, including equipment that will minimize carbon monoxide emis sions.

`` The Silver Bow Project is the clean est and most efficient thermal genera tion facility yet proposed in Montana," said Terry Webster, Continental's direc tor of environmental compliance. `` Our commitment to excellence means we will continue to work with the state and citizens of Montana to retain this dis tinction of environmental stewardship."

Chief Executive Judy Jacobson wel comed the dismissal as a good Christmas present.

`` I'm just very pleased that we've got ten this far with it. I'd love to see them up and running," she said. She added that the plant is important to an indus trial area west of Butte and could be used to further attract industry.

The project is expected to employ 900 workers during construction, and employ 25 full-time people after it opens.

-- Reporter Leslie McCartney may be reached via e-mail at leslie.mccartney(at)(at)mtstandard.com.