No. 15-8109

IN THE UNITED STATES COURT OF APPEALS
FOR THE TENTH CIRCUIT

WILDEARTH GUARDIANS, *et al.*,
Petitioners-Appellants,

v.

U.S. BUREAU OF LAND MANAGEMENT,
Respondent-Appellee,

and

WYOMING MINING ASSOCIATION, *et al.*,
Intervenors-Appellees,

STATE OF WYOMING, *et al.*,
Respondents-Intervenors.

On Appeal from the U.S. District Court for the District of Wyoming
(Case No. 2:13-cv-00042-ABJ) (Alan B. Johnson, J.)

BRIEF OF THE INSTITUTE FOR POLICY INTEGRITY AT NEW YORK UNIVERSITY SCHOOL OF LAW AS AMICUS CURIAE IN SUPPORT OF PETITIONERS-APPELLANTS

Jayni Foley Hein
Jason A. Schwartz
INSTITUTE FOR POLICY INTEGRITY
139 MacDougal Street, Room 317
New York, NY 10012
(212) 998-6093
jason.schwartz@nyu.edu
Counsel for Amicus Curiae Institute for Policy Integrity

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RULE 26.1(a) CORPORATE DISCLOSURE STATEMENT

Pursuant to Federal Rules of Appellate Procedure 26.1(a) and 29(c)(1), the Institute for Policy Integrity at New York University School of Law states that it does not have a parent company, nor has it issued publicly held stock.

Dated: February 5, 2016

/s/Jason A. Schwartz
Jason A. Schwartz
INSTITUTE FOR POLICY INTEGRITY
139 MacDougal Street, Room 317
New York, NY 10012
(212) 998-6093
jason.schwartz@nyu.edu
Counsel for Amicus Curiae Institute for Policy Integrity

TABLE OF CONTENTS

TABLE OF AUTHORITIES

Cases

Statutes

Rules

Other Authorities

GLOSSARY

BLM	Bureau of Land Management
BOEM	Bureau of Ocean Energy Management
EIA	Energy Information Administration
Interior	Department of the Interior
MMS	Minerals Management Service
NEPA	National Environmental Policy Act

STATEMENTS OF IDENTITY, INTEREST, AND AUTHORITY TO FILE

The Institute for Policy Integrity at New York University School of Law[1] ("Policy Integrity") seeks to file this *amicus curiae* brief in support of Petitioners.

Policy Integrity has separately submitted a motion for leave to file, under Federal Rules of Appellate Procedure 29(a)-(b). As that motion details, Policy Integrity is a non-partisan think tank dedicated to improving the quality of government decisionmaking through advocacy and scholarship in administrative law, economics, and public policy. Policy Integrity is a collaborative effort of faculty; a full-time staff of attorneys and economists; law students; and a Board of Advisors comprised of leaders in public policy, law, and government. Our economists and legal scholars are leading experts on the economic analysis of climate change in the contexts of resource management and regulatory decisionmaking, having published numerous papers, reports, and comments on these topics. We have an institutional interest in promoting rational analysis by federal agencies on how their resource management decisions affect the market forces of supply and demand, and the resulting environmental effects.

Under Federal Rule of Appellate Procedure 29(c) , Policy Integrity states that no party's counsel authored any part of this brief. No person or entity—other than

[1] No part of this brief purports to present New York University School of Law's views, if any.

the *amicus curiae* and its counsel—contributed money intended to fund this brief's preparation or submission.

SUMMARY OF ARGUMENT

The Bureau of Land Management's ("BLM") environmental impact statement for the Wright Area coal leases is based on an irrational assumption about coal supply and demand. The assumption contradicts fundamental economic principles, is disproven by actual market conditions, and is inconsistent with other agencies' practices for conducting economic and environmental analyses. Because of this flawed assumption, BLM's presentation of the climate consequences of leasing, versus taking no action, is inaccurate and misleading, in violation of the National Environmental Policy Act ("NEPA").

The Wright Area leases, located in the Powder River Basin, would generate more than 2 billion tons of low-cost coal from the two largest coal mines in the United States. *See* App. 1007.[2] The leases would produce up to 230 million tons of coal per year—more than twenty percent of the total U.S. coal used for electricity in 2010. App. 267–268.

In its environmental impact statement, BLM defies economic logic by concluding that the choice between approving the Wright Area lease extensions (the "Leasing Options") or rejecting them (the "No-Action Alternative") would

[2] References to documents in Petitioners' Appendix appear as "App. [page]."

have no effect on total greenhouse gases emissions from coal mining and coal combustion in the United States. BLM irrationally reasoned that if it were to select the No-Action Alternative, other coal mines would increase production to *entirely* replace all 2 billion tons of coal anticipated from these Wright Area leases, such that the amount of coal burned in the United States—and the resulting carbon dioxide and methane emissions—would remain constant whether or not the lease extensions were approved. App. 988–989.

BLM's mistaken assumption runs counter to basic economic principles of supply and demand, as well as the empirical state of knowledge concerning the U.S. coal market. Approving the leases would flood the U.S. coal market with inexpensive Powder River Basin coal, leading to increased U.S. coal consumption and more greenhouse gas emissions. The difference between the Leasing Options and the No Action Alternative is decidedly *not* climate neutral.

BLM's error is particularly inexcusable in light of past Department of the Interior ("Interior") NEPA analyses. For more than 35 years in NEPA reviews of offshore oil and gas leasing decisions, Interior has consistently understood that a decision not to lease land for energy production will affect that energy resource's supply and price, and thus trigger consumers either to switch to energy substitutes or to conserve energy. Interior has developed sophisticated analytical tools to calculate the shift under a No-Action Alternative from offshore oil and gas to other

energy substitutes and to conservation, and the agency assesses the resulting environmental costs or benefits, including climate change effects. Other agencies, such as the Surface Transportation Board, the Forest Service, the State Department, the Office of Surface Mining Reclamation and Enforcement (another Interior sub-agency), the Federal Energy Regulatory Commission, and the Nuclear Regulatory Commission, have also conducted the proper analysis in NEPA reviews of their energy management decisions. These analyses have been required or praised by multiple courts, including the U.S. Courts of Appeals for the D.C. Circuit and for the Eighth Circuit, and the U.S. District Courts for the Districts of Colorado and Minnesota.

Finally, even if BLM's assumption of "perfect coal substitution" was correct, the agency did not apply this assumption consistently through its environmental impact statement, and, consequently, its presentation of the economic benefits of the Leasing Options versus the No-Action Alternative is misleading.

In short, BLM's mistaken assumption that taking no action on the Wright Area leases would have no net effect on greenhouse gas emissions departs from a 35-year history of proper analysis by BLM's sister agencies, and violates NEPA's procedural mandate to rigorously evaluate all reasonable alternatives, including the No-Action Alternative. The lease approvals should be set aside.

ARGUMENT

I. BLM Violated NEPA by Failing to Adequately Compare the Climate Impacts of Lease Approvals versus the No-Action Alternative

By relying on an incorrect assumption about the market impacts of its coal lease approvals, BLM violated NEPA's mandate to rigorously and objectively evaluate all reasonable alternatives to proposed actions, including the "no action" alternative. *See* 42 U.S.C. § 4332(C)(iii); 40 C.F.R. § 1502.14.

The U.S Supreme Court has held that agencies must "consider and disclose the actual environmental effects" of proposed projects in a way that "brings those effects to bear on [their] decisions." *Balt. Gas & Elec. Co. v. Natural Res. Def. Council, Inc.*, 462 U.S. 87, 97 (1983). Analysis of alternatives is the "heart of the environmental impact statement." 40 C.F.R. § 1502.14. NEPA requires federal agencies to "[r]igorously explore and objectively evaluate all reasonable alternatives," including the "no action" alternative. *Id*. Agencies must "present the environmental impacts of the proposal and the alternatives in comparative form, thus sharply defining the issues and providing a clear basis for choice among options by the decisionmaker and the public." *Id*. Agencies must also analyze the "[e]nergy requirements and conservation potential of various alternatives." 40 C.F.R. § 1502.16(e). Compliance with NEPA is required "to the fullest extent possible," 42 U.S.C. § 4332, a command which the U.S. Supreme Court has

affirmed is "neither accidental nor hyperbolic." *Flint Ridge Dev. Co. v. Scenic Rivers Ass'n*, 426 U.S. 776, 787 (1976).

As detailed below, BLM's assumption that leasing the Wright Area tracts would have no effect on U.S. coal demand, consumption, or greenhouse gas emissions is flawed as a matter of economic theory, disproven by U.S. coal market analysis, and inconsistent with other agencies' practices. BLM's environmental impact statement failed to rigorously evaluate the No-Action Alternative or to provide a clear basis for choice among the options. The lease approvals should be set aside.

II. BLM's Assumption That, Compared to No Action, Approving the Leases Would Have No Impact on Total Greenhouse Gas Emissions from Coal Mining and Combustion Departs from Basic Economic Principles and Understates the Leases' Relative Climate Impacts

BLM's assumption that leasing these Powder River Basin coal tracts will have no net effect on domestic coal consumption and greenhouse gas emissions contradicts fundamental economic principles. Significant changes in coal supply will affect coal's price and, therefore, consumption and emission levels.

The Leasing Option will generate over 2 billion tons of additional, inexpensive Powder River Basin coal; it is a serious error to assume that, under the No-Action Alternative, all 2 billion tons would be completely replaced by coal from other sources, with no effect on overall coal consumption or emissions. BLM failed to analyze how coal directly competes with natural gas, nuclear, and renewable

energy resources in electricity generation, such that increasing coal prices prompts fuel-switching to these less carbon-intensive alternatives, as well as greater energy conservation. BLM also ignored how overall greenhouse gas emissions will vary among substitute sources of coal. BLM should have—and easily could have—evaluated the No-Action Alternative's climate effects.

A. Basic Economic Principles Provide That Any Significant Change in Coal Supply Will Change Price and Demand and, Therefore, Total Coal Combustion and Emissions

The basic economic principles of supply and demand provide that significant changes in coal supply will affect coal's price and, therefore, consumption levels. Greater coal consumption by power plants will increase greenhouse gas emissions. Increasing the supply of any normal good (including coal) puts downward pressure on that good's market price; this is a basic tenant of the law of supply and demand. N. Gregory Mankiw, *Principles of Economics* 74–78, 80–81 (5th ed. 2008).[3] Lower coal prices encourage higher levels of consumption, while higher coal prices discourage consumption. *See id*. at 67–68.

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[3] Excerpt in Addendum. This Court may take notice of basic economic principles of supply and demand, as well as classic economic textbooks and peer-reviewed articles. *See Citizens for Alternatives to Radioactive Dumping v. U.S. Dep't of Energy*, 485 F.3d 1091, 1096 (10th Cir. 2007) ("In dealing with scientific and technical evidence, extra-record evidence 'may illuminate whether an [environmental impact statement] has neglected to mention a serious environmental consequence, failed adequately to discuss some reasonable alternative, or otherwise swept stubborn problems or serious criticism . . . under the rug.'") (alterations in original).

Approving the Wright Area leases would increase the supply of inexpensive Powder River Basin coal, lowering U.S. coal prices and ultimately increasing the amount of coal purchased and burned. *See id.* at 74–76, 812–815. The leases at issue have lower production costs than many other coal tracts. *See* App. 983 (stating that Powder River Basin coal enjoys "competitive mining costs when compared to delivered costs of coal from other coal producing regions"); App. 1107 (stating that substitute coal "is more costly"). Thus, leasing these tracts would reduce the "marginal cost" of coal (that is, the cost of producing one additional unit), which would increase the total amount of coal that the U.S. coal industry is willing to produce. *See* Mankiw, *supra* at 74–76, 81; Envtl. Prot. Agency, *Guidelines for Preparing Economic Analyses* A-1–A-2 (2010).[4] In other words, leasing these tracts would shift the supply curve out, because more coal would be supplied for a given price. *See* Figure 1. This, in turn, would increase the quantity of coal purchased for a given price, because the demand curve for U.S. coal is "downward sloping" (that is, the quantity of coal demanded increases as price decreases). *See* Mankiw, *supra* at 67–68, 80–81; Figure 1. These are textbook economic principles.

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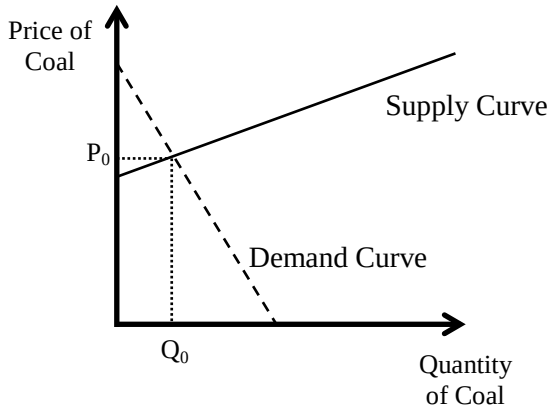
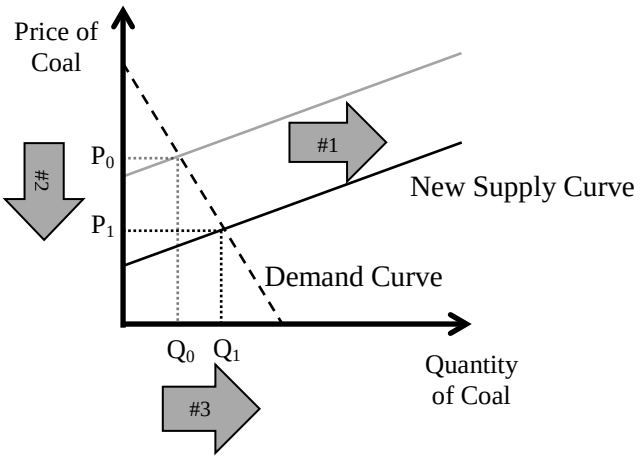
[4] Excerpt in Addendum, full text *at* http://yosemite.epa.gov/ee/epa/eerm.nsf/vwAN/EE-0568-21.pdf/$file/EE-0568-21.pdf. This Court may take notice of federal agencies' publicly available reports. *Winzler v. Toyota Motor Sales U.S.A., Inc.*, 681 F.3d 1208, 1213 (10th Cir. 2012).

Figure 1: Consequences of Outward Shift in Coal's Supply Curve

(a) U.S. Coal Market *Before* New Government Leases



(b) U.S. Coal Market *After* New Government Leases
As supply increases (#1), price declines (#2), and quantity demanded increases (#3)



Alternatively, in the No-Action Alternative, the cost of using coal to generate electricity would be higher relative to coals' cost under the Leasing Options. Demand for coal would fall as consumers conserve energy or substitute less-expensive (and, incidentally, cleaner) energy, including natural gas and renewable sources. *See* App. 581. This, in turn, would reduce greenhouse gas emissions, as compared to the Leasing Option's climate impacts. *See* App. 582.

It is well settled that coal directly competes with natural gas, nuclear, and renewable energy resources in the generation of electricity. App. 995–997; App. 581 ("[T]he high coal cost case . . . reflect[s] . . . a switch from coal to natural gas, nuclear, and renewables in the electricity sector . . . ."). Economists measure how coal, natural gas, and other fuels act as substitutes in the electricity market by analyzing "cross-price elasticity" (that is, how responsive producers are in swapping inputs when relative prices change). *See* Mankiw, *supra* at 99. For example, the U.S. Energy Information Administration ("EIA") found that for the U.S. market, a 10-percent increase in the ratio of the price of coal to the price of natural gas leads to a 1.4-percent increase in the use of natural gas over coal. EIA, *Fuel Competition in Power Generation and Elasticities of Substitution* 1 (2012).[5] In other words, the cross-price elasticity of demand for natural gas is 0.14 with respect to coal's price. *Id*. Other economists reach similar conclusions. Ko and Dahl, for example, surveyed three decades of literature and estimated the cross-price elasticity of demand for natural gas to be 0.40, with respect to coal's price. James Ko & Carol Dahl, *Interfuel Substitution in U.S. Electricity Generation*, 33 APPLIED ECONOMICS 1833, 1835 (2001) (see "average" cross-price elasticity

[5] Excerpt in Addendum; full text *at* https://www.eia.gov/analysis/studies/fuelelasticities/pdf/eia-fuelelasticities.pdf. This Court may take notice of reasonably indisputable information on government websites. *See New Mexico ex rel. Richardson v. BLM*, 565 F.3d 683, 702 n.22 (10th Cir. 2009).

calculated under Column "Egc," indicating elasticity of gas with respect to coal). *See also* Nate Blair et al., *Long-Term National Impacts of State-Level Policies* 8 (Nat'l Renewable Energy Lab. Conf. Paper 620-40105, June 2006) (discussing how "higher coal prices would dramatically increase" use of renewable wind energy).[6] These estimates represent short-run elasticities; over time, substitution effects become more pronounced as power plants make technological changes that facilitate fuel-switching, and as long-term investments favor natural gas and renewable energy. *See* Mankiw, *supra* at 105–106.

These studies are consistent with evidence in the record describing that fuel-switching—from coal to natural gas, nuclear, and renewables—occurs when coal prices increase. *See* App. 581. Moreover, they are consistent with recent trends in the displacement of coal-fired generation with natural gas-fired generation. Since 2008, Appalachian coal's increasing prices and "a sustained decline in the delivered cost of natural gas" have "substantially shifted the dispatch pattern for baseload [electricity] generation in some parts of the country, favoring natural gas-fired units over coal-fired units." EIA, *Fuel Competition*, *supra* at 1. The relative change in fuel prices was a primary driver for this coal-to-gas shift. *Id*.

In addition, if BLM does not approve these leases, the higher cost of using coal to generate electricity, as compared to the Leasing Options, would create

[6] Excerpts in Addendum.

incentives for power plants to improve efficiency and for consumers to conserve energy. *See, e.g.*, *infra* Section III.B. (detailing the Department of the Interior's analysis of increased energy conservation as oil supply falls and price rises).

Changes in the relative amounts of coal, natural gas, renewable sources, and nuclear energy used to generate electricity—as well as changes in total energy demand—would, in turn, change total greenhouse gases emissions. Coal is the most carbon-intensive of the primary fuels used to generate electricity; the carbon dioxide emissions associated with natural gas combustion are about 50 percent lower than those associated with coal. *See* App. 996–997; EIA, *How Much Carbon Dioxide is Produced When Different Fuels Are Burned?* (June 18, 2015).[7] Nuclear, wind, and solar electricity generation can essentially eliminate greenhouse gas emissions.

In short, BLM's unexamined and unsupported assumption that leasing the Wright Area tracts would have no effect on greenhouse gas emissions is contradicted by fundamental economics and coal market analyses. The environmental impact statement fails to meet NEPA's requirements, and should be set aside.

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[7] Excerpt in Addendum, full text *at* https://www.eia.gov/tools/faqs/faq.cfm?id=73&t=11.

B. Considering the Size and Nature of these Powder River Basin Leases, It Is a Fallacy to Assume that This Coal Would Be Perfectly Substituted by Other Coal, With No Effect on Price, Consumption, or Emissions

Moving beyond theory to the specific leases at issue, BLM's assumption of perfect substitution is not even a reasonable approximation for reality, given the size and characteristics of the contemplated leases and the U.S. coal market. The lease approvals represent an enormous amount of inexpensive, sub-bituminous coal that is particularly valuable to power plants. *See* App. 983. If these leases are not issued, utilities will face higher coal costs, which will lead to a greater percentage of natural gas and renewable energy production, as well as energy conservation, and therefore, lower greenhouse gas emissions. *See* App. 581–582.

BLM acknowledges that Powder River Basin coal is cheaper to produce than coal from other regions, and its low sulfur content makes it valuable for power plants, which need to comply with acid rain regulations. For example, BLM states: "PRB [Powder River Basin coal] is mined using surface mining methods which are generally safer and less labor intensive than underground mining. . . . PRB coal reserves are in thick seams, resulting in more production from areas of similar land disturbance, and lower mining and reclamation costs." App. 982. Powder River Basin coal is "valuable in lowering sulfur dioxide (SO_2) pollution, as well as competitive mining costs when compared to delivered costs of coal from other coal producing areas." App. 983. In other words, alternative sources of coal are likely

more expensive and higher in sulfur, making them imperfect substitutes for the coal from the Wright Area leases. In the No-Action Alternative, then, utilities would face higher coal costs, which would lead to more fuel-switching to less carbon-intensive energy sources and more energy conservation, and therefore, lower greenhouse gas emissions. *See* App. 581.

Additionally, even if BLM's "perfect substitution" assumption were correct and, under the No-Action Alternative, other sources of coal completely made up for all 2 billion tons of coal anticipated from these Wright Area tracts, not all coal production and combustion generates identical greenhouse gas emissions. Methane (a greenhouse gas much more potent than carbon dioxide) is trapped in coal seams and so is released by coal mining operations. Coal production in different basins in the United States emits different amounts of methane. *See* Envtl. Prot. Agency, *Methane Emissions from Abandoned Coal Mines in the United States* 8–10 (2004).[8] Coal also emits slightly different levels of carbon dioxide when burned, depending on the coal's type and point of origin. *See* EIA, *Quarterly Coal Report: January–April 1994*, tbl. FE4 (1994) (publishing an article on "Carbon Dioxide Emission Factors for Coal").[9] In the No-Action Alternative, any coal substituting

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[8] Excerpt in Addendum, full text *at* http://www3.epa.gov/cmop/docs/amm_final_report.pdf.

[9] Excerpt in Addendum, full text *at* http://www.eia.gov/coal/production/quarterly/co2_article/co2.html.

for the Wright Area leases may emit relatively less or more methane and carbon dioxide. Yet, BLM does not analyze this environmental impact in its alternatives analysis.

Given the size of the Wright Area tracts, BLM's decision to lease them could have a significant influence on the market. The Powder River Basin produced approximately 55.5 percent of all coal mined in the United States, and 43.4 percent of the coal used for U.S. electricity generation (as of 2008). App. 984, 988. The Black Thunder and North Antelope Rochelle coal mines at issue are the two largest U.S. coal mines. App. 1007. Annually, the Wright Area lease approvals would produce about 24 percent of the coal used to generate electricity in the United States (at 2010 production levels). App. 267–268. In the No-Action alternative, removing over 20 percent of total U.S. production would be a non-marginal change that would affect overall coal prices and demand.

The 382 million tons of carbon dioxide emissions per year associated with these Wright Area coal leases would constitute about 6.5 percent of annual U.S. carbon dioxide emissions (based on 2008's total). *Compare* App. 987 (calculating annual emissions for the Black Thunder and North Antelope Rochelle leases) *with* App. 984 (stating total U.S. carbon dioxide emissions in 2008 were 5,839 million tons). Burning the coal produced from these leases would have a measurable effect on U.S. greenhouse gas emissions.

In short, BLM's flawed economic assumption renders its alternatives analysis ineffective and misleading, and the lease approvals must be vacated.

III. Other Federal Agencies—and Even BLM, during Previous NEPA Reviews—Properly Analyze the Supply and Demand of Natural Resources and Resulting Climate Effects

For over 35 years, in NEPA reviews of offshore oil leasing decisions, the Department of the Interior has consistently understood that a decision not to lease land for energy production will affect that energy resource's supply and price and thus trigger consumers either to switch to energy substitutes or to conserve energy. Interior has further analyzed how such shifts in consumption generate different consequences for air pollution, climate change, and overall environmental quality. The U.S. Court of Appeals for the D.C. Circuit has praised Interior's analysis of these substitution effects. Even BLM, back when it performed Interior's NEPA reviews of offshore leasing decisions in 1979, assessed the different environmental effects of energy substitutes under a No-Action Alternative—including different levels of carbon dioxide emissions.

Other agencies, such as the Surface Transportation Board, the Forest Service, the State Department, the Office of Surface Mining Reclamation and Enforcement (another Interior sub-agency), the Federal Energy Regulatory Commission, and the Nuclear Regulatory Commission, have also properly analyzed the effects of their energy management decisions in NEPA reviews, consistent with the advice of the

U.S. Court of Appeals for the Eighth Circuit and the U.S. District Courts of Colorado and Minnesota. BLM's mistaken assumption that taking no action on these Wright Area leases would have, compared to leasing, no net effects on greenhouse gas emissions represents a substantial break with a 35-year history of proper analysis by BLM's sister agencies and even by its own past self.

A. BLM Previously Understood the Connections between Leasing, Supply, Price, Substitutes, Conservation, and Emissions, back in a 1979 NEPA Review of an Offshore Oil Lease

Before the 1982 creation of a sub-agency within Interior responsible for offshore resources, the Office of the Secretary of the Interior developed the federal offshore oil and gas leasing program, and the Bureau of Land Management prepared environmental impact statements on leasing actions (then called simply "environmental statements"). In BLM's 1979 Final Environmental Statement on a proposed lease sale off the coast of Southern California, the agency analyzed the No-Action Alternative of withdrawing the sale:

> [I]f the subject sale were cancelled, the following energy actions or sources might be used as substitutes: Energy Conservation; Conventional oil and gas supplies; Coal; Nuclear power; Oil shale; Hydroelectric power; Solar energy; Energy imports; . . . . Vigorous energy conservation is an alternative that warrants serious consideration. The Project Independence Report of the Federal Energy Administration claims that energy conservation alone can reduce energy demand growth by 0.7 to 1.2 percent depending on the world price of oil. . . . The environmental impacts of a vigorous energy conservation program will be primarily beneficial.

BLM, *Final Environmental Statement, OCS Sale No. 48, Proposed 1979 Outer Continental Shelf Oil and Gas Lease Sale Offshore Southern California*, 1508–09 (1979).[10] *See also* BLM, *Draft Environmental Statement, Proposed Five-Year OCS Oil and Gas Lease Sale Schedule* 63 (1980) ("An alternative . . . to cease leasing . . . would result in the need to meet national energy needs through other sources, or to reduce energy consumption . . . .").[11]

Thus, as early as 1979, BLM recognized that canceling even a single oil and gas lease would cause the market to respond by substituting not just oil and gas from other sources, but alternative fuel types as well as increased energy conservation. BLM further recognized that the extent of energy conservation as a response depended on the price of the resource being replaced.

BLM explained in 1979 to decisionmakers and the public, over the course of 25 pages of analysis, how each possible substitute for the foregone offshore leasing carried its own environmental effects: net beneficial to the extent increased energy conservation or renewable energy offset the lost offshore oil and gas; a more mixed or net negative effect on environmental quality with switches to other types and sources of fossil fuels. BLM, *Final Envtl. Stmt. on Sale No. 48*, *supra* at 1508–

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[10] Excerpt in Addendum; full text *at* https://books.google.com/books?id=A3sRAAAAYAAJ. This Court may take notice of other agency's environmental impact statements, *see supra* notes 3-5.

[11] Excerpt in Addendum; full text *at* https://books.google.com/books?id=9awYAQAAIAAJ.

1532. BLM even noted in this 1979 analysis that different energy substitutes generated different carbon dioxide emissions: "A number of gases are associated with geothermal systems and may pose health and pollution problems. These gases include . . . carbon dioxide . . . . However, adverse air quality impacts are generally less than those associated with fossil-fuel plants." *Id.* at 1525.

B. Interior Uses Sophisticated Tools to Assess the Environmental Consequences of Substitutes for Offshore Oil Leases, and the D.C. Circuit Has Praised Its Modeling

Interior develops Five-Year Programs to manage the leasing of offshore (or "Outer Continental Shelf" ("OCS")) oil and gas resources. Its current Program covers the years 2012–2017; development of that Program and the related Environmental Impact Statement first began in 2009. *See* BOEM, *Outer Continental Shelf Oil and Gas Leasing Program: 2012–2017—Final Programmatic Environmental Impact Statement*, 8-1 (2012).[12]

In the decision document for the current offshore Program, Interior's Bureau of Ocean Energy Management ("BOEM") explained:

> In an environment of strong worldwide demand for oil and natural gas, a domestic supply cut equivalent to the production anticipated to result from a new Five Year Program would lead to a slight increase in world oil prices and a relatively larger increase in U.S. natural gas prices. All other things being equal, this would lead to a market

[12] Excerpt in Addendum; full text *at* http://www.boem.gov/Oil-and-Gas-Energy-Program/Leasing/Five-Year-Program/2012-2017/Download-PDF-of-Final-Programmatic-EIS.aspx.

> response providing . . . a slight reduction in oil and natural gas consumed, a substantial increase in oil imports, and added supplies provided by onshore hydrocarbon resources.
>
> BOEM uses its *Market Simulation Model* (*MarketSim*) to estimate the amount and percentage of substitutes the economy would adopt should a particular program area not be offered to lease. *MarketSim* is based on authoritative and publicly available estimates of price elasticities of supply and demand and substitution effects. . . .
>
> [I]n the event the NAA [No-Action Alternative] were implemented. . . . 68 percent of the oil and natural gas production foregone from this program would be replaced by greater imports, 16 percent by increased onshore production, [10 percent by other energy sources] . . . and 6 percent by a reduction in consumption.

BOEM, *Proposed Final Outer Continental Shelf Oil & Gas Leasing Program 2012–2017*, 110 (2012)[13]; *see also* BOEM, *2012–2017 Final Programmatic Environmental Impact Statement*, *supra* at 4-643 ("With less oil and gas available from the OCS under the No Action Alternative, consumers could obtain oil and gas from other sources, substitute to other types of energy, or consume less energy overall.").

BOEM explained in its Final Environmental Impact Statement that, compared to leasing offshore oil and gas, the energy substitutes anticipated under a No-Action Alternative will have different environmental consequences, including for climate change. For example, BOEM detailed how "Coal consumed in place of gas under the No Action Alternative will result in environmental costs . . . . The

[13] Excerpt in Addendum; full text *at* http://www.boem.gov/uploadedFiles/BOEM/Oil_and_Gas_Energy_Program/Leasing/Five_Year_Program/2012-2017_Five_Year_Program/PFP%2012-17.pdf.

combustion of coal in power plants or industrial boilers produces higher emissions . . . than the combustion of natural gas and results in greater CO_2 [carbon dioxide] emissions." *Id.* at 4-647. Similarly, BOEM's Economic Analysis Methodology calculates:

> [T]he emissions for carbon dioxide and nitrous oxide [another greenhouse gas] are greater under the NSOs [No-Sale Options] than from the program. However, there is more methane from the program than the NSOs. Though these impacts are not monetized, *they are not identical between having an OCS program and having the impacts of the NSOs.*

BOEM, *Economic Analysis Methodology for the Five Year OCS Oil and Gas Leasing Program for 2012–2017*, 29–30 (2012) (emphasis added).[14]

To repeat: BOEM, an Interior sub-agency, definitively concluded that the No-Action Alternative's climate consequences are "not identical" to the climate consequences of energy leasing. In a recent case challenging Interior's 2012-2017 offshore oil and gas leasing program, the D.C. Circuit favorably reviewed Interior's modeling of how "forgoing additional leasing on the OCS would cause an increase in the use of substitute fuels . . . and a reduction in overall domestic energy consumption from greater efforts to conserve in the face of higher prices." *Ctr. for Sustainable Economy v. Jewell*, 779 F.3d 588, 609 (D.C. Cir. 2015).

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[14] Excerpt in Addendum; full text *at* http://www.boem.gov/uploadedFiles/BOEM/Oil_and_Gas_Energy_Program/Leasing/Five_Year_Program/2012-2017_Five_Year_Program/PFP%20EconMethodology.pdf.

Importantly, nothing in BOEM's modeling is unique to the offshore oil and gas context. According to BOEM, "MarketSim's economics-based model representation of U.S. energy markets . . . simulates end-use domestic consumption of oil, natural gas, *coal* and electricity in four sectors (residential, commercial, industrial and transportation); primary energy production; and the transformation of primary energy into electricity." BOEM, *The Revised Market Simulation Model (MarketSim): Model Description* 2 (2012) (emphasis added).[15]

Interior's sophisticated modeling of the environmental effects of energy substitutes under No-Action Alternatives relative to offshore oil leasing is the culmination of 35 years of analysis. Interior has used the MarketSim model since at least its 2002–2007 Program for offshore leasing. *See* Minerals Mgmt. Serv. ("MMS"), *Energy Alternatives and the Environment*, 10 (2001)[16] ("MMS employs the MktSim2000 model to evaluate the impact of decreased OCS production resulting from no action."). Since at least the 1990s, Interior's Environmental Impact Statements have calculated the percentage of offshore production expected to be substituted by various energy alternatives under a No-Action scenario. MMS,

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[15] Excerpt in Addendum; full text *at* http://www.boem.gov/uploadedFiles/BOEM/Oil_and_Gas_Energy_Program/Leasing/Five_Year_Program/2012-2017_Five_Year_Program/FinalMarketSim%20Model%20Documentation.pdf.

[16] Excerpt in Addendum; full text *at* http://www.boem.gov/uploadedFiles/.BOEM/Oil_and_Gas_Energy_Program/Leasing/Five_Year_Program/EnergyAlternativesandEnv.pdf.

Energy Alternatives and the Environment, 13 (1996)[17] ("[F]or each unit of OCS gas not produced because of no action . . . conservation will account for about 0.14 units . . . ."); *see also id.* at 15 ("Significant environmental impacts associated with expanded importation of oil include: the generation of greenhouse gases . . . ."). And going back to the first Five-Year Program in 1980 (when BLM prepared the Environmental Statements), Interior has recognized that not all sources of the same fuel type present the same environmental effects—for example, offshore oil drilling presents lower spill risks than imported oil substituted under the no-action alternative. Interior, *5-Year OCS Leasing Program* 13b (1980).[18]

Before the 1990s, Interior did briefly assume that additional oil produced from newly-leased domestic, offshore regions would completely "back out" or replace foreign oil imports, barrel for barrel, rather than supplanting other energy sources or satisfying new demand. In 1988, the D.C. Circuit upheld Interior's "backing out" assumption in its 1982–1987 Offshore Leasing Plan, with two crucial caveats:

> The Secretary's "backing out" assumption is a rough estimation that would prove wrong (1) to the extent that some of the OCS production is exported, or (2) to the extent that OCS production is significant

[17] Excerpt in Addendum; full text *at* https://web.archive.org/web/19970507132125/http://www.mms.gov/omm/eppd/nrgalt.pdf

[18] Excerpt in Addendum; full text *at* http://www.boem.gov/uploadedFiles/BOEM/Oil_and_Gas_Energy_Program/Leasing/Five_Year_Program/PFP%2080-82.pdf

> enough to depress world oil prices and thereby increase domestic consumption of oil. Petitioners do not suggest that either scenario is likely.

NRDC v. Hodel, 865 F.2d 288, 309 (D.C. Cir. 1988). Not only did Interior start analyzing a broad range of energy substitutes for offshore oil leases shortly after that case, but the D.C. Circuit opinion proves how important an energy substitution analysis is for U.S. coal leases in the 21st century. In the 1980s, it may have been reasonable to assume that U.S. offshore oil production led to no meaningful exports or effects on worldwide prices; but such assumptions are patently unreasonable with respect to U.S. coal production in 2010. In 1982, U.S. offshore production of crude oil totaled just over 315 million barrels, or only 1.6 percent of the nearly 20 billion barrels produced from all sources worldwide.[19] Back then, the United States was heavily reliant on oil imports and so exported little of its offshore oil production. In contrast, in 2010, U.S. coal production made up 13.5 percent of worldwide production, and the United States exported 7 percent of its coal.[20] In a 2001 report on its offshore oil leasing program, Interior declared in no uncertain terms that "Examining other energy sources is an important aspect of the

---

[19] *Compare* EIA, *Crude Oil Production*, https://www.eia.gov/dnav/pet/PET_CRD_CRPDN_ADC_MBBL_A.htm *with* EIA, *International Energy Statistics*, https://www.eia.gov/cfapps/ipdbproject/iedindex3.cfm?tid=5&pid=57&aid=1&cid=ww,US,&syid=1982&eyid=2014&unit=TBPD. Excerpts in Addendum.

[20] EIA, *International Energy Statistics*, https://www.eia.gov/cfapps/ipdbproject/iedindex3.cfm?tid=1&pid=7&aid=1&cid=ww,US,&syid=1982&eyid=2012&unit=TST. Excerpt in Addendum.

No Action Alternative" under NEPA reviews. MMS, *Energy Alternatives and the Environment* 1 (2001). Given the role of federal coal leases in shaping global coal supply, prices, and demand, such an examination is all the more important for BLM's review of the Wright Area leases.

C. Other Agencies Analyze Supply and Demand in NEPA Reviews of Energy Management Decisions

Petitioners detail how two federal agencies—the Surface Transportation Board and the Forest Service—began, upon remand from federal courts, conducting the proper analysis of supply and demand in NEPA reviews of their energy management decisions. Pet. Br. 28–35. The U.S. Court of Appeals for the Eighth Circuit sharply criticized the Surface Transportation Board for "illogical[ly]" concluding that approving new railroad lines to Powder River Basin coal mines would not affect the demand for and consumption of coal, and for ignoring "widely used" models capable of forecasting such effects. *Mid States Coal. for Progress v. Surface Transp. Bd.*, 345 F.3d 520, 549–550 (8th Cir. 2003). "On remand, the Board undertook just such a study using the Energy Information Administration's (EIA) National Energy Modeling System (NEMS) . . . '[which] not only forecasts coal supply and demand but also quantifies environmental impacts.'" *Mayo Found. v. Surface Transp. Bd.*, 472 F.3d 545, 555 (8th Cir. 2006). *See also* Surface Transp. Bd., *Draft Environmental Impact Statement for the Tongue River Railroad*,

Appendix C.1-13 to 1-14 (2015)[21] (analyzing how approving a new coal railroad would only increase annual U.S. coal production by 0.13 percent, which "would not be significant enough to noticeably lower delivered coal prices (which includes transportation), and thus, would not increase total demand for coal").

Similarly, the U.S. District Court of Colorado "[could] not make sense" of the Forest Service's assumption that approving road construction through national forests to reach Colorado coal mines would not increase coal production and consumption. *High Country Conservation Advocates v. Forest Service*, 52 F. Supp. 3d 1174, 1197 (D. Colo. 2014). On remand, the Forest Service's draft environmental impact statement details that while the no-action alternative "has no impact on climate change," under the leasing option "coal mining, transportation, and combustion would increase the atmospheric concentrations of GHGs [greenhouse gases]." Forest Service, *Rulemaking for Colorado Roadless Areas—Supplemental Draft Environmental Impact Statement* 48–49 (2015).[22]

The State Department provides another example. In its environmental impact statements, the agency has estimated how, at different oil prices, approving international oil pipelines could affect production and greenhouse gas emissions.

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[21] Excerpt in Addendum, full text *at* http://www.tonguerivereis.com/documents/draft_eis/appendices/AppC_CoalProduction.pdf.

[22] Excerpt in Addendum, full text at http://www.fs.usda.gov/Internet/FSE_DOCUMENTS/fseprd485194.pdf.

See State Dep't, *Final Supplemental Environmental Impact Statement for the Keystone XL Project*, ES-16 (2014)[23] ("The 2013 Draft Supplemental EIS estimated how oil sands production would be affected by long-term constraints on pipeline capacity . . . if long-term . . . oil prices were less than $100 per barrel. The Draft Supplemental EIS also estimated a change in GHG emissions associated with such changes in production."). This analysis was strongly encouraged by comments from the Environmental Protection Agency. *See* Comments from EPA, to State Dep't, on Draft EIS for the Keystone XL Project, at 3 (July 16, 2010)[24] ("[I]t is reasonable to conclude that extraction will likely increase if the pipeline is constructed."). Even when the State Department concluded that a different pipeline approval would not affect energy substitutes, the agency first assessed the market and "conclude[d] that this amount of crude oil [3% of total U.S. processing] is not expected . . . to significantly impact end-use price or demand." *Sierra Club v. Clinton*, 746 F. Supp. 2d 1025, 1046 (D. Minn. 2010). The State Department's practice of assessing whether its actions would affect overall energy demand stands in stark contrast with this case, where BLM simply made an unsubstantiated

[23] Excerpt in Addendum; full text at http://keystonepipeline-xl.state.gov/documents/organization/221135.pdf.

[24] Excerpt in Addendum; full text at https://cdxnodengn.epa.gov/cdx-enepa-II/public/action/eis/details?downloadAttachment=&attachmentId=106705.

assumption that an effect on demand was unlikely, without conducting any analysis.

Other agencies that, during NEPA reviews, have properly analyzed how their energy management decisions might affect energy supply and demand, and so affect emissions, include the Office of Surface Mining Reclamation and Enforcement (another Interior sub-agency), the Federal Energy Regulatory Commission, and the Nuclear Regulatory Commission. *See* Office of Surface Mining, *Draft Stream Protection Rule Environmental Impact Statement*, at 4-175 to 4-176 (2015)[25] ("Modeling suggests that these Alternatives [to regulate surface coal mining to protect streams] could decrease national coal production . . . . [T]his analysis anticipates that the net effect on climate resiliency is positive at the national level under each Action Alternative . . . ."); *id.* at 4-160 to 4-161 "Under some Alternatives, the mix of production type, i.e., surface or underground, may also change. As discussed . . . surface and underground mining activities have different emissions profiles."); Fed. Energy Reg. Comm'n, *Lake Charles Liquefaction Project—Final Environmental Impact Statement*, 3-3 (2015)[26] ("If the No-Action Alternative is selected, it could result in the continued use of less clean-

[25] Excerpt in Addendum; full text at http://www.regulations.gov/#!documentDetail;D=OSM-2010-0021-0002.

[26] Excerpt in Addendum; full text at http://energy.gov/sites/prod/files/2015/08/f26/EIS-0491-FEIS-2015.pdf.

burning fossil fuels at levels that might otherwise have been reduced through replacement with LNG."); Nuclear Reg. Comm'n, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* §8.2 (1996)[27] ("Denial of a renewed license . . . may lead to the selection of other electric generating sources to meet energy demands . . . [or] to conservation measures . . . . [T]he environmental impacts of such resulting alternatives would be included as the environmental impacts of the no-action alternative.").

In short, at least nine different agencies—including Interior's Office of the Secretary and at least three Interior sub-agencies (Office of Surface Mining, Bureau of Ocean Energy Management, and Minerals Management Service)—in NEPA analyses stretching back over 35 years, have analyzed how their energy management decisions affect energy supply and demand, and so affect emissions. The economic theory is undisputed, the economic models are easily accessible, and the practice is widespread through the government. BLM's unexplained assumption of perfect substitution sharply breaks with 35 years of agency practice.

[27] Excerpt in Addendum; full text at http://www.nrc.gov/reading-rm/doc-collections/nuregs/staff/sr1437/v1/part08.html#_1_191.

IV. Even If BLM's Assumption of Perfect Substitution Were Accurate, then BLM's Calculation of the Economic Benefits of the Wright Area Leases Would Be Overestimated and Inaccurate

BLM assumes that taking no action on the Wright Area leases would have, compared to leasing, no net effects on carbon dioxide emissions, methane emissions, or climate change, because "there are multiple other sources of coal that could supply the coal demand." App. 989; *accord* App. 988. In other words, BLM assumes that, under the No-Action Alternative, other sources of coal will perfectly substitute for Wright Area coal. This brief has explained why that assumption is entirely inconsistent with economic theory, real market conditions, and past agency practices. Consequently, BLM's environmental impact statement presents a deeply inaccurate and misleading comparison of the Leasing Options and No-Action Alternative. However, even if BLM's perfect substitution assumption were correct, then BLM's environmental impact statement would be inaccurate and misleading in a different but equally problematic way.

BLM's environmental impact statement calculates the "economic benefits" of leasing the Wright Area coal and generating federal and state royalties. BLM states that, "Under the No Action Alternatives . . . potentially recoverable coal . . . would not be recovered and the economic benefits associated with mining that coal would not be realized by the state or federal government." BLM, *Final Environmental*

Impact Statement for the Wright Area Coal Lease Applications 3-307 (2010).[28] For each coal field, BLM calculates the "added" state and federal revenues generated by the Leasing Options, over and above the No-Action Alternative. "Federal revenues," for example, "are based on a projected coal price of $11.06 per ton * amount of recoverable coal . . . * federal royalty of 12.5 percent minus state's 50 percent share . . . ." App. 762.

Yet over 40 percent of U.S. coal production already comes from federal leases, and the federal government already collects royalties on those leases. EIA, *Sales of Fossil Fuels Produced from Federal and Indian Lands, FY 2003 through FY 2014*, tbl. 1 (2015).[29] If BLM is correct that, under the No-Action Alternative, other sources of coal would perfectly substitute for the Wright Area coal, then it must also be true that, under the Leasing Options, the Wright Area coal simply substitutes for other sources of coal that would otherwise be mined. At least some of those other sources—perhaps 40 percent or more—would surely have been other federal leases. But if the Wright Area leases perfectly supplant those other leases, those other leases will no longer generate federal revenue.

BLM never subtracts from its calculation of the Leasing Option's "economic benefits" the lost benefits from all those would-be sources of coal that will be

[28] Excerpt in Addendum.

[29] Excerpt in Addendum; full text at http://www.eia.gov/analysis/requests/federallands/pdf/eia-federallandsales.pdf.

supplanted by the Wright Area leases. Consequently, if BLM's assumption of perfect substitution is correct, then BLM's presentation of the economic benefits of the Leasing Option, compared to the No-Action Alternative, is inaccurate and misleading. If instead BLM's assumption of perfect substitution is incorrect (as argued above), then BLM's presentation of the climate consequences of the Leasing Option, compared to the No-Action Alternatives, is inaccurate and misleading. Either way, BLM has failed to execute its responsibilities under NEPA to fully inform decisionmakers and the public and to faithfully highlight differences between alternatives.

CONCLUSION

For the foregoing reasons, the Court should find that BLM's Wright Area environmental impact statement violated NEPA.

DATED: February 5, 2016

Respectfully submitted,

/s/ Jason A. Schwartz
Jayni Foley Hein
Jason A. Schwartz
INSTITUTE FOR POLICY INTEGRITY
139 MacDougal Street, Room 317
New York, NY 10012
(212) 998-6093
jason.schwartz@nyu.edu
Counsel for Amicus Curiae Institute for Policy Integrity

CERTIFICATE OF COMPLIANCE WITH WORD LIMITATION

I hereby certify that this Brief complies with the requirements of Fed. R. App. P. 32(a)(5) and (6) and 10th Cir. R. 32(a) because it has been prepared in 14-point Times New Roman, a proportionally spaced font. I further certifies that, in accordance with Federal Rule of Appellate Procedure 32(a)(7)(C) and 10th Cir. R. 32(b), this Brief of the Institute for Policy Integrity at New York University School of Law as *Amicus Curiae* in Support of Petitioners contains 6,977 words (excluding exempted sections), as counted by counsel's word processing system, and this complies with the applicable word limit established by the Court.

DATED: February 5, 2016

/s/ Jason A. Schwartz
Jayni Foley Hein
Jason A. Schwartz
INSTITUTE FOR POLICY INTEGRITY
139 MacDougal Street, Room 317
New York, NY 10012
(212) 998-6093
jason.schwartz@nyu.edu
Counsel for Amicus Curiae Institute for Policy Integrity

CERTIFICATE OF SERVICE

I hereby certify that on February 5, 2016, I filed the foregoing Brief of the Institute for Policy Integrity at New York University School of Law as *Amicus Curiae* in Support of Petitioners-Appellants through the Court's CM/ECF system, which will send a notice of filing to all parties, because all parties are registered CM/ECF users. The counsel of record are:

Beau Bryan Bump, bbbump@hollandhart.com
Michael R. Drysdale, drysdale.michael@dorsey.com
Andrew C. Emrich, acemrich@hollandhart.com
Peter Glaser, peter.glaser@troutmansanders.com
Merril Hirsh, merril.hirsh@troutmansanders.com
Michael Thomas Gray, michael.gray2@usdjo.gov
James Kaste, james.kaste@wyo.gov
Michael McGrady, mike.mcgrady@wyo.gov
Erik Petersen, erik.peterson@wyo.gov
John Most, john.most@usdoj.gov
Richard A. Mincer, rmincer@hirstapplegate.com
Thomas A. Nicholas III, nicholas@hirstapplegate.com
Nathaniel Shoaff, nathaniel.shoaff@sierraclub.org
Kristina R. Van Bockern, trvanbockern@hollandhart.com

DATED: February 5, 2016

/s/ Jason. A Schwartz
Jason A. Schwartz
Counsel for Amicus Curiae Institute for Policy Integrity

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/s/ Jason. A Schwartz
Jason A. Schwartz
Counsel for Amicus Curiae Institute for Policy Integrity

ADDENDUM

TABLE OF CONTENTS

EIA, *Crude Oil Production: Federal Offshore—Gulf of Mexico Field & PADD 5 Field*	87–88
EIA, *International Energy Statistics—Production of Crude Oil, Total Primary Coal Production*, and *Total Coal Exports*	89–91
Surface Transp. Bd., *Draft Environmental Impact Statement for the Tongue River Railroad* (2015), Appendix C.1-13 to 1-14.	92–93
Forest Service, *Rulemaking for Colorado Roadless Areas: Supplemental Draft Environmental Impact Statement* (2015), pp.48–49.	94–96
State Dept., *Final Supplemental Environmental Impact Statement for the Keystone XL Project* (2014), pp. ES-16–ES-17.	97–99
Comments from EPA to State Department on Draft Environmental Impact Statement for the Keystone XL Project, July 16, 2010, pp.1–3.	100–102
Office of Surface Mining, *Draft Stream Protection Rule Environmental Impact Statement* (2015), pp. 4-160–4-161, 4-175–4-176.	103–107
Fed. Energy Reg. Comm'n, *Lake Charles Liquefaction Project: Draft Environmental Impact Statement* (2015), p.3-3.	108–109
Nuclear Reg. Comm'n, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (1996), § 8.2	110–112
BLM, *Final Environmental Impact Statement for the Wright Area Coal Lease Applications* (2010), p.3-307.	113–114

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There are some markets in which the assumption of perfect competition applies perfectly. In the wheat market, for example, there are thousands of farmers who sell wheat and millions of consumers who use wheat and wheat products. Because no single buyer or seller can influence the price of wheat, each takes the price as given.

Not all goods and services, however, are sold in perfectly competitive markets. Some markets have only one seller, and this seller sets the price. Such a seller is called a *monopoly*. Your local cable television company, for instance, may be a monopoly. Residents of your town probably have only one cable company from which to buy this service. Still other markets fall between the extremes of perfect competition and monopoly.

Despite the diversity of market types we find in the world, assuming perfect competition is a useful simplification and, therefore, a natural place to start. Perfectly competitive markets are the easiest to analyze because everyone participating in the market takes the price as given by market conditions. Moreover, because some degree of competition is present in most markets, many of the lessons that we learn by studying supply and demand under perfect competition apply in more complicated markets as well.

QUICK QUIZ What is a market? • What are the characteristics of a perfectly competitive market?

DEMAND

We begin our study of markets by examining the behavior of buyers. To focus our thinking, let's keep in mind a particular good—ice cream.

THE DEMAND CURVE: THE RELATIONSHIP BETWEEN PRICE AND QUANTITY DEMANDED

The **quantity demanded** of any good is the amount of the good that buyers are willing and able to purchase. As we will see, many things determine the quantity demanded of any good, but when analyzing how markets work, one determinant plays a central role—the price of the good. If the price of ice cream rose to $20 per scoop, you would buy less ice cream. You might buy frozen yogurt instead. If the price of ice cream fell to $0.20 per scoop, you would buy more. This relationship between price and quantity demanded is true for most goods in the economy and, in fact, is so pervasive that economists call it the **law of demand**: Other things equal, when the price of a good rises, the quantity demanded of the good falls, and when the price falls, the quantity demanded rises.

quantity demanded
the amount of a good that buyers are willing and able to purchase

law of demand
the claim that, other things equal, the quantity demanded of a good falls when the price of the good rises

The table in Figure 1 shows how many ice-cream cones Catherine buys each month at different prices of ice cream. If ice cream is free, Catherine eats 12 cones per month. At $0.50 per cone, Catherine buys 10 cones each month. As the price rises further, she buys fewer and fewer cones. When the price reaches $3.00, Catherine doesn't buy any ice cream at all. This table is a **demand schedule**, a table that shows the relationship between the price of a good and the quantity demanded, holding constant everything else that influences how much consumers of the good want to buy.

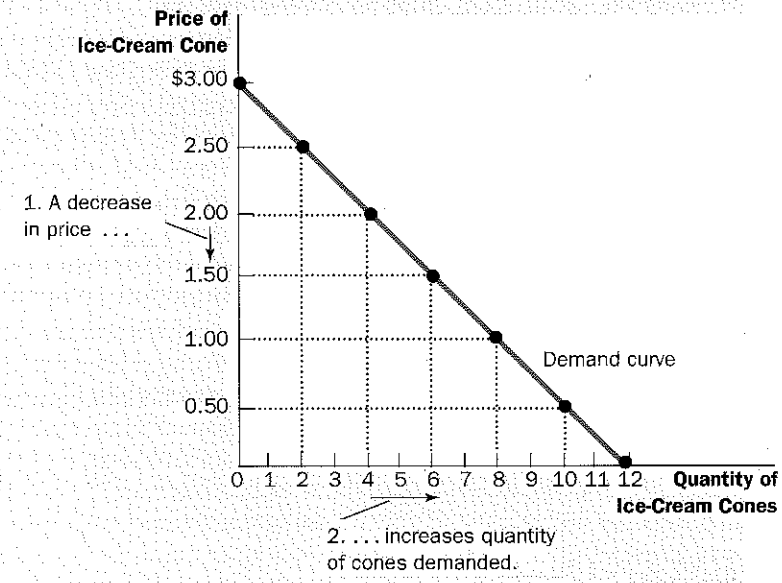
demand schedule
a table that shows the relationship between the price of a good and the quantity demanded

FIGURE 1

Catherine's Demand Schedule and Demand Curve

The demand schedule is a table that shows the quantity demanded at each price. The demand curve, which graphs the demand schedule, illustrates how the quantity demanded of the good changes as its price varies. Because a lower price increases the quantity demanded, the demand curve slopes downward.

Price of Ice-Cream Cone	Quantity of Cones Demanded
$0.00	12 cones
0.50	10
1.00	8
1.50	6
2.00	4
2.50	2
3.00	0



demand curve
a graph of the relationship between the price of a good and the quantity demanded

The graph in Figure 1 uses the numbers from the table to illustrate the law of demand. By convention, the price of ice cream is on the vertical axis, and the quantity of ice cream demanded is on the horizontal axis. The downward-sloping line relating price and quantity demanded is called the **demand curve**.

Market Demand versus Individual Demand

The demand curve in Figure 1 shows an individual's demand for a product. To analyze how markets work, we need to determine the *market demand*, the sum of all the individual demands for a particular good or service.

The table in Figure 2 shows the demand schedules for ice cream of the two individuals in this market—Catherine and Nicholas. At any price, Catherine's demand schedule tells us how much ice cream she buys, and Nicholas's demand schedule tells us how much ice cream he buys. The market demand at each price is the sum of the two individual demands.

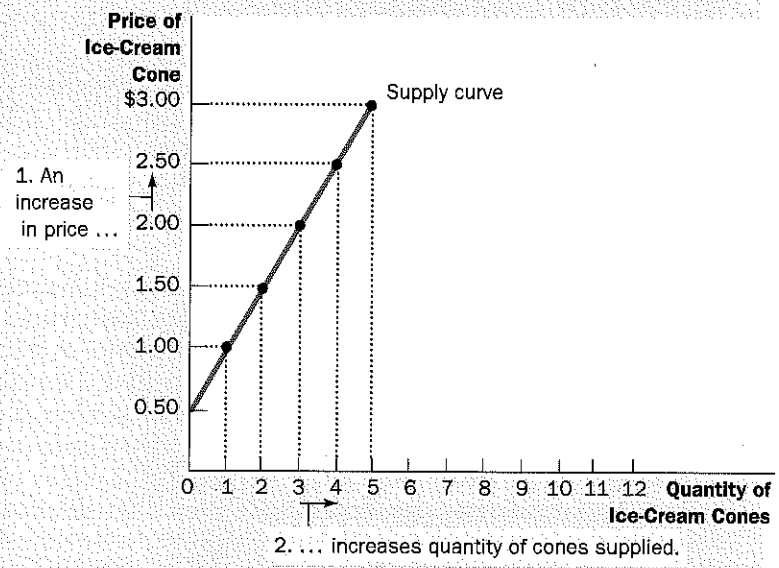
The graph in Figure 2 shows the demand curves that correspond to these demand schedules. Notice that we sum the individual demand curves horizontally to obtain the market demand curve. That is, to find the total quantity demanded at any price, we add the individual quantities, which are found on the horizontal axis of the individual demand curves. Because we are interested in analyzing how markets function, we work most often with the market demand curve. The market demand curve shows how the total quantity demanded of a good varies as the

5 FIGURE

Ben's Supply Schedule and Supply Curve

The supply schedule is a table that shows the quantity supplied at each price. This supply curve, which graphs the supply schedule, illustrates how the quantity supplied of the good changes as its price varies. Because a higher price increases the quantity supplied, the supply curve slopes upward.

Price of Ice-Cream Cone	Quantity of Cones Supplied
$0.00	0 cones
0.50	0
1.00	1
1.50	2
2.00	3
2.50	4
3.00	5



all the other factors beyond price that influence producers' decisions about how much to sell.

Shifts in the Supply Curve

Because the market supply curve holds other things constant, the curve shifts when one of the factors changes. For example, suppose the price of sugar falls. Sugar is an input into producing ice cream, so the fall in the price of sugar makes selling ice cream more profitable. This raises the supply of ice cream: At any given price, sellers are now willing to produce a larger quantity. The supply curve for ice cream shifts to the right.

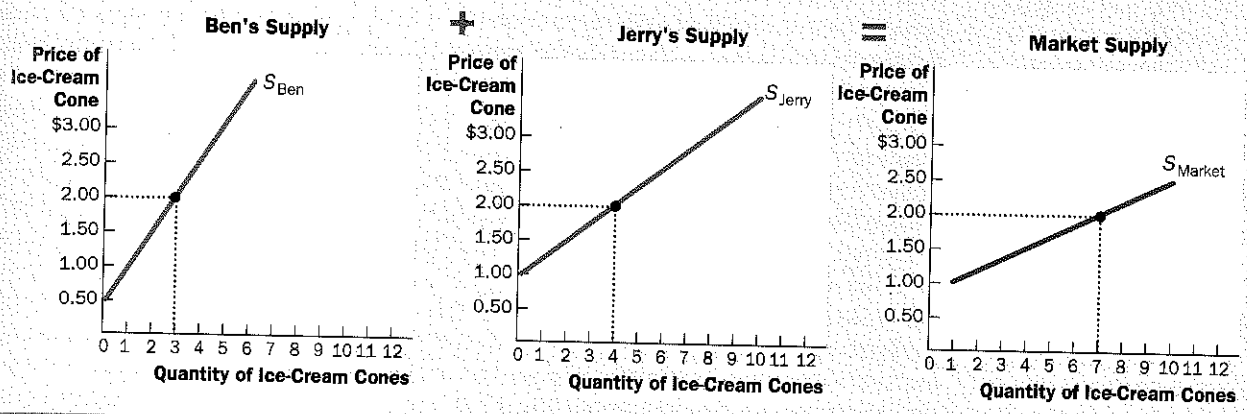
Figure 7 illustrates shifts in supply. Any change that raises quantity supplied at every price, such as a fall in the price of sugar, shifts the supply curve to the right and is called an *increase in supply*. Similarly, any change that reduces the quantity supplied at every price shifts the supply curve to the left and is called a *decrease in supply*.

There are many variables that can shift the supply curve. Here are some of the most important.

Input Prices To produce their output of ice cream, sellers use various inputs: cream, sugar, flavoring, ice-cream machines, the buildings in which the ice cream is made, and the labor of workers to mix the ingredients and operate the machines.

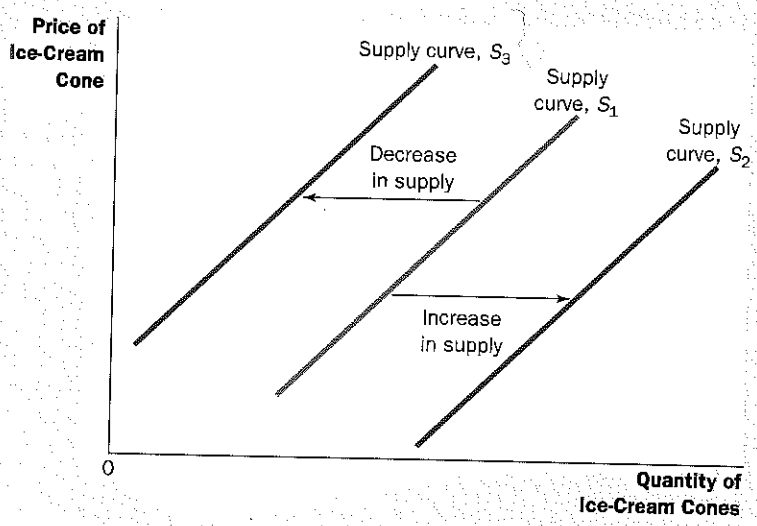
FIGURE 6

Price of Ice-Cream Cone	Ben		Jerry		Market
$0.00	0	+	0	=	0 cones
0.50	0		0		0
1.00	1		0		1
1.50	2		2		4
2.00	3		4		7
2.50	4		6		10
3.00	5		8		13



Market Supply as the Sum of Individual Supplies
The quantity supplied in a market is the sum of the quantities supplied by all the sellers at each price. Thus, the market supply curve is found by adding horizontally the individual supply curves. At a price of $2.00, Ben supplies 3 ice-cream cones, and Jerry supplies 4 ice-cream cones. The quantity supplied in the market at this price is 7 cones.

FIGURE 7



Shifts in the Supply Curve
Any change that raises the quantity that sellers wish to produce at any given price shifts the supply curve to the right. Any change that lowers the quantity that sellers wish to produce at any given price shifts the supply curve to the left.

When the price of one or more of these inputs rises, producing ice cream is less profitable, and firms supply less ice cream. If input prices rise substantially, a firm might shut down and supply no ice cream at all. Thus, the supply of a good is negatively related to the price of the inputs used to make the good.

Technology The technology for turning inputs into ice cream is another determinant of supply. The invention of the mechanized ice-cream machine, for example, reduced the amount of labor necessary to make ice cream. By reducing firms' costs, the advance in technology raised the supply of ice cream.

Expectations The amount of ice cream a firm supplies today may depend on its expectations about the future. For example, if a firm expects the price of ice cream to rise in the future, it will put some of its current production into storage and supply less to the market today.

Number of Sellers In addition to the preceding factors, which influence the behavior of individual sellers, market supply depends on the number of these sellers. If Ben or Jerry were to retire from the ice-cream business, the supply in the market would fall.

Summary The supply curve shows what happens to the quantity supplied of a good when its price varies, holding constant all the other variables that influence sellers. When one of these other variables changes, the supply curve shifts. Table 2 lists the variables that influence how much producers choose to sell of a good.

Once again, to remember whether you need to shift or move along the supply curve, keep in mind that a curve shifts only when there is a change in a relevant variable that is not named on either axis. The price is on the vertical axis, so a change in price represents a movement along the supply curve. By contrast, because input prices, technology, expectations, and the number of sellers are not measured on either axis, a change in one of these variables shifts the supply curve.

QUICK QUIZ Make up an example of a monthly supply schedule for pizza and graph the implied supply curve. • Give an example of something that would shift this supply curve, and briefly explain your reasoning. • Would a change in the price of pizza shift this supply curve?

2 TABLE

Variables That Influence Sellers
This table lists the variables that affect how much producers choose to sell of any good. Notice the special role that the price of the good plays: A change in the good's price represents a movement along the supply curve, whereas a change in one of the other variables shifts the supply curve.

Variable	A Change in This Variable . . .
Price of the good itself	Represents a movement along the supply curve
Input prices	Shifts the supply curve
Technology	Shifts the supply curve
Expectations	Shifts the supply curve
Number of sellers	Shifts the supply curve

SUPPLY AND DEMAND TOGETHER

Having analyzed supply and demand separately, we now combine them to see how they determine the price and quantity of a good sold in a market.

EQUILIBRIUM

Figure 8 shows the market supply curve and market demand curve together. Notice that there is one point at which the supply and demand curves intersect. This point is called the market's **equilibrium**. The price at this intersection is called the **equilibrium price**, and the quantity is called the **equilibrium quantity**. Here the equilibrium price is $2.00 per cone, and the equilibrium quantity is 7 ice-cream cones.

The dictionary defines the word *equilibrium* as a situation in which various forces are in balance—and this also describes a market's equilibrium. *At the equilibrium price, the quantity of the good that buyers are willing and able to buy exactly balances the quantity that sellers are willing and able to sell.* The equilibrium price is sometimes called the market-clearing price because, at this price, everyone in the market has been satisfied: Buyers have bought all they want to buy, and sellers have sold all they want to sell.

The actions of buyers and sellers naturally move markets toward the equilibrium of supply and demand. To see why, consider what happens when the market price is not equal to the equilibrium price.

Suppose first that the market price is above the equilibrium price, as in panel (a) of Figure 9. At a price of $2.50 per cone, the quantity of the good supplied (10 cones) exceeds the quantity demanded (4 cones). There is a **surplus** of the good: Suppliers are unable to sell all they want at the going price. A surplus is sometimes called a situation of *excess supply*. When there is a surplus in the ice-cream market,

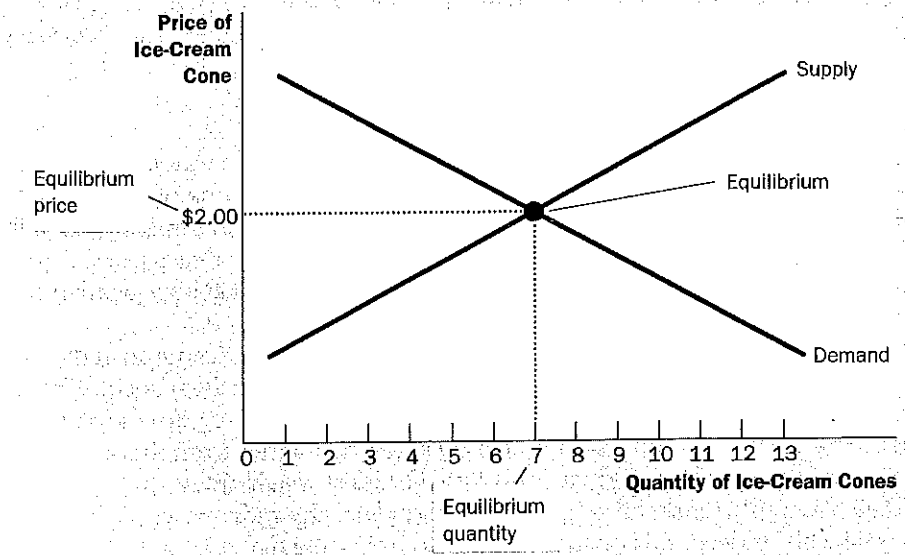
equilibrium
a situation in which the market price has reached the level at which quantity supplied equals quantity demanded

equilibrium price
the price that balances quantity supplied and quantity demanded

equilibrium quantity
the quantity supplied and the quantity demanded at the equilibrium price

surplus
a situation in which quantity supplied is greater than quantity demanded

FIGURE 8

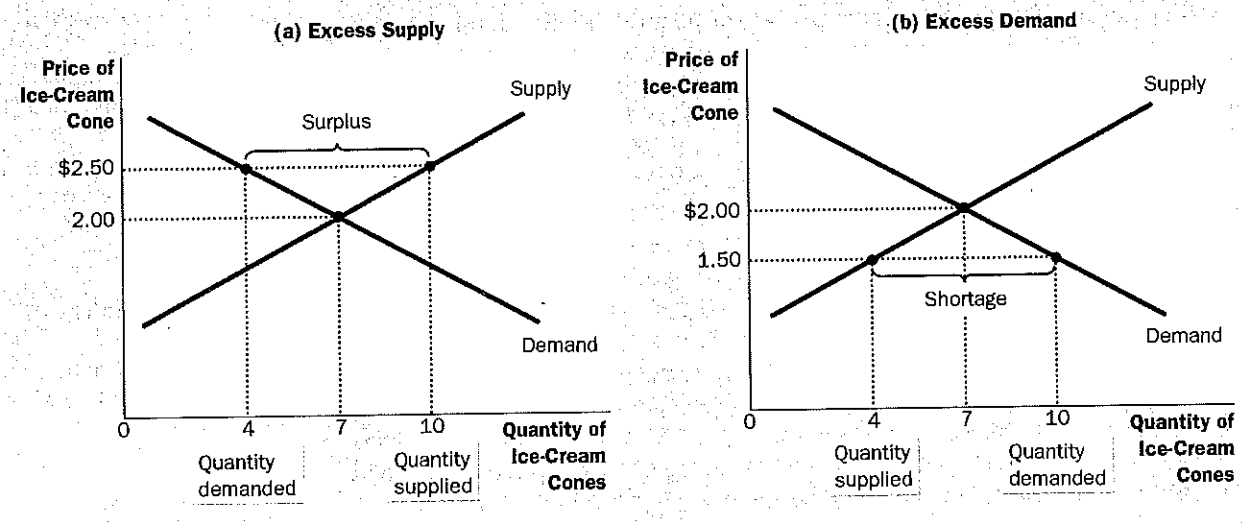


The Equilibrium of Supply and Demand
The equilibrium is found where the supply and demand curves intersect. At the equilibrium price, the quantity supplied equals the quantity demanded. Here the equilibrium price is $2.00: At this price, 7 ice-cream cones are supplied, and 7 ice-cream cones are demanded.

9 FIGURE

Markets Not in Equilibrium

In panel (a), there is a surplus. Because the market price of $2.50 is above the equilibrium price, the quantity supplied (10 cones) exceeds the quantity demanded (4 cones). Suppliers try to increase sales by cutting the price of a cone, and this moves the price toward its equilibrium level. In panel (b), there is a shortage. Because the market price of $1.50 is below the equilibrium price, the quantity demanded (10 cones) exceeds the quantity supplied (4 cones). With too many buyers chasing too few goods, suppliers can take advantage of the shortage by raising the price. Hence, in both cases, the price adjustment moves the market toward the equilibrium of supply and demand.



sellers of ice cream find their freezers increasingly full of ice cream they would like to sell but cannot. They respond to the surplus by cutting their prices. Falling prices, in turn, increase the quantity demanded and decrease the quantity supplied. Prices continue to fall until the market reaches the equilibrium.

shortage
a situation in which quantity demanded is greater than quantity supplied

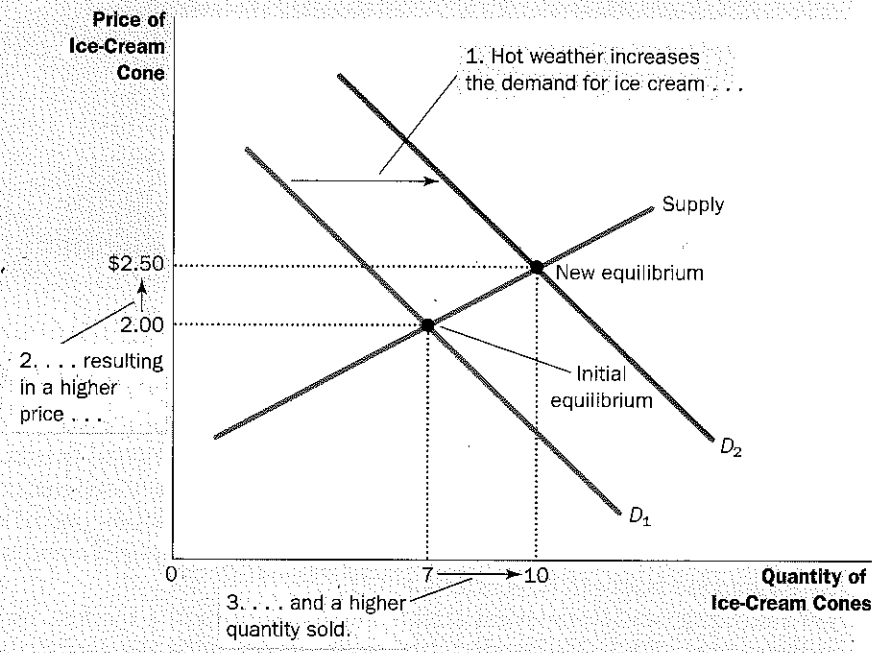
Suppose now that the market price is below the equilibrium price, as in panel (b) of Figure 9. In this case, the price is $1.50 per cone, and the quantity of the good demanded exceeds the quantity supplied. There is a **shortage** of the good: Demanders are unable to buy all they want at the going price. A shortage is sometimes called a situation of *excess demand*. When a shortage occurs in the ice-cream market, buyers have to wait in long lines for a chance to buy one of the few cones available. With too many buyers chasing too few goods, sellers can respond to the shortage by raising their prices without losing sales. As the price rises, the quantity demanded falls, the quantity supplied rises, and the market once again moves toward the equilibrium.

law of supply and demand
the claim that the price of any good adjusts to bring the quantity supplied and the quantity demanded for that good into balance

Thus, the activities of the many buyers and sellers automatically push the market price toward the equilibrium price. Once the market reaches its equilibrium, all buyers and sellers are satisfied, and there is no upward or downward pressure on the price. How quickly equilibrium is reached varies from market to market depending on how quickly prices adjust. In most free markets, surpluses and shortages are only temporary because prices eventually move toward their equilibrium levels. Indeed, this phenomenon is so pervasive that it is called the **law of supply and demand**: The price of any good adjusts to bring the quantity supplied and quantity demanded for that good into balance.

10 FIGURE

How an Increase in Demand Affects the Equilibrium
An event that raises quantity demanded at any given price shifts the demand curve to the right. The equilibrium price and the equilibrium quantity both rise. Here an abnormally hot summer causes buyers to demand more ice cream. The demand curve shifts from D_1 to D_2, which causes the equilibrium price to rise from \$2.00 to \$2.50 and the equilibrium quantity to rise from 7 to 10 cones.



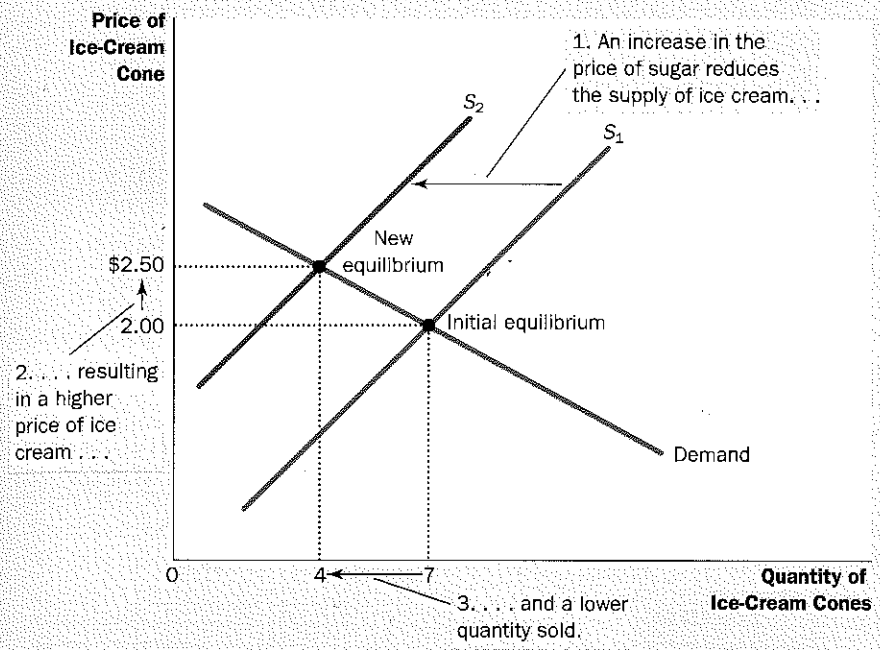
Supply refers to the position of the supply curve, whereas the *quantity supplied* refers to the amount suppliers wish to sell. In this example, supply does not change because the weather does not alter firms' desire to sell at any given price. Instead, the hot weather alters consumers' desire to buy at any given price and thereby shifts the demand curve to the right. The increase in demand causes the equilibrium price to rise. When the price rises, the quantity supplied rises. This increase in quantity supplied is represented by the movement along the supply curve.

To summarize, a shift *in* the supply curve is called a "change in supply," and a shift *in* the demand curve is called a "change in demand." A movement *along* a fixed supply curve is called a "change in the quantity supplied," and a movement *along* a fixed demand curve is called a "change in the quantity demanded."

Example: A Change in Market Equilibrium Due to a Shift in Supply Suppose that during another summer, a hurricane destroys part of the sugarcane crop and drives up the price of sugar. How does this event affect the market for ice cream? Once again, to answer this question, we follow our three steps.

1. The change in the price of sugar, an input into making ice cream, affects the supply curve. By raising the costs of production, it reduces the amount of ice cream that firms produce and sell at any given price. The demand curve does not change because the higher cost of inputs does not directly affect the amount of ice cream households wish to buy.
2. The supply curve shifts to the left because, at every price, the total amount that firms are willing and able to sell is reduced. Figure 11 illustrates this decrease in supply as a shift in the supply curve from S_1 to S_2.

FIGURE 11



How a Decrease in Supply Affects the Equilibrium
An event that reduces quantity supplied at any given price shifts the supply curve to the left. The equilibrium price rises, and the equilibrium quantity falls. Here an increase in the price of sugar (an input) causes sellers to supply less ice cream. The supply curve shifts from S_1 to S_2, which causes the equilibrium price of ice cream to rise from $2.00 to $2.50 and the equilibrium quantity to fall from 7 to 4 cones.

3. As Figure 11 shows, the shift in the supply curve raises the equilibrium price from $2.00 to $2.50 and lowers the equilibrium quantity from 7 to 4 cones. As a result of the sugar price increase, the price of ice cream rises, and the quantity of ice cream sold falls.

Example: Shifts in Both Supply and Demand Now suppose that a heat wave and a hurricane occur during the same summer. To analyze this combination of events, we again follow our three steps.

1. We determine that both curves must shift. The hot weather affects the demand curve because it alters the amount of ice cream that households want to buy at any given price. At the same time, when the hurricane drives up sugar prices, it alters the supply curve for ice cream because it changes the amount of ice cream that firms want to sell at any given price.
2. The curves shift in the same directions as they did in our previous analysis: The demand curve shifts to the right, and the supply curve shifts to the left. Figure 12 illustrates these shifts.
3. As Figure 12 shows, two possible outcomes might result depending on the relative size of the demand and supply shifts. In both cases, the equilibrium price rises. In panel (a), where demand increases substantially while supply falls just a little, the equilibrium quantity also rises. By contrast, in panel (b), where supply falls substantially while demand rises just a little, the equilibrium quantity falls. Thus, these events certainly raise the price of ice cream, but their impact on the amount of ice cream sold is ambiguous (that is, it could go either way).

Even among normal goods, income elasticities vary substantially in size. Necessities, such as food and clothing, tend to have small income elasticities because consumers choose to buy some of these goods even when their incomes are low. Luxuries, such as caviar and diamonds, tend to have large income elasticities because consumers feel that they can do without these goods altogether if their incomes are too low.

The Cross-Price Elasticity of Demand The **cross-price elasticity of demand** measures how the quantity demanded of one good responds to a change in the price of another good. It is calculated as the percentage change in quantity demanded of good 1 divided by the percentage change in the price of good 2. That is,

$$\text{Cross-price elasticity of demand} = \frac{\text{Percentage change in quantity demanded of good 1}}{\text{Percentage change in the price of good 2}}.$$

cross-price elasticity of demand
a measure of how much the quantity demanded of one good responds to a change in the price of another good, computed as the percentage change in quantity demanded of the first good divided by the percentage change in the price of the second good

Whether the cross-price elasticity is a positive or negative number depends on whether the two goods are substitutes or complements. As we discussed in Chapter 4, substitutes are goods that are typically used in place of one another, such as hamburgers and hot dogs. An increase in hot dog prices induces people to grill hamburgers instead. Because the price of hot dogs and the quantity of hamburgers demanded move in the same direction, the cross-price elasticity is positive. Conversely, complements are goods that are typically used together, such as computers and software. In this case, the cross-price elasticity is negative, indicating that an increase in the price of computers reduces the quantity of software demanded.

QUICK QUIZ Define the price elasticity of demand. • Explain the relationship between total revenue and the price elasticity of demand.

THE ELASTICITY OF SUPPLY

When we introduced supply in Chapter 4, we noted that producers of a good offer to sell more of it when the price of the good rises. To turn from qualitative to quantitative statements about quantity supplied, we once again use the concept of elasticity.

The Price Elasticity of Supply and Its Determinants

The law of supply states that higher prices raise the quantity supplied. The **price elasticity of supply** measures how much the quantity supplied responds to changes in the price. Supply of a good is said to be *elastic* if the quantity supplied responds substantially to changes in the price. Supply is said to be *inelastic* if the quantity supplied responds only slightly to changes in the price.

price elasticity of supply
a measure of how much the quantity supplied of a good responds to a change in the price of that good, computed as the percentage change in quantity supplied divided by the percentage change in price

The price elasticity of supply depends on the flexibility of sellers to change the amount of the good they produce. For example, beachfront land has an inelastic supply because it is almost impossible to produce more of it. By contrast, manufactured goods, such as books, cars, and televisions, have elastic supplies because

This analysis of the market for farm products also helps to explain a seeming paradox of public policy: Certain farm programs try to help farmers by inducing them *not* to plant crops on all of their land. The purpose of these programs is to reduce the supply of farm products and thereby raise prices. With inelastic demand for their products, farmers as a group receive greater total revenue if they supply a smaller crop to the market. No single farmer would choose to leave his land fallow on his own because each takes the market price as given. But if all farmers do so together, each of them can be better off.

When analyzing the effects of farm technology or farm policy, it is important to keep in mind that what is good for farmers is not necessarily good for society as a whole. Improvement in farm technology can be bad for farmers because it makes farmers increasingly unnecessary, but it is surely good for consumers who pay less for food. Similarly, a policy aimed at reducing the supply of farm products may raise the incomes of farmers, but it does so at the expense of consumers.

Why Did OPEC Fail to Keep the Price of Oil High?

Many of the most disruptive events for the world's economies over the past several decades have originated in the world market for oil. In the 1970s, members of the Organization of Petroleum Exporting Countries (OPEC) decided to raise the world price of oil to increase their incomes. These countries accomplished this goal by jointly reducing the amount of oil they supplied. From 1973 to 1974, the price of oil (adjusted for overall inflation) rose more than 50 percent. Then, a few years later, OPEC did the same thing again. From 1979 to 1981, the price of oil approximately doubled.

Yet OPEC found it difficult to maintain a high price. From 1982 to 1985, the price of oil steadily declined about 10 percent per year. Dissatisfaction and disarray soon prevailed among the OPEC countries. In 1986, cooperation among OPEC members completely broke down, and the price of oil plunged 45 percent. In 1990, the price of oil (adjusted for overall inflation) was back to where it began in 1970, and it stayed at that low level throughout most of the 1990s. (In the first decade of the 21st century, the price of oil rose again, but the main driving force was not OPEC supply restrictions but, rather, increased world demand, in part from a large and rapidly growing Chinese economy.)

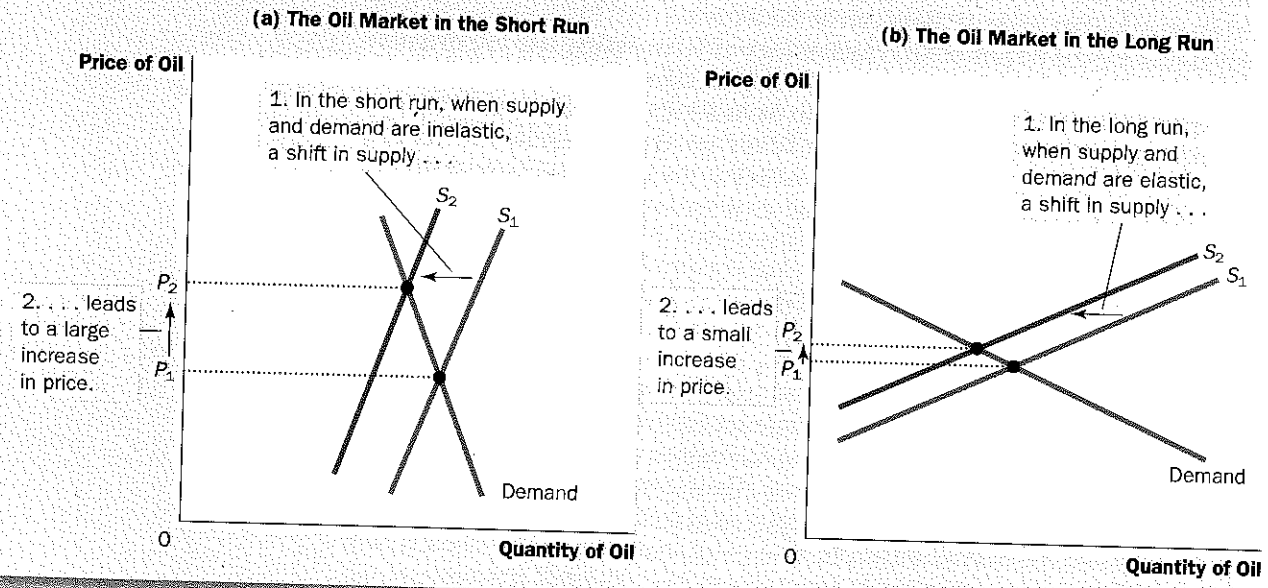
This OPEC episode of the 1970s and 1980s shows how supply and demand can behave differently in the short run and in the long run. In the short run, both the supply and demand for oil are relatively inelastic. Supply is inelastic because the quantity of known oil reserves and the capacity for oil extraction cannot be changed quickly. Demand is inelastic because buying habits do not respond immediately to changes in price. Thus, as panel (a) of Figure 8 shows, the short-run supply and demand curves are steep. When the supply of oil shifts from S_1 to S_2, the price increase from P_1 to P_2 is large.

The situation is very different in the long run. Over long periods of time, producers of oil outside OPEC respond to high prices by increasing oil exploration and by building new extraction capacity. Consumers respond with greater conservation, for instance by replacing old inefficient cars with newer efficient ones. Thus, as panel (b) of Figure 8 shows, the long-run supply and demand curves are more elastic. In the long run, the shift in the supply curve from S_1 to S_2 causes a much smaller increase in the price.

8 FIGURE

A Reduction in Supply in the World Market for Oil

When the supply of oil falls, the response depends on the time horizon. In the short run, supply and demand are relatively inelastic, as in panel (a). Thus, when the supply curve shifts from S_1 to S_2, the price rises substantially. By contrast, in the long run, supply and demand are relatively elastic, as in panel (b). In this case, the same size shift in the supply curve (S_1 to S_2) causes a smaller increase in the price.



This analysis shows why OPEC succeeded in maintaining a high price of oil only in the short run. When OPEC countries agreed to reduce their production of oil, they shifted the supply curve to the left. Even though each OPEC member sold less oil, the price rose by so much in the short run that OPEC incomes rose. By contrast, in the long run, when supply and demand are more elastic, the same reduction in supply, measured by the horizontal shift in the supply curve, caused a smaller increase in the price. Thus, OPEC's coordinated reduction in supply proved less profitable in the long run. The cartel learned that raising prices is easier in the short run than in the long run.

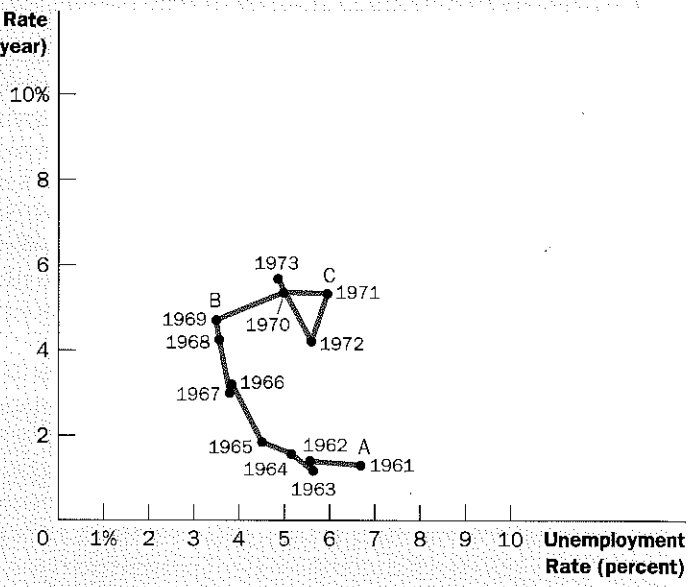
Does Drug Interdiction Increase or Decrease Drug-Related Crime?

A persistent problem facing our society is the use of illegal drugs, such as heroin, cocaine, ecstasy, and crack. Drug use has several adverse effects. One is that drug dependence can ruin the lives of drug users and their families. Another is that drug addicts often turn to robbery and other violent crimes to obtain the money needed to support their habit. To discourage the use of illegal drugs, the U.S. government devotes billions of dollars each year to reduce the flow of drugs into the country. Let's use the tools of supply and demand to examine this policy of drug interdiction.

7 FIGURE

The Breakdown of the Phillips Curve
This figure shows annual data from 1961 to 1973 on the unemployment rate and on the inflation rate (as measured by the GDP deflator). The Phillips curve of the 1960s breaks down in the early 1970s, just as Friedman and Phelps had predicted. Notice that the points labeled A, B, and C in this figure correspond roughly to the points in Figure 5.

Source: U.S. Department of Labor; U.S. Department of Commerce.



1970s, people's expectations of inflation caught up with reality, and the unemployment rate reverted to the 5 percent to 6 percent range that had prevailed in the early 1960s. Notice that the history illustrated in Figure 7 resembles the theory of a shifting short-run Phillips curve shown in Figure 5. By 1973, policymakers had learned that Friedman and Phelps were right: There is no trade-off between inflation and unemployment in the long run.

QUICK QUIZ Draw the short-run Phillips curve and the long-run Phillips curve. Explain why they are different.

SHIFTS IN THE PHILLIPS CURVE: THE ROLE OF SUPPLY SHOCKS

Friedman and Phelps had suggested in 1968 that changes in expected inflation shift the short-run Phillips curve, and the experience of the early 1970s convinced most economists that Friedman and Phelps were right. Within a few years, however, the economics profession would turn its attention to a different source of shifts in the short-run Phillips curve: shocks to aggregate supply.

This time, the change in focus came not from two American economics professors but from a group of Arab sheiks. In 1974, the Organization of Petroleum Exporting Countries (OPEC) began to exert its market power as a cartel in the world oil market to increase its members' profits. The countries of OPEC, such as Saudi Arabia, Kuwait, and Iraq, restricted the amount of crude oil they pumped and sold on world markets. Within a few years, this reduction in supply caused the world price of oil to almost double.

A large increase in the world price of oil is an example of a supply shock. A **supply shock** is an event that directly affects firms' costs of production and thus the prices they charge; it shifts the economy's aggregate-supply curve and, as a result, the Phillips curve. For example, when an oil price increase raises the cost of producing gasoline, heating oil, tires, and many other products, it reduces the quantity of goods and services supplied at any given price level. As panel (a) of Figure 8 shows, this reduction in supply is represented by the leftward shift in the aggregate-supply curve from AS_1 to AS_2. Output falls from Y_1 to Y_2, and the price level rises from P_1 to P_2. The combination of falling output (stagnation) and rising prices (inflation) is sometimes called *stagflation*.

supply shock
an event that directly alters firms' costs and prices, shifting the economy's aggregate-supply curve and thus the Phillips curve

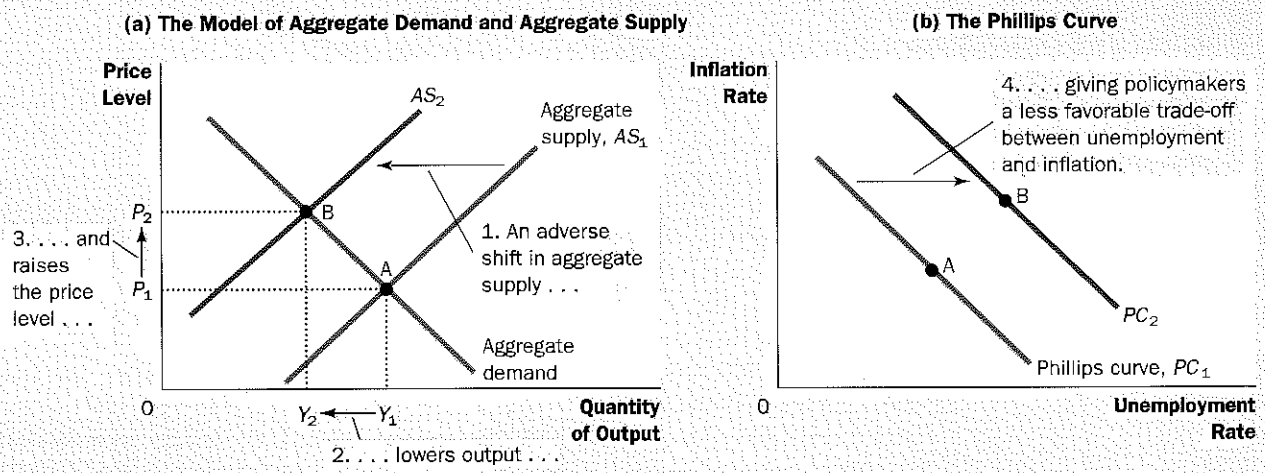
This shift in aggregate supply is associated with a similar shift in the short-run Phillips curve, shown in panel (b). Because firms need fewer workers to produce the smaller output, employment falls and unemployment rises. Because the price level is higher, the inflation rate—the percentage change in the price level from the previous year—is also higher. Thus, the shift in aggregate supply leads to higher unemployment and higher inflation. The short-run trade-off between inflation and unemployment shifts to the right from PC_1 to PC_2.

Confronted with an adverse shift in aggregate supply, policymakers face a difficult choice between fighting inflation and fighting unemployment. If they contract aggregate demand to fight inflation, they will raise unemployment further. If they expand aggregate demand to fight unemployment, they will raise inflation further. In other words, policymakers face a less favorable trade-off between inflation and unemployment than they did before the shift in aggregate supply: They

FIGURE 8

An Adverse Shock to Aggregate Supply

Panel (a) shows the model of aggregate demand and aggregate supply. When the aggregate-supply curve shifts to the left from AS_1 to AS_2, the equilibrium moves from point A to point B. Output falls from Y_1 to Y_2, and the price level rises from P_1 to P_2. Panel (b) shows the short-run trade-off between inflation and unemployment. The adverse shift in aggregate supply moves the economy from a point with lower unemployment and lower inflation (point A) to a point with higher unemployment and higher inflation (point B). The short-run Phillips curve shifts to the right from PC_1 to PC_2. Policymakers now face a worse trade-off between inflation and unemployment.



have to live with a higher rate of inflation for a given rate of unemployment, a higher rate of unemployment for a given rate of inflation, or some combination of higher unemployment and higher inflation.

Faced with such an adverse shift in the Phillips curve, policymakers will ask whether the shift is temporary or permanent. The answer depends on how people adjust their expectations of inflation. If people view the rise in inflation due to the supply shock as a temporary aberration, expected inflation will not change, and the Phillips curve will soon revert to its former position. But if people believe the shock will lead to a new era of higher inflation, then expected inflation will rise, and the Phillips curve will remain at its new, less desirable position.

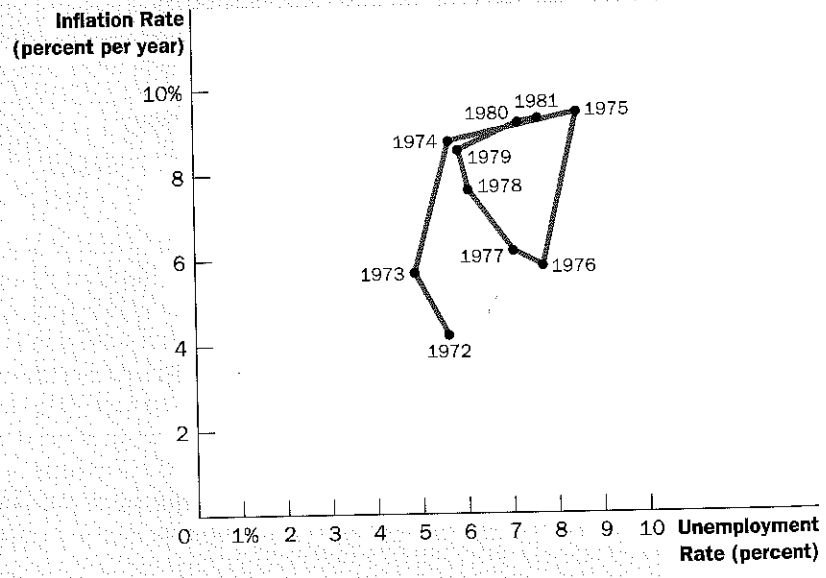
In the United States during the 1970s, expected inflation did rise substantially. This rise in expected inflation was partly attributable to the Fed's decision to accommodate the supply shock with higher money growth. (Recall that policymakers are said to *accommodate* an adverse supply shock when they respond to it by increasing aggregate demand in an effort to keep output from falling.) Because of this policy decision, the recession that resulted from the supply shock was smaller than it otherwise might have been, but the U.S. economy faced an unfavorable trade-off between inflation and unemployment for many years. The problem was compounded in 1979, when OPEC once again started to exert its market power, more than doubling the price of oil. Figure 9 shows inflation and unemployment in the U.S. economy during this period.

In 1980, after two OPEC supply shocks, the U.S. economy had an inflation rate of more than 9 percent and an unemployment rate of about 7 percent. This combination of inflation and unemployment was not at all near the trade-off that seemed possible in the 1960s. (In the 1960s, the Phillips curve suggested that an unemployment rate of 7 percent would be associated with an inflation rate of only

9 FIGURE

The Supply Shocks of the 1970s
This figure shows annual data from 1972 to 1981 on the unemployment rate and on the inflation rate (as measured by the GDP deflator). In the periods 1973–1975 and 1978–1981, increases in world oil prices led to higher inflation and higher unemployment.

Source: U.S. Department of Labor; U.S. Department of Commerce.



In The News

Will Stagflation Return?

In 2008 the eminent economist and monetary historian Allan Meltzer worried that the Federal Reserve was repeating the mistakes of the 1970s.

That '70s Show
By Allan H. Meltzer

Is the Federal Reserve an independent monetary authority or a handmaiden beholden to political and market players? Has it reverted to its mistaken behavior in the 1970s? Recent actions and public commitments, including Fed Chairman Ben Bernanke's testimony to Congress yesterday—where he warned of a steeper decline and suggested that more rate cuts lie ahead—leave little doubt on both counts.

An independent central bank is supposed to maintain the value of the currency and prevent inflation. In the 1970s and again now, Federal Reserve officials repeatedly promised themselves and each other that they would lower inflation. But as soon as the unemployment rate ticked up a bit, the promises were forgotten.

People soon recognized that avoiding possible recession overwhelmed any concern about inflation. Many concluded that inflation would increase over time and that the Fed would do little more than talk. Prices and wages fell very little in recessions. The result was inflation and stagnant growth: stagflation.

It's beginning to happen again. Unlike the response of wages and prices in the low inflation 1990s, expectations of rising inflation now delay or stop price and wage adjustment, inhibiting growth.

One lesson of the inflationary 1970s: A country that will not accept the possibility of a small recession will end up having a big one when the politicians at last respond to the public's complaints about inflation. Instead of paying the relatively small cost of a possible recession, the public pays the much larger cost of sustained inflation and a deeper recession. And enduring the deeper recession is the only way to convince the public that the Fed has at last decided to slow inflation . . . .

Surely Mr. Bernanke and his colleagues remember what happened in the 1970s. They console themselves with the belief that they will respond to any inflation that occurs by promptly raising interest rates. That repeats the commitments made repeatedly in the 1970s, which the Fed was unwilling to keep. The blunt fact is that there is rarely a popular time to raise interest rates. And with the growing streak of populism in the country, it will become more difficult.

The Fed's recent behavior is in sharp contrast to the European Central Bank. The ECB keeps its eye on both objectives, growth and low inflation. It doesn't shift back and forth from one to the other. The Fed should do the same. In the 1970s, because the Fed shifted from one goal to the other and back again, it achieved neither. Both inflation and unemployment rose on average, then fell together in the 1980s—after the Fed controlled inflation.

After 1985, Fed policy kept inflation and unemployment low. The result was 20 years of growth, and three of the longest peacetime expansions punctuated by short recessions.

We should not throw this policy away. Federal Reserve independence is a valuable right which should not be discarded. The Fed should insist on its obligation to prevent inflation and sustain growth, not sacrificing inflation to lower unemployment before the election.

Source: *The Wall Street Journal*, February 28, 2008.

1 percent. Inflation of more than 9 percent was unthinkable.) With the misery index in 1980 near a historic high, the public was widely dissatisfied with the performance of the economy. Largely because of this dissatisfaction, President Jimmy Carter lost his bid for reelection in November 1980 and was replaced by Ronald Reagan. Something had to be done, and soon it would be.

Guidelines for Preparing Economic Analyses

December 17, 2010

(updated May 2014)

National Center for Environmental Economics
Office of Policy
U.S. Environmental Protection Agency

Appendix A

Economic Theory

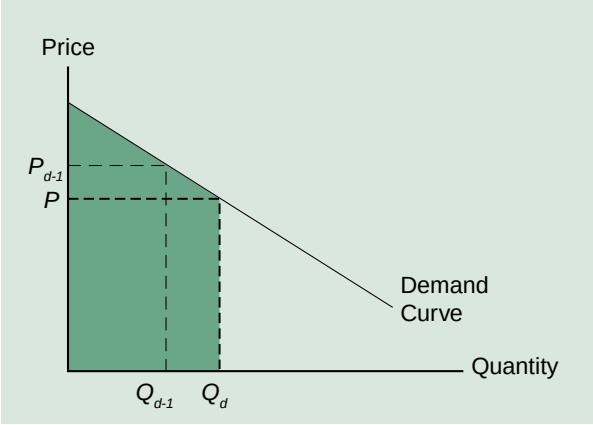
This appendix provides a brief overview of the fundamental theory underlying the approaches to economic analysis discussed in Chapters 3 through 9. The first section summarizes the basic concepts of the forces governing a market economy in the absence of government intervention. Section A.2 describes why markets may behave inefficiently. If the preconditions for market efficiency are *not* met, government intervention can be justified.[1] The usefulness of benefit-cost analysis (BCA) as a tool to help policy makers determine the appropriate policy response is discussed in Section A.3. Sections A.4 and A.5 explain how economists measure the economic impacts of a policy and set the optimal level of regulation. Section A.6 concludes and provides a list of additional references.

A.1 Market Economy

The economic concept of a market is used to describe any situation where exchange takes place between consumers and producers. Economists assume that consumers purchase the combination of goods that maximizes their well-being, or "utility," given market prices and subject to their household budget constraint. Economists also assume that producers (firms) act to maximize their profits. Economic theory posits that consumers and producers are rational agents who make decisions taking into account *all* of the costs — the full opportunity costs — of their choices, given their own resource constraints.[2] The purpose of economic analysis is to understand how the agents interact and how their interactions add up to determine the allocation of society's resources: what is produced, how it is produced, for whom it is produced, and how these decisions are made. The simplest tool economists use to illustrate consumers' and producers' behavior is a market diagram with supply and demand curves.

The demand curve for a single individual shows the quantity of a good or service that the individual will purchase at any given price. This quantity demanded assumes the condition of holding all else constant, i.e., assuming the budget constraint, information about the good, expected future prices, prices of other goods, etc. remain constant. The height of the demand curve in Figure A.1 indicates the maximum price, P, an individual with Q_d units of a good or service would be willing to pay to acquire an additional unit of a good or service. This amount reflects the satisfaction (or utility) the individual receives from an additional unit, known as the *marginal benefit* of consuming the good. Economists generally assume that the marginal benefit of an additional unit is slightly less than that realized by

Figure A.1 - Marginal and Total WTP



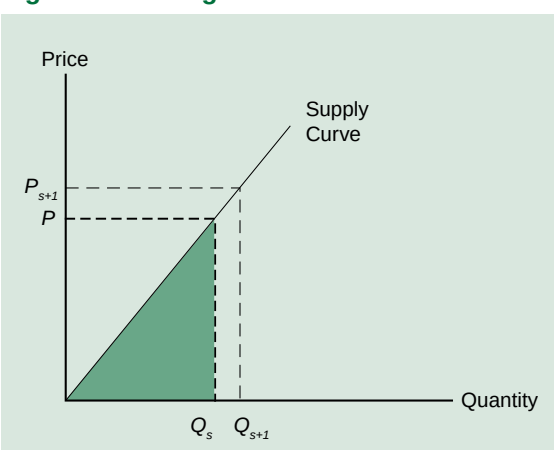
1 EPA's mandates frequently rely on criteria other than economic efficiency, so policies that are not justified due to a lack of efficiency are sometimes adopted.

2 *Opportunity cost* is the next best alternative use of a resource. The full opportunity cost of producing (consuming) a good or service consists of the maximum value of other goods and services that could have been produced (consumed) had one not used the limited resources to produce (purchase) the good or service in question. For example, the full cost of driving to the store includes not only the price of gas but also the value of the time required to make the trip.

the previous unit. The amount an individual is willing to pay for one more unit of a good is less than the amount she paid for the last unit; hence, the individual demand curve slopes downward. A market demand curve shows the total quantity that consumers are willing to purchase at different price levels, i.e., their collective willingness to pay (WTP) for the good or service. In other words, the market demand curve is the horizontal sum of all of the individual demand curves.

The concept of an individual's WTP is one of the fundamental concepts used in economic analyses, and it is important to distinguish between total and marginal WTP. Marginal WTP is the additional amount the individual would pay for one additional unit of the good. The total WTP is the aggregate amount the individual is willing to pay for the total quantity demanded (Q_d). Figure A.1 illustrates the difference between the marginal and total WTP. The height of the demand curve at a quantity Q_{d-1} gives the marginal WTP for the Q_{d-1}^{th} unit. The height of the demand curve at a quantity Q_d gives the marginal WTP for the Q_d^{th} unit. Note that the marginal WTP is greater for the Q_{d-1}^{th} unit. The *total* WTP is equal to the sum of the marginal WTP for each unit up to Q_d. The shaded area under the demand curve from the origin up to Q_d shows total WTP.

Figure A.2 - Marginal and Total Cost



An individual producer's supply curve shows the quantity of a good or service that an individual or firm is willing to sell (Q_s) at a given price. As a profit-maximizing agent, a producer will only be willing to sell another unit of the good if the market price is greater than or equal to the cost of producing that unit. The cost of producing the additional unit is known as the *marginal cost*. Therefore, the individual supply curve traces out the marginal cost of production and is also the marginal cost curve. Economists generally assume that the cost of producing one additional unit is greater than the cost of producing the previous unit because resources are scarce. Therefore the supply curve is assumed to slope upward. In Figure A.2, the marginal cost of producing the Q_s^{th} unit of the good is given by the height of the supply curve at Q_s. The marginal cost of producing the Q_{s+1}^{th} unit of the good is given by the height of the supply curve at Q_{s+1}, which greater than the cost of producing the Q_s^{th} unit, and greater than the price, P. The *total cost* of producing Q_s units is equal to the shaded area under the supply curve from the origin to the quantity Q_s. The market supply curve is simply the horizontal summation of the individual producers' marginal cost curves for the good or service in question.

In a competitive market economy, the intersection of the market demand and market supply curves determines the equilibrium price and quantity of a good or service sold. The demand curve reflects the marginal benefit consumers receive from purchasing an extra unit of the good (i.e., it reflects their marginal WTP for an extra unit). The supply curve reflects the marginal cost to the firm of producing an extra unit. Therefore, at the competitive equilibrium, the price is where the marginal benefit equals the marginal cost. This is illustrated in Figure A.3, where the supply curve intersects the demand curve at equilibrium price P_m and equilibrium quantity Q_m.

A counter-example illustrates why the equilibrium price and quantity occur at the intersection of the market demand and supply curves. In Figure A.3, consider some price greater than P_m where Q_s is greater than Q_d (i.e., there is *excess supply*). As producers discover that they cannot sell off their inventories, some will reduce prices slightly, hoping to attract more customers. At lower prices consumers will purchase more of the good (Q_d increases) although firms will be willing to sell less (Q_s

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U.S. Energy Information Administration

Fuel Competition in Power Generation and Elasticities of Substitution

June 2012

Independent Statistics & Analysis
www.eia.gov

U.S. Department of Energy
Washington, DC 20585

Executive Summary

This report analyzes the competition between coal, natural gas and petroleum used for electricity generation by estimating what is referred to by economists as the elasticity of substitution among the fuels. The elasticity of substitution concept measures how the use of these fuels varies as their relative prices change. It should be noted that many factors other than fuel prices play important roles in determining which power plants are run to meet electricity demand as it varies over time. These factors include generators' nonfuel variable operating costs, startup/shut down costs, emission rates and allowance costs, electricity grid flow constraints, and reliability constraints. Electricity system operators evaluate all of these factors when determining which plants and fuels to use.

The patterns of dispatching power generation have changed noticeably over the past few years. A number of factors, especially volatile fossil fuel costs, have altered the mix of energy sources used to produce electricity. Although petroleum has historically been a relatively modest component of the overall generation fuel mix, its share of generation was reduced even further by petroleum prices that began rising rapidly in the mid-2000s. More recently, a sudden increase in spot prices for Appalachian coal during 2008 has been followed by a sustained decline in the delivered cost of natural gas, both of which have substantially shifted the dispatch pattern for baseload generation in some parts of the country, favoring natural gas-fired units over coal-fired units.

Earlier academic studies analyzed fossil fuel substitution during the period of the 1980s and 1990s. This report updates the earlier work to reflect dispatching patterns during the period of 2005-2010. The model results indicate that for the United States as a whole, a 10-percent increase in the ratio of the delivered fuel price of coal to the delivered price of natural gas leads to a 1.4-percent increase in the use of natural gas relative to coal. Generators' use of petroleum is much more responsive to relative fuel price changes. A 10-percent increase in the price ratio of natural gas to petroleum leads to a 19-percent increase in the relative use of petroleum compared with natural gas. The model results are the most robust for the southeastern United States, while fuel substitution results for the Midwest and Texas are relatively insignificant.

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Interfuel substitution in US electricity generation

JAMES KO and CAROL DAHL‡*

486 E. Bexley St., Highland Ranch, CO 80126 and ‡*Petroleum Economics and Management Division of Economics and Business, Colorado School of Mines, Golden, CO 80401, USA*

Ongoing changes in the US electricity market include restructuring and increased competition. With this unfettering of the market, the fuel choice in generation is expected to become more flexible and responsive. To investigate this hypothesis, studies of US electricity fuel choices over the last three decades are summarized and the most recent analysis is provided on a market very different from the one on which earlier studies were done. Modern data handling techniques allow the consideration of the most comprehensive database including 185 utilities on monthly data for 1993. This paper finds fuel choice to show a considerable amount of price responsiveness, the amount of responsiveness is sensitive to the fuel substitution possibilities within the utility, and the amount of responsiveness seems to have increased recently for oil and natural gas.

I. INTRODUCTION

Considerable changes in the US power market in the last two decades have impinged upon power plant fuel use with more changes to come. Beginning in 1907, the industry had been regulated at the state level with the development of state regulatory commissions. Utilities were typically granted area wide franchises in exchange for a commitment to provide reliable power with regulation over entry, price and capacity investment decisions. Most often regulation took the form of a maximum rate of return, while the pass through of fuel costs to consumers, no doubt, had a distortionary effect on fuel use compared to a more competitive environment.

Federal Regulation began with the formation of the US Federal Power Commission in the 1935 Public Utility Act, which put electricity under interstate commerce regulation. The regulation of natural gas transportation at the Federal level began with the 1938 Natural Gas Act. This natural gas regulation along with the Federal regulation of natural gas prices, which began in 1952, also had an effect on fuel choice in the electric power market. However, regulatory changes in 1978 began the move towards deregulation in both of these markets. The Natural Gas Act of 1978 deregulated prices of some categories of natural gas and was followed by the Natural Gas Wellhead Decontrol Act of 1989, which removed all price controls by 1 January 1993.

In the electricity market, deregulation began in the wholesale market with the 1978 Public Utility Regulatory Act. This act facilitated entry by independent power producers since it required utilities to buy electricity from 'qualified facilities' at the avoided cost for the utility and likely impinged upon power plant fuel use.

Another distorting effect on fuel use was caused by the Power Plant and Industrial Fuels Use Act, which prohibited new gas burning facilities from 1977 to 1987. The Clean Air Act Amendments of 1990 implemented from 1990 to 2000 provide a further influence on powerplant fossil fuel use. (Viscusi *et al.*, 1992; Ko, 1996; Norman, 1996).

In the 1992 Energy Policy Act, the US Federal Energy Regulatory Commission (FERC), which replaced the Federal Power Commission in 1977, was required to come up with a proposal for free and open access of the US electric transmission grid. It did so in April 1996 with

* Corresponding author. e-mail: cadahl@mines.edu

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Table 1. *Fossil fuel price elasticity estimates for the thermal generation of electricity*

Reference	Data	Type	Fuels Used		Own Price Elasticities			Cross Price Elasticities					
					Ecc	Egg	Eoo	Ecg	Eco	Egc	Ego	Eoc	Eog
Hudson and Jorgenson (1974)	US	T	C,O,G,El		−0.33	−0.24	−0.84	0.09	0.30	0.16	0.20	1.09	0.39
Atkinson and Halvorsen (1976a)	US 1972-74	T	C,O,G		−0.01	−2.55	0.01	0.19	0.13	0.59	0.09	0.18	0.04
Atkinson and Halvorsen (1976b)	US-P31 1972	CS	C,G		−0.43	−1.43		0.09		0.45			
	US-P17 1972	CS	C,O		−1.15		−1.50		0.99			1.01	
	US-P60 1972	CS	O,G			0.21	−1.60				0.58		0.76
Griffin (1977)	OECD (US) 1955,60,65,69	CT	C,O,G		−0.66	−0.90	−3.46	0.16	0.50	nr	0.58	nr	nr
Griffin (1979)	OECD (US) 1955–69	CT	C,O,G	sr	−0.44	−0.68	−0.87	nr	nr	nr	nr	nr	nr
				lr	−0.86	−0.98	−4.27						
Haimor (1981)	US-P45 1970-75	CT	C,O,G		−0.49	−0.84	−1.31	0.09	0.40	0.22	0.40	0.90	0.38
	US-P101 1970-73	CT	C,G		−0.90	−1.28		0.76		0.67			
	US-P101 1974–75	CT	C,G		−0.28	−1.89		0.23		0.62			
	US-P101 1970-73	CT	C,O		−0.68		−3.07		0.71			2.92	
	US-P101 1974-75	CT	C,O		−0.37		−3.11		0.40			2.70	
	US-P99 1970-73	CT	O,G			−0.19	−0.58				0.59		0.62
	US-P99 1974-75	CT	O,G			−0.89	−0.08				−0.25		−0.12
Bopp and Costello (1990)	US 1977:1-86:6	T	C,O,G		−0.26	−0.14	−0.59	0.03	0.23	0.40	0.01	0.53	0.07
	US–NE	T	C,O,G		0.38	nr	−0.39	nr	nr	0.29	nr	0.57	nr
	US–NC	T	C,O,G		−0.12	nr	−1.29	1.14	nr	0.01	nr	nr	nr
	US–SE	T	C,O,G		−0.23	nr	−0.67	nr	0.73	0.82	nr	nr	nr
	US–SW	T	C,O,G		−0.52	−0.25	nr	nr	nr	nr	1.42	nr	nr
	US–W	T	C,O,G		nr	−0.40	−0.71	nr	nr	nr	1.15	nr	nr
McDonnell (1991)	US-ut 82 1987	CS	C,O,G,N,Hy,Ws		−0.47	−1.84	−2.25	0.17	0.10	0.82	0.01	0.47	0.01
Ko (1993)	US 1949-91	T	C,O,G		−0.25	−0.29	−0.13	0.02	0.26	0.08	0.30	0.97	0.19
			Average		−0.46	−0.86	−1.41	0.27	0.43	0.40	0.42	1.13	0.26
			Minimum		0.28	0.74	1.25	0.35	0.28	0.29	0.48	0.93	0.30
			Maximum		−1.15	−2.55	−4.27	0.02	0.10	0.01	−0.25	0.18	−0.12
			Standard Dev.		−0.01	0.21	0.01	1.14	0.99	0.82	1.42	2.92	0.76
			#		19	17	19	11	11	9	12	10	9

Table Definitions: T = Time Series; CS = Cross Section; CT = Cross Section Time Series; NC = North Central; NE = North East; SE = South East; SW = South West; US-P# = # US generation plants; US-ut# = # of US utilities; C = coal; G = natural gas; O = oil; N = nuclear; Hy = hydroelectric; Ws = wholesale power purchases; nr = not reported; sr = short run; lr = long run. Eij = the elasticity of fuel i with respect to price of fuel j for, $i, j = C,G,O$.

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National Renewable Energy Laboratory

Innovation for Our Energy Future

Long-Term National Impacts of State-Level Policies

Preprint

N. Blair, W. Short, P. Denholm, and D. Heimiller

To be presented at the WindPower 2006 Conference
Pittsburgh, Pennsylvania
June 4–7, 2006

Conference Paper
NREL/CP-620-40105
June 2006

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Table 1: Onshore Turbines Cost and Perf. Due to R&D

Resource Class	Install Year	Capacity Factor	Capital cost ($/kW)*	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
3	2000	32.9%	1136	7.76	5.15
3	2010	34.9%	1112	7.76	4.53
3	2020	37.6%	1082	7.76	4.04
3	2050	37.7%	1049	7.76	3.84
4	2000	34.8%	1136	7.76	5.15
4	2010	37.4%	1112	7.76	4.53
4	2020	40.9%	1082	7.76	4.04
4	2050	41.4%	1049	7.76	3.84
5	2000	40.2%	1081	7.76	5.15
5	2010	42.4%	1058	7.76	4.53
5	2020	44.2%	1020	7.76	4.04
5	2050	45.1%	995	7.76	3.84
6	2000	44.0%	1081	7.76	5.15
6	2010	45.8%	1058	7.76	4.53
6	2020	47.6%	1020	7.76	4.04
6	2050	48.3%	995	7.76	3.84
7	2000	54.4%	1044	7.76	5.15
7	2010	55.4%	980	7.76	4.53
7	2020	56.2%	963	7.76	4.04
7	2050	56.3%	963	7.76	3.84

* Overnight capital cost

Figure 5 indicates the average coal and natural gas costs currently used within the model, based on AEO 2005. Higher gas prices will be a minor driver but higher coal prices would dramatically increase the amount of wind capacity deployed in the future due to the prevalence of new coal capacity being built.

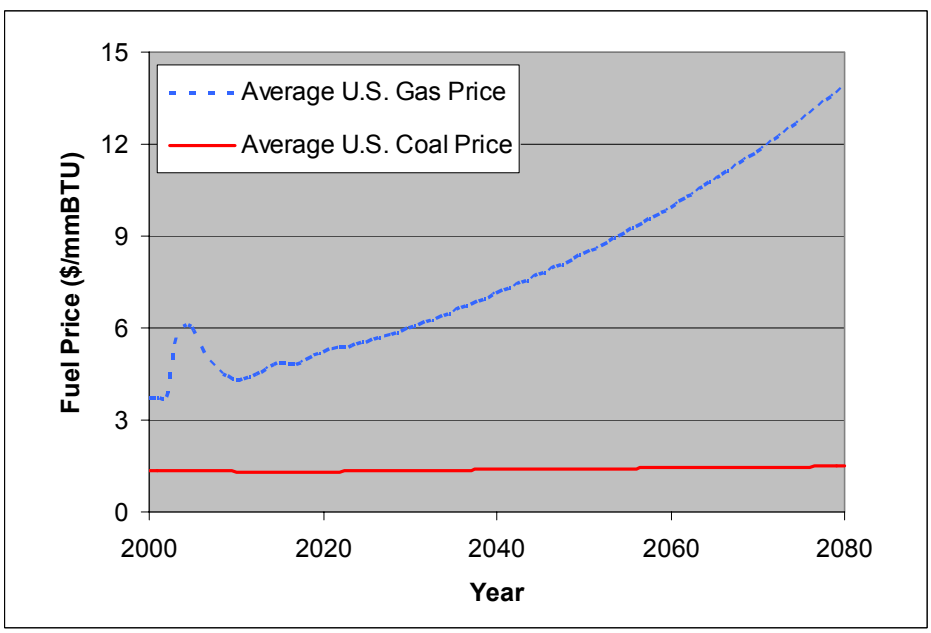


Figure 5. AEO 2005 Natural Gas and Coal Prices used in WinDS

EIA.gov

FREQUENTLY ASKED QUESTIONS

How much carbon dioxide is produced when different fuels are burned?

Different fuels emit different amounts of carbon dioxide (CO_2) in relation to the energy they produce when burned. To analyze emissions across fuels, compare the amount of CO_2 emitted per unit of energy output or heat content.

Pounds of CO_2 emitted per million British thermal units (Btu) of energy for various fuels:

Coal (anthracite)	228.6
Coal (bituminous)	205.7
Coal (lignite)	215.4
Coal (subbituminous)	214.3
Diesel fuel and heating oil	161.3
Gasoline	157.2
Propane	139.0
Natural gas	117.0

The amount of CO_2 produced when a fuel is burned is a function of the carbon content of the fuel. The heat content, or the amount of energy produced when a fuel is burned, is mainly determined by the carbon (C) and hydrogen (H) content of the fuel. Heat is produced when C and H combine with oxygen (O) during combustion. Natural gas is primarily methane (CH_4), which has a higher energy content relative to other fuels, and thus, it has a relatively lower CO_2-to-energy content. Water and various elements, such as sulfur and non-combustible elements in some fuels reduce their heating values and increase their CO_2-to-heat contents.

Learn more:

Carbon dioxide emissions per physical unit and million Btu for numerous fuels

Last updated: June 18, 2015

U.S. EPA
Coalbed Methane
OUTREACH PROGRAM

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

METHANE EMISSIONS FROM ABANDONED COAL MINES IN THE UNITED STATES: EMISSION INVENTORY METHODOLOGY AND 1990-2002 EMISSIONS ESTIMATES

U.S. Environmental Protection Agency
April 2004

2.0 Abandoned Mines as a Source of Methane Emissions

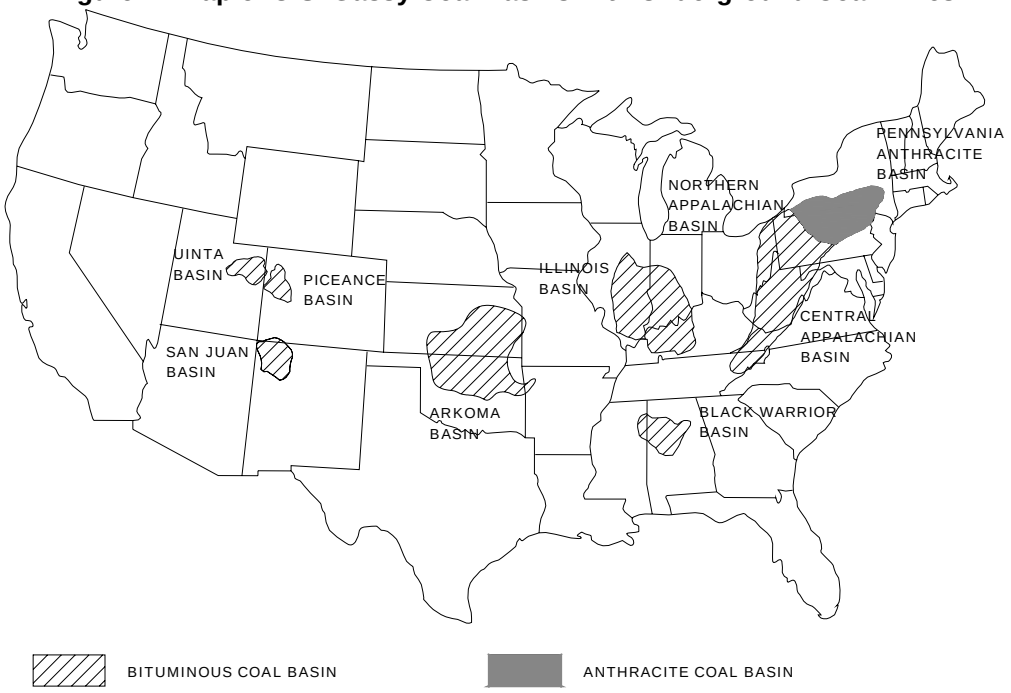
2.1 Overview of Coal Mine Methane

Coalbed methane is formed during coalification, the process that transforms plant material into coal. Organic matter accumulates in swamps as lush vegetation dies and decays. As this organic matter becomes more deeply buried, the temperature and pressure increase, subjecting the organic matter to extreme conditions that transform it into coal and methane, as well as byproducts including carbon dioxide, nitrogen, and water. As heat and pressure continue to increase, the carbon content ("rank") of the coal increases.

The methane trapped in coal seams is commonly referred to as coalbed methane (CBM) or coal seam gas. Generally, the deeper the coal seam and/or higher the coal rank, the higher the methane content. Coalbed methane is known as coal mine methane (CMM) when mining activity releases the methane, a potent greenhouse gas.

Not all coal seams are gassy (generally defined as mineable seams capable of producing more than 100 mcfd in coal mine ventilation emissions). In the U.S., gassy coals are located in the Appalachian Basins in the East, Black Warrior Basin in the South, the Illinois Basin in the Central U.S., and several western basins such as the San Juan and Powder River Basins. **Figure 2** shows the locations of gassy coal basins in the U.S.

Figure 2. Map of U.S. Gassy Coal Basins with Underground Coal Mines



2.1.1 Active Coal Mine Emissions

To ensure mine safety, active underground coal mines must remove methane from the mine using powerful ventilation systems. For particularly gassy mines, operators employ methane drainage systems to supplement their ventilation systems. In the U.S., these drainage systems consist of pre-mine vertical boreholes (drilled from the surface), in-mine horizontal boreholes drilled prior to mining, or vertical or in-mine gob wells.[3] The methane gas emitted through the ventilation and drainage systems is either released directly to the atmosphere or recovered and used.

2.1.2 Abandoned Coal Mine Emissions

As mines mature and coal seams are mined out, mines are closed and eventually abandoned. Often, mines may be sealed by filling shafts or portals with gravel and capping them with a concrete seal. Vent pipes and boreholes may be plugged in a similar manner to oil and gas wells.

As active mining stops, the mine's gas production decreases, but the methane liberation does not stop completely. Following an initial decline, abandoned mines can liberate methane at a near-steady rate over an extended period of time. The gas migrates up through conduits, particularly if they have not been sealed adequately. In addition, diffuse emissions can occur when methane migrates to the surface through cracks and fissures in the strata overlying the coal mine.

After they are abandoned, some mines may flood as a result of intrusion of groundwater or surface water into the void. Flooded mines typically produce gas for only a few years.

2.2 Factors Influencing Mine Methane Emissions

Within a coalbed, methane is stored both as a free gas in coal's pores and fractures, as well as on the coal surface through physical adsorption. As the partial pressure of methane in the fracture (cleat) system of the coal decreases, the methane desorbs from the coal and moves into the cleat system as free gas. The pressure differential between the cleat system and the open mine void[4] provides the energy to move the methane into the mine. Driven by this pressure differential between the gas in the mine and atmospheric pressure, the methane will eventually flow through existing conduits and will be emitted to the atmosphere.

Many factors can impact the rate of CMM emissions at both active and abandoned mines. The most important factor is the total gas (methane) content of the coal, which has been directly linked to methane emissions from mining activities (Grau, et al. 1981, EPA, 1990)

The time since abandonment is a critical factor affecting an abandoned mine's annual emissions, as the mine's emissions decline steeply as a function of time elapsed.[5] EPA has developed a decline curve, which describes the rate at which methane continues to desorb from

[3] A "gob" or "goaf" is the rubble zone formed by collapsed roof strata caused by the removal of coal.
[4] The mine void refers to the mined out area of the coal seam.
[5] The decline of CMM emissions begins with the cessation of coal production, although abandoned mine emissions officially begin only when active (forced) ventilation of the mine ceases.

the coal after abandonment, moves into the mine void, and is eventually released to the atmosphere. The decline curves are strong functions of time: the methane emissions rate decreases rapidly in the years immediately after a mine closure, and flattens out after several decades. The development of these decline curves is described in Section 4 of this report.

Other factors impacting the rate of methane emission include mine size, flooding, sealing, and the coal's permeability, porosity, and water saturation.

The remainder of this section discusses in greater detail several additional factors influencing abandoned mine emissions:

- Gas content and adsorption characteristics of coal
- Methane flow capacity of the mine
- Mine flooding
- Open (active) mine vents
- Mine seals

Each of these factors can impact methane emissions independent of the other factors, but in almost all cases several factors are important.

2.2.1 Gas Content and Adsorption Characteristics of Coal

Compared to many sedimentary rocks, coal beds have the capacity to store a large amount of methane gas.[6] Coal can hold a significant amount of methane in the adsorbed state because of the extensive internal surface area of the coal matrix (up to 250 square meters/gram, or 2.4 billion square feet per ton).[7] **Figure 3** illustrates the methane storage capacity of a middle rank coal compared with the storage capacity of a similar mass of (non-adsorbing) sandstone having a porosity of 15%. This figure illustrates that coal can contain significant quantities of methane even at very low pressures. The gas content of coal is generally expressed as standard cubic feet per short ton (scf/ton), or cubic meters per metric ton (m^3/tonne).[8]

This difference in storage capacity is due primarily to coal's internal pore structure. For example, porosity in sedimentary rock (e.g. sandstone and limestone) is mostly in the mesopore (20 to 500 angstroms) and macropore (>500 angstroms) range. In contrast, a significant fraction of the coal matrix is in the micropore range (<20 angstroms).[9] The methane content at a given temperature and pressure generally increases with coal rank because of the increase in the percentage of micropores and surface area available for methane adsorption (**Figure 4**).

[6] The quantity of gas that can be stored in the pore space of most sedimentary rock is a function of temperature and pressure as described by the real gas law.
[7] The density of the adsorbed methane is approximately its liquid density at atmospheric pressure boiling point (Yee et al., 1993).
[8] 32 scf/ton is approximately equal to 1 m^3/tonne.
[9] As coal increases in rank, the pore structure of the matrix changes. The percentage of the total matrix porosity in the micropore range increases with increasing rank from about 30% for a lignite to about 80% for an anthracite (Gan, et. al., 1972).

Carbon Dioxide Emission Factors for Coal

by

B.D. Hong and E. R. Slatick

Note: This article was originally published in Energy Information Administration, *Quarterly Coal Report, January-April 1994*, DOE/EIA-0121(94/Q1) (Washington, DC, August 1994), pp. 1-8.

Introduction

Coal is an important source of energy in the United States, and the Nation's reliance on this fossil fuel for electricity generation is growing. The combustion of coal, however, adds a significant amount of carbon dioxide to the atmosphere per unit of heat energy, more than does the combustion of other fossil fuels.(1) Because of a growing concern over the possible consequences of global warming, which may be caused in part by increases in atmospheric carbon dioxide (a major greenhouse gas), and also because of the need for accurate estimates of carbon dioxide emissions, the Energy Information Administration (EIA) has developed factors for estimating the amount of carbon dioxide emitted as a result of U.S. coal consumption.

Carbon dioxide emission factors for U.S. coals have previously been available from several sources. However, those emission factors have shortcomings because they are based on analyses of only a few coal samples. Most are single factors applied to all coals, regardless of rank (i.e., whether anthracite, bituminous, subbituminous, or lignite) or geographic origin. Because single factors do not account for differences among coals, they fail to reflect the changing "mix" of coal in U.S. coal consumption that has occurred in the past and will occur in the future. Lacking standardization, the factors previously available also differ widely from each other.(2)

EIA's emission factors will improve the accuracy of estimates of carbon dioxide emissions, especially at State and regional levels, because they reflect the difference in the ratio of carbon to heat content by rank of coal and State of origin. EIA's emission factors are derived from the EIA Coal Analysis File, a large database of coal sample analyses. The emission factors vary significantly by coal rank, confirming a long-recognized finding, and also within each rank by State of origin. These findings were verified statistically.

Two types of carbon dioxide emission factors have been developed. First are basic emission factors covering the various coal ranks by State of origin. These basic emission factors are considered as "fixed" for the foreseeable future until better data become available. Second are emission factors for use in estimating carbon dioxide emissions from coal consumption by State, with consuming-sector detail. These emission factors are based on the mix of coal consumed and the basic emission factors by coal rank and State of origin. These emission factors are subject to change over time, reflecting changes in the mix of coal consumed.

EIA's emission factors will not only enable coal-generated carbon dioxide emissions to be estimated more accurately than before, but they will also provide consistency in estimates. Energy and environmental analysts will find EIA's emission factors useful for analyzing and monitoring carbon dioxide emissions from coal combustion, whether they are estimated by the State of origin of the coal, consuming State, or consuming sector.

Coal Combustion and Carbon Dioxide Emissions

The amount of heat emitted during coal combustion depends largely on the amounts of carbon, hydrogen, and oxygen present in the coal and, to a lesser extent, on the sulfur content. Hence, the ratio of carbon to heat content depends on these heat-producing components of coal, and these components vary by coal rank.

Carbon, by far the major component of coal, is the principal source of heat, generating about 14,500 British thermal units (Btu) per pound. The typical carbon content for coal (dry basis) ranges from more than 60 percent for lignite to more than 80 percent for anthracite. Although hydrogen generates about 62,000 Btu per pound, it accounts for only 5 percent or less of coal and not all of this is available for heat because part of the hydrogen combines with oxygen to form water vapor. The higher the oxygen content of coal, the lower its heating value.(3) This inverse relationship occurs because oxygen in the coal is bound to the carbon and has, therefore, already partially oxidized the carbon, decreasing its ability to generate heat. The amount of heat contributed by the combustion of sulfur in coal is relatively small, because the heating value of sulfur is only about 4,000 Btu per pound, and the sulfur content of coal generally averages 1 to 2 percent by weight.(4) Consequently, variations in the ratios of carbon to heat content of coal are due primarily to variations in the hydrogen content.

The carbon dioxide emission factors in this article are expressed in terms of the energy content of coal as pounds of carbon dioxide per million Btu. Carbon dioxide (CO_2) forms during coal combustion when one atom of carbon (C) unites with two atoms of oxygen (O) from the air. Because the atomic weight of carbon is 12 and that of oxygen is 16, the atomic weight of carbon dioxide is 44. Based on that ratio, and assuming complete combustion, 1 pound of carbon combines with 2.667 pounds of oxygen to produce 3.667 pounds of carbon dioxide. For example, coal with a carbon content of 78 percent and a heating value of 14,000 Btu per pound emits about 204.3 pounds of carbon dioxide per million Btu when completely burned.(5) Complete combustion of 1 short ton (2,000 pounds) of this coal will generate about 5,720 pounds (2.86 short tons) of carbon dioxide.

Methodology and Statistical Checks

EIA's carbon dioxide emission factors were derived from data in the EIA Coal Analysis File, one of the most comprehensive data sources on U.S. coal quality by coalbed and coal-producing county. Most of the samples in the file were taken from coal shipments to U.S. Government facilities, from tipples and from mines. From the more than 60,000 coal samples in the File, 5,426 were identified as containing data on heat value and the ultimate analysis(6) needed for developing the relationship between carbon and heat content of the coal, that is, the carbon dioxide emission factors. Coal rank was assigned to each sample according to the standard classification method developed by the American Society for Testing and Materials. These data observations (samples) covered all of the major and most of the minor coal-producing States (Table FE1). Except for Arizona, North Dakota, and Texas, all of the major coal-producing States were considered to have a sufficiently large number of data observations to yield reliable emission factors.

The ratio of carbon to heat content was computed for each of the 5,426 selected coal samples by coal rank and State of origin under the assumption that all of the carbon in the coal is converted to carbon dioxide during combustion.(7) Variations in the ratios were observed across both coal rank and State of origin. Analysis was performed to determine whether these variations were statistically

The ratio of carbon to heat content was computed for each of the 5,426 selected coal samples by coal rank and State of origin under the assumption that all of the carbon in the coal is converted to carbon dioxide during combustion.[7] Variations in the ratios were observed across both coal rank and State of origin. Analysis was performed to determine whether these variations were statistically significant and to ensure that other factors pertaining to the samples (that is, the year the sample was collected and the degree of cleaning the sample received) were not significantly responsible for the observed variations.

Table FE1. Number of Observations by Coal Rank and State of Origin

State of Origin	Anthracite	Bituminous	Sub-bituminous	Lignite
Alabama	--	224	--	--
Alaska	--	--	--	--
Arizona	--	8	--	--
Arkansas	--	8	--	--
California	--	--	--	--
Colorado	--	164	18	--
Georgia	--	1	--	--
Idaho	--	2	--	--
Illinois	--	332	--	--
Indiana	--	51	--	--
Iowa	--	67	1	--
Kansas	--	19	--	--
Kentucky: East	--	486	--	--
Kentucky: West	--	151	--	--
Louisiana	--	--	--	--
Maryland	--	13	--	--
Missouri	--	86	--	--
Montana	--	6	23	2
Nevada	--	4	--	--
New Mexico	--	50	--	--
North Dakota	--	--	--	16
Ohio	--	228	--	--
Oklahoma	--	155	--	--
Oregon	--	--	2	--
Pennsylvania	523	679	--	--
South Dakota	--	--	--	3
Tennessee	--	271	--	--
Texas	--	--	--	11
Utah	--	104	2	--
Virginia	--	169	--	--
Washington	--	181	36	4
West Virginia	--	1,071	--	--
Wyoming	--	133	121	1
Total.	**523**	**4,663**	**203**	**37**

Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels, "Analysis of the Relationship Between the Heat and Carbon Content of U.S. Coals," September 1992.

Distributions of the data observations by year of collection and degree of cleaning were compiled (Table FE2). Because the dates of the samples range from 1900 through 1986, it was thought that changes in laboratory analysis techniques over the years might have influenced the resultant carbon-to-heat-content ratios. A regression analysis found that, with a R^2 value of only 0.01 (Table FE3), the year the sample was collected was not a useful factor in explaining the variation in the ratio, although there were small changes in the ratio over time.[8] This finding indicated that samples from earlier time periods could be combined with more recent samples to derive carbon dioxide emission factors.

Table FE2. Distribution of Observations by Year and Degree of Cleaning

Year	Number of Observations	Percent of Total
1900-1909	217	4.0
1910-1919	679	12.5
1920-1929	657	12.1
1930-1939	772	14.2
1940-1949	744	13.7
1950-1959	1,043	19.2
1960-1969	557	10.3
1970-1979	339	6.2
1980-1986	418	7.7
Total	5,426	100.0
Degree of Cleaning		
Raw	4,519	83.3
Washed	847	15.6

Degree of Cleaning		
Raw	4,519	83.3
Washed	847	15.6
Partially washed	60	1.1

Note: Total may not equal sum of components due to independent rounding.
Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels, "Analysis of the Relationship Between the Heat and Carbon Content of U.S. Coals," September 1992.

Of the total samples, 83 percent were raw coal, with the remainder either washed or partially washed. Cleaning should not materially affect the ratio of a coal's heat-to-carbon content because the process removes primarily non-combustible impurities. This was confirmed by an analysis of variance. There were differences in the carbon-to-heat-content ratios between washed or partially washed and raw coal, but with a R^2 value of 0.06, the differences did little to explain the variation in the ratios. Therefore, no data correction was warranted to account for the small effect that coal cleaning had on emission factors.

Analysis of variance was used to test the statistical significance of differences in the carbon-to-heat-content ratios across coal rank and across State of origin within coal rank. The continuous response variable (the carbon dioxide emission factor) was related to classification variables of rank and State of origin. The carbon dioxide emission factor was assumed to be a linear function of the parameters associated with the coal rank and State of origin.[9]

The statistical analyses (Table FE3) indicated that: (1) there are statistically significant differences in carbon dioxide emission factors across both coal rank and State of origin; (2) coal rank and State of origin each explain approximately 80 percent of the variation in carbon dioxide emission factors; and (3) State of origin combined with coal rank is a slightly more powerful explanatory variable than either coal rank or State of origin alone.

Table FE3. Summary of Statistical Analyses Carbon Dioxide Emission Factors by Coal Rank and State of Origin

Variable	F Test	R^2	MSE	Root MSE
Year Collected	***	0.01	55.18	7.43
Degree of Cleaning	***	0.06	52.07	7.22
Coal Rank	***	0.78	12.24	3.50
State of Origin	***	0.81	10.78	3.28
State of Origin Combined				
with Coal Rank	***	0.82	9.98	3.16

Notes: The F test indicates the statistical significance of differences in the emission factors across levels of the explanatory variable; *** indicates significance at the 0.001 level. R^2 (coefficient of determination) indicates the proportion of total variation in the emission factors explained by the model. MSE (mean square error) is the variance of the emission factors, and root MSE is the corresponding standard deviation.
Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels, "Analysis of the Relationship Between the Heat and Carbon Content of U.S. Coals," September 1992.

Carbon Dioxide Emission Factors by Coal Rank and State of Origin

The (arithmetic) average emission factors obtained from the individual samples (assuming complete combustion) (Table FE4)[10] confirm the long-recognized finding that anthracite emits the largest amount of carbon dioxide per million Btu, followed by lignite, subbituminous coal, and bituminous coal. The high carbon dioxide emission factor for anthracite reflects the coal's relatively small hydrogen content, which lowers its heating value.[11] In pounds of carbon dioxide per million Btu, U.S. average factors are 227.4 for anthracite, 216.3 for lignite, 211.9 for subbituminous coal, and 205.3 for bituminous coal.

Table FE4. Average Carbon Dioxide Emission Factors for Coal by Rank and State of Origin

State of Origin	Anthracite	Bituminous	Sub-bituminous	Lignite
Alabama	--	205.5	--	--
Alaska	--	--	[a]214.0	--
Arizona	--	209.7	--	--
Arkansas	--	211.6	--	[b]213.5
California	--	--	--	[c]216.3
Colorado	--	206.2	212.7	--
Georgia	--	206.1	--	--
Idaho	--	205.9	--	--
Illinois	--	203.5	--	--
Indiana	--	203.6	--	--
Iowa	--	201.6	[d]207.2	--
Kansas	--	202.8	--	--
Kentucky: East	--	204.8	--	--
Kentucky: West	--	203.2	--	--
Louisiana	--	--	--	[b]213.5
Maryland	--	210.2	--	--
Missouri	--	201.3	--	--
Montana	--	209.6	213.4	220.6
Nevada	--	201.8	--	--
New Mexico	--	205.7	[e]208.8	--
North Dakota	--	--	--	218.8

Nevada	--	201.8	--	--
New Mexico	--	205.7	[e]208.8	--
North Dakota	--	--	--	218.8
Ohio	--	202.8	--	--
Oklahoma	--	205.9	--	--
Oregon	--	--	210.4	--
Pennsylvania	227.4	205.7	--	--
South Dakota	--	--	--	217.0
Tennessee	--	204.8	--	--
Texas	--	[f]204.4	--	213.5
Utah	--	204.1	207.1	--
Virginia	--	206.2	--	--
Washington	--	203.6	208.7	211.7
West Virginia	--	207.1	--	--
Wyoming	--	206.5	212.7	215.6
U.S. Average	**227.4**	**205.3**	**211.9**	**216.3**

[a]Based on carbon and heat content data supplied by Usibelli Coal Mining Company for the subbituminous C coal currently being produced in the State.

[b]Based on the CO_2 emission factor for Texas lignite.

[c]Based on the CO_2 emission factor for U.S. lignite.

[d]Derived from "Element Geochemistry of Cherokee Group Coals (Middle Pennsylvanian) from South-Central and Southeastern Iowa," *Technical Paper No. 5*, Iowa Geological Survey (Iowa City, IA, 1984), pp. 15, 48, and 49.

[e]Based on the CO_2 emission factor for subbituminous A coal.

[f]Based on the CO_2 ratio for U.S. high-volatile bituminous coal.

Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels, "Analysis of the Relationship Between the Heat and Carbon Content of U.S. Coals," September 1992.

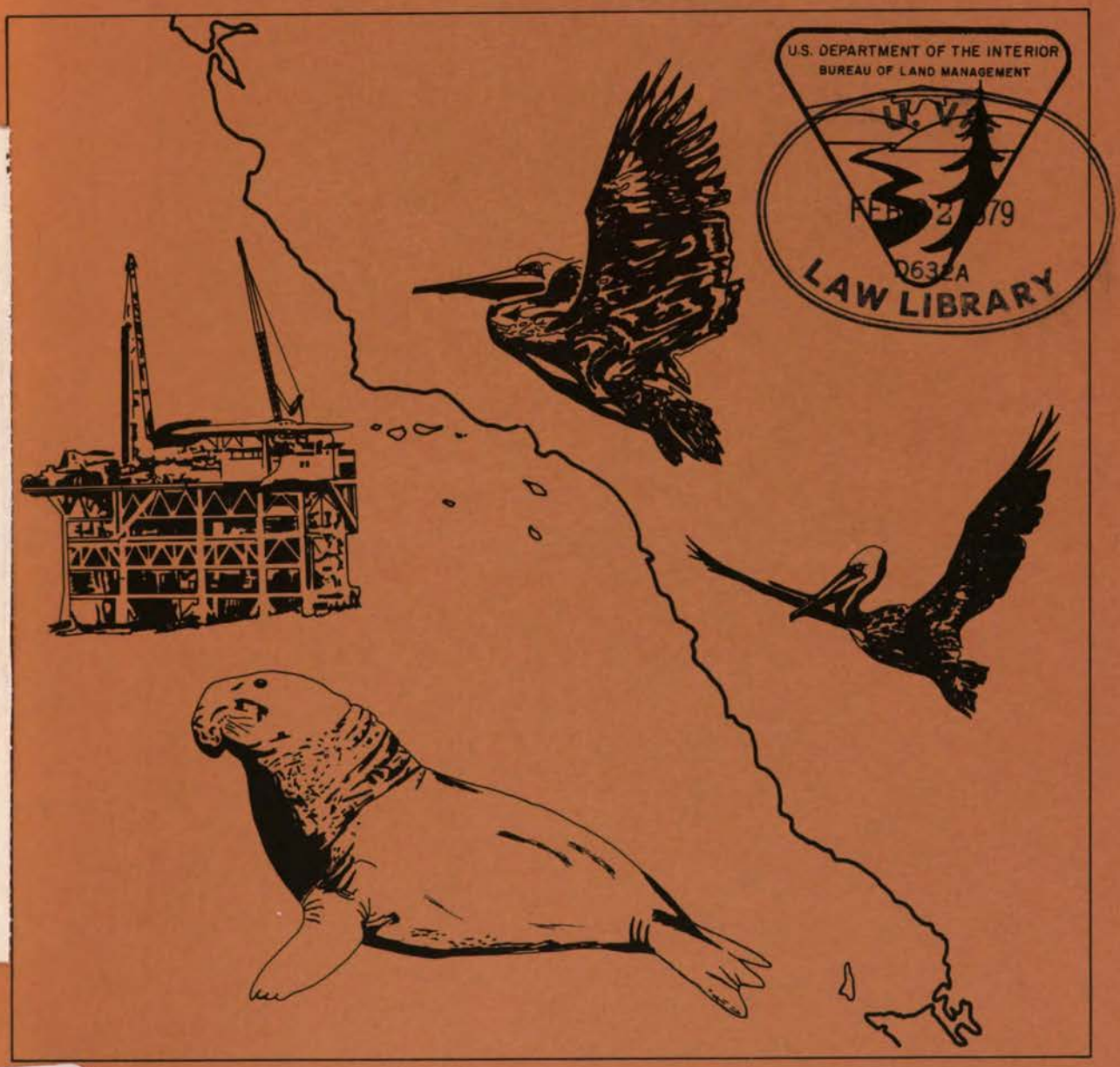
In general, the carbon dioxide emission factors are lowest for coal produced in States east of the Mississippi River (Figure FE1), where the predominant coals are bituminous in rank and therefore have relatively low emission factors. By comparison, the coal deposits in the West are largely subbituminous coals, which have relatively high emission factors. In a broad sense, the geographic differences reflect the greater degree of coalification--the process that transformed plant material into coal under the influence of heat and pressure--in the coal-bearing areas in the East.

In the Appalachian Coal Basin, the emission factors for bituminous coal range from a low of 202.8 pounds of carbon dioxide per million Btu in Ohio to a high of 210.2 in Maryland.(12) Pennsylvania anthracite, which is produced in small amounts, has the highest emission factor among all coal ranks (227.4). For Illinois Basin coal, all bituminous in rank, the emission factors are relatively uniform, ranging from 203.2 in western Kentucky to 203.6 in Indiana.

UNITED STATES DEPARTMENT OF THE INTERIOR

FINAL ENVIRONMENTAL STATEMENT

OCS SALE NO. 48 Volume 3 of 5



Proposed
1979 OUTER CONTINENTAL SHELF
OIL AND GAS LEASE SALE
OFFSHORE SOUTHERN CALIFORNIA

Prepared by the
Bureau of Land Management

Director

Alternative Energy Sources

It is anticipated that the oil and gas that would become available from this proposal in the next 25-year period could provide significant contribution to this region's energy supply; if the subject sale were cancelled, the following energy actions or sources might be used as substitutes:

- Energy conservation
- Conventional oil and gas supplies
- Coal
- Nuclear power
- Oil shale
- Hydroelectric power
- Solar energy
- Energy imports
  - Oil imports
  - Natural gas pipeline imports
  - Liquefied natural gas imports
- Geothermal energy
- Other energy sources
- Combination of alternatives

This section briefly discusses these alternatives. For more detailed information on each of these energy sources and environmental impacts, refer to the study Energy Alternatives: A Comparative Analysis, (University of Oklahoma, 1975) prepared for the Bureau of Land Management by The Science and Public Policy Program of the University of Oklahoma.

1. Energy Conservation

a. Description: Vigorous energy conservation is an alternative that warrants serious consideration. The Project Independence Report of the Federal Energy Administration claims that energy conservation alone can reduce energy demand growth by 0.7 to 1.2 percent depending on the world price of oil. Aside from these savings, it is now widely recognized that wasteful consumption habits impose social costs that can no longer be afforded, as do pollution and an inequitable distribution of fuel.

The residential and commercial sectors of the economy are often characterized as inefficient energy consumers. Inadequate insulation, inefficient heating and cooling systems, poorly designed appliances, and excessive lighting are often noticed in these sectors. Reductions in consumption beyond those induced by fuel price increases could be achieved by new standards on products and building, and/or subsidies and incentives. Such incentives include standards for improved thermal efficiency in existing homes and offices and minimum thermal standards for new homes and offices.

Excessive consumption is also evident in the industrial sector where energy inefficient work schedules, poorly maintained equipment, use of equipment with extremely low heat transfer efficiencies, and failure to recycle heat and waste materials are all commonplace. Estimated energy savings of between 10 and 30 percent may be available in this sector of the economy.

Transportation of people and goods accounts for approximately 25 percent of nationwide energy use. Energy inefficiency in the transportation sector varies directly with automobile usage. Automobiles, which account for 90 percent of all passenger movement in the nation, use more than twice as much energy per passenger mile as buses. Moreover, the average car carries only 1.3 passengers. Using short- and mid-term conservation measures such as consumer education, lower speed limits, rate and service improvements on public transit and rail freight transit, energy savings of 15 to 25 percent might be achieved.

Other policies which could encourage fuel conservation in transportation include standards for more efficient new autos and incentives to reduce miles traveled. An important new development in the fuel economy area could be the modification of the standard internal combustion engine. Although such an engine is now in the advanced stages of development, further study by automotive engineers, industry, and concerned federal agencies is necessary before an acceptable engine may be designed.

Significant energy savings are clearly possible through accelerated conservation efforts. The Project Independence Report estimates that conservation alone could result in a 2.2 million barrel per day reduction in petroleum demand by 1985. In addition, several of the strategies mentioned above have been at least partially implemented by the Energy Policy and Conservation Act of 1975 (P.L. 94-163).

b. Environmental Impacts: The environmental impacts of a vigorous energy conservation program will be primarily beneficial. The exact nature and magnitude of these impacts will depend on whether there is a net reduction in energy use or whether the reduction is accomplished through technological change and substitutions. For the former, the net impacts will simply be that there are fewer pollutants of all kinds unleashed. As an example, the 2.2 million barrel per day savings by 1985 mentioned above would result in a diminishment nationwide of various pollutants by the following amounts.[a]

CO--4 lbs/1,000 gals = 189 tons/day
Hydrocarbons--3 lbs/1,000 gals = 142 tons/day
Particulates--23 lbs/1,000 gals - 1,088 tons/day
NO_x--60 lbs/1,000 gals = 2,838 tons/day
SO_2--157 lbs/1,000 gals = 7,426 tons/day

[a]HUD Contract #H2026R: "Research Evaluation of a System of Natural Air Conditioning."

However, if energy conservation is achieved by technological change or substitution, the net reductions will be those above, less the incremental pollutants from other sources, as well as any new pollutants which might arise from these other sources.

2. Conventional Oil and Gas Supplies

a. Description: Large quantities of oil and gas still remain in the United States. The U.S. Geological Survey (1975) estimates that onshore crude oil measured reserves as of December 31, 1974, were about 31 billion barrels, indicated reserves were 4.33 billion barrels, inferred reserves were 20.4 billion barrels, and undiscovered recoverable resources ranged from 37 billion barrels with a 95 percent probability and 81 billion barrels with a 5 percent probability.

Despite the magnitude of reserves, domestic oil production is likely to continue to decline from its peak production rate attained in 1970. All of the twelve oil production forecasts discussed in the Project Independence Blueprint claimed that, in the next few years, the United States petroleum production decline would continue. Most of these same forecasts predict increasing domestic production by the late 1970's, but only under the most favorable conditions in terms of prices, development of OCS resources, regulations, and environmental constraints.

The development of new reserves required to meet gas demand will depend on continued development of onshore areas and of commercially viable nuclear stimulation or massive hydraulic fracturing to produce natural gas from low permeability reservoirs. Additional domestic oil reserves are recoverable through secondary and tertiary extraction techniques. However, the additional oil that is attainable in this manner is in many cases "old" and hence has been subject to price controls. These controls have diminished the incentive for using these sophisticated and expensive recovery methods.

In a study of future natural gas production rates Duane and Karnitz (1975) concluded that the upper production limits of natural gas are now being approached. Two constraints are identified: the level of recoverable resources, and the production level that can be sustained for a reasonable time period. Once assumption of these two levels are made, there is not much room for variations in the maximum potentially attainable production rate. Assuming the current Potential Gas Committee's estimate of recoverable domestic natural gas resources (1,845 tcf for the U.S. including Alaska), the study considers two possible levels of natural gas production: 25 to 30 tcf/year under optimistic conditions, and 20-25 tcf/year under less optimistic conditions.

A detailed description of the crude oil and natural gas systems is found in Chapter 3 and 4 of Energy Alternatives: A Comparative Analysis.

The substitute directly for the subject sale, a combination of onshore and OCS production from other areas and continued foreign imports would be required to make up for the estimated total production of this proposed sale of 0.715 billion barrels of oil and 0.860 trillion cubic feet of gas, over a 25-year period.

b. Environmental Impact: This substitution would entail environmental impacts such as land subsidence, soil sterilization, and disruption of existing land use patterns. Equipment failure, human error, and blowouts may also impair environmental quality. Moreover, poor well construction, particularly in older wells, and oil spills can result in ground and surface water pollution.

The magnitude of these impacts would depend on whether the increased production resulted from improved recovery methods or new discoveries. If improved recovery is realized, the impacts will likely be of little significance and will occur in already developed areas. Should new discoveries be found, and this is unlikely, the impact will be more significant and disruptive, as the whole new infrastructure would have to be built from the ground up.

The water pollutants from onshore oil production are oil and dissolved solids. The amounts of each vary over a wide range. A summary of this is available in Energy Alternative: A Comparative Analysis.

Air pollutants (particulates, NO_x, SO_x, hydrocarbons and CO) result from blowouts and subsequent evaporation and burning. These are generally insignificant, except locally. These effects will be basically the same, whether the production is onshore or offshore.

Given the fact that onshore supplies are dwindling, California would have to continue its reliance on other regions and foreign imports for needed oil and gas. The decline in these supplies, even with energy conservation, could mean industrial shutdowns, unemployment rises, higher consumer prices, and changes in standard of living. The lack of natural gas will mean additional use of "dirtier" alternative fuels (oil, coal) with consequent impacts on air quality and human health.

3. Coal

a. Description: Coal is the most abundant energy resource in the United States. Coal deposits underlying nearly 460,000 square miles in 37 States constitute one-quarter of the known world supply and account for 80 percent of our proven fuel reserves. Proved reserves of coal contain 125 times the energy consumed in 1970. A detailed discussion of the coal resource system can be found in Chapter 1 of Energy Alternatives: A Comparative Analysis.

To replace the energy expected to be realized from the proposed Southern California sale, 203 million tons of coal would be necessary. Though domestic reserves could easily provide this quantity, serious limitations to coal development exist. In many uses, particularly in California, coal is an imperfect substitute for oil or natural gas. In many other cases, coal use and production is restricted by government constraints, limited availability of low sulfur deposits, inadequate mining, conversion and pollution abatement technology, and the hazardous environmental impacts associated with coal extraction and electricity generated from coal. Coal production is also threatened by the unique set of labor problems associated with mining and new strict standards for coal mine safety.

Although U.S. coal resources are very large, as with other extractable mineral fuels, there is some geographic dislocation. Most of our coal is found west of the Mississippi River far from the industrial areas of California. Also, much of the western coal is in arid or semi-arid areas where scarcity of water could constrain development.

The portion of the domesticated reserve base that is available for use depends on whether the coal deposit can legally be mined, and if it can, whether it is suited for underground or surface mining. Surface mines may recover up to 90 percent of the coal in a given mine; underground mines may recover 50 to 60 percent using room and pillar methods. Both underground and exposed coal deposits are found in the Eastern Province. However, statistics indicate that at the 1972 price only 12 percent of the total resource could be considered economically recoverable. As with other extractable hydrocarbons, the quantity of available coal is a function of coal's market price. Current increases in the market price for coal are making more of this resource base available for domestic consumption.

If an alternative to proposed OCS Sale No. 48 is greater reliance on coal, it may be expected that mining would increase in western states to provide the necessary fuel source.

b. Environmental Impact

i. Coal Utilization: Combustion of coal results in various emissions, notably SO_2 and particulates. If the expected production from this sale is replaced by coal, there will be an increase in these pollutants, especially if coal is substituted for the natural gas presently used. Technology to control these emissions is available but has not yet been proven sufficient to be widely applied. The sulfur content of eastern coal varies considerably but approximately 65 percent of the developed resources have a sulfur content exceeding 1 percent. Most of the U.S. low slufur coal is located in the western states, far from major markets in California. Any large scale shift to coal would

require relaxation of emission regulations or improvement of technologies to convert coal to gaseous or liquid fuels.

ii. Surface Mining: The 203 million tons of coal that would be necessary to replace production from this proposed sale would require two large open-pit mines (assuming 5 x 10^6 tons annually each). The primary impact of surface mining is disruption of the land. This affects all local flora and fauna, water quality, and increases landscape problems due to erosion and runoff from the miner. Reclamation is difficult in the western states due to the lack of water to assist in revegetation. Other problems include acid mine water drainage, leachings from spoil piles, processing waste, and the disturbance caused by access and transportation. Noise and vibration resulting from operations can also be expected. Finally, surface mining causes conflicts with other resources uses (agriculture, recreations, water, wildlife habitat, as examples).

The land use of strip-mining ranges from 0.18 to 5.19 acres/10^{12} Btu extracted, depending on seam thickness and Btu content of the coal. Assuming a figure of two acres/10^{12} Btu, the total surface disturbance to substitute coal for oil and gas from this proposed lease sale could be on the order of 9,778 acres.

iii. Underground Mining: To replace the expected production from proposed Sale No. 48, four underground mines would be required (assuming 2 x 10^6 annual tons each). Underground mining primarily affects land and water quality. The land impacts are those that arise from subsidence, waste disposal, and access and transportation. Very little surface is disturbed. Subsidence can destroy structures, cause landslides and earthquakes, and disrupt groundwater circulation patterns. The amount of subsidence can control by the mining method used and the amount of coal removed. Both have detrimental effects on the economics of the operation.

Water quality is affected by both processing waste and the drainage of acid mine-water into surrounding areas. These can be minimized through the proper methods of control both during and after operations. Entrances can be sealed and waste piles can be replaced in the mine. This would also help minimize subsidence. There are also pollution problems associated with road and coal dust and the like, but these are minimal and easily controlled. Other disturbing aspects of mining have much less of an impact in an underground than a surface mine. Working conditions of underground mines have been improved under the Federal Coal Mining Health and Safety Act of 1969, although further efforts are needed to reduce health hazards. This program has resulted in increasing costs of underground mining relative to surface mining, which has even more severe environmental restraints and impacts.

iv. Coal Transportation: The five major transportation systems (road, rail, water, conveyor, and pipeline) all have some adverse environmental impacts. These include air and noise pollution, safety, land use, trash, disposal, and aesthetics. However, since spill problems are not associated with coal, most of the impacts can be controlled with greater care and consideration. A slurry pipeline also requires large supplies of water and must adequately dispose of this at the other end. Water availability is a problem in many areas of the U.S., especially in the west where energy resource requirements will have to compete with other existing commercial and private users for a limited and fragile supply.

v. Coal Conversion: Technology for conversion of coal into gaseous and liquid hydrocarbons has been established for several decades and a number of relatively low-capacity commercial plants exist in various parts of the world. However, few cost-effective advanced technologies have progressed beyond the pilot plant stage.

Numerous problems remain before commercial development of synthetic fuels from coal can proceed. Specific technical problems must be solved. The cost effectiveness of synthetic fuels from coal will depend on prices of other fuels, primarily oil and natural gas.

Control of adverse environmental effects will increase the cost of producing synfuels. Possible constraints on development include technological constraints; availability of skilled workers, raw materials (coal, water, steel), capital; and institutional constraints: government policies (energy resource leasing, coal mining regulations, permit procedures, etc.) and the willingness of industry to invest in development of new technologies. Present prices for synthetic natural gas are $5.35 per thousand cubic feet versus about $2.30 for conventional natural gas at the burner tip in California (American Gas Association, 1977).

Synthetic oil and gas could contribute substantially to energy supplies by the year 2000--up to 14 percent according to the synfuels Inter-Agency Task Force (Report to the President's Energy Resources Council, November 1975). However, the most important contributors would be high-Btu gas from coal, and synthetic crude oil from oil shales. Prospects for coal liquefication and low-Btu gas appear less attractive. The success of these energy sources will depend on developing technology, the cost of the impacts, especially coal, and the cost of conventional oil and gas.

vi. Coal Gasification: Gaseous fuels with low, intermediate, or high energy content can be produced. Low and intermediate gases are produced in a two-stage process involving preparation and gasification, and the output is utilized as feedstock for electric

generators. A third process, upgrading, is required to produce high-Btu gas, which produces an end product usable by the consumer.

Among low-Btu gasification processes under development are: Lurgi, Koppers-Totzek (both in commercial use), Bureau of Mines Stirred Fixed Bed, and Westinghouse Fluidized Bed. Among high Btu-gasification processes are: Lurgi High-Btu gasification process, HYGAS, BI-Gas, Synthane, and CO_2 Acceptor.

The environmental impacts of coal gasification are those of mining plus those resulting from the production processing. Gasification processes have lower primary efficiency than direct coal combustion; more coal will have to be gasified to reach an equivalent Btu output. However, it is likely that coal gasification will achieve primary efficiencies of 70 percent (Hale, 1975) which is about twice that of coal to electricity end use. Water impacts of processing can be minimized by recycling and evaporation. However, large inputs of water are required for some of the technologies, thus creating the potential for conflicts in water-short areas. For example, a Koppers-Totzek gasifier producing 250×10^9 Btu per day will require water in the amount of 463,000 gallons per day and coal in the amount of 10,570 tons per day. To substitute for this proposed sale, 2.1 complexes would require 1 million gallons of water per day and 8.1 million tons of coal per year. The land use required for these plants, based on 330 acres per plant, would be 693 acres.

Air pollution could include sulfur dioxide, particulates, nitrous oxides, hydrocarbons, and carbon monoxides.

Land impacts result from solid waste disposal plus the land use for plant, coal storage, cooling sands, etc. Solid wastes include ash, sulfur and minute quantities of some radioactive isotopes.

vii. Coal Liquefaction: As with coal gasification, production of liquid fuels from coal requires either addition of hydrogen or removal of carbon from the compounds in the coal. Coal liquefaction can be viewed as a change in the carbon to hydrogen ratio that can be accomplished by one of these reactions: hydrogenation, pyrolysis, or catalytic conversion. Of these, only the last is in commercial operation. Among liquefaction processes under development are: synthoil, H-Coal, Solvent Refined Coal, Consol Synthetic Fuel, COED, TOSCOAL, and Fischer-Tropsch.

Again, the impacts of liquefaction will be those of mining and those of the processing plants. The available technologies have a recovery of from 0.5 to 3 barrels of oil per ton of coal processed.

Water effluents from liquefaction plants could contain amounts of phenols, solids, oil, ammonia, phosphates, and others. The waste water could be treated to remove most of these.

Air pollution could result from particulates, nitrogen and sulfur oxides, and other gases. Pollution control facilities would be required, but would lower the economic attractiveness of the plants.

Solid wastes would be mostly ash. Residue could be buried in the mine with little further environmental impact, if liquefaction plants are sited at the mine mouth.

Impacts from this alternative would probably be absorbed by states other than California.

4. Nuclear Power

a. Description: The predominant nuclear system used in the United States is the uranium dioxide fueled, light water moderated and cooled nuclear powerplant. Research and development is being directed toward other types of reactors, notably the breeder reactor and fusion reactors.

As of December 31, 1975, 56 nuclear plants with capacity of 37,500 NW were licensed to operate. At the end of 1975 nuclear power generated about 8 percent of the nation's electricity. However, about half of the electric power capacity now under construction is nuclear powered. Nuclear power development has encountered delays in licensing and siting, environmental constraints, and manufacturing and technical problems. Future capacity will be influenced by the availability of plant sites, plant licensing consideration, environmental factors, nuclear fuel cost, rate of development of the breeder and fusion reactors, and capital costs. In order to meet future uranium fuel requirements, it will be necessary to locate additional ore reserves through increased exploratory drilling activity.

Fuel cycle costs of nuclear reactors have increased only slightly since 1965, from a range of about 17 cents to 22 cents per million Btu, to about 30 cents in 1974. Present trends in reactor capital costs are signficantly narrowing the economic advantage offered by fuel cycle costs, over coal and oil-fired plants.

b. Environmental Impact: Although nuclear plants do not emit particulates or gaseous pollutants from combustion, the potential for serious environmental problems exists. Some airborne and liquid radioactive materials are released to the environment during normal operation. The amounts released are very small and potential exposure has been shown to be less than the average level of natural radiation

exposure. The plants are designed and operated in such a way that the probability of harmful radioactivity released from accidents is very low.

Nuclear plants use essentially the same cooling process as fossil-fuel plants and thus share the problem of heat dissipation from cooling water. However, light water reactors require larger amounts of cooling water and discharge greater amounts of waste heat to the water than comparably sized fossil-fuel plants. The effects of thermal discharges may be beneficial in some though not all cases. Adverse effects can often be mitigated by use of cooling ponds or cooling towers.

Low level radioactive wastes from normal operation of a nuclear plant must be collected, placed in protective containers, and shipped to a Federally-licensed storage site and buried. High level wastes created within the fuel elements remain there until the fuel elements are processed. Currently, spent fuel is stored at NRC-licensed facilities. Plans call for recovering unused fuels at reprocessing plants, solidifying the wastes, and placing them in storage at a Federal Repository.

Primary residuals from light water reactors are waste heat and radioactive emissions. For a 1,000 MW(e) plant operating at a 75 percent load factor a 33 percent efficient nuclear plant would emit 47×10^{12} Btu's of waste heat annually. For comparison, a 40 percent efficient fossil fuel plant would emit 36×10^{12} Btu's of waste heat.

To substitute for this Southern California proposed sale, it would take more than two 1,000 MW(e) light water reactors to supply the equivalent energy, assuming 40 percent plant efficiency and 80 percent loading. First core loading of these plants would require 1,500 tons of enriched uranium (U_3O_8), with annual reloadings requiring over 500 tons total. This kind of substitution assumes that <u>all</u> oil and gas produced from this sale would generate electricity. Nationally, only 8 percent of oil and 18 percent of gas consumed is utilized to generate energy.

There are also impacts on land, water, and air quality arising from the mining of these uranium ores. Dwindling amounts of high grade reserves will increase the amounts of land mined for lower grade radioactive ores--primarily in western states. The mining operations will be similar to coal, but the nature and distribution of the deposits mean "lesser" impact while radioactive trailings cause unusual problems for disposal, the environment, and human health.

A more complete discussion of uranium mining and processing, their economics and environmental impacts, and nuclear fission and fusion can be found in Chapters 6 and 7 of <u>Energy Alternatives: A Comparative Analysis</u>.

5. Oil Shale

a. Description: Large areas of the United States are known to contain oil shale deposits but those in the Green River formation in Colorado, Wyoming, and Utah, have the greatest commercial potential. The oil shale resources of the Green River formation are estimated at 1,781 billion barrels, of which 129 billion barrels are classes one and two resources, 186 billion barrels are class three resources, and 1,466 billion barrels are class four resources.[a]

To substitute the energy equivalent estimated to be produced from this proposed Mid-Atlantic sale, 1.25 billion tons of oil shale would have to be mined and processed.

b. Environmental Impact: Oil shale development poses serious environmental problems. With surface or conventional underground mining, it is very difficult to dispose of the huge quantities of spent shale, which occupy a larger volume than before the oil was extracted. Inducing revegetation in an area of oil shale development is difficult and may take more than ten years. In-place processing avoids many of these environmental hazards. The spent shale problem is much less severe with underground mining.

Air pollutants from the mining will come from dust and vehicular traffic. These will be predominantly particulates, followed by NO_x and CO, with minimal amounts of hydrocarbons SO_x and aldehydes.

The mining of oil shale requires little water, both for operations and for reclaiming solid wastes. Water pollutants are considered negligible but may arise if saline water were encountered during the operations and had to be disposed of.

However, the processing (retorting) operations consume large quantities of water and generate large amounts of waste water. The waste water must be treated and can be reused in the processes. Therefore, it has been assumed that water pollution will not be a problem outside the complex. However, the limited availability of input water in the development area could lead to resource use conflicts.

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[a]U.S. Energy Outlook, National Petroleum Council, Washington, D.C., 1972, pp. 207-208. Classes one and two deposits are at least 30 feet thick and average 30 gallons of oil per ton of shale, and include only the most accessible and better defined deposits. Class three deposits are as rich as classes one and two but more poorly defined and less favorably located. Class four deposits are lower grade, poorly defined deposits ranging down to 15 gallons of oil per ton of shale.

Air pollutants vary with the technology used. Solid waste comprises the greatest problem of oil shale processing. The volume of the waste is greater than the volume of the input. Therefore, backfilling and the like would not provide a sufficient disposal space. Finally, there are the impacts of access and of transporting the products. These are analogous to those of coal mining in the case of access, and petroleum distribution in the case of transporting the product.

A fuller description of this energy source can be found in Chapter 2 of Energy Alternatives: A Comparative Analysis.

6. Hydroelectric Power

a. Description: Hydropower is energy from falling water, which is used to drive turbines and thus produce electricity. Conventional hydroelectric developments convert the energy of natural regulated stream flows falling from a height of produce electric power. Pumped storage projects generate electric power by releasing water from an upper to a lower storage pool and then pumping the water back to the upper pool for repeated use. A pumped storage project consumes more energy than it generates but converts offpeak, low value energy to high value peak energy. A more detailed discussion of this energy source is found in Chapter 9 of the study Energy Alternatives: A Comparative Analysis

Many of the major hydroelectric sites operating today were developed in the early 1950's. Thirty to forty years ago hydroelectric plants supplied as much as 30 percent of the electricity produced in the United States. Although hydroplant production has steadily increased, thermal-electric plant production has increased at a faster rate.

As of May 1974, total conventional hydropower developed in the contiguous United States was 54,885 MW, nearly one-half of which was in the western states of Washington, Oregon, and California. Some 6,878 MW of conventional hydro capacity are now being installed, about 90 percent of which is in the western part of the country.

Much of recent hydroelectric development has been pumped storage capacity. As of May 1974, the total developed pumped storage capacity in the contiguous United States was 8,119 MW; capacity under construction was 6,253 MW.

The undeveloped potential for hydroelectric generation is about 93,000 MW in the lower 48 states and about 32,000 MW in Alaska. However, it is likely that hydroelectric power will continue to represent a declining percentage of the total U.S. energy mix due to the following: high capital costs, seasonal variations in waterflows, land use conflicts, environmental effects, water use, and flood control constraints. Sites

with the greatest production capacity and lowest development costs have already been exploited.

b. Environmental Impact: Construction of a hydroelectric dam represents an irreversible commitment of the land resource beneath the dam and lake. Flooding eliminates wildlife habitat and prevents other uses such as agriculture, mining, and free-flowing river recreation.

Hydroelectric projects do not consume fuel and do not cause air pollution. However, use of streams for power may displace recreational and other uses. Water released from reservoirs during summer months may change ambient water temperatures and lower the oxygen content of the river downstream, adversely affecting indigenous fish. Fluctuating reservoir releases during peak load operation may also adversely affect fisheries and downstream recreation. Screens placed over turbines prevent the entrance of fish, but small organisms may pass through and may be killed.

Fish may die from nitrogen supersaturation, which results at a dam when excess water escapes from the draining reservoir. High nitrogen levels in the Columbia and Snake Rivers pose a threat to the salmon and steelhead resources of these rivers. Other adverse impacts to water quality include possible saline water intrusion into waterways and decreased ability of the waters to accommodate waste discharges.

Air quality will only be affected by dust and emissions during the construction phase. Afterwards, if the impoundment is used for recreation, motor exhausts would occur.

7. Solar Energy

a. Description: Applications of solar energy must take into account the following:

Solar energy is a diffuse, low intensity source.

Its intensity is continuously variable with time of day, weather, and season.

Its availability differs widely between geographic areas.

Potential applications of solar energy show a wide range. Among them are:

Thermal energy for buildings
Water heating, space heating, space cooling, combined systems

Renewable clean fuel sources

Combustion of organic matter

Bioconversion of organic materials to methane

Pyrolysis of organic materials to gas, liquid, and solid fuels

Chemical reduction of organic materials to oil

Electric power generation

Thermal conversion

Photovoltaic - residential/commercial, ground central station, space central station

Wind energy conversion

Ocean thermal difference

b. Impacts: Although fuel costs foor backup systems and maintenance costs for solar units are small when compared with operating costs of conventional heating and cooling systems, the high initial or "fixed" costs of solar units make them unattractive to many homeowners and builders. The typical solar heating system for a home costs $5,000-$6,000 (including costs of a standby conventional furnace) compared to $1,000-$2,000 for a conventional fossil-fuel home heating unit. However, the rising cost of the gas and oil needed by the conventional heaters means that, over time, the greater fixed costs of solar systems will be balanced by their lack of fuel costs.

Large-scale generation of electricity using solar energy is another promising application which is receiving increased funding. A number of technical and engineering problems now prevent commercialization of solar steam-electric plants, though pilot projects are well underway. It is estimated that solar electricity will be available on a significant scale in 10 to 15 years or more.

Additional detail on this resource alternative is found in Chapter 11 of Energy Alternatives: A Comparative Analysis (U.S. Government Federal Policy Task Force Review Group, Solar Energy Analysis, 1978; Solar Energy: Progress and Problems, 1978, EPA; Distributed Energy Systems in California's Future, 1978; U.S. DOE and Lawrence Berkeley Laboratories, et al.).

Among the disadvantages of solar-energy are high capital costs, expensive maintenance of solar collectors, thermal waste disposal, and distortion of local thermal balances.

b. Environmental Impact: The impacts so far identified with solar energy are relatively minimal. The primary effects of the use of this energy source on a wide scale will be land use. Due to the low density of the energy, large areas will be necessary for the collectors. However, the land use compares favorably with other forms of energy use such as coal extraction.

The only other area for concern known so far is thermal pollution. Direct use in space heating has no thermal effects. However, for solar electric power generation, heat will have to be collected and transferred to the generator. Some localized thermal pollution may occur as a result, but the problem is not expected to be significant. Finally, solar plants can only operate intermittently. Thus, the energy will have to be either stored, or backup fossil-fuel plants will have to be built. These will have their own sets of environmental constraints.

8. Oil Imports

a. Description: U.S. reliance on imported oil has increased steadily in the last decade. Competition on the world market and recent cutbacks in Middle Eastern oil exports (oil embargo of 1973) have raised concerns about availability of oil imports in the future. Declining resource availability and increasing domestic demand restrict potential imports from the Western Hemisphere nations, particularly Venezuela and Canada. Increasing imports from the Middle East brings problems of stability of supply, balance of payments, and U.S. off-loading capacity.

In February, 1977, U.S. imports of petroleum and petroleum products were 7,724,000 barrels/day.

During calendar year 1976, the U.S. imported an average of 5,287,000 barrels of crude oil and 1,927,000 barrels of refined oil each day (DOE, 1978). The peak production of 220,000 barrels per day from this proposed sale thus represents less than 2 percent of daily U.S. crude imports. To import the equivalent barrels of oil needed to replace the oil and gas from this proposed sale would total $11 billion dollars at $13 a barrel.

b. Environmental Impact: The primary hazard to the natural environment of increased oil imports is the possibility of oil spills, which can result from accidental discharge, intentional discharge, and tanker casualties. Intentional discharges would result largely from uncontrolled deballasting of tankers. The effects of chronic low-level pollution are largely unknown. The worldwide tanker casualty analysis indicates that, overall, an insignificant amount of the total volume of transported oil is spilled due to tanker accidents. However, a single incident such as the breakup of the TORREY CANYON in 1967 or the AMOCO

CADIZ in 1978 can have disastrous results. Of more concern than tanker spills is the impact to the social and economic environment. The potential for a future embargo under this option is such that American productivity and policy could become subserviant to foreign influence. On a more subtle level, political alignments and policies of the United States could become tied to those of foreign oil powers. This option is the least acceptable for continued American energy independence.

9. Natural Gas Imports

a. Description: Imports of natural gas via pipeline have come largely from Canada, with small amounts from Mexico. In 1973, net pipeline imports from Canada were 1,028 bcf, about 4.6 percent of total natural gas used in the United States. These imports were about 33 percent of Canada's natural gas production. Natural gas pipeline imports from Mexico have not been a significant part of U.S. supply. In 1973, imports from Mexico were 1.6 bcf.

Mexico could be a significant source of future imports because of its relatively large natural gas resource base, in the Tampico-Tobasco region. Imports from Mexico were of a local nature until 1957 and have declined since 1969 but could be of major significance in the future. Canadian intentions to gradually phase out oil exports to the U.S. also puts into question increased natural gas pipeline exports.

Natural gas imports would have to be about .094 billion cubic feet per day to replace the gas production estimated to be available from this proposed Southern California sale.

b. Environmental Impact: The environmental impacts of increasing gas imports derive mainly from the possible increased use of land for pipeline construction. A further impact is the risk of explosions and fires. As with imports of oil, California could become dependent on foreign control of supply. Fluctuations of that supply could influence quality of life, productivity, and employment. American policies could also become influenced by decisions of foreign gas producers, much as they could under the option of increasing oil imports.

10. Liquified Natural Gas Imports

a. Description: The growing shortage of domestic natural gas has encouraged projects to import liquified natural gas (LNG) under long-term contract. Large scale shipping of LNG is a relatively new industry. Several LNG projects are now under consideration on the Pacific, Atlantic, and Gulf coasts. Security of foreign LNG is questionable. The complexity of the length of time involved in implementing these proposals has been increased by the need for negotiating preliminary contracts, securing the approval of the Federal Power Commission and

the exporting country, and making adequate provision for environmental and safety concerns in the proposed U.S. facilities.

b. Environmental Impacts: The environmental impacts of LNG imports arise from tankers; terminal, transfer, and regasification facilities; and transportation of gas. The primary hazard of handling LNG is the possibility of a fire or explosion during transportation, transfer, or storage.

Receiving and regasification facilities will require prime shoreline locations and dredging of channels. Regasification of LNG will release few pollutants to the air or water.

LNG imports will influence the U.S. balance of payments. This impact will depend on the origin and purchase price of the LNG, the source of the capital, and the country (U.S. or foreign) in which equipment is purchased and LNG tankers are built. Section I.E.11 discussed the proposed LNG terminal sites in Southern California.

11. Geothermal Energy

a. Description: Geothermal energy is primarily heat energy from the interior of the earth. It may be generated by radioactive decay of elements such as uranium or thorium, and friction due to tidal or crustal plate motions.

There are four major types of geothermal systems: hot water, vapor dominated, geopressured reservoires, and hot dry rock systems.

In addition to electricity, geothermal energy can offer a potential for space heating, industrial processing, and other nonelectric uses in many areas which presently are highly dependent upon oil and gas for energy needs. However, geothermal electric generating plants are smaller than conventional plants and require a greater amount of steam to generate the same amount of energy. This is due to the fact that temperatures and pressures associated with geothermal areas are lower than those created at conventional power plants. In some areas, geothermal resources may have potential for space heating, industrial processing, adn other non-electric uses.

The greatest potential for geothermal energy in the U.S. is found in the Rocky Mountain and Pacific regions; some potential exists in the Gulf Coastal Plain of Texas and Louisiana. The Geysers field in California is the most extensively developed source of geothermal energy in the United States. It has been producing power since 1969. Exploration efforts are also underway in the Imperial Valley, Salton Sea, Mono Lake, and Modoc County, California.

Within 20 years, geothermal energy may account for about 1 to 2 percent of total U.S. energy and about 5 percent of California's total energy consumption.

b. Environmental Impact: A number of gases are associated with geothermal systems and may pose health and pollution problems. These gases include ammonia, boric acid, carbon dioxide, carbon monoxide, hydrogen sulfide, and others. However, adverse air quality impacts are generally less than those associated with fossil-fuel plants. Also associated with geothermal energy systems are saline waters which must be disposed of and isolated from contact with ground water regimes.

Land quality problems stem from disturbance due to construction of related facilities, and possible ground subsidence which, in turn, can cause structural failures and loss of ground water storage capacity.

12. Other Energy Sources: The high cost and rapidly shrinking reserves of the traditional energy fuels have encouraged research into new and different sources for potential energy. Some of these alternate sources have been known for decades but high costs and technical problems have prevented their widespread use. They include tidal power, wind power, organic fuels and ocean thermal-gradients, among others.

Environmental impacts of these alternatives are difficult to assess, especially as a great amount of research and development remains to be completed before operational scale systems can be developed, tested, and evaluated for production and application.

The date of commercial availability of such alternatives will depend on the cost of the traditional energy fuels, the level of Federally subsidized research through ERDA assistance, and the solution of engineering and technical problems.

13. Combination of Alternatives: Within California, a combination of some of the most viable energy sources available to this area, discussed above, could be utilized to attain an energy equivalent comparable to that estimated to be produced within the 25-year field life anticipated by this proposed action. However, this combination of alternatives, in order to attain the needed energy mix peculiar to the infrastructure of this area, would have to consist of energy sources attainable now or within the 25-year timeframe that are transferable to the technology presently used, i.e., viable substitutes would have to be available for the petroleum and natural gas required by the petrochemical industrial complex, the petroleum used for the transportation sector, and the electricity and fuels used in the Southern California residential and commercial sectors.

Part II of the Energy Alternatives: A Comparative Analysis, particularly Chapter 16 "Comparing the Economic Costs of Energy Alternatives", discusses the factors that must be involved in developing technically and economically appropriate energy alternatives.

The most viable domestically available energy alternatives for the California region, technologies and economies allowing, probably would consist of the use of coal (for use in coal-fired power plants), coal gasification plants (to provide synthetic natural gas), nuclear power and solar energy (to provide energy for space heating), and oil shale processing (to provide petroleum), in addition to conventional oil and gas resources. The environmental impacts of each of these alternatives has been discussed briefly in the previous sections.

Based upon the range of undiscovered recoverable resources estimated by the USGS for this proposed Southern California sale area, Table VIII.C.13-1 presents the energy equivalents which would be required for other energy sources to substitute for this proposed action.

The future U.S. energy source mix will depend on a multiplicity of factors, among them the identification of resources, research and development efforts, development of technology, rate of economic growth, the economic climate, changes in life-style and priorities, capital investment decisions, energy prices, world oil prices, environmental quality priorities, government policies, and availability of imports.

The Project Independence Report estimated U.S. energy demand and domestic supply for four cases. These data are shown below (see Tables VIII.C.13-2 and 3).

The increases in domestic supply under the accelerated supply case are due largely to the following:

Standardization and expedited licensing to increase nuclear capacity 15% by 1985.

Significant new leasing, exploration and development of the Pacific, Gulf of Alaska, and Atlantic OCS.

Additional oil and gas pipelines from Alaska to the lower 48 states.

Increased Federal leasing and actions to allow additional oil shale production.

Opening National Petroleum Reserves #1 and #4 to full scale commercial development.

Table VIII.C.3-1

ENERGY NEEDED FROM OTHER SOURCES TO REPLACE ANTICIPATED OIL AND GAS PRODUCTION FROM PROPOSED OCS SALE NO. 48, SOUTHERN CALIFORNIA

Total Crude Oil Production (barrels) (Based on Conditional Mean Resources; 25-year production schedule)	0.715 billion
Total Natural Gas Production (cubic feet) (Conditional Mean; 25-years)	0.86 trillion
Crude Oil Btu Equivalent[a]	4.00×10^{15}
Natural Gas Btu Equivalent[b]	8.78×10^{14}
Total Oil & Gas Btu Equivalent	4.88×10^{15}
Energy Alternative Source Equivalents	
Oil alone (barrels)	0.872 billion
Total field life (years)	25
Annual average	34.857 million
Daily average	95,500
Gas alone (cubic feet)	4.77×10^{12}
Total field life (years)	25
Annual average (cubic feet)	1.91×10^{11}
Daily average (cubic feet)	524 million
Coal (tons)[c]	203 million
Annual average (tons)	8.13 million
Daily average (tons)	22.3 thousand
Coal gasification	
Low Btu[d]	
Number of plants	2.14
Coal required (tons)	
Total volume	206 million
Annual average	8.25 million
Daily average	22.6 million
Oil Shale[e]	
Total volume (tons)	1.25 billion
Annual average	49.9 million
Daily average	136.7 thousand

Table VIII.C.3-1 (Cont.)

Nuclear capacity[f]	
Number of light water reactors (1,000 MW(e) capacity)	3.71
First core fuel U_3O_8[g]	1,038 tons
Annual reload	37 tons

[a]Assuming one barrel of oil equals 5.6 x 10^6 Btu.
[b]Assuming one cubic foot of natural gas equals 1,021 Btu.
[c]Assuming one ton of coal equals 24 x 10^6 Btu.
[d]Assuming Koppers-Totzek processing requiring 10,570 tons/day of coal for an output of 250 x 10^9 Btu's/day. Also assumes coal of 8,780 Btu's per pound.
[e]Assuming high grade shale recovery of 0.7 barrels per ton of oil shale.
[f]One kilowatt-hour equals 3,412 Btu at a theoretical conversion rate of other energy forms to electricity at 100% efficiency. Capacity is calculated assuming an 80% plant factor and 33% efficiency of fossil fuel electricity generation.
[g]Assuming 30 metric tons enriched U_3O_8 first core fuels, and 10 metric tons enriched U_3O_8 annual reloads with plutonium recycle for each normalized 1,000 MW(e) light water reactor.

Table VIII.C.3-2

U.S. ENERGY DEMAND AND DOMESTIC SUPPLY, 1985

World Oil Price	$11 Per Barrel Demand (quads)	Domestic Supply (quads)[a]
Base case w/ and w/o emergency programs	102.9	96.3
Accelerated supply	104.2	104.8
Conservation	94.2	91.8
Accelerated supply plus conservation	96.3	96.3

Quad - a quadrillion Btu's.

[a]The data cites in this section are taken from: Federal Energy Administration, Project Independence Report, November, 1974. A more recent report, The National Energy Outlook, by FEA updates this material.

Table VIII.C.3-3 shows the breakdown of total domestic fuel supplies for the base case and the accelerated supply case.

Table VIII.C.3-3

DOMESTIC FUEL CONSUMPTION BY SOURCE, 1985
(in quads)

	1972 Actual	$11 World Oil Base Case	Accel. Supply
Coal	12.5	22.9	20.7
Oil	22.4	31.3	38.0
Gas	22.1	24.8	25.5
Hydro and Geothermal	2.9	4.8	4.8
Nuclear	0.6	12.5	14.7
Synthetics			0.4
Imports	11.7	6.5	0
Total	72.1	102.9	104.2

Possible mandatory allocation or other actions to assure critical materials and equipment to meet expected production levels.

For the base case, the Project Independence Report envisions the role of alternative energy sources as the following:

Petroleum production is severely constrained in the short run and greatly affected by world oil prices in the long run. Before 1977 there is little that can prevent domestic production from declining or at best remaining constant.

Coal production will increase significantly, but is limited by lack of markets. Increases are limited by rate of electric growth, increasing nuclear capacity, and environmental restrictions.

Potential increases in natural gas production are limited.

Nuclear power is expected to grow from 4.5% to 30% of total electric power generation.

Synthetic fuels will not play a major role between now and 1985.

Shale oil could reach 250,000 B/D by 1985 at $11 world oil prices, but would be lower if $7 prices prevail.

Geothermal, solar, and other advanced technologies are large potential sources, but will not contribute to our energy supplies until after 1985.

In the interest of clarity of presentation, the early parts of this section have discussed separately each potential alternative form of energy as a possible substitute to the proposed sale. However, it is unlikely that there will ever be a single definitive choice between energy sources, or that development of one source will preclude development of others. Different energy sources will differ in their rate of development and the extent of their contribution to total U.S. energy supplies. Understanding of the extent to which they may replace or complement offshore oil and gas requires reference to the total national energy picture. Relevant factors are:

Historical relationships indicate that energy requirements will grow at approximately the same rate as gross national product.

Energy requirements can be constrained to some degree through the price mechanisms in a free market or by more direct constraints. One important type of direct constraint operating to reduce energy requirements is through the substitution of capital investment in lieu of energy; e.g., insulation to save fuel. Other potentials for lower energy use have more far-reaching impacts and may be long range in their implementation--they include rationing, altered transportation modes, and major changes in living conditions and life styles. Even severe constraints on energy use can be expected to only slow, not halt, the growth in energy requirements within the timeframe of this statement.

Energy sources are not completely interchangeable. Solid fuels cannot be used directly in internal combustion engines for example. Fuel conversion potentials are severely limited in the short term although somewhat greater flexibility exists in the longer run and generally involve choices in energy-consuming capital goods.

The principal competitive interface between fuels is in electric powerplants. Moreover, the full range is flexibility in energy use is limited by environmental considerations.

A broad spectrum of research and development is being directed to energy conversion--more efficient nuclear reactors, coal gasification and liquefaction, liquified natural gas (LNG), and shale retorting, among others. Several of these should assume important roles in supplying future energy requirements, though their future competitive relationship is not yet predictable.

Major potential for filling the supply/demand imbalance for domestic resources are:

- More efficient use of energy
- Environmental acceptable systems which will permit production and use of larger volumes of domestic coals.
- Accelerated exploration and development of all domestic oil and gas resources.
- Development of the Nation's oil shale resources.

Of the foregoing, increased domestic oil and gas production offers considerable possibilities, although adequate incentives must exist for indicated and undiscovered domestic resources to be discovered and extracted.

The acceptability of oil and gas imports as an alternative is diminished by:

- The security risks inherent in placing reliance for essential energy supplies on sources which have demonstrated themselves to be politically unstable and prone to use interruption of petroleum supplies to exert economic and political pressure on their customers.

- The aggravation of unfavorable international trade and payments balances which would accompany substantial increases in oil and gas imports.

- Apparent high costs of liquefying and transporting natural gas other than overland by pipeline.

California and PAD V oil balance is shown in Table VIII.C.3-4 as taken from Energy Alternatives for California: Paths to the Future, Ahern et al., 1975.

UNITED STATES DEPARTMENT OF THE INTERIOR

DRAFT ENVIRONMENTAL IMPACT STATEMENT

PROPOSED FIVE-YEAR OCS OIL AND GAS LEASE SALE SCHEDULE

MARCH 1980 - FEBRUARY 1985

DIRECTOR

than Beaufort in this regard. Impacts to breeding waterfowl may also differ. While omission of a Chukchi Sea sale would significantly reduce the potential oil spill risk to waterfowl breeding on barrier islands and feeding in estuaries in that area, Beaufort Sea is more heavily utilized by waterfowl than is the Chukchi Sea shore area.

3. Alternative 7: Include 25 Lease Sales on the Proposed Schedule, Omitting St. George Basin, Northern Aleutian Shelf, Navarin Basin, Norton Basin and Chukchi Sea Sea from the Five-Year Schedule

a. Description of Alternative 7

This alternative would reduce the projected oil resources anticipated for Alternative 1 by approximately 3.9 million B/D, thus reducing the amount of Alaskan oil which would need to be transported and refined. The Department of Energy does not anticipate production of gas from these areas because of market constraints and the cost of conversion to LNG.

b. Summary of Environmental Impacts of Alternative 7

This alternative would result in only one frontier area in Alaska, Kodiak, being considered in the five-year schedule. All impacts discussed for the Bering Sea and the Chukchi Sea lease sales under Alternative 1 would be removed. Since the Bering Sea hosts an abundance of sea birds, breeding and migrating waterfowl, and breeding and migrating marine mammals, overall impacts of the schedule on these resources would be much reduced from Alternative 1. In addition, impacts to land use and coastal planning in Alaska, as discussed for Alternative 3, would be substantially reduced, since all areas which are considered least prepared for onshore infrastructure and land use impacts would be omitted from consideration for leasing at this time. In addition, technology for adverse ice conditions would be developed in the Beaufort Sea, rather than the Chukchi Sea, resulting in differing environmental and economic effects as discussed in Alternative 6.

This alternative would result in a slower paced schedule, allowing for concentration of manpower and funding resources in fewer geographic areas and fewer sales.

E. Alternative 8: No Action

1. Description of Alternative 8

An alternative to the proposed schedule is to cease leasing Federal OCS areas for oil and gas development, beginning in March 1980. This alternative would result in the need to meet national energy needs through other sources, or to reduce energy consumption, or a combination of both. One directly substitutable source of OCS oil and gas is imported oil and gas; however, the Administration is committed to the reduction of oil imports, due to the adverse economic and political repercussions of dependence on foreign sources of oil. Additional production of onshore oil and gas represent another source of direct substitutes for OCS resources. In lieu of adequate onshore sources of oil and gas, or

importation, energy requirements could be met using alternate energy sources, such as solar energy, nuclear power and conservation measures, or a combination of these alternatives. Trends in alternative sources of energy to OCS production are discussed in Section I.B.6.

2. Summary of Environmental Impacts of Alternative 8

The impacts associated with Alternative 1 would be eliminated or largely eliminated should this alternative be adopted. Some impacts to marine and coastal ecosystems would result should importation of oil be increased. These impacts would accrue largely to the lower 48 States where refining centers and oil product import ports exist. Socioeconomic impacts related to Alternative 1 would be elimianted, but could be replaced with infrastructure, employment and population impacts associated with the development of additional coal extraction and processing, oil shale processing, nuclear plant and LNG plant construction, and other facilities associated with alternative energy production.

Adverse environmental effects to onshore ecosystems could also be expected; the nature and extent would depend upon the type, level and location of such alternative energy production. It is likely that the western portion of the United States would receive the bulk of such impact, due to the location of a substantial amount of alternative energy sources in the Rocky Mountain States.

Depending upon the extent of conservation and/or shortfall of energy, economic dislocation could also occur.

OCS EIS/EA
BOEM 2012-030

Outer Continental Shelf Oil and Gas Leasing Program: 2012-2017

Final Programmatic Environmental Impact Statement

July 2012

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standards will depend on market penetration. While not attempting a definitive analysis, we can make some rough, order-of magnitude approximations to demonstrate the scale of potential savings. Replacing half of all currently existing residences and commercial buildings over the next 25 years, through new construction or retrofits, with buildings that are 25 percent more efficient in space heating (a conservative estimate, since space heating will likely account for a disproportionate level of total energy savings), would translate into an aggregate 12.5 percent reduction in space heating energy demand, or about 564 trillion Btu of natural gas and 164 trillion Btu of oil. If 10 percent of these buildings met Energy Star and/or LEED standards and realized a further 25 percent improvement from the new baseline, they would save an additional 42 trillion Btu of natural gas and 12 trillion Btu of oil from space heating. In total, under these assumptions more efficient new buildings could save approximately 782 trillion Btu of oil and natural gas per year within 25 years.

4.5.7.2 Analysis of the Environmental Effects of the No Action Alternative

The selection of the No Action Alternative would eliminate all oil and gas activities that were projected to occur under the Program. OCS-related activities could still occur, however, in these areas as a result of leasing activity during previous and future programs. At the same time, the No Action Alternative would require energy substitutes to replace the oil and gas production that would not occur as a result of the Program. The energy substitutions would be associated with their own potential environmental impacts that could occur within or outside program areas that were considered in the proposed action.

4.5.7.2.1 Energy Substitutions for OCS Oil and Gas. With less oil and gas available from the OCS under the No Action Alternative, consumers could obtain oil and gas from other sources, substitute to other types of energy, or consume less energy overall. Similarly, energy production may shift from OCS oil and gas to onshore oil and gas, overseas oil and gas production, or domestic production of oil and gas alternatives (e.g., coal). Each of these shifts in consumption and production relative to the proposed action yield environmental impacts that this section evaluates.

The process for calculating these impacts begins with the application of MarketSim, a multi-market equilibrium model that simulates the energy supply, demand, and price effects of OCS oil and gas production compared with baseline projections from the EIA's Annual Energy Outlook. In addition to simulating oil and natural gas markets, MarketSim includes separate modules for coal and electricity, enabling the model to capture the broad effects of the No Action Alternative across individual segments of the energy market. Modeling each of these sectors, MarketSim produces an estimate of the energy market's response to the absence of production that would occur as a result of the No Action Alternative.

Table 4.5.7-7 presents the changes in energy markets projected by MarketSim for the No Action Alternative. The table presents the quantities of the energy sources that would be used to replace the lost production of OCS hydrocarbons under the No Action Alternative. The quantities of domestic onshore production of both oil and natural gas is projected to increase but

TABLE 4.5.7-7 Cumulative Energy Substitutions for Oil and Gas Under the No Action Alternative

Energy Sector	Quantity[a]	Replacement Percent (%)
Domestic onshore oil	53–402	1–3
Domestic onshore gas	759–2,326	13–17
Oil imports	3,540–7,870	56–62
Gas imports	458–1,224	8–9
Other	108–274	2
Coal	335–925	5–6
Electricity[b]	146–388	3
Reduced demand[c]	330–814	6

[a] Quantities expressed as energy equivalents of a million bbl (Mbbl) of oil. Values derived from MarketSim output rounded to the nearest Mbbl. Range of values based on price assumptions of $60 and $160/bbl for oil and $4.27 and $11.39 per million cubic feet of gas. Quantities were calculated for a 40 year time period, which is slightly different than the 40-50 year assumed life of the program.

[b] Electricity generated from sources other than oil, gas or coal such as nuclear, hydro, solar and wind.

[c] Demand reductions resulting from energy conservation.

will make up for only a fraction of foregone OCS production. To ensure that demands for oil and gas are met, MarketSim projects a sharp increase in oil and gas imports under the No Action Alternative, via both tanker and pipeline. The model also projects that the reduction in OCS oil and gas production under the No Action Alternative will be replaced by an increase in domestic coal and electricity production and by energy conservation.

MarketSim projects that natural gas consumption will decline, while domestic consumption of oil, coal, and electricity will increase. Given that domestic oil production declines under the No Action Alternative, the increase in oil consumption may be somewhat unexpected. This increase in consumption reflects the fact that oil and gas are substitutes within the industrial sector and, to a lesser extent, the residential and commercial sectors. Therefore, as natural gas prices increase under the No Action Alternative, consumption of substitutes, including oil, increases. The increase in oil prices under the No Action Alternative may cause substitution in the opposite direction (i.e., from gas to oil), but the impact of increased gas prices is the more dominant of the two effects.

substituted impacts, some issues of particular environmental concern from energy substitutions are listed below.

Acid Mine Drainage from Coal Mining. Runoff from coal mining sites may increase the acidity of surface waters near and downstream from coal mining sites, adversely affecting habitat for aquatic organisms and limiting human recreational uses.

Contamination of Groundwater from Oil and Gas Extraction. The extraction of oil and gas from onshore sources can, in some cases, lead to the contamination of local groundwater supplies. For example, focusing on shale gas extracted from wells in Pennsylvania and New York, Osborn et al. (2011) found that average methane concentrations in drinking water wells increased with proximity to the nearest gas well and were 17 times greater than wells not located near extraction sites (Osborn et al. 2011). In addition, oil and gas wells may lead to groundwater contamination from accidental spills, losses of well control, and/or pipeline leaks.

Water Discharges from Oil and Gas Operations.[32] To facilitate resource extraction from subsurface formations, oil and gas producers use water to develop pressure, causing oil and gas to rise to the surface (e.g., enhanced oil recovery and hydraulic fracturing). Producers must manage these waters as well as waters extracted from geologic formations during oil/gas extraction. The environmental impacts associated with this "produced water" vary based on the geologic characteristics of the reservoir that produced the water and the separation and treatment technologies employed by producers.

Coal Combustion Impacts. Coal consumed in place of gas under the No Action Alternative will result in environmental costs associated with diminished air quality and the disposal of coal combustion residuals. The combustion of coal in power plants or industrial boilers produces higher emissions of NO_x, SO_x, and PM than the combustion of natural gas and results in greater CO_2 emissions.[33] In addition, coal combustion residuals generated by power plants or coal-fired industrial boilers may pose a risk to local groundwater supplies when disposed in surface impoundments or landfills when such units are not properly maintained.

Socioeconomic and Sociocultural Effects. Sections 4.4.9.1 and 4.4.13.1 describe the effects of the proposed action on socioeconomic and sociocultural conditions, respectively, in the GOM. OCS oil- and gas-related activities have been an important source of employment and income in GOM coastal areas. According to Henry et al. (2002), the nature of blue-collar jobs in the oil and gas industry has been instrumental in the formation and persistence of Cajun culture in South Louisiana. The No Action Alternative would result in reduced employment and income opportunities and potentially could affect the stability and cohesion of communities and cultures. The No Action Alternative could also be interpreted as a boom-bust event. The infrastructure and population of affected areas in the GOM have developed over decades in association with a regular occurrence of lease sales and resulting OCS activities. The No Action Alternative could result in situations in which local infrastructure and populations could not be maintained,

[32] This discussion is based on USEPA (2008a).

[33] For detailed emissions data for power plants, see USEPA (2010d).

8 CONSULTATION AND COORDINATION

8.1 PROCESS FOR THE PREPARATION OF THE 2012-2017 OCS OIL AND GAS LEASING PROGRAMMATIC ENVIRONMENTAL IMPACT STATEMENT

8.1.1 Draft Proposed Program and Draft PEIS

Preparation and review of the draft programmatic environmental impact statement (PEIS) closely paralleled that of the 2012-2017 Outer Continental Shelf (OCS) Oil and Gas Leasing Program (the Program) decision documents. Comments received on the program decision documents were also reviewed for consideration in the preparation of the PEIS.

In January 2009, the previous Administration published a Draft Proposed Program (DPP) and a Notice of Intent (NOI) to prepare a programmatic environmental impact statement (PEIS) that requested comments from States, local governments, Native groups, federally recognized tribes, the oil and gas industry, Federal agencies, and other interested individuals and groups and set out a schedule for scoping meetings in the areas of the DPP. In February 2009, the Secretary of the Interior extended the comment period on the DPP and postponed the scoping meetings to allow time to consider further public comment before determining which areas in the DPP should be scoped and analyzed for consideration in subsequent program proposals. A preliminary revised Program was proposed on March 31, 2010.

8.1.2 Scoping for the Draft PEIS

An NOI to prepare and scope the Program PEIS was published in the *Federal Register* (75 FR 16828) on April 2, 2010. That NOI invited the public to provide comments on the scope and content of the PEIS and identified as many as 14 locations where public scoping meetings might be held.

On June 30, 2010, Secretary of the Interior Salazar announced that the public scoping meetings would be postponed in response to the Deepwater Horizon (DWH) incident. The additional time would be used to evaluate safety and environmental requirements of offshore drilling. On December 1, 2010, Secretary Salazar announced an updated oil and gas strategy for the OCS. The new strategy continued a moratorium for areas in the Eastern Gulf of Mexico (GOM) and eliminated the Mid-Atlantic and South Atlantic Planning Areas from consideration for potential sales and development through the 2017 planning horizon. The Western GOM, Central GOM, Cook Inlet, Chukchi Sea, and Beaufort Sea OCS Planning Areas would continue to be considered in the PEIS. Subsequently, on January 4, 2011, a Notice of Scoping Meetings for the proposed 2012-2017 OCS oil and gas leasing program PEIS was published in the *Federal Register* (76 FR 376) and a second scoping period was conducted from January 6, 2011, through March 31, 2011. During this scoping period, public scoping meetings were scheduled for 12 locations in the GOM (three locations), Alaska (eight locations), and Washington, D.C. The scheduled Alaska meetings for Point Hope and Point Lay were not held because of inclement

Proposed Final Outer Continental Shelf Oil & Gas Leasing Program 2012-2017

June 2012

U.S. Department of the Interior
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Rocky Mountain (PADD IV): Colorado, Idaho, Montana, Utah, and Wyoming
Pacific (PADD V): Alaska, Arizona, California, Hawaii, Nevada, Oregon, and Washington

*Offshore production in state waters is included with onshore production for each PADD. Federal OCS production is not included in the PADDs.
** Natural gas is often used as a fuel in offshore production.
***2009 Data. 2010 State Energy Totals not available at time of document.

Sources:
Oil Production- http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm
OCS Oil Production - http://www.boemre.gov/stats/OCSproduction.htm
Gas Production - http://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGM_mmcf_a.htm
OCS Gas Production - http://www.boemre.gov/stats/OCSproduction.htm
Oil Consumption - http://www.eia.gov/dnav/pet/pet_cons_psup_dc_r50_mbbl_a.htm
Gas Consumption - http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_m.htm
Total Energy Consumption – http://www.eia.gov/state/seds/sep_use/notes/use_print2009.pdf
OCS crude oil and natural gas production -
http://www.eoearth.org/files/156001_156100/156002/ocsproduction2010_doi.xls
Petroleum conversion factors -
http://www.eia.gov/kids/energy.cfm?page=about_energy_conversion_calculator-basics#oilcalc
2010, million Btu per barrel (5.8)
Natural gas conversion
factors: http://www.eia.gov/kids/energy.cfm?page=about_energy_conversion_calculator-basics#oilcalc
2010, Btu per cubic foot (1,025)

In the United States, almost half of the total inter-PADD petroleum product movements by pipeline, tanker, or barge in 2011 were from the Gulf Coast (PADD 3), an area with significant refining capacity, to the East Coast (PADD 1), a major population center. For crude oil, nearly two-thirds (341,576 Mbbl per year) of inter-PADD movements by pipeline, tanker, or barge were movements from Gulf Coast (PADD 3) to the Midwest (PADD 2). These volumes include crude oil produced in the GOM and imports to the Gulf Coast region that move inland to refineries in the Midwest. As pipeline receipts of Canadian oil sands crude oil and increased production from North Dakota's Bakken formation have bolstered Midwest crude oil supplies in recent years, the volume of crude oil moving by pipeline from the Gulf Coast to the Midwest has steadily declined. This increase in crude oil to the Midwest from sources other than the GOM has reduced its need for crude oil supplies from the Gulf Coast. Still, overall the vast majority of the inter-regional crude oil pipeline movements occur among the states of the Midwest, Gulf Coast and Rocky Mountain PADDs, with very little crude oil pipeline activity into or out of the East and West Coasts.

Alternatives to the Contribution of OCS Oil and Natural Gas

In the Five Year EIS, the term No Action Alternative (NAA)[49] refers to the No Sale Option for all program areas. In the NAA, no new OCS leasing would take place for at least 5 years and domestic oil and natural gas production would be reduced appreciably since replacements for depleting offshore fields would be delayed for at least that long. If no OCS oil and gas lease sales were held during the period covered by the new Five Year Program, energy markets would find substitutes to satisfy most of the demand that would

[49] See additional discussion in Net Economic Value section, below.

have been met by production resulting from the oil and natural gas resources made available by the additional lease sales to be held under the program. In an environment of strong worldwide demand for oil and natural gas, a domestic supply cut equivalent to the production anticipated to result from a new Five Year Program would lead to a slight increase in world oil prices and a relatively larger increase in U.S. natural gas prices. All other things being equal, this would lead to a market response providing increases in imported oil and natural gas and greater production of domestic onshore oil and natural gas, coal, and other energy substitutes. It would lead to a small reduction in the total amount of natural gas consumed in the United States, with oil consumption rising slightly.[50] Most of the foregone production would be replaced by other sources. The net result in the United States would be a slight reduction in oil and natural gas consumed, a substantial increase in oil imports, and added supplies provided by onshore hydrocarbon resources.

BOEM uses its *Market Simulation Model* (*MarketSim*) to estimate the amount and percentage of substitutes the economy would adopt should a particular program area not be offered for lease. *MarketSim* is based on authoritative and publicly available estimates of price elasticities of supply and demand and substitution effects. Elasticity measures the sensitivity of consumers or producers to changes in product price.

Table 9 demonstrates how energy markets would compensate in the event the NAA were implemented. Under the mid-price scenario of $110 per barrel and $7.38 per mcf, 68 percent of the oil and natural gas production foregone from this program would be replaced by greater imports, 16 percent by increased onshore production, 5 percent by a switch to coal, 3 percent by increased electricity from other sources, 2 percent by a switch to other energy sources, and 6 percent by a reduction in consumption.[51] Without the expected production from the Five Year Program, 10 billion BOE (BBOE) over 40 to 50 years would be deferred and offset by increased supplies from other energy sources. These energy sources would increase as follows: oil and natural gas imports by 6.8 BBOE (equal to current U.S. imports for almost 1.5 years), onshore oil and natural gas production by 1.6 BBOE (equal to almost half a year of current onshore production), and other energy sources by 1.0 BBOE. Consumption of oil and natural gas would be expected to decline by 0.6 BBOE (equal to less than 2 months of current U.S. oil and gas consumption) spread over the next 40 to 50 years.

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[50] This increase in oil consumption reflects the fact that oil and natural gas are substitutes within the industrial sector and, to a lesser extent, the residential and commercial sectors. The loss of a given amount of OCS production is likely to result in greater increases in natural gas prices than in oil prices, because the price of oil is largely decided in the world market while the price of natural gas is largely set in smaller regional markets. Therefore, as natural gas prices increase under the NAA compared to the exploration and development (E&D) scenarios due to reduced OCS production, consumption of substitutes, including oil, increases. The increase in oil prices under the NAA may cause some offsetting substitution in the opposite direction, from oil to natural gas, but the impact of increased natural gas prices is the more dominant of the two effects.

[51] Total does not sum to 100 percent due to independent rounding and conversion to equivalent units of energy (e.g., Btu to BOE).

Table 9: Results of No Action Alternative (No New Program)

Energy Sector	Quantity (BBOE) over 40 years	Percent of OCS Production Replaced
Onshore Production	**1.6**	**16**
Onshore Oil	0.1	1
Onshore Natural Gas	1.5	15
Imports	**6.8**	**68**
Oil Imports	5.9	60
Natural Gas Imports	0.9	9
Coal	**0.5**	**5**
Electricity from sources other than Coal, Oil, and Natural Gas	**0.3**	**3**
Other Energy Sources	**0.2**	**2**
Reduced Demand	**0.6**	**6**

Given its relative ease of transport, oil prices are set on the world market. Natural gas is not as easily transported, thus its prices are influenced much more by regional supply. Therefore, in the absence of production from a new Five Year Program, U.S. natural gas prices would increase proportionally more than oil prices. Based on *Marketsim* results, this would result in substitution away from natural gas and toward oil and other energy sources.

The distribution of reduced consumption and switching to alternative sources by sector depends largely on the amount of consumption and relative price elasticities of demand across the sectors. The transportation and industrial sectors accounted for almost 95 percent of U.S. oil consumption (approximately 72 and 23 percent of oil respectively) in 2010. Residential and commercial consumption accounted for the residual 5 percent. Other forms of energy cannot readily substitute for most of the oil and natural gas consumed in the transportation and industrial sectors in the near term. In the U.S. transportation sector, a decline in oil consumption would likely be the result of a reduction in miles traveled and/or the purchase of more fuel efficient vehicles. In addition to the modest price increase associated with these scenarios, the cost of developing an alternative fuel infrastructure hinders efforts to extend the use of alternative transportation fuels, although automobile companies have unveiled and/or announced plans for new gasoline-electric hybrid, plug–in hybrid, and electric vehicles.

A detailed discussion of the model and alternative sources of energy in the context of the PFP for 2012-2017 appears in *Energy Alternatives and the Environment* (BOEM 2012-021), which can be found with other program documents at http://www.boem.gov.

OCS Study
BOEM – 2012-022

Economic Analysis Methodology for the Five Year OCS Oil and Gas Leasing Program for 2012-2017

June 2012

Prepared by

Economics Division of the Bureau of Ocean Energy Management

June 2012

United States Department of the Interior
BUREAU OF OCEAN ENERGY MANAGEMENT
Washington, DC

Environmental and Social Costs

The oil spill rates used in the environmental and social costs calculations from the OECM were changed to consider historical data from 1996-2010. This new study period includes recent trends and makes the Proposed Final Program analysis consistent with the Programmatic EIS.

The air emission factors were updated for the OECM. These new factors were based on a more in-depth analysis of the air quality data. In addition, the model now also calculates round-trip emissions for tankers carrying both imports and Alaskan oil to the continental U.S. The model also includes separate emissions factors to account for differences in impacts between platforms and caissons. Tables of the emissions factors are included in the OECM documentation (Industrial Economics, Inc. et al., 2012a).

Consumer Surplus

The MarketSim model was adjusted to net out all consumer surplus that represents a transfer from domestic producer surplus for each of the modeled fuels. This is discussed in the section titled Netting out Domestic Producer Surplus.

The MarketSim documentation is being published along with this document. The documentation provides more technical information on the elasticities and how price changes, energy market substitutions, and reduced demand are calculated (Industrial Economics, Inc., 2012b).

Unmonetized Impacts

The Net Benefits analysis captures the important costs and benefits associated with new OCS leasing that can be reliably estimated. However, there are other potential impacts that cannot be monetized which are discussed below.

Greenhouse Gas Emissions

The OECM monetizes air emissions factors for six different pollutants (NO_x, SO_x, PM_{10}, $PM_{2.5}$, CO, and VOCs), but it does not apply a monetary value on the damages of greenhouse gas (GHG) emissions. The model does calculate the level of emissions that would be emitted under both the program and the NSOs for carbon dioxide, methane, and nitrous oxide. Most of the GHG effect will occur with consumption rather than production of oil and gas which changes little between the program and NSO scenarios.

Moreover, because GHG are global pollutants, an estimate of discharges stemming from the NSO includes emissions from the production of oil and gas that is imported to the U.S. and from the round-trip tanker voyages that are necessary to transport the oil to the U.S. Table 7 shows the estimates of GHG emissions by program area for the mid-price case. As shown in the table, the emissions for carbon dioxide and nitrous oxide are greater under the NSOs than from the program. However, there is more methane from the program than the NSOs. Though these impacts are not monetized, they are not identical between having an OCS program and having the impacts of the NSOs.

Table 7: Greenhouse Gas Emissions

	Program Emissions			NSO Emissions			Difference		
	thousands of tons								
	CO_2	CH_4	N_2O	CO_2	CH_4	N_2O	CO_2	CH_4	N_2O
Central GOM	79,907	867	2.22	234,080	157	2.42	-154,173	711	-0.20
Western GOM	21,410	285	0.53	54,164	36	0.56	-32,755	249	-0.02
Eastern GOM (2 Sales)	615	9	0.02	2,939	2	0.03	-2,324	7	-0.01
Chukchi Sea	4,324	28	0.11	57,760	40	0.62	-53,436	-12	-0.51
Beaufort Sea	1,485	11	0.03	11,570	8	0.12	-10,086	3	-0.09
Cook Inlet	760	6	0.02	5,240	4	0.06	-4,480	2	-0.04

* These values are the OECM results for the mid-price case with prices of $110 per barrel and $7.83 per mcf.

Unmonetized Costs

Passive Use Values

In general, the Net Benefits analysis includes cost estimates of many types of use values, but does not include some values that would be associated as nonuse or passive use values. Evidence of nonuse values can be found in the trade-offs people make to protect or enhance environmental resources that they do not use. Nonuse or passive use values exist under both the program and under the energy substitutes that would be necessary under the NSO.

Within the Net Benefits analysis, certain passive-use or nonuse values are not qualitatively captured. The various types of nonuse values are:

- Option value means that an individual's current value includes the desire to preserve the opportunity to use a resource in the future.

- Bequest value refers to an individual's value for having an environmental resource available for his or her children and grandchildren to experience. It is based on the desire to make a current sacrifice to raise the well-being of one's descendants. Bequest value is not necessarily equivalent to the value of any information gained as a result of delaying leasing activities.

- Existence value means that an individual's utility may be increased by the knowledge of the existence of an environmental resource, even though the individual has no current or potential direct use of the resource.

Altruistic value occurs out of one individual's concern for another. A large body of literature discusses studies of these values. However, the extent to which these estimates are transferrable to the BOEM context is probably quite limited. The values were developed using stated preference techniques and the results from such analysis are often highly dependent on the resource and specific context (which would include resource conditions, possible improvements or degradation as a result of policy changes, payment vehicles, etc.). If one were interested in evaluating the extent to which households or individuals hold nonuse values (or a bequest value in particular) for OCS oil and gas

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Consumer Surplus and Energy Substitutes for OCS Oil and Gas Production: The Revised Market Simulation Model (MarketSim)

Model Description

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by

Industrial Economics, Incorporated
2067 Massachusetts Avenue
Cambridge, MA 02140

model also increases the granularity with which it models production and consumption. Each fuel is modeled separately for residential, commercial, industrial, and transportation demand with the own-price and cross-price elasticity specific to each submarket and fuel.[1] Additionally, each fuel's production is modeled at a more detailed level than solely based on domestic onshore, domestic offshore, and import sources. This complexity allows MarketSim to simulate changes in prices and the resulting substitution effects between fuels as OCS oil and gas production increases.

Model Description

What follows is the general framework for MarketSim's economics-based model representation of U.S. energy markets. The model simulates end-use domestic consumption of oil, natural gas, coal and electricity in four sectors (residential, commercial, industrial and transportation); primary energy production; and the transformation of primary energy into electricity. The model mostly represents U.S. energy markets, but it also captures interaction with world energy markets as appropriate.

As a point of departure for scenario analyses, MarketSim is calibrated to reproduce a specified baseline projection, such as the reference case in the Energy Information Administration's (EIA) *Annual Energy Outlook (AEO)* or other output produced by the EIA's National Energy Modeling System (NEMS), for the baseline projection. The user-specified offshore production scenario then is added to the production side of the market equilibration, and the model adjusts prices until all markets converge on a new equilibrium.

Baseline Supply and Demand Projections

The baseline supply and demand projections in MarketSim were obtained from a customized model run of EIA's NEMS model.[2] The standard NEMS runs conducted for EIA's *AEO* series assume the issuance of new leases for OCS oil and natural gas production. Given that the purpose of MarketSim is to assess the market impacts of new leases relative to a scenario without new leasing, these new leases should not be included in the MarketSim baseline. Thus, the customized NEMS runs developed for use in MarketSim deviated from the reference case in the *AEO* by removing new offshore leasing on the OCS off the lower 48 states from the model's calculations.[3] The results of this NEMS run constitute the baseline data incorporated into the model.

While the customized NEMS run includes no new leasing on the OCS off the lower 48, EIA was unable to develop a NEMS scenario that restricted new leasing on the Alaska OCS. Given the structure of NEMS' oil and gas module for Alaska, it was not possible to limit offshore Alaskan production in the model. The baseline data in MarketSim therefore reflect some new leasing activity in the Alaska OCS Region. If BOEM is able to estimate the quantity of offshore oil and gas production likely in Alaska

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[1] The exception to this is coal. Given that coal consumption is dominated by the electricity and industrial sectors, MarketSim does not estimate changes in coal consumption for the residential and commercial sectors.

[2] This NEMS projection forecasts production and consumption through the year 2030. For a description of how this forecast was extrapolated through 2064, see Industrial Economics, Inc., 2012. *Offshore Environmental Cost Model (OECM) and Market Simulation Model (MarketSim) User Guides,* prepared for BOEM.

[3] See supporting documentation accompanying the delivery of the NEMS output, "Alternate Scenarios of Energy Markets under Various Offshore Crude Oil and Natural Gas Resource Assumptions," attachment of letter from Howard Gruenspecht, Acting EIA Administrator, to Walter D. Cruickshank, Acting Director. Mineral Management Service, 4 June 2009. The data incorporated into MarketSim are from the "Constrained Supply" scenario described in this document.

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Energy Alternatives and the Environment

By

William E. King
Economist

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U.S. Department of the Interior
Minerals Management Service
Environmental Division

Herndon, VA

3.5. Non-Energy Uses

Natural gas, primarily methane, is also used as a chemical feedstock. Among the products made from natural gas are chemicals like methanol, ammonia, and formaldehyde that are converted into final products like fertilizer, detergents, and glues.

4. The No Action Alternative

The National Environmental Policy Act requires consideration of a No Action Alternative to every major Federal action significantly affecting the environment. In the case of the 5-Year Program, no action means that the MMS would hold no OCS oil and gas lease sales during the 5-year period covered by the Program. An absence of lease sales means production firms do not obtain rights to new oil and natural gas resources on the OCS. As a result, the oil and natural gas that would have been produced as a consequence of sales over that 5-year period would not be available to consumers.

This section reports the results of an investigation into the most likely response of oil and natural gas markets to a curtailment of their supplies from the OCS and the ensuing environmental impacts. Under these assumptions, markets would have to respond to a reduction in supply equal to the anticipated production from the 5-Year Program. Note that in a typical year almost two-thirds of OCS production on a Btu basis consists of natural gas (MMS 2001). The other one-third or so is oil and NGL's.

4.1. Methodology

The MMS employs the MktSim2000 model to evaluate the impact of decreased OCS production resulting from no action. The MktSim2000 estimates changes in quantities of alternatives to OCS natural gas and oil traded in domestic markets. This same model, which includes oil and gas submodels, also performs other analyses used in the development of the 5-Year Program. A more detailed description of the market simulation model can be found in a companion paper to this one (King 2001).

4.2. Market Response to a Reduction in OCS Production

The MMS ran the market simulation model for cases representing all program alternatives with both low-moderate and high price assumptions. The purpose of these runs was to demonstrate the response of oil and gas markets to a reduction in OCS production under a variety of circumstances. The low-moderate price case is based on prices of $18 per barrel of oil and $2.11 per mcf of gas. The high price case uses prices of $30 per barrel of oil and $3.52 per mcf of gas. The results for the different program alternatives are virtually identical.

82
OCS Report
MMS 96-00

Energy Alternatives and the Environment

Revised August 1996

Prepared By
William E. King

U.S. Department of the Interior
Minerals Management Service **Herndon, VA**

IV.B.2 Results for Natural Gas

Table 4 also reveals that for each unit of OCS gas not produced because of no action, MMS anticipates the following results:

- U.S. onshore gas production will increase by about 0.41 units
- imports will increase by about 0.12 units
- conservation will account for about 0.14 units
- switching to oil will amount to the equivalent of about 0.33 units

In absolute terms at the most likely price this amounts to:

- 4.58 trillion cubic feet of onshore gas
- 1.34 trillion cubic feet of gas imports (mostly from Canada)
- conservation equivalent to 1.56 trillion cubic feet of gas
- switching to oil equivalent to 3.68 trillion cubic feet of gas

substituting for the 11.16 trillion cubic feet of OCS natural gas lost through no action.

In absolute terms at the high price this amounts to:

- 13.45 trillion cubic feet of onshore gas
- 3.94 trillion cubic feet of gas imports (mostly from Canada)
- conservation equivalent to 4.59 trillion cubic feet of gas
- switching to oil equivalent to 10.83 trillion cubic feet of gas

substituting for the 32.81 trillion cubic feet of OCS natural gas lost through no action.

Of the reduced consumption of natural gas at the most likely price, the equivalent of about 3.68 trillion cubic feet of gas would consist of switching to oil. This means that an additional 0.65 billion barrels of oil would clear the market. Assuming that imports constitute 88 percent of any additional oil traded in the U.S. market, then this adds another .57 billion barrels of oil to imports. Thus, as a result of no action, an additional 3.45 billion barrels of oil would have to be imported by the U.S. The corresponding import estimate for the high price case is 8.78 billion barrels of oil. Table 5 shows these calculations in detail.

IV.C Environmental Impacts from the Market Response to a Reduction in OCS Production

IV.C.1 Onshore Oil and Gas Production

Onshore oil and gas production often occur together from the same wells; furthermore, the impacts from efforts to recover the two resources are almost identical even in those cases

Groundwater can be contaminated from puncture of the aquifer or from leaching down from improperly sealed surface holding ponds or overflow of those ponds onto permeable surfaces. In many areas, sufficient interchange occurs between surface and groundwater sources that pollution of one leads to the contamination of the other.

For the most part, surface disturbance from oil and gas development is sufficiently limited that it causes relatively minor negative impacts on wildlife. A large portion of the negative impact on wildlife comes through water pollution and the impacts on wildlife living in or drinking from a water supply contaminated by oil and gas extraction activities. However, holding ponds can pose a significant threat to birds, especially waterfowl. Improperly safeguarded holding ponds can prove to be attractive to waterfowl and other birds looking for a safe resting and feeding location. Birds landing on these ponds may drown when the action of solvents in the pond material destroys the buoyancy of the birds' feathers.

Soil and vegetative disturbance is mostly a result of construction activities. However, soils can become contaminated and vegetation killed by spills of herbicidal chemicals.

Air pollution, noise, and odors are a consequence of the production process. Local standards usually control these impacts, but additional oil and gas production can increase cumulative levels of these forms of pollution.

IV.C.2 Imports

Significant environmental impacts associated with expanded importation of oil include:

- the generation of greenhouse gases and regulated air pollutants from both transport and dockside activities (emissions of NO_x, SO_x, and VOCs having an impact on acid rain, tropospheric ozone formation, and stratospheric ozone depletion)
- degradation of water quality in the instances of oil spills from either accidental or intentional discharges or tanker casualties
- possible destruction of flora and fauna and recreational and scenic land and water areas in the instance of oil spills
- public fear of the increased likelihood of oil spills.

Of these, the most significant are likely to be the impacts associated with oil spills. Table 6 shows by region the estimated additional spills greater than 1000 barrels associated with the no action alternative, along with their probabilities.

The environmental impacts from oil spills are well documented in the EIS for the 5-Year Program. While it is uncertain where the spills associated with additional imports will occur, the impacts will be similar to those associated with OCS production except that the risk of very large spills is enhanced by the use of large tankers to import oil. Compared to OCS

UNITED STATES DEPARTMENT OF THE INTERIOR

Office of the Secretary
Washington, D.C. 20240

February 14, 1980

Memorandum

To: The Secretary

Through: Executive Secretariat

From: Deputy Assistant Secretary--Policy, Budget and Administration

Subject: 5-Year OCS Leasing Program

BACKGROUND

The 5-year OCS leasing program is being prepared pursuant to Section 18 of the OCS Lands Act, as amended. Under the process established by that section, you are now asked to decide upon and transmit to the President and the Congress your proposed final program.

This step follows the preparation of your proposed program last June and its transmittal to the Congress, the Attorney General, and the Governors of the affected coastal States, and general availability for public comment. The proposed final program shall be accompanied by any comments received on the June program, along with an indication of why any specific recommendation of the Attorney General or a State or local government regarding that program was not accepted. Subsequent to your decision, a separate document will be prepared for transmittal to the President and the Congress which will represent the proposed final program. As discussed later, a substantial number of comments were received from State and local governments. The Attorney General did not comment.

Your present decision also follows BLM's preparation of a draft environmental statement (DES) on the leasing schedule, comment by interested parties on the DES, and preparation of a final environmental statement (FES). The FES was submitted to EPA on January 18, 1980, and EPA announced its availability on January 28, 1980. A Secretarial Issue Document (SID) has also been prepared to assist you in reaching your decision. In addition to using the SID in reaching your decision, you should carefully consider the treatment given many of the same issues in the FES. To assist you in this, extensive references to appropriate parts of the FES are made throughout the SID. The SID and the FES are attached. A summary of the comments received on the FES will be provided to you by separate memorandum.

The variety and geographic diversity of possible effects encompasses the wide spectrum of marine, coastal, and human resources which are differentially put at risk as a result of different levels of activity and different emphasis in geographic locations in each of the schedules. The Group 2 schedules significantly reduce or delay environmental effects off Alaska compared to the Group 1 schedules. There would be less disruption of Alaskan Native subsistence culture; less likelihood of disturbance of Alaskan endangered species, including the Bowhead whale; and lessened competition between the fishing and oil and gas industries for Alaska's port space and wharfage.

In schedules VIII and IX, these lesser effects off Alaska are simply reductions from the Group 1 potential. In NRDC, some additional offsetting effects can be expected in the Gulf of Mexico where substitute sales are scheduled, but these effects are not of the same potential magnitude as those avoided, because of less expected production and environmental sensitivity. Also, NRDC provides added protection to California and the North Atlantic by delaying or omitting sales in those areas.

Alternatives involving schedules from Group 1 would only be environmentally preferable if the adverse environmental effects of oil imports were greater than those of OCS production. Adoption of a Group 2 or 3 schedule would increase the possibility of spills from tankering of foreign oil, while selection of a Group 1 schedule would lessen, but not eliminate such effects. There is some evidence to suggest that substituting OCS oil production for tankered imports reduces the risk of very large oil spills along U.S. coasts. However, the estimates of oil spills greater than 1,000 barrels which appear in the FES and SID pertain to potential spills from OCS operations only and do not reflect changes in spills of foreign oil from tankers in U.S. waters due to backing out of imports by OCS production. While continued OCS leasing may ultimately prove to be environmentally superior, especially in light of improvements in environmental protection in OCS activities, the more conservative approach at this point is to regard the schedules of Group 2 and 3 as being environmentally preferable because they, in themselves, are less likely to damage the environment from oil spills than the schedules in Group 1.

Although it is necessary to identify the environmentally preferable alternative or alternatives, implementation of an environmentally preferable alternative is not necessarily most advantageous to the nation. Factors other than environmental effects, such as law or national policy should be considered. For example, section 102 of the 1978 Amendments to the OCS Lands Act specifies, inter alia, that the purposes of the Act are to

> preserve, protect, and develop oil and natural gas resources in the Outer Continental Shelf in a manner which is consistent with the need (A) to make such resources available to meet the needs as rapidly as possible, (B) to balance orderly energy resource development with protection of the human, marine, and coastal environments, (C) to insure the public a fair and equitable return on the resources of the Outer Continental Shelf, and (D) to preserve and maintain free enterprise competition....

U.S. Energy Information Administration

PETROLEUM & OTHER LIQUIDS

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- Crude Oil Production

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Federal Offshore--Gulf of Mexico Field Production of Crude Oil

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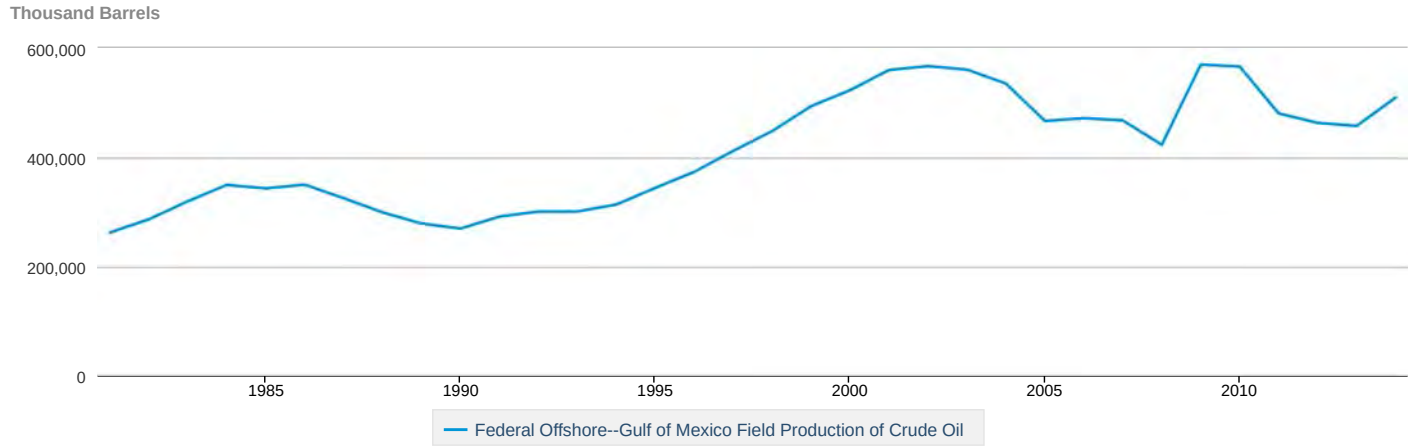

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Federal Offshore--Gulf of Mexico Field Production of Crude Oil (Thousand Barrels)

Decade	Year-0	Year-1	Year-2	Year-3	Year-4	Year-5	Year-6	Year-7	Year-8	Year-9
1980's		262,518	286,725	319,717	349,857	343,443	350,328	325,517	299,460	278,927
1990's	269,804	291,755	300,909	301,118	313,822	344,318	373,644	412,168	448,388	494,064
2000's	523,250	560,485	567,420	561,065	535,355	466,926	472,017	467,971	423,326	570,302
2010's	566,626	480,701	463,429	457,874	509,976					

- = No Data Reported; -- = Not Applicable; NA = Not Available; W = Withheld to avoid disclosure of individual company data.

Release Date: 1/29/2016
Next Release Date: 8/31/2016

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Federal Offshore PADD 5 Field Production of Crude Oil

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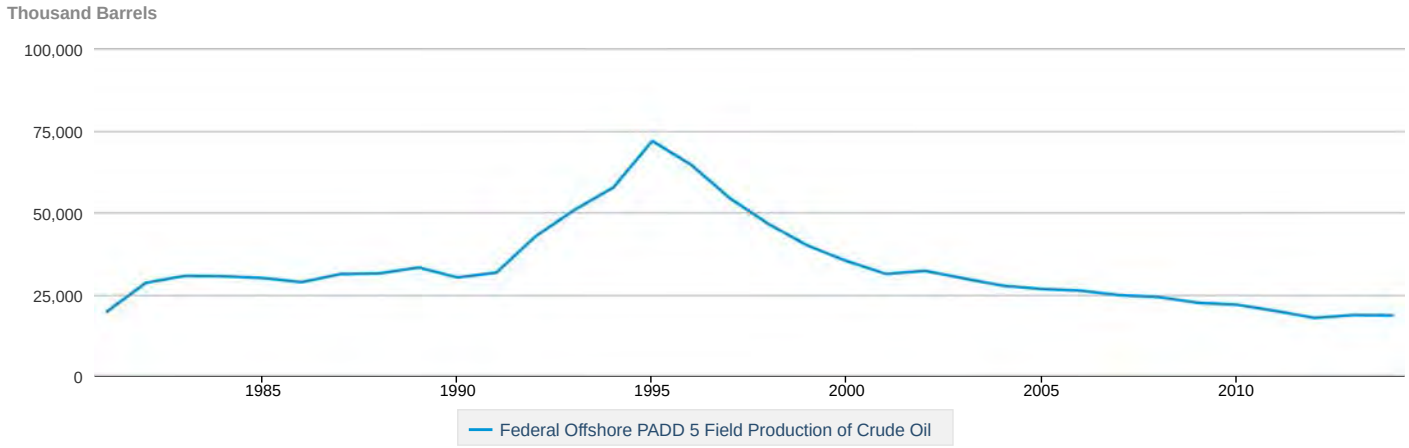

Source: U.S. Energy Information Administration

This series is available through the EIA open data API and can be downloaded to Excel or embedded as an interactive chart or map on your website.

Federal Offshore PADD 5 Field Production of Crude Oil (Thousand Barrels)

Decade	Year-0	Year-1	Year-2	Year-3	Year-4	Year-5	Year-6	Year-7	Year-8	Year-9
1980's		19,588	28,396	30,527	30,399	29,875	28,606	31,090	31,284	33,076
1990's	30,031	31,519	42,552	50,639	57,509	71,709	64,419	54,135	46,233	39,702
2000's	34,992	31,103	32,064	29,738	27,509	26,507	25,987	24,624	24,029	22,306
2010's	21,708	19,817	17,679	18,559	18,482					

- = No Data Reported; -- = Not Applicable; NA = Not Available; W = Withheld to avoid disclosure of individual company data.

Release Date: 1/29/2016
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Production | Consumption | Capacity | Bunker Fuels | Stocks | Reserves | Imports | Exports | CO2 Emissions | Heat Content

Country: World Start Year: 1982 End Year: 1982 UPDATE

Product: Crude Oil including Lease Condensate Unit: Thousand Barrels Per Day

Production of Crude Oil including Lease Condensate (Thousand Barrels Per Day) Units Conversion Download Excel

	1982
World	53454

Footnotes:

-- = Not applicable
(s) = Value is too small for the number of decimal places shown
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All Flows | Production | Consumption | Reserves | Imports | Exports | Carbon Dioxide Emissions | Heat Content

Country: World, United States Start Year: 2010 End Year: 2010 UPDATE

Product: Total Primary Coal Production Unit: Thousand Short Tons

Total Primary Coal Production (Thousand Short Tons) Units Conversion Download Excel

	2010
United States	1084368
World	7999455

Footnotes:

-- = Not applicable
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All Flows | Production | Consumption | Reserves | Imports | Exports | Carbon Dioxide Emissions | Heat Content

Country: United States Start Year: 2010 End Year: 2010 UPDATE

Product: Total Coal Unit: Thousand Short Tons

Total Coal Exports (Thousand Short Tons) Units Conversion Download Excel

	2010
United States	83178

Note: Import and export data for natural gas in BTUs is currently unavailable as we improve our methodology for this calculation. We will repost the data once this effort is complete.

Footnotes:

-- = Not applicable
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the lowest-estimated northern and southern alternative Tongue River Railroad capital cost as representative of all northern and southern alternatives. This choice results in the production of greater amounts of Tongue River coal than could be induced if OEA had used the higher cost estimate (i.e., it tends to overstate the production of Tongue River coal).

- **Coal displacement.** OEA concluded that Tongue River coal production would substantially displace other U.S. coal production. For example, if Tongue River coal production is 20 million tons, total U.S. coal production would only increase by 1 million tons due to the displacement of other coal production. From 2018 to 2037, across all 21 scenarios, on average, every ton of Tongue River coal produced would displace 0.76 ton of other Powder River Basin coal. Due to displacement of non-Powder River Basin coal, 0.95 ton of total U.S. coal, including Powder River Basin coal, would be displaced.

  The range of displacement would be from 0.57 ton (scenario 14) to 0.88 ton (scenario 4) per ton of other Powder River Basin coal, and from 0.90 ton (scenario 14) to 1.00 ton (scenario 3) of other U.S. coal per ton of Tongue River coal. In other words, for each ton of Tongue River coal produced, production of other Powder River Basin coal would decrease by an average of 0.76 ton and production of other U.S. coal would decrease by an average of 0.95 ton. Therefore, due to the displacement of the production of other coal, production of Tongue River coal would cause total U.S. coal production to increase, on average, by 1.4 million tons per year from 2018 to 2037 (1.4 million tons per year = 4.6% x 30.6 million tons per year).

  The increase in Powder River Coal production would range from an annual average of 2.4 million tons (scenario 4) to 14.8 million tons (scenario 20) and the increase in other U.S. coal production would range from zero (scenario 3) to 3.8 million tons (scenario 11). Single-year changes in U.S. production relative to the scenarios under the No-Action Alternative would range from a decrease of 2.7 million tons per year (scenario 12, in 2030) to an increase of 8.8 million tons per year (scenario 11, in 2018). The increase of up to 8.8 million tons per year would be small in comparison to total U.S. and world coal consumption.

  Under the six No-Action Alternative scenarios, U.S. coal production would average 1.04 billion tons per year, and would range from 0.97 billion tons per year (scenario 26) to 1.12 billion tons per year (scenario 2). Therefore, the average increase of 1.4 million tons per year in the action scenarios would be equal to approximately 0.13% of total U.S. coal production, and the maximum average annual increase of 3.8 million tons year per increase would equate to approximately 0.36% of total U.S. coal production. Both of these increases would be small relative to total U.S. coal production levels.

  Tongue River coal production would have an even smaller incremental effect on world coal production, which is projected to average 11.4 billion tons per year from 2018 to 2037. The small impact on U.S. and world coal production reflects two factors. First, the cost advantage of producing Tongue River coal would be significant enough to

out-compete other coals, but would not be significant enough to noticeably lower delivered coal prices (which includes transportation), and thus, would not increase total demand for coal. This, in turn, is partly because the minemouth price is often less than half the delivered cost for coal originating in the Powder River Basin. Second, the quantities involved would be small compared to the size of the U.S. coal market, and any impact on total incremental demand for coal would be small.

- **Coal exports.** OEA concluded that exports of Tongue River coal would range from 0.0% (scenarios 3 to 6, 9, 12 to 18, and 21 to 23) to 53% (scenario 20) of Tongue River coal production. On average, from 2018 to 2037, 4% of Tongue River coal would be exported. The overall tons of Powder River Basin coal exported in each of the 21 scenarios—within the low, medium, and high port capacity growth scenarios—remains the same; however, the mix of coal changes based on the economics of the different Powder River Basin coals.

  The amount of Tongue River coal exported would be low across most scenarios because other Powder River Basin coals with higher heat content would be more competitive for export. However, coal distribution would be sensitive to terminal capacity growth and the maximum amount and type of Tongue River coal production. Under the two scenarios with high Tongue River coal production and high terminal capacity growth (scenarios 11 and 20), the maximum share of annual potentially induced Tongue River coal that would be exported would increase to 38% and 53%, respectively (19 million of 50 million tons per year, scenario 11, and 38 million of 72 million tons per year, scenario 20). Scenario 20 assumes that, under the southern alternatives, exports would include the high-heat content coal from the Canyon Creek deposit.

  OEA's conclusions on exports are based on the 21 scenarios, and assume uncertainties that cannot be fully captured in a modeling framework. For example, the forecasts assume competitive economics and certainty within each scenario. OEA notes, however, that Arch Coal is the developer or co-developer of the Tongue River Railroad, the Otter Creek Mine, and one of the export terminals (Millennium Bulk Terminal). Hence, Arch Coal might choose to export rather than sell domestically when there are opportunities to maximize profits over the suite of assets that include mines, railroads, and export terminals. Although only a portion of Tongue River coal is projected to be exported, all scenarios show that the export terminals would be fully used to export other Powder River Basin coal. In addition, export levels remain the same at the maximum export terminal capacity across pairs of no-action and action scenarios, as Wyoming or other Montana Powder River Basin coal would be exported in lieu of Tongue River coal in the no-action scenarios.

- **Domestic distribution.** OEA concluded that Tongue River coal would be mostly destined for domestic markets. For all 21 scenarios, from 2018 to 2037, an average of 96% of Tongue River coal would be shipped domestically; the remaining 4% would be exported. Annual domestic distribution of Tongue River coal would range from 47 to 100% and annual exports would range from zero to 53%.

United States
Department of
Agriculture

Forest Service

Colorado
National Forests

November 2015

Rulemaking for Colorado Roadless Areas

Supplemental Draft Environmental Impact Statement

Colorado National Forests with roadless areas include:
Arapaho and Roosevelt; Grand Mesa, Uncompahgre, and Gunnison; Manti-La Sal (portion in Colorado); Pike and San Isabel; Rio Grande; Routt; San Juan; and White River National Forests

concentrations of GHG that cause climate change. The reasonably foreseeable quantity of GHGs makes this an important consideration of human-caused emissions. However, climate change will continue happening, regardless of this project or any other single project.

The overall estimated GHG emissions (including carbon dioxide, methane, and nitrous oxide) from reasonably foreseeable activities associated with the proposed rule range from about 13.7 to 43.2 million metric tons of per year. The average scenario is 28.1 million metric tons of CO_2eq annually. Methane accounts for 1.2 to about to 6.3 million metric tons CO_2eq, with an average scenario of 4.2 million metric tons of CO_2eq. To put this into context, the GHG footprint from the U.S. Forest Service business operations (including vehicles, building energy use, employee air and ground travel, and employee commuting) is approximately .3 million metric tons CO_2eq (USDA Forest Service, 2014). Therefore, reasonably foreseeable GHG emissions from future activities are equivalent to approximately 94 times the annual operational GHG footprint of the entire agency. Projected methane emission alone, under the average scenario, is about 14 times the annual GHG footprint from U.S. Forest Service business operations.

The total United States GHG emissions in 2013 were 6,673 million metric tons of CO_2eq. Therefore, the average annual reasonably foreseeable emissions associated with this rule could be the equivalent of .4% of US emissions in 2013. The methane venting component could be equivalent of .06% of US emissions in 2013.

The State of Colorado produced approximately 130 million metric tons of CO_2eq in 2010 from combined sectors of agriculture, waste management, industrial processes, gas production, coal mining and abandoned mines, residential and commercial fuel use, transportation, and electric power (CODEPH, 2014). Therefore, the average reasonably foreseeable annual emissions associated with the proposed rule could be equivalent to 22% of Colorado's 2010 GHG emissions. Some of these emissions would occur within Colorado and some outside of Colorado. The methane venting component, which would occur within the State, would be equivalent to about 3.1% of Colorado's 2010 GHG emissions.

It is important to consider that inventory methodology for Colorado's emissions and total U.S. emissions differ from the estimates offered in the Air Resource Report for the proposed action. For example, coal combustion associated with the proposed action may not happen in Colorado, or the United States. Therefore, it is not appropriate to resolve that the proposed action is responsible for a certain percentage of total State or National emissions. However, it is useful information that puts this project in a meaningful context.

There are reasonably foreseeable emissions from subsequent decisions, associated with tree-cutting and other vegetation for surface preparation, including roads and drainage pads. These considerations are significantly smaller than the primary GHG components of mining and venting, transportation, and combustion. Areas of surface disturbance may be revegetated after they are no longer needed. As trees and vegetation reestablish, they will grow and sequester carbon through photosynthesis. It is important to note that U.S. forests (including NFS lands), function as a carbon sink, and effectively offset approximately 13% of national emissions in 2013 (EPA, 2015).

Alternative A

There would be no reasonably foreseeable increase in emissions associated with coal mining, transportation, and combustion associated with this "no-action" alternative. Therefore, there are no

increases to atmospheric concentrations of greenhouse gases. This alternative has no impact on climate change, and climate change has no impact on this alternative.

Climate change is part of the environmental baseline and will continue in the absence of this project. Part of the baseline in the North Fork area includes mining on existing leases that contain an estimated 11.2 million tons of coal, and emissions associated with mining. However, the reduced emissions from choosing this alternative would not likely lessen impacts of climate change.

Alternative B

This alternative has no direct effects on emissions or climate change. However, reasonably foreseeable activities of coal mining, transportation, and combustion would increase the atmospheric concentrations of GHGs. Detailed estimated volumes of GHGs are provided in the air section under various production scenarios. However, it is difficult to estimate how much this will increase concentrations of GHGs, or any climate change impacts described above. Reasonably foreseeable emissions with Alternative B are greater than the other alternatives evaluated in this SDEIS. They are greater than Alternative C because of the duration of the mining activity to 2051. This alternative does not require methane capture, but leaves open the opportunity to evaluate it during subsequent steps of the leasing process. Methane capture or destruction would reduce GHG emissions associated with this alternative.

This alternative would likely have no effect on climate change impacts in CRAs, or other NFS lands. Anthropogenic climate change is not the result of any individual activity, but rather it is the result of many activities spanning many decades.

Alternative C

Alternative C has no direct effects on emissions or climate change. However, reasonably foreseeable activities of coal mining, transportation, and combustion will increase the atmospheric concentrations of GHGs. Detailed estimated volumes of GHGs are provided in the air section under various production scenarios. However, it is difficult to estimate how much this will increase atmospheric concentrations of GHGs, or any climate change impacts described above. Emissions from subsequent activities associated with Alternative C are less than Alternative B, because of the shorter duration of the mining activity through 2036. This alternative does not require methane capture, but leaves open the opportunity to evaluate it during subsequent steps of the leasing process. Methane capture or destruction would reduce the reasonably foreseeable GHGs associated with this alternative.

This alternative would likely have no effect on climate change impacts in CRAs, or other NFS lands. Anthropogenic climate change is not the result of any individual activity, but rather it is the result of many activities spanning many decades.

Threatened, Endangered, Proposed, and Sensitive Species

Analysis Methods

The scope of analysis is different than the other resources in this SDEIS because changed circumstances and new information require re-consultation on the Colorado Roadless Rule. The scope of analysis in this section includes a broad review of the Colorado Roadless Rule to ensure the earlier conclusions about effects to ESA-protected species and Regional Forester sensitive species and habitats still hold today. Consequently, this SDEIS:

United States Department of State
Bureau of Oceans and International
Environmental and Scientific Affairs

Final Supplemental Environmental Impact Statement

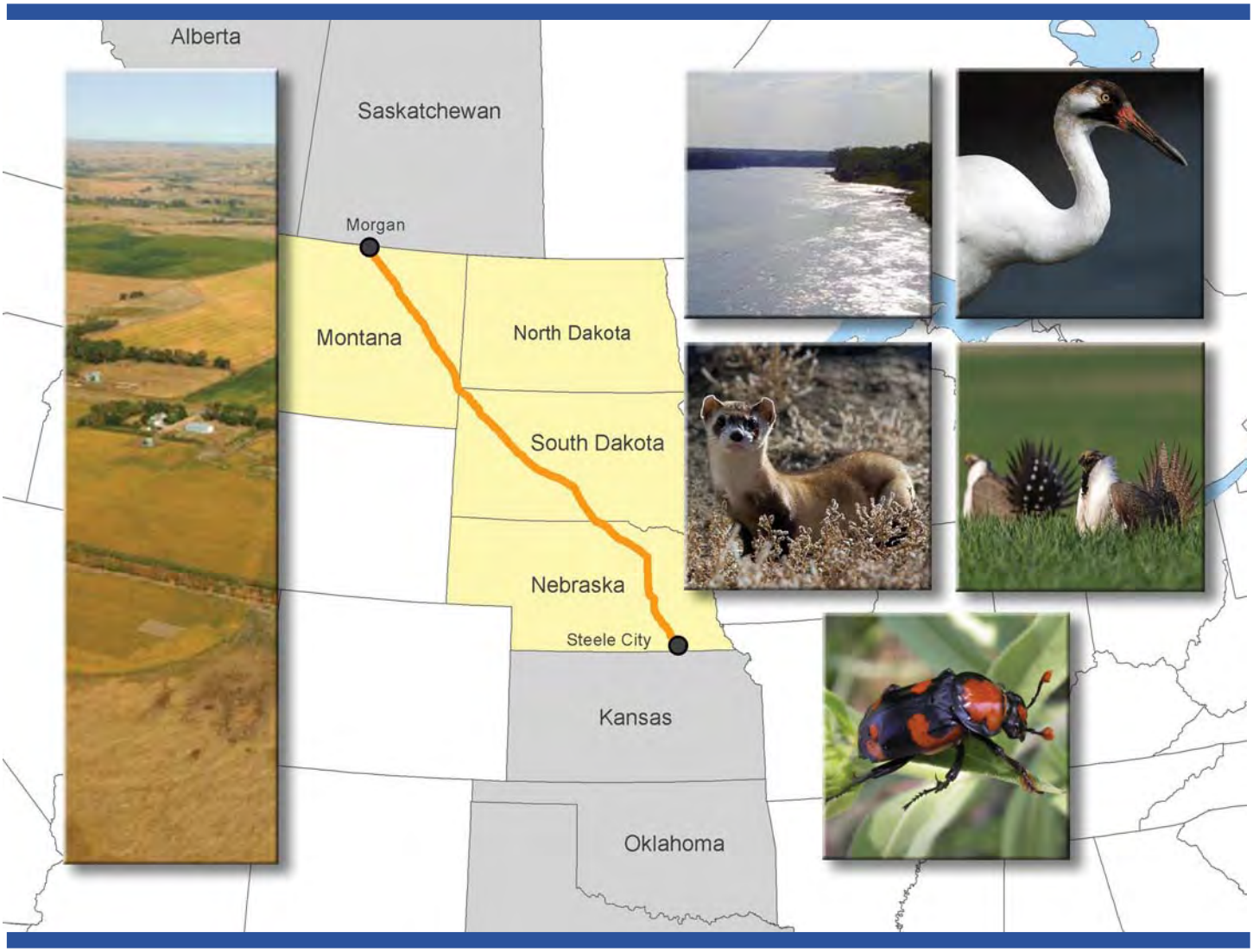
for the

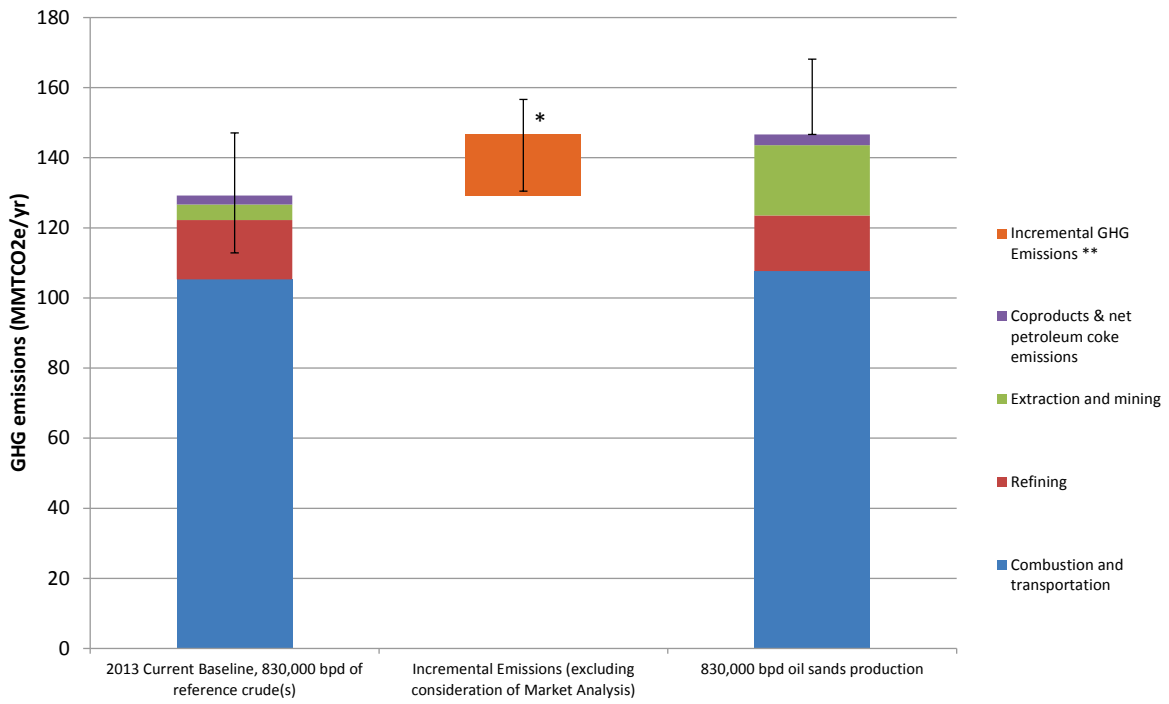
Keystone XL Project

Executive Summary

January 2014

Applicant for Presidential Permit: TransCanada Keystone Pipeline, LP





**** Note: The orange bar represents incremental emissions. The bar itself is for a single crude (Mexican Maya) from the TIAX study. The range bar is representative of all studies and reflects the 1.3 to 27.4 MMTCO2e annual incremental emissions presented in the Final Supplemental EIS.***

***** Incremental Emissions: This represents the difference between the 2013 Current Baseline and the 830,000 bpd Oil Sands Production, and excludes consideration of the Market Analysis. These Incremental Emissions represent the potential increase in emissions attributable to the proposed Project if one assumed that approval or denial of the proposed Project would directly result in a change in production of 830,000 bpd of oil sands crudes in Canada. However, as set forth in Section 1.4, Market Analysis, such a change is not likely to occur.***

Note: See Figure 4.14.3-7 in Section 4.14.3.5, Incremental GHG Emissions, for a full description of the information presented in this figure.

Figure ES-10 Incremental Well-to-Wheels GHG Emissions from WCSB Oil Sands Crudes Compared to Well-to-Wheels GHG Emissions from Displacing Reference Crudes

The above estimates represent the total incremental emissions associated with production and consumption of 830,000 bpd of oil sands crude compared to the reference crudes. These estimates represent the potential increase in emissions attributable to the proposed Project if one assumed that approval or denial of the proposed Project would directly result in a change in production of 830,000 bpd of oil sands crudes in Canada (See Section 4.14.4.2, Emissions and Impacts in Context, for additional information on emissions associated with increases in oil sands production). However, as set forth in Section 1.4, Market Analysis, such a change is not likely to occur under expected market conditions. Section 1.4 notes that approval or denial of any one crude oil transport project, including the proposed Project, is unlikely to significantly impact the rate of extraction in the oil sands or the continued demand for heavy crude oil at refineries in the United States based on expected oil prices, oil-sands supply costs, transport costs, and supply-demand scenarios.

The 2013 Draft Supplemental EIS estimated how oil sands production would be affected by long-term constraints on pipeline capacity (if such constraints resulted in higher transportation costs) if long-term WTI-equivalent oil prices were less than $100 per barrel. The Draft Supplemental EIS also estimated a change in GHG emissions associated with such changes in production. The additional data and analysis included in this Supplemental EIS provide greater insights into supply costs and the range of prices in which pipeline constraints would be most likely to impact production. If WTI-equivalent prices fell to around approximately $65 to $75 per barrel, if there were long-term constraints on any new pipeline capacity, and if such constraints resulted in higher transportation costs, then there could be a substantial impact on oil sands

production levels. As noted in E.S.3.1, Summary of Market Analysis, this estimated price threshold could change if supply costs or production expectations prove different than estimated in this analysis. This is discussed in Section 1.4.5.4, Implications for Production.

ES.4.1.3 Climate Change Effects

The total direct and indirect emissions associated with the proposed Project would contribute to cumulative global GHG emissions. However, emissions associated with the proposed Project are only one source of relevant GHG emissions. In that way, GHG emissions differ from other impact categories discussed in this Supplemental EIS in that all GHG emissions of the same magnitude contribute to global climate change equally, regardless of the source or geographic location where they are emitted.

As part of this Supplemental EIS, future climate change scenarios and projections developed by the Intergovernmental Panel on Climate Change and peer-reviewed downscaled models were used to evaluate the effects that climate change could have on the proposed Project, as well as the environmental consequences from the proposed Project.

Assuming construction of the proposed Project were to occur in the next few years, climate conditions during the construction period would not differ substantially from current conditions. However, during the subsequent operational time period, the following climate changes are anticipated to occur regardless of any potential effects from the proposed Project:

- Warmer winter temperatures;
- A shorter cool season;
- A longer duration of frost-free periods;
- More freeze-thaw cycles per year (which could lead to an increased number of episodes of soil contraction and expansion);
- Warmer summer temperatures;
- Increased number of hot days and consecutive hot days; and
- Longer summers (which could lead to impacts associated with heat stress and wildfire risks).

This Supplemental EIS assessed whether the projected changes in the climate could further influence the impacts and effects attributable to the proposed Project. Elevated effects due to projected climate change could occur to water resources, wetlands, terrestrial vegetation, fisheries, and endangered species, and could also contribute to air quality impacts. In addition, the statistical risk of a pipeline spill could be increased by secondary effects brought on by climatic change such as increased flooding and drought. However, this increased risk would still be much less than the risk of spills from other causes (such as third-party damage). Climate change could have an effect on the severity of a spill such that it could be reduced in drought conditions but increased during periods of increased precipitation and flooding.

ES.4.2 Potential Releases

The proposed Project would include processes, procedures, and systems to prevent, detect, and mitigate potential oil spills.

Many commenters raised concerns regarding the potential environmental effects of a pipeline release, leak, and/or spill. Impacts from potential releases from the proposed Project were evaluated by analyzing historical spill data. The analysis identified the types of pipeline system components that historically have been the source of spills, the sizes of those spills, and the distances those spills would likely travel. The resulting potential impacts to natural resources, such as surface waters and groundwater, were also evaluated as well as planned mitigation measures designed to prevent, minimize, and respond to spills.

ES.4.2.1 Historical Pipeline Performance

In response to numerous comments regarding pipeline performance, the Department analyzed historical incident data within the PHMSA and National Response Center incident databases to understand what has occurred with respect to crude oil pipelines and the existing Keystone Pipeline system.

Table ES-1 summarizes hazardous liquid pipeline incidents reported to the PHMSA across the United States from January 2002 through July 2012 and shows the breakdown of incidents by pipeline component. A total of 1,692 incidents occurred, of which 321 were pipe incidents and 1,027 were involving different equipment components such as tanks, valves, or pumps.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

JUL 16 2010

ASSISTANT ADMINISTRATOR
FOR ENFORCEMENT AND
COMPLIANCE ASSURANCE

Mr. Jose W. Fernandez
Assistant Secretary
Economic, Energy, and Business Affairs
U.S. Department of State
Washington, DC 20520

Ms. Kerri-Ann Jones
Assistant Secretary
Oceans and International Environmental and Scientific Affairs
U.S. Department of State
Washington, DC 20520

Dear Mr. Fernandez and Ms. Jones:

The Environmental Protection Agency (EPA) has reviewed the Draft Environmental Impact Statement (Draft EIS) for the Keystone XL project pursuant to our authorities under the National Environmental Policy Act (NEPA), Council on Environmental Quality (CEQ) NEPA regulations (40 CFR Parts 1500-1508), and Section 309 of the Clean Air Act.

We appreciate the substantial efforts by the State Department to solicit broad expert and public input to analyze the potential environmental impacts of the Keystone XL project, and believe the Draft EIS provides useful information and analysis. However, we think that the Draft EIS does not provide the scope or detail of analysis necessary to fully inform decision makers and the public, and recommend that additional information and analysis be provided. The topics on which we believe additional information and analysis are necessary include the purpose and need for the project, potential greenhouse gas (GHG) emissions associated with the project, air pollutant emissions at the receiving refineries, pipeline safety/spill response, potential impacts to environmental justice communities, wetlands and migratory birds.

Project Purpose and Need/Alternatives

We are concerned that the Draft EIS uses an unduly narrow purpose and need statement, which leads to consideration of a narrow range of alternatives. The Draft EIS considers issuance of a cross-border permit for the proposed project and to a limited extent, the no-action alternative (i.e., denying the permit). By using a narrow purpose and need statement, the Draft EIS rejects other potential alternatives as not meeting the stated project purpose. While we recognize that an objective of the applicant's proposal is to construct a pipeline to transport oil sands from Canada to Gulf Coast refineries in the United States, we believe the purpose and need to which the State

Department is responding is broader. Accordingly, EPA recommends that the State Department frame the purpose and need statement more broadly to allow for a robust analysis of options for meeting national energy and climate policy objectives.

In evaluating the need for the project and its alternatives, we also recommend that the discussion include consideration of different oil demand scenarios over the fifty-year project life. This would help ensure that the need for the project is clearly demonstrated. The Draft EIS uses one demand scenario that indicates that with permit denial, the demand for crude oil would continue at a rate such that U.S. refineries "would continue to acquire crude oil primarily from sources other than Canada to fulfill this demand and/or find alternative methods of delivery of Canadian oil sands." We recommend that this discussion be expanded to include consideration of proposed and potential future changes to fuel economy standards and the potential for more widespread use of fuel-efficient technologies, advanced biofuels and electric vehicles as well as how they may affect demand for crude oil.

In addition, we are concerned that the Draft EIS does not fully analyze the environmental impacts of the no-action and other alternatives, making a comparison between alternatives and the proposed project more difficult. EPA believes it is important to ensure that the differences in the environmental impacts of non-Canadian crude oil sources and oil sands crude be discussed. Alongside the national security benefits of importing crude oil from a stable trading partner, we believe the national security implications of expanding the Nation's long-term commitment to a relatively high carbon source of oil should also be considered.

GHG Emissions

The Draft EIS estimates GHG emissions associated with construction and operation of the pipeline itself and the refining process, although not the GHG emissions associated with upstream oil sands extraction intended for this pipeline or downstream end use. In order to fully disclose the reasonably foreseeable environmental impacts on the U.S. of the Keystone XL project, we recommend that the discussion of GHG emissions be expanded to include, in particular, an estimate of the extraction-related GHG emissions associated with long-term importation of large quantities of oil sands crude from a dedicated source. This would be consistent with the approach contemplated by CEQ's recent Draft NEPA Guidance on Consideration of the Effects of Climate Change and Greenhouse Gas Emissions (February 18, 2010).

Extraction and refining of Canadian oil sands crude are GHG-intensive relative to other types of crude oil. Our calculations indicate that on an annual basis, and assuming the maximum volume of 900,000 barrels per day (bpd) of pipeline capacity, annual well-to-tank emissions from the project would be 27 million metric tons carbon dioxide equivalent ($MMTCO_2e$) greater than emissions from U.S. "average" crude.[1] Accordingly, we estimate that GHG emissions from Canadian oil sands crude would be approximately 82% greater than the average crude refined in the U.S., on a well-to-tank basis. To provide some perspective on the potential scale of

[1] 900,000 bpd * (181 kgCO2e/bbl – 99 kgCO2e/bbl) *365 = 27 $MMTCO_2e$/yr. Based on average 2005 crude oil lifecycle GHG emissions estimates in EPA's Renewable Fuel Standard (RFS2) final rule (75 FR 14669); also see DOE/NETL. 2009. Petroleum-Based Fuels Life Cycle Greenhouse Gas Analysis - 2005 Baseline Model.

emissions, 27 million metric tons is roughly equivalent to annual CO_2 emissions of seven coal-fired power plants.[2]

Based on our review, there is a reasonably close causal relationship between issuing a cross-border permit for the Keystone XL project and increased extraction of oil sands crude in Canada intended to supply that pipeline. Not only will this pipeline transport large volumes of oil sands crude for at least fifty years from a known, dedicated source in Canada to refineries in the Gulf Coast, there are no significant current export markets for this crude oil other than the U.S. Accordingly, it is reasonable to conclude that extraction will likely increase if the pipeline is constructed. While we recognize that other pipeline projects are currently being planned that might bring additional pipeline capacity for oil transport should the Keystone XL project not be constructed, these other proposed pipelines appear to still be in the planning stages, and whether and when they will be approved or constructed appears uncertain. We also note that the Draft EIS discusses end use GHG emissions from combustion of refined oil, indicating they would not differ from those of conventional crude. Because they are easily calculated and are of interest to the public in obtaining a complete picture of the GHG emissions associated with the proposed project, it might be helpful to provide a quantitative estimate of these emissions.

In addition, we recommend that the State Department expand the discussion of alternatives or other means to mitigate the emissions. The analysis in the Draft EIS focuses primarily on carbon sequestration benefits that might accrue from re-vegetation measures proposed as mitigation for wetland losses associated with the pipeline. We believe there are a number of other mitigation opportunities to explore, including control of fugitive emissions, pumping station energy efficiency, and use of renewable power, where appropriate. In addition, we recommend that the State Department consider project alternatives that could significantly reduce extraction-related GHG emissions. For example, these alternatives could include a smaller-capacity pipeline or deferring the project until current efforts to reduce extraction-related GHG emissions through carbon capture and storage, improved energy efficiency, or new extraction technologies are able to lower GHG emissions to levels closer to those of conventional crude.

Air Quality Impacts - Refinery Emissions

We appreciate the efforts to predict pollutant emissions from refineries processing crude oil from the proposed project, and recognize that it is likely that some of the oil sands crude from the project would replace declining feedstock at existing refineries, and that some of the oil sands crude would supply newly upgraded or expanded facilities. We also agree with the Draft EIS's conclusion that there may be increases in air emissions from refineries in the area, and we recommend that additional information and analyses be presented to substantiate the conclusion that these increases "would not likely be major (Draft EIS, pp. 3.14-36)." Further, we recommend that additional information be provided concerning potential impacts from emissions associated with events such as start up, shut down, and malfunctions, which are not addressed by existing permits and which may have substantial adverse impacts.

[2] See, http://www.epa.gov/cleanenergy/energy-resources/calculator.html (translating 27 $MMTCO_2e$ to annual coal plant CO_2 emissions).

U.S. Department of the Interior
Office of Surface Mining Reclamation and Enforcement

DRAFT July 2015

Stream Protection Rule
Environmental Impact Statement

the No Action Alternative reduces the level of carbon that is removed from the atmosphere, thus contributing to climate change.

Under the No Action Alternative, air emissions and air quality impacts from coal mining would continue to be regulated under the CAA, and to a lesser extent SMCRA, and would continue to fluctuate with coal mining methods and activity levels. For a more complete discussion of the CAA, please refer to section 3.6.

4.2.4.2 Action Alternatives and Potential Effects on Air Quality, Greenhouse Gas Emissions, and Climate Change

This section identifies the aspects of the Action Alternatives expected to affect air emissions as a result of coal mining and related activities. While the elements of the Action Alternatives as described in Chapter 2 do not directly address air emissions from coal mining activities, implementation of the Action Alternatives may indirectly affect air quality. The requirements of Alternative 9 are not functionally different than the No Action Alternative; most current mining practices are consistent with the now-vacated 2008 SBZ rule and, accordingly, effects of Alternative 9 on air quality are anticipated to be Negligible. All other Action Alternatives have the potential to affect air quality in the following ways:

- **Changes in the amount of earth moving (haulage) required may affect the extent of wind transport of dust ($PM_{2.5}$ and PM_{10}), as well as emissions from mobile sources (combustion engines):** For instance, some Alternatives may require additional movement of surface material around a site, which would be expected to increase vehicle use on some sites. Vehicles are sources of nitrous oxide, carbon dioxide, and particulate matter emissions. Thus, rule elements found in some Action Alternatives may result in increases in air emissions on a per-mine basis. On the other hand, some Action Alternatives reduce overall levels of coal production, which may reduce the generation of dust and emissions from mobile sources.

- **Revegetation and reforestation requirements, as well as requirements to reduce burning of vegetation and other organic materials may reduce the wind transport of dust and increase the carbon sequestration potential of the landscape:** More stringent requirements for reforestation and revegetation of the postmining landscape reduce the extent to which materials are exposed to wind transport and increase the availability of biomass to sequester carbon from the atmosphere. Increased carbon sequestration may have a mitigating effect on the level of greenhouse gases in the atmosphere contributing to climate change. In addition, prohibitions on burning of vegetation and organic matter under the Action Alternatives reduce airborne particulates.

- **Changes in overall levels of surface and/or underground coal production affects: 1) the extent to which overburden is removed, resulting in fugitive methane emissions; 2) the level of activities, such as blasting, that contribute to dust and explosives emissions:** Costs associated with implementing some of the Action Alternatives are expected to affect the overall quantity of coal produced, which would affect the overall impact of coal mining on air quality. Under some Alternatives, the mix of production type, i.e., surface or underground, may also change. As discussed in Chapter 3, surface

and underground mining activities have different emissions profiles; therefore a shift in mine types affects the overall amount of fugitive methane emissions from coal mining. Other coal mining activities, such as vehicle use, wind erosion of soils, and blasting, may also be reduced with a reduction in overall production levels. Accordingly, the negative effects of these activities on air quality would likewise be reduced.

Table 4.2.4-1 summarizes the effects that various rule elements incorporated into the Action Alternatives may affect air quality. The remainder of this section describes the potential direction and magnitude of the expected impacts in each of the coal regions.

Table 4.2.4-1
SPR Elements and Potential Effects on Air Quality, Greenhouse Gases, and Climate Change

SPR Element	Criteria Pollutants and Greenhouse Gases
Baseline Data Collection and Analysis	
Monitoring During Mining and Reclamation	
Definition of Material Damage to the Hydrologic Balance	
Corrective Action Thresholds	
Stream Definitions	
Mining Through Streams	■
Activities In or Near Streams Including Excess Spoil and Coal Refuse	■
AOC Variances	■
Surface Configuration	■
Revegetation, Topsoil Management, and Reforestation	■
Fish and Wildlife Protection and Enhancement	■

The "Criteria Pollutants and Carbon Dioxide" column identifies Action Alternative elements that may: 1) result in additional earthmoving activities, thereby increasing the production of particulate matter and emissions of criteria pollutants from operation of vehicles and other equipment; and/or 2) result in additional vegetated land cover (e.g., reforestation) thereby reducing wind erosion of materials and increasing the carbon sequestration potential of the landscape. In addition to the direct effects of the SPR elements on criteria pollutants and carbon dioxide, indirect impacts on methane and other emissions are also expected. While not associated with any particular rule element, the collective cost burden of implementing the Alternatives may change overall levels of coal production, thus affecting the levels of methane and other air pollutants emitted through the course of coal mining activities. That is, removing overburden to extract coal results in fugitive methane emissions. Consequently, increasing or reducing the level of mining activity likewise increases or reduces emissions. The EPA

Potential Effects on Carbon Sequestration

Each of the Action Alternatives (excluding Alternative 9) specifies additional reforestation/ revegetation and riparian corridor requirements. These changes expedite the return of postmining land to a native forest ecosystem and maintain riparian vegetative. While a primary objective of these requirements is reduction of erosion and sedimentation, trees and other vegetation remove carbon dioxide from the atmosphere and transform the carbon into biomass. This type of carbon sequestration is enhanced by improved and expedited reforestation. Section 4.2.2 evaluates the benefits of the Action Alternative in terms of preserved (forest that is preserved from cutting for mining) and improved (better forest management practices) forest land. The evaluation of the carbon sequestration benefits in this section accordingly reference the reforestation analysis described in Section 4.2.2, as increased forest results in increased carbon sequestration potential.

Social Costs of Carbon

Section 4.2.2 describes the potential climate stabilization benefits of reforestation. Reduced methane emissions likewise contribute to climate stabilization. To the extent that the Action Alternatives influence carbon emissions, they may also influence a variety of socioeconomic outcomes related to climate change, including agricultural productivity, human health, flooding damages, and various ecosystem services. The value of reducing levels of carbon in the atmosphere reflects the avoided damage generated by that carbon if it is present. The Interagency Working Group on the Social Cost of Carbon issued guidelines in 2010, and an update in 2013, to help agencies assess the climate change-related benefits of reducing carbon emissions and integrate these estimates into their assessments of regulatory impacts in cost-benefit analyses (Interagency Working Group on Social Cost of Carbon, 2010 and 2013). The Interagency guidance provides a social cost of carbon (SCC) dollar value based on the average of three specific models. The SCC related to a specific proposed action is calculated by multiplying the change in emissions in that year by the SCC value appropriate for that year. The net present value of the benefits can be calculated by multiplying each of these future benefits by an appropriate discount factor and summing across all affected years.

This analysis does not monetize the methane emissions and increased carbon sequestration effects of the Action Alternatives for multiple reasons. Most fundamentally, data limitations prevent a quantitative analysis of the net effect of each Alternative on carbon emissions from coal mining. As noted earlier, available evidence suggests that the Alternatives would have varying offsetting effects on greenhouse gas emissions. For instance, some Alternatives would result in changes that would increase emissions, such as an increase in the amount of time hauling vehicles are operated. Conversely, some of the same Alternatives would increase the number of acres of forest reestablished or undisturbed annually, which would increase the carbon storage potential when compared to the No Action Alternative.

In addition, the Action Alternatives could influence coal use at power plants and thereby affect the emission of greenhouse gases and associated social costs. Modeling suggests that these Alternatives could decrease national coal production; however, predicting the direction and magnitude of impacts on overall U.S. greenhouse gas emissions is highly complex. The impact depends on factors such as the change in coal prices, the technological flexibility that power producers have to switch to substitute fuels, the price trends for those substitutes, the emissions

profile for those substitutes, changes in coal export markets, and a variety of other considerations.

While this analysis anticipates that the net effect on climate resiliency is positive at the national level under each Action Alternative (excluding Alternative 9), i.e., less carbon in the atmosphere due to increased carbon sequestration and reduced methane emission, data gaps prevent quantifying, and therefore monetizing, the magnitude of this benefit.

4.2.4.5 Summary of Effects

The qualitative and quantitative findings discussed above are synthesized to summarize impacts of the Action Alternatives on air quality, greenhouse gas emissions, and climate change in each coal region. Table 4.2.4-9 provides this summary, using the criteria established in Section 4.0 (Table 4.0.2-1). Importantly, none of the Action Alternatives explicitly target air quality resources. Regardless, implementation of the elements of the Action Alternatives may have both beneficial and adverse effects on air quality, greenhouse gas emissions, and climate change. On the beneficial side, the Alternatives may increase carbon sequestration potential due to reforestation and riparian corridor requirements of Alternatives (except for Alternative 9) and reduce fugitive methane emissions from coal extraction due to reductions in overall production levels (with the exception of Alternatives 2 and 9). However, the Alternatives may also increase the use of equipment and vehicles to haul materials and therefore increase emissions from these sources. While data are not available to quantify the net effect of the Action Alternatives on emissions or ambient air quality, the net effects to air quality, greenhouse gas emissions, and climate change are likely to be Minor Beneficial at the national scale (except under Alternative 9).

An analysis of the effect of changes in coal production on methane emissions shows that the changes in methane emissions by region and nationally are small relative to baseline emissions, constituting less than one-half of one percent of coal mining methane emissions. This effect is beneficial across Alternatives 3, 4, 5, 6, 7, and 8 (Preferred). Alternative 9 results in a negligible difference from No Action with respect to methane emissions. Alternative 2 results in a slight increase in methane emissions at the national level, although this adverse effect is minor in the context of total methane emissions in the region. Furthermore, available data suggest that emissions of other criteria pollutants and carbon dioxide are minor as compared to the methane emissions and therefore marginal changes in these emissions are likely to result in Negligible effects on air quality regionally and nationally. Finally, the increased carbon sequestration potential due to increased forest postmining and riparian corridor requirements is a benefit across all of the Action Alternatives with the exception of Alternative 9.

At a regional scale, beneficial impacts are focused in Appalachia across Alternatives 3, 4, 5, 6, 7, and 8 (Preferred). While a predicted shift from surface to underground production under Alternative 2 may increase methane emissions from coal extraction in Appalachia, this effect is minor and may be offset to some extent by the beneficial effects on air quality of reforestation and riparian corridor requirements (as described in Section 4.2.2). Four other regions are also expected to experience Minor Beneficial effects on air quality from increased reforestation and reduced fugitive methane emissions (Colorado Plateau, Gulf Coast, Illinois Basin, and Northern Rocky Mountains and Great Plains) under Alternatives 2, 3, 4, 7, and 8 (Preferred). The Illinois

Lake Charles Liquefaction Project
Final Environmental Impact Statement

FERC/EIS-0258F

Docket Nos.
CP14-119-000,
CP14-120-000,
and CP14-122-000

August
2015

Federal Energy Regulatory Commission
Office of Energy Projects
Washington, DC 20426

Lake Charles Liquefaction Project
Final Environmental Impact Statement

Trunkline Gas Company, LLC, Lake Charles LNG Company, LLC, and Lake Charles LNG Export Company, LLC

FERC Docket Nos. CP14-119-000, CP14-120-000, and CP14-122-000
DOE Docket Nos. 11-59-LNG and 13-04-LNG
FERC/EIS-0258F, DOE/EIS-0491

Cooperating Agencies:

U.S. Department of Energy

U.S. Coast Guard

U.S. Fish and Wildlife Service

U.S. Army Corps of Engineers

U.S. Department of Transportation

ship operators will be required to install SO_X emission reduction equipment or switch to low sulfur fuels, such as LNG.

If the No-Action Alternative is selected, it could result in the continued use of less clean-burning fossil fuels at levels that might otherwise have been reduced through replacement with LNG; it could also result in the increased consumption of other fossil fuels to satisfy any future growth in demand that might otherwise be addressed in whole or part by LNG. Consequently, the more severe air emissions and other adverse environmental impacts associated with the use of less clean-burning fossil fuels would not be reduced and may increase if the No-Action Alternative were to be adopted, irrespective of the fact that many countries are cognizant of the environmental impacts of these fuels and prefer to use natural gas as an energy source.

There has been a recent renewed interest in nuclear fuel as a source of electric power generation, although the U.S. Energy Information Administration (2014a) estimates the proportion of electricity generated in the United States by nuclear power will decrease from 19 percent to 16 percent by 2040, with actual nuclear generating capacity remaining fairly static over the long term. Whereas global nuclear capacity is still projected to rise, led by China, Korea, India, and Russia (IEA, 2012a, 2014b), regulatory hurdles, public concerns over facility safety and nuclear waste disposal, project costs, and plant construction lead times make it unlikely that sufficient nuclear capacity could be available to serve all the markets targeted by the Lake Charles Liquefaction Project on a compatible timeline. Further, plans for nuclear power generation have been scaled back in some countries, reflecting policy reconsideration following the 2011 accident at the Fukushima Daiichi nuclear power plant near Fukushima, Japan (IEA, 2012a).

Renewable sources may become an increasingly significant factor in meeting future energy demands worldwide. Hydropower is the predominant renewable source for electric power generation, which contributes to more than 16 percent of electricity generation worldwide and about 85 percent of global renewable electricity (IEA, 2014a). The IEA expects hydropower to remain as the predominant renewable energy source through 2035 (IEA, 2013). However, as with nuclear power generation, there are high costs associated with developing substantial hydropower projects and a long development time between project conception and operation. Other promising renewable energy resources include solar, ocean energy, biomass, and wind, as discussed in more detail below.

With respect to solar energy, photovoltaic production is increasing as the cost of photovoltaic systems decreases. Photovoltaic cells have the potential to supplement electric power generation resources. In 2012 solar energy accounted for 2.2 percent of global electricity production (Observ'ER, 2013).

Ocean energy is a largely unexplored renewable resource. Technologies to capture ocean energy are in their infancy, and environmental and engineering considerations are being studied to better understand the implications of placing power-generating facilities in the ocean. In 2012, ocean energy accounted for 0.01 percent of global electricity production (Observ'ER, 2013).

Biomass categories for electric power generation include solid biomass, liquid biomass, biogas, and renewable household waste. Like ocean energy, this is an emerging area of study and biomass research covers diverse applications. For example, researchers are working to accelerate the development of applications that use algal biomass as a fuel source. Burning of wood pellets in Europe for power generation is increasing, and wood pellet exports from the United States to Europe increased to over 3 million short tons per year in 2013 (Energy Information Administration, 2014b). In 2012, biomass

United States Nuclear Regulatory Commission

Protecting People and the Environment

Generic Environmental Impact Statement for License Renewal of Nuclear Plants (NUREG-1437 Vol. 1)

8. Alternatives to License Renewal

[**Prev** | **Next** | **Table of Contents**]

8.1 Introduction

[**Prev** | **Next** | **Table of Contents**]

The Nuclear Regulatory Commission's (NRC's) environmental review regulations implementing the National Environmental Policy Act (NEPA) (10 CFR Part 51) require that the NRC consider all reasonable alternatives to a proposed action before acting on a proposal, including consideration of the no-action alternative. The intent of such a consideration is to enable the agency to consider the relative environmental consequences of an action given the environmental consequences of other activities that also meet the purpose of the action, as well as the environmental consequences of taking no action at all. The information in this chapter does not constitute NRC's final consideration of alternatives to license renewal. Therefore, the rule accompanying this Generic Environmental Impact Statement (GEIS) does not contain any conclusions regarding the environmental impact or acceptability of alternatives to license renewal. Accordingly, the NRC will conduct a full analysis of alternatives at individual license renewal reviews. NRC expects that information contained in this chapter will be used in the analysis of alternatives for the supplemental environmental impact statements prepared for individual license renewals. As defined in Chapter 1, the proposed action is the granting of a renewed license. Additionally, the purpose of such a proposal is to provide an option that allows for power generation capability beyond the term of a current nuclear power plant operating license in order to meet future system generating needs as such needs may be determined by state, utility, and, where authorized, federal (other than NRC) decision makers. This chapter examines the potential environmental impacts associated with denying a renewed license (i.e., the no action alternative); the potential environmental impacts from electric generating sources other than nuclear license renewal; the potential impacts from instituting additional conservation resources to reduce the total demand for power; and the potential impacts from power imports.

The no-action alternative is the denial of a renewed license. In general, if a renewed license were denied, a plant would be decommissioned and other electric generating sources would be pursued if power were still needed. It is important to note that NRC's consideration of the no-action alternative does not involve the determination of whether any power is needed or should be generated. The decision to generate power and the determination of how much power is needed are at the discretion of state and utility officials.

While many methods are available for generating electricity, and a huge number of combinations or mixes can

be assimilated to meet a defined generating requirement, such expansive consideration would be too unwieldy to perform given the purposes of this analysis. Therefore, NRC has determined that a reasonable set of alternatives should be limited to analysis of single, discrete electric generation sources and only electric generation sources that are technically feasible and commercially viable.

To generate this reasonable set of alternatives, NRC included commonly known generation technologies and consulted various state energy plans to identify the alternative generation sources typically being considered by state authorities across the country. From this review, NRC has established a reasonable set of alternatives to be examined in this chapter. These alternatives include wind energy, photovoltaic (PV) cells, solar thermal energy, hydroelectricity, geothermal energy, incineration of wood waste and municipal solid waste (MSW), energy crops, coal, natural gas, oil, advanced light water reactors (LWRs), and delayed retirement of existing non-nuclear plants. NRC has considered these alternatives pursuant to its statutory responsibility under NEPA. NRC's analysis of these issues in no way preempts or displaces state authority to consider and make decisions regarding energy planning issues.

This chapter also includes a discussion of conservation and power import alternatives. Although these alternatives do not represent discrete power generation sources, they represent options that states and utilities may use to reduce their need for power generation capability. In addition, energy conservation and power imports are possible consequences of the no-action alternative. While these two alternatives are not options that fulfill the stated purpose and need of the proposed action *per se* (i.e., options that provide power generation capability), they nevertheless are considered in this chapter because they are important tools available to energy planners in managing need for power and generating capacity.

The potential environmental impacts evaluated include land use, ecology, aesthetics, water quality, air quality, solid waste, human health, socioeconomics, and culture. These impacts are addressed in terms of construction impacts and operational impacts (Tables 8.1 and 8.2 , respectively). This chapter occasionally mentions economic costs of particular alternatives for descriptive purposes; they do not provide a basis for an NRC decision on license renewal. In addition such economic costs may change prior to specific license renewal decisions as improvements occur to particular technologies. Additionally, this chapter discusses the relative construction and operating costs of various technologies where available.

8.2 Environmental Impacts of the No-Action Alternative

[**Prev** | **Next** | **Table of Contents**]

As discussed in the introduction, the no-action alternative is denial of a renewed license. Denial of a renewed license as a power generating capability may lead to a variety of potential outcomes. In some cases, denial may lead to the selection of other electric generating sources to meet energy demands as determined by appropriate state and utility officials. In other cases, denial may lead to conservation measures and/or decisions to import power. In addition, denial may result in a combination of these different outcomes. Therefore, the environmental impacts of such resulting alternatives would be included as the environmental impacts of the no-action alternative. Additionally, a denial of a renewed license would lead to facility decommissioning and its associated impacts; these impacts would also represent impacts of the no-action alternative.

The environmental impacts expected from decommissioning are analyzed in NUREG-0586, *Final Generic Environmental Impact Statement of Decommissioning of Nuclear Facilities* (1988). Consequently, NUREG-0586 represents some of the environmental impacts associated with denial of a renewed license. The

analysis in Section 8.3 is equally applicable to the no-action alternative in that the alternatives analyzed in this section are all possible actions resulting from denial of a renewed license. Therefore, Section 8.3 represents additional impacts of the no-action alternative.

8.3 Environmental Impacts of Alternative Energy Sources

[**Prev** | **Next** | **Table of Contents**]

This section describes the technologies and evaluates the environmental impacts of 13 energy supply or demand alternatives identified by NRC as capable of satisfying the purpose and need of the proposed action [i.e., to provide an option that allows for power generation capability beyond the term of a current nuclear power plant operating license to meet future system generating needs as such needs may be determined by state, utility, and, where authorized, federal (other than NRC) decision makers]. The technologies were selected because they correspond with those generally considered in state energy plans as potential generating technologies, or they were proposed as alternatives to nuclear license renewal in comments to the Draft GEIS. Many of these technologies differ dramatically from nuclear, and it is important to evaluate them using a consistent standard. A reference generating capacity of 1000 MW(e) is used in evaluating environmental impacts, because this is the approximate generating capacity of many nuclear plants.

The section evaluates impacts that could occur during construction (Table 8.1) or operation (Table 8.2) of each alternative technology. Environmental resources considered include land use, ecology, aesthetics, water quality, air quality, human health, socioeconomics, and cultural resources. The tables provide more detailed information, and the text highlights the more important impacts. References are omitted in the text when they are included in the impact tables.

License renewal decisions may vary considerably among states and utilities based on numerous factors, of which environmental factors are but one set. These decisions may be reached by utilities and states prior to NRC involvement. NRC staff evaluated the process used by 10 states with nuclear power plants to decide which electricity supply and demand options to implement. (NRC examined state energy plans of California, Florida, Illinois, Massachusetts, Michigan, Minnesota, New York, Texas, Vermont, and Wisconsin.) NRC determined that integrated resource planning in some form is used in almost all of these states. Nuclear technology and license renewal are not emphasized in most of these plans, which are developed by either state energy offices or state public service commissions. It is apparent in the plans that nuclear generating plants submitted for license renewal would be required to demonstrate the overall benefits of license renewal over alternative technologies before states would approve renewal. The options would include large, central generating stations powered by nonrenewable sources of energy, probably coal or natural gas, or advanced technologies powered by those same fuels. Some states not enamored of conventional nuclear power may be amenable to considering advanced nuclear technologies. Renewable energy sources have the potential to replace at least some of the generating capacity lost through decommissioning nuclear plants. Solar thermal energy, PV cells, wind energy, hydroelectricity, energy crops, and incineration of MSW and wood waste have some potential in most states surveyed. Geothermal energy has potential in states like California where the resource is prevalent.

Besides sources of power generation, other alternatives are mentioned in state energy plans. Demand-side management (DSM) is viewed in every state as a means to help meet electricity forecasts. Other alternatives include end-use conservation and purchases of power from other utility systems in the United States, Canada, or Mexico. While these two alternatives are not options that fulfill the stated purpose and need of the proposed action *per se* (i.e., options that provide power generation capability), they nevertheless are considered in this

BLM

FINAL
Environmental Impact Statement for the Wright Area Coal Lease Applications

Volume 1 of 2
Chapters 1 - 4

West Loadout Facilities
Black Thunder Mine, Wyoming

Elk on Reclaimed Rangeland
Jacobs Ranch Mine, Wyoming

Elk on Reclaimed Rangeland
Black Thunder Mine, Wyoming

Loadout Facilities in Porcupine Creek Valley
North Antelope Rochelle Mine, Wyoming

Wyoming State Office – High Plains District

NATIONAL SYSTEM OF PUBLIC LANDS

July 2010

If the LBA tract is leased and mined under the Proposed Action, the potential additional state revenues would range from about $574 million to $687 million. For Alternative 2, BLM's preferred alternative, the potential additional state revenues would range from about $629 million to $753 million.

The base of economic activity provided by wages and local purchases would continue for up to about 3.6 additional years, depending on which alternative is selected.

3.17.1.2.2 No Action Alternative

Under the No Action Alternatives, the North Hilight Field, South Hilight Field, West Hilight Field, West Jacobs Ranch, North Porcupine, and South Porcupine coal lease applications would be rejected and the potentially recoverable coal included in an LBA tract under the Proposed Action or Alternative 2, BLM's preferred alternative, would not be recovered and the economic benefits associated with mining that coal would not be realized by the state or federal government. Currently approved mining operations and associated economic benefits would continue on the existing Black Thunder Mine leases, but would cease between 1.6 and 7.1 years earlier than under the Proposed Actions or Alternative 2 for the North, South, and West Hilight Field LBA Tracts. Currently approved mining operations and associated economic benefits would continue on the existing Jacobs Ranch Mine leases, but would cease between 16.7 and 22.8 years earlier than under the Proposed Action or Alternative 2 for the West Jacobs Ranch LBA Tract. Currently approved mining operations and associated economic benefits would continue on the existing North Antelope Rochelle Mine leases, but would cease between 3.3 and 7.8 years earlier than under the Proposed Actions or Alternative 2 for the North and South Porcupine LBA Tracts. Job losses, both those directly associated with the mines, as well as those secondary jobs supported by the mines, would occur following the cessation of operations.

As discussed in Section 2.2, a decision to reject the LBA lease applications at this time would not preclude an application to lease the tracts in the future.

3.17.2 Population

3.17.2.1 Affected Environment

Campbell County's population rose from 33,698 in 2000 to an estimated 40,473 in July 2008. This represents a 23 percent growth since 2000 and makes Campbell County the second fastest growing county in the state (following only Sublette County, which ranked fifth in growth in the nation between July 2006 and July 2007). Campbell County's population ranks it as the third most populous of Wyoming's 23 counties (U.S. Census Bureau 2008).

The majority of the three applicant mines' employees and support services reside in Gillette and Wright. It is estimated that the total population in the