

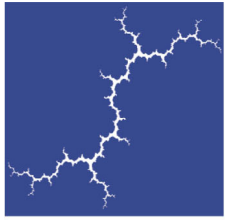
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APPENDIX 1



Synapse
Energy Economics, Inc.

Declining Markets for Montana Coal

**Prepared for the Northern Plains
Resource Council**

March 1, 2013

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1. Executive Summary

Arch Coal, a global coal producer and marketer, has announced plans to develop the Otter Creek mine in the area of Ashland, Montana, and has submitted an application to the U.S. Department of Transportation's Surface Transportation Board to construct a new rail line to connect the Otter Creek mine to an existing BNSF rail line.

The Otter Creek mine claims it will produce 20 million tons of coal per year. Like other Northern Powder River Basin mines, Otter Creek coal is high in sodium, with concentrations ranging from 5.8 to 8.8 percent, much higher than the 1.2 percent typical of the Southern Powder River Basin. Because sodium causes slagging problems at power plants, demand for the coal is limited.¹ The few plants within Otter Creek's competitive area that currently accept high-sodium coal are primarily located in the upper Midwest in Minnesota, Wisconsin, and Michigan.²

Domestic demand for coal has declined by 14 percent since its historical peak in 2007, and the future of coal for U.S. power generation is uncertain at best.³ According to the U.S. Energy Information Administration (EIA), only five new coal units were added in 2012, versus 50 coal unit retirements.⁴ The steadily worsening outlook for coal is primarily a result of the following factors:

- **Coal has lost its cost advantage.** Falling prices of natural gas coupled with higher mining and transportation costs for coal have eroded coal's competitiveness, leading to less frequent dispatch of coal units and lower demand for coal. Over the past decade, coal's net generation decreased by ten percent, while natural gas increased by nearly 50 percent.⁵ Little new coal capacity is likely to be added over the coming decades.⁶
- **Large numbers of coal plants are retiring in response to environmental regulations.** Strict new environmental regulations would require substantial new capital investments and increase operating costs for coal plants. This has led to coal plants across the country becoming uneconomic and announcing retirement, or converting to other fuel sources. Recent estimates project that a significant portion of the current coal fleet—up to 77 gigawatts—will retire by 2020.
- **Otter Creek has a limited number of potential customers, and these coal plants are becoming uneconomic.** High sodium content limits Otter Creek's customer base,⁷ and many of these potential customers may retire or convert to other fuels due to the high costs of complying with new environmental regulations—in fact, several have already

¹ Boiler slag is the molten bottom ash produced in wet bottom boilers.

² Norwest Corporation. 2006. *Otter Creek Property Summary Report*. Salt Lake City: Norwest Corporation.

³ EIA Form 923, Schedule 5A, 2007, 2011.

⁴ Based on preliminary data for 2012 from the EIA published in *Electric Power Monthly*. 24 January 2013. <http://www.eia.gov/electricity/monthly/backissues.html>

⁵ EIA. 2001-2012. Form 923, Schedule 5A.

⁶ EIA. 2012 Annual Energy Outlook. http://www.eia.gov/forecasts/aeo/MT_electric.cfm

⁷ The high sodium content of Otter Creek coal (and other Northern PRB coal) causes slagging problems in boilers. See footnote 3.

announced their retirements.⁸ Our analysis shows that the majority of these plants will be uneconomic compared both to the costs of operating existing natural gas plants and to the total costs of constructing and operating new natural gas plants.

- **Renewable portfolio standards, energy efficiency policies, and the likelihood of future carbon limits are reducing demand for coal.** Standards and goals for renewable energy are increasing the amount of renewables on the grid and heightening demand for natural gas as a complementary energy source due to its ability to adjust output much more quickly than coal. At the same time, increasingly aggressive energy efficiency investments are lowering energy demand across the board. Finally, a future price on carbon would drastically lower demand for coal, with generation falling to as little as 4 percent by 2040 under a carbon fee of \$25.⁹ Many utilities and planning commissions are already factoring carbon prices into their planning.

The long-term viability of coal is severely threatened. Demand for coal is falling across the United States, and Otter Creek's coal market is further limited by the coal's high sodium content and connection to Northern, rather than Southern rail lines. In short, it is unreasonable to expect that there will be much, if any, domestic demand for Otter Creek coal when the mine becomes operational in 2017. There is, therefore, no justification for expanding rail transportation infrastructure to connect the Otter Creek coal mine to struggling domestic markets.

2. Introduction

Domestic demand for coal has declined by 14 percent since its historical peak in 2007, and the future of coal for U.S. power generation is uncertain at best.¹⁰ According to the U.S. Energy Information Administration (EIA), only five new coal units were added in 2012, versus 50 coal unit retirements.¹¹

Several factors are reducing the nation's demand for coal. Falling costs of substitutes such as natural gas and renewable energy have eroded coal's cost advantage in much of the United States. A combination of new and more stringent environmental regulations has turned the tables on the profitability of coal plants across the nation, many of which now face difficult decisions among installing expensive environmental retrofits, converting to natural gas, or shuttering completely. On top of this, energy efficiency and the economic crisis have slowed electricity demand growth rates to a fraction of what they were during the heyday of coal plant construction. In many states, renewable portfolio standards are accelerating the transition away from coal to wind, solar, hydroelectricity, and biomass, as well as highlighting the advantages of natural gas's quick ramping ability for balancing intermittent resources. All of these factors have led to falling demand for coal and pose a serious threat to coal's long-term viability in the United States.

⁸ See footnote 35.

⁹ EIA. 2012 Annual Energy Outlook www.eia.gov/pressroom/presentations/sieminski_01142013.ppt

¹⁰ EIA Form 923, Schedule 5A, 2007, 2011.

¹¹ Based on preliminary data for 2012 from the EIA published in *Electric Power Monthly*. 24 January 2013. <http://www.eia.gov/electricity/monthly/backissues.html>

This report summarizes some of the key domestic energy trends and projections that are expected to challenge all U.S. coal producers in the coming decades, and highlights the obstacles facing the developers of the Otter Creek coal mine in Montana.

The Otter Creek Project

Arch Coal, a global coal producer and marketer, has announced plans to develop the Otter Creek mine in the area of Ashland, Montana, and has submitted an application to the U.S. Department of Transportation's Surface Transportation Board to construct a new rail line to connect the Otter Creek mine to an existing BNSF rail line.

The Otter Creek mine claims it will produce 20 million tons of coal per year. Like other Northern Powder River Basin mines, Otter Creek coal is high in sodium, with concentrations ranging from 5.8 to 8.8 percent, much higher than the 1.2 percent typical of the Southern Powder River Basin. Because sodium causes slagging problems at power plants, demand for the coal is limited.¹² The few plants within Otter Creek's competitive area that currently accept high-sodium coal are primarily located in the upper Midwest in Minnesota, Wisconsin, and Michigan.¹³

This report discusses several challenges facing the Otter Creek project, including:

- Coal electric generating capacity and generation per year will decrease in the future because of environmental costs, higher costs for coal, low natural gas prices, and, in all likelihood, greenhouse gas regulations.
- As a result, U.S domestic coal use will decline, increasing competitive pressures in the mining industry.
- Montana coal is at a relative disadvantage relative to Wyoming and other Southern Powder River Basin coals and, therefore, will likely see an even greater drop in production.

There is therefore no compelling justification for the expansion of transportation infrastructure for Montana coal based on domestic demand projections.

3. The Rapid Shift Away from Coal

U.S. coal is produced primarily for electricity generation; nearly 93 percent of coal consumed in the United States in 2011 was used by the electric power sector.¹⁴ For many years, coal's dominant position in electricity generation was unrivaled. In the late 1990s, more than half of the electricity generated in the United States came from coal. By April 2012, this share had declined to 33 percent—nearly equivalent to that of natural gas. Figure 1 shows this decline of approximately 1 percent per year over the past decade, which began even prior to 2009 when natural gas prices

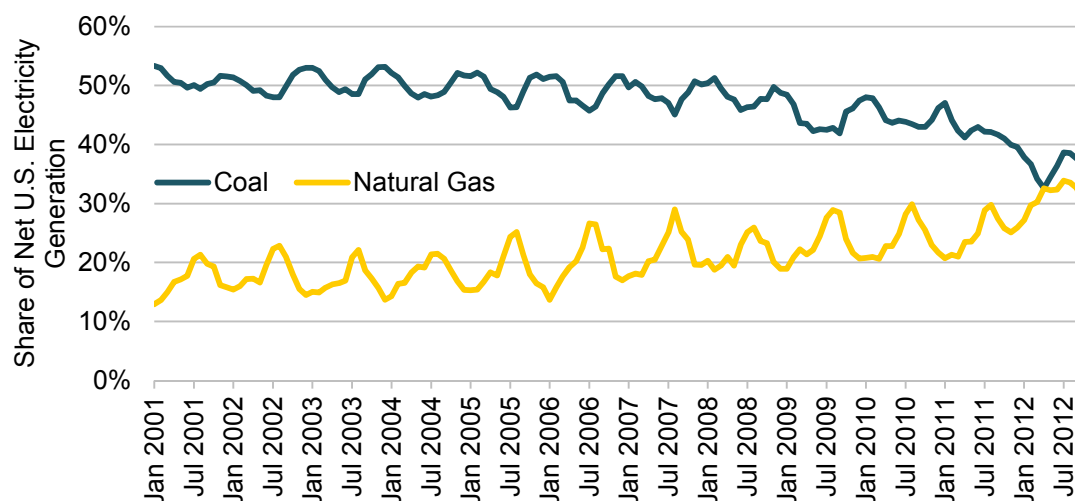
¹² Boiler slag is the molten bottom ash produced in wet bottom boilers.

¹³ Norwest Corporation. 2006. *Otter Creek Property Summary Report*. Salt Lake City: Norwest Corporation.

¹⁴ EIA. 2012. *Quarterly Coal Report: July-September 2012*. Washington, DC: U.S. Department of Energy. <http://www.eia.gov/coal/production/quarterly/pdf/qcr.pdf>

were much higher. Both natural gas prices and coal use rose slightly in 2012, but have not returned to their pre-2009 levels.

Figure 1. Share of Monthly Net U.S. Electricity Generation by Coal and Natural Gas, Jan. 2001 to Nov. 2012



Source: EIA Form 923, Schedule 5A, 2001 - 2012

Mining operations in the Powder River Basin, including those owned by Arch Coal, have not been impervious to this decline in coal consumption. From 2011 to 2012, the volume of coal sold by Arch Coal declined 11 percent as the company “idled equipment until coal market fundamentals improve.”¹⁵ Westmoreland Coal and Cloud Peak Energy, owners of several coal mines near the Otter Creek mine, also faced declining demand in 2012. While production steadily increased to nearly 20 million tons a year at Cloud Peak’s Spring Creek mine from 2006 to 2010, mine production has declined by nearly 11 percent in the past two years.¹⁶ Both companies cite lower natural gas prices as a primary factor driving reduced domestic demand.¹⁷

While coal production has declined in nearly every region of the United States over the past year, Montana coal producers have suffered a greater percentage decline in demand than the national average, and nearly twice as great a decline as that of lower-sodium Wyoming coal. In the 52 weeks ending on February 11, 2013, production declined by 8.7 percent nationally but fell by 11.4 percent in Wyoming and 21.4 percent in Montana.¹⁸

¹⁵ Arch Coal. 2013. 10-K Filing to the Securities and Exchange Commission. <http://www.sec.gov/>

¹⁶ According to Cloud Peak Energy’s 2013 10-K Filing to the Securities and Exchange Commission (<http://www.sec.gov/>), annual production at the Spring Creek mine declined from 19.3 million tons in 2010 to 17.2 million tons in 2012.

¹⁷ Westmoreland Coal. 2012. 10-Q: For the Quarterly Period Ended September 30, 2012. http://www.westmoreland.com/library/2012_SEC_Filings/Westmoreland_Coal_Co_September_10-Q_as_filed_November_8_2012.pdf; Cloud Peak Energy. 2013. 10-K to the Securities and Exchange Commission. <http://www.sec.gov/>

¹⁸ EIA. February 14, 2013. Weekly U.S. Coal Production Overview (DOE/EIA 0218/06). <http://www.eia.gov/coal/production/weekly/>

Coal's decline can be attributed to a number of factors, including competition from substitutes, loss of customers due to more stringent environmental regulations, policy support for renewable energy, and energy efficiency investments. These factors are discussed in greater detail below.

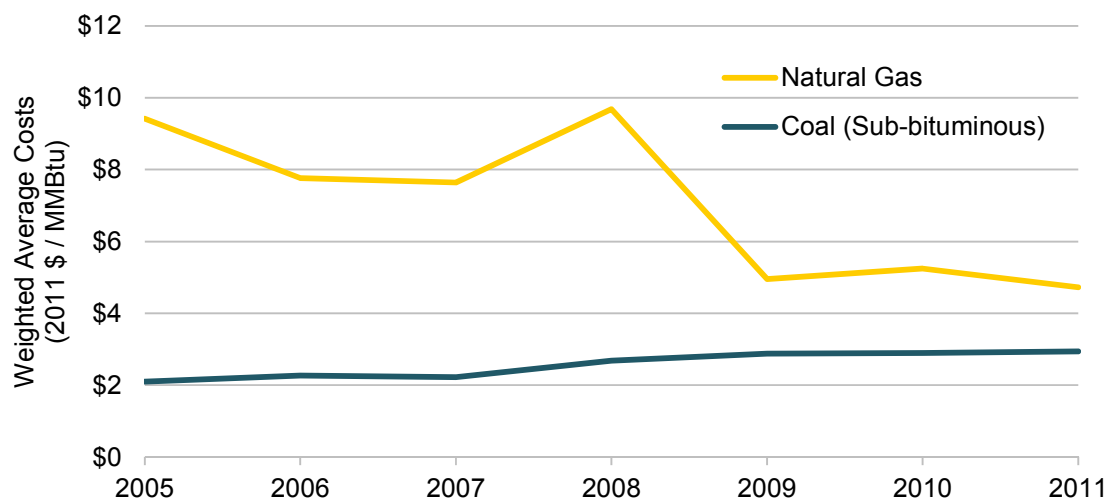
4. Coal's Disappearing Cost Advantage

Although once considered among the most inexpensive energy sources, in recent years the delivered price of coal has risen while the cost of substitutes—particularly natural gas and wind energy—has declined precipitously.

The rise of natural gas

More efficient natural gas extraction techniques, particularly hydraulic fracturing, have enabled the extraction of large reserves of shale gas that were previously uneconomic. Since 2007, shale gas production has risen rapidly—from less than 5 billion cubic feet per day, to more than 25 billion cubic feet per day.¹⁹ Natural gas prices have fallen correspondingly, while the average price of subbituminous coal (primarily from Western basins) has slowly risen, as displayed in Figure 2.

Figure 2. Weighted Average Real Natural Gas and Subbituminous Coal Prices per MMBTU for the Electric Power Industry, 2005 to 2011



Source: EIA, *Electric Power Annual 2011*, Table 7.4,
http://www.eia.gov/electricity/annual/html/epa_07_04.html

These low natural gas costs have had a dramatic impact on the dispatch order of existing power plants, as reflected in the relative monthly net generation values of coal and natural gas in Figure 1. For power plants that purchase their coal from higher-cost or geographically distant regions, natural gas has become more economic than coal.

¹⁹ EIA. 2013. Natural Gas Weekly Update: Monthly Dry Shale Gas Production. Washington, DC: U.S. Department of Energy.

Historically, natural gas plants have functioned primarily as load-following peaker plants—operating only at times of peak demand—due to higher fuel costs. As fuel costs decline, however, natural gas plants are transitioning to serving more baseload (i.e., operating during more hours of the year), enabled in part by the large amount of existing, under-utilized generating capacity at natural gas power plants.

In 2011, the United States had 457 gigawatts (GW) of natural gas nameplate capacity.²⁰ If one assumes a 90 percent capacity factor (that is, that on average natural gas plants were to be in operation 90 percent of the time), today's natural gas plants have the potential to produce more than 3.6 million gigawatt-hours (GWh)

Yet in 2011, natural gas generated only 1 million GWh—just 28 percent of their potential.²¹ This mismatch between capacity and generation is partially the result of the rapid build-out of gas plants during the late 1990s and early 2000s when gas prices were low.²²

Electricity generators are now beginning to more fully utilize that capacity, repurposing natural gas plants to serve baseload, or in some cases even converting coal plants to natural gas boilers. These impacts are clearly apparent in the change in share of net generation by fuel type from 2002 through 2011: the total electricity generated from coal declined by 10 percent, while the total electricity generated from natural gas increased by 46 percent in this period (see Figure 1).²³

Escalating coal transport costs

The locus of U.S. coal production has been moving westward for decades as Western coal production rapidly increased, overtaking Appalachian production levels in the late 1990s. Appalachian coal reached its zenith around 1990 and has been generally declining ever since, primarily due to increasingly adverse mining conditions and rising costs.

As Appalachian coal prices shot upward, Powder River Basin coal became competitive in eastern markets—despite the vast physical distance and transportation costs. A recent EIA analysis found that for the majority of power plants receiving Central Appalachian coal in 2007, Powder River Basin coal had become the lowest-cost option by 2010 (Figure 3).

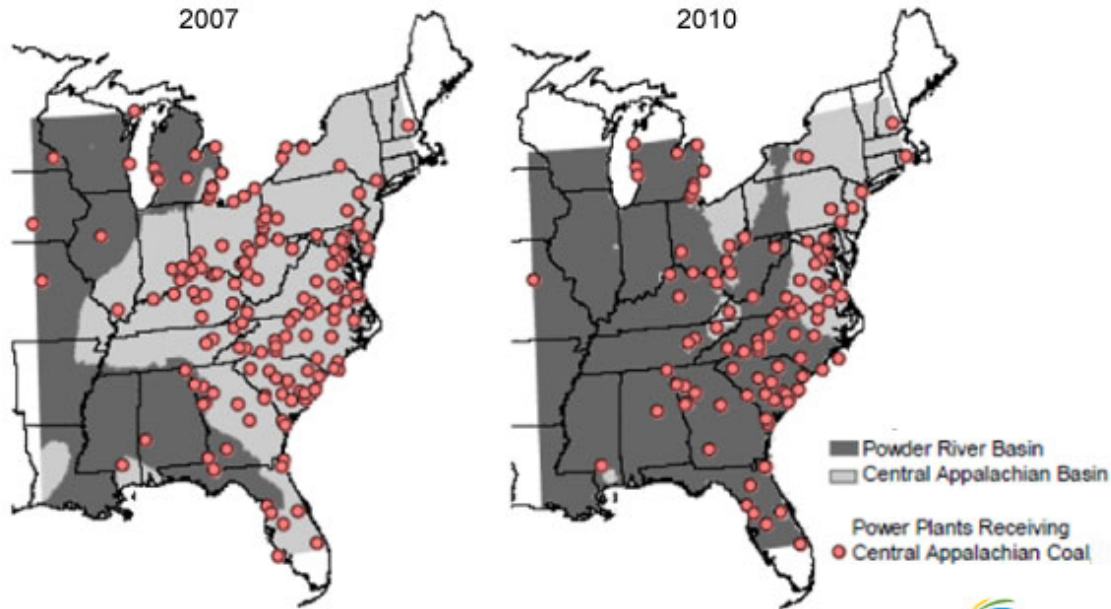
²⁰ EIA. 2011. Form 860.

²¹ EIA. 2011. Form 923.

²² From 2000 to 2011, natural gas generating capacity in the United States increased by 85 percent—from 220 GW to 457 GW—while net generation from natural gas increased by only 59 percent. EIA. 2001-2011. Form 860.

²³ EIA. 2001-2012. Form 923, Schedule 5A.

Figure 3. EIA Analysis of Lowest Delivered Cost of Coal by Coal Basin, 2007 and 2010



Source: U.S. Energy Information Administration



Note: Dark grey shading indicates that for plants in these areas, Powder River Basin coal has the lowest delivered cost. Light grey shading indicates that for plants in these areas, Central Appalachian Basin coal has the lowest delivered cost. Red circles indicate plants receiving Central Appalachian Basin coal.

Source: EIA. July 2013. Coal Transportation to the Electric Power Sector.

<http://www.eia.gov/coal/transportationrates/>

Yet, while Powder River Basin coal is clearly winning the competition with Central Appalachian coal in the East, both are losing ground in the wider U.S. domestic marketplace. From 2010 to 2012, both basins' production levels fell by nearly 10 percent, as other fuels became increasingly economic, displacing coal altogether.²⁴

One major factor affecting coal's competitiveness is the cost of transportation. Transportation costs accounted for nearly 60 percent of the delivered cost of Powder River Basin coal in 2010.²⁵ That is, on average, the transportation cost of Powder River Basin coal is typically greater than the cost of coal itself, and these costs have increased significantly since 2001. Appalachian and Illinois Basin coal have experienced the highest increases in transportation costs; increases in real, inflation-adjusted transportation costs for Powder River Basin coal, however, have also been significant, rising 14 percent from 2001 to 2010 (see Figure 4).

For all U.S. coal, high-and-rising transportation costs are harming the fuel's competitiveness with natural gas (which is transported domestically by pipelines at a much cheaper rate), and wind power, which is very nearly costless to operate (although it does have fixed, capital costs). Rising

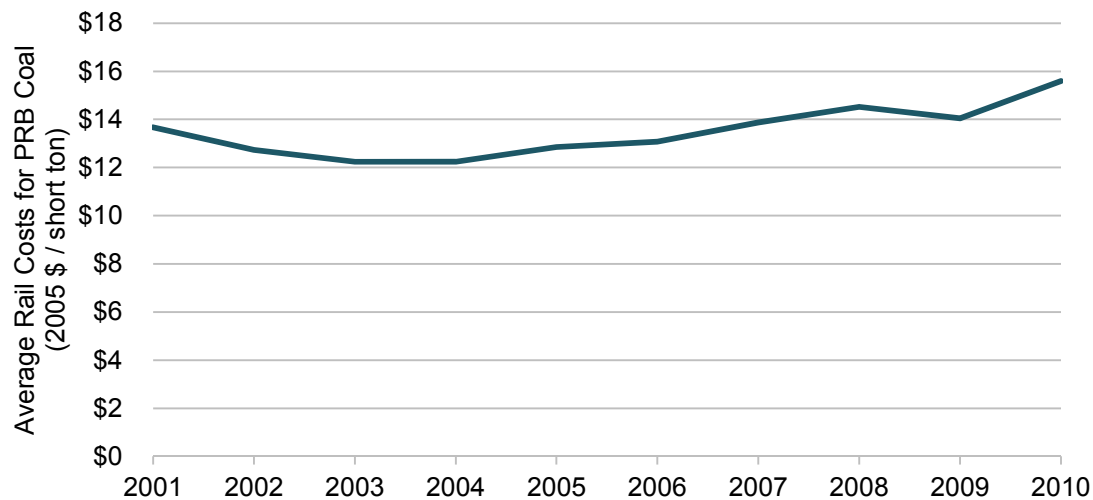
²⁴ EIA. 2013. Monthly Coal Production Forecast January 2002 - January 2013.

<http://www.eia.gov/coal/production/weekly/forecast/monthprodforecast2002.xls>

²⁵ EIA. 2012. "Cost of Transporting Coal to Power Plants Rose almost 50 Percent in Decade." *Today in Energy*, November 19, 2012. <http://www.eia.gov/todayinenergy/detail.cfm?id=8830>

transportation costs are contributing to coal's decline, and will certainly hinder the ability of Otter Creek and other Powder River Basin coal to expand in eastern markets.

Figure 4. Real Average Transportation Costs of Powder River Basin Coal, 2001 to 2010



Source: EIA, *Coal Transportation Rates to the Electric Power Sector, Trends 2001-2010*, Table 7, http://www.eia.gov/coal/transportationrates/excel/table7_PRB_Averages.xls

Mining costs on the rise

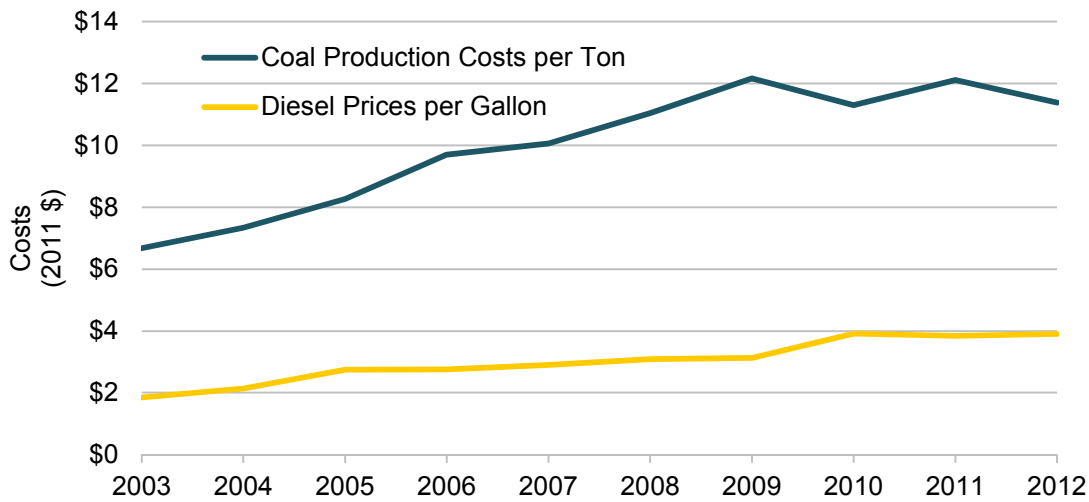
Higher mining costs, too, have eaten into coal's once-significant cost advantage. Coal producers in the Powder River Basin were hit especially hard by skyrocketing oil and steel prices during the 2000s due to their dependence on diesel fuel to power earth-moving equipment and their dependence on steel for the manufacture of mine supports. Arch Coal's Powder River Basin production costs have escalated at an average annual rate of nearly 7 percent since 2003.²⁶

As shown in Figure 5, diesel prices in particular have increased rapidly over the past few years, with real prices rising by an average annual rate of more than 8 percent from 2003 to 2012.²⁷ Arch Coal explicitly notes its exposure to fuel prices in its 10-K filings, stating, "Our coal mining operations use significant amounts of steel, diesel fuel, explosives, rubber tires and other mining and industrial supplies.... We also use significant amounts of diesel fuel and tires for the trucks and other heavy machinery we use, particularly at our Black Thunder mining complex. If the prices of mining and other industrial supplies, particularly steel-based supplies, diesel fuel and rubber tires, increase, our operating costs could be negatively affected."

²⁶ Arch Coal. 2013. 10-K Filing to the Securities and Exchange Commission. <http://www.sec.gov>

²⁷ EIA. 2013. *Short-Term Energy Outlook - Annual Average Diesel Price*. Washington, DC: U.S. Department of Energy. <http://www.eia.gov/forecasts/steo/>

Figure 5. Arch Coal Production Costs and Diesel Fuel Prices, 2003 to 2012



Source: Arch Coal 10-K 2013 Filing, EIA Diesel Fuel Prices (AEO 2012).

The EIA's 2012 *Annual Energy Outlook* reference case projects that oil prices will increase at an average annual rate of 2.5 percent (after correcting for inflation) from 2013 to 2035, which may lead to a continuing rise in mining costs over time.²⁸ Clearly substitution to other fuels and more efficient technologies will mitigate some of the effect on coal production costs, but recent experience has highlighted coal producers' vulnerability to rising commodity costs.

Coal is no longer competitive

Natural gas electricity generation costs have fallen below those of coal. Coal also faces competition from existing renewable energy sources, such as solar and wind, which, of course, have no fuel costs.

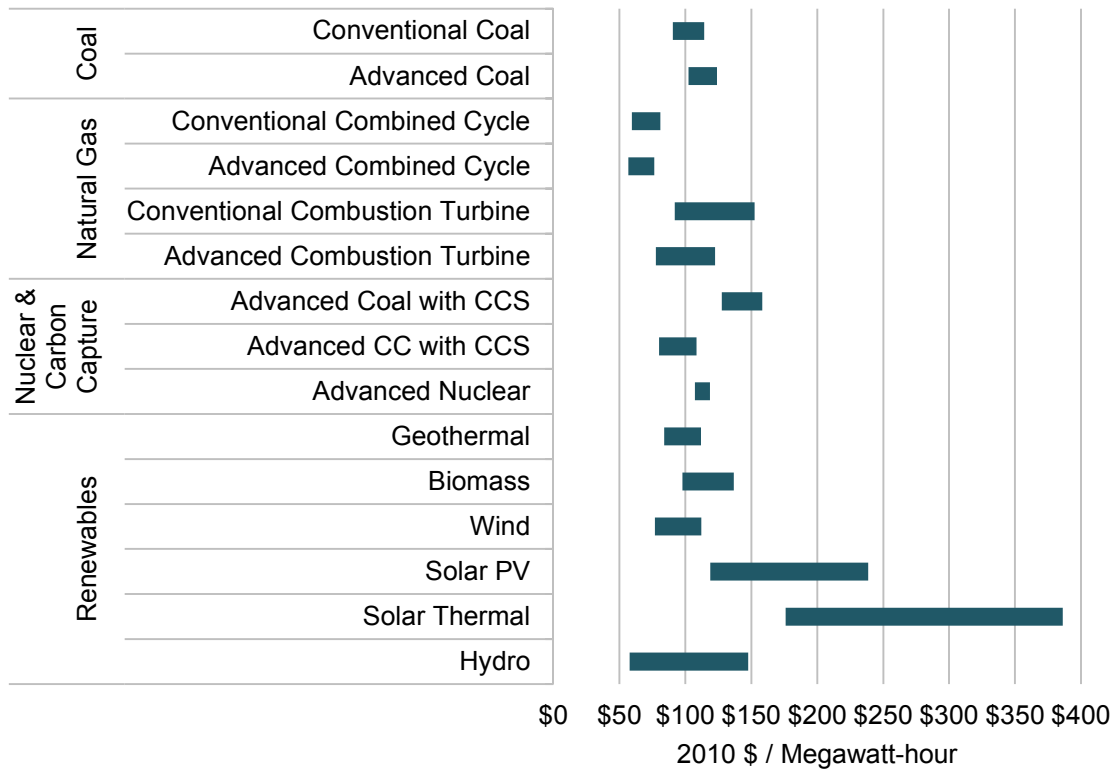
Coal's market position is even more precarious, however, when analyzed in terms of the total levelized cost of energy for newly constructed plants. Levelized costs are a convenient way of comparing various energy technologies by looking at the cost per megawatt hour (in real dollars) of construction and operation over the entire life of a plant, taking into account capital costs, fuel costs, operating and maintenance costs, financing costs, and an assumed utilization rate.

Historically, coal has maintained low levelized costs by balancing its large capital outlays with lower fuel costs, but this is no longer the case. Natural gas plants are much less expensive to build, can be built quickly, and possess much faster ramp rates that enable them to provide back-up generation for variable energy sources such as wind.²⁹ In the EIA's recent projection of 2017 average levelized costs for various energy technologies, natural gas combined-cycle plants clearly outperformed conventional and advanced coal, and natural gas combustion turbines exhibited nearly equivalent costs to coal, but with a wider range of costs due to regional variation in local labor markets, and the cost and availability of fuel (see Figure 6).

²⁸ EIA. 2012. *Annual Energy Outlook 2012*. Washington, DC: U.S. Department of Energy.

²⁹ Higher ramping rates allow natural gas plants to quickly increase and decrease electricity output to match offset fluctuations in variable energy sources such as wind.

Figure 6. Levelized Cost of Energy for Various Technologies, 2017



Note: Assumed capacity factors are: coal = 85%, combined cycle = 87%, combustion turbines = 30%, nuclear = 90%, geothermal = 91%, biomass = 83%, wind = 33%, solar PV = 25%, solar thermal = 20%, and hydro = 53%.

Source: Levelized Cost of New Generation Resources in the Annual Energy Outlook 2012, Table 2, http://www.eia.gov/forecasts/aeo/electricity_generation.cfm

It comes as no surprise, then, that few coal plants are being proposed or constructed (see the section below on 'The Future of U.S. Coal-Powered Electric Generation'). Natural gas is simply more economic, better suited for the integration of renewable energy, and not as susceptible to costly environmental retrofits as coal plants.

5. Regulation favors shift away from coal

New, stricter environmental regulations are adding to the costs of operating coal-fired power plants. Many of the nation's aging coal plants are widely expected to retire over the next few

decades, to be replaced by natural gas, renewables, and energy efficiency measures.³⁰ This section describes each of the federal environmental regulations affecting coal plants in turn.³¹

National Ambient Air Quality Standards

National Ambient Air Quality Standards (NAAQS) set maximum air quality limitations that must be met at all locations across the nation. Compliance with the NAAQS can be determined through air quality monitoring stations, which are stationed in various cities throughout the United States, or through air quality dispersion modeling. States with areas found to be in “nonattainment” of a particular NAAQS are required to set enforceable requirements to reduce emissions from sources contributing to nonattainment such that the NAAQS are achieved and maintained. The U.S. Environmental Protection Agency (EPA) has established NAAQS for six pollutants: sulfur dioxide (SO₂), nitrogen dioxides (NO₂), carbon monoxide (CO), ozone, particulate matter (measured as particulate matter less than or equal to 10 micrometers in diameter (PM₁₀) and particulate matter less than or equal to 2.5 micrometers in diameter (PM_{2.5})), and lead.

In nonattainment areas, coal plants and other sources must comply with emission reduction requirements known as “Reasonably Available Control Technology” (RACT) to bring the areas into attainment of the NAAQS. New major sources, including major modifications at existing sources, must comply with very strict emissions reductions consistent with “lowest achievable emissions reductions” (LAER) as well as obtain emission offsets.

EPA is currently in the process of drafting new, more stringent NAAQS for SO₂, PM_{2.5}, and ozone.

- On June 22, 2010, EPA revised³² the standard for SO₂ by establishing a new 1-hour standard at a level of 75 parts per billion (ppb) in place of the existing annual and 24-hour standards for SO₂. EPA plans to make area designations for the new SO₂ standard by June 3, 2013, and compliance would be required in 2017.
- On December 14, 2012, EPA strengthened the annual PM_{2.5} standard from 15 µg/m³ to 12 µg/m³, and retained the current 24-hour standard at 35 µg/m³. EPA will make final area designations for the new standard by December 2014. Once designations are made, states with non-attainment areas will have to develop a State Implementation Plan within three years outlining how they will reduce pollution to meet the standard by 2020.
- In March 2008, EPA strengthened the 8-hour ozone standard from 84 ppb to 75 ppb. On September 16, 2009, EPA announced that because the 2008 standard was not as protective as recommended by EPA’s panel of science advisors, it would reconsider the 75 ppb standard. In 2010, EPA proposed lowering the 8-hour ozone standard from 75 ppb to between 60 and 70 ppb, and September 2, 2011, the Administration announced that EPA would not finalize its proposed reconsideration of the 75 ppb standard ahead of the regular 5-year NAAQS review cycle. The next 5-year review for 8-hour ozone is expected

³⁰ Elliott, Gold, and Hayes. August 2011. Avoiding a Train Wreck: Replacing Old Coal Plants with Energy Efficiency. ACEEE White Paper. http://aceee.org/files/pdf/white-paper/Avoiding_the_train_wreck.pdf

³¹ For more detailed information on up-coming environmental regulations see Miller. January 2013. A Primer on Pending Environmental Regulations and their Potential Impacts on Electric System Reliability. NESCAUM. <http://www.nescaum.org/>

³² 75 Fed. Reg. 35520 (June 22, 2010)

in 2013. Compliance with the upcoming standard would likely be required in the 2019-2020 timeframe.

Cross State Air Pollution Rule

The Cross State Air Pollution Rule (CSAPR) was finalized in 2011, establishing the obligations of each affected state to reduce emissions of NO_x and SO₂ that significantly contribute to another state's PM_{2.5} and ozone non-attainment problems. The rule targets coal and other electric generating units, and uses a cap and-trade approach to limit each state to emissions below a level that significantly contributes to non-attainment in downwind states.

On August 21, 2012, CSAPR was vacated by the U.S. Court of Appeals for the District of Columbia. EPA has filed a petition for *en banc* rehearing of that decision; even if EPA fails to salvage CSAPR through the courts, however, the Agency must still promulgate a replacement rule to implement Clean Air Act requirements to address the transport of air pollution across state boundaries. In the meantime, the court left the requirements of the 2005 Clean Air Interstate Rule in place.

Regional Haze Rules

One of the national goals set out in the Clean Air Act is reducing existing visibility impairment from human-made air pollution in all "Class I" areas (e.g., most national parks and wilderness areas).³³ EPA's Regional Haze Rule—issued in 1999, and revised in 2005—requires states to create plans to significantly improve visibility conditions in Class I areas with the goal of achieving natural background visibility conditions by 2064. These requirements are implemented through state plans with enforceable reductions in haze-causing pollution from individual sources and with other measures to meet "reasonable further progress" milestones.³⁴ The first progress milestone is 2018.

A key component of this program is the imposition of air pollution controls on coal plants and other existing facilities that impact visibility in Class I areas. Specifically, the rules require installation of "best available retrofit technology" (BART) that is developed for such facilities on a case-by-case basis. In addition, EPA's BART determinations specify particular emission limits for each BART-eligible facility. EPA evaluates BART for the air pollutants that impact visibility in our national parks and wilderness areas – namely SO₂, PM, and nitrogen oxides (NO_x). Under the Clean Air Act, states develop Regional Haze requirements, but EPA approves state plans for compliance. If EPA finds the plans are not consistent with the Clean Air Act, it adopts a federal plan with BART and reasonable progress requirements. Affected facilities must comply with the BART determinations as expeditiously as practicable but no later than five years from the date EPA approves the state plan or adopts a federal plan.³⁵

³³ 42 U.S.C. § 7491(a)(1)

³⁴ 40 C.F.R. §51.308-309

³⁵ EPA's regulations allow certain states in the "Grand Canyon Visibility Transport Region" to participate in an SO₂ trading program in lieu of adopting source-specific SO₂ BART requirements, if the trading program will result in greater reasonable progress toward attaining the national visibility goal than source-specific BART. Although nine states were originally eligible to participate, today only three states are opting to participate in this program – New Mexico, Utah, and Wyoming. These states agreed to a gradually declining cap on SO₂ emissions from all emission sources. If the declining caps are exceeded in any year, then even greater SO₂ emission reductions have to be

Mercury and Air Toxics Standards

In 2000, EPA determined it was appropriate and necessary to regulate toxic air emissions (or hazardous air pollutants) from coal and other steam electric generating units. As a result, EPA adopted strict emission limitations for hazardous air pollutants that are based on the emissions of the cleanest existing sources.³⁶ These emission limitations are known as Maximum Achievable Control Technology (MACT). The final MATS rule, approved in December 2011, sets strict stack emissions limits for mercury, other metal toxins, other organic and inorganic hazardous air pollutants, as well as acid gasses. Compliance with MATS is required by 2015, with a potential extension to 2016.

Coal Combustion Residuals Disposal Rule

Coal-fired power plants generate a tremendous amount of ash and other residual wastes, which are commonly placed in dry landfills or slurry impoundments. The risk associated with wet storage of coal combustion residuals (CCR) was dramatically revealed in the catastrophic failure of the ash slurry containment at the Kingston coal plant in Roane County, Tennessee in December 2008, releasing over a billion gallons of slurry and sending toxic sludge into tributaries of the Tennessee River.

On June 21, 2010, EPA proposed to regulate CCR for the first time either as a Subtitle C hazardous waste or Subtitle D solid waste under the Resource Conservation and Recovery Act. The current rulemaking is 30 years overdue. If the EPA classifies CCR as hazardous waste, a cradle-to-grave regulatory system would apply to CCR, requiring regulation of the entities that create, transport, and dispose of the waste. Under a Subtitle C designation, the EPA would regulate siting, liners, run-on and run-off controls, groundwater monitoring, fugitive dust controls, and any corrective actions required; in addition, the EPA would implement minimum requirements for dam safety at impoundments. Under a solid waste Subtitle D designation, the EPA would require minimum siting and construction standards for new coal ash ponds, compel existing unlined impoundments to install liners, and require standards for long-term stability and closure care.

The EPA is currently evaluating which regulatory pathway will be most effective in protecting human health and the environment. In 1999, EPA released a series of technical papers to Congress documenting cases in which damages are known to have occurred from leakages and spills from coal ash impoundments.³⁷ In the current proposed rule, the EPA recognizes a substantial increase in the types and quantities of potentially toxic CCR caused by air pollution control equipment.

achieved—although the reductions can be met through emissions trading, rather than imposition of specific emission limitations on any one facility. This program is called the Backstop Trading Program. As of the date of this testimony, EPA has not yet approved the Backstop Trading Program to meet Regional Haze requirements in any of the three states' Regional Haze plans, so the trading program is not yet federally enforceable.

³⁶ Clean Air Act §112(d)

³⁷ EPA. March 15, 1999. Technical Background Document for the Report to Congress on Remaining Wastes from Fossil Fuel Combustion: Potential Damage Cases.

http://www.epa.gov/osw/nonhaz/industrial/special/fossil/ffc2_397.pdf

Use of more advanced air pollution control technology reduces air emissions of metals and other pollutants in the flue gas of a coal-fired power plant by capturing and transferring the pollutants to the fly ash and other air pollution control residues. The impact of changes in air pollution control on the characteristics of CCRs and the leaching potential of metals is the focus of ongoing research by EPA's Office of Research and Development.³⁸

Steam Electric Effluent Limitation Guidelines

Following a multi-year study of steam-generating units across the country, EPA found that coal-fired power plants are currently discharging a higher-than-expected level of toxic-weighted pollutants into waterways. Current effluent regulations were last updated in 1982 and do not reflect the changes that have occurred in the electric power industry over the last thirty years, and do not adequately manage the pollutants being discharged from coal-fired generating units. Coal ash ponds and flue gas desulfurization systems used by such power plants are the source of a large portion of these pollutants, and are likely to result in an increase in toxic effluents in the future as environmental regulations are promulgated and pollution controls are installed. No new rule has yet been proposed, but EPA is under a court order to issue the proposed regulation by April 19, 2013 and a final rule in May 22, 2014.³⁹ New requirements will be implemented in 2014 to 2019 through the five-year National Pollutant Discharge Elimination System permit cycle.⁴⁰

Clean Water Act Cooling Water Intake Structure Rule

On March 28, 2011, the EPA proposed a long-expected rule implementing the requirements of Section 316(b) of the Clean Water Act at existing power plants.⁴¹ Section 316(b) requires “that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact.” Under this new rule, EPA set new standards reducing the impingement and entrainment of aquatic organisms from cooling water intake structures at new and existing electric generating facilities.

The rule provides that:

- Existing facilities that withdraw more than two million gallons per day are subject to an upper limit on fish mortality from impingement, and must implement technology to either reduce impingement or slow water intake velocities.
- Existing facilities that withdraw at least 125 million gallons per day are required to conduct an entrainment characterization study to establish a “best technology available” for the specific site.

³⁸ 75 Fed. Reg. 35139 (June 21, 2010).

³⁹ See U.S. Environmental Protection Agency website. Accessed February 21, 2013. Available at: <http://water.epa.gov/scitech/wastetech/guide/steam-electric/amendment.cfm>

⁴⁰ See U.S. Environmental Protection Agency. *Steam Electric ELG Rulemaking*. UMRA and Federalism Implications: Consultation Meeting. October 11, 2011. <http://water.epa.gov/scitech/wastetech/guide/upload/Steam-Electric-ELG-Rulemaking-UMRA-and-Federalism-Implications-Consultation-Meeting-Presentation.pdf>

⁴¹ 33 U.S.C. § 1326.

Title V Greenhouse Gas Tailoring Rule

Under EPA's Greenhouse Gas Tailoring Rule, coal plants and other large sources of greenhouse gas emissions are subject to permitting requirements. A "large source" is a new facility with emissions of at least 100,000 tons per year of carbon dioxide equivalent (CO₂e) or an existing facility that emits at least 100,000 tons per year CO₂e and is making changes that would increase greenhouse gas emissions by at least 75,000 tons per year CO₂e. These sources are required to obtain permits under the New Source Review Prevention of Significant Deterioration and Title V Operating Permit programs and must install Best Available Control Technology (BACT) for greenhouse gases. The BACT requirement only applies, however, if the project also increases emissions of at least one non-greenhouse-gas pollutant.

New Source Performance Standards

Under Section 111 of the Clean Air Act, EPA sets technology-based standards for new sources on a category-by-category basis. These standards are set based on the best demonstrated available technology (BDAT) and apply to all new sources built or modified following promulgation of the standard.

On March 27, 2012, EPA proposed⁴² New Source Performance Standards for greenhouse gas emissions from new electric generating units, such as coal-fired power plants. The standard was set at 1,000 lbs CO₂e/MWh, which is equivalent to the emission rate that a combined-cycle natural gas unit can achieve. A new coal plant would have to employ carbon capture and sequestration (CCS) technology with the capability of removing 50 percent of CO₂ emissions in order to meet the standard. The rule also allows a unit's emissions to be averaged over 30 years to achieve an annual average emission rate of 1,000 lbs CO₂e/MWh. This option allows the phase-in of CCS within the first 10 years of operation.

While New Source Performance Standards apply only to new facilities, Section 111(d) of the Clean Air Act requires states to develop plans for *existing* sources of any non-criteria pollutants (i.e., a pollutant for which there is no NAAQS) and non-hazardous air pollutant whenever EPA promulgates a standard for a new source. These plans are subject to EPA review and approval, similar to state implementation plans under the NAAQS program.

The implications of forthcoming environmental regulations for coal plants

EPA's increasingly stringent environmental regulations will have substantial impacts on the coal industry. Many coal plants will require retrofits to comply with the regulations, and a significant number of plants may be retired as they become too expensive to operate.⁴³ Further detailed analysis of these impacts is discussed in the following section.

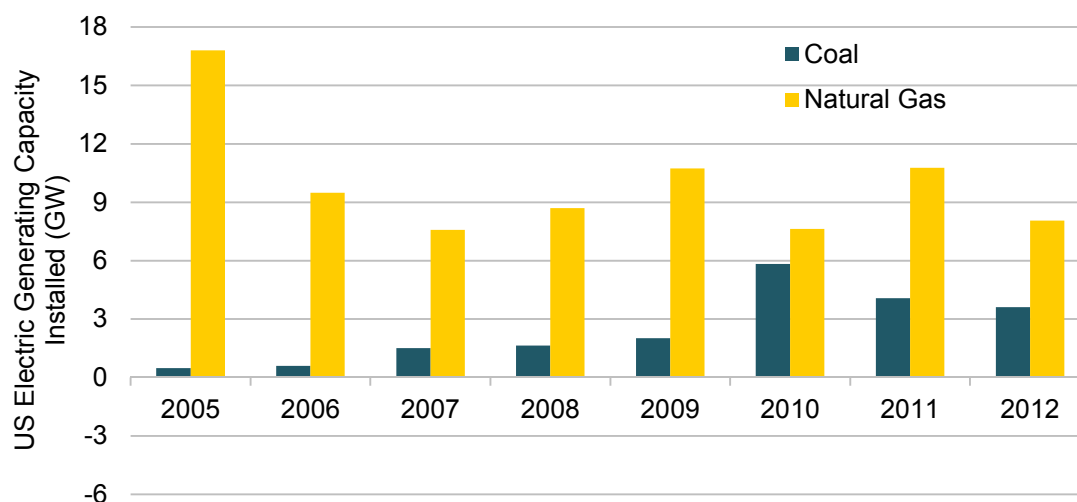
⁴² 77 Fed. Reg. 22392 (April 13, 2012)

⁴³ EPA performed an analysis of the costs of compliance with each of the four major rules expected to impact the electric industry. Annual compliance costs are projected to total \$10.2 billion for MATS, \$853 million for CSAPR, \$600 million to \$1.5 billion for CCR depending on which option is finalized, and \$397 million for 316(b). Source: U.S. Government Accountability Office, July 2012. *EPA Regulations and Electricity: Better Monitoring by Agencies could Strengthen Efforts to Address Potential Challenges*. <http://www.gao.gov/assets/600/592542.pdf>

6. The Future of U.S. Coal-Powered Electric Generation

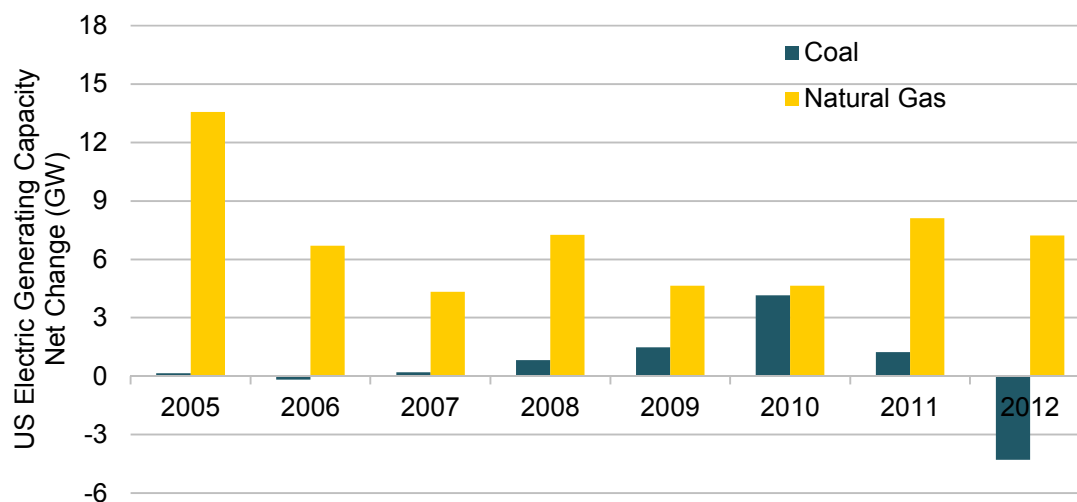
Competition from other generation technologies and forthcoming environmental regulations are pushing much of the existing U.S. coal fleet into retirement, and few coal plant additions are expected. Newly installed electric generating facilities are dominated by natural gas (see Figure 7), and the net change in generating facilities (new installations less retirements) favors natural gas over coal even more strongly (see Figure 8).

Figure 7. Newly Installed Generating Capacity by Year, 2005 to 2012



Source: EIA Form 860, 2005–2012

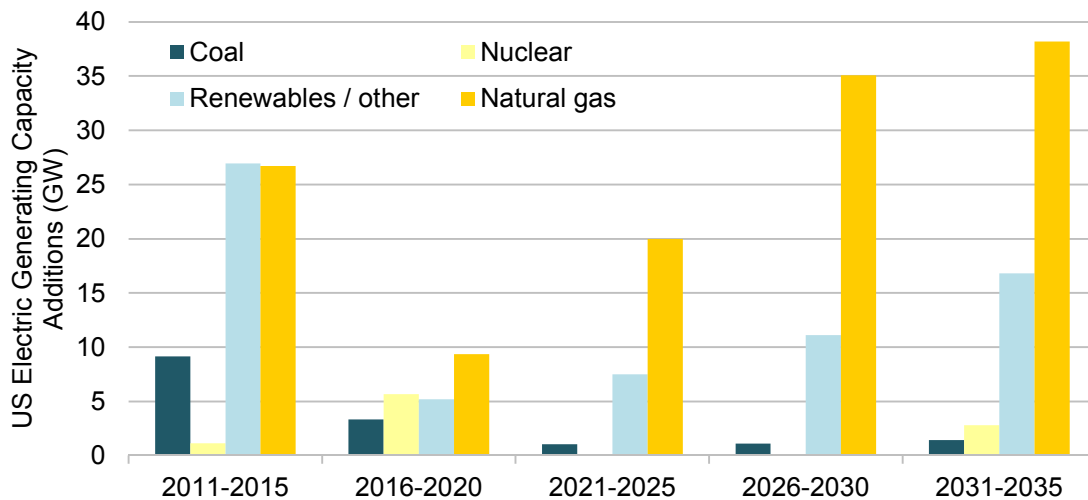
Figure 8. Net Change in Generating Capacity by Year, 2005 to 2012



Source: EIA Form 860, 2005-2012

EIA's 2012 *Annual Energy Outlook* reference case projects very little new coal capacity to be added over the next twenty years, while large amounts of capacity are projected to soon retire. As Figure 9 demonstrates, most new capacity is expected to be a mixture of natural gas and renewables, not coal.

Figure 9. Electricity generation capacity additions by fuel type, including combined heat and power, 2011 to 2035 (GW)



Source: EIA. 2012 Annual Energy Outlook. http://www.eia.gov/forecasts/aeo/MT_electric.cfm

At the same time that little new coal capacity is expected to be added, significant amounts may soon be retired. Already, plants totaling 30 GW of coal capacity have announced their retirements by 2016. The Brattle Group's most recent forecast of likely coal retirements in response to tightening environmental regulations was 59 to 77 GW.⁴⁴ As of February 2013, Black & Veatch estimates that nearly 62 GW of coal capacity will be retired by 2020, up slightly from what the company estimated in mid-2012.⁴⁵

Coal plant retirements include many of Otter Creek's potential customers

Coal plant retirements will make it increasingly difficult for Otter Creek coal to find buyers for its high-sodium coal. Already several of the ten coal plants identified as the initial target market for the mine's coal have announced their retirement or conversion to natural gas or biomass.⁴⁶ It is reasonable to expect that many more of the potential customers for Otter Creek coal will be retired in the near future as units face escalating costs of environmental upgrades.

Costs of operating electric generating units include both fixed and variable components. Fixed costs are invariant to the amount of generation (e.g. investment capital, property taxes, and fixed operation and maintenance expenses). Variable, or "running," costs strongly depend on the

⁴⁴ The Brattle Group. October 2012. *Potential Coal Plant Retirements: 2012 Update*. http://www.brattle.com/_documents/UploadLibrary/Upload1082.pdf

⁴⁵ Maloney, Peter. 2013. Black & Veatch Updates Coal-fired Power Plant Retirement Estimates. Platts.

⁴⁶ Conversion of Hoot Lake to natural gas by 2020 was approved by the Minnesota Public Utilities Commission in January 2013 (<http://minnesota.publicradio.org/display/web/2013/01/31/business/hoot-lake-plant-stop-burning-coal>), several units of Syl Laskin will switch to natural gas (<http://fresh-energy.org/2013/01/news-release-clean-air-victory-in-northern-minnesota-as-minnesota-power-announces-phasing-out-coal-at-two-minnesota-plants/>), while Bayfront will be converted to biomass (<http://www.jsonline.com/blogs/business/68594702.html> ; <http://www.woodbioenergymagazine.com/magazine/2012/1012/article-old-pro-excel.php>).

amount of generation (e.g. fuel costs, emissions costs, and variable operation and maintenance expenses).

Pollution control technologies affect the forward-going cost of a unit in several ways. First, these technologies require investment capital and increase the fixed costs at a unit in a given year, which depend, in part, on the size of the unit; smaller units are more expensive to retrofit on a dollar per kilowatt basis. Second, emission control equipment requires electricity to run—called the “parasitic load”—reducing the net output of a generating unit; in other words, the same fuel usage results in less electricity output. Finally, many emission controls also require the use of a chemical reagent, purchase of which increases variable operation and maintenance costs.⁴⁷

The dispatch order of generation units—which units are called upon to generate electricity in a given hour and which are not—is driven by unit variable costs, but the decision to construct a new plant or retrofit a plant with new environmental controls is based on the combination of the additional fixed costs of the environmental controls and the variable costs. Together these constitute the “forward-going operating costs.”

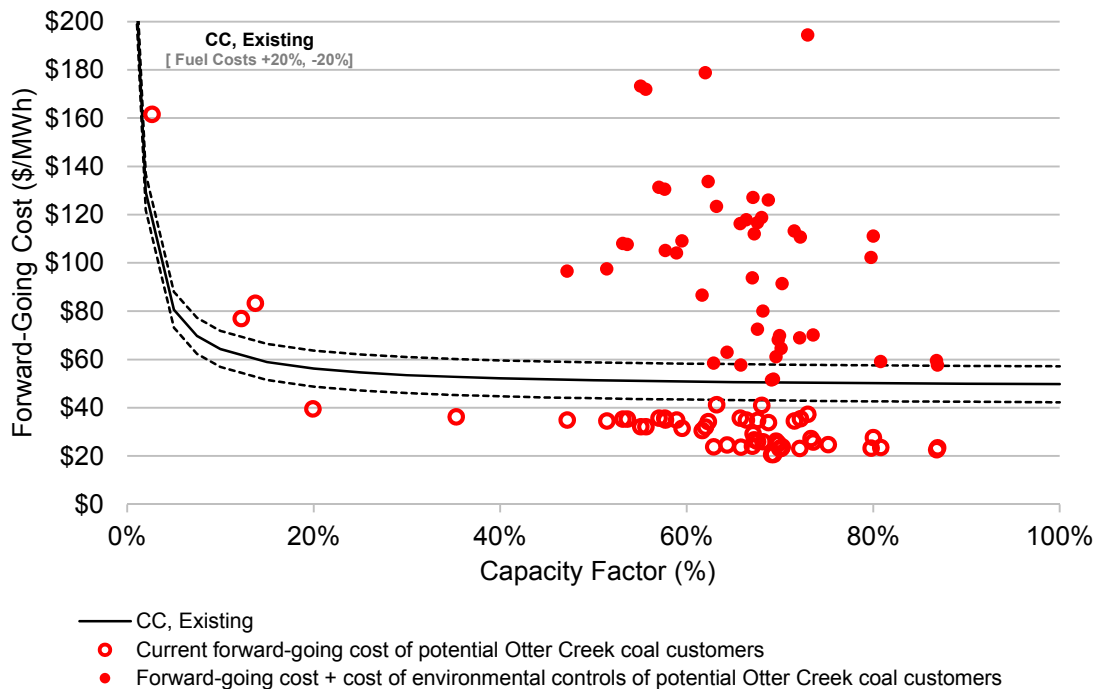
Synapse Energy Economics performed an analysis of the 52 units identified by Norwest as potential Otter Creek customers, based on each unit’s operating characteristics and estimated capital expenditures for the specific environmental upgrades that would be needed to comply with EPA regulations assuming a \$15 per ton CO₂ carbon price. The coal fuel costs used for this analysis conservatively assume that the current cost of delivered coal remains the same, ignoring the likelihood that these costs will increase due to higher transportation and mining costs over the next decade.⁴⁸

Figure 10 displays the forward-going operating costs of these coal units, first without any carbon price or environmental upgrades (the hollow red circles) and then with both an approximately \$15 per ton carbon price and the specific environmental technologies that each plant would need to be in compliance with federal law (the solid red circles). The solid circles are the relevant costs that will be considered when deciding whether to retire a unit or retrofit it with new environmental controls.

⁴⁷ Wilson, Rachel. July 23, 2012. “Direct Testimony of Rachel S. Wilson.” *Case No. 2012-00063, Application of Big Rivers Electric Corporation, Before the Public Service Commission of Kentucky.*

⁴⁸ Estimated from EIA. 2010. Form 923.

Figure 10. Forward-going costs of existing coal units by capacity factor (\$/MWh) relative to the total levelized cost of an existing natural gas combined cycle unit



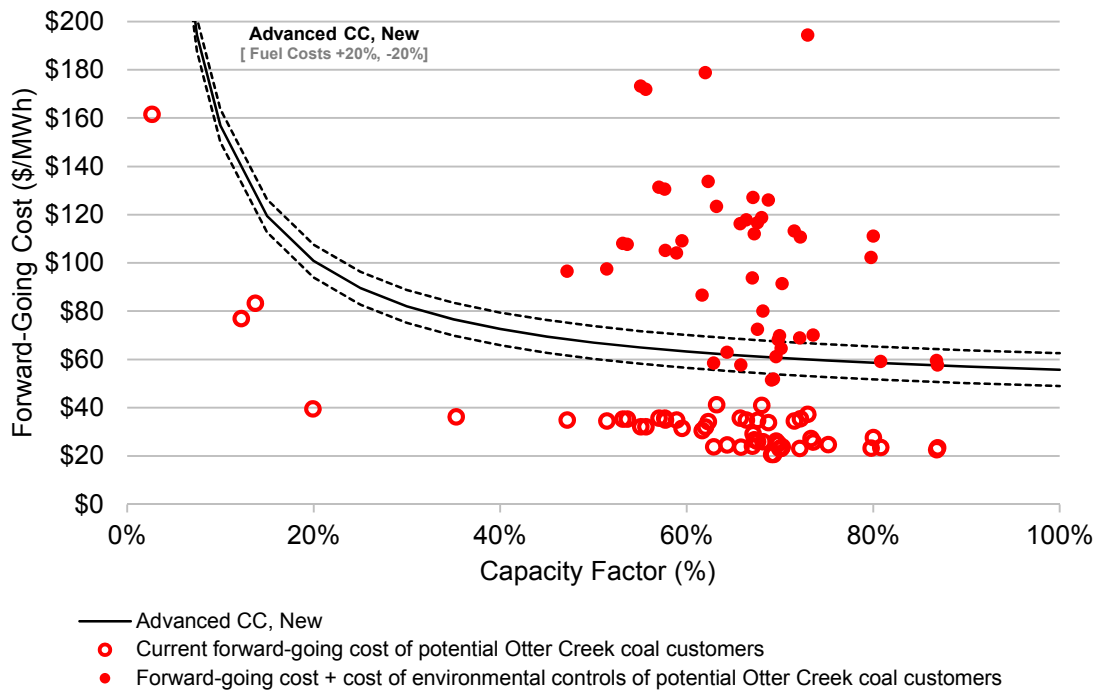
Source: Authors' calculations.

Shown also on Figure 10 is the fixed plus variable cost of a typical existing combined-cycle natural gas plant with the \$15 per ton carbon price included. The dashed lines above and below the natural gas line combined cycle cost represent 20 percent higher and lower fuel costs, with natural gas fuel costs derived from *Annual Energy Outlook* projections through 2022.

While the majority of the coal plants identified as potential Otter Creek customers were more economic to operate than an existing combined-cycle natural gas plant prior to the environmental upgrades and carbon price, this is no longer the case once the environmental costs are factored in. Our analysis estimates that these units face environmental control capital expenditures ranging from \$141 million to \$822 million. The decision of whether to retrofit these units, convert them to natural gas, or retire them will be based on each unit's variable costs, plus the environmental capital costs, the carbon price, and reduced efficiency due to the parasitic load. It is reasonable to expect that many units will find it difficult to justify their continued operation and will likely retire rather than bear the expense of an environmental retrofit.

Figure 11 presents the same analysis, but this time in comparison to the higher costs of an advanced new combined-cycle gas plant, including the cost to construct the plant itself. The results are striking: After complying with environmental regulations, the majority of Otter Creek's potential customers' costs will be higher than the cost of building and operating a new combined-cycle natural gas plant.

Figure 11. Forward-going costs of existing coal units by capacity factor (\$/MWh) relative to the total levelized cost of new advanced natural gas combined cycle unit



Source: Authors' calculations.

7. Other Policies Reducing Demand for Coal

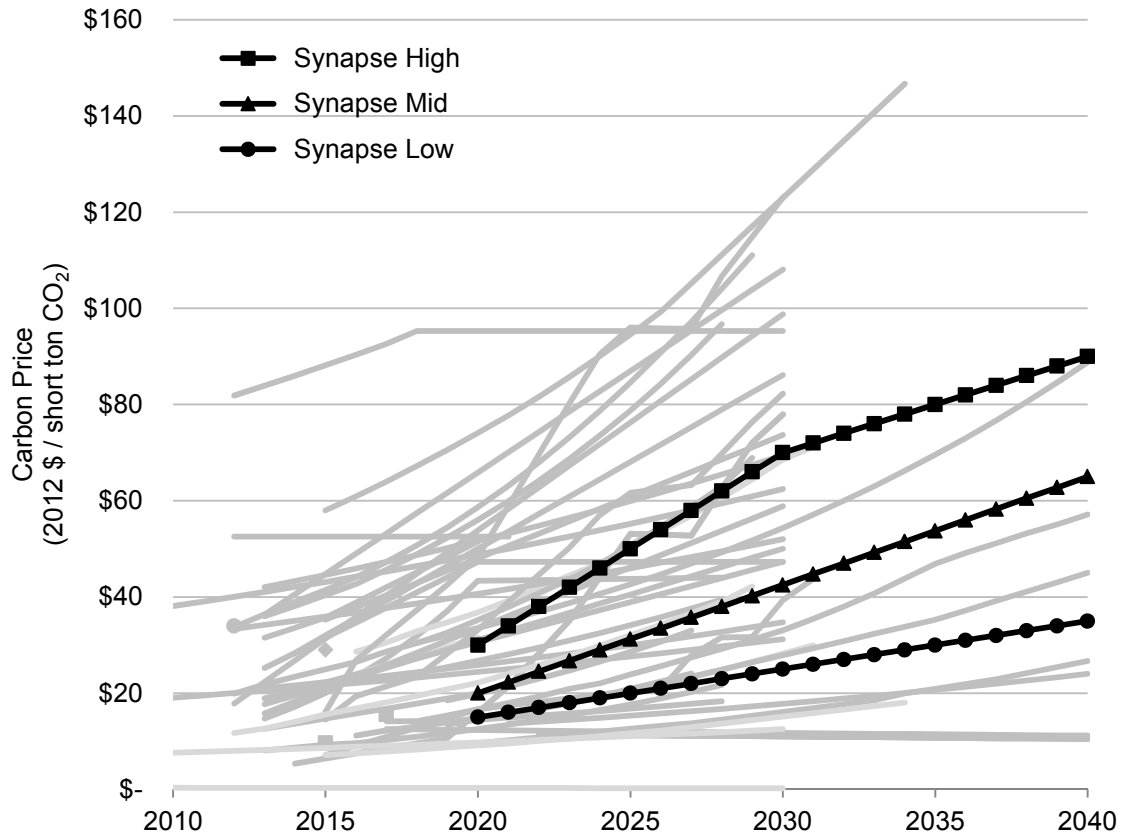
Several other categories of energy and environmental policies, at both the federal and state levels, are likely to have the effect of reducing domestic demand for U.S. coal. The sections below discuss the expected impact of carbon policies, renewable portfolio standards, and energy efficiency measures.

Future carbon policy favors shift away from coal

While there is not currently a federal law or proposed rulemaking requiring a carbon control technology, cap-and-trade program, or tax on emissions of CO₂, discussions at the EPA and at the Congressional level are ongoing. Due to coal's high rate of carbon emissions, demand for this fuel would be impacted significantly by a national or regional carbon policy.

Based on a review of more than 40 current carbon price estimates and related analyses, including CO₂ price estimates used by electric utilities in planning, Synapse Energy Economics developed low, mid, and high estimates of future carbon prices for the period 2020 to 2040. Synapse's 2020 carbon price projections range from \$15 to \$30 per ton of CO₂, with a mid-case of \$20 per ton of CO₂. The Synapse carbon price projections are compared to the range of utility carbon price forecasts in Figure 12.

Figure 12. Synapse CO₂ price forecasts compared to the range of utility forecasts

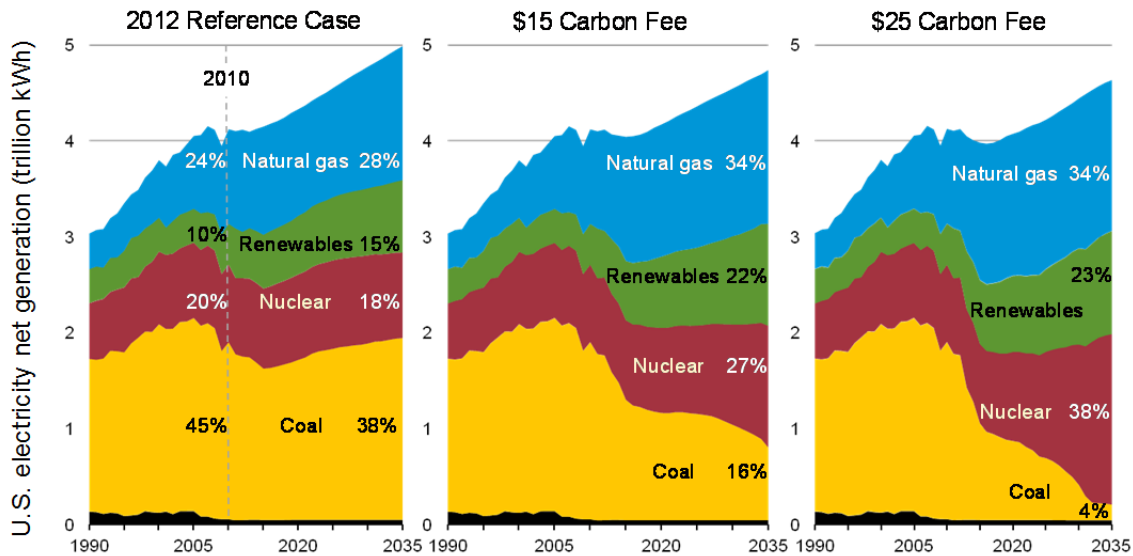


Source: Wilson, Rachel, Patrick Luckow, Bruce Biewald, Frank Ackerman, and Ezra Hausman. 2012. 2012 Carbon Dioxide Price Forecast. Cambridge: Synapse Energy Economics, Inc. <http://www.synapse-energy.com/Downloads/SynapseReport.2012-10.0.2012-CO2-Forecast.A0035.pdf>

The EIA's 2012 *Annual Energy Outlook* reports the projected impact of \$15 and \$20 per ton CO₂ emissions fees starting in 2013⁴⁹ (similar to Synapse's low and mid cases) on net electricity generation in the United States. Figure 13 below shows EIA's reference case with no CO₂ emissions fee on the left, a \$15 per ton case in the center, and a \$20 per ton case on the right. In all three cases, coal declines from 45 percent of net generation in 2010, but the decline is much more pronounced in the carbon fee scenarios. Under a \$15 per ton CO₂ fee, coal declines to 16 percent of generation by 2035, while under a \$25 per ton CO₂ fee, coal declines to just 4 percent of generation by the end of the period modeled.

⁴⁹ AEO CO₂ prices escalate 5 percent each year through 2035.

Figure 13. U.S. Electricity Net Generation (Trillion kWh) under Reference, \$15, and \$25 Carbon Fee Scenarios



Source: EIA. *Annual Energy Outlook 2012*. www.eia.gov/pressroom/presentations/sieminski_01142013.ppt

EIA's projections highlight the vulnerability of coal demand to carbon policy, even at a low carbon price. As outlined in the Synapse Energy Economics 2012 *Carbon Dioxide Price Forecast* report, federal legislation requiring reductions in carbon dioxide emissions is likely to occur in this decade prompted by one or more of the following factors.⁵⁰

- Technological opportunity;
- A patchwork of state emission targets for 2020, spurring industry demand for federal action;
- A U.S. Supreme Court decision to allow nuisance lawsuits to go ahead, resulting in a financial threat to energy companies; and
- Increasingly compelling evidence of climate change.

Such policy will certainly reduce demand for coal nationally, as the costs of carbon adds significantly to the overall cost of energy produced by coal. Capturing and storing carbon emissions at the smokestack (i.e. carbon capture and sequestration) is not yet economic (see Figure 6), and coal will likely continue to face significant competition from low-cost natural gas and renewable resources for the foreseeable future.

Substitution due to renewable mandates

Volume I of Norwest's *Otter Creek Summary Report* describes the limited market for Montana Powder River Basin coal with high sodium content.⁵¹ Montana coal will have difficulty competing

⁵⁰ Wilson, Rachel, Patrick Luckow, Bruce Biewald, Frank Ackerman, and Ezra Hausman. 2012. 2012 Carbon Dioxide Price Forecast. Cambridge: Synapse Energy Economics, Inc. <http://www.synapse-energy.com/Downloads/SynapseReport.2012-10.0.2012-CO2-Forecast.A0035.pdf>

⁵¹ Norwest Corporation. 2006. *Otter Creek Property Summary Report*. Salt Lake City: Norwest Corporation.

with Wyoming coal due to both the high sodium characteristics of the coal and higher transportation costs for all but a few regions of the United States. The Norwest report lists ten plants that are willing to accept high-sodium coal and which constitute the likely initial market for Otter Creek coal, all located in Minnesota, Michigan, or Wisconsin. An additional fourteen plants are then listed as potential customers. These plants are located in North Dakota, West Virginia, Montana, Arizona, Washington, and Kansas.

All of the states that represent potential markets for Otter Creek coal, with the exceptions of West Virginia and North Dakota, have mandatory renewable portfolio standards requiring that their electric utilities deliver set shares of electricity from renewable or alternative energy sources. North Dakota has a voluntary renewable energy target. While these policies vary in their requirements and goals, as shown in Table 1, taken together they indicate that renewable energy generation will constitute a growing share of the electricity delivered in the states where Arch Coal hopes to market coal from the Otter Creek mine.

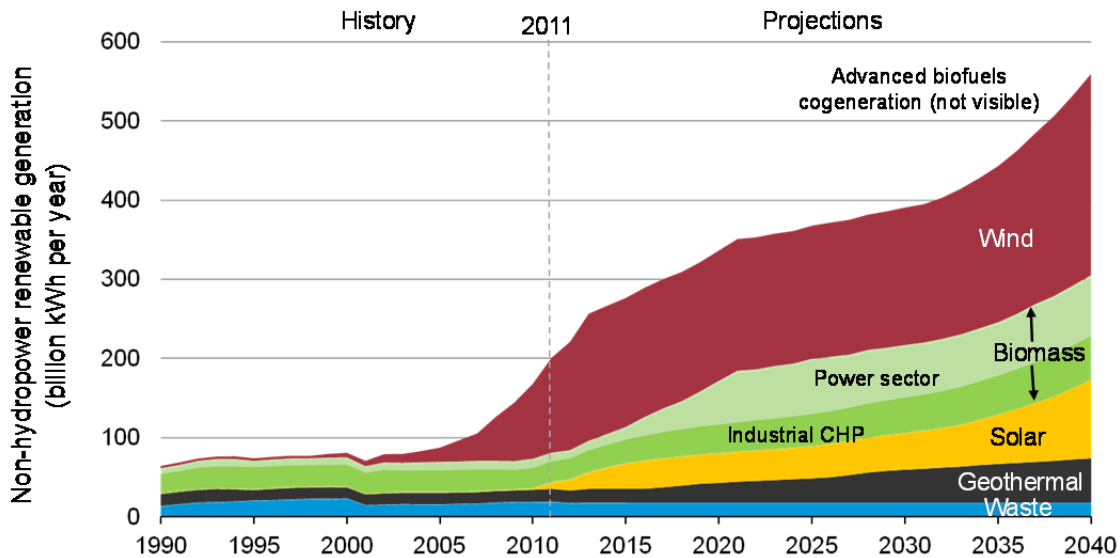
Table 1. State renewable energy requirements

State	Requirement
Mandatory RPS Requirement	
Arizona	15% by 2025
Kansas	20% by 2020
Michigan	10% by 2020
Minnesota	30% by 2020
Montana	15% by 2015
Washington	15% by 2020
Wisconsin	10% by 2015
Voluntary Goals	
North Dakota	10% by 2015

Source: Database of State Incentives for Renewables and Efficiency, January 2013.
<http://www.dsireusa.org/rpsdata/RPSspread011113.xlsx>

Nationwide, EIA projects that non-hydroelectric renewable generation will more than double between 2011 and 2040, partially as a result of state or national policies favoring renewable energy (Figure 14). These policies will further squeeze national demand for coal and contribute to increasing competition among coal suppliers.

Figure 14. Non-hydro renewable generation, 2011 to 2040 (thousand GWh)

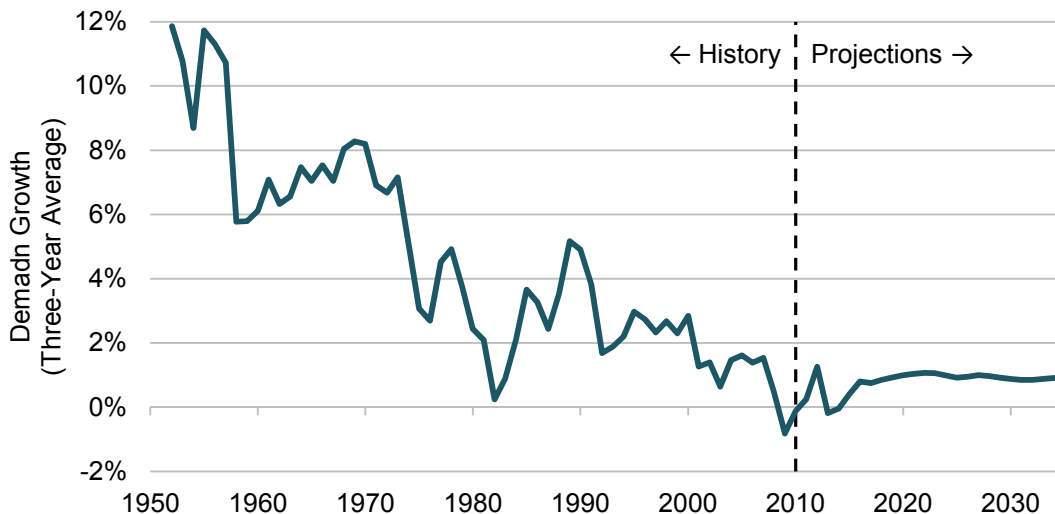


Source: EIA. Annual Energy Outlook 2012. www.eia.gov/pressroom/presentations/sieminski_01142013.ppt

Demand reduction due to energy efficiency

The growth rate of electricity demand has declined precipitously over the past sixty years, from 9.8 percent annually during the 1950s to only 0.7 percent per year during the past decade.⁵² As displayed in Figure 15, the EIA projects that the pace of growth of electricity demand will remain very slow through 2035 due to new appliance standards and investments in energy-efficient equipment.

Figure 15. Growth in U.S. electricity demand, 1950 to 2035



Source: EIA, 2012 Annual Energy Outlook http://www.eia.gov/forecasts/aeo/MT_electric.cfm

⁵² EIA. 2013. Annual Energy Outlook 2012.

EIA's regional projections show Otter Creek's prospective Midwestern, Kansas, and North Dakota customers with even lower electricity demand growth rates, ranging from 0.1 to 0.3 percent per year for the period 2010 to 2035, likely as the result of reduced economic growth and aggressive energy efficiency policies.⁵³ According to the American Council for an Energy-Efficient Economy, the Midwestern states that Norwest identifies as Otter Creek's initial market, together with Montana and Arizona, rank among the 20 states with the highest incremental energy savings as a percent of retail electricity sales.⁵⁴

Slow electricity demand growth, renewable portfolio standards, and competition from low-cost natural gas suggest that Montana coal will find it challenging to maintain its current sales, much less expand sales in the future.

8. Conclusions

Domestic demand for coal is in decline, and this is especially true for Otter Creek's particular type of high-sodium coal. The steadily worsening outlook for coal is primarily a result of the following factors:

- **Coal has lost its cost advantage.** Falling prices of natural gas coupled with higher mining and transportation costs for coal have eroded coal's competitiveness, leading to less frequent dispatch of coal units and lower demand for coal. Over the past decade, coal's net generation decreased by ten percent, while natural gas increased by nearly 50 percent.⁵⁵ Little new coal capacity is likely to be added over the coming decades.⁵⁶
- **Large numbers of coal plants are retiring in response to environmental regulations.** Strict new environmental regulations would require substantial new capital investments and increase operating costs for coal plants. This has led to coal plants across the country becoming uneconomic and announcing retirement, or converting to other fuel sources. Recent estimates project that a significant portion of the current coal fleet—up to 77 GW—will retire by 2020.
- **Otter Creek has a limited number of potential customers, and these coal plants are becoming uneconomic.** High sodium content limits Otter Creek's customer base,⁵⁷ and many of these potential customers may retire or convert to other fuels due to the high costs of complying with new environmental regulations—in fact, several have already announced their retirements.⁵⁸ Our analysis shows that the majority of these plants will be uneconomic compared both to the costs of operating existing natural gas plants and to the total costs of constructing and operating new natural gas plants.

⁵³ EIA. 2013. 2012 Annual Energy Outlook. <http://www.eia.gov/forecasts/aeo/er/index.cfm>

⁵⁴ Foster, Ben, et al. 1012. The 2012 State Energy Efficiency Scorecard. American Council for an Energy-Efficient Economy. <http://www.aceee.org/research-report/e12c>

⁵⁵ EIA. 2001-2012. Form 923, Schedule 5A.

⁵⁶ EIA. 2012 Annual Energy Outlook. http://www.eia.gov/forecasts/aeo/MT_electric.cfm

⁵⁷ The high sodium content of Otter Creek coal (and other Northern PRB coal) causes slagging problems in boilers. See footnote 3.

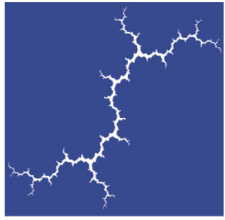
⁵⁸ See footnote 35.

- **Renewable portfolio standards, energy efficiency policies, and the likelihood of future carbon limits are reducing demand for coal.** Standards and goals for renewable energy are increasing the amount of renewables on the grid and heightening demand for natural gas as a complementary energy source due to its ability to adjust output much more quickly than coal. At the same time, increasingly aggressive energy efficiency investments are lowering energy demand across the board. Finally, a future price on carbon would drastically lower demand for coal, with generation falling to as little as 4 percent by 2040 under a carbon fee of \$25.⁵⁹ Many utilities and planning commissions are already factoring carbon prices into their planning.

The long-term viability of coal is severely threatened. Demand for coal is falling across the United States, and Otter Creek's coal market is further limited by the coal's high sodium content and connection to Northern, rather than Southern rail lines. In short, it is unreasonable to expect that there will be much, if any, domestic demand for Otter Creek coal when the mine becomes operational in 2017. There is, therefore, no justification for expanding rail transportation infrastructure to connect the Otter Creek coal mine to struggling domestic markets.

⁵⁹ EIA. 2012 Annual Energy Outlook www.eia.gov/pressroom/presentations/sieminski_01142013.ppt

APPENDIX 1



Synapse
Energy Economics, Inc.

Declining Markets for Montana Coal

**Prepared for the Northern Plains
Resource Council**

March 1, 2013

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1. Executive Summary

Arch Coal, a global coal producer and marketer, has announced plans to develop the Otter Creek mine in the area of Ashland, Montana, and has submitted an application to the U.S. Department of Transportation's Surface Transportation Board to construct a new rail line to connect the Otter Creek mine to an existing BNSF rail line.

The Otter Creek mine claims it will produce 20 million tons of coal per year. Like other Northern Powder River Basin mines, Otter Creek coal is high in sodium, with concentrations ranging from 5.8 to 8.8 percent, much higher than the 1.2 percent typical of the Southern Powder River Basin. Because sodium causes slagging problems at power plants, demand for the coal is limited.¹ The few plants within Otter Creek's competitive area that currently accept high-sodium coal are primarily located in the upper Midwest in Minnesota, Wisconsin, and Michigan.²

Domestic demand for coal has declined by 14 percent since its historical peak in 2007, and the future of coal for U.S. power generation is uncertain at best.³ According to the U.S. Energy Information Administration (EIA), only five new coal units were added in 2012, versus 50 coal unit retirements.⁴ The steadily worsening outlook for coal is primarily a result of the following factors:

- **Coal has lost its cost advantage.** Falling prices of natural gas coupled with higher mining and transportation costs for coal have eroded coal's competitiveness, leading to less frequent dispatch of coal units and lower demand for coal. Over the past decade, coal's net generation decreased by ten percent, while natural gas increased by nearly 50 percent.⁵ Little new coal capacity is likely to be added over the coming decades.⁶
- **Large numbers of coal plants are retiring in response to environmental regulations.** Strict new environmental regulations would require substantial new capital investments and increase operating costs for coal plants. This has led to coal plants across the country becoming uneconomic and announcing retirement, or converting to other fuel sources. Recent estimates project that a significant portion of the current coal fleet—up to 77 gigawatts—will retire by 2020.
- **Otter Creek has a limited number of potential customers, and these coal plants are becoming uneconomic.** High sodium content limits Otter Creek's customer base,⁷ and many of these potential customers may retire or convert to other fuels due to the high costs of complying with new environmental regulations—in fact, several have already

¹ Boiler slag is the molten bottom ash produced in wet bottom boilers.

² Norwest Corporation. 2006. *Otter Creek Property Summary Report*. Salt Lake City: Norwest Corporation.

³ EIA Form 923, Schedule 5A, 2007, 2011.

⁴ Based on preliminary data for 2012 from the EIA published in *Electric Power Monthly*. 24 January 2013. <http://www.eia.gov/electricity/monthly/backissues.html>

⁵ EIA. 2001-2012. Form 923, Schedule 5A.

⁶ EIA. 2012 Annual Energy Outlook. http://www.eia.gov/forecasts/aeo/MT_electric.cfm

⁷ The high sodium content of Otter Creek coal (and other Northern PRB coal) causes slagging problems in boilers. See footnote 3.

announced their retirements.⁸ Our analysis shows that the majority of these plants will be uneconomic compared both to the costs of operating existing natural gas plants and to the total costs of constructing and operating new natural gas plants.

- **Renewable portfolio standards, energy efficiency policies, and the likelihood of future carbon limits are reducing demand for coal.** Standards and goals for renewable energy are increasing the amount of renewables on the grid and heightening demand for natural gas as a complementary energy source due to its ability to adjust output much more quickly than coal. At the same time, increasingly aggressive energy efficiency investments are lowering energy demand across the board. Finally, a future price on carbon would drastically lower demand for coal, with generation falling to as little as 4 percent by 2040 under a carbon fee of \$25.⁹ Many utilities and planning commissions are already factoring carbon prices into their planning.

The long-term viability of coal is severely threatened. Demand for coal is falling across the United States, and Otter Creek's coal market is further limited by the coal's high sodium content and connection to Northern, rather than Southern rail lines. In short, it is unreasonable to expect that there will be much, if any, domestic demand for Otter Creek coal when the mine becomes operational in 2017. There is, therefore, no justification for expanding rail transportation infrastructure to connect the Otter Creek coal mine to struggling domestic markets.

2. Introduction

Domestic demand for coal has declined by 14 percent since its historical peak in 2007, and the future of coal for U.S. power generation is uncertain at best.¹⁰ According to the U.S. Energy Information Administration (EIA), only five new coal units were added in 2012, versus 50 coal unit retirements.¹¹

Several factors are reducing the nation's demand for coal. Falling costs of substitutes such as natural gas and renewable energy have eroded coal's cost advantage in much of the United States. A combination of new and more stringent environmental regulations has turned the tables on the profitability of coal plants across the nation, many of which now face difficult decisions among installing expensive environmental retrofits, converting to natural gas, or shuttering completely. On top of this, energy efficiency and the economic crisis have slowed electricity demand growth rates to a fraction of what they were during the heyday of coal plant construction. In many states, renewable portfolio standards are accelerating the transition away from coal to wind, solar, hydroelectricity, and biomass, as well as highlighting the advantages of natural gas's quick ramping ability for balancing intermittent resources. All of these factors have led to falling demand for coal and pose a serious threat to coal's long-term viability in the United States.

⁸ See footnote 35.

⁹ EIA. 2012 Annual Energy Outlook www.eia.gov/pressroom/presentations/sieminski_01142013.ppt

¹⁰ EIA Form 923, Schedule 5A, 2007, 2011.

¹¹ Based on preliminary data for 2012 from the EIA published in *Electric Power Monthly*. 24 January 2013. <http://www.eia.gov/electricity/monthly/backissues.html>

This report summarizes some of the key domestic energy trends and projections that are expected to challenge all U.S. coal producers in the coming decades, and highlights the obstacles facing the developers of the Otter Creek coal mine in Montana.

The Otter Creek Project

Arch Coal, a global coal producer and marketer, has announced plans to develop the Otter Creek mine in the area of Ashland, Montana, and has submitted an application to the U.S. Department of Transportation's Surface Transportation Board to construct a new rail line to connect the Otter Creek mine to an existing BNSF rail line.

The Otter Creek mine claims it will produce 20 million tons of coal per year. Like other Northern Powder River Basin mines, Otter Creek coal is high in sodium, with concentrations ranging from 5.8 to 8.8 percent, much higher than the 1.2 percent typical of the Southern Powder River Basin. Because sodium causes slagging problems at power plants, demand for the coal is limited.¹² The few plants within Otter Creek's competitive area that currently accept high-sodium coal are primarily located in the upper Midwest in Minnesota, Wisconsin, and Michigan.¹³

This report discusses several challenges facing the Otter Creek project, including:

- Coal electric generating capacity and generation per year will decrease in the future because of environmental costs, higher costs for coal, low natural gas prices, and, in all likelihood, greenhouse gas regulations.
- As a result, U.S domestic coal use will decline, increasing competitive pressures in the mining industry.
- Montana coal is at a relative disadvantage relative to Wyoming and other Southern Powder River Basin coals and, therefore, will likely see an even greater drop in production.

There is therefore no compelling justification for the expansion of transportation infrastructure for Montana coal based on domestic demand projections.

3. The Rapid Shift Away from Coal

U.S. coal is produced primarily for electricity generation; nearly 93 percent of coal consumed in the United States in 2011 was used by the electric power sector.¹⁴ For many years, coal's dominant position in electricity generation was unrivaled. In the late 1990s, more than half of the electricity generated in the United States came from coal. By April 2012, this share had declined to 33 percent—nearly equivalent to that of natural gas. Figure 1 shows this decline of approximately 1 percent per year over the past decade, which began even prior to 2009 when natural gas prices

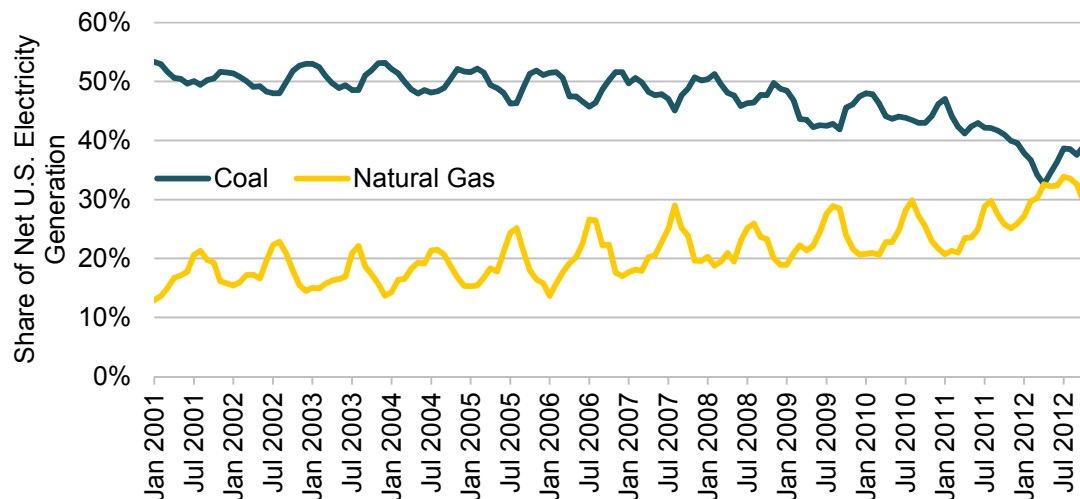
¹² Boiler slag is the molten bottom ash produced in wet bottom boilers.

¹³ Norwest Corporation. 2006. *Otter Creek Property Summary Report*. Salt Lake City: Norwest Corporation.

¹⁴ EIA. 2012. *Quarterly Coal Report: July-September 2012*. Washington, DC: U.S. Department of Energy. <http://www.eia.gov/coal/production/quarterly/pdf/qcr.pdf>

were much higher. Both natural gas prices and coal use rose slightly in 2012, but have not returned to their pre-2009 levels.

Figure 1. Share of Monthly Net U.S. Electricity Generation by Coal and Natural Gas, Jan. 2001 to Nov. 2012



Source: EIA Form 923, Schedule 5A, 2001 - 2012

Mining operations in the Powder River Basin, including those owned by Arch Coal, have not been impervious to this decline in coal consumption. From 2011 to 2012, the volume of coal sold by Arch Coal declined 11 percent as the company “idled equipment until coal market fundamentals improve.”¹⁵ Westmoreland Coal and Cloud Peak Energy, owners of several coal mines near the Otter Creek mine, also faced declining demand in 2012. While production steadily increased to nearly 20 million tons a year at Cloud Peak’s Spring Creek mine from 2006 to 2010, mine production has declined by nearly 11 percent in the past two years.¹⁶ Both companies cite lower natural gas prices as a primary factor driving reduced domestic demand.¹⁷

While coal production has declined in nearly every region of the United States over the past year, Montana coal producers have suffered a greater percentage decline in demand than the national average, and nearly twice as great a decline as that of lower-sodium Wyoming coal. In the 52 weeks ending on February 11, 2013, production declined by 8.7 percent nationally but fell by 11.4 percent in Wyoming and 21.4 percent in Montana.¹⁸

¹⁵ Arch Coal. 2013. 10-K Filing to the Securities and Exchange Commission. <http://www.sec.gov/>

¹⁶ According to Cloud Peak Energy’s 2013 10-K Filing to the Securities and Exchange Commission (<http://www.sec.gov/>), annual production at the Spring Creek mine declined from 19.3 million tons in 2010 to 17.2 million tons in 2012.

¹⁷ Westmoreland Coal. 2012. 10-Q: For the Quarterly Period Ended September 30, 2012. http://www.westmoreland.com/library/2012_SEC_Filings/Westmoreland_Coal_Co_September_10-Q_as_filed_November_8_2012.pdf; Cloud Peak Energy. 2013. 10-K to the Securities and Exchange Commission. <http://www.sec.gov/>

¹⁸ EIA. February 14, 2013. Weekly U.S. Coal Production Overview (DOE/EIA 0218/06). <http://www.eia.gov/coal/production/weekly/>

Coal's decline can be attributed to a number of factors, including competition from substitutes, loss of customers due to more stringent environmental regulations, policy support for renewable energy, and energy efficiency investments. These factors are discussed in greater detail below.

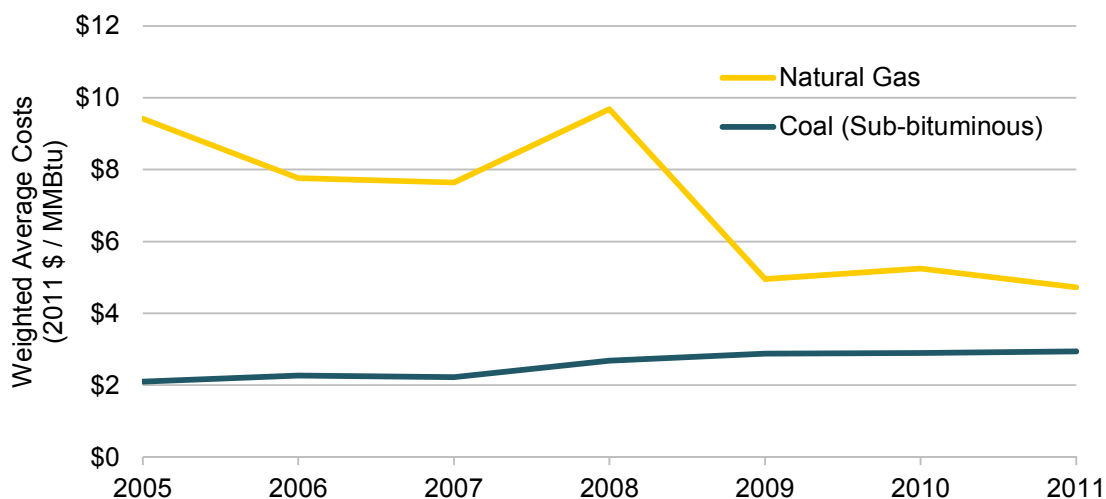
4. Coal's Disappearing Cost Advantage

Although once considered among the most inexpensive energy sources, in recent years the delivered price of coal has risen while the cost of substitutes—particularly natural gas and wind energy—has declined precipitously.

The rise of natural gas

More efficient natural gas extraction techniques, particularly hydraulic fracturing, have enabled the extraction of large reserves of shale gas that were previously uneconomic. Since 2007, shale gas production has risen rapidly—from less than 5 billion cubic feet per day, to more than 25 billion cubic feet per day.¹⁹ Natural gas prices have fallen correspondingly, while the average price of subbituminous coal (primarily from Western basins) has slowly risen, as displayed in Figure 2.

Figure 2. Weighted Average Real Natural Gas and Subbituminous Coal Prices per MMBTU for the Electric Power Industry, 2005 to 2011



Source: EIA, *Electric Power Annual 2011*, Table 7.4,
http://www.eia.gov/electricity/annual/html/epa_07_04.html

These low natural gas costs have had a dramatic impact on the dispatch order of existing power plants, as reflected in the relative monthly net generation values of coal and natural gas in Figure 1. For power plants that purchase their coal from higher-cost or geographically distant regions, natural gas has become more economic than coal.

¹⁹ EIA. 2013. Natural Gas Weekly Update: Monthly Dry Shale Gas Production. Washington, DC: U.S. Department of Energy.

Historically, natural gas plants have functioned primarily as load-following peaker plants—operating only at times of peak demand—due to higher fuel costs. As fuel costs decline, however, natural gas plants are transitioning to serving more baseload (i.e., operating during more hours of the year), enabled in part by the large amount of existing, under-utilized generating capacity at natural gas power plants.

In 2011, the United States had 457 gigawatts (GW) of natural gas nameplate capacity.²⁰ If one assumes a 90 percent capacity factor (that is, that on average natural gas plants were to be in operation 90 percent of the time), today's natural gas plants have the potential to produce more than 3.6 million gigawatt-hours (GWh)

Yet in 2011, natural gas generated only 1 million GWh—just 28 percent of their potential.²¹ This mismatch between capacity and generation is partially the result of the rapid build-out of gas plants during the late 1990s and early 2000s when gas prices were low.²²

Electricity generators are now beginning to more fully utilize that capacity, repurposing natural gas plants to serve baseload, or in some cases even converting coal plants to natural gas boilers. These impacts are clearly apparent in the change in share of net generation by fuel type from 2002 through 2011: the total electricity generated from coal declined by 10 percent, while the total electricity generated from natural gas increased by 46 percent in this period (see Figure 1).²³

Escalating coal transport costs

The locus of U.S. coal production has been moving westward for decades as Western coal production rapidly increased, overtaking Appalachian production levels in the late 1990s. Appalachian coal reached its zenith around 1990 and has been generally declining ever since, primarily due to increasingly adverse mining conditions and rising costs.

As Appalachian coal prices shot upward, Powder River Basin coal became competitive in eastern markets—despite the vast physical distance and transportation costs. A recent EIA analysis found that for the majority of power plants receiving Central Appalachian coal in 2007, Powder River Basin coal had become the lowest-cost option by 2010 (Figure 3).

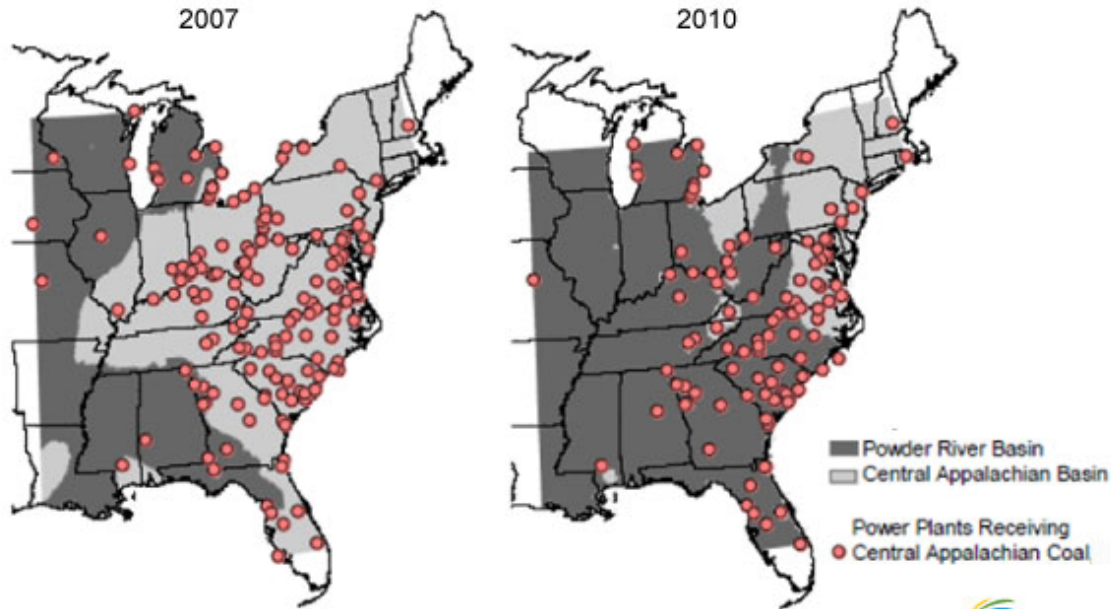
²⁰ EIA. 2011. Form 860.

²¹ EIA. 2011. Form 923.

²² From 2000 to 2011, natural gas generating capacity in the United States increased by 85 percent—from 220 GW to 457 GW—while net generation from natural gas increased by only 59 percent. EIA. 2001-2011. Form 860.

²³ EIA. 2001-2012. Form 923, Schedule 5A.

Figure 3. EIA Analysis of Lowest Delivered Cost of Coal by Coal Basin, 2007 and 2010



Source: U.S. Energy Information Administration



Note: Dark grey shading indicates that for plants in these areas, Powder River Basin coal has the lowest delivered cost. Light grey shading indicates that for plants in these areas, Central Appalachian Basin coal has the lowest delivered cost. Red circles indicate plants receiving Central Appalachian Basin coal.

Source: EIA. July 2013. *Coal Transportation to the Electric Power Sector*.

<http://www.eia.gov/coal/transportationrates/>

Yet, while Powder River Basin coal is clearly winning the competition with Central Appalachian coal in the East, both are losing ground in the wider U.S. domestic marketplace. From 2010 to 2012, both basins' production levels fell by nearly 10 percent, as other fuels became increasingly economic, displacing coal altogether.²⁴

One major factor affecting coal's competitiveness is the cost of transportation. Transportation costs accounted for nearly 60 percent of the delivered cost of Powder River Basin coal in 2010.²⁵ That is, on average, the transportation cost of Powder River Basin coal is typically greater than the cost of coal itself, and these costs have increased significantly since 2001. Appalachian and Illinois Basin coal have experienced the highest increases in transportation costs; increases in real, inflation-adjusted transportation costs for Powder River Basin coal, however, have also been significant, rising 14 percent from 2001 to 2010 (see Figure 4).

For all U.S. coal, high-and-rising transportation costs are harming the fuel's competitiveness with natural gas (which is transported domestically by pipelines at a much cheaper rate), and wind power, which is very nearly costless to operate (although it does have fixed, capital costs). Rising

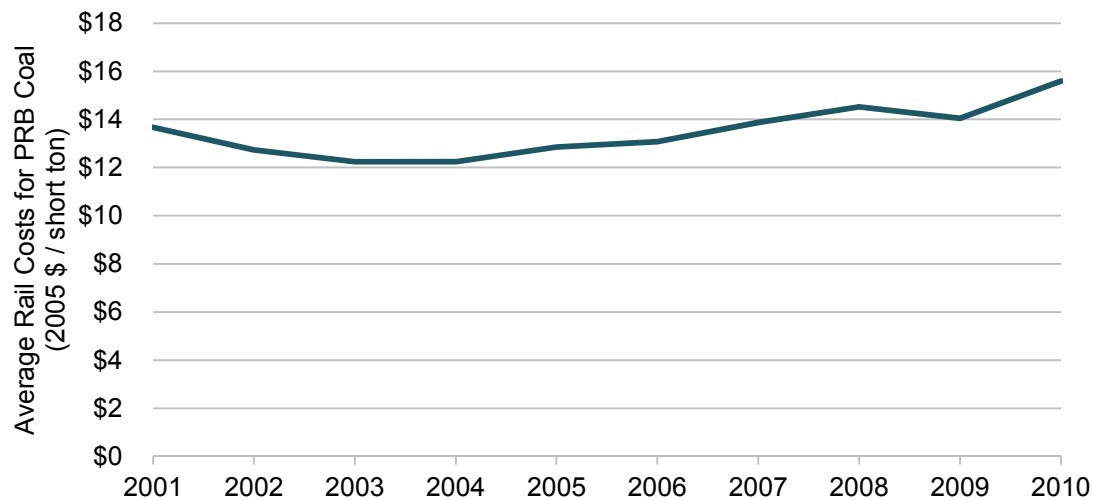
²⁴ EIA. 2013. Monthly Coal Production Forecast January 2002 - January 2013.

<http://www.eia.gov/coal/production/weekly/forecast/monthprodforecast2002.xls>

²⁵ EIA. 2012. "Cost of Transporting Coal to Power Plants Rose almost 50 Percent in Decade." *Today in Energy*, November 19, 2012. <http://www.eia.gov/todayinenergy/detail.cfm?id=8830>

transportation costs are contributing to coal's decline, and will certainly hinder the ability of Otter Creek and other Powder River Basin coal to expand in eastern markets.

Figure 4. Real Average Transportation Costs of Powder River Basin Coal, 2001 to 2010



Source: EIA, *Coal Transportation Rates to the Electric Power Sector, Trends 2001-2010*, Table 7, http://www.eia.gov/coal/transportationrates/excel/table7_PRB_Averages.xls

Mining costs on the rise

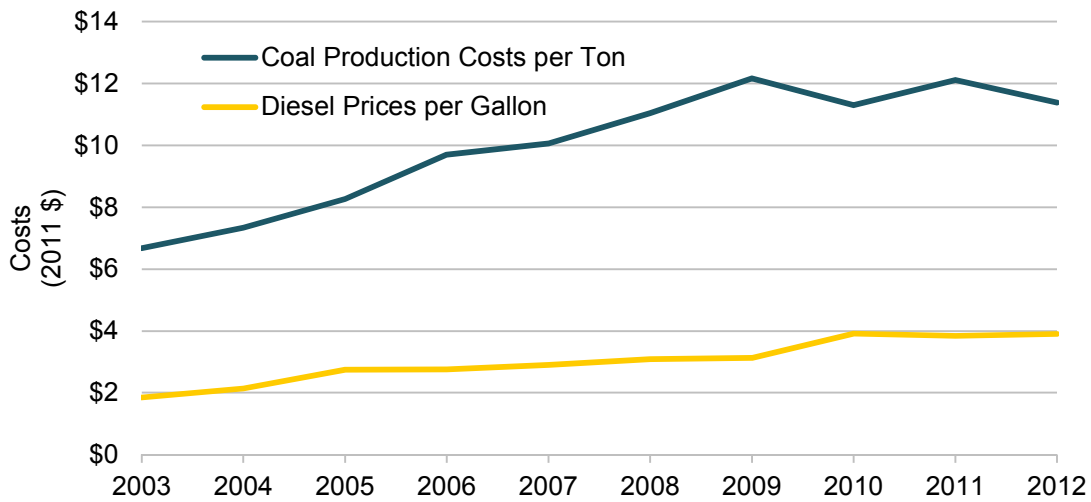
Higher mining costs, too, have eaten into coal's once-significant cost advantage. Coal producers in the Powder River Basin were hit especially hard by skyrocketing oil and steel prices during the 2000s due to their dependence on diesel fuel to power earth-moving equipment and their dependence on steel for the manufacture of mine supports. Arch Coal's Powder River Basin production costs have escalated at an average annual rate of nearly 7 percent since 2003.²⁶

As shown in Figure 5, diesel prices in particular have increased rapidly over the past few years, with real prices rising by an average annual rate of more than 8 percent from 2003 to 2012.²⁷ Arch Coal explicitly notes its exposure to fuel prices in its 10-K filings, stating, "Our coal mining operations use significant amounts of steel, diesel fuel, explosives, rubber tires and other mining and industrial supplies.... We also use significant amounts of diesel fuel and tires for the trucks and other heavy machinery we use, particularly at our Black Thunder mining complex. If the prices of mining and other industrial supplies, particularly steel-based supplies, diesel fuel and rubber tires, increase, our operating costs could be negatively affected."

²⁶ Arch Coal. 2013. 10-K Filing to the Securities and Exchange Commission. <http://www.sec.gov>

²⁷ EIA. 2013. *Short-Term Energy Outlook - Annual Average Diesel Price*. Washington, DC: U.S. Department of Energy. <http://www.eia.gov/forecasts/steo/>

Figure 5. Arch Coal Production Costs and Diesel Fuel Prices, 2003 to 2012



Source: Arch Coal 10-K 2013 Filing, EIA Diesel Fuel Prices (AEO 2012).

The EIA's 2012 *Annual Energy Outlook* reference case projects that oil prices will increase at an average annual rate of 2.5 percent (after correcting for inflation) from 2013 to 2035, which may lead to a continuing rise in mining costs over time.²⁸ Clearly substitution to other fuels and more efficient technologies will mitigate some of the effect on coal production costs, but recent experience has highlighted coal producers' vulnerability to rising commodity costs.

Coal is no longer competitive

Natural gas electricity generation costs have fallen below those of coal. Coal also faces competition from existing renewable energy sources, such as solar and wind, which, of course, have no fuel costs.

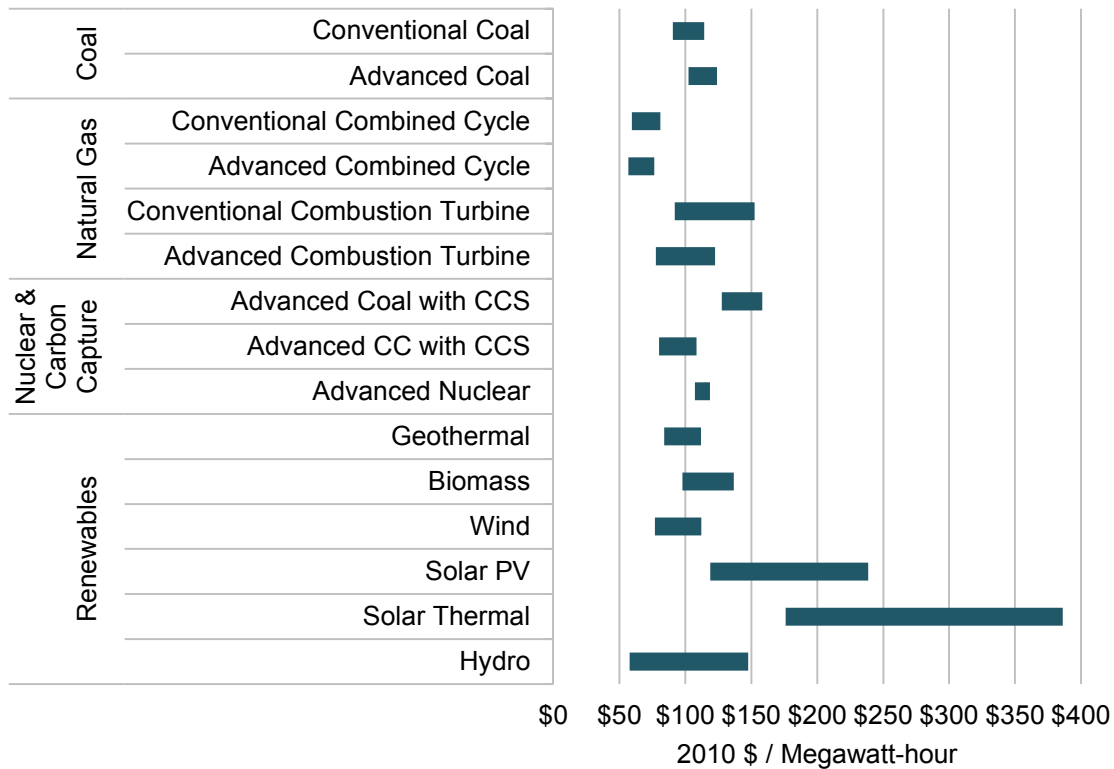
Coal's market position is even more precarious, however, when analyzed in terms of the total levelized cost of energy for newly constructed plants. Levelized costs are a convenient way of comparing various energy technologies by looking at the cost per megawatt hour (in real dollars) of construction and operation over the entire life of a plant, taking into account capital costs, fuel costs, operating and maintenance costs, financing costs, and an assumed utilization rate.

Historically, coal has maintained low levelized costs by balancing its large capital outlays with lower fuel costs, but this is no longer the case. Natural gas plants are much less expensive to build, can be built quickly, and possess much faster ramp rates that enable them to provide back-up generation for variable energy sources such as wind.²⁹ In the EIA's recent projection of 2017 average levelized costs for various energy technologies, natural gas combined-cycle plants clearly outperformed conventional and advanced coal, and natural gas combustion turbines exhibited nearly equivalent costs to coal, but with a wider range of costs due to regional variation in local labor markets, and the cost and availability of fuel (see Figure 6).

²⁸ EIA. 2012. *Annual Energy Outlook 2012*. Washington, DC: U.S. Department of Energy.

²⁹ Higher ramping rates allow natural gas plants to quickly increase and decrease electricity output to match offset fluctuations in variable energy sources such as wind.

Figure 6. Levelized Cost of Energy for Various Technologies, 2017



Note: Assumed capacity factors are: coal = 85%, combined cycle = 87%, combustion turbines = 30%, nuclear = 90%, geothermal = 91%, biomass = 83%, wind = 33%, solar PV = 25%, solar thermal = 20%, and hydro = 53%.

Source: Levelized Cost of New Generation Resources in the Annual Energy Outlook 2012, Table 2, http://www.eia.gov/forecasts/aeo/electricity_generation.cfm

It comes as no surprise, then, that few coal plants are being proposed or constructed (see the section below on 'The Future of U.S. Coal-Powered Electric Generation'). Natural gas is simply more economic, better suited for the integration of renewable energy, and not as susceptible to costly environmental retrofits as coal plants.

5. Regulation favors shift away from coal

New, stricter environmental regulations are adding to the costs of operating coal-fired power plants. Many of the nation's aging coal plants are widely expected to retire over the next few

decades, to be replaced by natural gas, renewables, and energy efficiency measures.³⁰ This section describes each of the federal environmental regulations affecting coal plants in turn.³¹

National Ambient Air Quality Standards

National Ambient Air Quality Standards (NAAQS) set maximum air quality limitations that must be met at all locations across the nation. Compliance with the NAAQS can be determined through air quality monitoring stations, which are stationed in various cities throughout the United States, or through air quality dispersion modeling. States with areas found to be in “nonattainment” of a particular NAAQS are required to set enforceable requirements to reduce emissions from sources contributing to nonattainment such that the NAAQS are achieved and maintained. The U.S. Environmental Protection Agency (EPA) has established NAAQS for six pollutants: sulfur dioxide (SO₂), nitrogen dioxides (NO₂), carbon monoxide (CO), ozone, particulate matter (measured as particulate matter less than or equal to 10 micrometers in diameter (PM₁₀) and particulate matter less than or equal to 2.5 micrometers in diameter (PM_{2.5})), and lead.

In nonattainment areas, coal plants and other sources must comply with emission reduction requirements known as “Reasonably Available Control Technology” (RACT) to bring the areas into attainment of the NAAQS. New major sources, including major modifications at existing sources, must comply with very strict emissions reductions consistent with “lowest achievable emissions reductions” (LAER) as well as obtain emission offsets.

EPA is currently in the process of drafting new, more stringent NAAQS for SO₂, PM_{2.5}, and ozone.

- On June 22, 2010, EPA revised³² the standard for SO₂ by establishing a new 1-hour standard at a level of 75 parts per billion (ppb) in place of the existing annual and 24-hour standards for SO₂. EPA plans to make area designations for the new SO₂ standard by June 3, 2013, and compliance would be required in 2017.
- On December 14, 2012, EPA strengthened the annual PM_{2.5} standard from 15 µg/m³ to 12 µg/m³, and retained the current 24-hour standard at 35 µg/m³. EPA will make final area designations for the new standard by December 2014. Once designations are made, states with non-attainment areas will have to develop a State Implementation Plan within three years outlining how they will reduce pollution to meet the standard by 2020.
- In March 2008, EPA strengthened the 8-hour ozone standard from 84 ppb to 75 ppb. On September 16, 2009, EPA announced that because the 2008 standard was not as protective as recommended by EPA’s panel of science advisors, it would reconsider the 75 ppb standard. In 2010, EPA proposed lowering the 8-hour ozone standard from 75 ppb to between 60 and 70 ppb, and September 2, 2011, the Administration announced that EPA would not finalize its proposed reconsideration of the 75 ppb standard ahead of the regular 5-year NAAQS review cycle. The next 5-year review for 8-hour ozone is expected

³⁰ Elliott, Gold, and Hayes. August 2011. Avoiding a Train Wreck: Replacing Old Coal Plants with Energy Efficiency. ACEEE White Paper. http://aceee.org/files/pdf/white-paper/Avoiding_the_train_wreck.pdf

³¹ For more detailed information on up-coming environmental regulations see Miller. January 2013. A Primer on Pending Environmental Regulations and their Potential Impacts on Electric System Reliability. NESCAUM. <http://www.nescaum.org/>

³² 75 Fed. Reg. 35520 (June 22, 2010)

in 2013. Compliance with the upcoming standard would likely be required in the 2019-2020 timeframe.

Cross State Air Pollution Rule

The Cross State Air Pollution Rule (CSAPR) was finalized in 2011, establishing the obligations of each affected state to reduce emissions of NO_x and SO₂ that significantly contribute to another state's PM_{2.5} and ozone non-attainment problems. The rule targets coal and other electric generating units, and uses a cap and-trade approach to limit each state to emissions below a level that significantly contributes to non-attainment in downwind states.

On August 21, 2012, CSAPR was vacated by the U.S. Court of Appeals for the District of Columbia. EPA has filed a petition for *en banc* rehearing of that decision; even if EPA fails to salvage CSAPR through the courts, however, the Agency must still promulgate a replacement rule to implement Clean Air Act requirements to address the transport of air pollution across state boundaries. In the meantime, the court left the requirements of the 2005 Clean Air Interstate Rule in place.

Regional Haze Rules

One of the national goals set out in the Clean Air Act is reducing existing visibility impairment from human-made air pollution in all "Class I" areas (e.g., most national parks and wilderness areas).³³ EPA's Regional Haze Rule—issued in 1999, and revised in 2005—requires states to create plans to significantly improve visibility conditions in Class I areas with the goal of achieving natural background visibility conditions by 2064. These requirements are implemented through state plans with enforceable reductions in haze-causing pollution from individual sources and with other measures to meet "reasonable further progress" milestones.³⁴ The first progress milestone is 2018.

A key component of this program is the imposition of air pollution controls on coal plants and other existing facilities that impact visibility in Class I areas. Specifically, the rules require installation of "best available retrofit technology" (BART) that is developed for such facilities on a case-by-case basis. In addition, EPA's BART determinations specify particular emission limits for each BART-eligible facility. EPA evaluates BART for the air pollutants that impact visibility in our national parks and wilderness areas – namely SO₂, PM, and nitrogen oxides (NO_x). Under the Clean Air Act, states develop Regional Haze requirements, but EPA approves state plans for compliance. If EPA finds the plans are not consistent with the Clean Air Act, it adopts a federal plan with BART and reasonable progress requirements. Affected facilities must comply with the BART determinations as expeditiously as practicable but no later than five years from the date EPA approves the state plan or adopts a federal plan.³⁵

³³ 42 U.S.C. § 7491(a)(1)

³⁴ 40 C.F.R. §51.308-309

³⁵ EPA's regulations allow certain states in the "Grand Canyon Visibility Transport Region" to participate in an SO₂ trading program in lieu of adopting source-specific SO₂ BART requirements, if the trading program will result in greater reasonable progress toward attaining the national visibility goal than source-specific BART. Although nine states were originally eligible to participate, today only three states are opting to participate in this program – New Mexico, Utah, and Wyoming. These states agreed to a gradually declining cap on SO₂ emissions from all emission sources. If the declining caps are exceeded in any year, then even greater SO₂ emission reductions have to be

Mercury and Air Toxics Standards

In 2000, EPA determined it was appropriate and necessary to regulate toxic air emissions (or hazardous air pollutants) from coal and other steam electric generating units. As a result, EPA adopted strict emission limitations for hazardous air pollutants that are based on the emissions of the cleanest existing sources.³⁶ These emission limitations are known as Maximum Achievable Control Technology (MACT). The final MATS rule, approved in December 2011, sets strict stack emissions limits for mercury, other metal toxins, other organic and inorganic hazardous air pollutants, as well as acid gasses. Compliance with MATS is required by 2015, with a potential extension to 2016.

Coal Combustion Residuals Disposal Rule

Coal-fired power plants generate a tremendous amount of ash and other residual wastes, which are commonly placed in dry landfills or slurry impoundments. The risk associated with wet storage of coal combustion residuals (CCR) was dramatically revealed in the catastrophic failure of the ash slurry containment at the Kingston coal plant in Roane County, Tennessee in December 2008, releasing over a billion gallons of slurry and sending toxic sludge into tributaries of the Tennessee River.

On June 21, 2010, EPA proposed to regulate CCR for the first time either as a Subtitle C hazardous waste or Subtitle D solid waste under the Resource Conservation and Recovery Act. The current rulemaking is 30 years overdue. If the EPA classifies CCR as hazardous waste, a cradle-to-grave regulatory system would apply to CCR, requiring regulation of the entities that create, transport, and dispose of the waste. Under a Subtitle C designation, the EPA would regulate siting, liners, run-on and run-off controls, groundwater monitoring, fugitive dust controls, and any corrective actions required; in addition, the EPA would implement minimum requirements for dam safety at impoundments. Under a solid waste Subtitle D designation, the EPA would require minimum siting and construction standards for new coal ash ponds, compel existing unlined impoundments to install liners, and require standards for long-term stability and closure care.

The EPA is currently evaluating which regulatory pathway will be most effective in protecting human health and the environment. In 1999, EPA released a series of technical papers to Congress documenting cases in which damages are known to have occurred from leakages and spills from coal ash impoundments.³⁷ In the current proposed rule, the EPA recognizes a substantial increase in the types and quantities of potentially toxic CCR caused by air pollution control equipment.

achieved—although the reductions can be met through emissions trading, rather than imposition of specific emission limitations on any one facility. This program is called the Backstop Trading Program. As of the date of this testimony, EPA has not yet approved the Backstop Trading Program to meet Regional Haze requirements in any of the three states' Regional Haze plans, so the trading program is not yet federally enforceable.

³⁶ Clean Air Act §112(d)

³⁷ EPA. March 15, 1999. Technical Background Document for the Report to Congress on Remaining Wastes from Fossil Fuel Combustion: Potential Damage Cases.

http://www.epa.gov/osw/nonhaz/industrial/special/fossil/ffc2_397.pdf

Use of more advanced air pollution control technology reduces air emissions of metals and other pollutants in the flue gas of a coal-fired power plant by capturing and transferring the pollutants to the fly ash and other air pollution control residues. The impact of changes in air pollution control on the characteristics of CCRs and the leaching potential of metals is the focus of ongoing research by EPA's Office of Research and Development.³⁸

Steam Electric Effluent Limitation Guidelines

Following a multi-year study of steam-generating units across the country, EPA found that coal-fired power plants are currently discharging a higher-than-expected level of toxic-weighted pollutants into waterways. Current effluent regulations were last updated in 1982 and do not reflect the changes that have occurred in the electric power industry over the last thirty years, and do not adequately manage the pollutants being discharged from coal-fired generating units. Coal ash ponds and flue gas desulfurization systems used by such power plants are the source of a large portion of these pollutants, and are likely to result in an increase in toxic effluents in the future as environmental regulations are promulgated and pollution controls are installed. No new rule has yet been proposed, but EPA is under a court order to issue the proposed regulation by April 19, 2013 and a final rule in May 22, 2014.³⁹ New requirements will be implemented in 2014 to 2019 through the five-year National Pollutant Discharge Elimination System permit cycle.⁴⁰

Clean Water Act Cooling Water Intake Structure Rule

On March 28, 2011, the EPA proposed a long-expected rule implementing the requirements of Section 316(b) of the Clean Water Act at existing power plants.⁴¹ Section 316(b) requires “that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact.” Under this new rule, EPA set new standards reducing the impingement and entrainment of aquatic organisms from cooling water intake structures at new and existing electric generating facilities.

The rule provides that:

- Existing facilities that withdraw more than two million gallons per day are subject to an upper limit on fish mortality from impingement, and must implement technology to either reduce impingement or slow water intake velocities.
- Existing facilities that withdraw at least 125 million gallons per day are required to conduct an entrainment characterization study to establish a “best technology available” for the specific site.

³⁸ 75 Fed. Reg. 35139 (June 21, 2010).

³⁹ See U.S. Environmental Protection Agency website. Accessed February 21, 2013. Available at: <http://water.epa.gov/scitech/wastetech/guide/steam-electric/amendment.cfm>

⁴⁰ See U.S. Environmental Protection Agency. *Steam Electric ELG Rulemaking*. UMRA and Federalism Implications: Consultation Meeting. October 11, 2011. <http://water.epa.gov/scitech/wastetech/guide/upload/Steam-Electric-ELG-Rulemaking-UMRA-and-Federalism-Implications-Consultation-Meeting-Presentation.pdf>

⁴¹ 33 U.S.C. § 1326.

Title V Greenhouse Gas Tailoring Rule

Under EPA's Greenhouse Gas Tailoring Rule, coal plants and other large sources of greenhouse gas emissions are subject to permitting requirements. A "large source" is a new facility with emissions of at least 100,000 tons per year of carbon dioxide equivalent (CO₂e) or an existing facility that emits at least 100,000 tons per year CO₂e and is making changes that would increase greenhouse gas emissions by at least 75,000 tons per year CO₂e. These sources are required to obtain permits under the New Source Review Prevention of Significant Deterioration and Title V Operating Permit programs and must install Best Available Control Technology (BACT) for greenhouse gases. The BACT requirement only applies, however, if the project also increases emissions of at least one non-greenhouse-gas pollutant.

New Source Performance Standards

Under Section 111 of the Clean Air Act, EPA sets technology-based standards for new sources on a category-by-category basis. These standards are set based on the best demonstrated available technology (BDAT) and apply to all new sources built or modified following promulgation of the standard.

On March 27, 2012, EPA proposed⁴² New Source Performance Standards for greenhouse gas emissions from new electric generating units, such as coal-fired power plants. The standard was set at 1,000 lbs CO₂e/MWh, which is equivalent to the emission rate that a combined-cycle natural gas unit can achieve. A new coal plant would have to employ carbon capture and sequestration (CCS) technology with the capability of removing 50 percent of CO₂ emissions in order to meet the standard. The rule also allows a unit's emissions to be averaged over 30 years to achieve an annual average emission rate of 1,000 lbs CO₂e/MWh. This option allows the phase-in of CCS within the first 10 years of operation.

While New Source Performance Standards apply only to new facilities, Section 111(d) of the Clean Air Act requires states to develop plans for *existing* sources of any non-criteria pollutants (i.e., a pollutant for which there is no NAAQS) and non-hazardous air pollutant whenever EPA promulgates a standard for a new source. These plans are subject to EPA review and approval, similar to state implementation plans under the NAAQS program.

The implications of forthcoming environmental regulations for coal plants

EPA's increasingly stringent environmental regulations will have substantial impacts on the coal industry. Many coal plants will require retrofits to comply with the regulations, and a significant number of plants may be retired as they become too expensive to operate.⁴³ Further detailed analysis of these impacts is discussed in the following section.

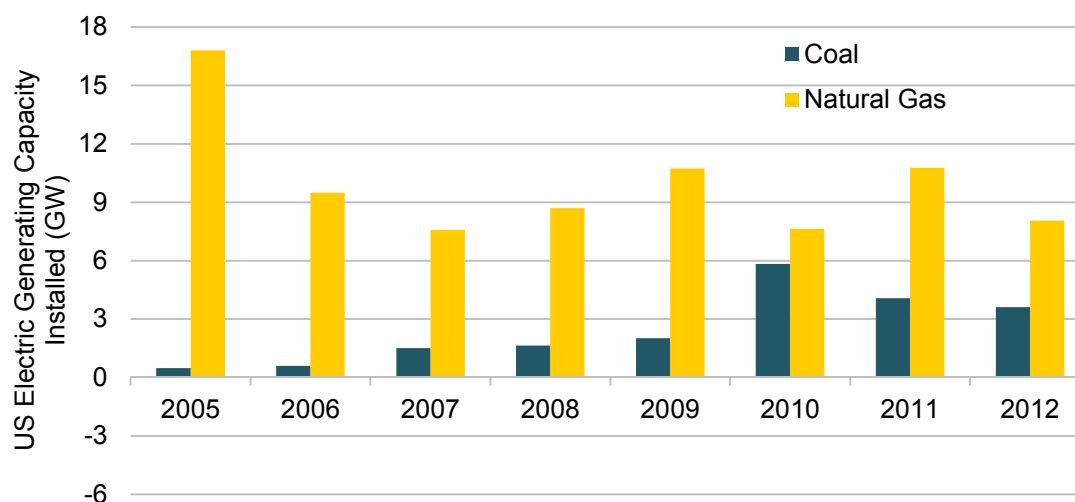
⁴² 77 Fed. Reg. 22392 (April 13, 2012)

⁴³ EPA performed an analysis of the costs of compliance with each of the four major rules expected to impact the electric industry. Annual compliance costs are projected to total \$10.2 billion for MATS, \$853 million for CSAPR, \$600 million to \$1.5 billion for CCR depending on which option is finalized, and \$397 million for 316(b). Source: U.S. Government Accountability Office, July 2012. *EPA Regulations and Electricity: Better Monitoring by Agencies could Strengthen Efforts to Address Potential Challenges*. <http://www.gao.gov/assets/600/592542.pdf>

6. The Future of U.S. Coal-Powered Electric Generation

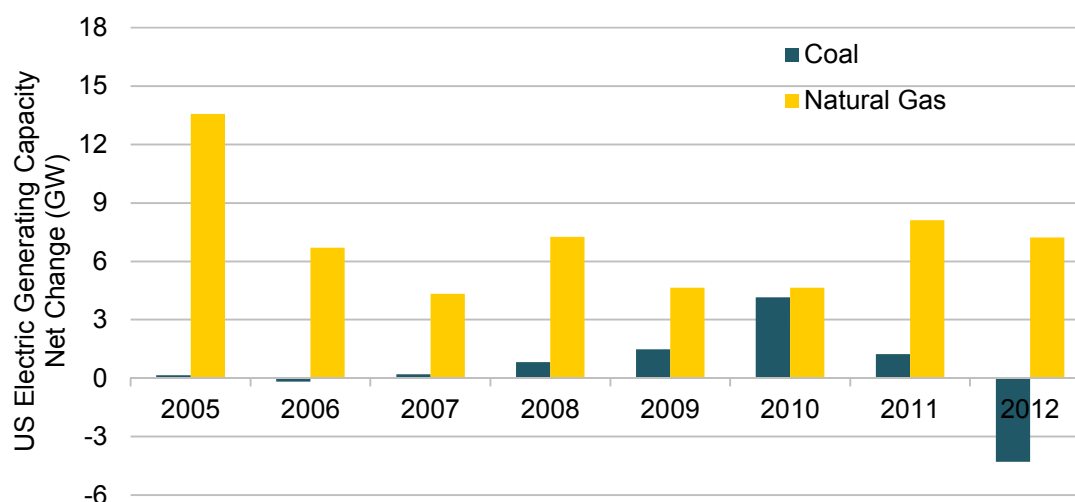
Competition from other generation technologies and forthcoming environmental regulations are pushing much of the existing U.S. coal fleet into retirement, and few coal plant additions are expected. Newly installed electric generating facilities are dominated by natural gas (see Figure 7), and the net change in generating facilities (new installations less retirements) favors natural gas over coal even more strongly (see Figure 8).

Figure 7. Newly Installed Generating Capacity by Year, 2005 to 2012



Source: EIA Form 860, 2005–2012

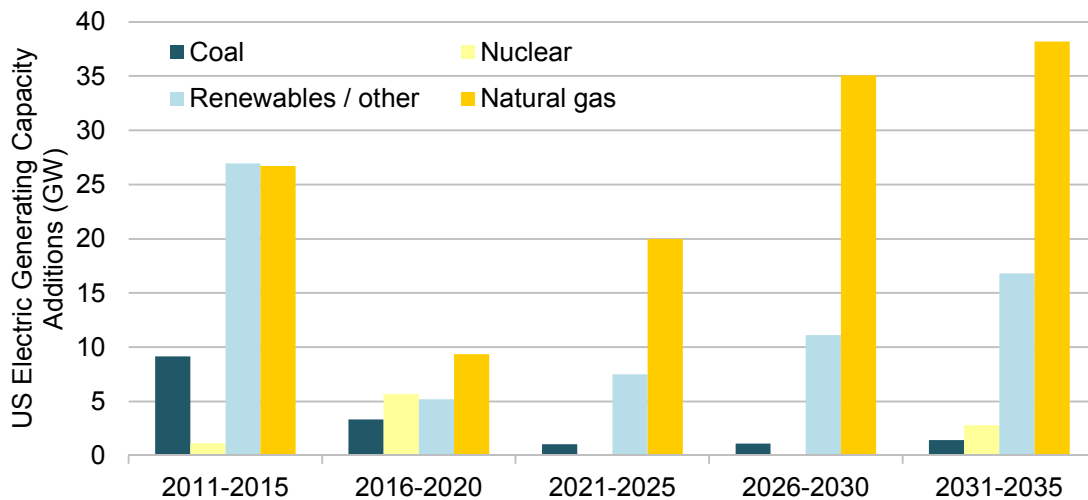
Figure 8. Net Change in Generating Capacity by Year, 2005 to 2012



Source: EIA Form 860, 2005-2012

EIA's 2012 *Annual Energy Outlook* reference case projects very little new coal capacity to be added over the next twenty years, while large amounts of capacity are projected to soon retire. As Figure 9 demonstrates, most new capacity is expected to be a mixture of natural gas and renewables, not coal.

Figure 9. Electricity generation capacity additions by fuel type, including combined heat and power, 2011 to 2035 (GW)



Source: EIA. 2012 Annual Energy Outlook. http://www.eia.gov/forecasts/aeo/MT_electric.cfm

At the same time that little new coal capacity is expected to be added, significant amounts may soon be retired. Already, plants totaling 30 GW of coal capacity have announced their retirements by 2016. The Brattle Group's most recent forecast of likely coal retirements in response to tightening environmental regulations was 59 to 77 GW.⁴⁴ As of February 2013, Black & Veatch estimates that nearly 62 GW of coal capacity will be retired by 2020, up slightly from what the company estimated in mid-2012.⁴⁵

Coal plant retirements include many of Otter Creek's potential customers

Coal plant retirements will make it increasingly difficult for Otter Creek coal to find buyers for its high-sodium coal. Already several of the ten coal plants identified as the initial target market for the mine's coal have announced their retirement or conversion to natural gas or biomass.⁴⁶ It is reasonable to expect that many more of the potential customers for Otter Creek coal will be retired in the near future as units face escalating costs of environmental upgrades.

Costs of operating electric generating units include both fixed and variable components. Fixed costs are invariant to the amount of generation (e.g. investment capital, property taxes, and fixed operation and maintenance expenses). Variable, or "running," costs strongly depend on the

⁴⁴ The Brattle Group. October 2012. *Potential Coal Plant Retirements: 2012 Update*. http://www.brattle.com/_documents/UploadLibrary/Upload1082.pdf

⁴⁵ Maloney, Peter. 2013. Black & Veatch Updates Coal-fired Power Plant Retirement Estimates. Platts.

⁴⁶ Conversion of Hoot Lake to natural gas by 2020 was approved by the Minnesota Public Utilities Commission in January 2013 (<http://minnesota.publicradio.org/display/web/2013/01/31/business/hoot-lake-plant-stop-burning-coal>), several units of Syl Laskin will switch to natural gas (<http://fresh-energy.org/2013/01/news-release-clean-air-victory-in-northern-minnesota-as-minnesota-power-announces-phasing-out-coal-at-two-minnesota-plants/>), while Bayfront will be converted to biomass (<http://www.jsonline.com/blogs/business/68594702.html> ; <http://www.woodbioenergymagazine.com/magazine/2012/1012/article-old-pro-excel.php>).

amount of generation (e.g. fuel costs, emissions costs, and variable operation and maintenance expenses).

Pollution control technologies affect the forward-going cost of a unit in several ways. First, these technologies require investment capital and increase the fixed costs at a unit in a given year, which depend, in part, on the size of the unit; smaller units are more expensive to retrofit on a dollar per kilowatt basis. Second, emission control equipment requires electricity to run—called the “parasitic load”—reducing the net output of a generating unit; in other words, the same fuel usage results in less electricity output. Finally, many emission controls also require the use of a chemical reagent, purchase of which increases variable operation and maintenance costs.⁴⁷

The dispatch order of generation units—which units are called upon to generate electricity in a given hour and which are not—is driven by unit variable costs, but the decision to construct a new plant or retrofit a plant with new environmental controls is based on the combination of the additional fixed costs of the environmental controls and the variable costs. Together these constitute the “forward-going operating costs.”

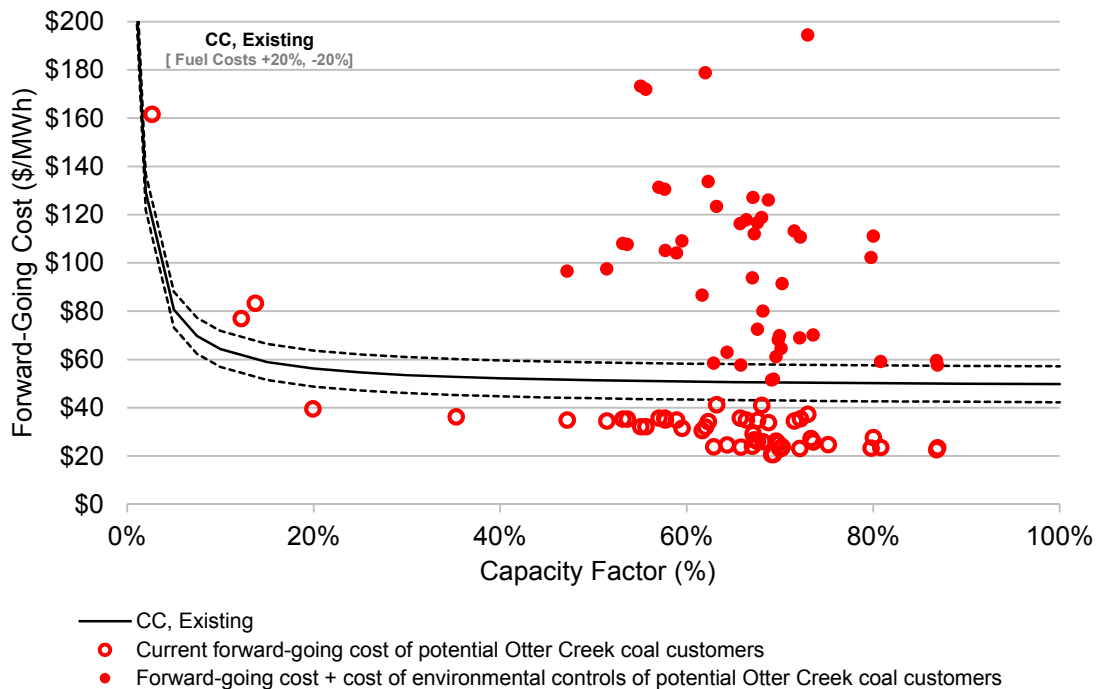
Synapse Energy Economics performed an analysis of the 52 units identified by Norwest as potential Otter Creek customers, based on each unit’s operating characteristics and estimated capital expenditures for the specific environmental upgrades that would be needed to comply with EPA regulations assuming a \$15 per ton CO₂ carbon price. The coal fuel costs used for this analysis conservatively assume that the current cost of delivered coal remains the same, ignoring the likelihood that these costs will increase due to higher transportation and mining costs over the next decade.⁴⁸

Figure 10 displays the forward-going operating costs of these coal units, first without any carbon price or environmental upgrades (the hollow red circles) and then with both an approximately \$15 per ton carbon price and the specific environmental technologies that each plant would need to be in compliance with federal law (the solid red circles). The solid circles are the relevant costs that will be considered when deciding whether to retire a unit or retrofit it with new environmental controls.

⁴⁷ Wilson, Rachel. July 23, 2012. “Direct Testimony of Rachel S. Wilson.” *Case No. 2012-00063, Application of Big Rivers Electric Corporation, Before the Public Service Commission of Kentucky.*

⁴⁸ Estimated from EIA. 2010. Form 923.

Figure 10. Forward-going costs of existing coal units by capacity factor (\$/MWh) relative to the total levelized cost of an existing natural gas combined cycle unit



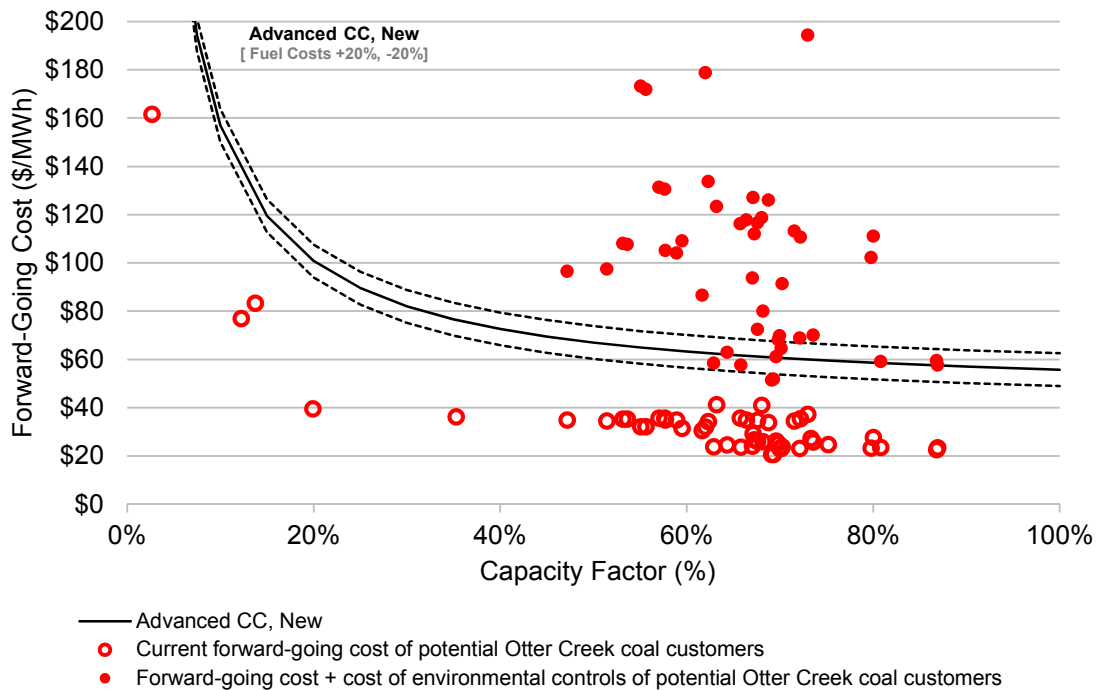
Source: Authors' calculations.

Shown also on Figure 10 is the fixed plus variable cost of a typical existing combined-cycle natural gas plant with the \$15 per ton carbon price included. The dashed lines above and below the natural gas line combined cycle cost represent 20 percent higher and lower fuel costs, with natural gas fuel costs derived from *Annual Energy Outlook* projections through 2022.

While the majority of the coal plants identified as potential Otter Creek customers were more economic to operate than an existing combined-cycle natural gas plant prior to the environmental upgrades and carbon price, this is no longer the case once the environmental costs are factored in. Our analysis estimates that these units face environmental control capital expenditures ranging from \$141 million to \$822 million. The decision of whether to retrofit these units, convert them to natural gas, or retire them will be based on each unit's variable costs, plus the environmental capital costs, the carbon price, and reduced efficiency due to the parasitic load. It is reasonable to expect that many units will find it difficult to justify their continued operation and will likely retire rather than bear the expense of an environmental retrofit.

Figure 11 presents the same analysis, but this time in comparison to the higher costs of an advanced new combined-cycle gas plant, including the cost to construct the plant itself. The results are striking: After complying with environmental regulations, the majority of Otter Creek's potential customers' costs will be higher than the cost of building and operating a new combined-cycle natural gas plant.

Figure 11. Forward-going costs of existing coal units by capacity factor (\$/MWh) relative to the total levelized cost of new advanced natural gas combined cycle unit



Source: Authors' calculations.

7. Other Policies Reducing Demand for Coal

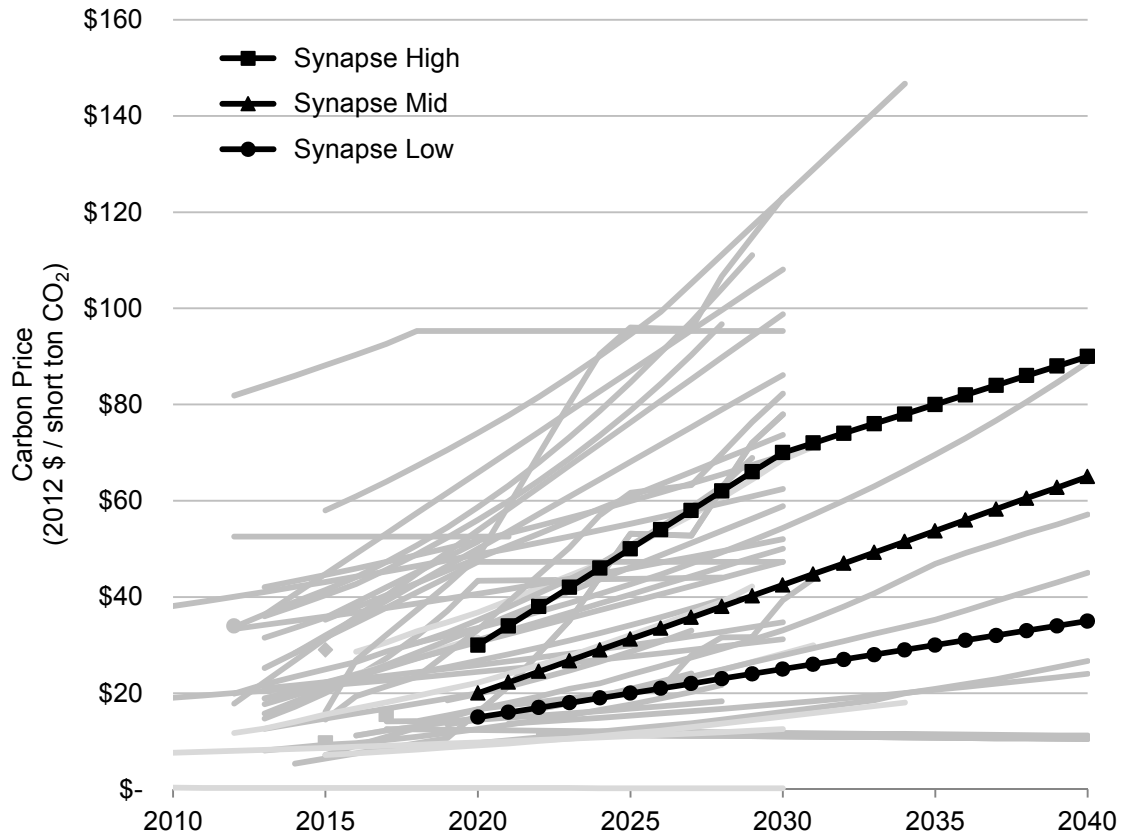
Several other categories of energy and environmental policies, at both the federal and state levels, are likely to have the effect of reducing domestic demand for U.S. coal. The sections below discuss the expected impact of carbon policies, renewable portfolio standards, and energy efficiency measures.

Future carbon policy favors shift away from coal

While there is not currently a federal law or proposed rulemaking requiring a carbon control technology, cap-and-trade program, or tax on emissions of CO₂, discussions at the EPA and at the Congressional level are ongoing. Due to coal's high rate of carbon emissions, demand for this fuel would be impacted significantly by a national or regional carbon policy.

Based on a review of more than 40 current carbon price estimates and related analyses, including CO₂ price estimates used by electric utilities in planning, Synapse Energy Economics developed low, mid, and high estimates of future carbon prices for the period 2020 to 2040. Synapse's 2020 carbon price projections range from \$15 to \$30 per ton of CO₂, with a mid-case of \$20 per ton of CO₂. The Synapse carbon price projections are compared to the range of utility carbon price forecasts in Figure 12.

Figure 12. Synapse CO₂ price forecasts compared to the range of utility forecasts

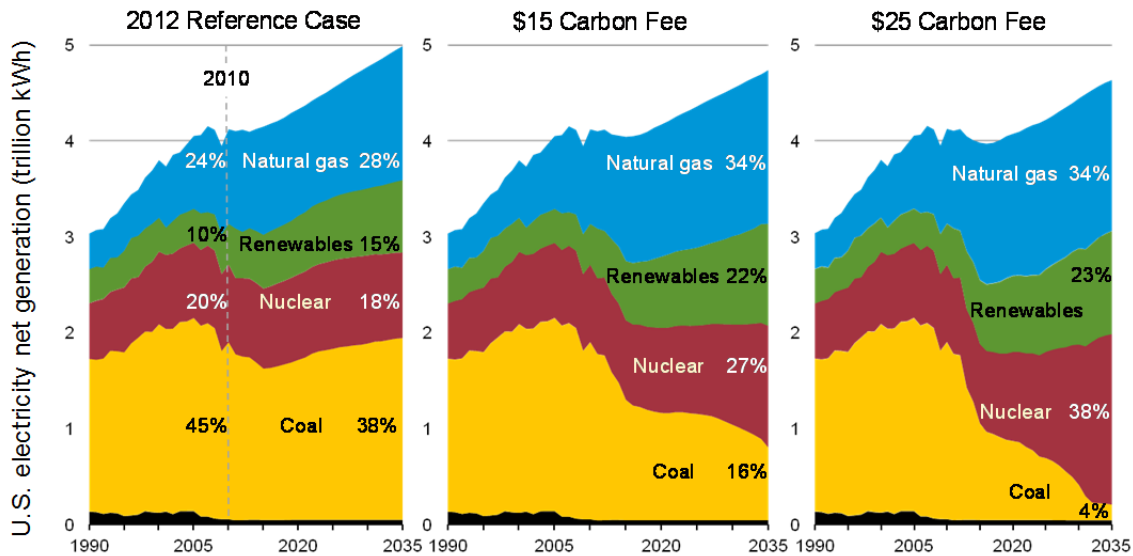


Source: Wilson, Rachel, Patrick Luckow, Bruce Biewald, Frank Ackerman, and Ezra Hausman. 2012. 2012 Carbon Dioxide Price Forecast. Cambridge: Synapse Energy Economics, Inc. <http://www.synapse-energy.com/Downloads/SynapseReport.2012-10.0.2012-CO2-Forecast.A0035.pdf>

The EIA's 2012 *Annual Energy Outlook* reports the projected impact of \$15 and \$20 per ton CO₂ emissions fees starting in 2013⁴⁹ (similar to Synapse's low and mid cases) on net electricity generation in the United States. Figure 13 below shows EIA's reference case with no CO₂ emissions fee on the left, a \$15 per ton case in the center, and a \$20 per ton case on the right. In all three cases, coal declines from 45 percent of net generation in 2010, but the decline is much more pronounced in the carbon fee scenarios. Under a \$15 per ton CO₂ fee, coal declines to 16 percent of generation by 2035, while under a \$25 per ton CO₂ fee, coal declines to just 4 percent of generation by the end of the period modeled.

⁴⁹ AEO CO₂ prices escalate 5 percent each year through 2035.

Figure 13. U.S. Electricity Net Generation (Trillion kWh) under Reference, \$15, and \$25 Carbon Fee Scenarios



Source: EIA. *Annual Energy Outlook 2012*. www.eia.gov/pressroom/presentations/sieminski_01142013.ppt

EIA's projections highlight the vulnerability of coal demand to carbon policy, even at a low carbon price. As outlined in the Synapse Energy Economics 2012 *Carbon Dioxide Price Forecast* report, federal legislation requiring reductions in carbon dioxide emissions is likely to occur in this decade prompted by one or more of the following factors.⁵⁰

- Technological opportunity;
- A patchwork of state emission targets for 2020, spurring industry demand for federal action;
- A U.S. Supreme Court decision to allow nuisance lawsuits to go ahead, resulting in a financial threat to energy companies; and
- Increasingly compelling evidence of climate change.

Such policy will certainly reduce demand for coal nationally, as the costs of carbon adds significantly to the overall cost of energy produced by coal. Capturing and storing carbon emissions at the smokestack (i.e. carbon capture and sequestration) is not yet economic (see Figure 6), and coal will likely continue to face significant competition from low-cost natural gas and renewable resources for the foreseeable future.

Substitution due to renewable mandates

Volume I of Norwest's *Otter Creek Summary Report* describes the limited market for Montana Powder River Basin coal with high sodium content.⁵¹ Montana coal will have difficulty competing

⁵⁰ Wilson, Rachel, Patrick Luckow, Bruce Biewald, Frank Ackerman, and Ezra Hausman. 2012. 2012 Carbon Dioxide Price Forecast. Cambridge: Synapse Energy Economics, Inc. <http://www.synapse-energy.com/Downloads/SynapseReport.2012-10.0.2012-CO2-Forecast.A0035.pdf>

⁵¹ Norwest Corporation. 2006. *Otter Creek Property Summary Report*. Salt Lake City: Norwest Corporation.

with Wyoming coal due to both the high sodium characteristics of the coal and higher transportation costs for all but a few regions of the United States. The Norwest report lists ten plants that are willing to accept high-sodium coal and which constitute the likely initial market for Otter Creek coal, all located in Minnesota, Michigan, or Wisconsin. An additional fourteen plants are then listed as potential customers. These plants are located in North Dakota, West Virginia, Montana, Arizona, Washington, and Kansas.

All of the states that represent potential markets for Otter Creek coal, with the exceptions of West Virginia and North Dakota, have mandatory renewable portfolio standards requiring that their electric utilities deliver set shares of electricity from renewable or alternative energy sources. North Dakota has a voluntary renewable energy target. While these policies vary in their requirements and goals, as shown in Table 1, taken together they indicate that renewable energy generation will constitute a growing share of the electricity delivered in the states where Arch Coal hopes to market coal from the Otter Creek mine.

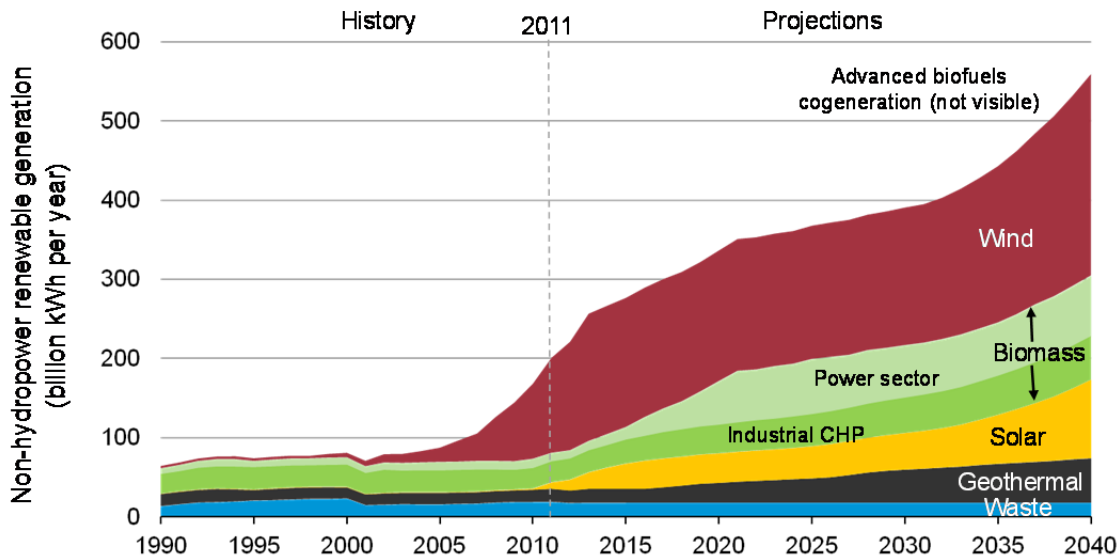
Table 1. State renewable energy requirements

State	Requirement
Mandatory RPS Requirement	
Arizona	15% by 2025
Kansas	20% by 2020
Michigan	10% by 2020
Minnesota	30% by 2020
Montana	15% by 2015
Washington	15% by 2020
Wisconsin	10% by 2015
Voluntary Goals	
North Dakota	10% by 2015

Source: Database of State Incentives for Renewables and Efficiency, January 2013.
<http://www.dsireusa.org/rpsdata/RPSspread011113.xlsx>

Nationwide, EIA projects that non-hydroelectric renewable generation will more than double between 2011 and 2040, partially as a result of state or national policies favoring renewable energy (Figure 14). These policies will further squeeze national demand for coal and contribute to increasing competition among coal suppliers.

Figure 14. Non-hydro renewable generation, 2011 to 2040 (thousand GWh)

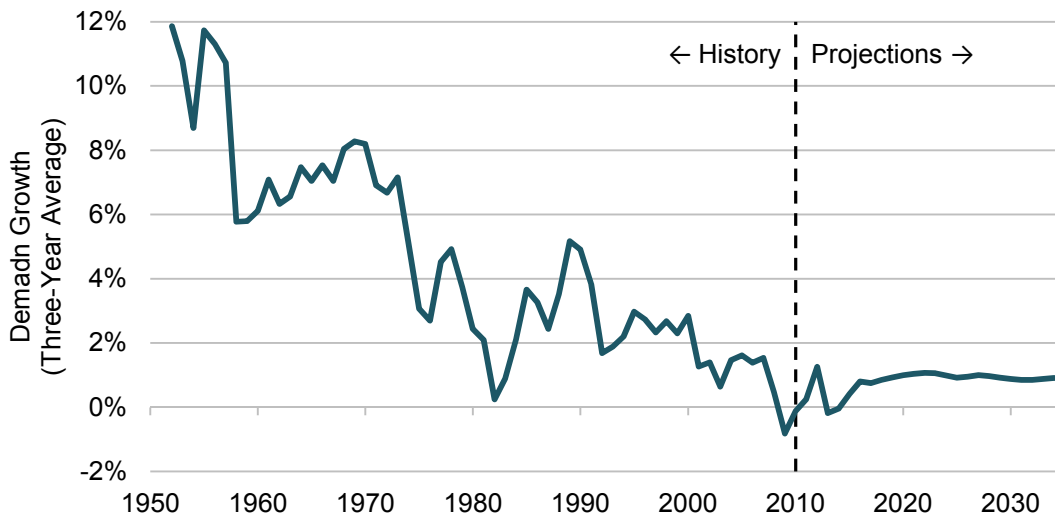


Source: EIA. Annual Energy Outlook 2012. www.eia.gov/pressroom/presentations/sieminski_01142013.ppt

Demand reduction due to energy efficiency

The growth rate of electricity demand has declined precipitously over the past sixty years, from 9.8 percent annually during the 1950s to only 0.7 percent per year during the past decade.⁵² As displayed in Figure 15, the EIA projects that the pace of growth of electricity demand will remain very slow through 2035 due to new appliance standards and investments in energy-efficient equipment.

Figure 15. Growth in U.S. electricity demand, 1950 to 2035



Source: EIA, 2012 Annual Energy Outlook http://www.eia.gov/forecasts/aeo/MT_electric.cfm

⁵² EIA. 2013. Annual Energy Outlook 2012.

EIA's regional projections show Otter Creek's prospective Midwestern, Kansas, and North Dakota customers with even lower electricity demand growth rates, ranging from 0.1 to 0.3 percent per year for the period 2010 to 2035, likely as the result of reduced economic growth and aggressive energy efficiency policies.⁵³ According to the American Council for an Energy-Efficient Economy, the Midwestern states that Norwest identifies as Otter Creek's initial market, together with Montana and Arizona, rank among the 20 states with the highest incremental energy savings as a percent of retail electricity sales.⁵⁴

Slow electricity demand growth, renewable portfolio standards, and competition from low-cost natural gas suggest that Montana coal will find it challenging to maintain its current sales, much less expand sales in the future.

8. Conclusions

Domestic demand for coal is in decline, and this is especially true for Otter Creek's particular type of high-sodium coal. The steadily worsening outlook for coal is primarily a result of the following factors:

- **Coal has lost its cost advantage.** Falling prices of natural gas coupled with higher mining and transportation costs for coal have eroded coal's competitiveness, leading to less frequent dispatch of coal units and lower demand for coal. Over the past decade, coal's net generation decreased by ten percent, while natural gas increased by nearly 50 percent.⁵⁵ Little new coal capacity is likely to be added over the coming decades.⁵⁶
- **Large numbers of coal plants are retiring in response to environmental regulations.** Strict new environmental regulations would require substantial new capital investments and increase operating costs for coal plants. This has led to coal plants across the country becoming uneconomic and announcing retirement, or converting to other fuel sources. Recent estimates project that a significant portion of the current coal fleet—up to 77 GW—will retire by 2020.
- **Otter Creek has a limited number of potential customers, and these coal plants are becoming uneconomic.** High sodium content limits Otter Creek's customer base,⁵⁷ and many of these potential customers may retire or convert to other fuels due to the high costs of complying with new environmental regulations—in fact, several have already announced their retirements.⁵⁸ Our analysis shows that the majority of these plants will be uneconomic compared both to the costs of operating existing natural gas plants and to the total costs of constructing and operating new natural gas plants.

⁵³ EIA. 2013. 2012 Annual Energy Outlook. <http://www.eia.gov/forecasts/aeo/er/index.cfm>

⁵⁴ Foster, Ben, et al. 1012. The 2012 State Energy Efficiency Scorecard. American Council for an Energy-Efficient Economy. <http://www.aceee.org/research-report/e12c>

⁵⁵ EIA. 2001-2012. Form 923, Schedule 5A.

⁵⁶ EIA. 2012 Annual Energy Outlook. http://www.eia.gov/forecasts/aeo/MT_electric.cfm

⁵⁷ The high sodium content of Otter Creek coal (and other Northern PRB coal) causes slagging problems in boilers. See footnote 3.

⁵⁸ See footnote 35.

- **Renewable portfolio standards, energy efficiency policies, and the likelihood of future carbon limits are reducing demand for coal.** Standards and goals for renewable energy are increasing the amount of renewables on the grid and heightening demand for natural gas as a complementary energy source due to its ability to adjust output much more quickly than coal. At the same time, increasingly aggressive energy efficiency investments are lowering energy demand across the board. Finally, a future price on carbon would drastically lower demand for coal, with generation falling to as little as 4 percent by 2040 under a carbon fee of \$25.⁵⁹ Many utilities and planning commissions are already factoring carbon prices into their planning.

The long-term viability of coal is severely threatened. Demand for coal is falling across the United States, and Otter Creek's coal market is further limited by the coal's high sodium content and connection to Northern, rather than Southern rail lines. In short, it is unreasonable to expect that there will be much, if any, domestic demand for Otter Creek coal when the mine becomes operational in 2017. There is, therefore, no justification for expanding rail transportation infrastructure to connect the Otter Creek coal mine to struggling domestic markets.

⁵⁹ EIA. 2012 Annual Energy Outlook www.eia.gov/pressroom/presentations/sieminski_01142013.ppt

APPENDIX 2

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9300 Lee Highway
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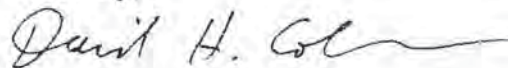
**Re: Docket No. FD 30186, Tongue River Railroad Company, Inc.—Rail
Construction and Operation—in Custer, Powder River and Rosebud
Counties, Mont.; Information Request #1**

Dear Messrs. Blodgett and Summerville:

In reference to the January 23, 2013 request received from Ms. Vicki Rutson for certain information required for the environmental review in this proceeding, please find attached a document which responds to the five questions posed in that request.

Please let us know if you have any questions about the attached responses.

Sincerely,



David H. Coburn
Attorney for Tongue River Railroad Company

cc: Director Victoria Rutson

- 1. The December 17, 2012 supplemental application (“Supplemental Application”) states that coal from the Otter Creek mine could move east or west for domestic use or export, including export to Asia. See Rowlands VS at 4. Please provide more specific information about the potential market locations for the coal that would be transported from the mines identified in the Supplemental Application via the Tongue River Railroad. If TRRC does not have this information, OEA requests a detailed explanation of why this information cannot be supplied.**

Response: TRRC does not have specific information about the markets to which the coal that it would transport would be destined. The coal that TRRC expects to transport will originate at the Otter Creek mine, which is owned by a subsidiary of Arch Coal, Inc., as well as from mines that TRRC anticipates could be developed at other points in the Ashland area where there are known reserves of coal. Coal from the Otter Creek mine will not be available for sale for at least several more years, perhaps 2017 at the earliest. This takes into account the time it will take, following permitting, to develop the mine, obtain the required land rights for the rail line, and construct the railroad (a process which will take about 20 months spread out over three years assuming eight month construction seasons). Given the variety of factors that can influence the timeline (e.g., weather-spawned development or construction delays, market volatility) and the fact that coal will not be available for sale for at least several years, predictions as to exactly where that coal will be sold and shipped cannot be made at this time.

The Otter Creek mine is accordingly being developed on the basis that there will be a market for the coal mined there, but without any specific domestic or foreign purchasers for the coal identified at this early stage. There are no contracts in place to purchase the coal and Arch is neither actively marketing the coal to be produced at Otter Creek nor able to do so given the long lead time until the mine and railroad are developed. As TRRC stated in its Application, destination markets will be determined by the market forces in play at the time when the coal is mined. Nonetheless, as stated in the Application and explained further below, there is ample reason to believe that there will be market for the coal once it becomes available for transport.

The level of uncertainty as to identification of specific destinations for coal that TRRC would transport is even greater with respect to coal mined at other mines that could be developed in the Ashland area. At this time, there are no proposals to develop such mines or mine permits pending. While TRRC believes that it is likely that at some point other mines in the area will be developed to exploit the significant resource located there, identifying where the coal from those anticipated mines will be transported is speculative at this time because the timelines for such other mines to begin production are even longer than for the Otter Creek mine.

For the above reasons, TRRC cannot offer more detailed information on the location of specific markets for the coal it will transport. However, historical information is available on where Montana coal has found a market. The table attached at Exhibit 1, which is compiled from U.S. Energy Information Administration data, shows for each

year between 2007 and 2012, the largest percentage of Montana coal has been used for electricity generation within the state, with the next largest volumes being transported to electric utilities in Michigan, Minnesota, and Washington. Smaller volumes have been transported to primarily Midwest and Northern Plains states, and to Arizona. (The 2012 data shown on the Table is not complete at this time.)

The table at Exhibit 2, also compiled from EIA data, identifies the specific utilities to which Montana coal has been transported between 2007 and 2012. These utilities include Xcel Energy, DTE Energy (Detroit Edison), Allete Inc. (Minnesota Power); CMS Energy and Wisconsin Energy, among others. Arch anticipates that these same utilities in the Upper Midwest states will remain the largest potential domestic customers for the Otter Creek coal, as well as the Centralia units in Washington, one of which is scheduled to remain operational through 2025.

The July 12, 2006 study, entitled “Otter Creek Property Summary Report”, prepared by Norwest Corporation for the Montana Land Board in advance of that Board’s decision to lease the Otter Creek coal tracts to an affiliate of Arch is attached as Exhibit 3. Chapter 4 of the Report discusses the potential market for the Otter Creek coal. Table 4-1 identifies the specific plants in the Upper Midwest and Washington that currently purchase coal from Montana mines at Spring Creek, Decker and Rosebud. The Report is consistent with Arch’s view that these plants are potential customers for Otter Creek coal. The same plants are likewise potential customers for coal mined at other Ashland area mines that are developed.

Otter Creek coal is located relatively close to the surface and has a low ratio of coal to overburden, versus generally higher strip ratios at other Montana mines. See comparison of PRB mine strip ratios set forth at Exhibit 4. This means that the coal can be mined efficiently and at a lower cost than at the other Montana mines with which Otter Creek coal would compete, which will make that coal more competitive.

In addition to the above domestic market opportunities, there is also an export market for Montana coal. This is discussed in the Application and in TRRC’s January 28, 2013 Reply to the Petition to Revoke filed by NPRC. According to EIA’s most recent statistics, in 2011, over 13 million tons of Montana coal were exported. This compares to over 25 million tons distributed domestically. See EIA report at Exhibit 5. The exported coal includes a few million tons of coal exported to Canada for use in generating electricity.

Some of the TRRC-transported coal could be exported to Europe through the Midwest Energy Resources Company facility at Superior, WI, from which Montana coal is currently shipped via Great Lakes and ocean vessels to Europe. The largest markets in Europe are the UK and Spain.

Some other portion of the TRRC-transported coal could be exported to Asia via the Westshore Terminals south of Vancouver, BC, via which Montana coal is currently exported. The coal might also be exported through facilities proposed to be constructed

in the State of Washington were such facilities to be developed. However, as noted in TRRC's Reply to the Petition to Revoke, it is far from certain that these planned facilities, now in the permitting phase, will be constructed, and markets exist for Otter Creek coal regardless of whether the plans for those facilities ever come to fruition. The volume of TRRC-transported coal that could be exported to Asia will in part turn on the availability of additional export capacity and thus relatively lesser amounts of coal will be exported to Asia in the event that these facilities are not developed.

To the extent that TRRC-transported coal were exported to Asia, the most likely recipient nations include South Korea, Japan, and China. See Census Bureau data at Exhibit 6. South Korea is a more likely potential destination than other Asian nations due to relative geographic proximity to the North American west coast, which translates to lower ocean transport costs.

The contention that many parties have made in their scoping comments that all of the Otter Creek coal will be exported to China is not supported by any facts. Arch has no contracts and no fixed plans to ship any of the Otter Creek coal to China. Whether it is exported to China at all is very much an open question given the historically greater use of Montana coal for domestic electricity generation than for export and market forces that could dictate a greater demand for the coal for domestic use and/or for export to nations other than China. According to Census and EIA data, South Korea ranks well ahead of China in terms of its import from the United States of thermal or steam coal, the type of coal exported from the PRB. See Exhibits 6 and 7.

It is not possible to accurately predict what percentage of the TRRC-transported coal would be consumed domestically versus exported, and which nations would likely receive coal that is exported, this many years in advance of any production from the Otter Creek/Ashland area. Multiple factors will dictate whether coal will be exported at all and, if so, where it will be exported. These factors include the following: the cost of competitive fuel, and in particular natural gas; regulatory developments that could influence the ability of domestic and foreign utilities to use coal versus other fuels; and technological advances in the use of coal, which include the further development of carbon capture technologies, and the commercial development of coal to liquid and coal to gas conversion facilities. Montana coal's attractiveness to the domestic market will also be influenced by the availability of coal at competitive prices from other coal producing areas in the United States. In this regard, it bears note that EIA forecasts growing domestic use of coal as an energy resource beginning after 2016 and growth over current usage levels by several quadrillion Btu's by 2035. See page 11 of EIA, *Annual Energy Outlook Early Release 2013*, attached at Exhibit 8. Thus, predictions that there will be little or no domestic market for Otter Creek coal in the future do not comport with the opinions of unbiased market observers and analysts.

For that coal which may be exported, factors that would influence the specific destination of any coal would include the following: the cost of available competitive fuel (e.g., coal is currently attractive in Europe due to the high cost of natural gas there);

the cost of ocean and other transportation and the availability of export and import facilities.

Finally, the variability of the above factors over time, and the general dynamism of energy markets, suggests that over the life of the Otter Creek mine the percentage of the coal used domestically versus the percentage exported will vary.

- 2. The Supplemental Application states that Otter Creek coal may find markets overseas through U.S. ports along the Atlantic, Pacific, Great Lakes or Gulf Coasts. See Supplemental Application at 20. Please provide information about any potential plans to transport Otter Creek coal through U.S. ports in these locations.**

See response to question 1. Generally, to the extent that the coal is exported, transit distance within the United States suggests that it is more likely to be exported through Great Lakes and Pacific ports than Gulf Coast or Atlantic ports, should Great Lakes and Pacific ports have available capacity. At this point, however, there are no specific plans to export any of the coal for the reasons discussed in response to question 1.

- 3. Please provide any information about potential shippers with whom Arch Coal has negotiated or signed contracts to ship Powder River Basin (PRB) coal from the Northern PRB on the Tongue River Railroad.**

As noted above, to TRRC's knowledge, no contracts have been negotiated or signed to date.

- 4. Please provide justification for construction and operation of the Montco Mine spur to Terminus Point #1 (including information about the Montco mine itself and other mines in the vicinity that might potentially be served by the spur in the future).**

TRRC is aware that there are reserves of coal in the Ashland area, including coal on the Northern Cheyenne Reservation and at the area formerly designated for mining known as the Montco Mine. The Application thus seeks authority to construct a portion of the TRRC line (referred to in the Application as the Montco Mine Spur) to serve this coal resource.

While precise information on the amount of marketable coal in that area remains under review, the reserves are known to be substantial. Based on that knowledge and the reasonable assumption that coal developers may emerge to develop one or more mines in the area that would be served by Terminus Point #1, TRRC believes that there is an economic justification for the Montco Mine spur and that authorization of that portion of the TRRC line is in the public interest and would advance a sound transportation system.

In addition, authorizing the Montco Mine spur in this proceeding would be most efficient from TRRC's perspective and that of the STB and other permitting agencies.

Doing so would allow the environmental review and transportation merits assessments to be accomplished at the same time as the review of the portion of the line that would serve the Otter Creek mine, thereby saving significant time and resources that otherwise would be required were permitting of the Montco Mine spur to be delayed.

- 5. The Supplemental Application states that 3.7 trains per day would travel on the Tongue River Railroad. Because this number represents the average number of trains per day, please provide the maximum number of trains per day that could potentially travel on the Tongue River Railroad in the reasonably foreseeable future if the line is approved and constructed.**

As discussed in TRRC's Reply to Petition to Revoke, the predicted 3.7 average number of loaded trains per day was based on the assumption that the Otter Creek mine will reach its anticipated maximum production level of 20 million tons of coal per year. This is a simple average based on the capacity of a unit coal train and this maximum production level. (20 million tons/year divided by 125 cars/train times 365 days/year) = 3.65 trains/day, which was rounded up to 3.7 trains/day in the Application.)

Many factors on the rail network can cause more or less trains to traverse the line on a given day. These factors include track maintenance, service interruptions caused by derailments, weather or other issues; the level of any delays in loading rail cars at the mine or delays at destination.

The maximum number of trains/day that could use the line were no siding built on the TRRC line is between 3 and 4 loaded trains and approximately 7 to 8 total (loaded and empty) trains/day. Were an 8500 foot siding built on the TRRC line (as the Application notes is possible were traffic levels to demand the need for a siding) the maximum number of trains/day that could be transported would be about 5 loaded trains/day or a total of about 10 loaded and empty trains/day.

APPENDIX 3

AEO2013 Early Release Overview

Executive summary

Projections in the *Annual Energy Outlook 2013* (AEO2013) Reference case focus on the factors that shape U.S. energy markets through 2040, under the assumption that current laws and regulations remain generally unchanged throughout the projection period. This early release focuses on the AEO2013 Reference case, which provides the basis for examination and discussion of energy market trends and serves as a starting point for analysis of potential changes in U.S. energy policies, rules, or regulations or potential technology breakthroughs. Readers are encouraged to review the full range of cases that will be presented when the complete AEO2013 is released in early 2013, exploring key uncertainties in the Reference case. Major highlights in the AEO2013 Reference case include:

Crude oil production, particularly from tight oil plays, rises sharply over the next decade

The advent and continuing improvement of advanced crude oil production technologies continue to lift projected domestic supply. Domestic production of crude oil increases sharply in AEO2013, with annual growth averaging 234 thousand barrels per day (bpd) through 2019, when production reaches 7.5 million bpd (Figure 1). The growth results largely from a significant increase in onshore crude oil production, particularly from shale and other tight formations. After about 2020, production begins declining gradually to 6.1 million bpd in 2040 as producers develop sweet spots first and then move to less productive or less profitable drilling areas.

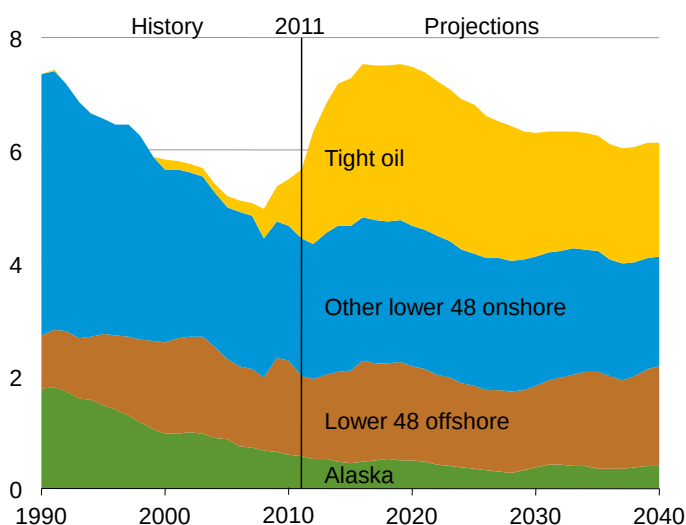
Natural gas production is higher throughout the AEO2013 Reference case projection than it was in AEO2012, with natural gas increasingly serving the industrial and electric power sectors, as well as an expanding export market

Relatively low natural gas prices, facilitated by growing shale gas production, spur increased use in the industrial and electric power sectors, particularly over the next 15 years. Natural gas use (excluding lease and plant fuel) in the industrial sector increases by 16 percent, from 6.8 trillion cubic feet per year in 2011 to 7.8 trillion cubic feet per year in 2025. Although natural gas also continues to capture a growing share of total electricity generation, natural gas consumption by power plants does not increase as sharply as generation because new plants are very efficient. After accounting for 16 percent of total generation in 2000, the natural gas share of generation rose to 24 percent in 2010 and is expected to continue increasing, to 27 percent in 2020 and 30 percent in 2040. In the AEO2013 Reference case, natural gas also reaches other new markets, such as exports, as a fuel for heavy-duty freight transportation (trucking), and as a feedstock for producing diesel and other fuels.

Motor gasoline consumption is lower in AEO2013 relative to the level in AEO2012, reflecting the introduction of more stringent corporate average fuel economy standards; growth in diesel fuel consumption is moderated by increased use of natural gas in heavy-duty vehicles

AEO2013 incorporates the greenhouse gas (GHG) and corporate average fuel economy (CAFE) standards for light-duty vehicles (LDVs)¹ through the 2025 model year, which increases the new vehicle fuel economy from 32.6 miles per gallon (mpg) in 2011 to 47.3 mpg in 2025. The increase in vehicle efficiency reduces gasoline use in the transportation sector by 0.5 million bpd in 2025 and by 1.0 million bpd in 2035 in AEO2013 compared to the *Annual Energy Outlook 2012* (AEO2012) Reference case (Figure 2).

Figure 1. U.S. domestic crude oil production by source, 1990-2040 (million barrels per day)



Furthermore, the improved economics of liquefied natural gas (LNG) for heavy-duty vehicles results in an increase in natural gas use in heavy-duty vehicles that offsets a portion of diesel fuel consumption. The use of petroleum-based diesel fuel is also reduced by the increased use of diesel produced using gas-to-liquids (GTL) technology. Natural gas use in vehicles reaches 1.7 trillion cubic feet (including GTL) by 2040, displacing 0.7 million bpd of other motor fuels.²

The United States exports more natural gas than projected in the AEO2012 Reference case

U.S. dry natural gas production increases throughout the projection period (Figure 3), outpacing domestic consumption by 2020 and spurring net exports of natural gas. Higher volumes of shale gas production in AEO2013 are central to higher total production volumes and an earlier transition to net exports than was projected in the AEO2012 Reference case. U.S. exports of LNG from domestic sources rise to approximately 1.6 trillion cubic feet in 2027, almost double the 0.8 trillion cubic feet projected in AEO2012.

¹U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards: Final Rule," *Federal Register*, Vol. 77, No. 199 (Washington, DC: October 15, 2012), website www.gpo.gov/fdsys/pkg/FR-2012-10-15/pdf/2012-21972.pdf.

²Liquid motor fuels include diesel and liquid fuels from GTL processes. Liquid fuel volumes from GTL for motor vehicle use are estimated based on the ratio of onroad diesel and gasoline to total diesel and gasoline.

Industrial production expands in response to the initial competitive advantage of low natural gas prices

Industrial production grows more rapidly in AEO2013 due to the benefit of strong growth in shale gas production and an extended period of relatively low natural gas prices, which lower the costs of both raw materials and energy, particularly through 2025. Specific industries benefit from the greater availability of natural gas at relatively low prices. For example, industrial production grows by 1.7 percent per year from 2011 to 2025 in the bulk chemicals industries—which also benefit from increased production of natural gas liquids—and by 2.8 percent per year in the primary metals industries, as compared with 1.4 percent and 1.1 percent per year, respectively, in the AEO2012 Reference case. In the long term, growing competition from abroad in these industries limits output growth, as other nations develop and install newer, more energy-efficient facilities. The higher level of production also leads to greater industrial natural gas demand (excluding lease and plant fuel), which grows to more than 8.3 quadrillion Btu in 2035 in AEO2013, compared to 7.2 quadrillion Btu in 2035 in AEO2012. Most of the increase in industrial energy demand is the result of higher output in the manufacturing sector.

Renewable fuel use grows at a much faster rate than fossil fuel use

The share of generation from renewables grows from 13 percent in 2011 to 16 percent in 2040. Electricity generation from solar and, to a lesser extent, wind energy sources grows as recent cost declines make them more economical. However, the AEO2013 projection is less optimistic than AEO2012 about the ability of advanced biofuels to capture a rapidly growing share of the liquid fuels market. As a result, biomass use in AEO2013 totals 4.2 quadrillion Btu in 2035 (compared to 5.4 quadrillion Btu in AEO2012) and 4.9 quadrillion Btu in 2040, up from 2.7 quadrillion Btu in 2011.

With improved efficiency of energy use and a shift away from the most carbon-intensive fuels, U.S. energy-related carbon dioxide (CO₂) emissions remain more than 5 percent below their 2005 level through 2040

Total U.S. energy-related CO₂ emissions do not return to their 2005 level (5,997 million metric tons) by the end of the AEO2013 projection period (Figure 4). Emissions from motor gasoline demand in AEO2013 are lower than in AEO2012 as a result of the adoption of fuel economy standards, biofuel mandates, and shifts in consumer behavior. Emissions from coal use in the generation of electricity are lower as power generation shifts from coal to lower-carbon fuels, including natural gas and renewables.

Introduction

In preparing the AEO2013 Reference case, the U.S. Energy Information Administration (EIA) evaluated a wide range of trends and issues that could have major implications for U.S. energy markets. This overview presents the AEO2013 Reference case and compares it with the AEO2012 Reference case released in June 2012 (see Table 1 on pages 15-16). Because of the uncertainties inherent in any energy market projection, the Reference case results should not be viewed in isolation. Readers are encouraged to review the alternative cases when the complete AEO2013 publication is released, in order to gain perspective on how variations in key assumptions can lead to different outlooks for energy markets.

To provide a basis against which alternative cases and policies can be compared, the AEO2013 Reference case generally assumes that current laws and regulations affecting the energy sector remain unchanged throughout the projection (including the implication that laws that include sunset dates do, in fact, end at the time of those sunset dates). This assumption helps increase the comparability of the Reference case with other analyses, clarifies the relationship of the Reference case to other AEO2013 cases, and enables policy analysis with less uncertainty regarding unstated legal or regulatory assumptions.

Figure 2. Liquids consumption by light-duty vehicles in the United States, AEO2012 and AEO2013 Reference cases, 2010-2040 (million barrels per day)

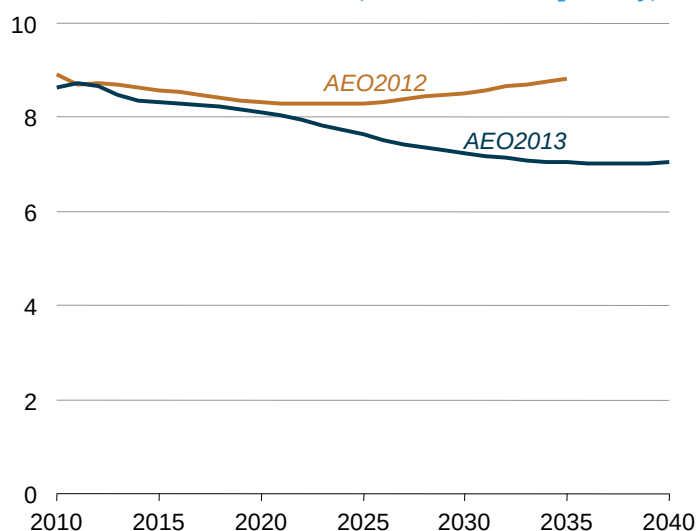
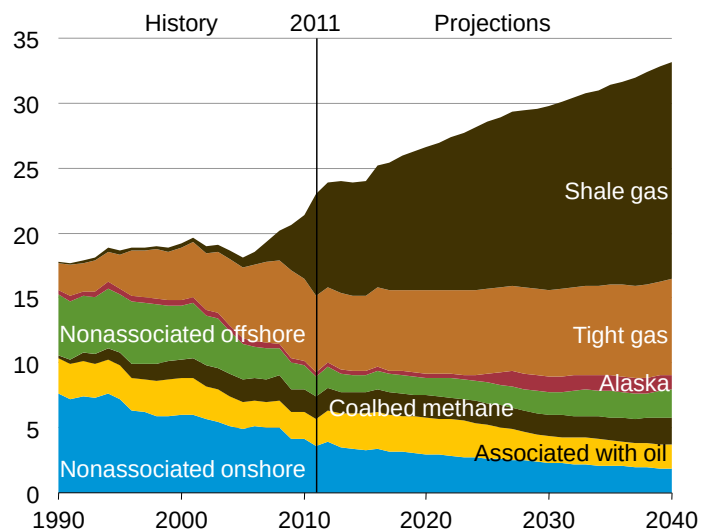


Figure 3. U.S. dry natural gas production by source, 1990-2040 (trillion cubic feet)

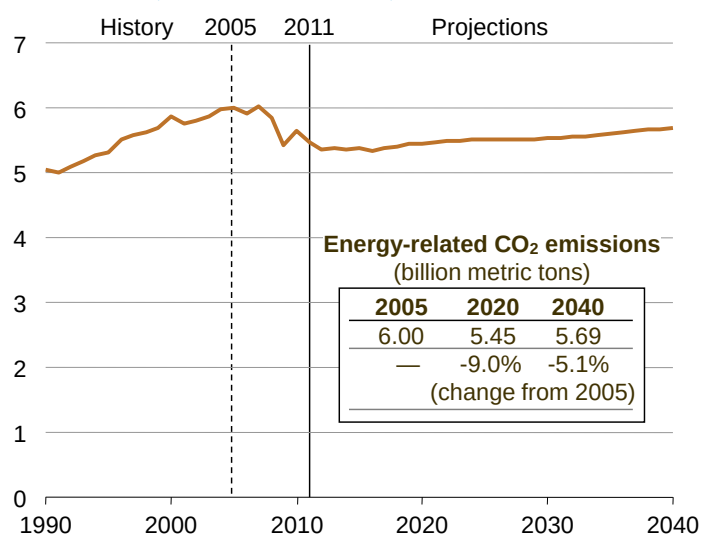


As in past editions, the complete AEO2013 will include additional cases, many of which reflect the impacts of extending a variety of current energy programs beyond their current expiration dates and the permanent retention of a broad set of programs that currently are subject to sunset provisions. In addition to the alternative cases prepared for AEO2013, EIA has examined proposed policies at the request of Congress over the past few years. Reports describing the results of those analyses are available on EIA's website.³

Key updates made for the AEO2013 Reference case include the following:

- Extension of the projection period through 2040, an additional five years beyond AEO2012.
- Adoption of a new Liquid Fuels Market Module (LFMM) in place of the Petroleum Market Module used in earlier AEOs provides for more granular and integrated modeling of petroleum refineries and all other types of current and potential future liquid fuels production technologies. This allows more direct analysis and modeling of the regional supply and demand effects involving crude oil and other feedstocks, current and future processes, and marketing to consumers.
- A shift to the use of Brent spot price as the reference oil price. AEO2013 also presents the average West Texas Intermediate (WTI) spot price of light, low-sulfur crude oil delivered in Cushing, Oklahoma, and includes the U.S. annual average refiners' acquisition cost of imported crude oil, which is more representative of the average cost of all crude oils used by domestic refiners.
- A shift from using regional natural gas wellhead prices to using representative regional natural gas spot prices as the basis of the natural gas supply price. Due to this change, the methodology for estimating the Henry Hub price was revised.
- Updated handling of data on flex-fuel vehicles (FFVs) to better reflect consumer preferences and industry response. FFVs are necessary to meet the Renewable Fuels Standard (RFS), but the phasing out of CAFE credits for their sale and limited demand from consumers reduce their market penetration.
- A revised outlook for industrial production to reflect the impacts of increased shale gas production and lower natural gas prices, which result in faster growth for industrial production and energy consumption. The industries affected include, in particular, bulk chemicals and primary metals.
- Incorporation of a new aluminum process flow model in the industrial sector, which allows for diffusion of technologies through choices made among known commercial and emerging technologies based on relative capital costs and fuel expenditures and provides for a more realistic representation of the evolution of energy consumption than in previous AEOs.
- An enhanced industrial chemical model, in several respects: the baseline liquefied petroleum gas (LPG) feedstock data have been aligned with 2006 survey data; use of an updated propane-pricing mechanism that reflects natural gas price influences in order to allow for price competition between LPG feedstock and petroleum-based (naphtha) feedstock; and specific accounting in the Industrial Demand Model for propylene supplied by the LFMM.
- Updated handling of the U.S. Environmental Protection Agency's (EPA) National Emissions Standards for Hazardous Air Pollutants for industrial boilers and process heaters to address the maximum degree of emissions reduction using maximum achievable control technology. An industrial capital expenditure and fuel price adjustment for coal and residual fuel has been applied to reflect risk perception about the use of those fuels relative to natural gas.

Figure 4. U.S. energy-related CO₂ emissions, 1990-2040 (billion metric tons)



- Augmentation of the construction and mining models in the Industrial Demand Model to better reflect AEO2013 assumptions regarding energy efficiencies in off-road vehicles and buildings, as well as the productivity of coal, oil, and natural gas extraction.
- Adoption of final model year 2017 to 2025 GHG emissions and CAFE standards for LDVs, which increases the projected fuel economy of new LDVs to 47.3 mpg in 2025.
- Updated handling of the representation of purchase decisions for alternative fuels for heavy-duty vehicles. Market factors used to calculate the relative cost of alternative-fuel vehicles, specifically natural gas, now represent first buyer-user behavior and slightly longer breakeven payback periods, significantly increasing the demand for natural gas fuel in heavy trucks.
- Updated modeling of LNG export potential, which includes a rudimentary assessment of pricing of natural gas in international markets.

³See "Congressional Requests," website www.eia.gov/analysis/reports.cfm?t=138.

- Updated power generation unit costs that capture recent cost declines for some renewable technologies, which tend to lead to greater use of renewable generation, particularly solar technologies.
- Reinstatement of the Clean Air Interstate Rule (CAIR) after the court's announcement of intent to vacate the Cross-State Air Pollution Rule (CSAPR).
- Modeling of California's Assembly Bill 32, the Global Warming Solutions Act (AB 32), that allows for representation of a cap-and-trade program developed as part of California's GHG reduction goals for 2020. The coordinated regulations include an enforceable GHG cap that will decline over time. AEO2013 reflects all covered sectors, including emissions offsets and allowance allocations.
- Incorporation of the California Low Carbon Fuel Standard, which requires fuel producers and importers who sell motor gasoline or diesel fuel in California to reduce the carbon intensity of those fuels by 10 percent between 2012 and 2020 through the increased sale of alternative low-carbon fuels.

Economic growth

The recovery from the 2008-09 recession continues on a slow path in the AEO2013 Reference case. Consumer confidence surveys are still roughly 25 percent below prerecession levels nearly two years after the official end of the recession in 2009. The slower economic growth in the early years of the projection has implications for the long term, with a lower economic growth rate leading to a slower recovery in employment.

Table 2 compares key long-run economic growth in the AEO2013 and AEO2012 Reference cases to growth rates experienced during the past 30 years. Even though overall GDP growth is slightly lower in the AEO2013 Reference case than the historical period, import growth is slower than export growth, allowing more of the domestic production to satisfy domestic demand. As a result, industrial production growth is higher in AEO2013 than in AEO2012.

Beyond 2013, the economic assumptions underlying the AEO2013 Reference case reflect trend projections that do not include short-term fluctuations. Economic growth projections for 2013 are consistent with those published in EIA's September 2012 *Short-Term Energy Outlook*.

Energy prices

Crude oil

Oil prices are influenced by a number of factors, including some elements that have mainly short-term impacts. Others, such as expectations about future world demand for petroleum and other liquids and production decisions by the Organization of

Table 2. Comparison of key economic growth rates from 2011-2040 to growth from 1980-2010 (percent per year, unless otherwise noted)

	AEO2013	AEO2012 ¹	1980-2010
U.S. Indicators			
Real GDP	2.5	2.6	2.7
Real disposable income	2.3	2.5	2.9
Real consumer spending	2.2	2.3	3.0
Real private investment	4.0	4.2	2.8
Real exports	5.5	5.9	5.3
Real imports	3.8	4.1	6.2
Real government expenditures	0.6	0.5	2.2
Federal funds rate (average rate over period)	3.4	3.6	5.8
Unemployment rate (average rate over period)	5.9	6.4	6.3
Output per hour in nonfarm business	1.9	1.9	2.1
International Indicators			
Real GDP: Major trading countries ²	1.8	1.8	2.4
Real GDP: Other trading countries ³	4.0	4.2	4.5

¹For period from 2011 to 2035.

²Major U.S. trading partners include Australia, Canada, Switzerland, United Kingdom, Japan, Sweden, and the Eurozone.

³Other trading partners include Argentina, Brazil, Chile, China, Colombia, Mexico, Hong Kong, Indonesia, India, Israel, Korea, Malaysia, Philippines, Russia, Saudi Arabia, Singapore, Thailand, Taiwan, and Venezuela.

Source: **History:** U.S. Bureau of Economic Analysis; Federal Reserve; and U.S. Bureau of Labor Statistics. **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A; and AEO2012 National Energy Modeling System, run REF2012.D020112C.

the Petroleum Exporting Countries (OPEC), affect prices over the longer term. Supply and demand in the world oil market are balanced through responses to price movements, and the underlying supply and demand expectations are both numerous and complex. The key determinants of long-term petroleum and other liquids supply and prices can be summarized in four broad categories: the economics of non-OPEC petroleum liquids supply; OPEC investment and production decisions; the economics of other liquids supply; and world demand for petroleum and other liquids.

For AEO2013, the oil price is represented by spot prices for light, sweet Intercontinental Exchange Brent crude oil instead of WTI crude oil traded on NYMEX. This change was made to better reflect the price refineries pay for imported light, sweet crude oil and takes into account the divergence of WTI prices from those of globally traded benchmark crudes such as Brent. WTI prices have diverged from other benchmark crude prices because of insufficient pipeline capacity to move crude oil to and from Cushing, Oklahoma (the location at which WTI prices are quoted), and the growth of midcontinent and Canadian oil production that has overwhelmed the transportation infrastructure needed to move crude from Cushing to the U.S. Gulf of Mexico.

Among the key assumptions defining the Reference case over the projection period are average economic growth of 1.8 percent per year for major U.S. trading partners; average annual economic growth in other U.S. trading partners of 4.0 percent; and declining liquid fuels consumption per unit of GDP. The OPEC market share of total liquid fuels production remains at approximately 40 to 45 percent over the projection period. Production from non-OPEC countries increases to levels above those in AEO2012. In the AEO2013 Reference case, the Brent spot oil price decreases from \$111 per barrel (in 2011 dollars) in 2011 to \$96 per barrel in 2015. After 2015, the Brent price increases, reaching \$163 per barrel in 2040 (or about \$269 per barrel in nominal dollars) as growing demand leads to the development of more costly resources (Figure 5). A wide range of price scenarios and discussion of the significant uncertainty surrounding future world oil prices will be included in the complete AEO2013 publication released in early 2013.

Liquid products

Real prices (in 2011 dollars) for motor gasoline and diesel delivered to the transportation sector in the AEO2013 Reference case increase from \$3.45 and \$3.58 per gallon, respectively, in 2011 to \$4.32 and \$4.94 per gallon in 2040. Although both prices dip modestly over the early portion of the projection period, increases are steady thereafter. Motor gasoline prices in 2035 are slightly higher in AEO2013 than in AEO2012, but diesel prices are considerably higher in 2035. The diesel share of total domestic liquids production rises, and the gasoline share falls, as a result of incorporation of the model year 2017 to 2025 GHG and CAFE standards for LDVs. Increasing demand for distillate puts pressure on refiners to increase distillate yield and results in higher prices relative to gasoline.

Natural gas

For AEO2013, the Henry Hub spot price is projected using a new methodology. Previously, the Henry Hub prices were based on the average national wellhead price and its historical relationship with the Henry Hub price. Given historical correlations, the projected difference between the Henry Hub price and the national average wellhead price increased as the wellhead price rose over the projection period. The Henry Hub spot prices in the AEO2013 Reference case are based on natural gas prices that balance the supply and demand for Gulf Coast natural gas, which contributes to a lower Henry Hub price projection in AEO2013 than in AEO2012.

With increasing natural gas production, reflecting continued success in tapping the nation's extensive shale gas resource, Henry Hub spot natural gas prices remain below \$4 per million Btu (2011 dollars) through 2018 in the AEO2013 Reference case. The resilience of drilling activity, despite low natural gas prices, is in part a result of high crude oil prices, which significantly improve

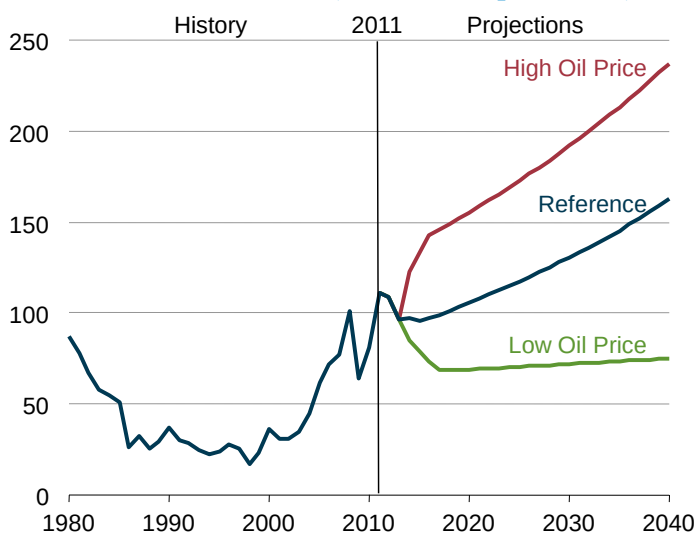
the economics of natural gas plays that have relatively high liquids content (crude oil, lease condensates, and natural gas liquids). Also contributing to growing production volumes are improved drilling efficiencies, which result in a greater number of wells being drilled more quickly, with fewer rigs and higher initial production rates.

After 2018, natural gas prices increase steadily as tight gas and shale gas drilling activity expands to meet growing domestic demand for natural gas and offsets declines in natural gas production from other sources. Natural gas prices rise as lower cost resources are depleted and production gradually shifts to less productive and more expensive resources. Henry Hub spot natural gas prices (in 2011 dollars) reach \$5.40 per million Btu in 2030 and \$7.83 per million Btu in 2040.

Coal

The average minemouth price of coal increases by 1.4 percent per year in the AEO2013 Reference case, from \$2.04

Figure 5. Average annual Brent spot crude oil prices in three cases, 1980-2040 (2011 dollars per barrel)



per million Btu in 2011 to \$3.08 per million Btu in 2040 (2011 dollars). The upward trend of coal prices primarily reflects an expectation that cost savings from technological improvements in coal mining will be outweighed by increases in production costs associated with moving into reserves that are more costly to mine. The upward trend in the minemouth price of coal in the AEO2013 Reference case is similar to the trend in the AEO2012 Reference case, but the average price through the projection period in AEO2013 is generally higher, primarily because of the smaller share of total coal production accounted for by production from lower-cost mines in the West and higher price projections for coking coal.

Electricity

Following the recent rapid decline of natural gas prices, real average delivered electricity prices in the AEO2013 Reference case fall from 9.9 cents per kilowatthour in 2011 to as low as 9.2 cents per kilowatthour in 2015, as natural gas prices remain relatively low. Retail electricity prices are influenced by fuel prices, particularly natural gas prices. However, the relationship between retail electricity prices and natural gas prices is complex, and many factors influence the degree to which and the timeframe over which they are linked. These factors include the share of natural gas generation in a region, the level of costs associated with electricity transmission and distribution systems not directly linked to fuel costs, the mix of competitive versus cost-of-service pricing, and the number of customers who purchase power directly from wholesale power markets. As a result, it can take time for fuel price changes to affect electricity prices, and the impacts will vary from region to region.

In the AEO2013 Reference case, electricity prices are lower throughout the projection than they were in the AEO2012 Reference case. Natural gas prices to electricity generators are significantly lower than those in AEO2012 in the first few years and are between 3 percent and 5 percent lower from 2025 to 2035, while the cost of coal is higher after 2015. As a result, reliance on natural gas-fired generation in the electric power sector increases, with lower operating costs per kilowatthour than in AEO2012. In the long term, however, both natural gas prices and electricity prices rise. Electricity prices in 2035 are 10.1 cents per kilowatthour (2011 dollars) in the AEO2013 Reference case, compared with 10.3 cents per kilowatthour in the AEO2012 Reference case. In AEO2013, the prices continue rising to 10.8 cents per kilowatthour in 2040.

Energy consumption by sector

Transportation

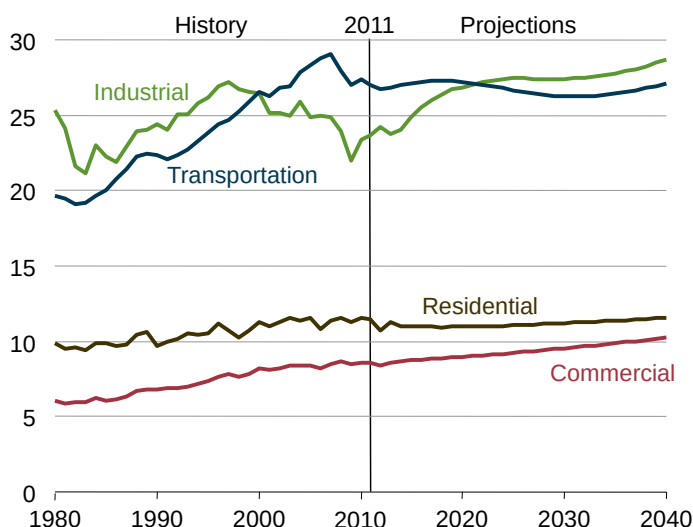
Delivered energy consumption in the transportation sector remains relatively constant at about 27 quadrillion Btu from 2011 to 2040 in the AEO2013 Reference case (Figure 6). Energy consumption by LDVs (including commercial light trucks) declines in the Reference case, from 16.1 quadrillion Btu in 2011 to 14.0 quadrillion Btu in 2025, due to incorporation of the model year 2017 to 2025 GHG and CAFE standards for LDVs. Despite the projected increase in LDV miles traveled, energy consumption for LDVs further decreases after 2025, to 13.0 quadrillion Btu in 2035, as a result of fuel economy improvements achieved through stock turnover as older, less efficient vehicles are replaced by newer, more fuel-efficient vehicles. Beyond 2035, LDV energy demand begins to level off as increases in travel demand begin to exceed fuel economy improvements in the vehicle stock.

Sales of alternative-fuel vehicles in the AEO2013 Reference case are lower than those in AEO2012. The majority of the reduction relative to AEO2012 is reflected in sales of flex-fuel vehicles (FFVs), which in 2035 are about 1.3 million, or less than one-half the 2.9 million FFV sales in the AEO2012 Reference case. Sales of battery-powered electric vehicles also are considerably lower in the AEO2013 Reference case than in AEO2012, with annual sales in 2035 estimated to be about 119,000, or 65 percent lower. Reductions in battery electric vehicles are offset by increased sales of hybrid and plug-in hybrid vehicles, which grow to about

1.3 million vehicles in 2035—about 20 percent higher than in the AEO2012 Reference case. Continued fuel economy improvement in vehicles using other alternative fuels, gasoline, and diesel, combined with growth in the use of hybrid technologies (including micro, mild, full, and plug-in hybrid vehicles), limit the use of electric vehicles over the projection. Although about one-half of new LDV sales in 2040 use diesel, alternative fuels, or hybrid technology, only a small share, less than 1 percent, are all-electric.

Energy demand for heavy trucks increases from 5.2 quadrillion Btu in 2011 to 7.1 quadrillion Btu in 2035 (compared with 6.2 quadrillion Btu in 2035 in the AEO2012 Reference case) and then to 7.6 quadrillion Btu in 2040. Higher industrial output in AEO2013 leads to greater growth in vehicle-miles traveled by freight trucks, which leads to higher energy demand by heavy vehicles in AEO2013 as compared with AEO2012. Factors used to calculate the economic effectiveness of heavy-duty alternative-fuel vehicles have been updated to represent the travel behavior of first-time buyers and

Figure 6. Delivered energy consumption by sector, 1980-2040 (quadrillion Btu)



economic breakeven hurdles that, when coupled with very competitive natural gas prices, significantly increase demand for natural gas fuel in heavy trucks. As a result, natural gas use in heavy-duty vehicles increases to 1.7 trillion cubic feet in 2040, displacing 0.7 million barrels of liquid fuels per day. The AEO2013 Reference case includes the GHG Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles published by the EPA and the National Highway Traffic Safety Administration in September 2011.⁴

Industrial

Approximately one-third of total U.S. delivered energy, 24.0 quadrillion Btu, was consumed in the industrial sector in 2011. In the AEO2013 Reference case, total industrial delivered energy consumption grows by 16 percent, to 27.8 quadrillion Btu in 2035 (0.8 quadrillion Btu higher than in the AEO2012 Reference case) and 28.7 quadrillion Btu in 2040. The rate of growth in total industrial energy consumption is greater from 2011 to 2025 than after 2025 in AEO2013, as industry responds to the lower natural gas prices resulting from the expansion of shale gas production in the near term. After 2025, increased international competition and rising natural gas prices as a result of more modest growth in shale gas production lead to slower growth in industrial energy consumption. The industry that consumes the most energy is bulk chemicals, where energy consumption grows from 5.7 quadrillion Btu in 2011 to 6.6 quadrillion Btu in 2024, before declining to 6.0 quadrillion Btu in 2035 and 5.8 quadrillion Btu in 2040.

The energy-intensive industries initially exhibit strong growth in shipments and energy consumption, but most of the growth in shipments and energy consumption occurs before 2025. In 2011, the energy-intensive industries constitute 27 percent of shipments and 63 percent of industrial energy consumption. In 2040, the energy-intensive industry share of shipments falls to 20 percent, and their share of energy consumption falls to 56 percent. Shipments decline noticeably after 2025 for the aluminum, bulk chemicals, and iron and steel industries, because those industries are more affected by international competition than others. Energy use in the energy-intensive industries increases by 0.9 percent per year from 2011 to 2025 and then falls by 0.2 percent per year from 2025 to 2035.

Non-energy-intensive industries show a different pattern of shipment growth and energy consumption, in part because they are not affected as much as the energy-intensive industries by international competition and energy prices. Non-energy-intensive industry shipments and energy consumption grow throughout the period from 2011 to 2035 in the AEO2013 Reference case, with shipments increasing by 51 percent from 2011 to 2025 and 22 percent from 2025 to 2035, and energy consumption growing at an annual rate of 1.2 percent from 2011 to 2035 (plastics is the only non-energy-intensive industry that shows a decline in energy use). However, the rate of growth in their energy consumption from 2011 to 2025 is roughly twice as high as the rate after 2025, because growth in shipments is slower after 2025. In 2035, the non-energy-intensive industries constitute 53 percent of total industrial shipments and 41 percent of industrial energy consumption.

Two new environmental policies that affect parts of the industrial sector are incorporated in the AEO2013 Reference case. California's AB 32 is a comprehensive law limiting the state's GHG emissions, including those from stationary sources; and the extension of the National Emissions Standards for Hazardous Air Pollutants to industrial boilers and process heaters addresses the maximum degree of emission reduction possible using the maximum achievable control technology (Boiler MACT). Although both AB 32 and the Boiler MACT policies have minimal effects on industrial energy consumption, AB 32 results in a relatively low GHG allowance price, as is also shown in California's own analyses.⁵

Residential

Residential delivered energy consumption remains roughly constant in the AEO2013 Reference case from 2011 to 2040, reflecting consumption levels lower than those in AEO2012. Delivered electricity consumption is 5.7 quadrillion Btu and natural gas consumption is 4.3 quadrillion Btu in 2035 in the AEO2013 Reference case, compared with 5.9 quadrillion Btu and 4.8 quadrillion Btu, respectively, in the AEO2012 Reference case. The lower consumption levels in the AEO2013 Reference case are explained in part by a change in the handling of data on heating and cooling degree days in the projection. The AEO2013 Reference case uses a 30-year trend of historical data as the basis for degree days in both the residential and commercial sectors. Previously, average data for the most recent historical decade were used to represent degree days for the projection period without reflecting any trend over time, which tended to underestimate cooling demand and overestimate heating demand. The change, in combination with updated population projections, results in 6 percent fewer population-weighted heating degree days and 12 percent more population-weighted cooling degree days in 2035, which reduces energy consumption for space heating and increases energy consumption for space cooling. Since more energy is consumed for heating than cooling, this results in a net reduction of delivered energy in AEO2013 when compared with AEO2012.

The updated technology and cost parameters for residential lighting lead to lower electricity consumption. The first round of standards in the Energy Independence and Security Act of 2007 (EISA) are implemented in years 2012 through 2014, with 2014 lighting consumption about 18 percent below its 2011 level. EISA also established a second-tier standard in 2020. In the AEO2012

⁴U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles; Final Rule," *Federal Register*, Vol. 76, No. 179 (September 15, 2011), pp. 57106-57513, website www.gpo.gov/fdsys/pkg/FR-2011-09-15/html/2011-20740.htm.

⁵See California Environmental Protection Agency, Air Resources Board, "Allowance Price Containment Reserve Analysis," website www.arb.ca.gov/regact/2010/capandtrade10/capv3appg.pdf.

Reference case, the standard was assumed to be met with improved, halogen-type incandescent technology; but in AEO2013, halogen-type incandescent bulbs are not available in 2020 and beyond, and households adopt more efficient technologies, such as compact fluorescent and light-emitting diode bulbs.

Commercial

Commercial sector energy consumption grows from 8.6 quadrillion Btu in 2011 to 10.2 quadrillion Btu in 2040 in the AEO2013 Reference case, slower than in the AEO2012 Reference case, despite similar growth in square footage in both cases. Growth in commercial electricity consumption averages 0.8 percent per year from 2011 to 2040 in AEO2013, lower than the 1.0-percent average annual growth in commercial floorspace. Changing trends for personal computer adoption, increasing data center efficiency, and slower-than-expected adoption of new data centers as a result of the recent recession all lead to lower electricity consumption in the AEO2013 Reference case than in AEO2012. In addition, decreasing costs for solid-state lighting technologies contribute to an increase in shipments throughout the commercial sector. Distributed generation and combined heat-and-power systems generate 63 billion kilowatthours of electricity in 2035, 47 percent more than in the AEO2012 Reference case. Decreasing technology costs and rapidly increasing capacity in the near term, especially in existing construction, account for higher levels of electricity generation in the commercial sector in the AEO2013 Reference case. Growth of natural gas consumption in the commercial sector continues to average roughly 0.4 percent annually in the AEO2013 Reference case, similar to the rate in the AEO2012 Reference case.

Energy consumption by primary fuel

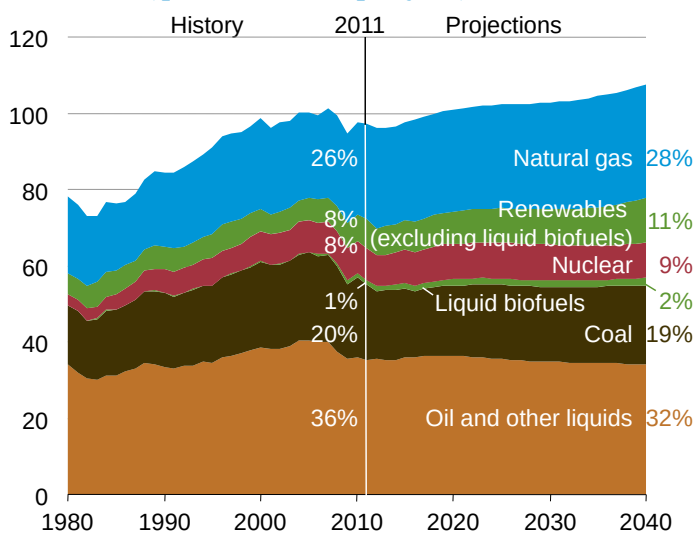
Total primary energy consumption grows by 7 percent in the AEO2013 Reference case, from 98 quadrillion Btu in 2011 to 104 quadrillion Btu in 2035—2.5 quadrillion Btu less than in AEO2012—and continues to grow at a rate of 0.6 percent per year, reaching about 108 quadrillion Btu in 2040 (Figure 7). The fossil fuel share of energy consumption falls from 82 percent in 2011 to 78 percent in 2040, as consumption of petroleum-based liquid fuels falls, largely as a result of the incorporation of new fuel efficiency standards for LDVs.

While total liquid fuels consumption falls, consumption of domestically produced biofuels increases significantly, from 1.3 quadrillion Btu in 2011 to 2.1 quadrillion Btu in 2040, and its share of total U.S. liquid fuels consumption grows from 3.5 percent in 2011 to 5.8 percent in 2040. The increases are much smaller than those in AEO2012, however, as a result of diminished FFV penetration, a smaller motor gasoline pool for blending ethanol, and reduced production of cellulosic biofuels, which to date has been well under the targets set by the EISA. (EPA issued waivers that substantially reduced the cellulosic biofuels obligation under the RFS for 2010, 2011, and 2012.) In addition, the production tax credit for cellulosic biofuels is scheduled to expire at the end of 2012.

Total U.S. consumption of liquid fuels, including both petroleum-based fuels and biofuels, which was 37.0 quadrillion Btu (18.9 million bpd) in 2011, increases to 37.6 quadrillion Btu (19.8 million bpd) in 2019 in the AEO2013 Reference case, then declines to 35.8 quadrillion Btu (18.9 million bpd) in 2035 before rising to 36.1 quadrillion Btu (about 18.9 million bpd) in 2040. Biofuel consumption increases over most of the projection period. The transportation sector dominates demand for liquid fuels, although its share (as measured by energy content) declines modestly, from 71 percent of total liquids consumption in 2011 to 70 percent in 2040.

In the AEO2013 Reference case, natural gas consumption rises from 24.4 trillion cubic feet in 2011 to 28.7 trillion cubic feet in 2035 (about 2.1 trillion cubic feet higher than in the AEO2012 Reference case) and continues to grow to 29.5 trillion cubic feet in 2040.

Figure 7. U.S. primary energy consumption by fuel, 1980-2040 (quadrillion Btu per year)



The largest share of the growth is for electricity generation. Demand for natural gas in the electric power sector increases from 7.6 trillion cubic feet in 2011 to approximately 9.5 trillion cubic feet in 2040, with a portion of the growth attributable to the retirement of 49 gigawatts of coal-fired capacity by 2022. Natural gas consumption in the industrial sector is also higher in AEO2013 than was projected in AEO2012, due to the rejuvenation of the industrial sector as it benefits from surging shale gas production that is accompanied by slow price growth, particularly from 2011 through 2019, when the price of natural gas remains below 2010 levels. Some industries, such as bulk chemicals, are more strongly affected than others. In the residential sector, natural gas consumption declines throughout the projection period. Because natural gas is used in the residential sector directly for heating but not for cooling, residential natural gas consumption is affected by the 6-percent reduction in heating degree days described above.

Total coal consumption—including the portion of coal-to-liquids (CTL) consumed as liquids—increases from 19.7 quadrillion Btu (999 million short tons) in 2011 to 20.5

quadrillion Btu (1,071 million short tons) in 2040 in the AEO2013 Reference case. Coal consumption, mostly for electric power generation, falls off through 2016. After 2016, coal-fired electricity generation increases slowly as the remaining coal-fired capacity is used more intensively, but little capacity is added. Coal consumption in the electric power sector in 2035 in the AEO2013 Reference case is about 0.6 quadrillion Btu (23 million short tons) lower than projected in the AEO2012 Reference case. The startup of the first CTL plants is delayed to 2023 in the AEO2013 Reference case, with penetration of the technology far more modest than in AEO2012.

Total consumption of marketed renewable fuels grows by 1.6 percent per year in the AEO2013 Reference case. Growth in consumption of renewable fuels results mainly from the implementation of the federal RFS for transportation fuels and state renewable portfolio standard (RPS) programs for electricity generation. Marketed renewable energy includes wood, municipal waste, biomass, and hydroelectricity in the end-use sectors; hydroelectricity, geothermal, municipal solid waste, biomass, solar, and wind for generation in the electric power sector; and ethanol for gasoline blending and biomass-based diesel in the transportation sector, of which 2.2 quadrillion Btu is included with liquid fuel consumption in 2040. Excluding hydroelectricity, renewable energy consumption in the electric power sector grows from 1.6 quadrillion Btu in 2011 to 4.5 quadrillion Btu in 2040, with biomass accounting for 24 percent of the growth and wind 44 percent. Generation of electricity from solar photovoltaic (PV) energy exhibits the fastest growth. Starting from a small base, PV accounts for 17 percent of total electricity generated from renewable energy sources, excluding hydropower, in 2040.

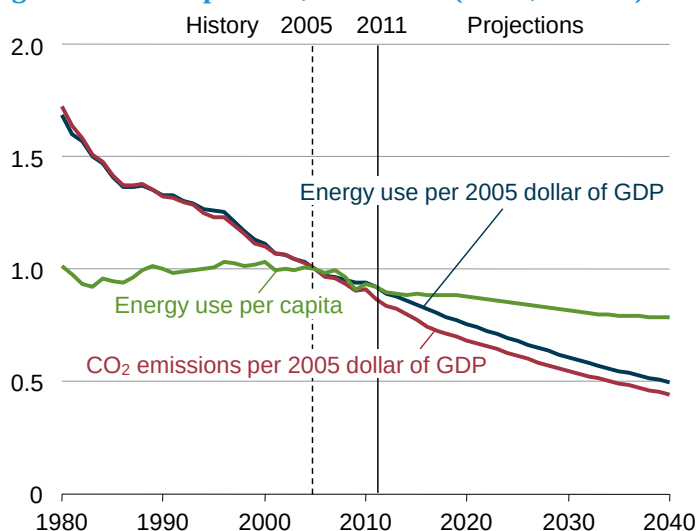
Energy intensity

Population is a key determinant of energy consumption through its influence on demand for travel, housing, consumer goods, and services. U.S. energy use per capita was fairly constant from 1990 to 2007, but it began to fall after 2007. In the AEO2013 Reference case, energy use per capita continues to decline due to the impacts of improving energy efficiency (e.g., new appliance and CAFE standards) and changes in the ways energy is used in the U.S. economy. Total U.S. population increases by 29 percent from 2011 to 2040, but energy use grows by only 10 percent, with energy use per capita declining by 15 percent from 2011 to 2040 (Figure 8).

From 1990 to 2011, energy use per dollar of GDP declined on average by 1.7 percent per year, in large part because of shifts within the economy from manufactured goods to the service sectors, which use relatively less energy per dollar of GDP. The dollar-value increase in the service sectors (in constant dollar terms) was 16 times the corresponding increase for the industrial sector over the same period. As a result, the share of total shipments accounted for by the industrial sector fell from 30 percent in 1991 to 22 percent in 2011. In the AEO2013 Reference case, the industrial share of total shipments reverses the earlier trend, largely due to the benefits of increased domestic production of natural gas, and increases to more than 23 percent in 2016. After 2016, however, the share resumes its decline, falling to less than 22 percent in 2040. Energy use per 2005 dollar of GDP declines by 46 percent from 2011 to 2040 in AEO2013 as the result of a continued shift from manufacturing to services (and, even within manufacturing, to less energy-intensive manufacturing industries), rising energy prices, and the adoption of policies that promote energy efficiency.

CO₂ emissions per 2005 dollar of GDP have historically tracked closely with energy use per dollar of GDP. In the AEO2013 Reference case, however, as lower-carbon fuels account for a larger share of total energy use, CO₂ emissions per 2005 dollar of GDP decline more rapidly than energy use per 2005 dollar of GDP, falling by 56 percent from 2005 to 2040, at an annual rate of 2.3 percent per year.

Figure 8. Energy use per capita and per dollar of gross domestic product and emissions per dollar of gross domestic product, 1980-2040 (index, 2005=1)



Energy production and imports

Net imports of energy decline both in absolute terms and as a share of total U.S. energy consumption in the AEO2013 Reference case (Figure 9). The decline in energy imports reflects increased domestic petroleum and natural gas production, increased use of biofuels (much of which are produced domestically), and demand reductions resulting from rising energy prices and the adoption of new efficiency standards for vehicles. The net import share of total U.S. energy consumption is 9 percent in 2040, compared with 19 percent in 2011 (the share was 30 percent in 2005).

Liquids

U.S. production of crude oil in the AEO2013 Reference case increases from 5.7 million bpd in 2011 to 7.5 million bpd in 2019, 13 percent higher than in AEO2012 (Figure 10). Despite a decline after 2019, U.S. crude oil production remains above 6.0 million bpd through 2040. Higher production volumes result mainly from increased onshore oil production, predominantly from tight (very low permeability) formations.

In AEO2013, onshore tight oil production accounts for 51 percent of total lower 48 onshore oil production in 2040, up from 33 percent in 2011. As with shale gas, the application of horizontal drilling and hydraulic fracturing significantly increases the development of tight oil resources. Offshore crude oil production trends upward over time, fluctuating between 1.4 and 1.8 million bpd, as the pace of development activity quickens and new large development projects, predominantly in the deepwater and ultradeepwater portions of the Gulf of Mexico, are brought into production.

The faster growth of tight oil production through 2020 in AEO2013 results in higher domestic crude oil production than in AEO2012 throughout most of the projection. Tight oil production declines after 2020 as more development moves into lower-productivity areas (with lower initial production rates and flatter decline curves), resulting in flattening of production after 2030. Total U.S. liquids production in AEO2013 is higher than in AEO2012 due to increased tight oil production through 2025; however, lower production of biofuels and natural gas plant liquids, as well as the decline in tight oil production beginning in 2021, results in lower levels of total domestic liquids production after 2025 in AEO2013 than in AEO2012.

U.S. dependence on imported liquid fuels continues to decline in the AEO2013 Reference case, primarily as a result of increased domestic oil production. Imported liquid fuels as a share of total U.S. liquid fuel use reached 60 percent in 2005 before dipping below 50 percent in 2010 and falling further to 45 percent in 2011. The import share continues to decline to 34 percent in 2019 and then rises to about 37 percent in 2040, due to a decline in domestic production of tight oil that begins in about 2021 (Figure 11).

Natural gas

Cumulative production of dry natural gas from 2011 through 2035 in the AEO2013 Reference case is about 8 percent higher than in AEO2012, primarily reflecting continued increases in shale gas production that result from the dual application of horizontal drilling and hydraulic fracturing. Another contributing factor is ongoing drilling in shale and other plays with high concentrations of natural gas liquids and crude oil, which, in energy-equivalent terms, have a higher value than dry natural gas. Cumulative production levels for tight gas and coalbed methane exceed those in the AEO2012 Reference case through 2035 by 3 percent and make material contributions to the overall increase in production. Lower 48 offshore natural gas production fluctuates between 1.8 and 2.8 trillion cubic feet per year, about the same as in AEO2012. New, larger-volume development projects, particularly in the deepwater Gulf of Mexico, remain directed principally toward liquids rather than natural gas. Offshore natural gas production is expected to reverse a years-long overall decline in about 2015, however, after which annual volumes generally increase to 2.8 trillion cubic feet in 2035 and remain at about that level through the balance of the projection period.

Figure 9. Total energy production and consumption, 1980-2040 (quadrillion Btu)

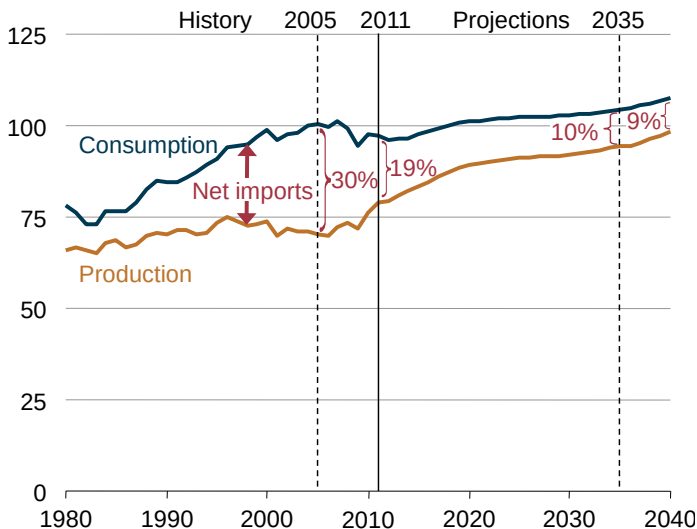
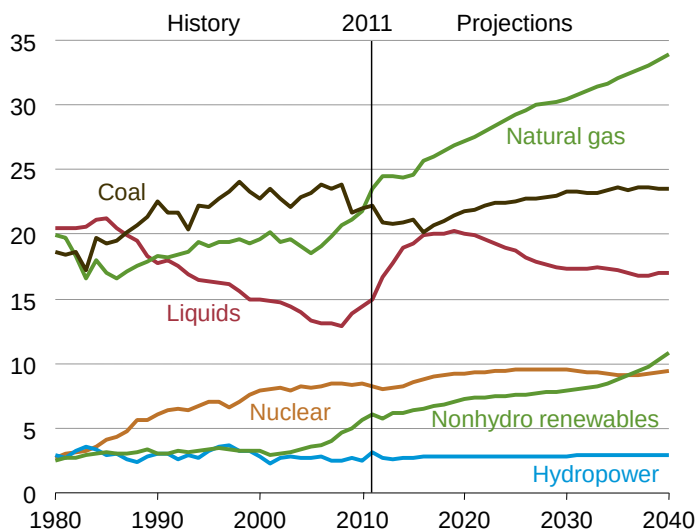


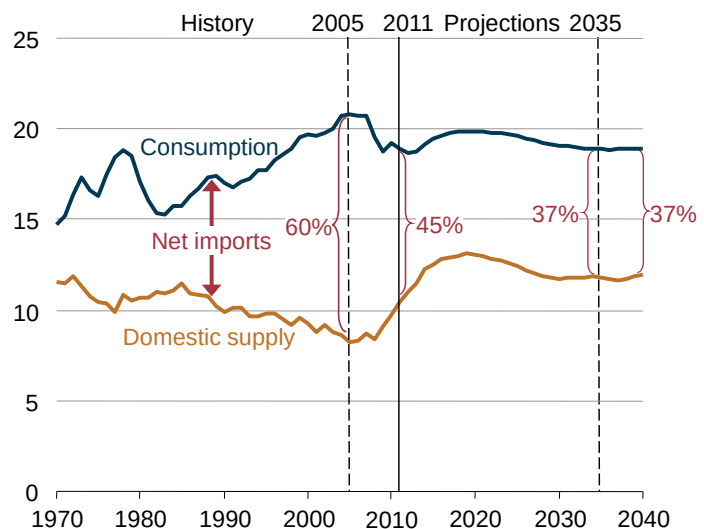
Figure 10. U.S. energy production by fuel, 1980-2040 (quadrillion Btu)



Lower 48 offshore natural gas production fluctuates between 1.8 and 2.8 trillion cubic feet per year, about the same as in AEO2012. New, larger-volume development projects, particularly in the deepwater Gulf of Mexico, remain directed principally toward liquids rather than natural gas. Offshore natural gas production is expected to reverse a years-long overall decline in about 2015, however, after which annual volumes generally increase to 2.8 trillion cubic feet in 2035 and remain at about that level through the balance of the projection period.

In the AEO2013 Reference case, the United States becomes a net exporter of LNG starting in 2016, as it did in the AEO2012

Figure 11. U.S. liquid fuels supply, 1970-2040 (million barrels per day)



Reference case, and an overall net exporter of natural gas in 2020, two years earlier than in AEO2012. U.S. exports of LNG from new liquefaction capacity are assumed to start at a level of 0.6 billion cubic feet per day in 2016 and increase to 4.5 billion cubic feet per day in 2027, as peak export volumes are shipped out of facilities in the Gulf Coast and Alaska. Over the projection period, cumulative net pipeline imports of natural gas from Canada and Mexico in the AEO2013 Reference case are considerably lower than those projected in the AEO2012 Reference case, with the United States becoming a net pipeline exporter of natural gas in 2021, or three years earlier than in AEO2012. In the AEO2013 Reference case, net pipeline imports from Canada fall steadily over most of the projection period, and net pipeline exports to Mexico grow by 387 percent. U.S. cumulative net LNG exports from 2011 through 2035 are up by 69 percent in AEO2013 compared with AEO2012, due in part to increased use of LNG in markets outside North America, strong domestic production, and low U.S. natural gas prices relative to other global markets. As in the AEO2012 Reference case, the Alaska natural gas pipeline is not constructed in the AEO2013 Reference case, because assumed high capital costs and low natural gas prices in the lower 48 states make it uneconomical to proceed with the pipeline project over the projection period.

Coal

While coal remains the leading fuel for U.S. electricity generation, its share of total generation in all years is slightly lower in the AEO2013 Reference case than was projected in the AEO2012 Reference case, and coal consumption in the electricity sector is lower than in AEO2012 in most years of the projection period. While still growing in most years after 2016, coal consumption in the power sector and for the production of coal-based synthetic liquids increases more slowly than in AEO2012; however, higher coal exports combined with lower imports keep the differences in coal production between the AEO2013 and AEO2012 Reference cases relatively small.

In the AEO2013 Reference case, domestic coal production increases at an average rate of only 0.2 percent per year, from 22.2 quadrillion Btu (1,096 million short tons) in 2011 to 23.5 quadrillion Btu (1,167 million short tons) in 2040. Over the projection period, however, production growth is uneven. From 2011 to 2016, low natural gas prices and the retirement of a sizable amount of coal-fired generating capacity lead to a substantial decline in electricity sector coal consumption, which, in turn, contributes to a 2.0-quadrillion-Btu decline in coal production over those years. After 2016, increases in coal use for electricity generation and exports lead to a gradual recovery in U.S. coal production. From 2016 to 2040, coal production grows at an average rate of 0.6 percent per year, from 20.2 quadrillion Btu to 23.5 quadrillion Btu. Regionally, coal producers in both the Interior and Western regions see their shares of total U.S. coal production increase over the projection period, while Appalachia's share declines. From 2011 to 2040, the Appalachian region's share of total coal production (on a Btu basis) falls from 38 percent to 32 percent.

Electricity generation in 2011 accounts for 91 percent of total U.S. coal consumption on a Btu basis. In the AEO2013 Reference case, projected coal consumption in the electric power sector in 2035 (18.5 quadrillion Btu) is 0.6 quadrillion Btu lower than in the AEO2012 Reference case (19.0 quadrillion Btu). The reduced outlook for coal consumption in this sector is generally attributable to lower natural gas prices and higher coal prices that, taken together, support increased generation from natural gas in the AEO2013 Reference case. More generation from nonhydroelectric renewables also contributes to the reduced outlook for electricity sector coal consumption in AEO2013. Coal consumed at CTL plants is lower in this year's outlook, reaching 0.2 quadrillion Btu in 2035 as compared with 1.2 quadrillion Btu in AEO2012. With a more robust outlook for coal imports by Asian countries, AEO2013 shows higher U.S. coal exports than AEO2012.

Total U.S. coal consumption increases from 19.7 quadrillion Btu in 2011 to 20.4 quadrillion Btu in 2040, reflecting average growth of 0.1 percent per year. As with production, growth rates for coal consumption are uneven over the projection, with consumption declining by 2.7 percent per year from 2011 to 2016, but then increasing by 0.7 percent per year from 2016 to 2040.

Electricity generation

Total electricity consumption in the AEO2013 Reference case, including both purchases from electric power producers and on-site generation, grows from 3,841 billion kilowatthours in 2011 to 4,930 billion kilowatthours in 2040, an average annual rate of 0.9 percent—about the same rate as in the AEO2012 Reference case through 2035.

The combination of slow growth in electricity demand, competitively priced natural gas, programs encouraging renewable fuel use, and the implementation of new environmental rules dampens future coal use. The AEO2013 Reference case assumes implementation of the CAIR as a result of an August 2012 federal court decision to vacate the CSAPR. The lower natural gas prices in the early years of the AEO2013 Reference case result in switching from coal to natural gas-fired generation, more than offsetting any increase in coal-fired generation that might have occurred in the absence of CSAPR. AEO2013 continues to model the implementation of the Mercury and Air Toxics Standards (MATS), although the implementation date is assumed to move from 2015 to 2016 due to the large number of plants requesting extensions to comply. Once MATS is in place, SO₂ levels are reduced to well below the levels resulting from either CAIR or CSAPR.

Coal remains the largest energy source for electricity generation throughout the projection period, but its share of total generation declines from 42 percent in 2011 to 35 percent in 2040 (Figure 12). Market concerns about GHG emissions continue to dampen the expansion of coal-fired capacity in the AEO2013 Reference case, even under current laws and policies. Low projected fuel prices for new natural gas-fired plants also affect the relative economics of coal-fired capacity, as does the continued rise in

construction costs for new coal-fired power plants. As retirements far outpace new additions, total coal-fired generating capacity falls from 318 gigawatts in 2011 to 278 gigawatts in 2040 in the AEO2013 Reference case.

Electricity generation using natural gas is higher in the AEO2013 Reference case than was projected in the AEO2012 Reference case because of lower projected natural gas prices. New natural gas-fired plants also are much cheaper to build than new renewable or nuclear plants. In 2016, the year that MATS is assumed to be implemented and coal-fired generation hits its lowest point, natural gas-fired generation in AEO2013 is 10 percent higher than in AEO2012 (and in 2035 it is still 9 percent higher).

Electricity generation from nuclear power plants grows by 14 percent in the AEO2013 Reference case, from 790 billion kilowatthours in 2011 to 903 billion kilowatthours in 2040, accounting for about 17 percent of total generation in 2040 (compared with 19 percent in 2011). Nuclear generating capacity increases from 101 gigawatts in 2011 to a high of 114 gigawatts in 2025 through a combination of new construction (5.5 gigawatts), uprates at existing plants (8.0 gigawatts), and retirements (0.6 gigawatts). After 2025, retirements outpace additions, resulting in a slight decline to 113 gigawatts in 2040. AEO2013 incorporates the latest information about planned nuclear plant construction and continues to use the updated estimate of the potential for capacity uprates at existing units developed for AEO2012. About 7 gigawatts of existing nuclear capacity is retired, primarily after 2030, because not all owners of existing nuclear capacity are expected to apply for and receive license renewals to operate their plants beyond 60 years.

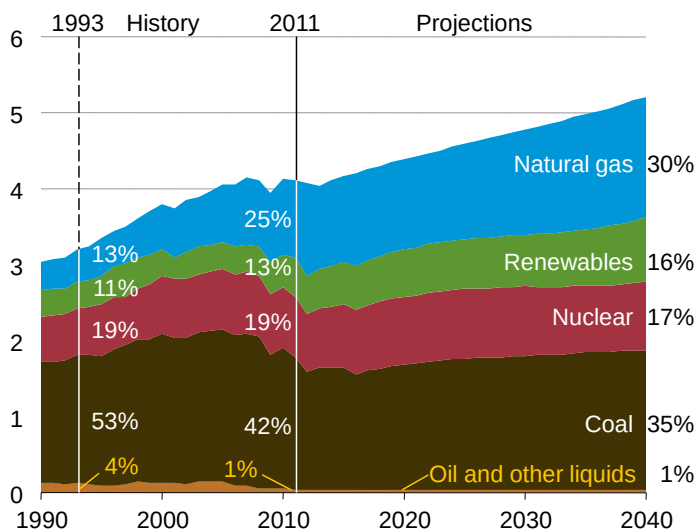
Increased generation from renewable energy, excluding hydropower, accounts for 32 percent of the overall growth in electricity generation from 2011 to 2040. Generation from renewable resources grows in response to federal tax credits, state-level policies, and federal requirements to use more biomass-based transportation fuels, some of which can produce electricity as a byproduct of their production process. Capital costs for new technologies were updated for AEO2013, resulting in fairly significant initial cost reductions for wind (13 percent) and solar PV (22 percent) relative to AEO2012. Reported renewable capacity already under construction has increased in recent years and is represented in AEO2013. Growth in renewable generation is supported by many state requirements, as well as new regulations on CO₂ emissions in California. The share of U.S. electricity generation coming from renewable fuels (including conventional hydropower) grows from 13 percent in 2011 to 16 percent in 2040. In the AEO2013 Reference case, federal subsidies for renewable generation are assumed to expire as enacted. Extensions of such subsidies could have a large impact on renewable generation. The long-run projections for renewable capacity are also sensitive to natural gas prices and the relative costs of alternative generation sources.

Energy-related CO₂ emissions

Total U.S. energy-related CO₂ emissions do not return to their 2005 level (5,997 million metric tons) by the end of the AEO2013 projection period.⁶ Growth in demand for transportation fuels is moderated by rising fuel prices and new, stricter federal CAFE standards for model years 2017 to 2025, which reduce transportation emissions from 2018 until they begin to rise near the end of the projection period. Transportation emissions in 2040 are 26 million metric tons below the 2011 level. Largely as a result of the inclusion of the new CAFE standards in AEO2013, transportation-related CO₂ emissions in 2035 are 94 million metric tons below their level in the AEO2012 Reference case.

State RPS requirements and abundant low-cost natural gas help shift the fuel mix for electricity generation away from coal and reduce emissions in both the residential and commercial sectors from the levels in AEO2012. Growth in residential sector emissions is flat over the projection period, and commercial sector emissions rise only slightly, by 0.3 percent annually.

Figure 12. Electricity generation by fuel, 1990-2040
(trillion kilowatthours per year)

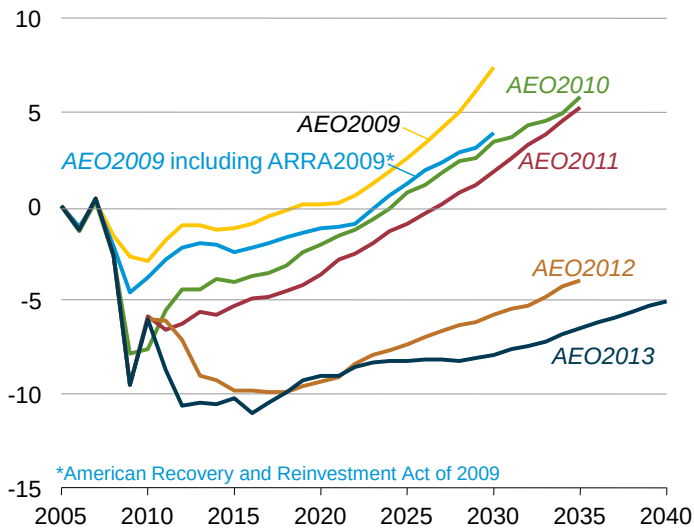


Only industrial energy-related CO₂ emissions are higher in AEO2013 as compared to AEO2012. While industrial coal emissions in AEO2013 are 48 million metric tons lower than in AEO2012 by 2035, natural gas emissions from the industrial sector are 67 million metric tons higher by 2035, and electricity-related emissions allocated to the industrial sector are 77 million metric tons higher. With emissions from petroleum slightly lower, the net result is that industrial sector emissions are 80 million metric tons higher in the AEO2013 Reference case than in AEO2012. Over the projection period from 2011 to 2040, industrial emissions grow at a rate of 0.3 percent annually.

The projected growth rate for U.S. energy-related CO₂ emissions has declined successively in each *Annual Energy Outlook* since AEO2005 (see Figure 13, which shows projections starting with AEO2009), reflecting both market and policy drivers. Using 2030 as a common year, the AEO2006 projection for total energy-related CO₂ emissions was 8,114 million metric tons, with coal accounting for 3,226

⁶The year 2005 is the base year for the Obama Administration's goal for emission reductions of 17 percent by 2020. In 2020, energy-related CO₂ emissions in the AEO2013 Reference case are 9 percent below their 2005 level.

Figure 13. U.S. energy-related carbon dioxide emissions in recent AEO Reference cases (percent change from 2005)



million metric tons (40 percent) and natural gas 1,452 million metric tons (18 percent). In AEO2010, total energy-related CO₂ emissions had dropped to 6,176 million metric tons in 2030, with 2,296 million metric tons (37 percent) coming from coal and 1,315 million metric tons (21 percent) from natural gas. In AEO2013, the 2030 values have fallen to 5,523 million metric tons for total energy-related CO₂ emissions, with 1,874 million metric tons (34 percent) coming from coal and 1,468 metric tons (27 percent) from natural gas. The change reflects both market and policy factors, including the adoption of tighter economy fuel standards, the implementation of efficiency standards, and a continued shift to less carbon-intensive fuels.

List of Acronyms

AB 32	Global Warming Solutions Act of 2006	LDVs	Light-duty vehicles
AEO	<i>Annual Energy Outlook</i>	LFMM	Liquid Fuel Market Module
AEO2011	<i>Annual Energy Outlook 2011</i>	LNG	Liquefied natural gas
AEO2012	<i>Annual Energy Outlook 2012</i>	MACT	Maximum achievable control technology
AEO2013	<i>Annual Energy Outlook 2013</i>	MATS	Mercury and Air Toxics Standards
bpd	barrels per day	mpg	miles per gallon
Btu	British thermal units	NGL	Natural gas liquids
CAFE	Corporate average fuel economy	NHTSA	National Highway Traffic Safety Administration
CAIR	Clean Air Interstate Rule	NO _x	Nitrogen oxides
CHP	Combined heat and power	OCS	Outer Continental Shelf
CO ₂	Carbon dioxide	OECD	Organization for Economic Cooperation and Development
CTL	Coal-to-liquids	OPEC	Organization of the Petroleum Exporting Countries
CSAPR	Cross-State Air Pollution Rule	PV	Photovoltaics
EIA	U.S. Energy Information Administration	RFS	Renewable fuel standard
EISA2007	Energy Independence and Security Act of 2007	RPS	Renewable portfolio standard
EOR	Enhanced oil recovery	SO ₂	Sulfur dioxide
EPA	U.S. Environmental Protection Agency	TRR	Technically recoverable resource
FFV	Flex-fuel vehicle	USGS	United States Geological Survey
GDP	Gross domestic product	WTI	West Texas Intermediate
GHG	Greenhouse gas		
GTL	Gas-to-liquids		

Table 1. Comparison of projections in the AEO2013 and AEO2012 Reference cases, 2010-2040

Energy and economic factors	2010	2011	2025		2035		2040
			AEO2013	AEO2012	AEO2013	AEO2012	AEO2013
Primary energy production (quadrillion Btu)							
Petroleum	14.37	15.05	18.70	17.69	17.27	16.82	17.01
Dry natural gas	21.82	23.51	29.22	26.91	32.04	28.60	33.87
Coal	22.04	22.21	22.54	22.25	23.60	24.14	23.54
Nuclear/Uranium	8.43	8.26	9.54	9.60	9.14	9.28	9.44
Hydropower	2.54	3.17	2.86	2.99	2.90	3.04	2.92
Biomass	4.05	4.05	5.27	6.26	5.83	9.07	6.96
Other renewable energy	1.31	1.58	2.32	2.22	2.91	2.81	3.84
Other	0.76	1.20	0.85	0.69	0.90	0.91	0.89
Total	75.31	79.02	91.29	88.61	94.59	94.67	98.46
Net imports (quadrillion Btu)							
Liquid fuels and other petroleum ^a	20.53	18.62	15.89	15.85	16.00	16.09	15.99
Natural gas (- indicates exports)	2.69	2.02	-1.56	-0.76	-2.53	-1.33	-3.55
Coal/other (- indicates exports)	-1.58	-2.32	-3.02	-1.75	-3.32	-2.32	-2.95
Total	21.64	18.31	11.31	13.34	10.14	12.44	9.49
Consumption (quadrillion Btu)							
Liquid fuels and other petroleum ^a	37.76	37.02	36.87	36.58	35.82	37.70	36.07
Natural gas	24.32	24.91	27.28	26.14	29.06	27.26	29.83
Coal	20.81	19.66	19.35	20.02	20.09	21.15	20.35
Nuclear/Uranium	8.43	8.26	9.54	9.60	9.14	9.28	9.44
Hydropower	2.54	3.17	2.86	2.99	2.90	3.04	2.92
Biomass	2.87	2.74	3.82	4.17	4.23	5.44	4.91
Other renewable energy	1.31	1.58	2.32	2.22	2.91	2.81	3.84
Other	0.31	0.35	0.30	0.28	0.26	0.24	0.29
Total	98.35	97.70	102.34	101.99	104.41	106.93	107.64
Liquid fuels (million barrels per day)							
Domestic crude oil production	5.47	5.67	6.79	6.40	6.26	5.99	6.13
Other domestic production	4.25	4.74	5.63	5.75	5.56	6.75	5.83
Net imports	9.43	8.51	7.08	7.14	7.06	7.25	7.00
Consumption	19.17	18.95	19.50	19.20	18.86	19.90	18.95
Natural gas (trillion cubic feet)							
Dry gas production + supplemental gas	21.40	23.06	28.65	26.34	31.41	27.99	33.21
Net imports (- indicates exports)	2.60	1.95	-1.58	-0.79	-2.55	-1.36	-3.55
Consumption	23.78	24.37	26.87	25.53	28.71	26.63	29.54
Coal (million short tons)							
Production and waste coal	1,098	1,108	1,134	1,134	1,194	1,231	1,195
Net exports	64	96	124	71	136	94	123
Consumption	1,049	999	1,010	1,063	1,058	1,137	1,071

Table 1. Comparison of projections in the AEO2013 and AEO2012 Reference cases, 2010-2040 (continued)

			2025		2035		2040
Energy and economic factors	2010	2011	AEO2013	AEO2012	AEO2013	AEO2012	AEO2013
Prices (2011 dollars)							
Brent spot crude oil (dollars per barrel)	81.31	111.26	117.36	--	145.41	--	162.68
West Texas Intermediate spot crude oil (dollars per barrel)	81.08	94.86	115.36	135.35	143.41	148.03	160.68
Natural gas at Henry Hub (dollars per million Btu)	4.46	3.98	4.87	5.75	6.32	7.52	7.83
Domestic coal at minemouth (dollars per short ton)	36.37	41.16	52.02	44.97	58.57	51.59	61.28
Average electricity price (cents per kilowatthour)	10.0	9.9	9.5	9.9	10.1	10.3	10.8
Economic indicators							
Real gross domestic product (billion 2005 dollars)	13,063	13,299	18,985	19,185	24,095	24,539	27,277
GDP chain-type price index (2005 = 1.000)	1.110	1.134	1.429	1.424	1.713	1.758	1.871
Real disposable personal income (billion 2005 dollars)	10,017	10,150	14,259	14,286	17,752	18,217	19,785
Value of industrial shipments (billion 2005 dollars)	5,842	6,019	8,548	7,973	9,779	8,692	10,616
Primary energy intensity (thousand Btu per 2005 dollar of GDP)	7.53	7.35	5.39	5.32	4.33	4.36	3.95
Energy-related carbon dioxide emissions (million metric tons)	5,634	5,471	5,501	5,552	5,607	5,758	5,691

^aIncludes petroleum-derived fuels and non-petroleum-derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids and crude oil consumed as a fuel.

-- = not applicable.

Notes: Quantities reported in quadrillion Btu are derived from historical volumes and assumed thermal conversion factors. Other production includes liquid hydrogen, methanol, and some inputs to refineries. Net imports of petroleum include crude oil, petroleum products, unfinished oils, alcohols, ethers, and blending components. Other net imports include coal coke and electricity. Both coal consumption and coal production include waste coal consumed in the electric power and industrial sectors.

Sources: AEO2013 National Energy Modeling System, run REF2013.D102312A; and AEO2012 National Energy Modeling System, run REF2012.D020112C.

APPENDIX 4

***Changes in the Market for
Montana Powder River Basin Coal
between 1986 and 2012***

**a report prepared for the
Northern Plains Resource Council**

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Summary

In the Tongue River Railroad's new application to the U.S. Surface Transportation Board, the Railroad asserts that: "Although US domestic electric utilities represent the prime demand potential for Otter Creek coal that the [Tongue River Railroad Company] would haul, additional tonnages could be anticipated for export markets." (Exhibit D, Operating Plan, p. 2) This is a seriously misleading description of the market for the coal the Railroad would carry, suggesting as it does that the market for that coal remains largely the same as when the Railroad originally was authorized more than a quarter of a century ago.

In fact, as this report will document, the market for Tongue River Valley coal has changed dramatically between 1986 and 2012:

- i. **The growth in demand for PRB coal has decelerated dramatically since 1986.** The five-year average annual growth rate in the demand for PRB coal in 1988, two years after the TRR initially received its permits, was almost 9 percent. For the next thirteen years, the average annual growth rate across five-year periods was, in general, above five percent. In 2002 it fell to about 3 percent; in 2005 it fell to about 2 percent. In 2009 it fell to 1 percent. And for the 2005 to 2010 period it fell to zero percent.
- ii. **The market for Tongue River Valley coal has not been sufficient to justify developing that coal or building the TRRR for the quarter of a century since the TRRR was originally authorized.** The limited domestic U.S. market in the upper Midwest for the Otter Creek coal the TRRR would carry was recognized in the appraisals and evaluations that were conducted when that coal was put up for lease in 2009.
- iii. **Coal demand in the historical markets for PRB coal, the upper Midwest, are projected to decline.** The U.S. Energy Information Administration projections indicate a decline in demand in the near term and that there will not be a return to 2010 levels of consumption in those markets for two decades.
- iv. **The reduced U.S. domestic demand for coal for electric generation is likely to continue for several reasons:**
 - a. The total life-cycle cost of natural gas fueled electric generators has been lower than the costs of coal-fired generators for almost a decade. As a result new electric generators have largely been fueled by natural gas.
 - b. Natural gas-fueled generators are more flexible in adapting to demand or intermittent renewable energy supply than are coal-fired generators.
 - c. Natural gas fueled generators have significantly fewer environmental problems and environmental costs associated with them, including lower carbon emissions.
 - d. In recent years the cost of natural gas has declined while the cost of coal has risen. Projections indicate this pattern is likely to continue in the near term.

- e. Many older and less efficient coal-fired generators are scheduled for retirement because of their high cost of operation and difficulty in meeting contemporary environmental standards.
- v. **The primary potential source of new demand for PRB coal is not domestic U.S. markets but Asian markets served by new or expanded west coast coal ports and upgraded rail links from the PRB to those west coast ports.**

Introduction

The Tongue River Railroad (TRRR) was initially authorized by the Interstate Commerce Commission (ICC) in 1986. Twenty-six years later the TRRR had not been built and as a result of a decision by the ICC's successor regulatory agency, the Surface Transportation Board (STB or Board) in June 2012, the sponsors of the TRRR were required to submit a new application because of the lengthy period of time since the TRRR had been initially authorized.

In the TRRR's new application for authority to construct and operate the proposed railroad, the TRRR stated that: "Except as set forth herein, all of the facts and findings relied upon by the Board, including the environmental report, are largely unchanged from the 1986 Decision..." (p. 2-3) In addition, the new application asserts that: "Although US domestic electric utilities represent the prime demand potential for Otter Creek coal that the [Tongue River Railroad Company] would haul, additional tonnages could be anticipated for export markets." (Exhibit D, Operating Plan, p. 2)

In fact, as will be shown below, the coal market that the TRRR can be expected to serve has changed dramatically since the mid-1980s when the TRRR was proposed and authorized. Rather than serving U.S. domestic markets, the TRRR and the Otter Creek coal it would carry, will primarily serve Asian export markets. This dramatic change in U.S. coal markets is recognized by Arch Coal who holds the lease on the Otter Creek coal as well as the U.S. Department of Energy. That change in the market for Otter Creek and other Powder River Basin (PRB) coal will require the building of coal ports on the Columbia River and the west coast of the United States and will involve in a significant increase in rail traffic between the PRB and the U.S. west coast and upgrades of the railroad infrastructure between Miles City and the west coast.

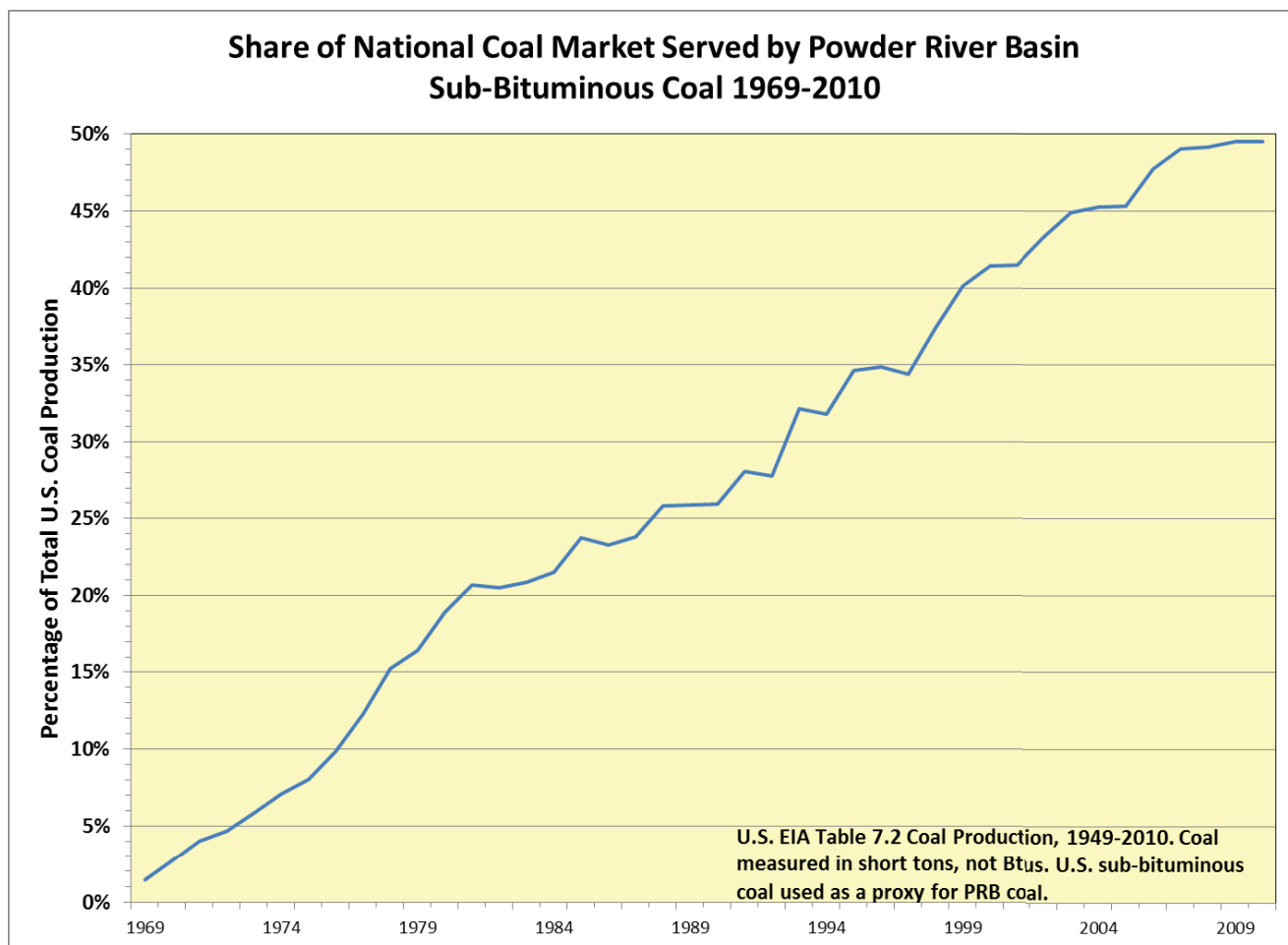
Dramatic Changes in U.S. Coal Markets between 1986 and 2012

Until recently the PRB coal fields seemed destined to continue to rapidly expand coal production to serve domestic American demand for coal to fuel electric generators to the south and east of Wyoming

and Montana. PRB coal production has expanded so rapidly over the last 40 years that it went from being an insignificant source of coal for U.S. markets to the dominant national coal fields. By 2007 the PRB coal was the source of almost half the coal burned in the U.S. measured in terms of tonnage. See Figure A. The low sulfur content and very low mining costs allowed PRB coal to successfully compete with other American coal sources across a good part of the continental United States.

However, at the end of the twentieth century, technical and economic changes were laying the basis for significant changes in the U.S. market for coal.

Figure A



Improvements in Gas-Fueled Electric Generation

In general, the capital costs associated with coal-fired generation are substantially higher than the capital costs associated with natural gas-fired generation. It also takes a considerably longer period of time to design, site, permit, and construct a coal-fired facility. This adds to the capital costs and capital risk. The trade-off that can justify these higher capital costs is the potential that coal is a much less

expensive fuel that could be converted to electricity more efficiently than early single-cycle natural gas plants. That is, the higher capital costs were incurred to reduce the fuel cost per unit of electricity produced. This is a front loaded investment that takes decades of continuous generation to pay off which increases the investment risk and recently led capital markets to be leary of investments in coal-fired generation.

Put the other way around, one attraction of using natural gas to generate electricity is that the capital investment necessary is significantly lower, and the facility can be built more quickly and in smaller increments without sacrificing efficiency. That lower capital cost and investment risk can justify the higher fuel cost per unit of electricity generated by using natural gas as the fuel.

It has been improvements in the efficiency of natural gas-fired generators in converting natural gas into electricity, the lower investment costs, and the smaller modular units whose capacity additions can be better timed to meet load growth that have helped support the shift in new electrical generating capacity from coal to natural gas fuel. Fewer air quality problems associated with the combustion of natural gas also have reduced the costs associated with using natural gas by both reducing the investment in air pollution abatement equipment and avoiding the reductions in the efficiency of converting the thermal energy into electricity that air pollution controls can cause.¹

Finally natural gas-fired electric generators are more flexible in adapting to changes in the need for more or less generation. Coal-fired plants have to be more slowly ramped up and down. In addition, the efficiency of natural gas-fired plants does not deteriorate as quickly as they are ramped down. This flexibility makes natural gas-fired plants good complements for renewable resources such as wind and solar whose production can fluctuate significantly within relatively short period of time. Given that recently many states have been adopting “renewable portfolio standards” that require electric utilities to serve a specified percentage of their load with renewable resources, natural gas-fired generators have become more attractive because they are a more cost-effective complement to intermittent renewable resources than coal.

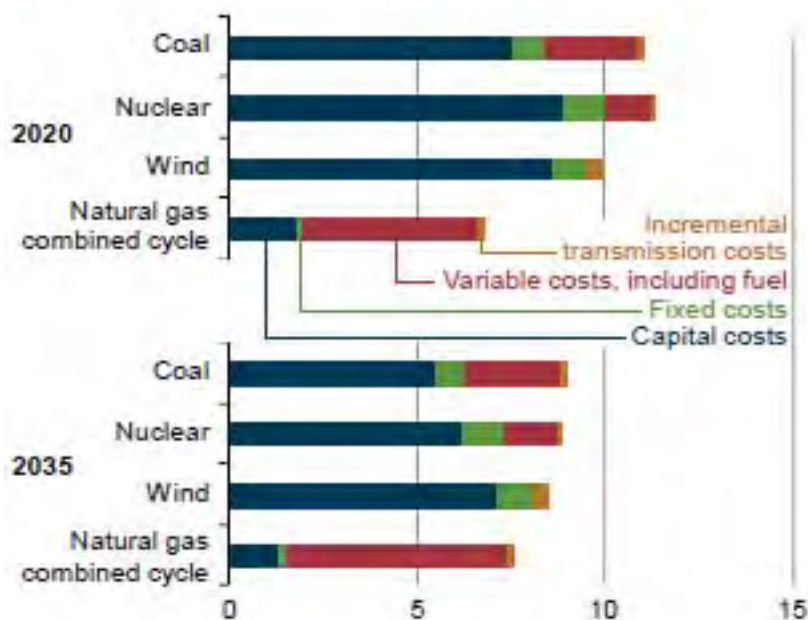
The Annual Energy Outlook 2011 projected significant differences between the levelized cost of a megawatt hour from a coal-fired generator compared to a gas-fired combined cycle generator: \$102 for coal versus \$70 for natural gas, a cost advantage for the natural gas plant of over 30 percent. Natural gas plants had the levelized cost advantage despite having variable operating costs (fuel and variable operations and maintenance costs) that were almost twice as large on a per unit of electrical output basis. The natural gas combined cycle plants offset that fuel cost disadvantage with capital costs that were only about a quarter of those of a coal-fired plant on a megawatt hour basis.² On net, the total cost per unit of electricity produced was lower for gas-fueled electric generation. See Figure B.

¹ Annual Energy Outlook 1995, p. 30, Energy Information Administration, U.S. Department of Energy, January 1995, DOE/EIA-0383(95).

² These are projected costs for 2020 stated in 2009 dollars. Figure 81, p. 75, DOE/EIA-0383 (2011), April 2011.

Figure B.

Figure 81. Levelized electricity costs for new power plants, 2020 and 2035 (2009 cents per kilowatthour)



Source: Annual Energy Outlook 2011, Figure 81, p. 75, DOE/EIA-0383(2011)

The Costs of Meeting Environmental Quality Regulations

One of the primary forces driving the shift from coal to natural gas as the preferred fuel for electric generation over the last decade, a shift towards what appears to be a significantly more costly fuel, has been the increasing costs of meeting ever more stringent pollution control costs on coal-fired generators and the uncertainty about future regulation of those coal plant emissions including the equivalent of a carbon tax. The Environmental Protection Agency, under pressure from the courts, has been increasing the pollution control requirements on older coal-fired plants that had been “grandfathered” in under the Clean Air Act and its amendments.

In addition, the requirements that haze producing emissions not impact National Parks and Wilderness areas have begun to be enforced. Coal-fired electric generators are often the primary source of the haze-producing emissions.³ The power plant emissions most threatening to human health, including

³ US EPA proposed a Regional Haze Rule in 2011 in response to court decisions ordering EPA to implement the provisions of the Clean Air Act (amended) that mandate “prevention of any future, and the remedying of any existing, impairment of visibility in the mandatory class I Federal areas which impairment results from manmade air pollution.” 42 U.S.C. 749(a)(1). Those mandatory Class I areas are primarily National Parks and Wilderness

mercury and other toxic metals as well as sulfur oxides and tiny particulates are the pollutants most closely linked with coal combustion. Those emissions are being subject to stricter limits. Also, most electric utility planners expect greenhouse gas emissions to ultimately be subject to limits and/or penalties or taxes, and since coal is the most carbon intensive of the electric plant fuels, such greenhouse gas controls are likely to be more costly for coal-fired plants. In addition, the solid and liquid waste byproducts associated with coal-combustion, which are quite toxic, are also coming under increasingly strict regulation. Finally, public opposition to siting new coal-fired electric plants and public support for the retirement of existing coal-fired plants has grown.

The result of this near perfect storm of concerns about the environmental costs associated with coal-fired electric generators has virtually eliminated coal as a fuel for new electric generators in the United States and has led to the “early” “voluntary” retirement of a significant number of existing coal-fired generators. This has tended to permanently reduce the demand for coal in the United States.

Dramatic Declines in the Relative Cost of Natural Gas

The dramatic decline in the price of natural gas and the ongoing increases in the price of some U.S. coals, e.g. Central Appalachian coal, have certainly also pushed utilities toward a shift away from coal as a fuel for electric generation. The dramatic increase in the projected American supply of natural gas over the last decade has also provided some confidence that those natural gas prices will remain relatively low for some time into the future.

At any given time there is an existing set of electric generators that are powered by different energy sources. Renewable sources, such as hydroelectric, wind, and solar, have no fuel costs. Electric generators using fossil fuels, of course, have significant fuel costs that vary with the level of generation.

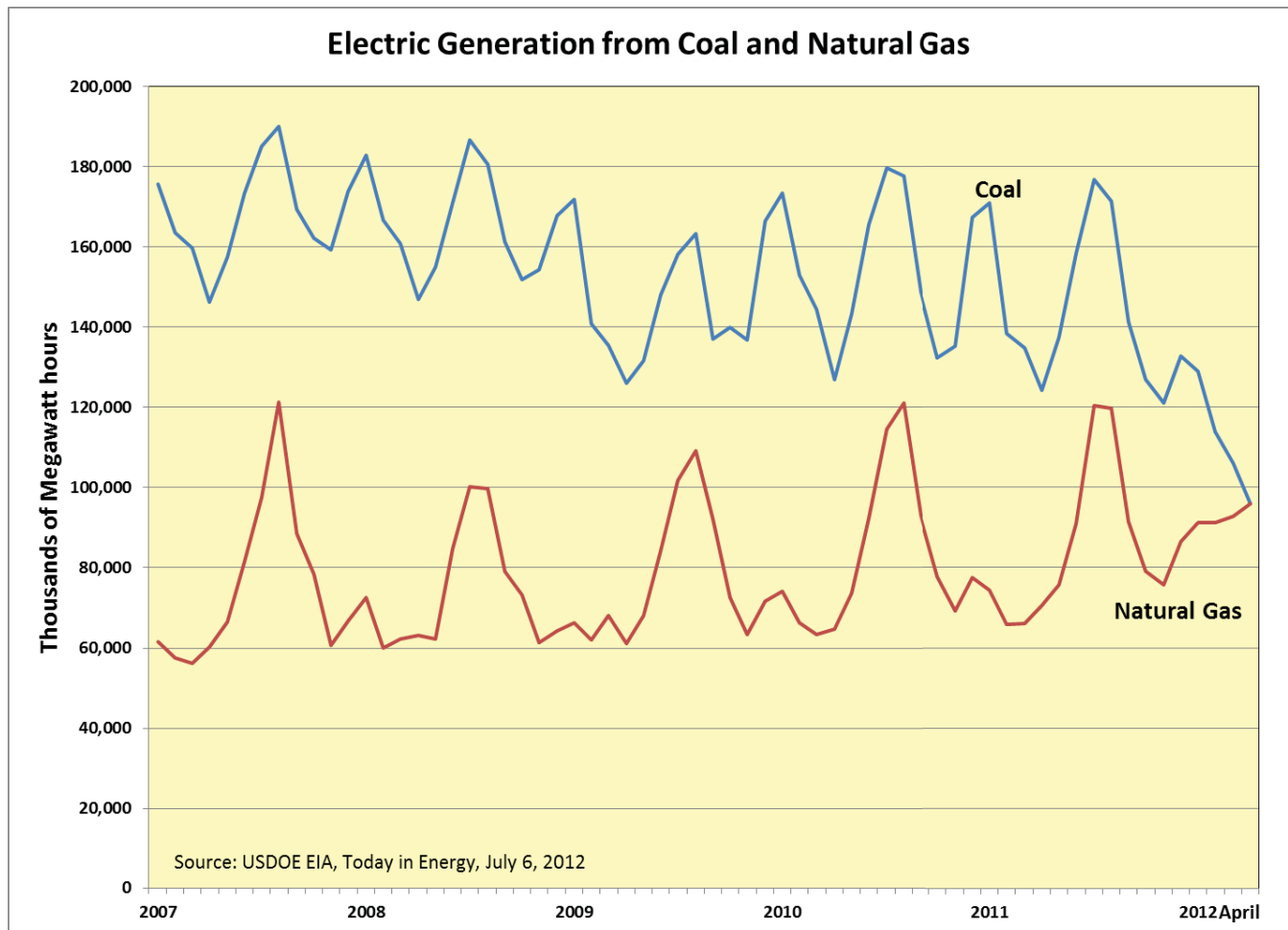
Because the demand for electricity varies considerably across the day and across the year, not all electric generators are operating at full capacity all or most of the time. In general, utilities first operate the generators with the lowest operating costs and as the demand for electricity increases, they turn to generators with higher operating costs. This “economic dispatch” of the generators that are cheapest to operate first and turning to the most expensive generators only during the periods of higher electric demand means that as relative fuel prices vary, the intensity of use of generators fired by coal and natural gas will vary too. As natural gas falls in price relative to coal, natural-gas-fired plants will be used more and coal-fired plants less. The same will happen if the cost of coal rises relative to natural gas.

That is exactly what has been happening as natural gas prices to electric generating plants tumbled to a ten-year low in the first quarter of 2012. For the first time in 40 years of record keeping, the use of coal declined and the use of natural gas rose to a point where natural gas-fueled generation equaled coal-

Areas. The haze-precursor pollutants include nitrogen oxides, sulfur dioxide, and particulate matter produced by coal-fired plants that also harm public health.

fired generation, each the source of about a third of the electricity being generated in the United States. For the 1990-2010 period coal typically had been the fuel for about half of the electricity generated in the U.S., while natural gas fueled less than 20 percent of generation. See Figure C. During the summer of 2012 coal's share of electric generation rose to 39 percent while the share of generation from natural gas rose only slightly. Projections are that by the end of 2012, coal consumption in the U.S. is expected to be at its lowest level since the mid-1990s.⁴

Figure C.



Financial Difficulties of Arch Coal and Other U.S. Coal Companies

The decline in the demand for coal in the United States has led to considerable financial pressure on American coal mining companies. Patriot Coal, into which Peabody Energy spun off most of its eastern coal properties, filed for bankruptcy July 2012. Most other major mining companies have reduced their

⁴ Value Line, September 7, 2012, Coal Industry, p. 593.

production, laying off workers to pare down costs. During 2012 the stock prices for most American coal companies also fell steeply. Arch Coal, the developer of the Otter Creek Tracts, saw its stock price fall to about \$5 a share in late July 2012, an all-time low. In mid-November it was trading for about \$6.40 about one-twelfth of its mid-2008 peak level. Arch is projected to suffer an overall loss for the year 2012. In September 2012 *Value Line* described Arch as an “attractive acquisition target.” Alpha Natural Resources, a coal mining company operating in both Appalachia and the PRB was similarly described as an “appealing buyout target.” In mid-November 2012, its stock was trading for about \$7 a share, down from \$65 at the beginning of 2011 and \$119 in the middle of 2008.⁵

In this severely depressed domestic U.S. coal market, it is unlikely that a large new PRB coal mine such as that proposed for Otter Creek represents can expect to sell its additional coal in the United States.

Changes in the Market for Montana PRB Coal between 1984 and 2012 as Seen by the U.S. Energy Information Administration (EIA)

We have the ability to look back at how the U.S. Department of Energy’s Energy Information Administration (EIA) described the U.S. market and projected the growth in coal production in the Western (largely the PRB) coal fields back in 1984 when TRRR was seeking permits and now in 2012 when it was reapplying for that permit.⁶ EIA has produced an Annual Energy Outlook (AEO) each year, a report on the status of energy use, including coal use, in the U.S. For consistency in our comparison, we review the “Coal Production by Region” figure that the EIA produces in almost all of the AEOs. This comparison allows us to see how the EIA expected Western coal production to grow over the following 20 years as of 1984, 1995, 1996, 2005, and 2012. This will give us a broad view of EIA’s projections of the role of PRB coal in the U.S. coal market as well as how EIA’s view of that market has changed over time.

In 1983 the PRB was producing about 225 million short tons of coal and was in a period of very rapid expansion. At that time the Western region had just reached about the same level of coal production as the eastern underground mines for the first time in history, and the Western region was predicted to produce about 430 million short tons of coal by 1995.⁷ In 1984 the EIA forecasted an almost meteoric rise in the amount of coal that would be produced by the PRB as the Western region was predicted to almost double its coal production in a ten year period. This projection of incredible growth was based on the looming implementation of EPA regulations that favored the low-sulfur coal of the PRB compared

⁵ *Value Line*, September 7, 2012.

⁶ In the earlier EIA domestic coal market projections, all coal sources in the West tended to be combined into an aggregate “Western” category. The PRB coal of Wyoming and Montana dominated this Western coal category. The Western category, however, did include coal produced in western Wyoming, Colorado, Utah, New Mexico, and Arizona. In that sense using “Western” coal as a proxy for PRB coal tends to exaggerate slightly the size of the PRB production.

⁷ U.S. DOE Annual Energy Outlook 1984.

to the high-sulfur coals of the Illinois and Appalachian coal regions. The U.S. was recovering from the energy crisis of the early 1980s and EIA projected a decreasing use of oil for electrical generation in favor of coal that could be produced domestically as opposed to imported oil. Newly developed coal surface mining techniques were also expected to allow the very low-cost, low-sulfur, PRB coal to expand its share of the national market. In short the EIA was projecting that the PRB would step into the domestic U.S. market for electric generation in a major way.

By 1995 the EIA's 1984 projection of 430 million short tons being produced in 1995 from the Western region was more than realized as about 440 million short tons were produced. The PRB had undergone an unprecedented level of growth that matched the EIA's high growth predictions as the U.S. built and fueled coal-fired electrical generation to offset the loss of generation from foreign and domestic oil and domestic natural gas.⁸ The Clean Air Act's 1990 amendments were also driving the continued growth of PRB coal production and the substitution of low-sulfur PRB coal for high-sulfur eastern coal.⁹ Yet during this explosive growth period, Montana PRB coal was almost left completely out of that growth. While the PRB as a whole almost doubled production in a ten year period, Montana's annual coal production grew from 33 million short tons to only 39 million short tons. In fact, over the 1980 to 2000 period Montana's production of coal had been fairly static.¹⁰

In the 1996 AEO the EIA predicted that in 2010 the Western region would produce just over 500 million short tons of coal.¹¹ While the Wyoming portion of the PRB was projected to continue to expand, in 1996 Montana coal production had already reached what would become its 2012 level of coal production of about 40 million short tons.¹²

In 2005 the EIA was still making projections of rapid growth in PRB coal production. In 2003 the Western region produced about 550 million short tons of coal which was more than the 1995 AEO predicted would be produced there by 2010. The 2005 AEO predicted that by 2025 the west would produce some 900 million short tons of coal. To put this in context, the U.S. total amount of sub-bituminous and bituminous coal produced for 2010 was just over 1 billion short tons.¹³ That is, the Western region was projected by the AEO 2005 to produce (by 2025) 90% of the total bituminous and sub-bituminous coal produced in 2010 in all of the U.S. This volume of coal would have been almost twice the coal that the PRB actually produced in 2010. In 2005 Montana coal production again was only a small fraction (9%) of total PRB coal production and continued its flat trajectory of coal production by producing 40 million short tons.¹⁴

⁸ IBID

⁹ U.S. DOE Annual Energy Outlook 1996

¹⁰ http://leg.mt.gov/content/publications/Environmental/2002deq_energy_report/coal.pdf

¹¹ IBID

¹² U.S. DOE Annual Coal Report 1996. Montana produced a little more than 38 million short tons of coal in 1996 which is very close to the 20 year average. In 2009, for example, Montana produced 39 million short tons of coal and in 2010 Montana produced 44 million short tons of coal.

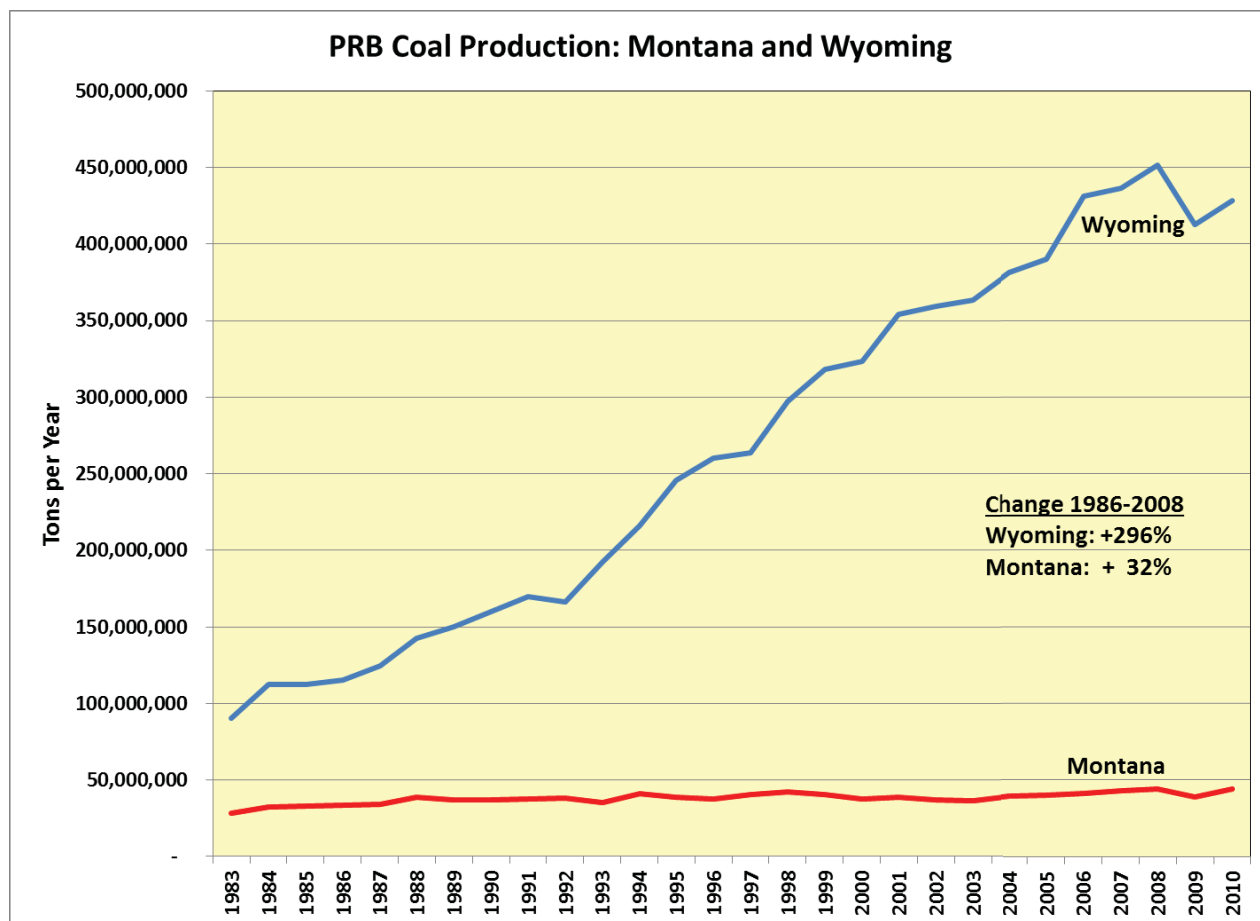
¹³ U.S. DOE Annual Coal Report 2010 Table 6

¹⁴ U.S. DOE 2005 Annual Coal Report 2005 Table 6

In AEO 2012, facing the reality of the Great Recession and its aftermath of slow economic growth as well as very low natural gas prices, the shift toward natural gas fueled new generators and the retirement of older coal-fired generators, EIA coal projections painted a dramatically different picture of present and future U.S. coal markets and the role of PRB coal in them. In 2010 the Wyoming PRB actually produced 468 million short tons of coal and Montana produced 44 million short tons.¹⁵ The AEO 2012 dramatically scaled back its projection of Western coal production in 2025 from 900 million short tons predicted in AEO 2005, to about 695 short tons. Although the Western region was predicted to continue to take over a somewhat larger portion of total coal consumed in the U.S., the general trend was for declining coal consumption in the U.S. in the short term followed by much slower growth than EIA had previously predicted. In the mid-1980s there were great expectations for Western (PRB) coal to expand to dominate other American coal fields, and indeed those expectations were fulfilled. That however was a tale of two PRBs. While the Wyoming portion of the PRB saw meteoric growth, the Montana portion of the PRB saw almost no growth at all after 1988. After the TRRR was approved in 1986, Wyoming PRB production expanded almost 10 times faster than Montana PRB production. See Figure D below. That exuberance about the future market for PRB coal was present when the Tongue River Railroad was initially proposed and approved in the first half of the 1980s. The fact that the TRRR was *not* built and the coal it was intended to carry did *not* get mined was an indication of the limited market to which the Montana PRB coal actually had access.

¹⁵ U.S. DOE Annual Coal Report 2010 Table 6

Figure D.



The divergent growth trends in Wyoming and Montana coal production are largely explained by the fact that Montana PRB coal cannot directly compete with much of the Wyoming PRB coal because of a significant transportation disadvantage (that will be discussed more below). This is not an abstract economic argument. Montana simply has not been able to expand its presence in the U.S. on the scale Wyoming has. The idea of meteoric growth that prevailed in the mid-1980s certainly did not come to fruition for Montana. In fact, as the rest of the PRB continued to grow and take an ever larger portion of the nation's electrical generating needs, the Montana portion of the PRB remained stagnant and decreased in percentage terms with respect to coal consumption in the U.S. as a whole. To understand why the Montana portion of the PRB has not experienced the growth of its neighbor to the south, it is important to understand where PRB coal actually gets sold and why.

The Limited and Shrinking Market for Montana PRB Coal

Of the 468 million short tons of coal that were produced by the PRB in 2010, about 330 million short tons were delivered to the West North Central and East North Central census divisions that we will collectively call the “North Central” region (e.g. the Upper Midwest).¹⁶ In other words, the vast majority of coal that is produced by the PRB is consumed by the North Central region. Because the Montana PRB coal lies several hundred miles north of the bulk of Wyoming’s PRB coal fields and also several hundred miles north of much of the most densely settled North Central region, it suffers from of a transportation disadvantage relative to the Wyoming PRB. In addition Montana coal tends to have higher sodium content which raises boiler and pollution control maintenance costs. For both of these reasons Montana coal has historically only been able to compete for less than one tenth of North Central market. Because Montana coal is hampered by its high sodium content and a very small geographic area where it has a transportation advantage over Wyoming coal, the prospects for Montana coal to expand production and sell its coal to the east or south has been limited and the actual realized coal sales quantity from Montana confirms this limited market. The fact that the TRRR did not get built after it was permitted in 1986 and Tongue River coal was not developed is additional evidence of the limited market the Montana’s PRB coal faced.

Of the 330 million short tons of PRB coal delivered to the North Central region in 2010, the Montana PRB contributed about 22 million short tons. This represented about 60% of the coal that Montana sold domestically.¹⁷ Montana kept about 11 million short tons for coal-fired generation within the state and shipped 3.3 million short tons to the west (Washington, Oregon, and Arizona). These three destinations represented about 99% of the coal that Montana sold into American markets.¹⁸ The point of this accounting is to show that Montana ships the majority of its coal to the North Central region. This has been true since at least 2001 when the EIA began publishing the Annual Coal Distribution reports showing coal flows from state to state. In 2001 Montana sold 83% of its coal to the North Central region and in 2008 Montana sold about 54% of their coal to the North Central region.¹⁹

Any new Montana PRB coal that is produced will be competing for the same market that Montana coal has had access to for the last 30 years. Wyoming will continue to dominate the sale of coal to the North Central region because of the transportation cost advantage it has in accessing the major coal markets there. Any new mines in Montana will be forced to either displace current Montana mines or look for new markets in which to sell their coal. In addition Montana coal faces the problem that the geographic area that has been Montana’s dominant coal market, a larger share of which Montana would like to

¹⁶ Annual Coal Distribution Report 2010 by the EIA. The West North Central census division is made up of ND, SD, MN, IA, NE MO, and KS. The East North Central census division is made up of WI, IL, IN, OH, and MI.

¹⁷ IBID.

¹⁸ Montana produced a total of 44.7 million short tons of coal in 2010 according to the EIA’s Annual Coal Report for 2010. 4.4 million short tons of that coal was produced at underground mines and is not included as PRB coal. Montana exported about 8 million short tons of coal in 2010 and about 3.6 million short tons of that coal would be considered PRB coal.

¹⁹ <http://www.eia.gov/coal/distribution/annual/> (see 2001, 2005, and 2011)

capture, is predicted to use less coal in the future. The traditional market for Montana's PRB coal is projected to shrink.

Because of the ongoing retirement of older coal-fired electrical power plants, the lingering effects of the Great Recession, and the decline in the price of natural gas, less coal is being burned in the places to which Montana historically sent its coal. The North Central region is predicted by the EIA and Peabody Energy to use less PRB coal in the near term and not return to the 2010 levels of PRB coal consumption until 2032.²⁰ This leaves Montana coal attempting to take over a larger portion of a shrinking market in which PRB coal historically has been unable to gain a major foothold. But the North Central region is not the only shrinking market into which Montana sells its coal.

Oregon and Washington, states that have both been small customers for Montana coal, are scheduled to retire their Boardman and Centralia coal fired-power plants by 2020 and 2025, respectively.²¹ As part of Oregon and Washington's continued strategy to rely less on fossil fuels, both states have agreed to retire their only coal-fired generators. The state of Montana itself, which keeps about 25% of Montana coal production for in-state use, is also planning to retire one of its coal-fired facilities. The Corette facility outside of Billings will be shut down in 2015 because of weak regional electric markets and the cost of installing new pollution control devices.²²

In short, Montana coal is facing stagnant or declining domestic American markets for its coal. This of course raises the question of where companies that own or have leased Montana coal, especially those planning new mines, are hoping to sell their coal, if it is not into the domestic American markets?

The Market for Otter Creek Coal Identified in the 2006 and 2009 Otter Creek Appraisals Done for the State of Montana

The limited eastern market for Otter Creek coal was also identified in two analyses carried out for the owners of the Otter Creek coal, the State of Montana (Department of Natural Resources) and Great Northern Properties in 2006 and 2009. Those studies sought to appraise the value of the Otter Creek tracts for coal production so the owners could evaluate lease offers including bonus bids.

Between 2001 and 2007, 90 to 95 percent of Montana coal sales have gone to nine states: Montana, North Dakota, Minnesota, Wisconsin, Michigan, Illinois, Indiana, Washington, and Oregon. Geography largely dictates the concentration of sales in these states. They are the states where Montana has a

²⁰ U.S. DOE Annual Energy Outlook 2010 and

http://www.peabodyenergy.com/mm/files/Investors/IR%20Presentations/AugustInvestorRoadshow_Final.pdf

²¹ <http://www.nwcouncil.org/news/2011/06/2.pdf>

²² <http://www.chem.info/News/FeedsAP/2012/09/topics-alternative-energy-ppl-montana-to-mothball-coal-fired-plant-in-2015/>

transportation cost advantage relative to Wyoming coal. Often that transportation cost advantage is small and both Montana and Wyoming coal is sold into the same markets.²³

Since 2001 both Montana and Wyoming have seen similar percentage increases in sales to these states, about 10 to 15 percent. That, however, masks some changes in competitive advantage. Montana, for instance, has lost all sales to Illinois where Wyoming sales have increased 78 percent. In Michigan and Indiana, Montana sales have been relatively static or declining while Wyoming sales have increased 69 percent and 40 percent, respectively. On the other hand, Montana sales to North Dakota and Minnesota have expanded while Wyoming sales have contracted. Montana sales to Washington have also increased while Wyoming has just begun to compete there. In Oregon, Wyoming sales have been steady but Montana's sales have fallen to zero. Meanwhile Wyoming has not been able to gain market share in Montana just as Montana has not been able to sell into Wyoming markets.

Looking at the ebb and flow of sales over this last decade, it is clear that it is in the northern states closest to Montana where Montana's market has expanded. The farther south the location, the more inroads Wyoming has made because of its transportation cost advantage. It is the distance by rail to the various electric generators that tends to dictate the markets to which Montana has access.

Otter Creek coal has relatively high sodium content. High-sodium levels in coal cause "slagging" in boilers and can interfere with air-pollution-control devices. Because of this, as the Norwest appraisal states, "Coals with high sodium content **share a limited market** due to slagging problems they cause in certain types of power plant boilers. **This limits the market for high sodium coals to a small number of mid-western electric generating plants and some industrial plants.**"²⁴ (Emphasis added)

In the 2006 analysis, Norwest was more explicit about exactly where that "small number of Mid-western generating plants" that represented the "limited market" available for Otter Creek coal were located.²⁵ In a section in that report labeled "Marketing," Norwest points out that Otter Creek coal ash ranges from 5.8 to 8.8 percent sodium, a high level compared to other coals in the western U.S. In the southern Powder River Basin of Wyoming, the sodium averages 1.2 percent while coals in Colorado average about 2.5 percent sodium. Norwest also points out that "most plants avoid burning high sodium coals. Exceptions include the following ten plants which are within the competitive area for Otter Creek currently accepting higher sodium coals."²⁶ Norwest then proceeds to list the 10 plants: 5 in Minnesota, 4 in Michigan and 1 in Wisconsin. Those electric-generating plants that Norwest says "would likely constitute the initial target market for Otter Creek coals" are shown in Figure E below, which was taken from that 2006 Norwest report.²⁷

²³ Domestic Distribution of U.S. Coal by Destination State, Consumer, Origin and Method of Transportation, 2007, Energy Information Administration, December 2008.

²⁴ P. 2-4. This warning about "limited markets" for Otter Creek coal is repeated elsewhere in the 2009 Norwest appraisal (pp. 2-3 and 2-5).

²⁵ Otter Creek Property Summary Report, Volume I of II, submitted to Great Northern Properties and Montana Department of Natural Resources and Conservation, July 12, 2006.

²⁶ Ibid. p. 4-1.

²⁷ Ibid. p. 4-1 and Figure 4.1.

Figure E
Electric Generation Plants That Would Likely Constitute the
Initial Target Market for Otter Creek Coals



Figure 4.1 from Norwest Corporation's "Otter Creek Property Summary Report," Vol. 1, July 12, 2006

Note that transportation costs generally limit the area where Montana has a transportation-cost advantage over Wyoming. These areas include a northern tier of states: North Dakota, Minnesota, Wisconsin, Michigan, and Illinois to the east and Washington and Oregon to the west.

The ten electric generators identified by Norwest as the "initial target market for Otter Creek coals" have a total consumption of about 20 million tons of coal per year, only 57 percent of the annual production level that Norwest envisions from the Otter Creek Tracts. In fact, Norwest expressed concern that between 2004 and 2005 this market had "decreased to 16.1 million tons. The difference in consumption rates appears to be due to the intrusion of coal from the Southern PRB [Wyoming Powder River Basin]." ²⁸

²⁸ Ibid.

Of course, all of these electric generators are currently served by other coal suppliers. Even if Otter Creek was able to displace 100 percent of the current coal suppliers, more than 40 percent of the Otter Creek coal would have to be sold to plants other than those identified by Norwest in its 2006 report as the “initial target market.” Norwest recognizes this, commenting that “The volume of coal shipped from Montana to the high sodium-accepting power plants is only about 20 million tpy [tons per year]. **Careful effort developing a solid market strategy will be necessary to determine how best to nudge into this market without destroying whatever price discipline, if any, currently exists.**”²⁹ (Emphasis added)

Note that Otter Creek coal would have to both “nudge” its way into this already served market, displacing the current coal producers, as well as fending off competition from Wyoming coal producers. Also note that in doing so, both Otter Creek coal and further inroads into this market from Wyoming coal are likely to drive the price of the high-sodium coal downward as Otter Creek and Wyoming mines compete to take as much of that market away from current suppliers as possible.

In the 2006 Report Norwest also identified another group of 14 generating plants with an annual consumption level of about 30 million tons of coal that might serve as a market for Otter Creek coal. These were plants “also served by Montana mines neighboring Otter Creek, including Rosebud, Absaloka, Decker, and Spring Creek.” The four Colstrip power plants in Montana were included in this additional potential market for Otter Creek coal.³⁰ This statement underlines who the current coal suppliers are that Otter Creek would have to displace: They are almost exclusively Montana coal suppliers. Only one of the initial ten generation plants and none of the second group of 14 plants were served by a non-Montana mine. The market Norwest expects to support the Otter Creek mine will first have to be taken from other Montana coal mines, ton for ton. As described by Norwest, this is a zero-sum game for Montana: Otter Creek coal can be sold only at the expense of other Montana coal producers.

In the evaluation and appraisal of the Otter Creek coal tracts prepared for the State of Montana by Norwest to support Montana’s Otter Creek leasing process, Norwest came to the following conclusions:

- i. The high-sodium character of the Otter Creek coal limits the market into which it can be sold.
- ii. The market for Otter Creek coal is “a small number of mid-western electric generating plants.”
- iii. Almost all of those Mid-western electric-generating plants are currently served by other Montana coal mines.
- iv. Otter Creek coal will have to compete with and displace other Montana coal mines to gain a share of that limited market.
- v. That competition will put downward pressure on the price for coal that all Montana mines will face as they compete for market share in this limited market.
- vi. Wyoming appears to be making inroads into the geographic area where transportation costs previously created a protected market for Montana coal.

When these conclusions from 2006 and 2009 are put in the contemporary, 2012, context of declining national demand for coal, the market potential in the states to the east of Montana appear even

²⁹ Ibid. p. 4-4.

³⁰ Ibid. p. 4-4, and Table 4.1.

bleaker. They certainly do not appear to support a very large new coal mine that is economically constrained by both its location and the quality of its coal.

The New Markets for Montana PRB Coal Envisioned by PRB Coal Companies: Exports to Asia

Montana has over 25% of the estimated recoverable coal reserves in the U.S. which, in turn, holds the largest coal reserves in the world.³¹ But Montana's share of total PRB coal production is not expanding and the markets to which the PRB has traditionally sold its coal are shrinking.³² Even during the rapid expansion of PRB coal sales to the nation, Montana's contribution remained static at about 40 million tons per year. Now PRB sales are forecast to decline before returning to a much slower growth rate. That raises the question of to where Montana coal companies that wish to expand production are really looking for additional sales?

The largest coal companies in the world, which own the largest coal tracts in the PRB, have been focusing on sending their coal to Asia due to the flagging U.S. market and a seemingly ever-expanding Asian market. Driven by a large perceived market for PRB coal in Asia, there are multiple new west coast coal ports in the permitting process, regular announcements of potential port expansions on the same coast, and the two largest coal ports on the west coast of North America (Westshore and Ridley on the Canadian coast) are in the midst of upgrading their facilities to try and accommodate this expanding export market. Ports across the U.S. from the Gulf of Mexico to Virginia have seen their coal export volumes increase as coal companies scramble to maintain sales and profits in the face of declining U.S. markets by selling to the expanding Asian markets as well as displacing other suppliers in Europe. In 2011 the U.S. almost set a record for the largest volume of coal exported and is on track to break the 1981 U.S. record in 2012.³³

Recent slowdowns due to environmental regulation, port infrastructure problems, and flooding have curbed the development and export of Australian, Indonesian, and Russian coal. Suddenly the world seemed hungry for coal even as U.S. consumption has slowed. All of this leaves the owners of the PRB coal, one of the world's largest and cheapest sources of coal, anxious to export its coal to make up for the lack of domestic demand and the increase in world export demand.

Peabody coal is faced with the reality that their market for 2012 appears to have decreased by 100-120 million short tons. Peabody's shipments of coal worldwide, in the second quarter of 2012, declined 104 million short tons versus the second quarter of 2011. More than offsetting this decline, Peabody

³¹ <http://www.eia.gov/beta/state/?sid=MT#tabs-3>

³² http://leg.mt.gov/content/publications/Environmental/2002deg_energy_report/coal.pdf

³³ <http://www.eia.gov/todayinenergy/detail.cfm?id=8490>

expects their exports from the U.S. to grow by 150-170 million short tons by 2017.³⁴ Peabody is betting it can wholly replace the declines in their sales within the U.S. and actually expand their coal production by offsetting U.S. domestic losses with the expansion of exports to Asia. Peabody is a major investor in the Gateway Pacific Terminal proposed in the state of Washington near Bellingham and has also secured long term agreements to export 5-7 million tons of coal per year through the Gulf Coast between 2014 and 2020. Peabody is specifically targeting Asia as they predict 450-550 million more short tons of coal will be exported there by 2016.³⁵ Peabody as well as many other large PRB coal companies are attempting to export their coal through any port that has excess capacity. Because that port capacity is simply not large enough, they are also actively attempting to build new export facilities.

Arch Coal, the current lease holder of the Otter Creek tracts and partner in the Tongue River Railroad, is also specifically focusing on exports as they make abundantly clear in their 2011 Annual Report.

Arch focused on becoming more global during 2011. With much of coal's growth occurring outside U.S. borders, we laid the foundation for future international growth by adding significant export capacity to further unlock the value of our metallurgical and thermal coal assets. Specifically, we invested in a proposed export facility in the state of Washington to complement our equity investment in the DTA export terminal in Virginia. We also locked up dedicated throughput space at ports along the Gulf of Mexico, the Eastern Seaboard and the western Canadian coast. Supporting these investments, we established new offices in Singapore and London to expand our customer relationships and increase our global breadth and depth.³⁶

As is clearly shown in Arch's comments above, it is a by any means, through any port, a full court press to ship more of their coal out of the U.S. Unlike Peabody that has diversified its coal fields so that it now reports half of its business profits overseas, Arch is much more American-centric. Although Arch talks of their international offices in Singapore and London, almost all of their coal plays currently are in the U.S. They are betting their future on their ability to export U.S. coal to the rest of the world. Nowhere is this more evident than in their leasing of Montana coal at Otter Creek, their investment in the Tongue River Railroad, and their investment in the Longview, WA, proposed coal port.

In January 2011, the Company purchased a 38% ownership interest in Millennium Bulk Terminals-Longview, LLC ("Millennium"), the owner of a brownfield bulk commodity terminal on the Columbia River near Longview, Washington, for \$25.0 million, plus additional future consideration upon the completion of certain project milestones. Millennium continues to work on obtaining the required approvals and necessary permits to complete dredging and other upgrades to enable coal, alumina and cementitious material shipments through the terminal. The Company will control 38% of the terminal's throughput and storage capacity, in order to facilitate export shipments of coal off the west coast of the United States.³⁷

The reason that Arch, as well as all of the major players in the PRB, are looking to export their coal is that the domestic market is at best stalled and at worst in permanent decline. A feverish pursuit of U.S.

³⁴ http://www.peabodyenergy.com/mm/files/Investors/IR%20Presentations/AugustInvestorRoadshow_Final.pdf

³⁵ Ibid.

³⁶ http://thomson.mobular.net/thomson/7/3271/4578/document_0/ArchAR11_FinalWebView.pdf page 12.

³⁷ http://thomson.mobular.net/thomson/7/3271/4578/document_0/ArchAR11_FinalWebView.pdf

export capacity has ensued as the major coal producers in the U.S. try to figure out how they can obtain a share of the international market. Montana coal has a transportation cost advantage with respect to Wyoming if that Montana coal can be shipped to Asia out of a northwestern American Pacific port. The coal companies have decided that if Montana coal is going to expand, it is going to expand into the international seaborne market. That is the reason that Cloud Peak, who owns, among other coal resources, the Spring Creek Mine in Montana and exported 4.7 million short tons of coal to Asia in 2011, is one of the few PRB producers to secure part of the very limited current port capacity at the Westshore export facility on the Canadian west coast. Cloud Peak's 2011 Annual Corporate Report talks more specifically about their exports and the transportation advantage that Montana has to the west coast of the U.S. for export.

These exports generally came from the Spring Creek Mine in the northern PRB of southeast Montana. This mine has higher energy coal than mines in the southern PRB and is approximately 200 miles closer to the terminals, giving it a quality and rail freight advantage over southern PRB mines. Demand for our coal from Asian utilities remains strong, but sales continue to be limited by West Coast export terminal capacity. We are working with several different groups trying to develop terminal projects and are hopeful that additional capacity will become available in the next few years. Increased export capacity and favorable market conditions would position us well to significantly increase exports, which would create new jobs and tax revenues in Montana and Wyoming.³⁸

Together Peabody, Arch, and Cloud Peak have made their hopes for Montana and Wyoming PRB coal abundantly clear. They are moving to export their coal to Asia. This current drive to export Montana coal to Asia stands in stark contrast to the market for Montana coal in the mid-1980s. In the mid-1980s the coal companies saw incredible growth potential for Montana coal in the markets of the American upper Midwest. When that potential was not realized they abandoned their hopes for coal deposits in the Tongue River Valley that were isolated from existing transportation infrastructure and thus required the additional cost of extending railroads to those coal fields. Clearly Arch coal is not counting on U.S. domestic coal markets to the east which did not support development of Tongue River Valley coal even when the demand for Powder River Basin coal was booming in the 1984-2008 period. The markets driving the current interest in the Otter Creek coal and the TRRR are not domestic U.S. markets to the east but foreign export markets to the west. The economic rationale for the TRRR has fundamentally changed.

Conclusions

PRB coal burst onto the American electrical generating stage thanks to EPA air emissions regulations and very low coal production costs. The mid-1980s saw a period of explosive growth in coal production in the Wyoming PRB while Montana PRB coal production lingered in the 40 to 45 million tons per year range between 1987 and 2010. Today the PRB sends most of its coal to the North Central region of the U.S. In EIA's 2012 projections, the North Central region of the U.S. is predicted to use less coal in the near future than it currently does and is predicted not to return to 2010 levels of consumption until 2032. Montana coal currently provides a little less than 7% of the total American coal used for electricity generation in the North Central region largely because of transportation disadvantages

³⁸ <http://www.cloudpeakenergy.com/investor-relations/annual-reports>

relative to Wyoming. Montana coal that is being burned for electrical generation in Oregon's and Washington's only coal-fired plants and one of Montana's electric generators will also soon come to a halt as the Boardman, Centralia, and Corette power plants are scheduled to all be retired before 2025. Montana has consistently been a small minority supplier of PRB coal to the U.S coal market as a whole even though it has larger reserves than the Wyoming PRB. However, Montana coal has a transportation advantage in reaching the west coast of the U.S. and Canada. As a result, major American coal companies have indicated their intention of refocusing their attention on exporting PRB coal to Asia. Because of this transportation advantage, Arch Coal, Cloud Peak, and Signal Peak are all focused on ways to export their coal, and specifically their Montana coal, to growing Asian markets.

The coal that could come from the Otter Creek tracts on the Tongue River Railroad is not focused on going east to the American Midwest coal markets. The economics of this fact are clear for the 1986 through 2008 period since the Tongue River Railroad was not built when it was first permitted and the Tongue River coal fields were not developed. The explosive growth of the Montana portion of the PRB that the coal companies had hoped for never came to fruition. Now we have another period of interest to develop the Tongue River coal fields and the TRRR to serve them, but this time the focus is decidedly on the export of Montana coal to Asia through new and expanded west coast coal ports and upgraded railroad infrastructure to facilitate the movement of large quantities of Montana and Wyoming coal to the west coast. The 2012 market for Montana coal is wholly different from what it was in the mid-1980s.

APPENDIX 5

VERIFIED STATEMENT OF
ANDREW BLUMENFELD

**BEFORE THE
SURFACE TRANSPORTATION BOARD**

STB FINANCE DOCKET NO. 30186

**TONGUE RIVER RAILROAD COMPANY, INC. – RAIL CONSTRUCTION
AND OPERATION – IN CUSTER, POWDER RIVER AND
ROSEBUD COUNTIES, MT**

**VERIFIED STATEMENT OF ANDREW BLUMENFELD IN SUPPORT OF
TONGUE RIVER RAILROAD COMPANY'S
REPLY TO PETITION TO REVOKE
SUPPLEMENTAL APPLICATION**

My name is Andrew Blumenfeld. I am Vice President of Analysis and Strategy for Arch Coal, Inc. ("Arch"). My business address is One CityPlace Drive, Suite 300, St. Louis, MO 63141. I am very familiar with the Otter Creek mine, which is a greenfield coal mining project owned and controlled by a subsidiary of Arch that is currently in the preliminary permitting process. The Otter Creek mine, and with other coal resources in the Ashland, MT area, could be developed for production in the coming years. I am also generally familiar with the Tongue River Railroad project and the December 17, 2012 Supplemental Application for Construction and Operation Authority (hereafter "Application") filed at the Surface Transportation Board by the Tongue River Railroad Company, which is owned by an entity in which Arch has invested.

I am providing this verified statement in response to the January 7, 2013 Petition to Revoke Supplemental Application submitted by Northern Plains Resource Council and Rocker Six Cattle Company (jointly, "NPRC"), as well as the November 2012 report prepared for NPRC by Power Consulting Inc. ("Power Report") and the Verified Statement of Mr. Gerald W. Fauth III, another consultant, which are attached as support for NPRC's Petition.

I. The Application Does Not Misrepresent the Destination Market for Ashland/Otter Creek Coal

NPRC, the Power Report and Mr. Fauth claim that the Application misrepresents the destination market for the coal to be transported from the Ashland/Otter Creek area by failing to acknowledge that the majority of that coal will be exported through coal export facilities that have been proposed for construction in Oregon and Washington rather than to power plants in the Upper Midwest, as has been the case since the TRRC line was first proposed in the 1980's. I agree generally with the proposition that the market for coal is dynamic and, over time, markets evolve and demand shifts. These market forces have a profound effect on product demand and mining and shipping priorities. However, I do not agree that it is a foregone conclusion, as the Powers Report and Mr. Fauth assert, that virtually all of the coal transported from the Otter Creek mine or the Ashland area will be exported to Asia through port facilities that have been proposed for development in Oregon and Washington. Some percentage of the coal may well be exported, as the TRRC Application states. However, it is far from a certainty that all or most of the coal will be exported from the Oregon and Washington facilities that they describe. There are several reasons for this.

A. Otter Creek/Ashland Coal Will be Competitive in the Domestic Coal Market

There remains a significant anticipated domestic market for Montana coal as has historically been the case and Otter Creek/Ashland coal will compete in that domestic market when the coal is developed. Today, almost twice as much Montana coal is used domestically as opposed to exported, according to the Energy Information Administration. *See* Energy Information Administration, Annual Coal Distribution Report, 2011 at <http://www.eia.gov/coal/distribution/annual/> (showing that almost twice as much Montana coal was

distributed domestically than was exported in 2011). Consistent with this historic pattern, I anticipate that the coal mined at Otter Creek will be highly competitive with PRB coal mined elsewhere in Montana and Wyoming and used today at numerous generating plants in the Upper Midwest, including facilities operated by Detroit Edison and Minnesota Power.

The cost to extract the Otter Creek coal, and other coal in the Ashland area, is relatively low which should allow such coal to compete for market share in the domestic coal market. The coal in the Ashland area is relatively shallow in the ground and the ratio of coal to overburden is lower than other operating mines in the region. Assuming a modest rate of production volume as indicated in the Application, this coal can be efficiently and cheaply extracted through the mining process for an extended period of time.

Although the proposed Colstrip Alignment for the TRRC line generally angles northwesterly, this does not mean that it would be uneconomic to use that route to transport Otter Creek coal eastbound. The primary objective for the rail spur is to connect the coal resource to the mainline of the BNSF. The additional mileage to move Otter Creek/Ashland coal to destinations in the Upper Midwest via Colstrip is not significant, adding only an additional 38 miles from Otter Creek to Miles City versus alternative routings for the railroad between Otter Creek and Miles City that have previously been under consideration. This additional mileage is de minimis in terms of the transportation cost and will not offset the significant extraction cost advantages enjoyed by Otter Creek/Ashland area coal in comparison to coal from many other Montana and Wyoming mines.

B. Export Opportunities are Also Present

While some percentage of the coal may be exported, it is uncertain that it would be exported from the Longview, Cherry Point or other export facilities that have been proposed for

Washington and Oregon, as Mr. Fauth and the Powers Report argue will be the case. That is because these facilities remain in the proposal stage and have not yet been permitted. These projects have generated opposition from certain groups, making uncertain whether final approval will be forthcoming or the timing of any such approval.

Further, export of coal from Otter Creek/Ashland does not necessarily mean that the coal will move westbound. It is possible that some of the coal may travel east for export to Europe from existing facilities, for example, at Superior, Wisconsin. Montana coal is already exported to Europe from that Lake Superior port and the volume is expected to increase in the future. See <http://www.midwestenergy.com/about.php>

C. Market Forces Will Determine How the Coal Will be Used

Market forces will determine how much coal from the Otter Creek/Ashland area will be used domestically, or exported from West Coast ports or Great Lakes ports, several years from now, when that coal becomes available for transportation following the permitting and development/construction phases for the TRRC and the mines. Those market forces are quite dynamic, and will vary based on several factors, including new technologies (such as liquefaction) that can affect the attractiveness of coal as an energy source and the price of natural gas, which has been low for several years but which is trending upward. Indeed, recent industry analyses have consistently revealed that PRB coal is currently competitive with natural gas and the upwardly trending prices of natural gas suggest this competition will continue and improve into the foreseeable future. Thus, what Mr. Fauth and Mr. Power describe as a declining market for domestic use of coal could transform to a growing domestic market in the next few years. The Application therefore correctly observes that the coal will be available for domestic use and export, and that market forces will dictate its use.

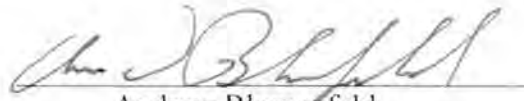
II. The Application Does Not Misstate the Volumes that Might Be Transported

Mr. Fauth claims that TRRC has understated in its Application the potential volumes of coal that it might transport, both in estimating that up to 20 million tons of Otter Creek coal will be transported and in failing to account for coal that might be transported from other Ashland area mines. However, the Application properly predicts the volume of coal to be transported from the Otter Creek mine. As indicated in the Application, Arch estimates that it intends to mine 20 million tons/year at that site, a volume estimate Arch has consistently maintained. The Application thus correctly presented a volume estimate based on Arch's plans for the Otter Creek mine.

The Application also notes that other mines may be developed in the Ashland area. *See* Application at 29. However, at this time no mines have been developed in that area and no party has announced any intention to develop any mines in that area.

VERIFICATION

I, Andrew Blumenfeld, hereby verify under penalty of perjury under the laws of the United States of America that the foregoing is true and correct to the best of my knowledge and belief.


Andrew Blumenfeld

Dated this 25th day of January, 2013.

APPENDIX 6

**OTTER CREEK
PROPERTY SUMMARY
REPORT**

Volume I of II

ENERGY, MINING, AND ENVIRONMENTAL CONSULTANTS

NORWEST
CORPORATION

**OTTER CREEK
PROPERTY SUMMARY
REPORT**

Volume I of II

Submitted to:
**GREAT NORTHERN
PROPERTIES, L.P.**

and:
**MONTANA DEPARTMENT
OF NATURAL RESOURCES
AND CONSERVATION**

July 12, 2006

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EXECUTIVE SUMMARY

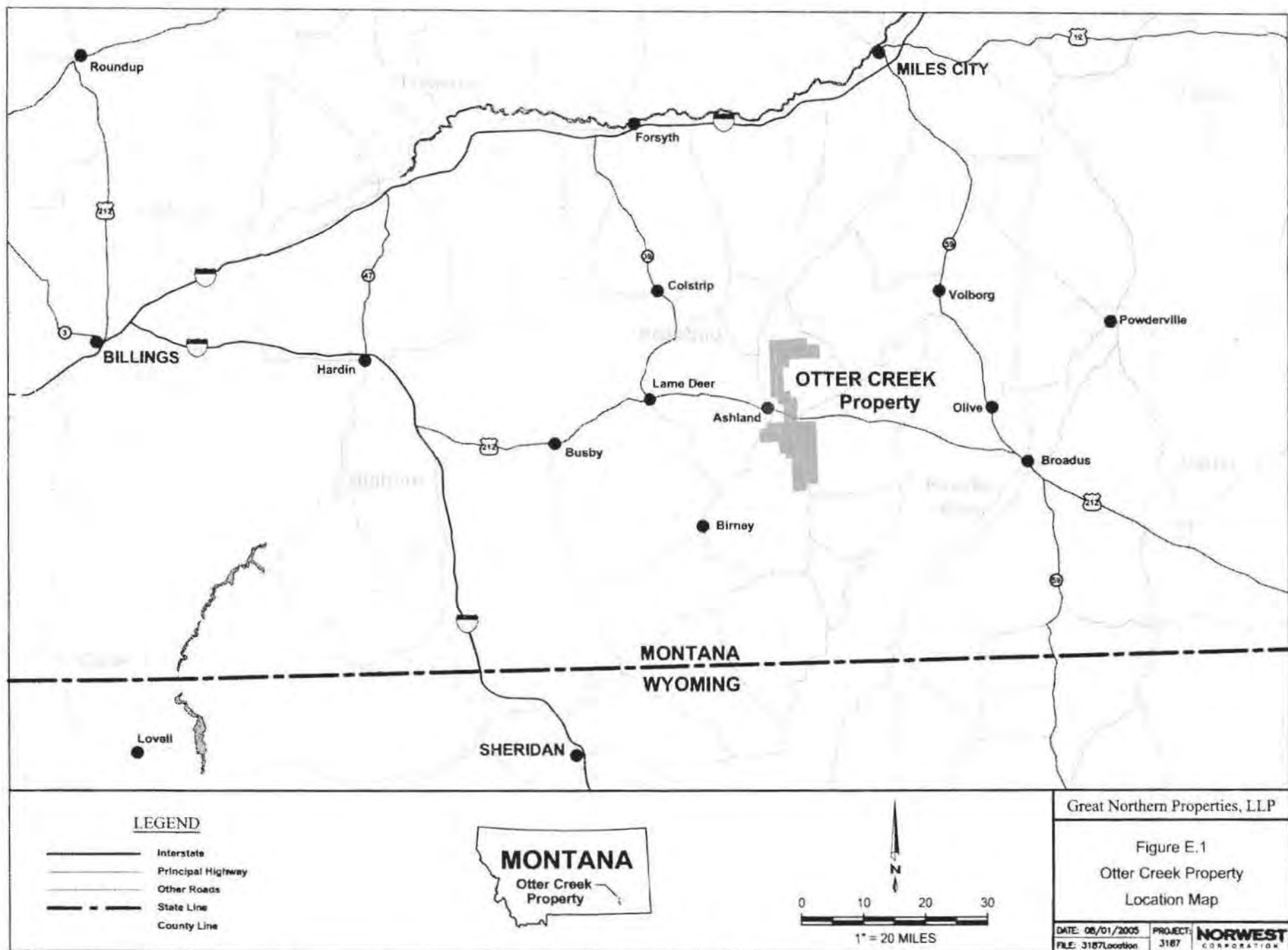
Norwest Corporation (Norwest) was contracted by Great Northern Properties L.P. (GNP) to analyze and interpret existing data regarding coal properties controlled by GNP and the State of Montana, collectively referred to as the Otter Creek Property. The Otter Creek Property covers a large area within Powder River and Rosebud counties, Montana. The tract trends north to south and encompasses over 100 square miles of land.

The overall project objectives consisted of updating the geologic model and resource estimates, identifying specific logical mining units (LMUs), preparing documents that describe each LMU in terms of geology, available resources, coal quality, mineability, strip ratio and range of expected mining costs. An additional objective of this study was to assess the vertical variation of sodium in the Knoblock Seam and to assess the opportunity for selective mining in order to minimize variations in coal quality.

The Otter Creek Property is located in the Ashland coalfield east of Billings, Montana. The Otter Creek Property is located in Rosebud and Powder River Counties, Montana. The general location of the property is shown on Figure E.1.

GNP coal resources are located within the boundaries of the Custer National Forest and comprise alternating sections of property held in fee by GNP and public domain property held by the State of Montana.

The coal resources of the Otter Creek Property have been the subject of several investigations starting in the mid 1970's. This has resulted in numerous data sets developed by several corporate and government entities.



The geologic data collected during the various programs amounted to more than 460 drill holes – these were utilized to characterize this resource.

The quantity of drilling that has been completed on the Otter Creek Property is sufficient to reasonably estimate overall coal tonnages in most areas within the property. The overall in-place resources are estimated at about 4.3 billion tons.

The coal averages 8,500 to 8,600 BTU/lb on an as-received basis. The high moisture content, which averages 27.5% to 28.0%, is fairly typical of Powder River Basin coals. The sulfur content of the coal is very low and with few exceptions the coal is classified as compliance coal, producing less than 1.2 pounds of SO₂/million BTU. The ash content of the coal is also low. The sodium content of the ash is considered high and averages between 6.0 and 7.0 percent.

Mine planning indicated the six discrete LMUs which are summarized in the table below.

Table E.1 LMU Summaries

LMU	Recoverable Tons (millions)	Moisture % (As-received)	Ash % (Dry Basis)	Sulfur % (Dry Basis)	Btu/lb (Dry Basis)	Sodium in Ash % (Dry Basis)
1	346	28.6	6.9	0.3	11,940	6.8-6.9
2	556	28.2	7.8-8.6	0.3-0.4	11,800-11,900	5.7-6.4
3	241	24.3	6.8	0.3	12,000	8.8
4	266	27.4	6.8	0.3	11,700-12,000	7.0-7.9
5	901	28.4	7.0-8.5	0.3	11,800-12,000	6.4-7.1
6	507	28.7	7.2-8.3	0.3	12,600	8.7-8.3

The coal quality data was analyzed to identify vertical variability within each major bench of the Knoblock seam. This indicated the following:

- An inverse relationship exists where the sodium content of the coal ash generally increases as the ash content decreases.
- Sulfur content however, is elevated in the top portion of the Upper Knoblock seam.
- Ash content is the highest in the top portions of all of the coal benches.
- The Upper Knoblock Seam is generally slightly lower in ash content and higher in Sodium Oxide than the lower portions of the Knoblock Seam.

Coal quality control programs and blending will likely be required during mining operations in order to maintain consistent product quality.

All LMUs are amenable to surface mining using draglines and truck-shovel fleets for overburden removal. These techniques are used at other mines in the region including Absaloka, Decker, Rosebud, and Spring Creek Mines. The smaller LMUs will require 70 to 80 cubic yard (CY) capacity draglines while the larger LMUs will need 110 to 120 CY draglines. The combined LMUs will require two draglines. For LMUs 1 through 4, the truck-shovel fleet will consist of 25 to 30 CY hydraulic excavators or shovels and 190 to 240 ton trucks.

When it is necessary to meet the customer's coal specifications, it may be possible to selectively mine the coal to improve the coal quality. The selective mining process removes zones within each seam that are usually higher in sulfur or sodium thereby resulting in a higher quality product.

The following table lists the production rates selected for the LMUs:

Table E.2 Production Rate by LMU

LMU	Yearly Production Rate (Tons)
1	8,500,000
2	12,700,000
3	6,000,000
4	6,000,000
5	21,200,000
6	12,000,000

Norwest developed an indicative mining cost estimate¹ for each LMU based on unit mining costs derived from actual and projected mining costs from mines having similar mining conditions. The average life-of-mine costs for the six LMU range from \$6.69 per ton to \$7.65 per ton. We also developed scoping capital costs for each LMU.

Montana coal, the Northern PRB, is noted for its heating value that is higher than most of the Southern PRB mines, its varying sulfur levels and its higher sodium levels. The sodium content of Otter

¹ Norwest recommends that additional engineering be performed to further refine the operating (and capital) costs.

Creek coal ranges from 5.8% to 8.8% and is high in comparison to other coals in the western US. but about the same as other Montana PRB mines. For example: coals from the southern Powder River Basin of Wyoming typically average 1.2% sodium while currently produced coals from Colorado average about 2.5% sodium. Sodium in ash can cause slagging problems in certain types of boilers in electric generating plants. As a result, most plants avoid burning high sodium coals. However, we have identified ten power plants within the competitive area for Otter Creek which currently accept higher sodium coals. These plants would likely constitute the initial target market for Otter Creek coals. The information and data used to assess the marketing is derived from FERC data. It is, from our experience, the best data available but not much audited for accuracy of reporting nor input into their database and perhaps even suspect. Nevertheless, we were able to estimate current FOB prices for coal similar to Otter Creek.

It should be noted that the volume of coal shipped from Montana to the high sodium-accepting power plants is only about 20 million tons per year. Careful effort developing a solid market strategy will be necessary to determine how best to nudge into this market without destroying whatever price discipline, if any, currently exists. All Montana mines have been operating for many years and are experiencing higher stripping ratios in the range of 3-4:1 at Spring Creek, climbing up to 9:1 and higher at Decker. These higher strip ratios put these mines at a disadvantage with respect to Otter Creek's projected operating costs, as they each must move more waste to uncover the same amount of coal as at Otter Creek. This higher cost, however, will be offset by Otter Creek's higher capital recovery / depreciation costs.

At present there are no established transportation links to the Otter Creek property. We assessed the options of rail and truck transportation to the rail spur to the line at Colstrip, located about 38 rail miles distant. From Colstrip the trains would continue on to their final destination. While the rail option has a higher initial capital, this is offset in only a few years by the reduced transportation costs. Therefore, we recommend the rail alternative.

INTRODUCTION AND OBJECTIVES

Great Northern Properties L.P. (GNP) has contracted Norwest Corporation (Norwest) to analyze and interpret existing data regarding coal properties controlled by GNP and the State of Montana, collectively referred to as the Otter Creek Property. The Otter Creek Property covers a very large area within Powder River and Rosebud counties, Montana. The tract trends north to south and encompasses over 100 square miles of land.

The overall project objectives consisted of updating the geologic model and resource estimates, identifying specific LMU's, and to prepare documents that describe each LMU in terms of geology, available resources, coal quality, mineability, strip ratio and range of expected mining costs. An additional objective of this study was to assess the vertical variation of sodium in the Knoblock Seam and to assess the opportunity for selective mining in order to minimize variations in coal quality.

As part of this study, Norwest was required to build independent geologic and coal quality models. The key geologic components and tasks associated with preparing the models and satisfying the objectives of the study were established as follows:

- Prepare and merge two separate drill hole databases into one consolidated stratigraphic and coal quality database.
- Construct correlation charts to ensure that the merged data sets conform to the same stratigraphic nomenclature and that seam correlations were correctly identified.
- Prepare digital surfaces of the seam structure, thickness and basic coal quality parameters.
- Upon completion of the digital surfaces, prepare maps locating the position of the seam outcrop, subcrop and weathered surfaces.
- Create a geologic model of the coal resource area and calculate the coal tonnage and overburden volumes of the in-place resource.
- Identify the quality distribution of the coal both laterally and vertically within the seams.
- Assist with identifying LMU's that could be developed within the property.

This report summarizes the geologic modeling, resource estimates and coal quality characteristics. This information will form the basis of future LMU delineation and mineability studies.

GEOLOGY AND COAL RESOURCES

LOCATION, TOPOGRAPHY AND LAND USE

The Otter Creek Property is located in the Ashland coalfield east of Billings, Montana. Access to the property from Billings is available by traveling east on Interstate Highway 90 to the town of Crow Agency in the Crow Indian Reservation. From that point access is provided by traveling east on U. S. Highway 212 to a point four miles east of Ashland, Montana. Final access to and through the property is provided by traveling south on Otter Creek Road, an improved all-weather dirt road that leads from Highway 212 to the town of Otter, Montana at the south end of the Otter Creek Property as shown in Figure 2.1. Numerous unimproved dirt (2-track) roads provide local access within the Otter Creek Property.

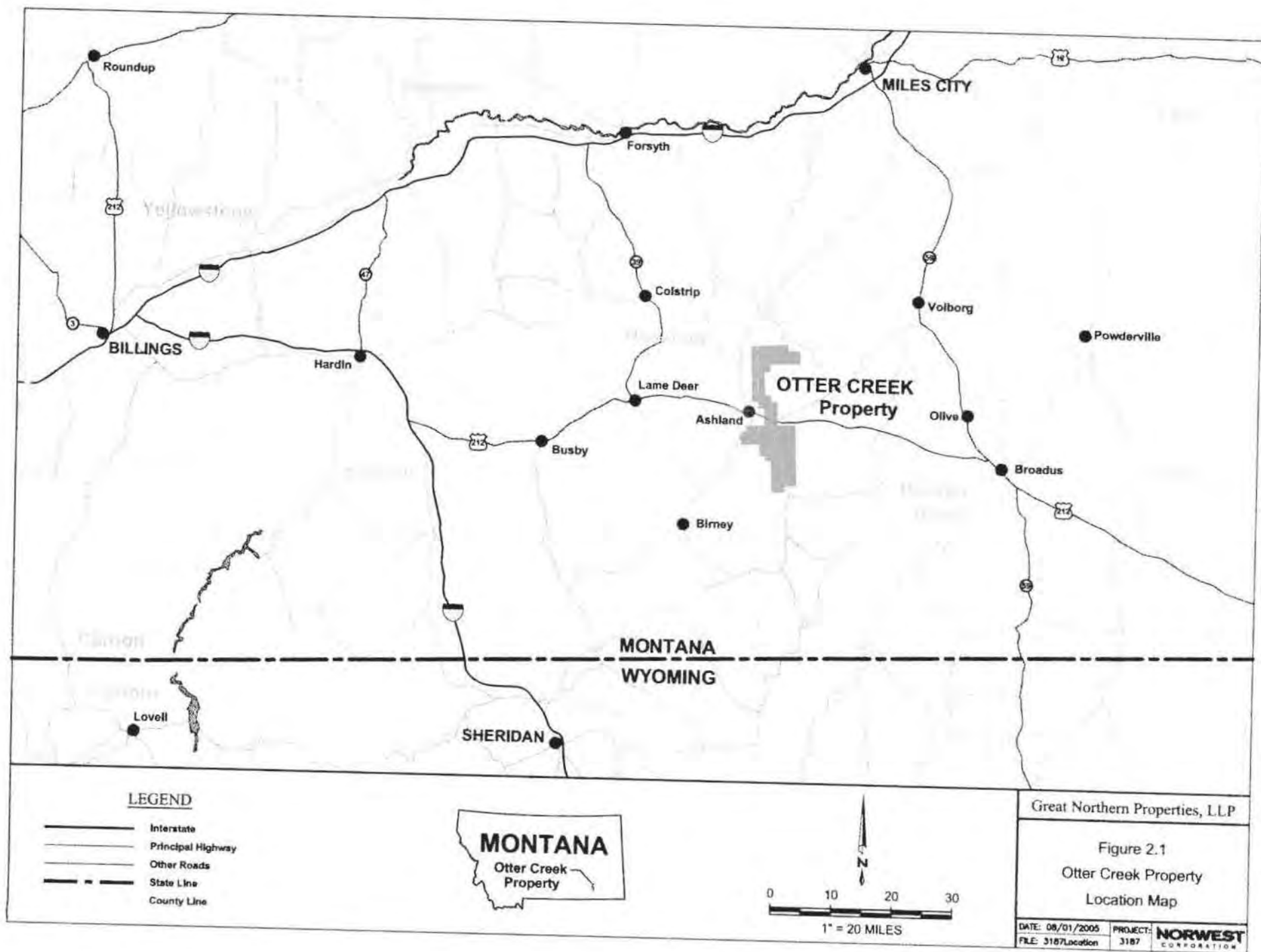
The Otter Creek Property is located in Rosebud and Powder River Counties, Montana. It is within the boundaries of the Custer National Forest but is comprised of alternating sections of property held in fee by GNP and public domain property held by the State of Montana. Coal ownership is illustrated in Appendix A, Map A2.1.

Topography in the area of the Otter Creek Property is characterized by rolling hills separated by broad valley regions. The rolling hills are covered by plains grasses and provide excellent rangeland for ranching and habitat for wildlife. Elevations within the property area range from less than 3,000 feet above sea level along Otter Creek that flows in a general north-south direction through the center of the property, to over 3,400 feet on the bluffs that flank Otter Creek.

DATA AND METHODOLOGY

Data Sources

The coal resources of the Otter Creek Property have been the subject of several investigations starting in the mid 1970's. This has resulted in numerous data sets developed by several corporate and government entities. Early investigations include drilling conducted by the Montana Bureau of Mines and Geology, Consolidation Coal Company, City Services, and GNP.



Most recently, in 2004, Kennecott Energy and the State of Montana initiated an exploration program that included the drilling of 54 holes of which 42 were core drilled providing for coal samples that were analyzed for their quality.

In addition to the drill hole data, regional geologic information was used from published reports by the U. S. Geological Survey.

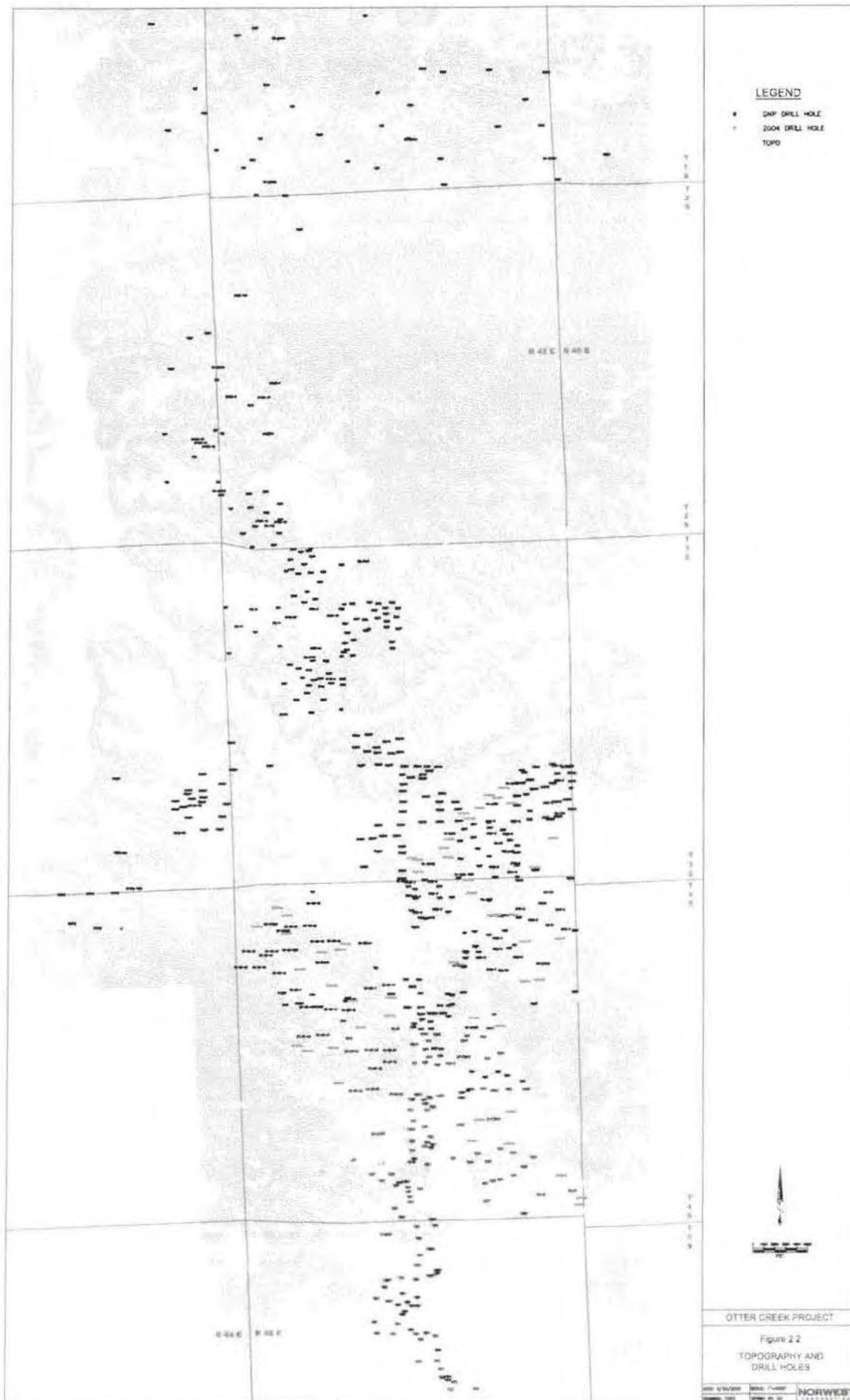
Nature of Geologic and Coal Quality Data

The geologic data collected during the programs described above have been provided to Norwest in electronic format. Several database files have been made available that contain pertinent information regarding the drill holes including hole location information, down-hole information including seam intercepts, coal thickness, in-seam rock partings, and coal quality data. In addition to this information, electronic copies of drill cutting and geophysical log records have been provided for many of the drill holes.

The exploration programs that have been conducted on the Otter Creek Property have provided extensive drill hole data that defines the coal resource potential of the property. The distribution of the drill holes that have been completed on the Otter Creek Property to date are shown in Figure 2.2 and Map A2.2.

All of the information provided to Norwest has been used to assess the accuracy of the data and to evaluate the resource potential of the Otter Creek Property.

As illustrated, over 460 drill holes have been utilized to characterize this resource. The distribution of drill holes across the property is uneven, with many concentrated in the central and southern portions of the property and generally fewer holes and more widespread coverage in the north. Additionally, there are many areas throughout the property that will require substantial drilling to accurately delineate the coal subcrop and burned zones.



Data Accuracy and Adequacy

Although the data provided to Norwest was in electronic format, it was in several different forms such as drill cutting/core logs, scanned geophysical logs, digital "las" files and tabulated drill hole data. This has allowed Norwest to make cross checks between the data represented on the cutting/core logs and geophysical logs with the various files of tabulated drill hole data. Where available, the data on the drill logs were compared against the tabulated data. This comparison indicated that the tabulated drill hole data were accurate and represented the data provided on the drill logs in their various forms.

The coal seam correlation and nomenclature used in the various data files were compared and checked to insure that the final data files were consistent in the seam correlation and in the naming of the seams present.

Geophysical logs were provided in electronic (las) format for holes drilled in 2004. Plots of these logs were prepared using Norwest's "Pinnacle" in-house geologic software. Top and bottom depths of the coal seams shown on the logs were determined by selecting the mid-point on the deflection of the resistivity and gamma-gamma density log traces. These depths were compared with those listed on the tabulated data and it was found that the resulting coal thickness measurements listed on the tabulated data understate the coal thickness by an average of 1.5%. This suggests that the coal thickness measurements used in this report are slightly on the conservative side.

It is important to point out that the most reliable method of measuring coal thickness penetrated in a drill hole is through the analysis of geophysical logs. Coal thickness derived from core measurement is usually limited in accuracy by frequent crushing of the core and by core loss.

Methodology

After all drill hole data had been checked for accuracy, it was combined into two master Excel files. One file contained coal depth and thickness information and the other file contained coal quality data. These files were then used to develop the geologic model utilizing Carlson Engineering's SurvCADD XML modeling software.

GEOLOGY AND MODELING RESULTS

The data files created by Norwest, described above, plus published data on coal deposits of the region enabled the development of a digital geologic model that accurately characterizes the coal resources present within the Otter Creek Property. The following section describes the coal deposit contained within the Otter Creek Property and the geologic model generated that represents these deposits.

Structure and Overburden

The Otter Creek Property lies in a region of the Powder River Basin that is structurally stable. No known faulting is present that dissects the coal seams within the property. The coal beds are nearly flat or gently dipping more as the result of depositional loading rather than tectonic deformation. The coal beds within the Otter Creek Property are very flat-lying having an average dip of one degree or less. Maps A2.3, Knoblock Seam Top Structure, and A2.4, Knoblock Seam Bottom Structure, illustrate the gently rolling structure of the property. These drawings, along with others that illustrate the geologic model, are presented in Appendix A of this report.

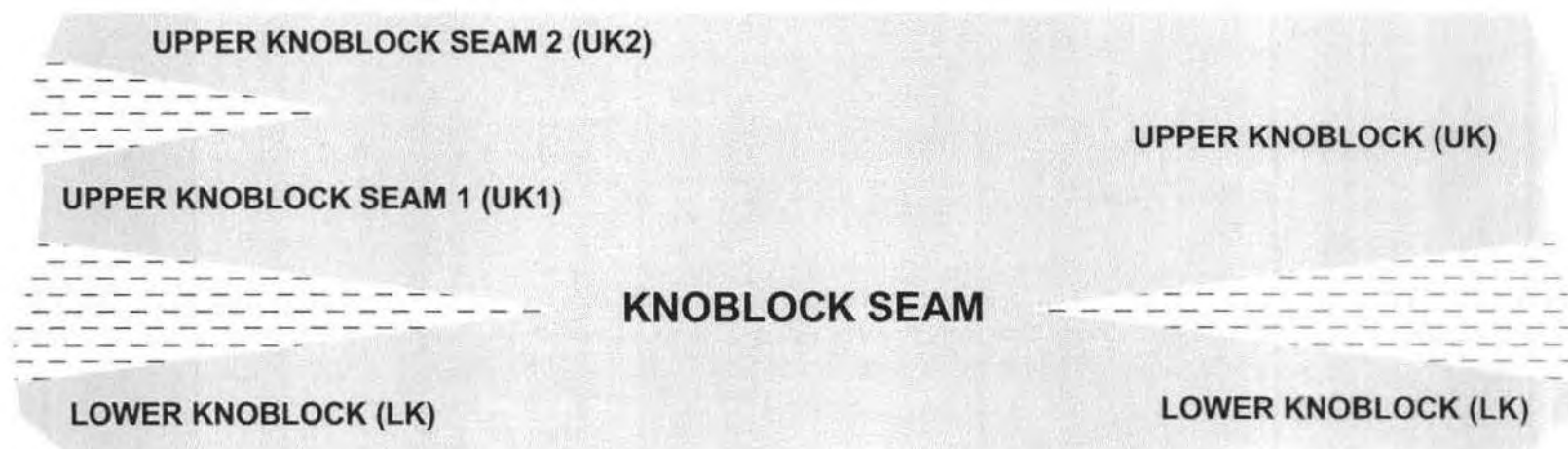
Stratigraphy

The coal seams of economic interest within the Otter Creek Property are contained within the Tongue River member of the Fort Union Formation of middle Paleocene age. The primary coal seam within the Otter Creek Property is the Knoblock (K) seam. This coal seam ranges in thickness from 19 feet to 75 feet and averages approximately 59 feet. The seam splits into two sub-seams, the Upper Knoblock (UK) and the Lower Knoblock (LK), in the southern and northern portions of the property. The Upper Knoblock splits again into two sub-seams in the extreme southern portion of the property. The upper sub-seam of this split is called the Upper Knoblock 2 (UK2) seam while the lower sub-seam is called the Upper Knoblock 1 (UK1) seam. Figure 2.3 below illustrates the relationship of the coal seam splits. The correlation of the sub-seams in the areas where the Knoblock splits is well defined by the drilling that has been completed.

Map A2.5 Drill Hole Correlation Charts, located in Appendix A, illustrates the relationship of the sub-seams within the property. It is important to point out that the thickness represented on the Isopach map represents the same interval used in the quality modeling for a given drill hole. Intervals of bone coal near the top or bottom of the coal seam were excluded in the thickness used to develop the Isopach map.

SOUTH

NORTH



Great Northern Properties, LLP

Figure 2.3
Otter Creek Property
Generalized Cross-Section

DATE: 06/01/2005	PROJECT: 3167	NORWEST CORPORATION
FILE: KnoblockSeamCross		

The Knoblock seam is thickest in the central area of the Otter Creek Property as shown on Map A2.6 Knoblock/UK/UK2 Seam Isopach. Also shown on this map is the thickness and extent of the Upper Knoblock 1 and 2 seams. In the northern area of the Otter Creek Property where the Knoblock seam is split into two sub-seams (UK and LK), the thickness of the parting or interburden that separates the two sub-seams generally increases in a northerly direction. Likewise, in the southern portion of the property, this interburden increases in thickness in a southerly direction. Map A2.7, illustrates the thickness of this interburden. The coal thickness of the Upper Knoblock 1 seam, the Lower of the sub-seams formed by the splitting of the Upper Knoblock seam in the extreme northern and southern portions of the property, is illustrated on Map A2.8, Upper Knoblock Seam 1 Isopach. The thickness of the interburden that separates the Upper Knoblock 1 seam from the Upper Knoblock 2 seam is illustrated on Map A2.9. The thickness of the Lower Knoblock seam, present in both the northern and southern portions of the Otter Creek Property, is illustrated on Map A2.10.

The coal seams present are covered by overburden consisting of interbedded fine-grained sandstones and mudstones. The thickness of the overburden is variable due to topography in the area. The overburden thickness has been modeled by subtracting the elevation of the top of the coal seam from the topographic elevation. This overburden thickness is illustrated on Map A2.11 Knoblock Seam Overburden Isopach.

Outcrop, Zone of Weathering and Burned Coal

Outcrops of the Knoblock seam and sub-seams are present on both sides of Otter Creek, which flows in a northerly direction through the center of the property and exits the property's western boundary near the town of Ashland. A zone of weathered or burned coal normally exists where the seam is found at near-surface depths. This zone of weathering was identified from observations recorded in drill hole lithologic logs. The zone's thickness is variable and ranges from as little as five feet in the southern portion of the property to over 150 feet in the northern portion of the property. After the zone of weathering had been identified in all of the drill holes, the zone was modeled by preparing a thickness grid. This thickness grid was then subtracted from the surface topography which resulted in an elevation grid representing this "weathered surface". The "weathered surface" is illustrated on Map A2.3, Drill Hole Location Map and Coal Seam

Correlation Cross-Sections. Where the modeled zone of weathering intersected the coal seam, the limit of that coal seam was trimmed to the base of the weathered zone to form a subcrop line. This subcrop line was transferred onto the resource maps that were used in calculating the tonnage of in-place coal resources. Of particular note is that for each coal bench or seam, two weathering lines were generated, one representing the intersection of the weathered surface with the top of the seam and the other the seam base. The importance of the two lines is the fact that with coals of this thickness, there are many instances when only top portions of the seam may be weathered while the lower portions are not.

In addition, after delineating the subcrop limits by the method described above, Norwest overlaid the prior representation of a burn line which was provided by GNP. It is apparent that this burn line was generated by sketching a representation of the burn area through drill holes which encountered coal burn and those that encountered un-weathered coal. It is expected that this "burn line" was determined through inspection of aerial photographs, though this has not been verified by Norwest.

Norwest compared the "zones of weathering" with the GNP "burn line". In general, the areas and lines compared well. It should be clearly noted that across the property the depth of weathering and areas of "burned" coal has been delineated to highly varying degrees of accuracy, based on the variable drill hole density. In-place resource estimations and in-place stripping ratios are very sensitive and dependent upon the degree of confidence of this weathering or burn zone. Prior to actual development of these properties, substantial amounts of additional drilling is warranted to verify the actual weathering limits.

RESOURCE ESTIMATION

The quantity of drilling that has been completed on the Otter Creek Property is sufficient to reasonably estimate overall coal tonnages in most areas within the property. Several areas, particularly in the north, warrant additional drilling. Norwest's estimates of resources are presented in two categories of tonnage within the property boundaries. These categories are referred to as *in-place resources* and *speculative resources*. Map A2.12 presents the in-place resources and associated coal quality by section. Also illustrated on this drawing are the subcrop line of the base of the Knoblock coal and the GNP burn line.

In-place resources as defined by Norwest include all resources that are delimited by the burn line and exist within a high degree of confidence resulting from a certain drill hole density, while the speculative resources are those that are projected between the GNP burn line and the projected subcrop line of the Lower Knoblock Seam. These speculative resources would consist of areas that may contain partially burned or oxidized coal. The areas containing these speculative resources are illustrated by shading on Maps A2.12 and A2.13. Norwest believes that it is very likely that substantial resources of this type exist but will require additional drilling to verify tonnage and specific locations.

Coal resources were calculated by measuring the volume of coal represented by the coal seam thickness intervals shown on the coal seam Isopach maps, limited by the subcrop lines formed by the intersection of the coal seam and the zone of weathering. The volume of coal was then converted to tons of coal by multiplying the volume by the factor of 77.6 pounds of coal per cubic foot. Table 2.1, Otter Creek Property, Coal Resource Summary found below, summarizes the coal resources classified by ownership. It provides the defined tons which are limited by the weathering zone on Map 2.3. Table 2.1 also lists speculative resources that represent resources that may be oxidized or partially burned. Again, additional outcrop drilling is needed to define this category of resources.

Table 2.1 represents the summary of an in-depth analysis of the coal resources present within the Otter Creek Property. Several detailed tables were generated in the analysis process, copies of which can be found in Appendix B. Included within these tables are detailed classifications of resources according to the USGS Circular 891, illustrating the Measured, Indicated and Inferred categories of reliability. Map A2.14 illustrates the data distribution and the resource classification areas.

Coal resources were calculated for the three prime mining tracts; Otter Creek Tract 1, Otter Creek Tract 2 and Otter Creek Tract3. Table 2.2, Otter Creek Property - Resource Summary of Tracts 1, 2, and 3 summarizes the coal resources by tract and by landowner within each tract. With the exception of one small 162 acre tract, all the coal is controlled by GNP or the State of Montana. Figure 2.4, Coal Ownership Map, Otter Creek Tracts 1,2, and 3 show the location of these the prime development tracts.

Otter Creek Property Resource Summary
Table 2.1, Total, Inplace and Speculative Resources

Ownership	Total Resources				In-place Resources			Speculative Resources		
	Acres	Waste (bcy)	Coal Tons	In-Place Ratio (CY/ton)	Acres	Waste (bcy)	Coal Tons	Acres	Waste (bcy)	Coal Tons
Total	62,034	16,201,971,882	4,324,951,299	3.7	51,305	14,326,037,698	3,767,763,101	10,729	1,875,934,183	557,188,198
State of Montana	12,551	3,669,435,534	1,056,225,648	3.5	10,742	3,357,323,849	948,900,268	1,809	312,111,685	107,325,380
Great Northern Properties	30,565	8,131,739,475	2,210,372,841	3.7	25,207	7,201,172,150	1,944,144,965	5,358	930,567,325	266,227,876
Other (Federal, Private, etc.)	18,918	4,400,796,872	1,058,352,810	4.2	15,356	3,767,541,699	874,717,868	3,562	633,255,173	183,634,942

GREAT NORTHERN PROPERTIES
OTTER CREEK PROJECT

TABLE 2.2
OTTER CREEK PROPERTY RESOURCE SUMMARY
TRACTS 1,2,AND 3

TRACT 1

Location		Coal Ownership Summary						Total Resources										Speculative Resources				Inplace Resources			
TR	SECTION	Coal Ownership	Acres	GAIP	State of	Private	Waste (Bbl)	Coal Tons	In-Place Ratio (C/Tons)	Moisture (%)			Dry Basis (%)	BTU/lb	GAIP Basis	% In Ash	Acres	Waste (Bbl)	Coal Tons	Private	Waste (Bbl)	Coal Tons	Acres	Waste (Bbl)	Coal Tons
DA11	25	GNP	528	528	0	0	152,245,529	52,212,795	2.2	29.15	26.35	7.13	0.27	11,824	12,038	4.46	0	0	0	0	0	0	0	0	0
DA11	26	MONTANA	597	0	597	0	18,761,893	6,905,540	3.8	24.53	25.44	6.93	0.25	12,025	12,946	4.18	278	41,869,117	17,809,734	568	132,485,542	852,478	0	0	
NA11	27	GNP	643	643	0	0	30,652,134	8,230,315	4.4	24.37	26.32	6.92	0.25	11,869	12,632	6.50	231	38,625,334	9,234,310	0	0	0	0	0	0
NA11	28	MONTANA	630	0	630	0	137,050,620	47,390,265	3.9	24.36	26.49	6.93	0.26	11,893	12,774	7.26	207	37,814,585	19,166,099	323	79,452,036	26,645,147	0	0	
NA11	29	GNP	627	627	0	0	711,748,126	63,531,658	3.9	24.64	26.37	6.98	0.26	11,835	12,628	7.13	0	0	0	0	0	0	0	0	0
NA11	30	MONTANA	631	0	631	0	379,735,238	97,762,325	3.9	24.32	26.74	6.78	0.26	11,980	13,056	7.63	0	0	0	0	0	0	0	0	0
NA11	31	GNP	617	617	0	0	472,694,645	62,277,825	3.8	23.97	26.58	6.97	0.26	11,821	12,605	7.62	0	0	0	0	0	0	0	0	0
NA11	32	MONTANA	549	0	549	0	117,232,557	26,847,144	2.6	24.53	26.26	6.78	0.22	11,824	12,791	7.25	151	25,080,323	1,400,348	452	177,864,045	43,877,036	0	0	
NA11	33	GNP	613	613	0	0	305,957,545	43,214,341	3.3	24.46	26.42	6.95	0.26	11,855	12,719	8.00	253	28,230,059	10,347,727	628	178,869,186	44,448,596	0	0	
GRAND TOTAL			8,889	3,128	3,471	0	1,364,134,980	433,257,236	3.0	24.36	26.38	6.89	0.26	11,836	12,618	6.82	1,148	184,179,861	62,936,437	4,837	1,149,964,926	272,788,796	0	0	
TOTAL GNP			3,128	0	0	0	992,881,474	243,281,938	2.8	24.46	26.43	6.97	0.26	11,916	12,911	8.46	434	64,685,997	39,686,843	2,281	423,886,477	232,805,867	0	0	
TOTAL STATE OF MONTANA			2,411	0	0	0	811,442,511	181,975,297	3.2	24.31	26.31	6.79	0.26	11,968	13,629	7.62	714	129,284,864	43,172,418	1,756	489,155,447	146,603,929	0	0	

TRACT 2

Location		Coal Ownership Summary						Total Resources										Speculative Resources				Inplace Resources						
TR	SECTION	Coal Ownership	Acres	GAIP	State of	Private	Waste (buft)	Coal Tons	In-Place Ratio (CY/ton)	Moisture (%)	AR Basis	Ash (%)	Dry Basis (%)	BTU/lb	GAIP Basis	% In Ash	Acres	Waste (buft)	Coal Tons	Private	Waste (buft)	Coal Tons	Acres	Waste (buft)	Coal Tons	Private	Waste (buft)	Coal Tons
DA11	10	State of Montana	472	0	472	0	38,188,748	13,305,534	3.8	24.54	26.25	7.06	0.30	11,785	12,680	7.48	336	64,791,508	16,315,648	74	156,235,444	6,920,885	0	0	0	0	0	0
DA11	11	GNP	674	674	0	0	113,642,817	58,209,442	3.8	24.51	26.47	6.89	0.27	11,990	12,636	7.58	72	14,581,129	1,933,314	821	156,891,267	38,806,461	0	0	0	0	0	0
DA11	12	State of Montana	568	0	568	0	189,070,348	73,294,300	2.7	24.55	26.47	6.79	0.28	12,320	13,690	6.20	0	0	0	0	0	0	0	0	0	0	0	0
DA11	13	GNP	463	463	0	0	271,598,428	55,900,317	1.8	24.95	26.31	6.70	0.26	12,602	13,880	6.20	0	0	0	0	0	0	0	0	0	0	0	0
DA11	14	State of Montana	438	0	438	0	114,235,241	37,940,481	3.7	24.66	26.33	6.58	0.27	12,071	13,414	6.26	0	0	0	0	0	0	0	0	0	0	0	0
DA11	15	GNP	380	380	0	0	55,128,038	13,092,246	1.7	24.07	26.14	6.79	0.29	11,654	12,888	7.67	43	7,350,368	3,776,207	317	47,792,738	18,109,010	0	0	0	0	0	0
DA11	16	GNP	720	720	0	0	12,145,372	13,036,568	0.8	24.13	27.67	7.83	0.32	11,871	13,829	7.16	0	0	0	0	0	0	0	0	0	0	0	0
DA11	17	State of Montana	612	0	612	0	29,361,763	23,185,241	4.3	24.12	27.69	7.65	0.32	11,904	12,842	7.53	0	0	0	0	0	0	0	0	0	0	0	0
DA11	18	GNP	342	342	0	0	18,253,869	18,145,989	1.7	24.44	27.44	7.89	0.32	11,872	13,840	8.36	0	0	0	0	0	0	0	0	0	0	0	0
DA11	19	GNP	674	674	0	0	252,664,617	90,989,553	2.8	24.74	26.52	7.18	0.30	11,919	13,684	7.66	0	0	0	0	0	0	0	0	0	0	0	0
DA11	20	State of Montana	548	0	548	0	17,647,437	27,266,744	4.9	24.16	26.26	7.13	0.28	11,874	13,380	7.05	0	0	0	0	0	0	0	0	0	0	0	0
DA11	21	GNP	718	718	0	0	88,764,863	75,721,718	4.7	24.16	26.13	7.13	0.30	11,900	12,840	8.40	0	0	0	0	0	0	0	0	0	0	0	0
DA11	22	State of Montana	625	0	625	0	181,445,009	11,847,640	2.7	24.16	26.08	6.75	0.32	11,860	13,371	7.29	32	6,137,060	1,168,718	765	184,213,649	18,418,362	0	0	0	0	0	
DA11	23	GNP	167	167	0	0	35,769,548	8,502,314	3.8	24.16	26.19	6.96	0.31	11,879	12,841	6.06	48	3,564,849	1,453,967	119	37,137,198	1,549,707	0	0	0	0	0	
DA11	24	State of Montana	188	0	188	0	77,707,623	17,940,527	6.9	24.14	26.05	7.11	0.30	11,837	13,361	6.97	84	191,347,711	29,774,488	634	1,828,443,893	667,282,576	0	0	0	0	0	
GRAND TOTAL			6,888	3,175	3,363	142	2,831,811,314	678,967,531	3.4	24.17	26.35	7.21	0.28	11,893	13,880	7.22	934	191,347,711	29,774,488	634	1,828,443,893	667,282,576	0	0	0	0	0	0
TOTAL GNP			3,314	0	0	0	978,487,896	330,875,221	3.8	24.13	27.08	7.44	0.31	9,908	9,746	6.57	184	27,677,963	6,226,980	1,815	962,816,496	225,746,434	0	0	0	0	0	0
TOTAL STATE OF MONTANA			3,263	0	0	0	1,823,773,966	328,828,116	3.1	24.23	26.30	7.21	0.29	11,988	12,899	7.21	271	75,880,348	20,448,267	2,882	949,881,218	246,371,794	0	0	0	0	0	0
TOTAL PRIVATE			162	0	0	0	18,957,896	18,145,985	1.1	24.14	27.04	7.85	0.32	11,872	12,840	8.38	0	0	0	0	0	0	0	0	0	0	0	0

TRACT 3

Coal Ownership Summary										Total Resources										Speculative Resources									
TR	SECTION	Coal Ownership	Acres	GAIP	State of	Private	Waste	Coal Tons	In-Place Ratio	Moisture (%)	AR Basis	Ash (%)	Dry Basis (%)	BTU/lb	GAIP Basis	% In Ash	Acres	Waste	Coal Tons	Private	Waste	Coal Tons	Acres	Waste	Coal Tons	Private	Waste	Coal Tons	
										C-VI					C-VII					C-VIII									
DA11	5	GNP	860	860	0	0	133,656,185	45,181,085	2.7	24.30	26.81	6.87	0.29	11,999	12,637	7.81	249	43,156,272	16,994,928	411	90,495,892	12,588,180	0	0	0	0	0		
DA11	6	State of Montana	828	0	828	0	228,927,070	63,862,089	3.5	24.32	26.86	6.77	0.27	12,051	12,925	9.06	41	7,895,129	3,820,038	585	218,870,642	40,848,551	0	0	0	0	0		
DA11	7	GNP	173	173	0	0	181,484,176	57,414,286	3.4	24.27	26.56	6.77	0.28	11,972	12,896	8.24	0	0	0	0	0	0	0	0	0	0	0		
DA11	8	State of Montana	502	0	502	0	158,897,296	43,178,875	3.3	24.30	27.02	6.78	0.27	12,044	12,913	8.56	99	2,348,193	296,047	613	159,245,489	33,146,923	0	0	0	0	0		
DA11	9	GNP	390	390	0	0	59,275,891	26,987,479	2.3	26.11	27.39	6.51	0.23	12,215	13,880	8.23	47	15,506,574	6,151,225	304	49,794,117	22,848,291	0	0	0	0	0		
DA11	10	GNP	72	72	0	0	3,193,262	1,721,942	3.8	26.17	27.31	6.89	0.29	11,875	12,843	7.67	37	4,980,262	1,564,515	3	102,295	137,368	0	0	0	0	0		
DA11	11	GNP	476	476	0	0	14,146,635	11,346,035	2.3	24.15	26.01	6.96	0.29	12,064	12,877	7.23	0	0	0	0	0	0	0	0	0	0	0		
DA11	12	State of Montana	476	0	476	0	88,441,737	47,877,865	1.5	24.21	27.62	6.80	0.27	12,060	12,813	6.18	0	0	0	0	0	0	0	0	0	0	0		
DA11	13	GNP	424	424	0	0	133,025,818	27,605,169	2.8	24.18	27.42	6.83	0.26	11,954	12,814	6.82	0	0	0	0	0	0	0	0	0	0	0		
DA11	14	State of Montana	640	0	640	0	34,435,483	19,311,568	1.0	24.25	26.53	6.98	0.26	11,911	12,648	6.01	0	0	0	0	0	0	0	0	0	0	0		
DA11	15	GNP	540	0	540		206,987,818	61,577,860	2.7	24.27	27.80	6.77	0.27	11,960	12,813	7.96	0	0	0	0	0	0	0	0	0	0	0		
DA11	21	GNP	640	640	0	0	163,781,848	72,055,955	2.3	24.18	27.13	6.79	0.32	11,817	12,814	8.82	0	0	0	0	0	0	0	0	0	0	0		
DA11	22	State of Montana	181	0	181	0	26,009,024	18,945,014	2.4	24.15	27.25	6.77	0.34	11,817	12,799	7.11	0	0	0	0	0	0	0	0	0	0	0		
GRAND TOTAL			3,883	2,781	3,882	0	1,733,383,476	594,984,838	3.4	24.26	27.11	7.80	0.28	11,872	12,868	8.18	426	68,438,212	26,362,211	2,954	1,668,980,880	386,543,227							
TOTAL GNP			2,781	2,781	0	0	699,737,345	244,896,441	3.4	24.26	27.10	7.16	0.28	11,858	12,818	8.82	175	50,627,978	24,340,278	2,614	638,166,445	144,194,144							
TOTAL STATE OF MONTANA			1,092	0	1,092	0	1,038,646,134	528,208,870	3.2	24.25	27.13	6.87	0.27	12,002	12,892	6.32	171	10,810,134	4,981,863	2,841	1,028,700,221	52,348,083							

COAL QUALITY

The coal resources contained within the Otter Creek Property are sub-bituminous in rank. Quality data have been made available through the analysis of core samples from 115 drill holes completed on the Otter Creek Property in the various drilling programs since the early 1970's. These data have defined the quality of the coal present within the property. The quality database contains proximate analysis, ultimate analysis, mineral analysis of ash, and in some cases equilibrium moisture analysis and density.

Quality Modeling

In general, core samples of coal from a given drill hole were sampled and analyzed in zones ranging from less than one foot to as much as ten feet in thickness. In some cases, these samples were combined to produce a physical composite. Because not all holes had physical composite samples, calculated mathematical composites were used for each of the drill holes containing quality data. These calculated values were double-weighted for both interval thickness and density. Where physical density data were not available for a sample this value was calculated using a linear regression analysis of the ash/density relationship of all samples having both data sets. A comparison of several physical composites with calculated composites of the same interval was made which validated that the composite method was accurate. Numerous tables of coal quality data were generated in the process of reducing the quality data. These intermediate stage tables are presented as back-up material and can be found in Appendix C.

The Knoblock coal averages 8,500 to 8,600 BTU/lb on an as-received basis. The high moisture content, which averages 27.5% to 28.0%, is fairly typical of Powder River Basin coals. The sulfur content of the coal is very low and with few exceptions the coal is classified as compliance coal, producing less than 1.2 pounds of SO₂/million BTU. The ash content of the coal is also low. Table 2.3 Otter Creek Property Coal Quality Summary, lists the statistics for selected parameters by seam.

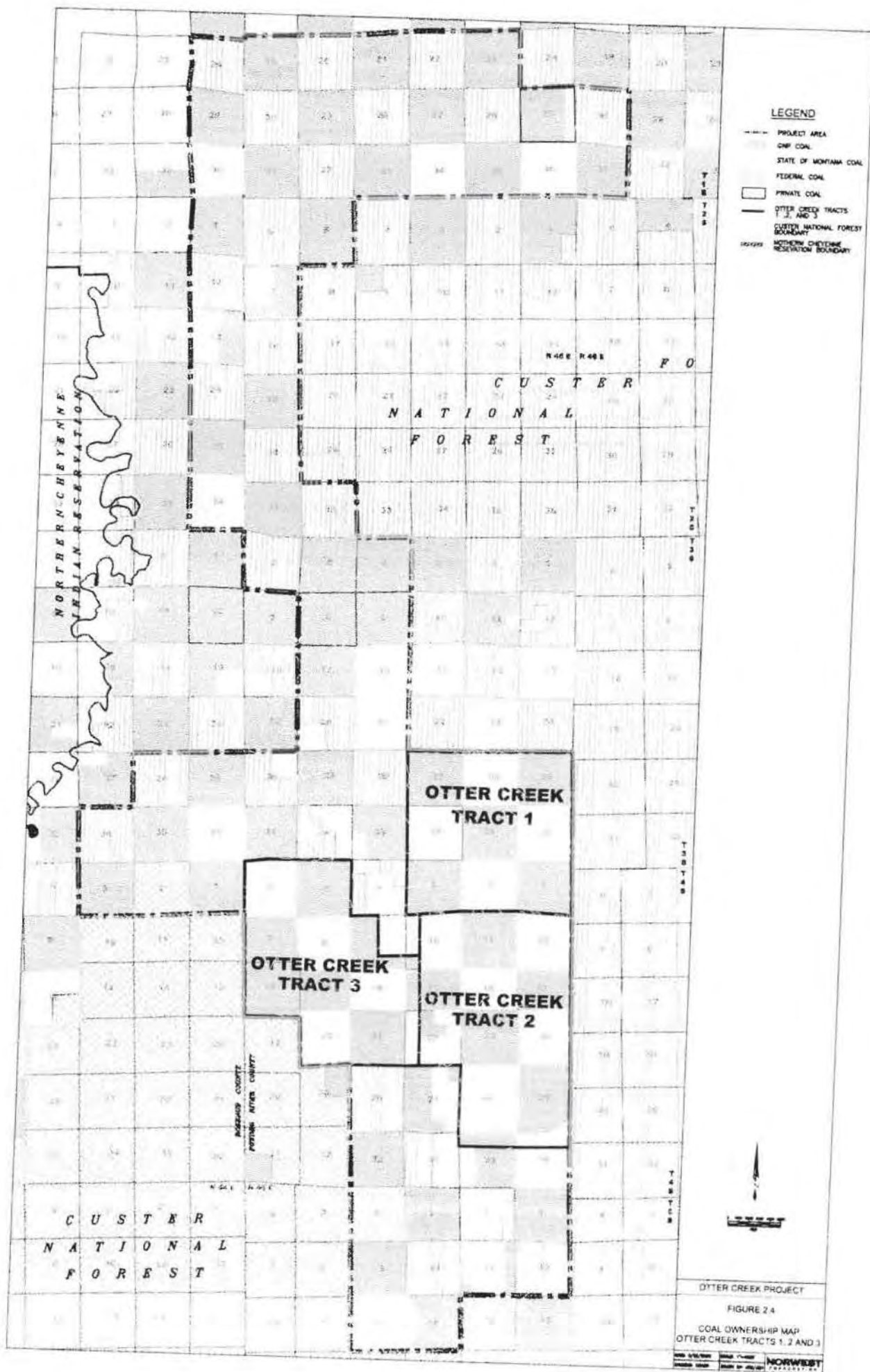


TABLE 2.3: OTTER CREEK PROPERTY COAL QUALITY SUMMARY

Upper Knoblock Seam											
	AS Received						Lb SO ₂ /		Lb NaO/	Dry	MAF
	Thickness	Moisture	Ash	Density	BTU/Lb	Sulfur	mmBTU	NaO	mm BTU	BTU/Lb	BTU/Lb
Min	2.0	22.39	3.32	1.22	6,798	0.12	0.29	0.73	0.00	9,345	11,238
Max	51.5	31.21	21.01	1.41	9,310	1.58	26.59	10.46	3.21	12,327	13,154
Mean	35.4	27.28	5.50	1.24	8,651	0.27	1.04	6.61	0.37	11,906	12,847
St. Dev.	16.6	2.29	5.70	0.06	979	0.48	11.87	2.82	1.39	1,334	1,083
Knoblock Seam											
	AS Received						Lb SO ₂ /		Lb NaO/	Dry	MAF
	Thickness	Moisture	Ash	Density	BTU/Lb	Sulfur	mmBTU	NaO	mm BTU	BTU/Lb	BTU/Lb
Min	3.6	24.21	3.48	1.22	5,806	0.09	0.20	0.02	0.00	8,896	10,235
Max	72.2	36.35	33.73	1.55	9,372	0.77	2.40	10.96	40.99	12,748	14,189
Mean	60.5	28.04	5.09	1.24	8,594	0.20	0.47	7.03	0.49	11,946	12,843
St. Dev.	11.4	2.99	7.10	0.08	883	0.24	0.71	2.56	11.11	1,174	765
Lower Knoblock Seam											
	AS Received						Lb SO ₂ /		Lb NaO/	Dry	MAF
	Thickness	Moisture	Ash	Density	BTU/Lb	Sulfur	mmBTU	NaO	mm BTU	BTU/Lb	BTU/Lb
Min	10.2	25.46	4.05	1.23	5,233	0.16	0.37	3.57	0.26	7,152	8,423
Max	22.7	31.10	18.99	1.39	8,804	0.46	3.67	10.46	2.94	12,191	13,207
Mean	16.4	27.68	6.97	1.26	8,325	0.27	0.80	6.01	0.56	11,534	12,702
St. Dev.	3.8	1.96	6.39	0.07	881	0.09	1.22	2.36	0.85	1,244	715

As shown on Table 2.3, the sodium content of the ash is considered high and averages between 6.0 and 7.0 percent. An inverse relationship exists in Powder River Basin coals where the sodium content of the coal ash generally increases as the ash content decreases. This relationship is strongly evident in the data regarding this coal. The higher sodium values are not surprising because of the low average ash content of the coals.

The calculated composite quality data were used to generate a quality model of the coal resources found within the property. This is important to identify the lateral variability in quality over the property and to visualize the spacing of data. Maps A2.15 and A2.16 illustrate the distribution of the in-place moisture of the Knoblock coal benches on an as-received quality basis. The moisture content of the coal shows little variability in all of the seams.

One noteworthy point is the lack of quality data in the northern portion of the property. The area north of the north half of Township 2 South, the area where the Knoblock seam splits into the Upper and Lower Knoblock seams, has no quality data. Core drill holes will need to be completed to characterize the quality of the coal in this area.

The ash content of the coal on a dry basis has been modeled and is shown on Maps A2.17 and A2.18. As can be seen on Map A2.17, the ash content of the Knoblock and Upper Knoblock seams is uniformly low but Map A2.18 shows a high ash zone (26.5%) in the Lower Knoblock seam. This zone is a one-drill hole anomaly and may be an isolated zone that is likely to be not representative of the ash content throughout the area.

The sulfur content of the coal is shown on Maps A2.19 and A2.20. Both these maps illustrate the consistently low nature of the sulfur content within the property.

The calorific value of the coal on a dry basis has been modeled and is illustrated on Maps A2.21 and A2.22. The MAF BTU value has also been modeled and is illustrated on Maps A2.23 and A2.24. These maps demonstrate the consistent nature of the coal regarding its heat value content. The only exception to this is a one drill hole anomaly in both the MAF and Dry BTU of the Lower Knoblock seam in the same area that showed elevated ash content. Because the MAF BTU is lower than adjacent holes the coal in this drill hole may be oxidized.

The sodium content in the coal ash has been modeled and is illustrated on Map A2.25 Knoblock/Upper Knoblock Sodium and Map A2.26 Lower Knoblock Sodium. Both of these maps show greater lateral variability than is shown on any of the other parameters modeled. A comparison of the maps regarding dry ash content, Maps A2.17 and A2.18 with the sodium content, Maps A2.25 and A2.26 show the areas having low ash coincide with the areas having the highest sodium content. The area of high ash illustrated on Map A2.18 is shown to have much lower sodium content (2.0%) than any holes surrounding it. It is evident from these data that when this coal property is mined, care in blending will be required to minimize the variability in the sodium content of the coal that would be produced. In addition, it is evident that additional drilling data will be required to implement coal quality programs.

Limited data were available regarding the equilibrium moisture of the coal. These data were used to model the variability in the equilibrium moisture and are illustrated on Map 2.27. Most of the equilibrium moisture data are from drill holes in the southern portion of the property but north of the zone where the Knoblock and Lower Knoblock split apart. The equilibrium moisture shows little variability but more data should be collected regarding this, particularly in the northern portion of the property.

Vertical Variability

The coal quality data was analyzed to identify vertical variability within each major bench of the Knoblock seam. This was done in two ways. First, a statistical approach was taken to assess variability in a general sense. Secondly, quality plots were generated for each hole in order to visually review the distribution of quality parameters from each individual drill hole.

For the statistical approach the coal quality data from each hole and seam were classified as to the relative position in each coal bench; the roof coal (the upper most sample in the drill hole), the upper half of the seam below the roof coal (the samples below the roof coal sample through the middle sample within the seam), the lower half of the seam above the floor coal (samples extending below the mid point of the seam down to but not including the bottom sample in the seam), and the floor coal (the lowest sample within the seam). These samples were then statistically analyzed. A summary of this investigation is presented in Table 2.4 Otter Creek Property - Coal Quality Vertical Comparison.

TABLE 2.4: OTTER CREEK PROPERTY - COAL QUALITY VERTICAL COMPARISON

	Thickness	AS Received					Lb SO ₂ /		Lb NaO/	Dry	MAF
		Moisture	Ash	Density	BTU/Lb	Sulfur	mmBTU	NaO	mm BTU	BTU/Lb	BTU/Lb
Upper Knoblock Seam Quality Data											
Roof Coal	2.30	26.48	8.83	1.28	8,282	0.89	8.49	4.65	1.06	11,310	12,489
Upper 1/2 Below	18.91	27.49	4.64	1.23	8,736	0.22	0.51	6.74	0.31	12,051	12,869
Lower 1/2 Above	16.86	27.08	6.04	1.25	8,611	0.25	0.62	6.71	0.34	11,821	12,872
Floor Coal	1.79	27.97	4.96	1.24	8,615	0.25	0.58	6.90	0.33	11,966	12,841
Knoblock Seam Quality Data											
Roof Coal	2.43	26.75	9.50	1.29	8,211	0.47	1.22	5.54	2.87	11,242	12,785
Upper 1/2 Below	29.70	28.19	4.42	1.23	8,642	0.15	0.36	7.56	0.37	12,032	12,822
Lower 1/2 Above	25.14	27.97	5.27	1.24	8,597	0.19	0.44	6.60	0.38	11,938	12,871
Floor Coal	1.99	28.35	7.16	1.26	8,338	0.54	1.34	6.47	0.78	11,664	12,885
Lower Knoblock Seam Quality Data											
Roof Coal	1.97	25.74	9.80	1.29	8,315	0.35	0.86	4.32	0.47	11,217	12,899
Upper 1/2 Below	8.59	27.95	6.17	1.25	8,270	0.19	0.55	5.79	0.52	11,497	12,566
Lower 1/2 Above	4.86	27.80	7.61	1.27	8,335	0.29	1.05	6.91	0.70	11,576	12,756
Floor Coal	1.40	28.41	5.47	1.24	8,642	0.61	1.40	6.71	0.41	12,077	13,070

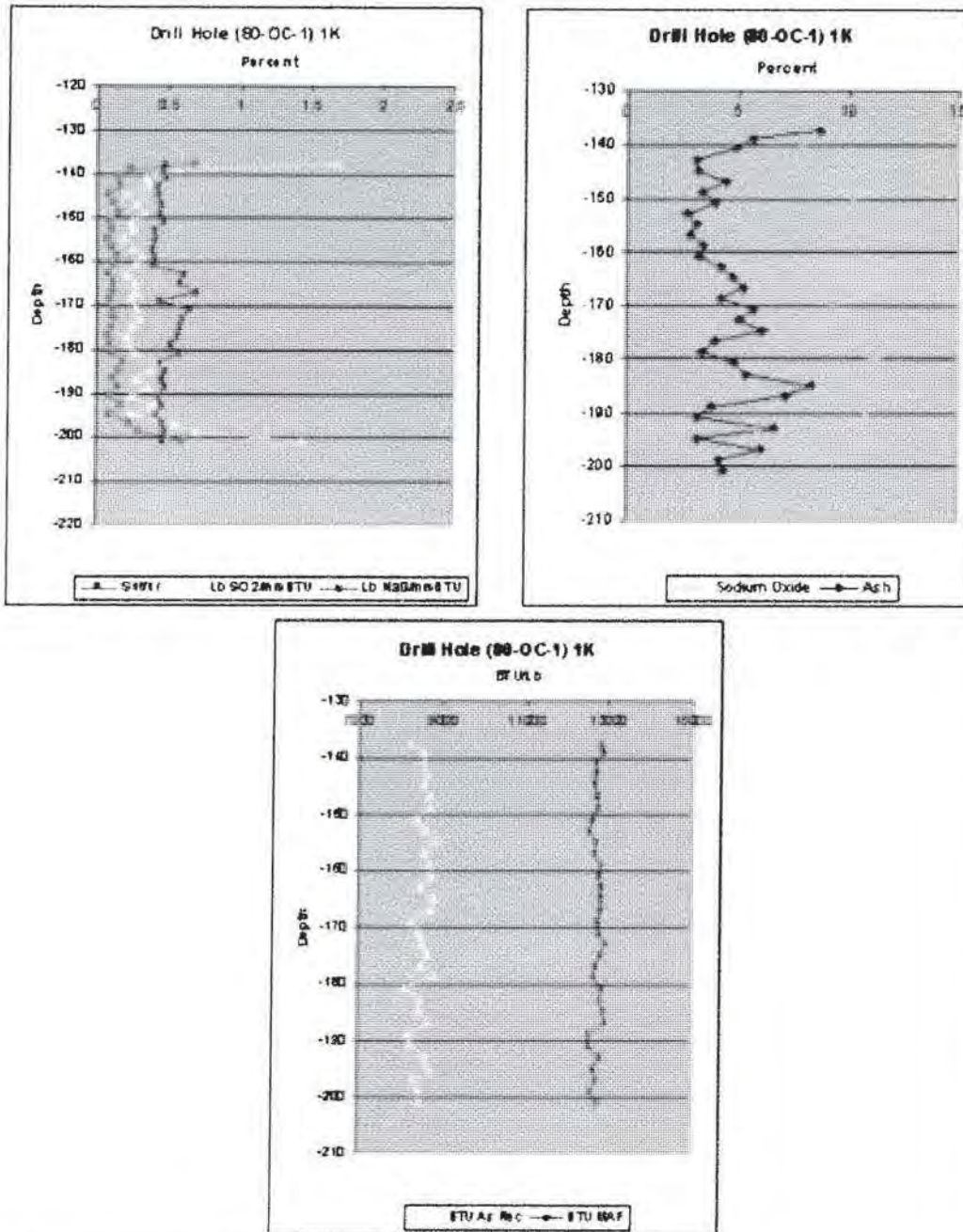
This comparison indicates the following:

- An increase in ash content in the roof and floor samples of all seams.
- The lower half of the Knoblock seam has a tendency to have higher ash content than the upper half.
- The Lower Knoblock is also higher in ash than the upper half of the Knoblock seam. This is not surprising because that portion of higher ash Knoblock is correlative to the Lower Knoblock seam.
- Correspondingly, the sodium oxide content is generally lower in the top portions of the benches and increases downward
- The lower ash portions of the seams generally contain the highest sodium oxide levels.
- The roof coal, due to its reduced calorific values, demonstrates elevated LB SO₂/mmBTU values.

The second way in which the quality data was reviewed vertically was to plot graphs of selected quality parameters with depth. Up to three graphs were generated for each drill hole containing quality data and have been plotted for a comparison of the vertical quality variation within each drill hole. Figure 2.5, Example Graphs of Coal Quality by Drill hole, illustrates how this quality data has been prepared. Similar graphs for all holes containing quality data are found in Appendix D. These graphs illustrate the tendency for the coal seams to have higher ash content in their roof and floor and as a result they also tend to have lower BTU value in these zones. The inverse relationship between the ash content and the sodium content in the ash is also very evident in most of these graphs.

Figure 2.5 Example Coal Quality Vertical Distribution

Hole 80-01-1 Knoblock Seam



Summary Conclusions and Opportunities Related to Blending

The primary conclusions derived from the lateral coal quality modeling and the review of the vertical variability of coal quality parameters are as follows:

- The coal averages 8,500 to 8,600 BTU/lb of coal on an as-received basis.
- Moisture content which averages 27.5% to 28.0% is fairly typical of Powder River Basin coals.
- The sodium content of the ash is considered high and averages between 6.0 and 7.0 percent.
- An inverse relationship exists where the sodium content of the coal ash generally increases as the ash content decreases.
- The sulfur content of the coal generally is consistently low, averaging approximately 0.27 % and with few exceptions, the coal is classified as compliance coal which produces less than 1.2 pounds of SO₂/million BTU.
- Sulfur content however, is elevated in the top portion of the Upper Knoblock seam.
- Ash content is the highest in the top portions of all of the coal benches.
- The Upper Knoblock Seam is generally slightly lower in ash content and higher in Sodium Oxide than the lower portions of the Knoblock Seam.
- Coal quality control programs and blending will need to be implemented during mining operations in order to maintain consistent product qualities.
- The opportunities for blending will need to be assessed on specific mining block areas as opposed to generalities applied to the entire Otter Creek project area.

MINING EVALUATION

Based on advice from GNP and the State of Montana, Norwest's focused our evaluation on the southern portion of the property because it is the most attractive for development from both resource and land control perspective. In this southern area, GNP and the State of Montana control the majority of the coal resources. In addition, the exploration drill hole density provides sufficient data to do a good evaluation of this property.

Norwest mining engineers evaluated the mineability of the Otter Creek coal resources by considering the topography, surface features, overburden depths, the thickness and dip of coal seams, the strip ratios, and coal outcrop lines. The geological investigation produced a series of maps showing these features and can be found in Appendix A to this report.

LOGICAL MINING UNITS

Norwest divided the southern portion of the Otter Creek reserve into a total of six LMUs. An LMU is an area of land in which the coal resources can be developed in an efficient, economical, and orderly manner as a unit with due regard to conservation of coal reserves and other resources. An LMU may consist of Federal leaseholds, private land, state lands combined under the effective control of a single operator that can be developed and operated as a single operation.

For the this study, each LMU has the following properties;

- Minimum of 200 million tons (Mt) of coal
- Maximum in-situ stripping ratio of 5:1 (five cubic yards of waste per ton of coal)
- Can be developed and operated as a single operation
- Can be separated from adjacent LMUs by physical boundaries such as stream channels, ridge lines or other naturally occurring barriers
- Sufficient resources for a minimum of a 40 year life.

In reality, all identified LMUs have more than 200 million tons of coal in-place, so that high-production, long-term mine plans could be developed. Reserves of this size are more likely to be attractive to major coal producers and energy project sponsors interested in

developing these resources. Table 3.1, LMU Reserves lists six LMUs with their related resource information. The LMUs are shown on Figure 3.1, LMU Map².

LMU 1 – Area A1

This LMU is located in Township 3S, Range 45 E, Sections 25, 26, 33, 34, 35 and 26 and Township 4S, Range 45 E, Sections 1, 2, and 3 and comprises the A1 mining area. It covers approximately 3,500 acres. At a maximum in-place strip ratio of 5:1, this LMU contains 355 million tons in two main seams. The average effective strip ratio, assuming 95% recovery, is 3.0:1 in place. Heat content averages 12,820 Btu (air dried basis), while sodium in ash averages 6.9 %.

There is a possible alluvial valley floor (AVF) lying on the south side of this LMU that contains 9 million tons of coal. This is shown separately to recognize that mining could possibly be restricted from this area, should it be classified as an AVF by the State.

Mining operations would primarily follow the strike of the coal outcrop, i.e., in a north-south and a northeast-southwest direction and advance easterly from the outcrop to the lease boundary. In the northern most portion of this LMU (Area A1), mining cuts are oriented north-south and northeast-south to take advantage of coal outcrop.

LMU 2 – Area A2 – A3

This LMU borders on the south of LMU 1 and lies primarily within Township 4S, R45E Sections 1, 2 10, 11, 12, 13, 14, 15, 22, 23, 24, 25 ,26, 35 and 36. It covers 5,000 acres and contains 510 million tons of coal at an average effective strip ratio of 2.8:1. Average heating content is 11,956 Btu (air dried basis), and sodium in ash averages 7.2%.

² Please note that only LMUs 1 through 4 are actually indicated on Figure 3.1. LMU 5 is a combination of LMUs 1 and 2 while LMU 6 is a combination of LMUs 3 and 4.

Table 3.1 Great Northern Properties LMU Reserves

LMU 2.11 Great Northern Properties LMU RECEIVED														Annual Production 40 Year Mine Life	
Mine Block	Waste Volumes (bcs)	Volume (bcs)	Coal		Recoverable Tons (bcs)	IN-SITU COAL QUALITY									
			In-Situ Tons (bcs)	As Received Moisture (%)		DRY		Moisture - Ash Free Btu (Btu/Bt)	Sulfur (%)	Ash (%)	Sulfur to Btu Ash (%)	Stripping Ratio Virgin (bcs/ton)	Effective (bcs/ton)		
LMU 1 AREA A1															
AREA A1 MAIN PITS	1,018,013,620	170,808,707	354,836,062		372,109,261	28.61		0.28		11,576	12,818		2.87	1.82	8.4
AREA A1 ASST	8,898,637	8,527,897	8,593,900		8,487,213	28.51		0.28		11,576	12,844		1.86	1.85	9.2
TOTAL AREA A1	1,026,912,257	179,336,604	363,430,062		380,596,474	28.61		0.28		11,576	12,830		2.82	2.97	8.6
LMU 2 AREA A2 AND A3															
AREA A2 and AREA A3	1,578,562,064	309,314,665	533,558,643		530,880,141	28.18		0.28		11,566	12,976		2.77	2.92	12.7
AREA A2 ASST	46,593,276	40,029,643	41,932,054		39,818,102	28.21		0.30		11,917	12,847		1.11	1.17	1.0
AREA A3 ASST	1,170,141	8,976,413	9,162,236		8,894,125	21.52		0.31		11,576	12,511		1.46	1.54	6.7
TOTAL AREA A2 AND A3 COMBINED	1,585,865,481	358,321,121	584,652,933		579,612,368	28.21		0.29		11,566	12,868		2.63	2.77	11.9
LMU 3 AREA B1															
AREA B1	777,594,178	242,865,305	283,587,814		240,908,233	28.30		0.27		12,012	12,881		3.07	3.23	6.0
LMU 4 AREA B2															
AREA B2	586,018,878	279,453,372	251,270,288		238,206,273	24.21		0.28		11,932	12,854		2.37	2.50	6.0
AREA B2 ASST	12,173,233	27,420,278	26,935,064		27,408,234	24.15		0.32		11,893	12,836		1.12	1.18	0.7
TOTAL AREA B2	598,192,111	306,873,650	278,205,352		265,614,507	24.28		0.30		11,928	12,853		2.24		6.7
LMU 5 AREA A1 AND A2															
AREA A1 and AREA A2	2,397,372,363	448,123,432	888,494,108		844,069,407	24.25		0.28		11,854	12,953		2.81	2.96	11.1
AREA A1 ASST	1,792,141	8,936,844	9,742,236		8,894,125	23.52		0.31		11,576	12,511		1.46	1.54	0.2
AREA A2 ASST	46,593,276	40,029,643	41,932,054		39,818,102	24.21		0.30		11,917	12,847		1.11	1.17	1.0
AREA A1 ASST	8,898,637	8,527,897	8,593,900		8,487,213	28.51		0.28		11,576	12,844		1.86	1.85	0.2
TOTAL AREA A1 AND A2 COMBINED	2,354,778,115	465,617,896	948,775,397		901,289,842	24.24		0.28		11,849	12,849		2.71	2.85	12.9
LMU 6 AREA B1 AND B2															
AREA B1 AND B2	1,134,214,989	481,918,577	564,837,901		478,015,006	24.28		0.28		11,932	12,868		2.72	2.87	12.0
AREA B1 ASST	12,173,233	27,420,278	26,935,064		27,408,234	24.15		0.32		11,893	12,836		1.12	1.18	0.3
TOTAL AREA B1 AND B2 COMBINED	1,086,588,228	509,338,856	591,772,965		505,423,240	24.24		0.28		11,964	12,865		2.64	2.77	12.7



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LEGEND

- TOPO
- LMU BOUNDARY
- TRACT BOUNDARY



GREAT NORTHERN PROPERTIES
EXHIBIT 3.1
OTTER CREEK PROJECT
LOGICAL MINING UNIT
MAP
DATE: 11/11/2010
BY: J. J. JENSEN
NORWEST
11/11/2010

There are two possible AVFs³, one lying on the north side and one lying on the west side of this LMU. These potential AVFs contain 40 million tons and 9 million tons of coal, respectively.

Mining operations are primarily oriented north-south and east-west in this LMU.

LMU 3 – Area B1

This LMU is located west of LMUs 1 and 2 and lies within Township 3S, R45E Sections 5, 6, 7, 8, 9, 17 and 18. It covers 2,400 acres and contains 254 million tons of coal at an average effective strip ratio of 3.2:1. Average heating content is 12,012 Btu (air dried basis), and sodium in ash averages 8.7%.

There are no likely AVFs found adjacent to this block.

Mining operations are primarily oriented northwest-southeast along the strike of the coal in this LMU.

LMU 4 – Area B2

This LMU borders on the south of LMU 3 and lies primarily within Township 3S, R45E Sections 15, 16, 17, 18, 20, 21, and 22. It covers 2,300 acres and contains 251 million tons of coal at an average effective strip ratio of 2.4:1. Average heating content is 11,932Btu (air dried basis), and sodium in ash averages 7.7%.

There is one potential AVF lying on the east side of this LMU; this is estimated to contain 29 million tons of coal.

Mining operations are primarily oriented northwest-southeast along the strike of the coal in this LMU.

LMU 5 – Area A1 and A2 Combined

This LMU combines the resources of Area A1 and A2 and is located in Township 4S, R45W and Township 3S, R45E. It covers a total 7,000 acres and contains 751 million tons of coal at an average effective strip ratio of 2.8:1. Average heating content is 11,969Btu (air dried basis), and sodium in ash averages 7.4%.

³ All AVFs are shown separately to recognize that mining could possibly be restricted from this area, should it be classified as an AVF by the State.

There are three potential AVFs: one lying south of Area A1; one lying north of Area A2; and one lying west of Area A2. These potential AVFs contains a total of 51 million tons of coal.

LMU 6 – Area B1 and B2 Combined

This LMU combines the resources of Area B1 and B2 and is located in Township 3S, R45E. It covers a total 4,700 acres and contains 505 million tons of coal at an average effective strip ratio of 2.9:1. Average heating content is 11,972Btu (air dried basis), and sodium in ash averages 8.2%.

There is one possible AVF lying east of Area B2. This potential AVF contains a total of 29 million tons of coal.

COAL QUALITY

Figure A.2 is a cross-section depicting the coal seams in relation to the surface of the land. A summary of coal quality by seam and seam thickness for each LMU is found in Table 3.2, LMU Coal Quality by Seam. This table shows that the quality of the Upper and Lower Knoblock Seams are nearly identical with only minor variations in any of the parameters.

MINING APPROACH

All LMUs are amenable to surface mining using draglines and truck-shovel fleets for overburden removal. These techniques are used at other mines in the region including Absaloka, Decker, Rosebud, and Spring Creek Mines. Large walking draglines working with large (850 hp) push dozers usually remove up to 150 feet of the overburden above the upper coal seam. Overburden greater than 150 feet in thickness and thick interburden are moved using truck-shovel fleets. For thin interburden, large wheel loaders, large push dozers and wheel scrapers can be used effectively. Drilling and blasting is generally required to fragment the overburden and thick interburdens. This eases the digging of this material and increases the equipment productivity.

For each LMU, the dragline was sized according to the accepted mining industry rule of thumb i.e. by dividing the largest annual dragline removal requirements by a dragline productivity factor of 250,000 bank cubic yards (BCY) per cubic yard of dragline bucket capacity. For example: An LMU requiring a maximum annual dragline volume of 30 million BCY would require a dragline having a bucket capacity of 120 cubic yards (CY). Therefore, the smaller LMUs will require 70 to 80 CY draglines while the larger

Table 3.2 Great Northern Properties LMU Coal Quality by Seam

LMU - MINE BLOCK		Seam	Seam Thickness (feet)	IN-SITU COAL QUALITY			
				As Received Moisture (%)	DRY		
					Ash (%)	Sulfur (%)	Btu (btu/lb)
LMU - 1	AREA A1	UK2	42.08	28.60	6.90	0.26	11,934
		LK	18.11	28.63	6.88	0.26	11,940
LMU - 2	AREA A2 - A3	UK2	37.08	28.35	7.75	0.28	11,888
		UK1	4.80	28.39	8.51	0.28	11,795
		LK	15.06	28.10	8.59	0.39	11,837
LMU - 3	AREA B1	UK2	44.30	24.30	6.77	0.27	12,012
		LK	19.33	24.30	6.78	0.27	12,011
LMU - 4	AREA B2	UK2	46.87	27.38	6.82	0.28	12,002
		LK	17.63	27.43	8.86	0.32	11,743
LMU - 5	AREA A1, A2 AND A3 COMBINED	UK2	43.42	28.39	6.99	0.27	11,960
		UK1	4.80	28.39	8.51	0.28	11,795
		LK	18.66	28.34	7.30	0.29	11,934
LMU - 6	AREA B1 AND B2 COMBINED	UK2	45.61	28.65	7.18	0.29	12,674
		LK	18.54	28.82	8.32	0.31	12,605

LMUs will need 110 to 120 CY draglines. The combined LMUs will require two draglines. For LMUs 1 through 4, the truck-shovel fleet will consist of 25 to 30 CY hydraulic excavators or shovels and 190 to 240 ton trucks.

Coal, when exposed the top surface of the seam, will need to be cleaned using a rubber tired dozer, or grader to scrape away any remaining loose overburden/interburden or oxidized coal. In addition, the upper portions (6 inches to 1 foot) of both the Upper and Lower Knoblock may need to be removed and wasted to help reduce the sulfur content of the shipped product. One mine in the area (Rosebud) currently is utilizing a pavement cutting machine to remove this top layer of coal and process significantly reduces the sulfur content in their shipped coal.

Coal will be loaded by mining shovels, larger front end loaders or hydraulic excavators into large capacity (up to 320 tons) bottom or rear dump trucks and hauled to a coal handling system. The coal will be crushed in multiple stages to a minus 2 inches product, the size required by most thermal coal customers, and placed into a stockpile or loaded into unit trains for shipment to customers, primarily in the Midwest.

When it is necessary to meet the customer's coal specifications, it may be possible to selectively mine the coal to improve the coal quality. The selective mining process removes zones within each seam that are usually higher in sulfur or sodium thereby resulting in a higher quality product.

As an alternate to truck haulage to the coal handling plant, additional studies may indicate that it is more cost-effective to crush the coal at the mining face, using portable hopper/crushers, and then load the crushed product directly onto overland conveyors for transport to a processing plant or unit train loadout facility.

The general mining sequence for each of the LMUs is shown on Figure 3.2, LMU Mine Plan Layout Map. Table 3.3 lists the production rates selected for the LMUs.

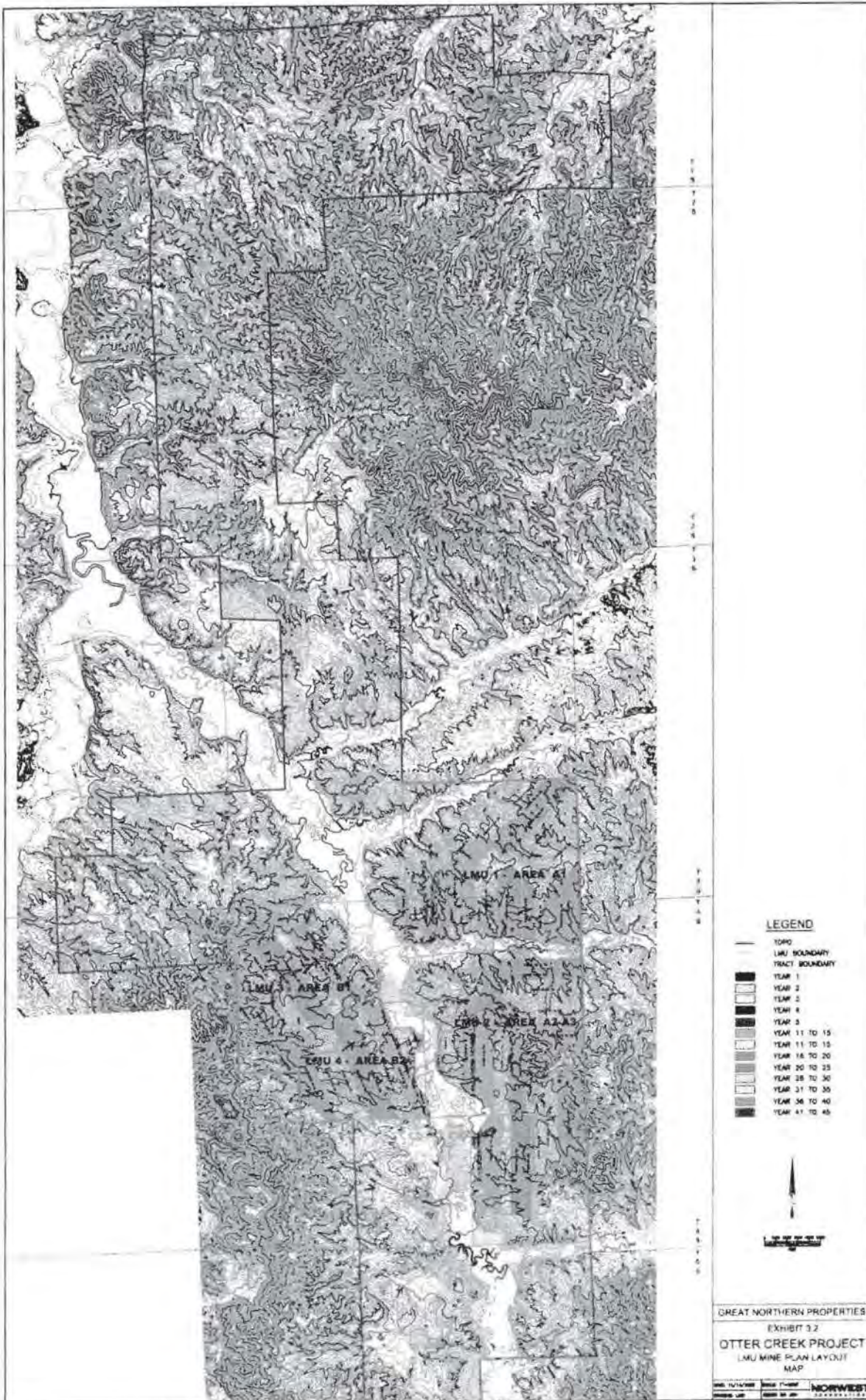


Table 3.3 Production Rate by LMU

LMU	Yearly Production Rate (Tons)
1	8,500,000
2	12,700,000
3	6,000,000
4	6,000,000
5	21,200,000
6	12,000,000

Mining Cost Estimate

Norwest developed a mining cost estimate for each LMU. Mining costs were based on an assessment of the volumes of waste and coal that would be moved over the life of the mine. When using dragline mining systems, as the overburden depths increase, some of the in-situ overburden needs to be moved twice (rehandled) by the dragline. Rehandle can range from 0% to 50% of the in-situ waste material – for the purpose of this study Norwest estimated the dragline rehandle at 25% of the dragline waste volumes (maximum 150 feet of overburden) and truck-shovel rehandle was estimated at 5%. All in-situ waste volumes were increased to reflect the appropriate rehandle percentage by material type. Table 3.4 LMU Mine Plan Volumes show the coal and overburden removal requirement in annual and 5 year increments for each LMU.

Mining costs were calculated based on unit mining costs derived from actual and projected mining costs from mines having similar mining conditions. The estimated final waste volumes and coal tons shown in Table 3.4 where used as inputs to the economic model. Tables 3.5 through 3.10 show the estimated mining costs for the individual LMUs. The average life-of-mine costs for the six LMU range from \$6.69 per ton to \$7.65 per ton.

Mining capital was estimated for each LMU. Table 3.11, Capital Expenditures shows the projected capital expenditures for development, mine infrastructure, coal handling plant, overburden and coal loading trucks and shovels, reclamation equipment and various support equipment including rubber tired dozers, graders, large dozers, water trucks, overburden and coal drills.

Table 3.3 Great Northern Properties LNU Mine Plan Volumes

Units	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6 to 10	Year 11 to 15	Year 16 to 20	Year 21 to 25	Year 26 to 30	Year 31 to 35	Year 36 to 40	Year 41 to 45	TOTALS
LNU 1 - AREA A1														
Coal Tons	3,490,000	8,590,000	8,590,000	8,590,000	8,590,000	42,500,000	42,500,000	42,500,000	42,500,000	42,500,000	42,500,000	42,400,000	180,000	335,000,000
In-Situ Dragline Volumes	5,760,000	18,500,000	28,000,000	18,500,000	18,500,000	104,000,000	104,000,000	104,000,000	104,000,000	104,000,000	104,000,000	104,000,000	200,000	275,300,000
In-Situ Truck-Shovel Volumes	200,000	400,000	2,300,000	1,200,000	2,100,000	28,000,000	33,700,000	15,500,000	15,500,000	34,000,000	70,000,000	48,000,000	0	256,300,000
Dragline Volumes with Rehandle	7,125,000	20,625,000	25,500,000	20,625,000	20,625,000	130,000,000	130,700,000	115,500,000	115,500,000	138,000,000	174,000,000	152,000,000	250,000	969,125,000
Truck-Shovel Volumes with Rehandle	310,000	630,000	3,110,000	1,630,000	2,835,000	38,245,000	46,410,000	21,735,000	21,735,000	58,000,000	116,000,000	80,000,000	0	349,115,000
Effective Strip Ratio	2.10	2.50	3.27	3.34	3.16	3.72	3.91	3.69	3.34	3.75	4.67	4.30	2.50	3.70
LNU 2 - AREA A2, A3														
Coal Tons	5,140,000	12,700,000	12,700,000	12,700,000	12,700,000	63,500,000	63,500,000	63,500,000	63,500,000	63,500,000	63,500,000	61,300,000	200,000	498,500,000
In-Situ Dragline Volumes	5,140,000	17,800,000	22,000,000	17,800,000	17,800,000	130,000,000	130,000,000	130,000,000	130,000,000	130,000,000	130,000,000	130,000,000	300,000	1,851,500,000
In-Situ Truck-Shovel Volumes	600,000	700,000	1,800,000	1,000,000	2,300,000	28,000,000	34,700,000	35,500,000	35,500,000	68,000,000	130,000,000	100,000,000	300,000	409,400,000
Dragline Volumes with Rehandle	6,425,000	22,200,000	27,400,000	22,200,000	22,200,000	163,000,000	163,700,000	163,500,000	163,500,000	198,000,000	268,000,000	230,000,000	600,000	1,260,900,000
Truck-Shovel Volumes with Rehandle	420,000	755,000	1,995,000	1,100,000	2,565,000	39,100,000	46,410,000	41,995,000	41,995,000	90,100,000	182,295,000	132,100,000	210,000	622,330,000
Effective Strip Ratio	1.35	1.81	2.32	2.68	3.14	3.18	3.30	3.54	3.34	4.40	5.38	5.01	2.93	3.90
LNU 3 - AREA B1														
Coal Tons	2,440,000	6,000,000	6,000,000	6,000,000	6,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	700,000	217,100,000
In-Situ Dragline Volumes	5,300,000	13,400,000	14,240,000	14,140,000	13,030,000	68,000,000	68,000,000	68,000,000	68,000,000	68,000,000	68,000,000	68,000,000	3,184,000	1,312,800,000
In-Situ Truck-Shovel Volumes	100,000	300,000	823,000	823,000	928,000	7,576,190	15,742,307	23,880,952	26,223,810	45,919,848	92,484,782	68,618,095	1,855,714	244,147,819
Dragline Volumes with Rehandle	6,000,000	16,750,000	17,000,000	17,000,000	16,355,000	83,500,000	83,500,000	83,500,000	83,500,000	113,919,848	159,499,000	151,600,000	3,890,000	914,150,000
Truck-Shovel Volumes with Rehandle	105,000	315,000	865,000	865,000	975,000	7,955,000	16,510,000	24,215,000	27,640,000	48,215,000	96,815,000	71,860,000	1,990,000	256,355,000
Effective Strip Ratio	2.75	2.84	3.11	3.09	2.83	3.05	3.04	4.52	4.75	6.12	6.48	7.43	8.51	4.54
LNU 4 - AREA B2														
Coal Tons	2,400,000	6,000,000	6,000,000	6,000,000	6,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	1,000,000	238,400,000
In-Situ Dragline Volumes	4,500,000	7,500,000	7,000,000	8,700,000	9,000,000	51,000,000	55,500,000	62,200,000	62,200,000	61,000,000	71,200,000	73,000,000	3,600,000	478,000,000
In-Situ Truck-Shovel Volumes	100,000	300,000	400,000	400,000	400,000	3,100,000	7,000,000	13,700,000	13,700,000	13,400,000	25,000,000	43,500,000	5,000,000	124,000,000
Dragline Volumes with Rehandle	5,425,000	8,125,000	8,250,000	10,375,000	11,250,000	64,875,000	69,125,000	77,900,000	77,900,000	74,400,000	96,200,000	116,500,000	4,500,000	598,500,000
Truck-Shovel Volumes with Rehandle	105,000	315,000	420,000	420,000	420,000	3,255,000	7,294,000	14,200,000	14,200,000	14,070,000	27,200,000	48,375,000	5,250,000	134,825,000
Effective Strip Ratio	2.39	1.57	1.61	1.92	1.95	2.27	2.55	3.87	3.90	3.84	3.87	4.50	8.09	3.40
LNU 5 - AREA A1, A2 AND A3														
Coal Tons	8,000,000	21,200,000	21,200,000	21,200,000	21,200,000	106,000,000	106,000,000	106,000,000	106,000,000	106,000,000	106,000,000	103,700,000	500,000	833,500,000
In-Situ Dragline Volumes	11,000,000	34,300,000	42,400,000	42,700,000	43,900,000	234,400,000	237,400,000	233,200,000	236,400,000	243,100,000	243,700,000	241,500,000	500,000	1,834,000,000
In-Situ Truck-Shovel Volumes	600,000	1,100,000	2,100,000	2,700,000	4,400,000	30,100,000	36,900,000	37,600,000	40,400,000	62,700,000	75,200,000	111,600,000	200,000	426,200,000
Dragline Volumes with Rehandle	11,750,000	42,875,000	53,000,000	53,775,000	54,875,000	293,000,000	297,000,000	279,125,000	295,500,000	303,875,000	304,625,000	301,875,000	625,000	1,291,200,000
Truck-Shovel Volumes with Rehandle	630,000	1,385,000	4,565,000	4,825,000	11,835,000	67,345,000	75,855,000	77,370,000	93,440,000	134,810,000	235,795,000	183,220,000	210,000	891,245,000
Effective Strip Ratio	1.67	2.09	2.76	2.76	3.15	3.40	3.52	3.56	3.67	4.14	5.18	4.68	2.78	3.82
LNU 6 - AREA B1 AND B2 COMBINED														
Coal Tons	4,800,000	12,800,000	12,800,000	12,800,000	12,800,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	2,300,000	475,100,000
In-Situ Dragline Volumes	9,700,000	20,700,000	21,640,000	22,640,000	22,640,000	118,704,000	134,200,000	151,228,000	154,168,000	170,212,000	182,792,000	195,844,000	6,704,000	1,218,120,000
In-Situ Truck-Shovel Volumes	100,000	400,000	1,223,818	1,423,818	1,328,711	10,076,190	22,723,857	34,780,952	37,623,810	59,319,848	78,004,782	111,918,095	6,005,714	348,747,819
Dragline Volumes with Rehandle	11,125,000	25,875,000	27,050,000	28,550,000	26,535,000	148,380,000	167,850,000	189,015,000	192,710,000	233,555,000	258,400,000	253,807,000	8,400,000	1,512,450,000
Truck-Shovel Volumes with Rehandle	310,000	630,000	1,385,000	1,405,000	1,395,000	11,110,000	23,860,000	38,628,000	39,505,000	62,325,000	81,905,000	117,535,000	7,230,000	387,185,000
Effective Strip Ratio	2.57	2.21	2.36	2.50	2.41	2.60	3.20	3.79	3.87	4.58	5.17	4.32	8.83	4.80

Table 3.7 LMC/3-0.2 Mine Cost Model

[illegible]

Table 3.11 Great Northern Properties Capital Expenditures

INITIAL EQUIPMENT REQUIREMENTS

EQUIPMENT	LMU 1 AREA A1	LMU 2 AREA A2-A3	LMU 3 AREA A1-A2-A3	LMU 4 AREA B1	LMU 5 AREA B2	LMU 6 AREA B1 -B2	EQUIPMENT COSTS/UNIT
Dragline - 70 cyd				1	1	2	\$38,000
Dragline - 110 cyd	1	2	3				\$46,000
Coal -Shovel 20 cyd	2	2	3	1	1	2	\$3,200
Rock-Shovel 30 cyd	1	2	2			1	\$4,300
Rock Shovel 20 cyd				1	1		\$3,800
OB Trucks - 210 ton				6	6		\$2,100
OB Trucks - 240 ton	6	12	12			6	\$2,300
Coal Trucks - 320 ton	6	8	14	4	4	8	\$3,200
R.T. Dozers	2	2	3	1	1	2	\$700
Dozers	3	3	4	3	3	4	\$1,800
Water Trucks	2	2	3	2	2	3	\$720
Motor Graders	2	2	3	2	2	3	\$1,400
Coal Handling Plant	1	1	1	1	1	1	Varied
Mine Facilities	1	1	1	1	1	1	Varied
OB-Coal Drills	1	2	3	1	1	2	\$2,300
Rec - Scrapers	2	2	4	2	2	2	\$1,250
Rec - Dozers	1	1	2	1	1	1	\$1,800

INITIAL CAPITAL COSTS

Capital x (000's)	LMU 1 AREA A1	LMU 2 AREA A2-A3	LMU 3 AREA A1-A2-A3	LMU 4 AREA B1	LMU 5 AREA B2	LMU 6 AREA B1 -B2
Land Acquisition						
Permitting - Engineering	\$5,000	\$5,000	\$5,000	\$5,000	\$5,000	\$5,000
Exploration Drilling	\$2,000	\$2,000	\$2,000	\$2,000	\$2,000	\$2,000
Mine Facilities	\$9,000	\$21,000	\$15,000	\$9,000	\$14,000	\$9,000
Coal Handling Plant	\$28,000	\$37,000	\$52,000	\$22,000	\$22,000	\$35,000
Miscellaneous Equipment and supplies	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000
Dragline - 70 cyd	\$0	\$0	\$0	\$38,000	\$38,000	\$76,000
Dragline - 110 cyd	\$46,000	\$92,000	\$138,000	\$0	\$0	\$0
30 cyd Rock Shovel	\$4,300	\$8,600	\$8,600	\$0	\$0	\$4,300
30 cyd Rock Shovel	\$0	\$0	\$0	\$3,800	\$3,800	\$0
210 to 240 Ton Rock Trucks	\$13,800	\$27,600	\$27,600	\$12,600	\$12,600	\$13,800
20 cyd Coal Excavators	\$6,400	\$6,400	\$9,600	\$3,200	\$3,200	\$6,400
290 to 320 Coal Bottom Dump Trucks	\$19,200	\$25,600	\$44,800	\$12,800	\$12,800	\$25,600
Mobile Equipment	\$13,340	\$15,640	\$22,560	\$12,640	\$12,640	\$19,560
Reclamation Equipment	\$4,300	\$4,300	\$8,600	\$4,300	\$4,300	\$4,300
TOTAL CAPITAL	\$154,240	\$248,040	\$336,560	\$128,240	\$133,240	\$203,860

MARKETING

ELECTRIC UTILITIES

Montana coal, the Northern PRB, is noted for its higher heating value than most of the Southern PRB mines, its varying sulfur levels and its higher sodium levels. The sodium content of Otter Creek coal ranges from 5.8% to 8.8% and is high in comparison to other coals in the western US, but about the same as other Montana PRB mines. For example: coals from the southern Powder River Basin of Wyoming typically average 1.2% sodium while currently produced coals from Colorado average about 2.5% sodium. Sodium in ash can cause slagging problems in certain types of boilers in electric generating plants. Higher sodium levels generally create greater slagging problems. As a result, most plants avoid burning high sodium coals. Exceptions include the following ten plants which are within the competitive area for Otter Creek currently accept higher sodium coals:

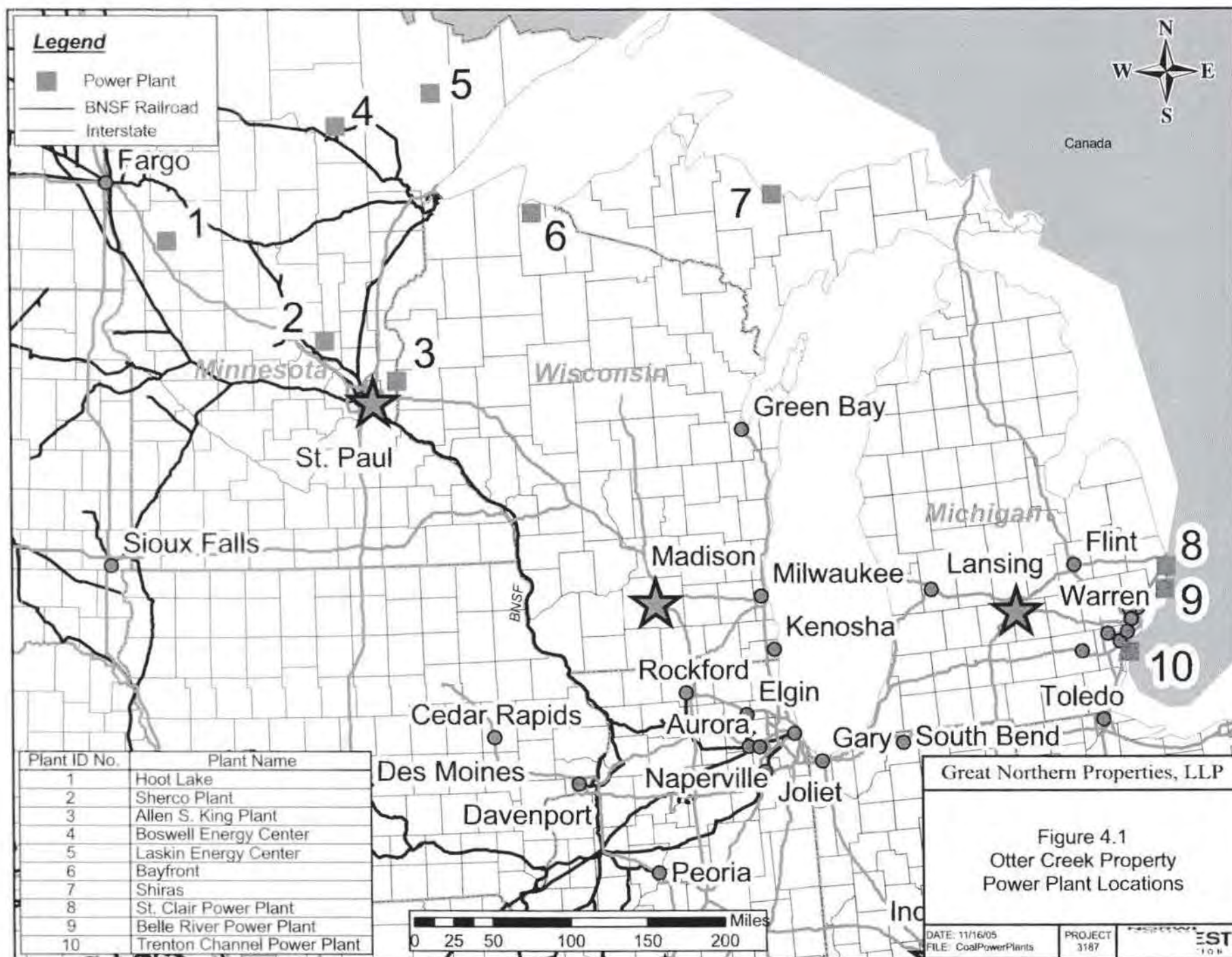
1. St. Clair - Detroit Edison
2. Bell River - Detroit Edison
3. Trenton Channel - Detroit Edison
4. Shiras - Marquette Board of Light & Power
5. Clay-Boswell - Minnesota Power
6. Hoot Lake - Otter Tail Corp.
7. Syl Laskin - Minnesota Power
8. King - Northern States Power
9. Sherburne County - Northern States Power
10. Bay Front (or Bayfront) - Northern States Power

The plants shown in the table would likely constitute the initial target market for Otter Creek coals. The plants are shown on Figure 4.1 numbered from the closest to the most distant plants. Total 2004 volume to these ten plants totaled 20.3 million tons in 2004. Through July of 2005 the annualized total consumption decreased to 16.1 million tons. The difference in consumption rates appears to be due to the intrusion of coal from the Southern PRB. In Table 4.1 below coal quality and delivered prices (discussed below) are also shown.

Table 4.1 Otter Creek Prices of Coal to Potential Customers

A	B	C	D	E	2004 FERC data										2005 FERC through July 2005										
					F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	
	Company Name				Contract Type	2004 Price (\$/ton)	2004 Quantity (tons)	2004 Heat Rate (Btu/lb)	2004 Moisture (%)	2004 Ash (%)	2004 Sulfur (%)	2004 Nitrogen (%)	2004 Phosphorus (ppm)	2004 Chlorine (ppm)	2005 Price (\$/ton)	2005 Quantity (tons)	2005 Heat Rate (Btu/lb)	2005 Moisture (%)	2005 Ash (%)	2005 Sulfur (%)	2005 Nitrogen (%)	2005 Phosphorus (ppm)	2005 Chlorine (ppm)	2005 Contract Type	2005 Price (\$/ton)
1	Orion Tail Corporation	Hoot Lake	MN	Spring Creek	442	9,258	0.38	4.6	143.38	\$ 26.55	600	\$ 0.021	\$ 12.60	\$ 13.95	341	9,247	0.37	4.8	158.42	\$ 29.30	\$ 12.60	\$ 16.70	C-12/07	\$ 10.00	
2	No States / So MNMuni Pwr Agy	Sherburne County	MN	Absaloka	5,851	8,704	0.64	9.2	95.58	\$ 16.64	700	\$ 0.020	\$ 14.00	\$ 2.64	912	8,716	0.63	9.2	115.65	\$ 20.16	\$ 14.00	\$ 6.16	S&C-06/07	\$ 5.85	
3	Northern States Power	King	MN	Absaloka	351	8,727	0.63	9.07	111.66	\$ 19.84	750	\$ 0.020	\$ 15.00	\$ 4.84	164	8,708	0.58	9.1	115.36	\$ 20.09	\$ 15.00	\$ 5.09	C-12/06	\$ 4.84	
4	Minnesota Power	Clay Boswell	MN	Decker	777	9,417	0.37	4.5	97.14	\$ 18.30	750	\$ 0.019	\$ 14.25	\$ 4.05	555	9,444	0.40	4.5	105.07	\$ 19.85	\$ 14.25	\$ 5.60	C	\$ 5.32	
4	Minnesota Power	Clay Boswell	MN	Spring Creek	867	9,273	0.34	4.2	100.12	\$ 18.57	750	\$ 0.019	\$ 14.25	\$ 4.32	693	9,211	0.36	4.5	106.08	\$ 19.54	\$ 14.25	\$ 5.29	C	\$ 5.03	
4	Minnesota Power	Clay Boswell	MN	Rosebud	2,083	8,773	0.70	8.9	97.02	\$ 17.02	750	\$ 0.019	\$ 14.25	\$ 2.77	1,503	8,693	0.72	9.1	100.89	\$ 17.54	\$ 14.25	\$ 3.29	C	\$ 3.13	
5	Minnesota Power	Syl Laskin	MN	Decker	408	9,468	0.37	4.4	106.07	\$ 20.09	800	\$ 0.019	\$ 15.20	\$ 4.89	265	9,413	0.37	4.3	117.79	\$ 22.17	\$ 15.20	\$ 6.97	C	\$ 6.63	
6	Northern States Power	Bayfront	WI	Decker	55	9,465	0.32	4.1	153.39	\$ 29.04	800	\$ 0.019	\$ 19.20	\$ 9.84	34	9,487	0.32	3.9	151.63	\$ 28.77	\$ 19.20	\$ 9.57	S	\$ 9.09	
7	Marquette Rd of Light and Power	Shiras	MI	Spring Creek	197	9,321	0.32	4.1	133.61	\$ 24.91	800	\$ 0.019	\$ 19.70	\$ 5.21	64	9,309	0.31	4.3	142.35	\$ 26.50	\$ 19.70	\$ 6.80	C	\$ 6.46	
8	Detroit Edison	St Clair	MI	Decker	2,352	9,115	0.37	4.5	146.04	\$ 27.79	800	\$ 0.019	\$ 21.70	\$ 6.09	1,036	9,478	0.38	4.4	125.30	\$ 23.75	\$ 21.70	\$ 2.05	S	\$ 1.95	
8	Detroit Edison	St Clair	MI	Spring Creek	1,458	9,330	0.31	4.1	91.36	\$ 17.05	800	\$ 0.019	\$ 17.05	\$ -	772	9,295	0.32	4.3	96.41	\$ 17.92	\$ 17.05	\$ 0.88	C-12/06	\$ 0.83	
9	Detroit Edison	Belle River	MI	Decker	2,452	9,515	0.37	4.5	146.03	\$ 27.79	800	\$ 0.019	\$ 21.70	\$ 6.09	996	9,477	0.38	4.4	125.61	\$ 23.81	\$ 21.70	\$ 2.11	S	\$ 2.00	
9	Detroit Edison	Belle River	MI	Spring Creek	1,401	9,330	0.33	4.1	91.36	\$ 17.05	800	\$ 0.019	\$ 17.05	\$ -	742	9,296	0.32	4.3	96.80	\$ 18.00	\$ 17.05	\$ 0.95	C-12/05	\$ 0.90	
10	Detroit Edison	Trenton Channel	MI	KY, PA & WY	1,418	10,850	0.68	6.0	135.25	\$ 29.35	800	\$ 0.019	\$ 17.30	\$ 12.05	1,310				\$ -					\$ -	
Sub Total						20,312									\$ 4.61	16,092	annualized total					\$ 3.82		\$ 3.53	
Other potential customers:																									
Consumers Energy		B.C. Cobb		Rosebud	929	9,045	0.50	6.7	128.28	\$ 23.21					464	9,004	0.47	6.8	\$ 128.23						
		Colstrip		Rosebud	6,378										3,867	8,495	0.67	9.5							
Salt River Project		Coronado	AZ	Spring Creek	71	10,850	0.68	6.0	135.25	\$ 29.35					167	9,327	0.32	4.0	\$ 144.15				C&S		
FVA		GRT Terminal		Spring Creek	243										262										
Montana-Dakota Utilities		Heskett		Rosebud	79	8,678	0.49	7.3	123.96	\$ 21.51					83	8,678	0.77	9.4	\$ 136.17				spot		
Consumers Energy		J.C. Wadcock		Rosebud	239	9,034	0.50	6.7	123.77	\$ 22.36					302	9,008	0.48	6.8	\$ 118.50				C-12/09		
KP&L, A Western Resources Co		Lawrence	KS	Spring Creek	246	8,979	0.33	8.90	108.75	\$ 19.53					-										
Montana-Dakota Utilities		Lewis & Clark		Rosebud	15	8,700	0.72	9.0	127.20	\$ 22.13					3	8,700	0.72	9.0	\$ 139.70						
Wisconsin Power & Light		Nelson Dewey		Spring Creek	307	9,354	0.32	4.0	112.00	\$ 20.95					240	9,362	0.32	4.1	\$ 127.99						
Wisconsin Power & Light		Prosque Isle		Spring Creek	466	9,103	0.28	4.4	110.84	\$ 20.14					274	9,059	0.28	4.9	\$ 117.21						
Northern Indiana Public Service		Rollin Shalier		Spring Creek	55	9,257	0.32	4.2	148.30	\$ 27.46					39	9,330	0.35	4.1	\$ 167.17						
United Power Association		Stanton		Spring Creek	266	9,228	0.49	7.3	100.59	\$ 18.56					442	9,285	0.33	5.4	\$ 96.76	C					
KP&L, A Western Resources Co		Tecumseh	KS	Spring Creek	105	8,979	0.33	6.9	108.80	\$ 19.54					-										
Monongahela Power		Willow Island		Spring Creek	8	11,586	1.33	8.0	179.02	\$ 41.48					-										
Sub-Total						9,407									10,529										
Total						29,719									26,621										
Total ex Colstrip						23,341									19,992										
11/16/2008 15:03																									
Absaloka						8,262									6,142										
Rosebud						9,723									10,665										
Decker						6,244									4,947										
Spring Creek						6,452									7,135										

NORWEST
CORPORATION3187 - OTTER CREEK PROPERTY
SUMMARY REPORT



The data in this table is derived from FERC data. It is, from our experience, the best data available but not much audited for accuracy of reporting nor input into their database. Columns 'J' and 'T', for instance, show the delivered price per million Btus. When we subtract our best estimate of loadout, rail, and in some cases loadout to barge and barge transportation costs, the resulting FOB mine prices vary widely and are, in some cases, negative. Averaging these resulting prices, as shown at the bottom of columns 'Q' & 'W', produces apparently unrealistic FOB prices. In further work on the mine feasibility, special focus should be directed to these elements.

Note that the column titled Contract/Spot in Table 4.1 indicates whether a power plant is being supplied via contracts or spot sales. We anticipate that the new prices on expiring contracts will be increased by \$4.00 to \$7.00 per ton plus any increased rail or barge costs. The spot market sales in 2005 to Detroit Edison's lakeside plants shows an upturn of about \$5.50 per ton over 2004 spot prices.

The volume of coal shipped from Montana to the high sodium-accepting power plants is only about 20 million tpy. Careful effort developing a solid market strategy will be necessary to determine how best to nudge into this market without destroying whatever price discipline, if any, currently exists.

The second group of power plants in Table 4.1 are (or were) also served by Montana mines neighboring Otter Creek, including Rosebud, Absaloka, Decker, and Spring Creek

All these mines have been operating for many years and are experiencing higher stripping ratios in the range of 3-4:1 at Spring Creek, climbing up to 9:1 and higher at Decker. These higher strip ratios put these mines at a disadvantage with respect to Otter Creek's projected operating costs, as they each must move more waste to uncover the same amount of coal as at Otter Creek. This higher cost, however, will be offset by Otter Creek's higher capital recovery / depreciation costs.

SYNFUEL PLANTS

Another important potential market for GNP coal is synthetic fuels. Very few properties contain such a huge coal reserve and at such an attractive stripping ratio (less than 3:1). Otter Creek could be considered an ideal property for a large scale synfuel plant.

This would probably entail attracting a large energy company with adequate financial capability to construct a mine mouth conversion plant at Otter Creek. Companies like Shell Oil, ConocoPhillips, Chevron-Texaco and ExxonMobil fit this profile. They would possibly be attracted by the large reserve base of Otter Creek.

TRANSPORTATION

At present there are no established transportation links to the Otter Creek property. Barring more rapid than anticipated construction of the Dakota Minnesota & Eastern railway, the product coal would likely get to market by rail or truck/rail.

RAIL

Sized product coal would be loaded at the mine into trains which would travel via a rail spur to the line at Colstrip, located about 38 rail miles distant. From Colstrip the trains would continue on to their final destination, a power plant among those shown in the prior figure and table. This alternative would require the construction of:

- Typical coal crushing, storage and loadout facilities at the mine to accommodate 12,000-ton unit trains
- A 38-mile rail spur from the mine to Colstrip to connect to the mainline.

Normally, the construction cost of the spur would be funded by the BNSF with the cost then rolled into the freight tariff. Alternatively, the construction cost could be funded by the mining company(ies) who should receive a corresponding (slight) tariff reduction to cover the railroad's avoided capital cost. The construction cost of the rail spur to Colstrip is estimated to be about \$78 million⁴.

Working on the assumption that the construction would be funded by the railroad, we estimate the freight rate to be 21 mills per ton/mile for a hypothetical 600 haul to the nearest power plant. The freight cost for the 600 mile journey would cost optimistically about \$12.60/ton.

TRUCK/RAIL

Sized product coal would be loaded at the mine into trucks which would travel about 50 miles on existing highways (including the towns of Ashland and Lame Deer) to the nearest access point to the mainline at Colstrip where the coal would be transferred onto

⁴ Based on the work performed by TransSystems Corporation (included in the "Tongue River Feasibility Report" prepared by Resource Data International, dated October 1997). Norwest escalated the 1997 capital cost estimates by 2.5% per year.

trains for the final leg to the recipient power plant. This alternative is more complex and would require the construction of:

Coal crushing, storage and loadout facilities at the mine to accommodate the loading of highway trucks with capacity of about 40 tons.

Truck unloading, storage and loadout facilities at Colstrip to accommodate the loading of unit trains.

The construction cost of the unloading, storage and loadout facilities at Colstrip is estimated to be between \$5-10 million. Assuming a work schedule of 350 working days per year, 24 hours per day, about 30 trucks per hour would be needed to move the production of 10 million tons per year. This is equivalent to one loaded truck every two minutes.

The budget trucking rate for the 50-mile haul to Colstrip is \$0.16/ton mile⁵. Therefore, the cost of the leg to Colstrip would be about \$6.40/ton. The balance of the 600 mile journey would cost \$11.87/ton for a total of \$18.27/ton delivered to the power plant.

CONCLUSION

Norwest does not believe that trucking the coal to Colstrip is a viable option for the following reasons:

Unacceptable Environmental and Social Impacts

As stated above, a loaded truck would pass through the communities of Ashland and Lame Deer about every two minutes. However, every two minutes an empty truck would also pass through the towns. This means that, on average, a coal truck would pass through the towns every minute of the day and night.

Norwest believes the impacts of this traffic on local schools and other aspects of the communities would be unacceptable and that approvals would not be granted.

⁵ Provided on September 29, 2005 by Mr. Ken Moizer, Sales Director, Savage Industries, a coal transportation company.

Unattractive Economics

The higher road transportation cost (\$5.67/ton) results in a yearly penalty of about \$56.7 million which means that the \$77 million capital cost of the rail spur (plus the \$5-10 million cost of the additional facilities at Colstrip) would be offset in less than two years.

APPENDIX 7

BEFORE THE
INTERSTATE COMMERCE COMMISSION

FINANCE DOCKET

TONGUE RIVER RAILROAD COMPANY;
CONSTRUCTION AND OPERATION
OF AN ADDITIONAL RAIL LINE FROM ASHLAND TO DECKER, MONTANA

FINANCE DOCKET NO. 30186 (Sub-No. 2)

VERIFIED STATEMENT OF
NORMAN H. BARTHLOW
MANAGER, FUEL SUPPLY, DETROIT EDISON

David M. Schwartz
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Attorneys for Applicant
Tongue River Railroad Company

Due Date: April 29, 1992



Norman H. Barthlow
Manager
Fuel Supply

2000 Second Avenue
Detroit, Michigan 48226
(313) 237-8000

April 23, 1992

Mr. Thomas E. Ebzery
c/o Sullivan & Worcester
Suite 806
1025 Connecticut Avenue, NW
Washington, DC 20036

Dear Tom,

This letter is to serve as an expression of our interest in the Tongue River Railroad extension and as such may be used as a Verified Statement.

My name is Norman H. Barthlow and I serve as Manager of Fuel Supply for The Detroit Edison Company. Detroit Edison is an investor owned utility serving approximately 7,600 sq. miles in the Southeastern Michigan area. It is a major coal consuming utility with more than half of its coal tonnage coming from the Powder River Basin. During 1991, Detroit Edison and its subsidiary purchased approximately 13 million tons of Powder River Basin coal.

Detroit Edison is in support of the Tongue River Railroad Road extension application (Finance Document No. 30188 - Sub No. 2).

Speaking on behalf of the Company, we feel that it is in our best interest to have the Tongue River Railroad in operation because it provides a shorter route for the delivery of Powder River Basin coal to its facilities.

The Powder River Basin coal that Detroit Edison consumes meets the 1990 Clean Air Act when it is burned exclusively. It also allows the use of other coals in a blend to meet the clean air requirements. As a consequence, Powder River Basin coal is attractive to coal consuming facilities now and in the future. In addition, the transportation options provided by the Tongue River Railroad, assuming the economic savings, should enhance the demand for this economic and environmentally acceptable coal.

Sincerely,

Notarized by:

Helen A. Bobowski

cc: V. Wood

HELEN A. BOBOWSKI
Notary Public, Wayne County, MI
My Commission Expires June 27, 1994

APPENDIX 8

Part II
TRRC No.: 2
Witness: Ethen

BEFORE THE
INTERSTATE COMMERCE COMMISSION

FINANCE DOCKET

TONGUE RIVER RAILROAD COMPANY;
CONSTRUCTION AND OPERATION
OF AN ADDITIONAL RAIL LINE FROM ASHLAND TO DECKER, MONTANA

FINANCE DOCKET NO. 30186 (Sub-No. 2)

VERIFIED STATEMENT OF
JOHN ETHEN, PRESIDENT
MIDWEST ENERGY RESOURCES COMPANY

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Attorneys for Applicant
Tongue River Railroad Company

Due Date: April 29, 1992

MIDWEST ENERGY RESOURCES COMPANY

Superior Midwest Energy Terminal
P.O. Box 787
Superior, Wisconsin 54880
Telephone: (715) 392-9807
Facsimile: (715) 392-9137



Subsidiary of
Detroit Edison
2000 Second Ave.
Detroit, MI 48226

April 23, 1992

Thomas E. Ebzery
c/o Sullivan & Worcester
Suite 806
1025 Connecticut Avenue, NW
Washington, DC 20036

RE: Finance Document No. 30186 (Sub. No.2)
Tongue River Railroad Company
Rail Construction and Operation

Dear Mr. Ebzery:

Midwest Energy Resources, Inc. ("Midwest"), a subsidiary of Detroit Edison Company, owns and operates a rail to water terminal in Superior, Wisconsin, for transfer of western coal to lake vessels for delivery to various Great Lakes ports. Midwest transferred in excess of 11 million tons of Powder River Basin coal in 1991 and, if demand warrants, is planning to expand the terminal to handle 20 million tons annually to meet future low sulfur coal demand. Detroit Edison, Midwest's parent company, owns and maintains approximately 1500 rail cars used for the shipment of such coal.

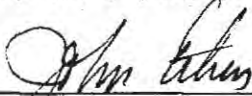
Midwest strongly supports the above Tongue River Railroad Application and urges ICC approval. The Tongue River Railroad would provide rail service to the vast underdeveloped low sulfur coal reserves along the Tongue River Valley in southeastern Montana which will be needed in meeting domestic energy needs in an environmentally advantageous and economic manner. At least some of the coal produced from these reserves could and likely would move through Midwest's Terminal to Detroit Edison and other utilities. Moreover, the proposed extension would reduce the rail mileage between existing mines in the Decker area on the current rail route through Huntley, Montana, to Midwest's Terminal, resulting in increased efficiencies, decreased diesel fuel consumption, and reduced rail transportation costs for the benefit of all ultimate consumers. Savings will also include the utilization of fewer coal cars to handle increased volumes due to the improved cycle time performance that will result from the more direct routing.

In summary, this proposed rail line would have a direct cost benefit to millions of electric energy customers and industry in the Upper Midwest and Great Lakes regions and provide a more cost effective means in meeting or exceeding the 1990 Clean Air Act. Again, Midwest requests ICC approval as quickly as possible for the construction and operation of the Tongue River Railroad extension.

Thomas E. Ebzery
April 23, 1992
Page 2

Thank you for this opportunity to respond.

Very truly yours,



John Ethen
President

Subscribed and Sworn to before me
this 23rd day of April, 1992.


Notary Public

kjl