REPORT OF THE SPECIAL RECLAMATION FUND ADVISORY COUNCIL

January 31, 2012

EXECUTIVE SUMMARY

The Special Reclamation Fund Advisory Council (the "Council") was established by the Legislature in 2001 in order to ensure the effective, efficient and financially stable operation of the Special Reclamation Fund (the "Fund"). (W.Va. Code § 22-1-17). The Fund is designated by the Legislature for the reclamation and rehabilitation of lands subject to permitted surface mining operations and abandoned after 1977, where the bond posted is insufficient to cover the cost of reclamation. The Special Reclamation Water Trust Fund was created "for the purpose of assuring a reliable source of capital to reclaim and restore water treatment systems on forfeited sites." (W.Va. Code § 22-3-11).

The Secretary of the Department of Environmental Protection is required to conduct formal actuarial studies every two years and conduct informal reviews annually on the Special Reclamation Fund and Special Reclamation Water Trust Fund.

The Fund is presently funded by a tax of 14.4 cents per ton of clean coal mined in West Virginia. From this revenue, funds based on a tax rate of 1.5 cents per ton are being paid into the Special Reclamation Water Trust Fund, while coal tax revenues based on 12.9 cents per ton are being paid into the Special Reclamation Fund. According to W.Va. Code § 22-3-11, "Beginning with the tax period commencing on July 1, 2009, and every two years thereafter, the special reclamation tax shall be reviewed by the Legislature to determine whether the tax should be continued: *Provided,* That the tax may not be reduced until the Special Reclamation Fund and Special Reclamation Water Trust Fund have sufficient moneys to meet the reclamation responsibilities of the state established in this section."

The Council is also required to make a report to the Legislature every year on the financial condition of the Fund. (W.Va. Code § 22-1-17). The report is to include: "A recommendation as to whether or not any adjustments to the special reclamation tax should be made considering the cost, timeliness and adequacy of bond forfeiture reclamation, including water treatment [and] A discussion of the council's required study issues."

In accordance with the statutory requirements, the Council submits the following:

1. **Recommendation**: Based upon the current status of the fund, as determined by the most recent actuarial analysis (the "Actuarial Valuation of the Special Reclamation Fund and Special Reclamation Water Trust Fund" conducted by Pinnacle Actuarial Resources, dated January, 2012) (the "Actuarial Valuation"), the unanimous recommendation of the Council is that the special reclamation tax remain at the present 12.9 cents per ton of coal, dedicated to the Special Reclamation Fund (SRF), and that the special reclamation tax be increased to 15 cents per ton of coal, dedicated to the Special Reclamation Water Trust Fund (SRWTF), for a total tax of 27.9 cents per ton. The Council believes that this incremental approach, as recommended by the Actuary, to achieve a projected fully funded status in the SRWTF, is a valid approach due to the need to continue to update actual costs, future forfeiture rates and the coal production from currently issued permits. This ongoing collection of new information allows for the various estimates and assumptions to be tested.
2. **Study issues**: Pursuant to W.Va. Code §22-1-17, the Council is also required to "Identify and define problems associated with the special reclamation

fund." The Council conducted a range of studies during 2011 to better assess the current and future financial condition of the funds:

a. Actuarial Valuation of the Special Reclamation Fund & Special Reclamation Water Trust Fund by Pinnacle Actuarial Resources, Inc.
b. Consensus Coal Production and Price Forecast for West Virginia: 2011 Update by Dr. George Hammond of West Virginia University Bureau of Business and Economic Research.
c. Development of Data Fields to Support Actuarial Analysis by Christine Risch of Marshall University Center for Business and Economic Research (CBER).
d. Decision Tree for Optimizing AMD Treatment at Special Reclamation Sites by Dr. Paul Ziemkiewicz of West Virginia University Water Research Institute (WRI).
e. Natural Attenuation of Major Mine Drainage Pollutants by Dr. Paul Ziemkiewicz of West Virginia University Water Research Institute (WRI).
f. Alternative Enforcement Evaluation by DEP.

Findings of these studies are outlined in the body of the report.

The Council recommends that the Legislature continue to examine the implications of the recent court rulings and subsequent lawsuit settlements on the Special Reclamation Fund, Abandoned Mine Lands, and voluntary efforts by citizen-led watershed groups to address historic mining-reclamation related liabilities. The Council further recommends that the

Legislature examine the mine reclamation and bonding programs of other states and as implemented in Tennessee by the federal Office of Surface Mining in order to determine if the statute and regulations creating the SRF and SRWTF in West Virginia have inappropriately structured SMCRA to assume long-term CWA liabilities. The Council further recommends the Legislature examine the separate and distinct authorities of the Clean Water Act (CWA) in assessing the eligibility of future forfeitures for transfer of liabilities to the SRWTF. The Council is concerned about default transfer of water treatment liability to the SRWTF when opportunities exist to pursue responsible parties under the CWA per the requirements of an NPDES (CWA Section 402) permit.

Background on the Special Reclamation Fund

Article 1, Chapter 22 of the Code of West Virginia was amended by the West Virginia Legislature in 2001, creating an eight member Special Reclamation Fund Advisory Council (the "Council") with the responsibility of ensuring the effective, efficient and financially stable operation of the Special Reclamation Fund. The legislation establishing the Council also increased the tax on clean coal mined in West Virginia, from three to seven cents per ton (the "Continuing Tax"), and levied an additional seven cents per ton (the "Temporary Tax"), to be deposited into the Fund. The revenues of the Fund were designated to pay for reclamation on post-1977 bond-forfeited sites.

The 2001 legislation provided for the Temporary Tax to be in effect for thirty-nine months. As a result of a 2005 actuarial report finding that the expiration of the Temporary Tax would result in nearly immediate insolvency of the fund, the Temporary Tax was extended by the Legislature in 2005, for an additional eighteen months. A 2007 actuarial study commissioned by the Council found that the failure to extend the Temporary Tax again would result in insolvency for the Fund. Accordingly, in 2008 the Legislature, through SB 751, enacted a temporary, twelve month tax of 7.4 cents to be allocated between the Fund and a Special Reclamation Water Trust Fund (the "SRWTF.") An updated actuarial study in 2008 concluded that terminating the tax would result in insolvency within a few years. In response, in the 2009 legislative session, the Legislature amended W.Va. Code § 22-3-11 to remove the expiration date for the Temporary Tax and provided instead for biennial review of the Tax by the Legislature. (Acts of the Legislature 2009, chapter 216).

Membership Status of the Special Reclamation Fund Advisory Council

On June7, 2011, Christine Risch, Marshall University, Center for Business and Economic Research, was appointed to the SRFAC serving as the Actuary/Economist member. Carolyn Atkinson serves as the member representing the Treasurer of the State of West Virginia. Dr. Paul Ziemkiewicz serves as the member representing the Director of the National Mine Land Reclamation Center at West Virginia University. Bill Raney serves as the member representing the interests of the coal industry. John Morgan serves as the member representing the interest of environmental protection organizations. Ronald Pauley serves as the member representing the interests of coal miners. The SRFAC member representing the interests of the general public is currently vacant.

FINANCES OF THE SPECIAL RECLAMATION FUND

This section of the Report to the Legislature outlines the financial status of the Special Reclamation Fund for calendar year 2011 and provides comments regarding the future financial position of the fund. The three key factors that have the most effect on the adequacy of the Special Reclamation Fund are the coal production levels in West Virginia, the risk of future forfeitures, and the cost of reclaiming existing and future bond-forfeited sites.

To summarize the data and analysis that follow, it should be noted that the Special Reclamation Fund (SRF) will cover all costs for both land reclamation and water treatment through June 2018. Starting in July 2018, the Special Reclamation Water Trust Fund (SRWTF) will begin covering the cost for water treatment—both water capital costs and ongoing water treatment costs. The SRF is presently solvent and the funded status is projected by the 2011 Actuarial Valuation to be over 100 percent funded using a 20-year cash flow basis and 97 percent funded using a 35-year cash flow basis. The SRWTF is currently accumulating 1.5 cent per ton coal tax revenue and interest, and is projected by the 2011 Actuarial Valuation to be 18 percent funded using a 20-year cash flow basis and 9 percent funded using a 35-year cash flow basis. Since 2001, despite a very aggressive reclamation schedule, the SRF and SRWTF have been serving the people of West Virginia well through providing for the reclamation of bond-forfeited sites. At the time of the initial legislation in 2001, there were 392 forfeited permits requiring reclamation, including some requiring water treatment. Since passage of that legislation, an additional 161 permits have forfeited as well, bringing the total to 553 permits requiring reclamation. Of those, work has been completed on 419 permits. With regard to water treatment, the Fund is treating water at 128 sites and has an additional 72 sites under review or construction; 76 sites have been determined to have no conditions requiring treatment, or have completed treatment. As of September 30, 2011, the Special Reclamation Fund had accumulated assets of $68.6 million while the Special Reclamation Water Trust Fund had accumulated $8.7 million in assets.

The Council finds that, based upon projections under the 2011 Actuarial Valuation performed by Pinnacle Actuarial Resources, LLC the SRF is sufficiently funded under the current 12.9 cent tax dedicated to the SRF. However, the Council is concerned that, based upon projections under the 2011 Actuary Valuation, as the SRWTF begins making payments for water capital and ongoing water treatment in Fiscal Year 2019, as currently projected, "the SRWTF will fall into a deficit position in the second year of operation-2020." (Actuarial Valuation, page 3). Declining coal production projected by the 2011 Consensus Coal Production Forecast, and the significant increase in water treatment costs resulting from court rulings in two cases, are contributing factors in the projected insolvency of the SRWTF.

Graphic summaries of the status of the Funds as well as potential future concerns are outlined in the following figures. First, historical revenues are presented. Cash flow projections are included in the attached Pinnacle Actuarial Valuation.

The SRF cash flow projection presents the basis for the positive outlook regarding the long-term adequacy of the SRF. However, the SRFWTF cash flow projection shows that the SRWTF will fall into a deficit position in the second year of operation. The status of the SRWTF is the basis of the Advisory Council's recommendations in this year's Report.

Closed Actuarial Valuation

The Council believes it is important to note that this Actuarial Valuation is a "closed" valuation in that it only considers liabilities associated with permits that have already been issued. The estimated Funds' liabilities account for both known forfeitures and anticipated forfeitures from permits issued before July 1, 2011. Similarly, the revenue projections limit the expected coal tax revenues to the portion of the total expected coal tax revenues that are attributable to the permits issued prior to July 1, 2011.

Pinnacle prepared a measurement of current liabilities and assets in accordance with the guidance set out in Governmental Accounting Standard Number 10, an excerpt of which is:

State and local governmental entities other than public entity risk pools are required to report an estimated loss from a claim as an expenditure/expense and as a liability if both of these conditions are met:

a. Information available before the financial statements are issued indicates that it is probable that an asset had been impaired or a liability had been incurred at the date of the financial statements. It is implicit in this condition that it must be probable that one or more future events will also occur, confirming the fact of the loss.

b. The amount of the loss can be reasonably estimated.

It is Pinnacle's position that the Fund should provide for liabilities on existing permits that may come under the responsibility of the fund. Permits that have not yet been issued are not the responsibility of the Fund until they become issued. While an "open" study may provide some interesting information, it is not relevant in defining a liability as of a certain date.

The actual revenues to the Fund in future years will be a combination of receipts from permits issued prior to July 1, 2011 and those issued afterwards.

The future balance of the Fund is dependent on both the forfeiture rate of the currently issued permits and the prospective forfeiture of permits issued after July 1, 2011 combined with the tax revenue from all active and future permits.

Water Treatment Funding

The current main funding mechanism for bond-forfeited sites is the 14.4 cent tax per ton of clean coal mined. In 2008, the Legislature authorized, but did not separately fund, the Special Reclamation Water Trust Fund ("SRWTF"). In reliance on the SRWTF statutory authorization, beginning in July 2008, coal tax revenues based on a tax rate of 1.5 cents per ton are being paid into the SRWTF. In addition, coal tax revenues based on 12.9 cents per ton are being paid into the SRF. Unless modified in response to future legislation, for budgeting and analysis purposes the DEP plans to continue paying all costs for both land and water reclamation work out of the SRF through FY 2018. Funding the water reclamation and treatment from the SRF will allow the SRWTF to build up assets, although it is not anticipated to be solvent without future continuing funding. The Council is continuing to look at alternatives for water treatment funding. The current balance in the SRWTF is $8.7M as of September 30, 2011. The projections from the 2011 Actuarial Valuation (p.24) show that a dedicated revenue of 20.56 cents per ton of coal would result in solvency for the SRWTF under this scenario through the year 2046. However, the Actuarial Valuation does “suggest an incremental approach toward the adequacy target be taken to allow the various estimates and assumptions to be tested”.

Figure 1

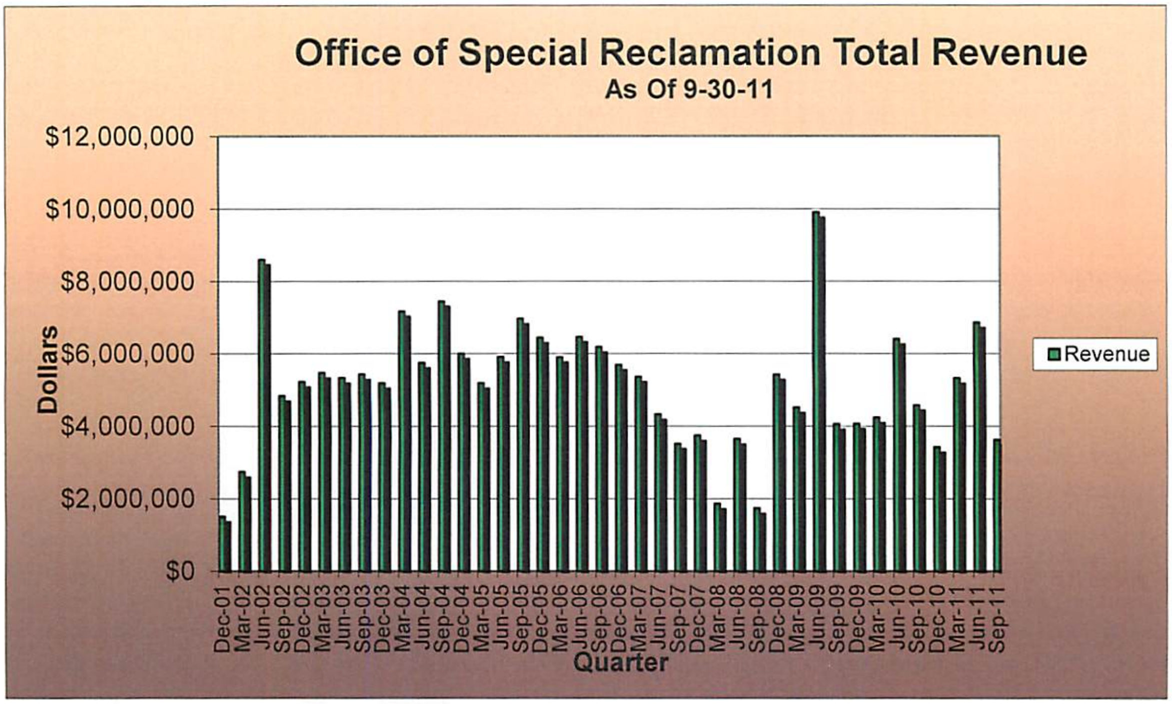


Figure 2

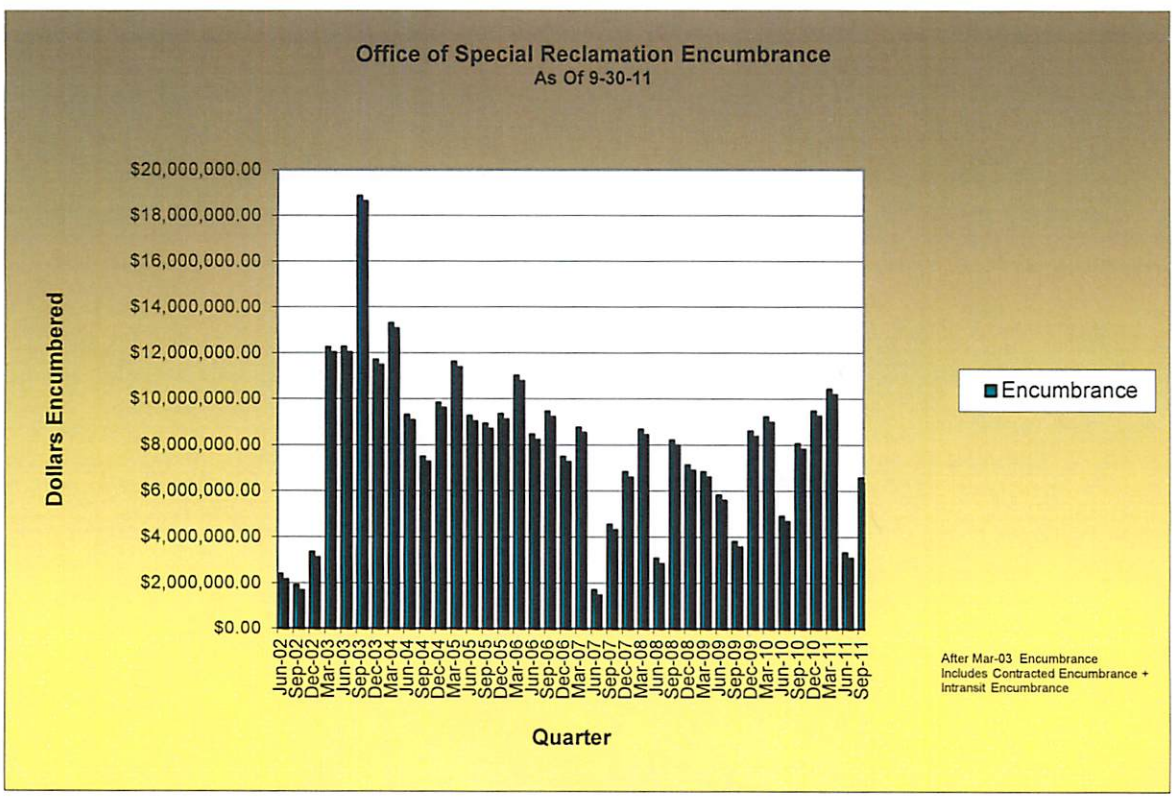
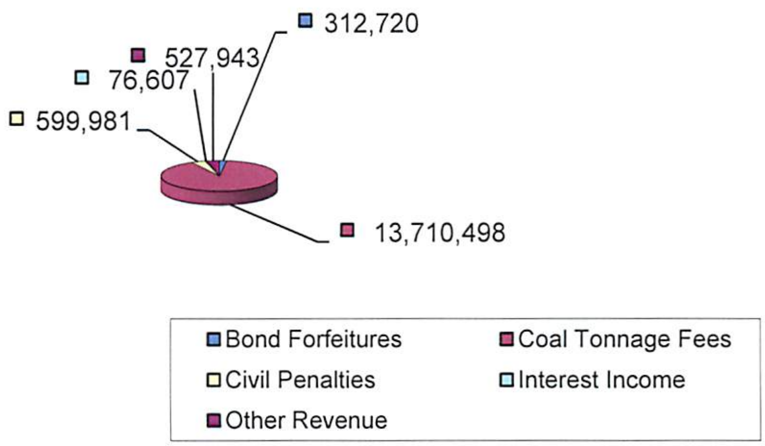


Figure 3. Revenue Sources



Study Issues

1. The SRF through FY 2018 and the SRWTF starting in FY 2019 has acquired liability for additional water treatment as a result of lawsuits filed against the DEP, as described below.

Identical complaints were filed in the Northern and Southern District Courts, Civil Actions No. 07-cv-87 (the "Northern District Case") and No. 2:07-0410 (the "Southern District Case"), assigned to Judge Irene Keeley and Judge John T. Copenhaver, Jr., respectively. Both cases were styled *West Virginia Highland Conservancy and West Virginia Rivers Coalition v. Randy C. Huffman, Secretary, West Virginia Department of Environmental Protection.*

The two suits alleged that the West Virginia Department of Environmental Protection (DEP) had violated, and continues to violate, the federal Clean Water Act (the Act) by failing to obtain West Virginia National Pollutant Discharge Elimination System (WV/NPDES) permits when the Division of Land Restoration reclaims and treats water at bond forfeited sites as directed by state law. The Northern District Case named 18 specific bond forfeited sites and the Southern District Case named 3 sites.

On March 26, 2009, the Northern District Court entered summary judgment in favor of Plaintiffs in the Northern District Case, and granted a permanent injunction. The injunction requires DEP to apply for, process, and issue WV/NPDES permits to itself for the discharge into waters and streams of pollutants from the eighteen bond-forfeited, coal mining sites at issue in the case, whose reclamation the agency is required to manage. DEP appealed this decision to the United States Court of Appeals for the Fourth Circuit ("Fourth Circuit Court of Appeals"). By order dated November 8, 2010, the Fourth Circuit Court of Appeals affirmed the Northern District Court's ruling.

Similarly, a motion for summary judgment in the Southern District Case was granted by Order dated August 24, 2009. The Southern District Court found that the Secretary of the DEP was "in violation of the National Pollutant Discharge Elimination System permitting requirements of the Clean Water Act." The Southern District Court ordered the Secretary to "apply for, and obtain, NPDES permits for all sites at issue in this action," and the parties subsequently submitted a joint stipulation agreeing to the same injunctive relief and timeframes for compliance set forth in the Northern District litigation. The Southern District Court entered final judgment August 31, 2010.

On January 11, 2010, the same Plaintiffs (West Virginia Highlands Conservancy and West Virginia Rivers Coalition) and the Sierra Club submitted a letter giving DEP notice of their intent to sue DEP regarding discharges from 131 additional bond forfeited sites on the same legal basis as the previous suits. Based on the outcome of the previous litigation, DEP engaged in settlement negotiations with the Plaintiffs and reached agreement regarding the permitting of the 21 sites in the previous litigation and the additional 131 sites. In August 2011, the Plaintiffs filed two new suits regarding the additional sites, *West Virginia Rivers Coalition, et al v. Huffman*, Civil Action No. 1:11-cv-118 (N.D. W.Va.), and *West Virginia Rivers Coalition, et al v. Huffman*, Civil Action No. 2:11-cv-524 (S.D. W.Va.), and lodged a proposed Consent Decree with both courts. The Northern District Court entered the Consent Decree on October 12, 2011. The Southern District Court has not yet entered the Consent Decree. A list of all bond forfeited sites at issue in all four suits is attached to the Consent Decree as Attachment A.

The Consent Decree resolves all four suits filed by the Plaintiffs regarding bond forfeited sites. The Consent Decree requires DEP to obtain WV/NPDES permits for all 21 bond forfeiture sites cited in the initial litigation by September 1, 2011. Thereafter, DEP will issue draft WV/NPDES permits for 50 additional sites by the end of each calendar year, beginning in 2012. The Consent Decree requires DEP to issue draft WV/NPDES permits for all bond forfeited sites listed in Attachment A to the Consent Decree by December 31, 2015. As required by the Consent Decree on December 1, 2011, DEP submitted a Treatment Cost Report to Plaintiffs and SRFAC, in which DEP determined the capital cost and annual operating and maintenance costs for water discharges from each bond forfeiture site to meet applicable water quality based effluent limitations. The DEP estimates these costs will amount to $33.1 million for one-time capital construction costs and $6 million in annual operations and maintenance costs.

Further, a third case presents potential for future litigation, should the legislature not adequately fund the SRF and SRWTF. *West Virginia Highlands Conservancy v. Secretary Salazar, DOI*, Civil Action No. 2:00-1062 (S.D. W.Va.). The West Virginia Highlands Conservancy (WVHC) had filed a motion with the U.S. District Court for the

Southern District of West Virginia to reopen the case and schedule further proceedings on the grounds that the recommendations of the Special Reclamation Advisory Council were not being followed with regard to funding the Special Reclamation Fund. Based upon the Legislature's extension of funding through the Continuing and Temporary taxes, the case was placed on the court's inactive docket as of May 2008; however, the court allowed the possibility of a renewed motion if the Legislature does not continue to provide sufficient monies for the Fund to remain solvent.

In March 2011, the WVHC moved once again to have the litigation reopened alleging continuing problems with the Fund. A status conference was held on August 5, and the court ordered the filing of a joint status report. On August 25, 2011, the WVHC and the Defendants filed a joint status report with the court. The WVHC stated that the court should not delay reopening the case until the new actuarial report and Advisory Council recommendations are issued, whereas the Defendants recommended that it was premature for the court to reopen this matter prior to the close of the 2012 legislative session.

2. Actuarial Valuation of the Special Reclamation Fund & Special Reclamation Water Trust Fund by Pinnacle Actuarial Resources, Inc.

While in many respects the 2011 analysis is similar to the analysis performed in 2010, there are a number of changes to key assumptions included in this year's analysis.

- Release and Forfeiture rates - based upon a review of the actual experience of permits in West Virginia since 1977, we developed revised expected release and forfeiture rates from those used in prior studies. Anticipated future forfeiture rates are now developed and applied by calendar year rather than based upon the year the permit was issued.
- Investment and Discount rates – we based the expected future investment returns and discount rates upon the most recent United States Treasury rates for short and long term durations.
- Expected land reclamation costs – future costs were based upon actual recent historical costs through June 30, 2011

- The future expected costs of water capital and water treatment are now based upon the costs of the currently open forfeited permits rather than the costs of the permits where the water treatment process has been completed.
- We have reflected the increased costs of water capital and water treatment necessary to achieve compliance with NPDES water quality standards. The increase costs were based upon the estimates developed by a joint effort of a team from West Virginia University and the Office of Special Reclamation.
- Based upon input from the Office of Special Reclamation, the length of time required for water treatment to achieve full compliance was increased from 17 years to at least the 35 years contemplated in our study. Thus, any water abandonment costs fall beyond the time horizon of our projections and would be in addition to the estimated costs.
- Since the costs of "Legacy Water Treatment permits" are included in the estimated costs to comply with the NPDES standards, the costs of the Legacy permits are included within the Water Treatment costs of permits forfeited prior to July 1st, 2011 rather than as a separate category.

3. Consensus Coal Production and Price Forecast for West Virginia: 2011 Update by Dr. George Hammond of West Virginia University Bureau of Business and Economic Research.

Coal production in West Virginia declined drastically in 2009. The state produced just 137.2 million short tons of coal in 2009, which was a 13.1 percent decrease from 2008. State coal production fell again in 2010, to 135.7 million tons. That was an additional 1.1 percent decline, which left state production 14.0 percent below 2008 (pre-recession) levels. The drop in state production during the past two years was likely related to a number of factors, including the economic downturn, lost production due to the Upper Big Branch mine explosion, as well as rising costs due to increasingly challenging geologic conditions and new safety regulations, a shortage of skilled workers, and increasing scrutiny of surface mine permits. Coal production in both northern and southern West Virginia decreased in 2009, but the drop was more severe in the south.

Coal production in the southern region declined to 98.8 million short tons of coal in 2009 from 116.7 million short tons in 2008. This translated into a 15.3 percent decrease in production from 2008 to 2009. Coal production also decreased in the northern region from 2008 (41.1 million tons) to 2009 (38.4 million tons), which was a 6.6 percent decline. Production trends within West Virginia diverged in 2010, with the northern region posting an increase of 7.9 percent, while production in the southern region declined by an additional 4.6 percent. These trends have continued into the first nine months of 2011, with northern coal production up by 8.3 percent compared to the same period in 2010. In contrast, southern coal production is up just 0.1 percent compared to the first nine months of 2010. This likely reflects a number of factors, including the loss of production due to the Upper Big Branch mine explosion, increasingly challenging geologic conditions, increasing regulatory scrutiny of surface mining permits (which primarily impacts the southern coal fields), and the impact of installation of pollution control equipment at power plants that allows the burning of higher sulfur coals produced in northern Appalachia and elsewhere.

The consensus forecast calls for state coal production to rise from 135.7 million tons in 2010 to 138.4 million tons in 2011, an increase of 2.0 percent. Rising coal production in 2011 is partly driven by strong export demand, particularly for metallurgical coal. Coal production declines in 2012 to135.8 million tons and again in 2013 to 129.5 million tons. Thereafter, coal production continues to decline through the forecast period, reaching 115.6 million tons by 2030.

4. Development of Data Fields to Support Actuarial Analysis by Christine Risch of Marshall University Center for Business and Economic Research (CBER).

MU CBER collected a data field describing ownership type classification for all open and forfeited permits. The classification defines whether a permit is publically or privately held. For forfeited permits the assignment was applied based on the permit's ownership at the time of forfeiture. This information was supplied to the actuary. The intent of the data was to provide additional information upon which to evaluate risk of forfeiture, with the assumption that publically-traded firms are less likely to forfeit. The actuary was unable

to include the information in this year's analysis because they determined that they also need that field for released permits in order to do a complete analysis. CBER is working on that data set for inclusion in the next actuarial study. The purpose of this addition will be to refine estimates of the near to mid-term adequacy of revenues received by the SRF and the SRWFT by incorporating risk based on permit ownership. As permits are increasingly held by highly capitalized firms the risk of forfeiture is expected to decline. A data field for number of permit transfers was also collected for CBER's internal analysis. This field was collected for open, closed and released permits. This data will be incorporated in a binomial analysis of the probability of forfeiture by permit.
MU CBER also provided data comparing various forecasts of annual acres forfeited to the SRF to actual acres forfeited for 2006-2010. This mini analysis allowed the Council to take a retrospective look at the short-term accuracy of one component of various actuarial forecasts.

5. Decision Tree for Optimizing AMD Treatment at Special Reclamation Sites by Dr. Paul Ziemkiewicz of West Virginia University Water Research Institute (WRI).

Every decision to build an AMD treatment system begins with development of a treatment strategy to meet water treatment objectives. There are dozens of methods for treating acid mine drainage and successful treatment systems often employ several methods in series. This study developed a decision tree for selecting mine drainage treatment methods based on site conditions and discharge water quality requirements in order to comply with the Clean Water Act. The decision tree winnows down the potential treatment options and estimates their construction cost. This project was completed in early 2011 and the decision tree was used to support DEP/OSR's planning process for estimating future water quality liabilities.

6. Natural Attenuation of Major Mine Drainage Pollutants by Dr. Paul Ziemkiewicz of West Virginia University Water Research Institute (WRI).

Legislation requires that SRFAC provides periodic actuarial studies to assess future demands on the SRWTF. Those future demands are driven by two factors that will increase the SRWTF liability: new forfeitures and new water quality treatment requirements. One factor will cause the liability to decrease: the natural attenuation of pollutants. Currently the actuarial study has no basis for estimating attenuation. Natural attenuation refers to the rate at weathering removes pollutants from mined rock. The rate of natural attenuation is likely a function of pollutant, rock type and mine type. This project is identifying the natural attenuation rates for common mine settings in West Virginia that affect the SRTF: surface mines, underground mines and refuse facilities. The project is scheduled for completion in July 2012. A search of international literature and available data from West Virginia sites indicated that the attenuation rate of sulfate, a major indicator of pyrite oxidation and TDS formation is between 2.0 and 2.5%/year. The latter value was used in the 2011 SFRAC Actuarial Report. This number will be validated by field sampling and evaluation of results from WVDEP's Discharge Monitoring Reports in 2012.

7. Alternative Enforcement Evaluation by DEP.

The DEP has begun to re-examine previous bond forfeitures to determine whether there are any persons or entities who may have liability for some or all of the Special Reclamation Fund's reclamation and water treatment costs from whom the DEP could pursue cost recovery. Initially, the DEP has identified the twenty largest Special Reclamation liabilities and referred these to OSM for assistance in investigating and identifying persons who controlled the companies which forfeited these bonds. OSM has provided the DEP with preliminary results for the first two of its investigations. The DEP has assigned legal counsel from its Office of Legal Services to review these preliminary investigations to determine whether any person/entity identified is worth pursuing. As investigations are conducted, the DEP will also be providing feedback to OSM to help OSM perform work that will be of the greatest value to the DEP.

The DEP also monitors and participates in bankruptcy proceedings of permit holders to, among other things, reduce or avoid revocation of permits that have reclamation liabilities in excess of the bond amount. By participating in a bankruptcy proceeding, DEP is sometimes able to encourage/facilitate the transfer (to a capable party) of sites with reclamation liability in excess of the bond amount. Other agency efforts in bankruptcy proceedings include filing and pursuing claims for reclamation costs and penalties, objecting to proposed sales or abandonments structured to avoid reclamation liability, collecting bonds and seeking recovery of reclamation costs, objecting to plans filed by debtors, persisting in informing those involved in the proceeding that a debtor must comply with environmental laws, and continuing to enforce environmental laws through the exercise of police powers, notwithstanding the bankruptcy "automatic stay".

Special Reclamation Fund Advisory Council Recommendations to the Legislature

Based upon conclusions drawn from information included in this report, the Council makes the following recommendations to the Legislature:

Consistent with the Actuarial Valuation recommendation to utilize an incremental approach, the Council recommends that the present 12.9 cent per ton tax dedicated to the SRF remain in force and that the tax dedicated to the SRWTF be increased to 15 cents per ton.

As a partial alternative to fully funding the SRWTF through a future increase in the tax, the Special Reclamation Fund Advisory Council recommends that, if possible, the Legislature commit a portion of excess coal severance tax or other revenues to the SRWTF, so it can begin to build value and help offset the cost of future water reclamation and ongoing treatment.

The Council recommends that the Legislature continue to examine the implications of the recent court rulings and subsequent lawsuit settlements on the Special Reclamation Fund, Abandoned Mine Lands, and voluntary efforts by citizen-led watershed groups to address historic mining-reclamation related liabilities. The Council further recommends that the Legislature examine the mine reclamation and bonding programs of other states and as implemented in Tennessee by the federal Office of Surface Mining in order to determine if the statute and regulations creating the SRF and SRWTF in West Virginia have inappropriately structured SMCRA to assume long-term CWA liabilities. The Council further recommends the Legislature examine the separate and distinct authorities of the Clean Water Act (CWA) in assessing the eligibility of future forfeitures for transfer of liabilities to the SRWTF. The Council is concerned about default transfer of water treatment liability to the SRWTF when opportunities exist to pursue responsible parties under the CWA per the requirements of an NPDES (CWA Section 402) permit.

The Council recommends an effort to investigate better returns with the State Investment Board.

The Council recommends the utilization of the model developed by Christine Risch to more effectively predict future forfeitures.

Special Reclamation Fund Advisory Council
Annual Report to the Legislature
January 1, 2012

Randy C. Huffman, Secretary DEP
Ex Officio
Designee: Ken Ellison
Director, Division of Land Restoration
601 57th Street
Charleston, WV 25304

John D. Perdue, Treasurer
Designee: Carolyn Atkinson
Assistant General Counsel
WV State Treasurer's Office
One Players Club Drive
Charleston, WV 25311

Paul Ziemkiewicz, Director
National Mine Land Reclamation Center
WVU – NRCCE Building
P.O. Box 6064
Morgantown, WV 26506

John S. L. Morgan
Morgan Worldwide
343 North Limestone Street
Lexington, Ky. 40508

Bill Raney, President
West Virginia Coal Association
Northgate Business Park
P.O. Box 3923
Charleston, WV 25339

Ronald Pauley
50 Sunset Drive
Sumerco, WV 25567

Christine M. Risch, Director of Research
Marshall University
Center for Business & Economic Research
One John Marshall Drive
Huntington, WV 25755-0003

Appendices for 2011 SRF Advisory Council Annual Report
(All Appendices as of 9-30-11)

A. **OSR Graphs:**
Total of Land and Water Permits Scheduled by Quarter
Land Permits To Be Contracted
Land Liabilities To Be Contracted
Permits Forfeited Since 6-30-01
Reclamation Projects Started Since 6-30-01
Contract Dollars Encumbered
Cash Balance
Total Revenue
Revenue by Source: Cumulative Bond Collected, Civil Penalties, Tax

B. **OSR Estimated Land Liability-WQ Capital Dollars vs. Contract Amount**

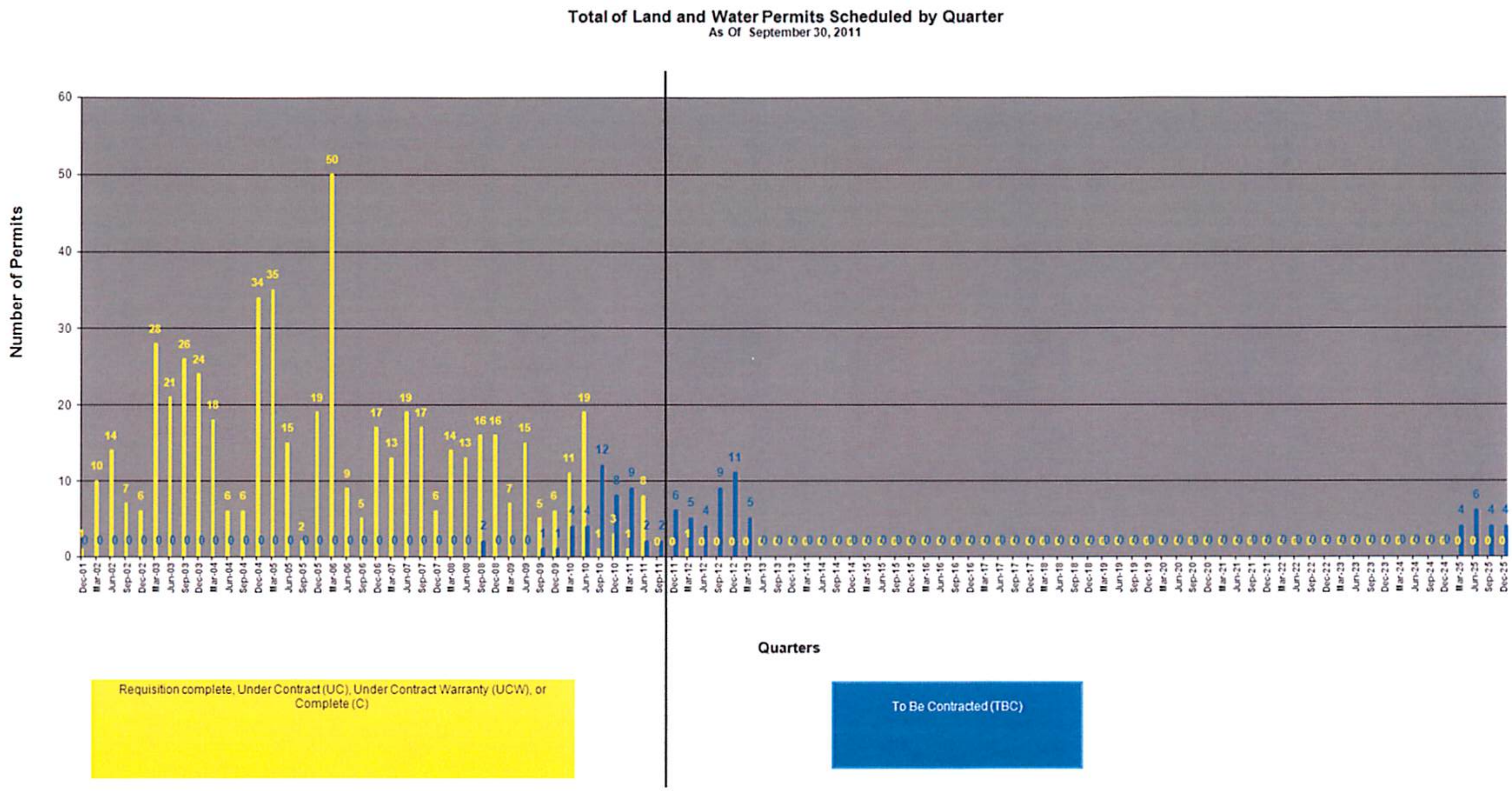
C. **Reports Commissioned by the Council**
Report for the WV Department of Environmental Protection
Office of Special Reclamation
An Actuarial Valuation of the Special Reclamation Fund and
Special Reclamation Water Trust Fund as of June 30, 2011
By Pinnacle Actuarial Resources, Inc., December 2011

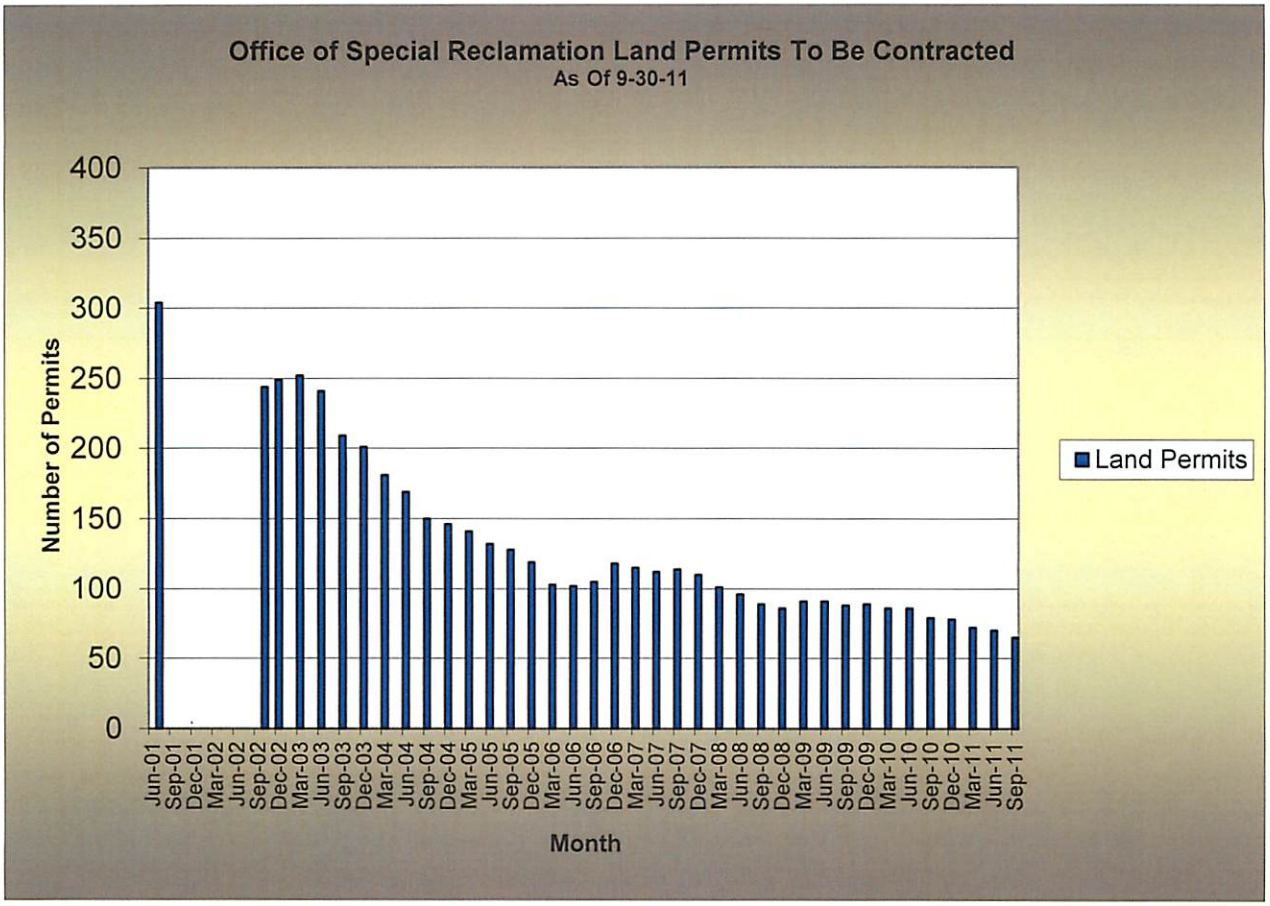
Consensus Coal Production and Price Forecast for West Virginia:
2011 Update
By George W. Hammond, Ph.D.
Bureau of Business and Economic Research,
College of Business and Economics
West Virginia University, December 2010

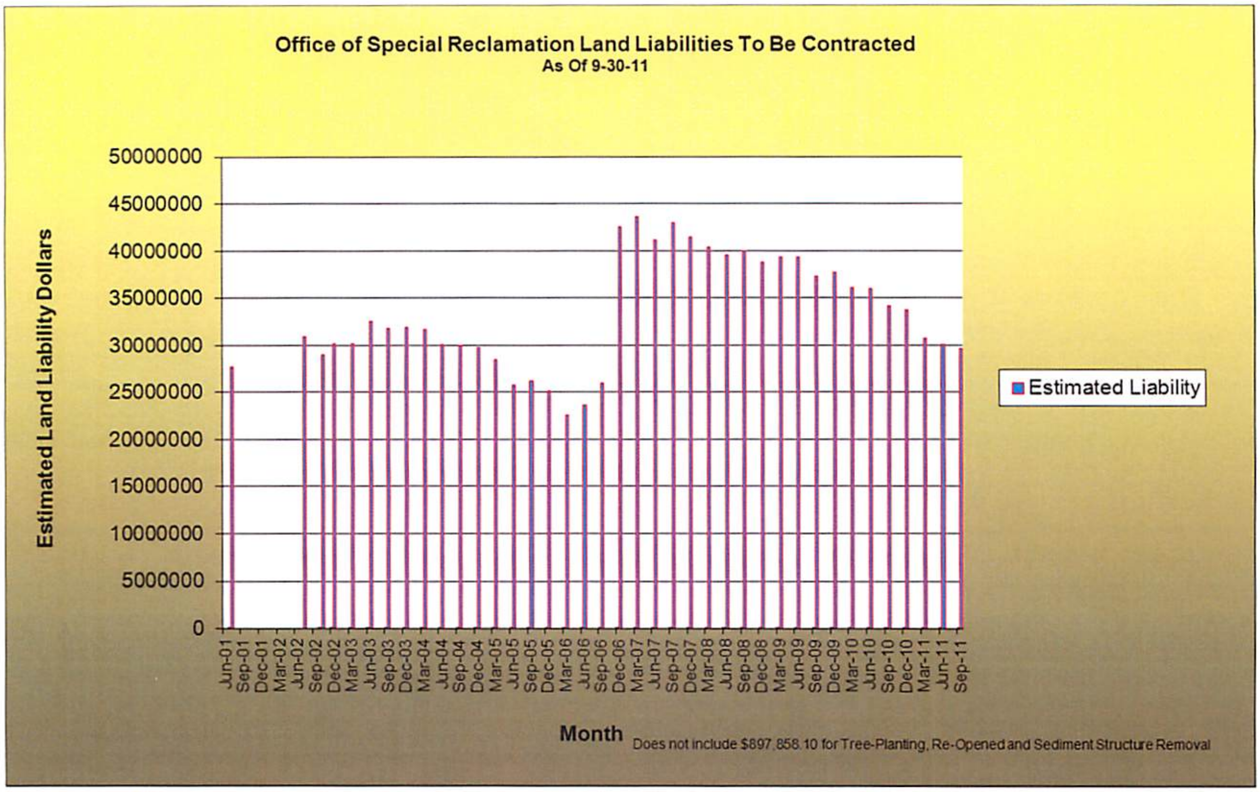
Various Reports generated by Christine M. Risch
Center for Business and Economic Research
Marshall University

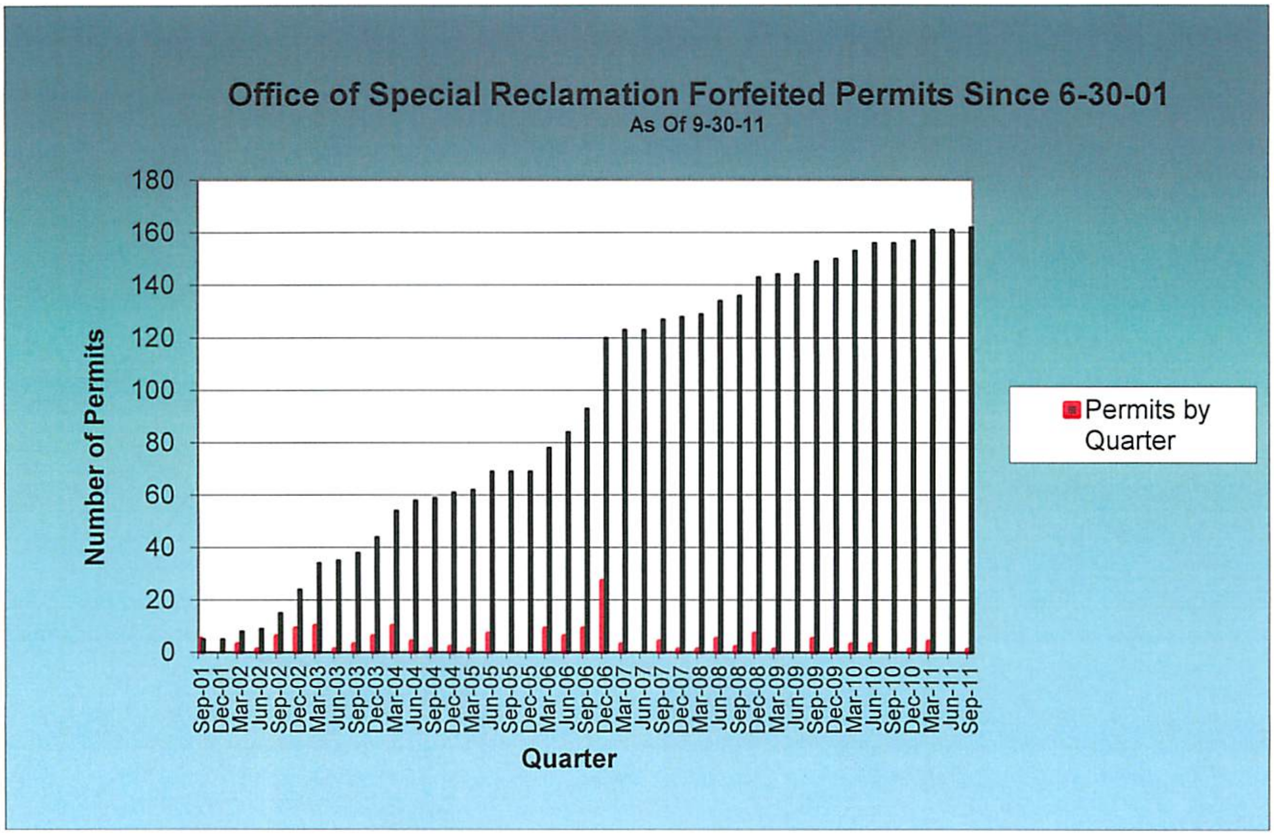
Various Reports generated by Paul Ziemkiewicz
West Virginia Water Research Institute
West Virginia University

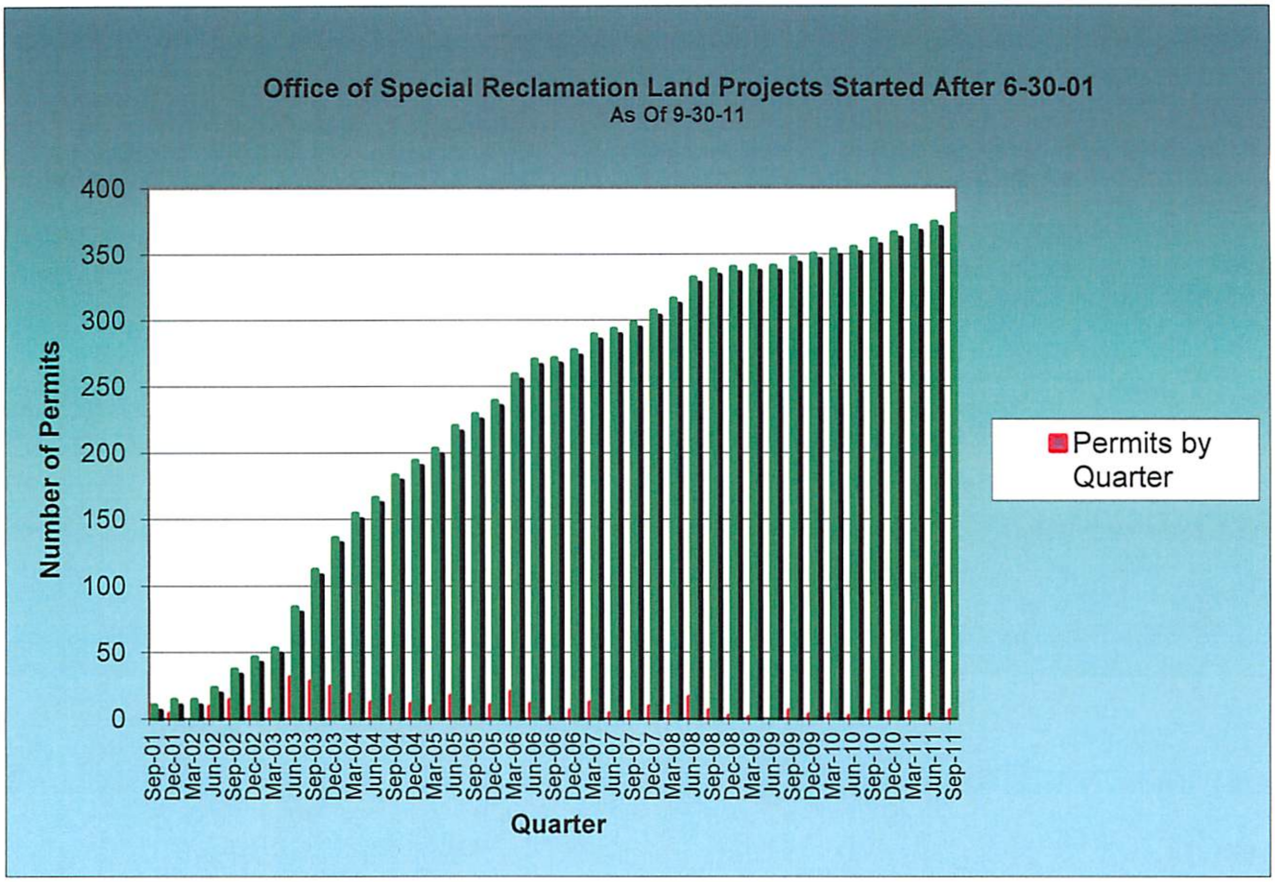
Appendix A


Total of Land and Water Permits Scheduled by Quarter
As Of September 30, 2011
Number of Permits
Quarters
Requisition complete, Under Contract (UC), Under Contract Warranty (UCW), or Complete (C)
To Be Contracted (TBC)

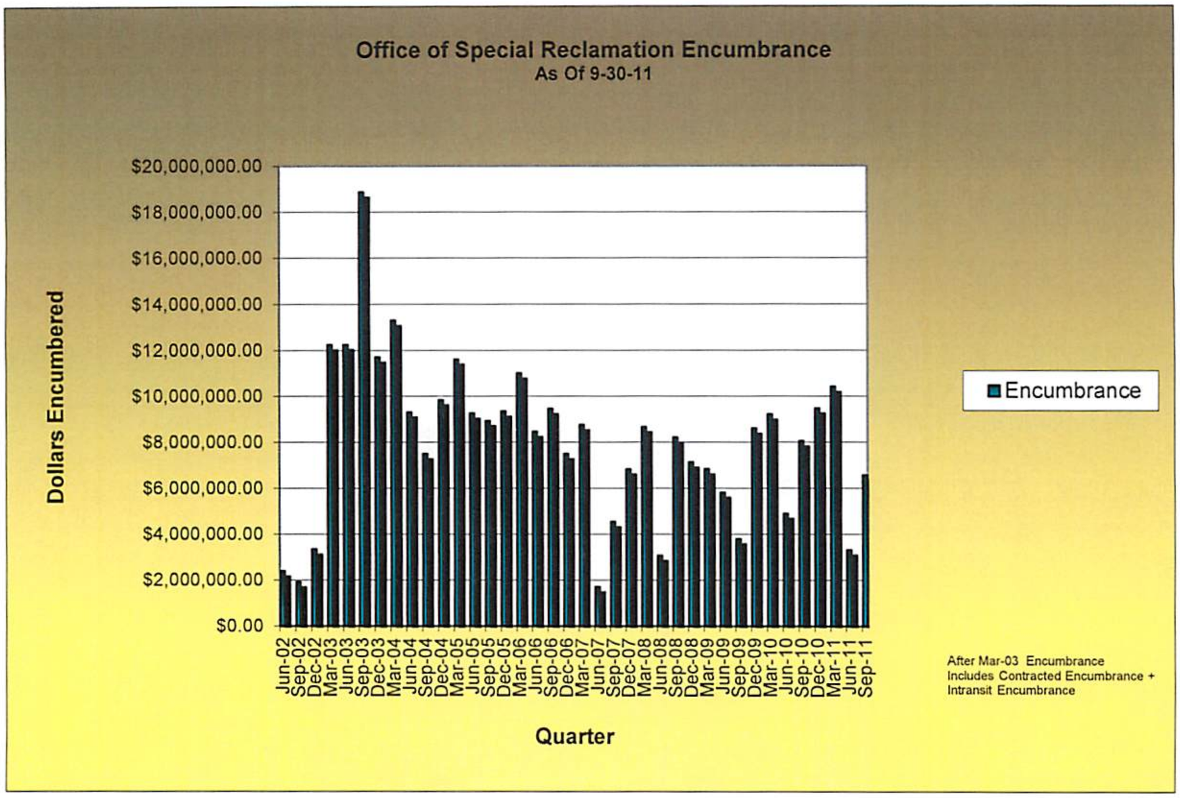

Office of Special Reclamation Land Permits To Be Contracted
As Of 9-30-11
400
350
300
250
200
150
100
50
0
Number of Permits
Jun-01
Sep-01
Dec-01
Mar-02
Jun-02
Sep-02
Dec-02
Mar-03
Jun-03
Sep-03
Dec-03
Mar-04
Jun-04
Sep-04
Dec-04
Mar-05
Jun-05
Sep-05
Dec-05
Mar-06
Jun-06
Sep-06
Dec-06
Mar-07
Jun-07
Sep-07
Dec-07
Mar-08
Jun-08
Sep-08
Dec-08
Mar-09
Jun-09
Sep-09
Dec-09
Mar-10
Jun-10
Sep-10
Dec-10
Mar-11
Jun-11
Sep-11
Month
Land Permits

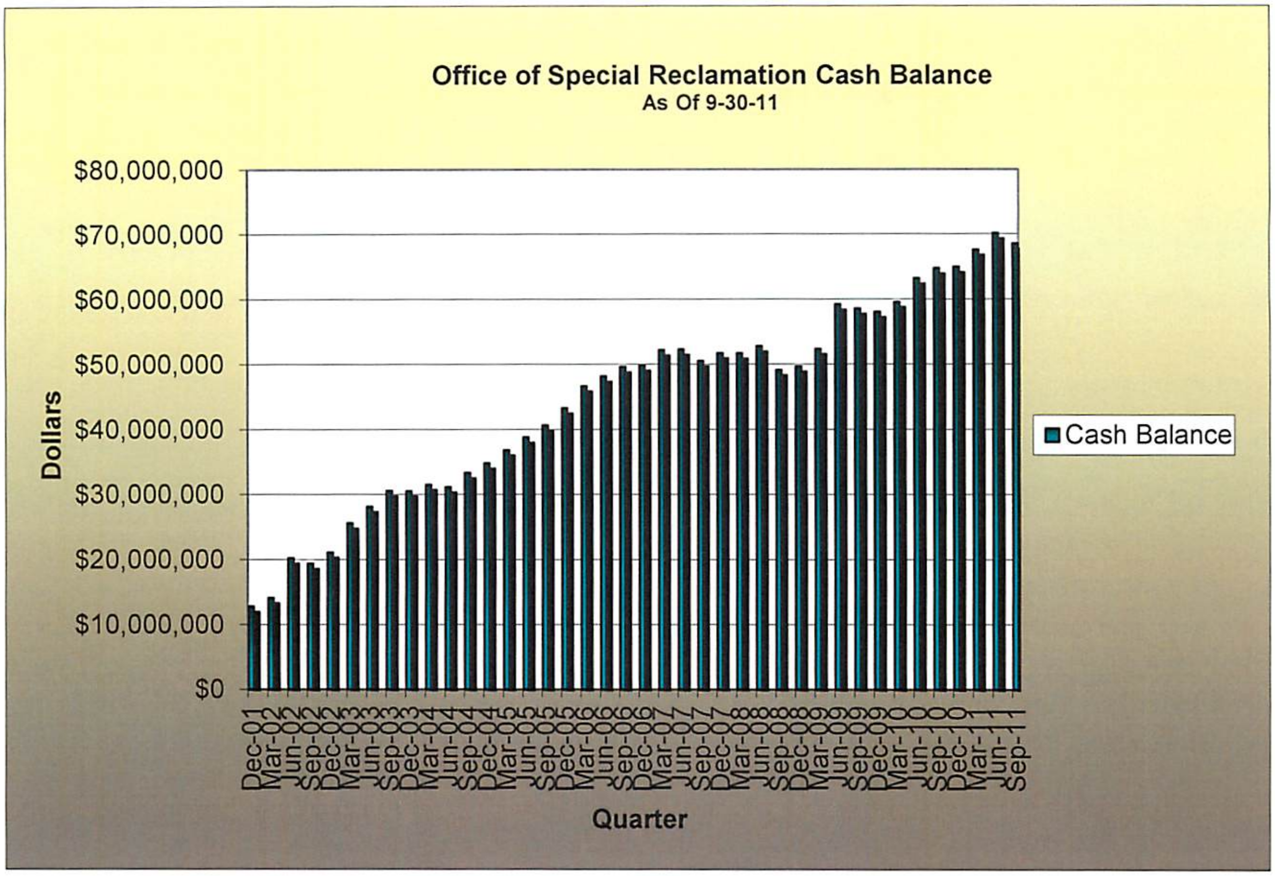

Office of Special Reclamation Land Liabilities To Be Contracted
As Of 9-30-11
Estimated Land Liability Dollars
50000000
45000000
40000000
35000000
30000000
25000000
20000000
15000000
10000000
5000000
0
Jun-01 Sep-01 Dec-01 Mar-02 Jun-02 Sep-02 Dec-02 Mar-03 Jun-03 Sep-03 Dec-03 Mar-04 Jun-04 Sep-04 Dec-04 Mar-05 Jun-05 Sep-05 Dec-05 Mar-06 Jun-06 Sep-06 Dec-06 Mar-07 Jun-07 Sep-07 Dec-07 Mar-08 Jun-08 Sep-08 Dec-08 Mar-09 Jun-09 Sep-09 Dec-09 Mar-10 Jun-10 Sep-10 Dec-10 Mar-11 Jun-11 Sep-11
Month
Estimated Liability
Does not include $897,858.10 for Tree-Planting, Re-Opened and Sediment Structure Removal

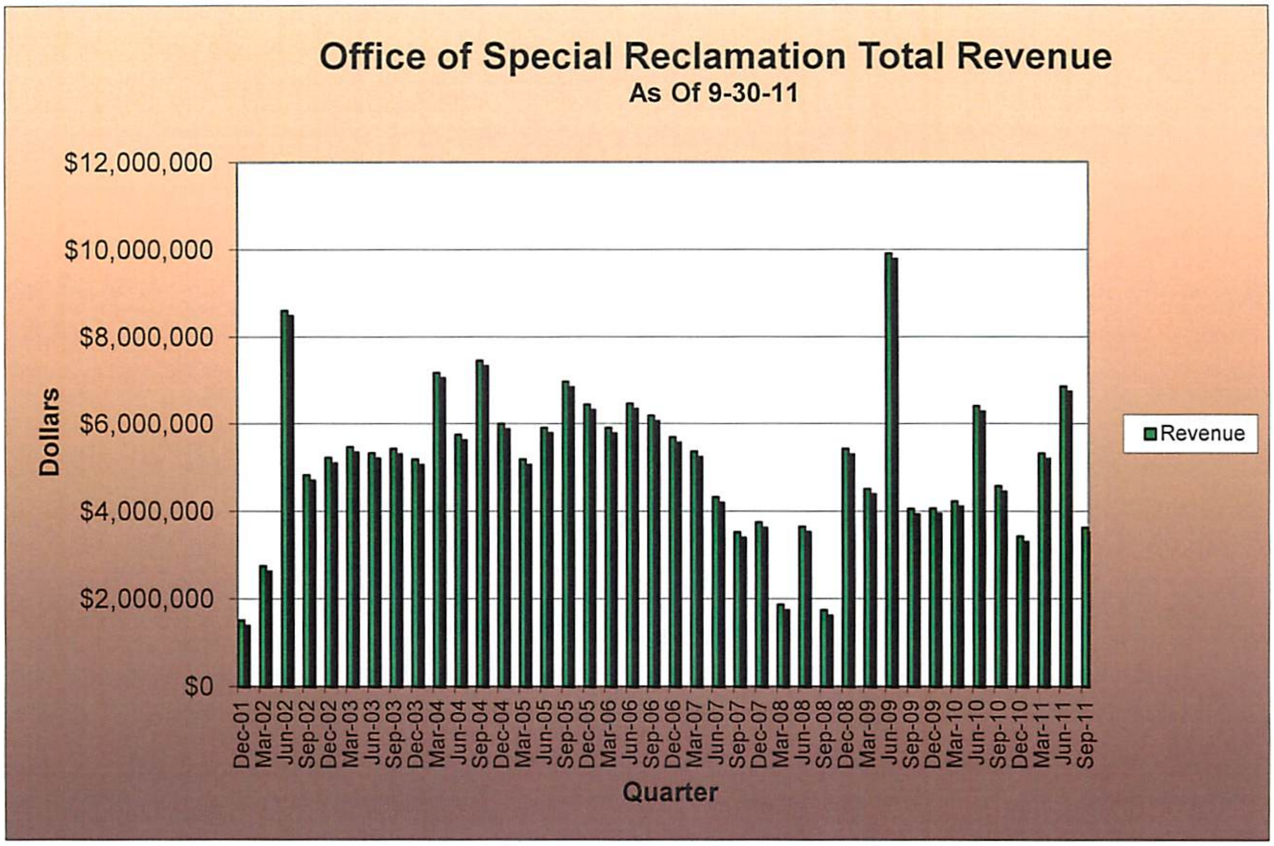

Office of Special Reclamation Forfeited Permits Since 6-30-01
As Of 9-30-11
Number of Permits
0
20
40
60
80
100
120
140
160
180
Sep-01
Dec-01
Mar-02
Jun-02
Sep-02
Dec-02
Mar-03
Jun-03
Sep-03
Dec-03
Mar-04
Jun-04
Sep-04
Dec-04
Mar-05
Jun-05
Sep-05
Dec-05
Mar-06
Jun-06
Sep-06
Dec-06
Mar-07
Jun-07
Sep-07
Dec-07
Mar-08
Jun-08
Sep-08
Dec-08
Mar-09
Jun-09
Sep-09
Dec-09
Mar-10
Jun-10
Sep-10
Dec-10
Mar-11
Jun-11
Sep-11
Quarter
Permits by Quarter

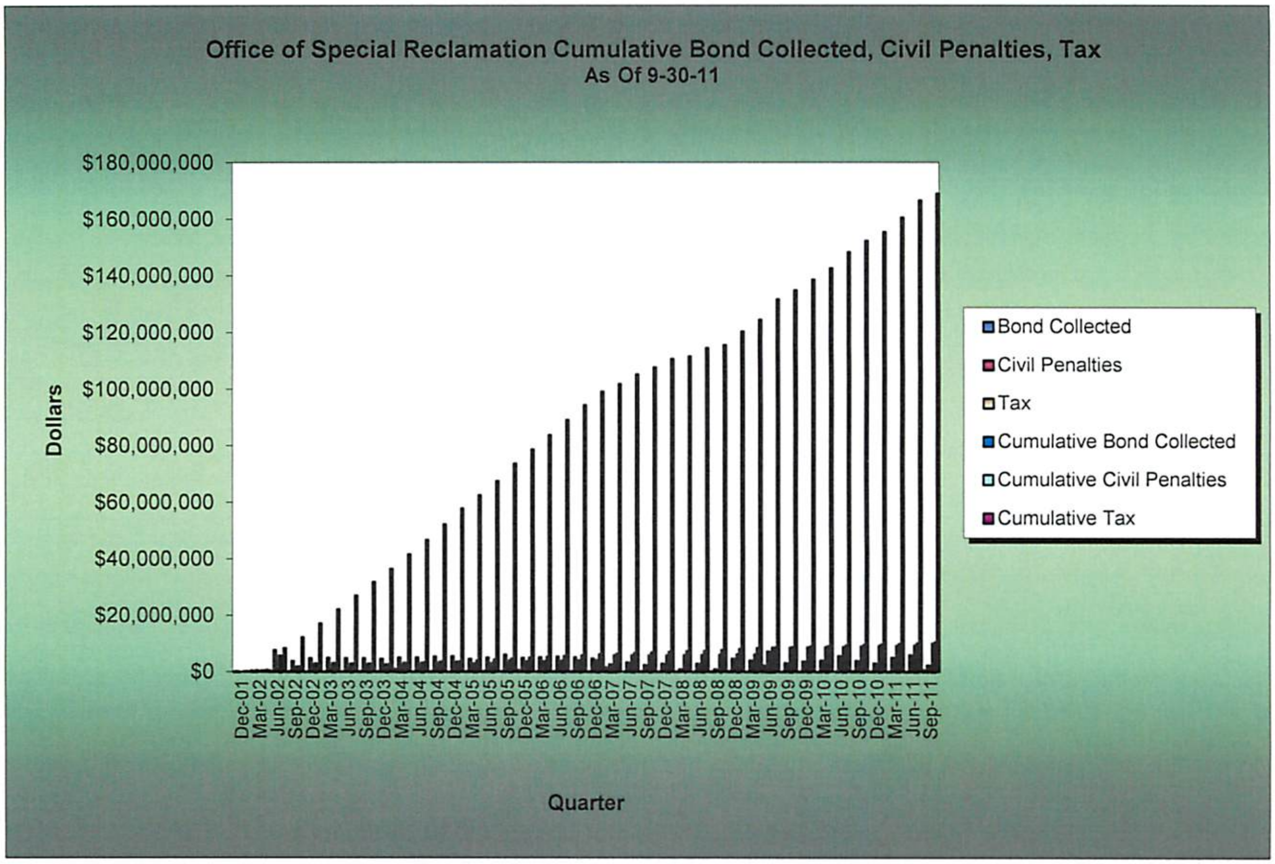


Office of Special Reclamation Land Projects Started After 6-30-01
As Of 9-30-11
Number of Permits
400
350
300
250
200
150
100
50
0
Sep-01
Dec-01
Mar-02
Jun-02
Sep-02
Dec-02
Mar-03
Jun-03
Sep-03
Dec-03
Mar-04
Jun-04
Sep-04
Dec-04
Mar-05
Jun-05
Sep-05
Dec-05
Mar-06
Jun-06
Sep-06
Dec-06
Mar-07
Jun-07
Sep-07
Dec-07
Mar-08
Jun-08
Sep-08
Dec-08
Mar-09
Jun-09
Sep-09
Dec-09
Mar-10
Jun-10
Sep-10
Dec-10
Mar-11
Jun-11
Sep-11
Quarter
Permits by Quarter


Office of Special Reclamation Encumbrance
As Of 9-30-11
Dollars Encumbered
$20,000,000.00
$18,000,000.00
$16,000,000.00
$14,000,000.00
$12,000,000.00
$10,000,000.00
$8,000,000.00
$6,000,000.00
$4,000,000.00
$2,000,000.00
$0.00
Jun-02
Sep-02
Dec-02
Mar-03
Jun-03
Sep-03
Dec-03
Mar-04
Jun-04
Sep-04
Dec-04
Mar-05
Jun-05
Sep-05
Dec-05
Mar-06
Jun-06
Sep-06
Dec-06
Mar-07
Jun-07
Sep-07
Dec-07
Mar-08
Jun-08
Sep-08
Dec-08
Mar-09
Jun-09
Sep-09
Dec-09
Mar-10
Jun-10
Sep-10
Dec-10
Mar-11
Jun-11
Sep-11
Quarter
Encumbrance
After Mar-03 Encumbrance
Includes Contracted Encumbrance +
Intransit Encumbrance


Office of Special Reclamation Cash Balance
As Of 9-30-11
$80,000,000
$70,000,000
$60,000,000
$50,000,000
$40,000,000
$30,000,000
$20,000,000
$10,000,000
$0
Dollars
Cash Balance
Quarter


Office of Special Reclamation Total Revenue
As Of 9-30-11
$12,000,000
$10,000,000
$8,000,000
$6,000,000
$4,000,000
$2,000,000
$0
Dollars
Revenue
Dec-01
Mar-02
Jun-02
Sep-02
Dec-02
Mar-03
Jun-03
Sep-03
Dec-03
Mar-04
Jun-04
Sep-04
Dec-04
Mar-05
Jun-05
Sep-05
Dec-05
Mar-06
Jun-06
Sep-06
Dec-06
Mar-07
Jun-07
Sep-07
Dec-07
Mar-08
Jun-08
Sep-08
Dec-08
Mar-09
Jun-09
Sep-09
Dec-09
Mar-10
Jun-10
Sep-10
Dec-10
Mar-11
Jun-11
Sep-11
Quarter


Office of Special Reclamation Cumulative Bond Collected, Civil Penalties, Tax
As Of 9-30-11
Dollars
$180,000,000
$160,000,000
$140,000,000
$120,000,000
$100,000,000
$80,000,000
$60,000,000
$40,000,000
$20,000,000
$0
Dec-01 Mar-02 Jun-02 Sep-02 Dec-02 Mar-03 Jun-03 Sep-03 Dec-03 Mar-04 Jun-04 Sep-04 Dec-04 Mar-05 Jun-05 Sep-05 Dec-05 Mar-06 Jun-06 Sep-06 Dec-06 Mar-07 Jun-07 Sep-07 Dec-07 Mar-08 Jun-08 Sep-08 Dec-08 Mar-09 Jun-09 Sep-09 Dec-09 Mar-10 Jun-10 Sep-10 Dec-10 Mar-11 Jun-11 Sep-11
Quarter
Bond Collected
Civil Penalties
Tax
Cumulative Bond Collected
Cumulative Civil Penalties
Cumulative Tax

Appendix B

OSR Land Liability vs. Land Contract Amount as of 09-30-11
For Contracts Awarded After 1-1-2000

REC START DATE	OFFICE	PERMIT	LAND STATUS	LIAB REPT POST DATE	EST LIABILITY	LAND CONTRACT AMOUNT
7/27/2000	N	EM-118	C	8/22/2001	$212,200.00	$298,585.47
7/28/2000	S	149-79	SSR	5/22/2001	$262,140.00	$171,553.80
12/12/2000	S	EM-133	C	5/22/2001	$150,285.00	$344,513.00
12/12/2000	S	P-731	C	5/22/2001	$213,724.00	$416,210.00
12/13/2000	S	P-751	C	4/23/2001	$269,401.00	$321,755.00
12/13/2000	S	R-734	C	5/22/2001	$367,048.00	$358,431.00
1/22/2001	S	S-3003-92	C	5/22/2001	$442,000.00	$737,054.40
1/30/2001	N	S-68-82	C	1/31/1996	$300,000.00	$146,309.70
2/26/2001	N	S-1032-86	C	4/20/1993	$39,400.00	$35,780.00
8/23/2001	S	D-108-82	C	5/10/1996	$3,770.00	$24,920.18
8/24/2001	S	U-4005-90	C	10/3/2003	$7,700.00	$2,490.00
9/19/2001	S	U-53-85	C	10/8/2003	$90,800.00	$128,002.06
10/25/2001	S	U-4012-86	C	4/10/2001	$224,637.00	$310,746.50
10/25/2001	S	U-4029-89	C	5/19/1997	$118,510.00	$108,841.20
11/28/2001	N	S-1006-92	C	11/17/1999	$30,000.00	$89,910.00
1/16/2002	N	U-1012-93	C	6/9/2000	$40,000.00	$67,096.90
4/5/2002	N	U-125-83	C	7/12/1996	$105,000.00	$149,168.65
5/1/2002	C	O-69-82	C	9/15/2003	$14,720.00	$14,720.00
5/2/2002	C	U-140-82	C	9/15/2003	$11,745.00	$11,745.00
5/2/2002	C	U-5027-86	C	9/16/2003	$6,605.00	$2,925.00
5/19/2002	C	UO-353	C	9/16/2003	$10,075.00	$10,075.00
6/24/2002	N	U-2037-86	C	2/29/2000	$72,000.00	$48,921.00
7/2/2002	S	S-3024-87	C	10/15/1999	$38,000.00	$67,396.00
7/2/2002	S	U-3003-89	C	10/15/1999	$30,000.00	$66,978.00
7/2/2002	S	U-3023-87	C	10/15/1999	$22,000.00	$14,600.00
7/3/2002	C	U-5035-87	SSR	4/23/1999	$123,000.00	$156,900.00
7/3/2002	C	S-5034-87	SSR	4/23/1999	$72,000.00	$73,900.00
8/14/2002	N	O-2044-88	C	6/9/2000	$297,000.00	$235,592.80
8/14/2002	N	S-2021-87	C	9/29/2000	$50,000.00	$10,750.00
8/14/2002	N	S-2052-86	C	11/8/1999	$60,000.00	$49,200.00
8/14/2002	N	U-2005-88	C	11/8/1999	$70,000.00	$109,830.00
8/14/2002	N	S-2006-93	C	10/15/1999	$37,500.00	$54,140.00
9/16/2002	S	S-96-85	C		$50,000.00	$162,100.00
9/16/2002	S	U-3046-87	C	4/17/2001	$225,000.00	$233,900.00
10/31/2002	S	U-3042-89	C	3/22/2002	$130,000.00	$130,565.00
10/31/2002	S	S-113-85	C	5/28/2001	$40,000.00	$9,100.00
10/31/2002	S	U-3031-93	C	5/29/2001	$201,000.00	$146,000.00
10/31/2002	S	U-4011-88	C	2/22/1999	$110,700.00	$115,022.50
11/22/2002	S	O-36-84	C	8/25/2000	$49,378.00	$183,690.00
11/22/2002	S	R-7-81	C	8/25/2000	$615,020.00	$783,862.00
12/4/2002	S	U-4011-90	C	10/15/1999	$3,500.00	$7,210.00
1/30/2003	S	U-42-85	C	10/15/1999	$8,200.00	$12,872.50

2/20/2003	S	S-3035-87	C	10/15/1999	$178,500.00	$637,700.00
2/20/2003	S	U-3036-87	C	10/15/1999	$42,000.00	$357,500.00
2/24/2003	C	S-5046-88	C	10/15/1999	$60,500.00	$48,185.00
4/15/2003	S	UO-727	C	12/12/1997	$18,720.00	$13,459.50
4/15/2003	S	UO-252	C	5/22/2003	$6,655.00	$4,758.46
4/18/2003	S	U-107-83	C	5/26/2000	$133,580.00	$249,700.00
4/18/2003	S	U-3066-88	C	5/26/2000	$83,275.00	$378,185.00
4/23/2003	S	EM-71	C	6/30/1998	$14,365.00	$12,100.16
4/23/2003	S	UO-623	C	10/15/1999	$10,500.00	$8,856.34
4/30/2003	S	S-682	C	5/26/2000	$27,735.00	$40,400.00
5/1/2003	N	S-1024-88	C	3/1/2000	$97,600.00	$92,937.00
5/1/2003	S	S-3050-86	C	5/26/2000	$160,492.00	$177,000.00
5/1/2003	S	S-65-76	C	5/26/2000	$24,842.00	$134,800.00
5/15/2003	S	D-125-82	C	5/26/2000	$79,360.00	$191,311.75
5/15/2003	S	U-3020-86	C	5/26/2000	$9,480.00	$71,500.00
5/15/2003	S	UO-571	C	5/26/2000	$19,775.00	$26,800.00
5/20/2003	S	S-3011-88	C	5/26/2000	$89,830.00	$130,900.00
5/22/2003	S	32-81	C	5/26/2000	$71,500.00	$105,770.00
5/22/2003	S	U-3074-87	C	5/26/2000	$176,760.00	$517,520.00
6/5/2003	S	56-81	SSR	5/26/2000	$173,992.00	$319,245.00
6/5/2003	S	R-3078-86	C	5/26/2000	$130,104.00	$237,536.00
6/10/2003	S	U-3017-87	C	5/26/2000	$77,737.00	$157,231.85
6/19/2003	S	U-3078-87	C	10/15/1999	$55,000.00	$62,600.00
6/19/2003	S	S-33-81	C	10/15/1999	$58,000.00	$68,500.00
6/19/2003	S	D-32-81	C	5/26/2000	$100,090.00	$88,000.00
6/19/2003	S	O-103-83	C	5/26/2000	$54,605.00	$109,125.00
7/29/2003	S	S-60-83	C	5/26/2000	$99,112.50	$74,750.00
8/6/2003	S	S-176-75	C	5/26/2000	$41,450.00	$76,510.00
8/6/2003	S	S-65-85	C	5/26/2000	$502,360.00	$944,770.00
8/13/2003	S	U-171-83	C	8/30/2002	$40,000.00	$70,839.90
8/13/2003	S	U-50-85	C	8/30/2002	$36,000.00	$41,496.40
8/14/2003	S	S-3020-88	C		$15,000.00	$27,467.50
8/14/2003	S	D-5-82	C	5/14/2003	$18,760.00	$11,007.50
9/2/2003	N	D-75-82	C	11/8/2001	$55,300.00	$115,000.00
9/2/2003	N	S-2002-92	C	11/26/2001	$164,600.00	$186,380.00
9/2/2003	N	U-1041-91	C	11/26/2001	$21,800.00	$77,300.00
9/12/2003	N	S-2009-89	C	8/3/2001	$75,000.00	$121,230.00
9/12/2003	S	S-90-82	C	5/26/2000	$63,200.00	$94,300.00
9/12/2003	S	U-3046-88	C	5/26/2000	$709,800.00	$1,145,450.00
9/18/2003	C	U-5006-95	C	5/22/2001	$62,000.00	$94,635.00
9/19/2003	S	D-10-81	C	9/10/2003	$28,200.00	$46,365.00
9/29/2003	S	S-99-83	C	5/26/2000	$46,950.00	$142,140.00
9/29/2003	S	U-40-85	C	5/26/2000	$136,505.00	$255,500.00
10/8/2003	S	O-3077-87	C	5/6/2003	$49,335.00	$27,750.00
10/14/2003	S	S-119-85	C	11/24/2003	$85,500.00	$66,600.00
10/17/2003	S	S-3009-89	C	5/26/2000	$118,040.00	$220,160.00
10/17/2003	S	S-3012-93	C	5/26/2000	$20,975.00	$71,684.00
10/17/2003	S	S-3070-88	C	5/26/2000	$62,450.00	$127,624.00
10/20/2003	S	U-3006-87	C	5/28/2003	$114,000.00	$72,900.00
10/31/2003	C	U-82-84	C	10/15/1999	$10,400.00	$13,597.50

11/12/2003	C	U-1-85	C	10/15/1999	$36,000.00	$21,659.88
11/13/2003	C	UO-406	C	2/3/1999	$32,000.00	$23,312.50
12/24/2003	N	S-1028-86	C	10/15/1999	$42,000.00	$40,800.00
12/24/2003	N	S-62-85	C	10/15/1999	$35,900.00	$99,180.00
12/24/2003	S	O-104-83	C	5/26/2000	$122,750.00	$94,254.90
12/24/2003	S	O-67-82	C	5/26/2000	$23,005.00	$72,566.10
12/24/2003	S	U-22-85	C	11/20/2002	$382,360.00	$449,007.49
1/9/2004	S	UO-694	C	10/15/1999	$54,300.00	$139,000.00
1/9/2004	S	UO-383	C	3/12/1999	$153,340.00	$255,500.00
2/5/2004	S	U-4012-94	C	3/10/2003	$180,000.00	$119,801.00
2/5/2004	S	U-4017-91	C	3/10/2003	$37,466.00	$40,201.00
2/5/2004	S	U-85-83	C	10/15/1999	$53,940.00	$152,201.00
2/5/2004	S	UO-439	C	10/15/1999	$100,380.00	$155,501.00
2/23/2004	S	S-3076-86	C	5/26/2000	$354,915.00	$749,003.00
3/2/2004	S	U-231-83	C	4/2/1999	$24,700.00	$110,835.00
3/2/2004	S	UO-155	C	5/13/1996	$89,573.00	$389,389.00
3/4/2004	C	P-654	C	6/5/2002	$171,000.00	$149,700.00
3/10/2004	S	R-721	C	4/14/2004	$40,000.00	$27,345.00
3/30/2004	N	O-46-84	C	6/9/2000	$90,000.00	$268,350.00
3/30/2004	N	O-46-85	C	6/9/2000	$56,000.00	$144,720.00
4/1/2004	N	U-1008-92	RO	7/29/2003	$550,000.00	$431,360.00
4/12/2004	S	S-3031-87	C	5/20/1996	$18,200.00	$20,615.00
4/26/2004	S	S-3019-87	C		$20,000.00	$49,140.00
5/4/2004	N	R-722	C	10/15/1999	$5,400.00	$3,620.00
5/4/2004	N	U-138-83	C	10/15/1999	$265,370.00	$844,390.00
5/24/2004	N	UO-380	C	6/9/2000	$50,000.00	$69,410.00
7/20/2004	S	D-60-82	C	5/20/1996	$30,000.00	$91,450.00
7/21/2004	N	S-24-83	C	11/8/2001	$127,000.00	$53,767.50
7/22/2004	S	13-79	C		$25,000.00	$46,750.00
8/30/2004	C	O-5059-86	C	4/10/2001	$65,436.00	$47,050.00
9/3/2004	C	U-6012-88	C	5/16/2003	$25,025.00	$24,573.00
9/4/2004	C	O-40-82	C	5/9/2003	$10,000.00	$54,700.00
9/4/2004	C	O-45-82	C	5/9/2003	$24,315.00	$57,700.00
11/12/2004	C	S-94-82	C	6/5/2002	$200,000.00	$91,502.00
11/12/2004	S	U-4013-88	C	4/23/2003	$211,211.00	$158,700.00
11/24/2004	S	U-26-83	C	3/22/2001	$132,370.00	$197,360.00
2/4/2005	S	S-3016-92	C	3/29/2004	$1,185,363.40	$1,191,550.00
3/29/2005	S	O-58-83	C	3/22/2002	$1,900,000.00	$2,373,659.00
5/12/2005	S	EM-116	C	4/23/2003	$465,000.00	$378,000.00
5/12/2005	S	U-4017-89	C	5/28/2003	$133,700.00	$108,000.00
5/12/2005	S	U-4002-94	C	4/10/2001	$100,958.00	$210,500.00
5/31/2005	S	U-4018-86	C	10/15/1999	$173,710.00	$207,316.00
6/8/2005	S	U-4027-88	C	4/10/2001	$274,588.00	$250,582.00
9/22/2005	S	S-3010-98	C	2/10/2004	$794,257.10	$370,900.00
12/29/2005	S	S-35-81	C	5/20/1996	$67,200.00	$122,600.00
1/3/2006	S	S-3028-87	C		$35,000.00	$138,000.00
1/3/2006	S	U-4020-87	C	6/28/2000	$53,690.00	$64,650.00
1/16/2006	S	R-4030-86	C		$469,240.00	$921,430.19
1/20/2006	S	U-3040-87	C	4/12/2001	$368,410.00	$610,470.00
1/20/2006	S	U-3045-86	C	5/7/2003	$376,722.00	$356,000.00

2/14/2006	S	S-3055-88	C	5/29/1996	$257,774.00	$254,860.00
2/14/2006	S	U-69-85	C	5/29/1996	$140,000.00	$217,400.00
3/13/2006	N	U-1012-93	C	6/9/2000	$40,000.00	$50,604.80
4/14/2006	C	S-6029-86	UCW		$50,000.00	$224,000.00
5/4/2006	S	U-154-83	C	10/15/1999	$54,635.00	$188,575.00
6/28/2006	C	U-5069-87	C	5/26/2000	$151,000.00	$186,750.00
1/8/2007	S	U-3053-88	C	5/27/1999	$33,375.00	$164,625.00
1/12/2007	S	U-3010-87	C	6/27/2006	$271,500.00	$232,140.00
1/17/2007	S	U-3003-86	C	6/16/2006	$157,488.00	$208,965.00
1/17/2007	S	UO-223	C	6/16/2006	$218,120.00	$199,035.00
3/19/2007	N	S-29-80	C	10/15/1999	$49,500.00	$26,200.00
3/19/2007	N	S-41-84	C	10/15/1999	$35,900.00	$50,400.00
3/19/2007	N	S-55-85	C	10/15/1999	$51,600.00	$175,300.00
3/19/2007	N	S-72-84	C	10/15/1999	$138,300.00	$124,510.00
4/13/2007	N	S-2023-92	UCW	12/13/2006	$2,620,101.00	$1,202,392.00
5/17/2007	S	D-73-82	C	5/9/2001	$117,200.00	$131,999.00
11/5/2007	S	P-664	C	8/31/2005	$177,000.00	$114,741.00
1/8/2008	S	O-172-83	C	2/10/2004	$111,000.00	$37,900.00
2/1/2008	S	I-544	C	1/30/2001	$5,000.00	$34,000.00
2/1/2008	S	O-20-85	C	11/6/2006	$34,580.00	$31,546.00
2/20/2008	C	O-16-82	SSR		$50,000.00	$138,600.00
2/20/2008	C	O-16-85	C		$50,000.00	$583,680.00
3/24/2008	S	U-4019-92	C	9/1/1998	$500,000.00	$96,000.00
3/26/2008	S	S-3031-90	C	3/29/2007	$602,000.00	$241,500.00
4/10/2008	S	187-74	C	10/15/1999	$192,810.00	$396,800.00
4/21/2008	S	P-61-83	C	10/15/1999	$49,300.00	$62,925.00
6/26/2008	S	S-23-77	C	10/15/1999	$934,080.00	$1,571,650.00
6/30/2008	N	S-1012-87	C	10/15/1999	$92,900.00	$158,150.00
6/30/2008	N	S-20-83	C	10/15/1999	$39,700.00	$31,160.00
7/10/2008	S	O-169-83	C	10/15/1999	$60,800.00	$99,870.00
7/10/2008	S	U-225-83	C		$76,800.00	$354,730.00
8/7/2008	S	S-19-85	UCW	1/26/2004	$101,500.00	$47,050.00
11/26/2008	C	120-79	UCW		$30,000.00	$330,694.00
7/22/2009	N	S-2003-03	UCW	3/29/2007	$2,096,350.00	$820,111.00
10/15/2009	S	O-3012-07	UCW	3/25/2009	$337,820.00	$117,300.00
1/26/2010	N	S-2009-01	UCW	8/31/2006	$2,069,075.00	$533,000.00
2/9/2010	N	S-1002-99	UCW	8/31/2006	$287,610.00	$151,460.00
5/21/2010	N	S-2018-88	UCW	12/31/2006	$864,543.00	$318,774.00
6/9/2010	N	U-2002-95	UCW	4/27/2007	$335,924.00	$251,909.00
7/22/2010	C	O-6013-88	UC	8/27/2003	$1,355,000.00	$1,391,557.00
7/22/2010	C	O-6021-89	UC	2/26/2003	$11,400.00	$25,000.00
7/22/2010	C	S-73-85	UC	8/27/2003	$258,000.00	$223,500.00
7/22/2010	C	U-6018-86	UC	2/26/2003	$13,000.00	$24,000.00
8/24/2010	N	U-2010-94	UCW	12/22/2008	$136,230.00	$183,420.00
11/30/2010	N	P-741	UC	8/4/2004	$400,000.00	$326,000.00
1/12/2011	N	S-100-84	UC	3/29/2007	$792,000.00	$1,366,126.00
1/12/2011	N	S-2004-02	UC	12/13/2006	$3,590,402.00	$2,571,571.00
1/12/2011	N	S-1004-88	UC	9/10/2003	$472,500.00	$369,000.00
1/12/2011	N	S-1019-87	UC	9/10/2003	$20,000.00	$149,000.00
1/12/2011	N	UO-401	UCW	9/22/2008	$1,476,730.00	$644,250.00

5/17/2011	N	S-1005-95	UC	9/10/2003	$565,000.00	$511,405.00
7/21/2011	C	U-5049-87	UC	11/4/2002	$145,100.00	$587,554.00
7/22/2011	N	U-2005-97	UC	1/22/2009	$131,000.00	$207,025.00
7/23/2011	C	S-41-80	UC	6/5/2002	$156,000.00	$392,477.00
Total:		**196**			**$43,000,234.00**	**$46,971,702.88**
Variance:						**9.24%**

Note: Excludes 10 permits where the variance exceeds 2 standard deviations under the mean or no Est Liability in database.

Total Unskewed:	**180**	**$42,287,319.00**	**$43,032,590.70**
Variance Unskewed:			**1.76%**

Note: The variance of these 16 permits exceeds 2 standard deviations over the mean. Increased liability over time, more detailed investigation prior to requisition, general inflation, increased costs for specific goods and services are contributing factors in the variance. Without these 16 permits, the Estimated Liability vs. Land Contract Amount variance is 1.76%.

Variance = (Contract Amount - Est Liability) / Est Liability

OSR WQ Cap vs. Water Contract Amount as of 09-30-11
For Contracts Awarded After 1-1-2000

DATE WQ CONST STARTED	OFFICE	PERMIT	LAND STATUS	WATER STATUS	LIAB REPT POST DATE	WQ TOTAL CAPITAL DOLLARS	WATER CONTRACT AMOUNT
9/16/2002	S	S-96-85	C	P		$67,500.00	$128,240.00
10/17/2002	N	S-26-85	C	ACT		$398,250.00	$243,705.23
12/19/2002	N	S-1032-86	C	ACT	4/20/1993	$364,500.00	$209,784.66
2/20/2003	N	S-60-84	C	ACT		$175,500.00	$282,062.00
4/25/2003	N	EM-32	C	ACT		$243,000.00	$168,890.00
5/1/2003	N	S-1024-88	C	ACT	3/1/2000	$209,250.00	$173,178.00
5/15/2003	N	176-77	C	ACT	5/26/2000	$54,000.00	$312,000.00
5/21/2003	N	S-10-81	C	ACT	7/21/2000	$452,250.00	$643,142.22
6/5/2003	S	EM-97	C	ACT	9/16/2003	$175,500.00	$341,775.00
6/5/2003	S	R-3078-86	C	ACT	5/26/2000	$209,250.00	$91,000.00
6/19/2003	S	D-32-81	C	ACT	5/26/2000	$209,250.00	$260,500.00
8/25/2003	N	40-81	C	ACT		$398,250.00	$413,962.40
8/27/2003	N	S-1063-86	C	ACT		$87,750.00	$324,561.00
9/29/2003	S	U-40-85	C	P	5/26/2000	$175,500.00	$89,500.00
10/8/2003	N	S-37-81	C	P		$364,500.00	$118,000.00
10/14/2003	N	65-78	C	ACT		$170,100.00	$1,142,151.00
10/14/2003	N	S-65-82	C	ACT	7/21/2000	$315,900.00	$1,600,000.00
10/14/2003	S	S-119-85	C	P	11/24/2003	$398,250.00	$150,000.00
11/4/2003	N	S-17-82	C	ACT	10/15/1999	$209,250.00	$589,265.32
11/7/2003	N	UO-519	C	ACT	3/14/2001	$398,250.00	$581,592.00
1/22/2004	N	O-1035-87	C	ACT		$173,677.50	$406,440.00
1/22/2004	N	O-43-85	C	ACT		$121,500.00	$202,975.00
1/22/2004	N	O-86-82	C	ACT	9/24/2003	$35,572.50	$35,125.00
2/5/2004	S	U-3055-87	C	P	10/28/2003	$209,250.00	$251,300.00
2/5/2004	S	S-86-85	C	ACT	7/24/2000	$209,250.00	$467,500.00
6/22/2004	N	S-1087-86	C	P		$209,250.00	$97,400.00
7/22/2004	S	19-75	C	P		$209,250.00	$116,710.00
8/16/2004	N	S-1030-86	C	P		$209,250.00	$87,794.00
8/17/2004	S	U-3083-87	C	P	3/19/1998	$195,750.00	$220,161.00
9/8/2004	C	O-1-81	C	ACT	10/26/1998	$324,000.00	$499,795.00
10/1/2004	N	S-52-83	C	ACT		$155,250.00	$298,745.00
2/10/2005	N	S-61-82	C	ACT		$121,500.00	$245,392.00
3/4/2005	N	237-76	C	ACT		$109,250.00	$503,239.00
3/4/2005	N	S-1035-86	C	ACT		$100,000.00	$449,125.00
5/12/2005	S	R-3-81	C	ACT		$175,500.00	$487,750.00
5/17/2005	N	S-1041-89	C	ACT	8/31/2000	$364,500.00	$312,985.00
5/24/2005	N	60-79	C	P		$54,000.00	$95,980.00
6/8/2005	N	U-2024-87	C	ACT		$184,997.92	$348,350.00
12/28/2005	N	S-21-84	C	ACT		$175,500.00	$208,543.30
12/29/2005	S	S-35-81	C	P	5/20/1996	$209,250.00	$284,400.00
1/3/2006	S	S-3028-87	C	P		$67,500.00	$412,280.00
4/14/2006	C	S-6029-86	UCW	ACT		$87,750.00	$2,497,373.00
5/4/2006	N	S-64-83	RO	ACT		$243,000.00	$316,385.00
6/7/2006	N	34-81	C	ACT		$175,500.00	$297,685.00

6/27/2006	N	D-35-82	TBC	ACT	8/4/2002	$2,892,400.00	$2,856,667.00
9/1/2006	N	S-2003-86	C	P		$364,500.00	$80,052.50
10/18/2006	S	S-99-83	C	P	5/26/2000	$95,500.00	$107,100.00
11/1/2006	S	S-3026-89	C	P	6/29/1998	$247,800.00	$420,500.00
11/9/2006	S	O-3086-87	C	P	7/25/2001	$87,750.00	$285,500.00
11/9/2006	S	O-43-84	C	ACT	7/25/2001	$87,750.00	$276,000.00
12/15/2006	N	65-77	C	P		$209,250.00	$308,028.50
12/15/2006	N	S-1009-88	C	P		$87,750.00	$159,608.00
5/3/2007	N	U-109-83	C	P		$209,250.00	$139,880.00
8/9/2007	N	67-78	C	ACT		$121,500.00	$321,000.00
9/21/2007	N	192-77	C	ACT		$2,070.90	$2,300.00
9/21/2007	N	S-1009-86	C	ACT		$396,179.10	$611,723.00
11/27/2007	N	S-122-80	C	ACT	12/13/2006	$548,012.00	$395,158.00
1/9/2008	N	184-77	C	UC		$153,983.70	$380,167.00
1/9/2008	N	S-2004-86	C	P		$21,516.30	$139,798.75
2/12/2008	C	UO-396	C	ACT		$87,750.00	$435,825.00
2/20/2008	C	O-69-82	C	P	9/15/2003	$87,750.00	$287,225.00
3/26/2008	S	S-3031-90	C	P	3/29/2007	$159,000.00	$137,500.00
5/1/2008	S	U-4013-91	C	P	5/22/2001	$157,010.00	$132,987.00
5/23/2008	S	P-656	C	ACT	6/30/2005	$778,000.00	$997,400.00
6/12/2008	N	3-72	C	P		$324,000.00	$123,985.00
8/7/2008	S	S-19-85	UCW	P	1/26/2004	$225,000.00	$429,106.00
8/29/2008	N	S-1008-89	C	UC		$243,000.00	$446,825.00
9/15/2008	N	S-1045-87	C	ACT	10/15/1999	$209,250.00	$664,207.00
11/26/2008	C	120-79	UCW	ACT		$209,250.00	$744,924.00
1/6/2009	C	U-5071-86	C	ACT		$243,000.00	$677,795.00
3/25/2009	C	S-6020-87	C	P		$209,250.00	$414,800.00
3/25/2009	S	149-79	SSR	P	5/22/2001	$377,230.00	$359,750.00
3/31/2009	N	51-78	C	ACT		$209,250.00	$299,900.80
6/1/2009	C	S-6033-86	C	UC	7/25/2001	$209,250.00	$415,235.40
6/1/2009	N	S-28-83	C	ACT		$209,250.00	$347,902.50
6/15/2010	N	S-2003-88	TBC	UC	12/13/2006	$716,414.00	$589,630.00
7/22/2010	C	O-6013-88	UC	UC	8/27/2003	$2,467,307.00	$932,400.00
7/22/2010	C	S-73-85	UC	UC	8/27/2003	$235,000.00	$95,700.00
8/30/2010	C	S-6-85	C	UC	4/27/1999	$243,000.00	$497,000.00
1/12/2011	N	P-177-85	C	UC		$121,500.00	$311,940.00
2/18/2011	N	S-1018-88	C	UC	12/8/2000	$209,250.00	$594,960.00
5/17/2011	N	S-1005-95	UC	UC	9/10/2003	$276,000.00	$805,210.00
Total:		**82**				**$22,927,170.92**	**$34,232,431.58**
Variance:							**49.31%**

Note: Excludes 4 permits where the variance exceeds 2 standard deviations under the mean.

Total Unskewed:	**71**		**$21,428,154.62**	**$25,190,505.83**
Variance Unskewed:				**17.56%**

Note: The variance of these 11 permits exceeds 2 standard deviations over the mean. Sparse WQ data at time of Tiff Hilton's liability estimation, new seeps found after estimation, additional roads, more and larger ponds required after original estimation are the factors in the variance. For S-6029-86 a large underground AMD pool and other problems were discovered during requisition planning, which were not addressed in the initial liability estimate. Without these 11 permits, the variance is 17.56%.

Variance = (Water Contract Amt - WQ Total Cap Dollars) / WQ Total Cap Dollars

Appendix C

PINNACLE
ACTUARIAL RESOURCES, INC.
The Firm of Choice

January 12, 2012

Special Reclamation Advisory Council
c/o Department of Environmental Protection
Division of Land Restoration – Office of Special Reclamation
601 57th Street S.E.
Charleston, West Virginia 25304

Dear Council Members:

Pinnacle Actuarial Resources, Inc is pleased to provide the enclosed final report to the Special Reclamation Advisory Council of the West Virginia Department of Environmental Protection. The report provides summary and various details regarding the actuarial valuation of the Special Reclamation Fund and the Special Reclamation Water Trust Fund as of June 30, 2011.

If you have any questions, comments, suggested wording revisions or require anything further please call John Wade at (317) 889-5760. Thank you for allowing us to be of service to the Council again this year. We look forward to the opportunity to work with you again in the near future.

Sincerely,

Christopher S. Carlson

Christopher S. Carlson, FCAS, MAAA
Consulting Actuary

John E Wade

John E. Wade, ACAS, MAAA
Senior Consulting Actuary

Report for the

West Virginia Department of Environmental Protection

Office of Special Reclamation

Actuarial Valuation

of the

Special Reclamation Fund &

Special Reclamation Water Trust Fund

Actuarial Analysis

as of June 30, 2011

PINNACLE
ACTUARIAL RESOURCES, INC.
The Firm of Choice

3040 Riverside Drive, Suite 206
Upper Arlington, Ohio 443221

374 Meridian Parke Lane, Suite C
Greenwood, IN 46142

REPORT ORGANIZATION

EXECUTIVE SUMMARY provides a thumbnail sketch of the results of our analysis.

ACTUARIAL CERTIFICATION attests that this valuation has been conducted in accordance with generally accepted actuarial principles and practices.

SECTION 1 describes the actuarial model in detail and the development of the assumptions used to estimate the revenues and liabilities of the Special Reclamation Fund and the Special Reclamation Water Trust Fund.

SECTION 2 provides a projection of required income for solvency through fiscal year 2035.

SECTION 3 describes the data reviewed and used in the report.

SECTION 4 describes the actuarial assumptions used in the valuation.

EXHIBITS have been included as a separate section of the report, primarily replacing tables previously embedded within the body of the report. These exhibits contain significant information (and sometimes significant amounts of information) that clarify the development of our estimates.

The timely completion of our report depended on complete responses to our data and information requests. The Department of Environmental Protection staff provided us with timely and complete responses to all of our requests for information. We wish to thank them, especially Lewis Halstead, Jennifer Paxton, Tom McCarthy, Jean Sheppard, Michael Sheehan, David McCoy and Yvonne Anderson for their time and providing us with their counsel as well as the information that we used in this report.

EXECUTIVE SUMMARY

This report from Pinnacle Actuarial Resources provides the Department of Environmental Protection (DEP) with information regarding the funded status of the Special Reclamation Fund (SRF) and an analysis of the SRF's projected financial status under a range of operational parameters. This report updates and expands our previous actuarial study completed in 2010. This analysis also incorporates the newly provided information regarding future water treatment costs under the expanded National Pollutant Discharge Elimination System (NPDES) standards as developed through the joint efforts of Dr. Ziemkiewicz of the Water Research Institute at West Virginia University and Michael Shannon and his team in the Office of Special Reclamation. The inclusion of this information has led to significant increases in the estimated cost of water treatment facilities and on-going expenses for both the permits currently under the supervision of the Office of Special Reclamation and the anticipated reclamation costs of permits projected to be forfeited in the future.

This valuation is a "closed" valuation in that it only considers liabilities associated with permits that have already been issued. The estimated Funds' liabilities account for both known forfeitures and anticipated forfeitures from permits issued before July 1, 2011. Accordingly, we have included in this report reclamation liabilities based on the date of forfeiture as well as based on the issue date of permit, to provide the SRF Advisory Council with a complete picture of the fund's current obligations.

The estimates in this report are actuarial central estimates. As actuarial central estimates, they represent an expected value within the range of reasonably possible outcomes. The bond recoveries are considered as an income item rather than an adjustment to the liabilities as the Fund is responsible for the reclamation from first dollar regardless of bond collection. The estimates do not consider any excess insurance or other recoveries because there is no excess insurance and no other recoveries are expected. The estimated liability at June, 30, 2011 is based on permit and forfeiture data through June 30, 2011 and data clarifications and corrections received through December 23, 2011.

BACKGROUND ON COAL TAX RATES FOR FUNDS

In Senate Bill No. 751, a separate Special Reclamation Water Trust Fund (SRWTF or Water Trust Fund) was established effective July 1, 2008. Beginning in July 2008, coal tax revenues based on a tax rate of 1.5 cents per ton are being paid into the Special Reclamation Water Trust Fund. In addition, coal tax revenues based on 12.9 cents per ton (7 cents plus 5.9 cents per SB 751) are being paid into the Special Reclamation Fund (SRF). These rates have continued into 2011 and our estimates assume they will for the foreseeable future.

Unless modified in response to future legislation, for budgeting and analysis purposes the Department of Environmental Protection plans to continue paying all costs for both land and water reclamation work out of the Special Reclamation Fund (SRF) through June 2018. This delay may allow the SRWTF to build up assets and reach a position where it is large enough to begin covering water treatment costs – both water capital costs and ongoing water treatment costs.

ASSUMPTION CHANGES

While in many respects this analysis is similar to the analysis performed in 2010, there are a number of changes to key assumptions included in this year's analysis.

- Release rates
- Forfeiture rates
- Investment rates
- Discount rates
- Underlying land reclamation costs based upon actual recent historical costs
- Costs of water capital and water treatment of the currently open forfeited permits.
- Increased costs of water treatment to achieve compliance with NPDES water quality standards
- Length of time required for water treatment to achieve full compliance
- Inclusion of Legacy Water Treatment costs within the Water Treatment costs of permits forfeited prior to July 1st, 2011 instead of a separate category

These changes and the impact are described in more detail in the text of the report.

FUNDED STATUS

Separate projections of the SRF and the SRWTF have been developed to show the overall financial solvency of each fund.

For the funded status, we have compared the present value of future expenditures with the current value of the Fund's assets plus the present value of future income. Using a 20-year cash-flow projection, the funded status of the Special Reclamation Fund is over 100 percent and for the Special Reclamation Water Trust Fund is 18 percent. We also developed a longer 35 year time period projection the funded status is 97 percent for the SRF and 9 percent for the SRWTF.

We estimate on a cash flow basis that the Special Reclamation Fund's assets and future revenues cover the expected costs through 2038. With the significantly increased costs in water treatment, we project that the Special Reclamation Water Trust Fund will fall into a deficit position in the second year of operation - 2020.

VALUATION RESULTS

Expenditures

Tables A-1 through A-4 below show the present value of future expenditures from July 2011 to June 2030 and from July 2011 to June 2046 for the Special Reclamation Fund and the Special Reclamation Water Trust Fund. The future expenditures associated with these Funds include:

- land capital expenditures, (restoring the land to agreed setting)
- water capital expenditures, (creation of water treatment facilities)
- ongoing water treatment expenditures
- water abandonment expenditures, (removal of treatment facilities) and
- administration costs.

These amounts include the Department of Environmental Protection estimated costs for reclamation activities on permits that have already been forfeited, including the estimated on-going water treatment costs, which have increased significantly over the past 12 months. The projected amounts are the discounted present value of projected cash flows using a discount rate equal to the expected investment returns based upon recent returns on US Treasury Notes. Since the estimated annual reclamation cost inflation rate of 4 percent in the earlier years is far greater the implicit discount rate, the discounted figures are higher than the estimated costs in 2011 dollar terms. This difference means that more money needs to be invested today to cover the cost inflated expenditures in years to come.

A complete description of all of the assumptions used in the valuation can be found in Section 4. The Water Capital and Water Abandonment costs are only included in the Special Reclamation Fund figures until July of 2019, at which point following a ten year capital build up, the Water Trust Fund will begin covering water capital and water abandonment costs.

- Table A-1 - Special Reclamation Fund 20 Year Expenditures
- Table A-2 - Special Reclamation Fund 35 Year Expenditures
- Table A-3 - Special Reclamation Water Trust Fund 20 Year Expenditures
- Table A-4 - Special Reclamation Water Trust Fund 35 Year Expenditures

Table A-1 **Special Reclamation Fund** Liability as of June 30, 2011 for Known and Expected Forfeitures ***Limited to a 20-Year Cash Flow*** (Present Value in $ Millions)			
	Currently Forfeited Permits	Projected Future Forfeitures	**Total Liabilities**
Land Capital	$12.1	$91.6	$103.8
Water Capital	62.8	7.5	70.3
Water Abandonment	0.0	0.0	0.0
Ongoing Water Treatment	35.2	1.8	37.0
Administration			48.7
Total			**$ 259.7**

For comparison purposes, the 20-Year SRF cost projection in 2010 was $313.8 million.

Table A-2 Special Reclamation Fund Liability as of June 30, 2011 for Known and Expected Forfeitures ***Cash Flow Projection through 2046*** (Present Value in $ Millions)			
	Currently Forfeited Permits	Projected Future Forfeitures	**Total Liabilities**
Land Capital	$12.1	$123.2	$135.4
Water Capital	62.8	7.5	70.3
Water Abandonment	0.0	0.0	0.0
Ongoing Water Treatment	35.2	1.8	37.0
Administration			78.2
Total			**$320.8**

For comparison purposes, the 35-Year SRF cost projection in 2010 was $390.8 million.

Table A-3 **Special Reclamation Water Trust Fund** Liability as of June 30, 2011 for Known and Expected Forfeitures ***Limited to a 20-Year Cash Flow*** (Present Value in $ Millions)			
	Currently Forfeited Permits	Projected Future Forfeitures	**Total Liabilities**
Land Capital	$0.0	$0.0	$0.0
Water Capital	0.0	15.9	15.9
Water Abandonment	0.0	0.0	0.0
Ongoing Water Treatment	93.5	27.5	120.9
Administration			0.0
Total			**$136.8**

For comparison purposes, the 20-Year SRWTF cost projection in 2010 was $77.7 million.

Table A-4 **Special Reclamation Water Trust Fund** Liability as of June 30, 2011 for Known and Expected Forfeitures ***Cash Flow Projection through 2046*** (Present Value in $ Millions)			
	Currently Forfeited Permits	Projected Future Forfeitures	**Total Liabilities**
Land Capital	$0.0	$0.0	$0.0
Water Capital	0.0	23.6	23.6
Water Abandonment	0.0	0.0	0.0
Ongoing Water Treatment	186.5	82.4	268.9
Administration			0.0
Total			**$292.5**

For comparison purposes, the 35-Year SRWTF cost projection in 2010 was $147.1 million.

Revenues

The SRF and SRWTF receive revenues from several sources. The primary funding source for both Funds is tax on current coal extraction. The second funding source, available only to the SRF, is from the underlying security on forfeited permits, as the Fund collects the bond amounts associated with the forfeited permits and/or civil penalties and court settlements. The third funding source, available to both Funds, is interest income earned on the SRF and SRWTF assets invested in a fixed income fund managed by the West Virginia Investment Management Board.

As with the projection of expenses, we have developed income projections across both a 20 year and 35 year time horizon for each Fund. Future revenue streams have been discounted at the implicit annual investment returns for both the SRF and the SRWTF.

- Table B-1 - Special Reclamation Fund 20 Year Revenue
- Table B-2 - Special Reclamation Fund 35 Year Revenue
- Table B-3 - Special Reclamation Water Trust Fund 20 Year Revenue
- Table B-4 - Special Reclamation Water Trust Fund 35 Year Revenue

In general, the expected income levels are very similar to the income projections in 2010.

Table B-1
Special Reclamation Fund
Revenue Projection as of June 30, 2011 for Known and Expected Forfeitures
Limited to a 20-Year Cash Flow

(Present Value in $ Millions)

Coal Tax Current Permits	Bond Forfeiture, Civil Penalties & Court Settlements	Interest Income	**Total Income**
$161.7	$45.5	$9.4	**$216.7**

Table B-2
Special Reclamation Fund
Revenue Projection as of June 30, 2011 for Known and Expected Forfeitures
Cash Flow Projections Through 2046
(Present Value in $ Millions)

Coal Tax Current Permits	Bond Forfeiture, Civil Penalties & Court Settlements	Interest Income	**Total Income**
$179.9	$50.7	$11.5	**$242.0**

Table B-3 **Special Reclamation Water Trust Fund** Revenue Projection as of June 30, 2011 for Known and Expected Forfeitures ***Limited to a 20-Year Cash Flow*** (Present Value in $ Millions)			
Coal Tax Current Permits	Bond Forfeiture, Civil Penalties & Court Settlements	Interest Income	**Total Income**
$18.8	$0.0	$0.9	**$19.7**

Table B-4 **Special Reclamation Water Trust Fund** Revenue Projection as of June 30, 2011 for Known and Expected Forfeitures ***Cash Flow Projections Through 2046*** (Present Value in $ Millions)			
Coal Tax Current Permits	Bond Forfeiture, Civil Penalties & Court Settlements	Interest Income	**Total Income**
$20.9	$0.0	$0.9	**$21.8**

Fund Status as of June 30, 2011

The Special Reclamation Fund had accumulated assets of $70.2 million while the Special Reclamation Water Trust Fund had accumulated $5.9 million in assets as of June 30, 2011. The SRF balance is approximately $7 million higher than the balance at the time of the prior report. This level reflects both the significant reclamation efforts in the past year and the revenue from various sources including the coal tax collections.

In Tables C-1 and C-2 below, we combine the projected reclamation liabilities, current assets and expected future revenue to produce the Funded Status for each of the Funds. A Funded Status of above 100 percent indicates that the current revenue structure (i.e. legislated coal tax revenues and amounts of permit bonds) should provide sufficient funding to meet the long-term obligations of the Fund for the reclamation of forfeitures of permitted mining operations. A Funded Status of less than 100 percent would indicate that the Fund's assets, combined with expected future revenues, are not sufficient to cover the expected future expenditures for the reclamation of forfeitures of the permitted mining operations.

Table C-1 **Special Reclamation Fund** Funded Status as of June 30, 2011 (in $ Millions)		
	20 Years	Through 2046
Present Value of Future Revenues	216.7	242.0
Assets as of June 30, 2011	70.2	70.2
Assets + Present Value of Future Revenues	286.8	312.2
Present Value of Future Expenditures	259.7	320.8
Funded Status	110.4%	97.3%
Year Fund Balance Becomes Negative	2039	

Table C-2 **Special Reclamation Water Trust Fund** Funded Status as of June 30, 2011 (in $ Millions)		
	20 Years	Through 2046
Present Value of Future Revenues	19.7	21.8
Assets as of June 30, 2011	5.9	5.9
Assets + Present Value of Future Revenues	25.6	27.7
Present Value of Future Expenditures	136.8	292.5
Funded Status	18.7%	9.5%
Year Fund Balance Becomes Negative	2020	

The Funded Status of the Special Reclamation Fund is at a higher level this year compared to last year as the expected revenue has increased while the present value of the future expenditures declined slightly. Due primarily to the increased expected cost of currently forfeited sites with water treatment, the Funded Status of the Special Reclamation Water Trust Fund has declined significantly since our last review.

In Tables D and E in the attached exhibits, we provide projections of the estimated cash flows over the next 35 years. The elements shown in the projection are:

The expenditures are comprised of:

- Land capital expenditures
- Water capital expenditures
- Ongoing water treatment expenditures
- Water abandonment expenditures – delayed beyond the study horizon
- Administration costs

The revenues are comprised of:

- Coal tax receipts
- Bond forfeitures, civil penalties, and court settlements
- Investment income

The investment income is determined by applying varied US Treasury based interest rates against the prior year-end closing fund balance plus one-half the year's income less one- half of the year's expenditure. For projected years where the total fund balance is negative, total investment income is set to zero.

Tables D and E show the projected cash flow for the next 35 years assuming continuation of current law, whereby the coal tax continues to be collected at a rate of 14.4 cents per ton with 1.5 cents per ton allocated to the Special Reclamation Water Trust Fund.

Table D Summary shows that under the current law, the SRF balance is projected to fall below zero in Fiscal Year 2039. Subsequently, future income is projected to continue to be less than the expected required expenditures.

Table E Summary shows the accumulation of assets in the Water Trust Fund. The SRWTF plans begin making payments for water capital and ongoing water treatment in Fiscal Year 2019. The Fund is projected to have sufficient capital to operate until some point in 2020 before experiencing a deficit. We expect that the Water Trust Fund will have accumulated $17.2 million at the end of fiscal year 2018.

Table F below shows the expected capital costs for reclamation based upon previously forfeited permits in 2011 dollars. With the current bond limit of $5,000 per acre, the expected receipts from permits issued in the future will not be sufficient to cover the expected reclamation costs for Underground Permits or Other Permits.

Table F
Cost Per Acre by Permit Type
(in 2011 Dollars)

Based on Forfeited Permits	**Surface**	**Underground**	**Other Types**
Land Capital	2,898.24	13,259.83	9,575.60
Water Capital	913.81	1,024.62	1,804.78
Water Abandonment	203.38	538.46	473.16
Total Capital	4,015.43	14,822.91	11,853.55

For comparison purposes, we provide the key elements of the analysis that have been impacted by the cost assumptions to comply with the NPDES water quality standards.

Water Capital Costs Per Acre by Permit Type			
	Surface	**Underground**	**Other Types**
Cost in 2010 Analysis	674.30	2,547.06	2,167.38
Cost in 2011 Analysis	913.81	1,024.62	1,804.78

Annual Water Treatment Costs Per Acre by Permit Type			
	Surface	**Underground**	**Other Types**
Cost in 2010 Analysis	1.60	15.81	37.43
Cost in 2011 Analysis	101.39	141.27	199.22

While these increased costs are alarming, they are not unexpected. We note that the water construction costs of all of the treatment sites currently in operation as shown in line (1) of Table 1.2 of the Exhibit package were slightly more than $4 million. In order to adjust those treatment facilities to comply with the NPDES standards, an additional $17 million is anticipated to be needed, shown in line (6) of Table 1.2. In addition, there are 42 forfeited sites with water treatment facilities yet to be constructed. The estimated water capital costs for these new water treatment facilities exceed $30 million, shown on line (7) of Table 1.2.

Prior to the introduction of the revised annual operating and maintenance water treatment costs for the operating forfeited sites and legacy water treatment sites, the annual expenditure was approximately $3.2 million as displayed in Appendix A. Based on the information provided by the teams at West Virginia University and the Office of Special Reclamation, the annual water treatment costs for these same currently operating sites exceed $3.7 million.

We do note that the prior analyses figures were developed using the costs on closed water treatment expenses which did not in any way reflect the current or future cost structures. We used the new NPDES standards in our current projections to provide a more reasonable basis for future costs in this component.

Special Reclamation Water Trust Fund Council Proposed Tax Rate

We also were requested by the Council to provide a cash flow projection assuming a Special Reclamation Water Trust Fund tax rate of 15 cents per ton of coal.

Using this increased tax rate of 15 cents per ton of coal for the Special Reclamation Water Trust Fund, we project that the Fund could cover the water capital and water treatment expenditures through 2037 prior to developing a deficit. This estimate continues to assume that the Water Trust Fund will be used for any expenditure until fiscal year 2019. This requested alternative cash flow is provided in Tables 2.7, 2.8 and 2.9.

ACTUARIAL CERTIFICATION

The State of West Virginia's Department of Environmental Protection retained Pinnacle Actuarial Resources, Inc to perform an actuarial valuation of the Special Reclamation Fund for the purposes of reporting the progress of the Fund.

Christopher S. Carlson, FCAS, MAAA, Consulting Actuary and John E. Wade, ACAS, MAAA, Senior Consulting Actuary are members of the American Academy of Actuaries and meet its Qualification Standards of Actuaries Issuing Statement of Actuarial Opinion in the United States to render the actuarial opinion contained here.

This valuation has been conducted in accordance with generally accepted actuarial principles and practices. The actuarial assumptions and methods employed in the measurement of the liability have been selected by Pinnacle Actuarial Resources, Inc. after consultation with the staff of the Department of Environmental Protection and the Special Reclamation Fund Board.

The results shown in this report are reasonable actuarial results. However, a different set of results could also be considered reasonable actuarial results. The reason for this is that actuarial standards of practice describe a "central estimate" for each assumption, rather than a single best-estimate value. Thus, reasonable results differing from those presented in this report could have been developed by selecting different points within the best-estimate ranges for various assumptions.

Christopher S. Carlson, FCAS, MAAA
Consulting Actuary
Pinnacle Actuarial Resources, Inc

John E. Wade, ACAS, MAAA
Senior Consulting Actuary
Pinnacle Actuarial Resources, Inc

December 2011

SECTION 1

ACTUARIAL VALUATION

BACKGROUND

This is the second actuarial valuation performed by Pinnacle Actuarial Resources, Inc. of the Special Reclamation Fund and the Special Reclamation Water Trust Fund. Prior valuations were completed by the Hay Group in 2007 and 2008. As in the prior valuations, forfeiture and release rates and reclamation costs have been selected on per permit or per acre bases separately for Underground, Surface, and Other permits. We have revised selections of expected future release rates based upon the available data. We have also reviewed the forfeiture data and developed expected forfeiture rates, based upon the fiscal calendar year rather than the year of permit issuance. This selection process is described more fully later in this document.

This valuation builds on the prior analyses valuations and develops separate updated reclamation costs for the different types of permits using the most up-to-date costs as reported in the Department of Environmental Protection database.

We have prepared a measurement of current liabilities and assets in accordance with the guidance set out in Governmental Accounting Standard Number 10, an excerpt of which is:

State and local governmental entities other than public entity risk pools are required to report an estimated loss from a claim as an expenditure/expense and as a liability if both of these conditions are met:

a. *Information available before the financial statements are issued indicates that it is probable that an asset had been impaired or a liability had been incurred at the date of the financial statements. It is implicit in this condition that it must be probable that one or more future events will also occur, confirming the fact of the loss.*
b. *The amount of the loss can be reasonably estimated.*

This valuation is a "closed" valuation in that it only considers liabilities associated with permits that have already been issued. With regard to the basis for the fund's liabilities, we believe the accounting rules are framed to require the fund to account for both known forfeitures and anticipated forfeitures from existing permits. Accordingly, we have included in this report reclamation liabilities based on the date of forfeiture as well as based on the date of permit, to provide the SRF Advisory Council with a complete picture of the fund's obligations.

DISTRIBUTION AND USE

The purpose of this report is to provide information to the Department of Environmental Protection to address the long-term funding requirements for both the Special Reclamation Fund and the Special Reclamation Water Trust Fund. It may be given to the SRF Advisory Council and the State of West Virginia's external auditor. However, we ask that this report be reproduced only in its entirety so that the reader has the full benefit of the information provided. Other distribution or use of this report or the estimates contained in it before it is made available to the public requires our prior, written permission.

LIMITATIONS AND RELIANCES

We relied without audit or verification on issued permits, forfeited permits, investment return and other information supplied for this analysis by Tom McCarthy, Jean Sheppard, Yvonne Anderson, David McCoy, Michael Sheehan and Jennifer Paxton, all employees of the West Virginia Department of Environmental Protection. We reviewed the data for overall reasonableness and consistency. When inconsistencies in the data arose, we worked with the above named individuals to gain a better understanding and were able to make the required adjustments as needed. Especially with the introduction of new estimates late in the analysis process, there may be additional issues in the data files that our review did not uncover. As such, if issues are discovered with the data as provided, we would ask to be informed as our estimates heavily rely upon the data.

ACTUARIAL MODEL

The actuarial model combines the Department of Environmental Protection Special Reclamation Unit's estimated reclamation expenditures of the permits that have already been forfeited with the projection of estimated expenditures associated with the estimated numbers and types of future forfeited permits. The actuarial model uses separate release and forfeiture rates to project the expected number of existing permits/acres to be released and the number of permits/acres that are expected to be forfeited in the future. The model assumes that the SRF does not incur any additional costs when a permit is released. The model projects four types of expenditures associated with a forfeited permit. A forfeited permit is expected to produce associated revenues to the SRF in the form of the amount of the bond associated with the permit and/or any associated civil penalties or court settlements.

The four types of reclamation expenditures associated with a forfeited permit are:

- Land capital expenditures
- Water capital expenditures
- Ongoing water treatment costs
- Water abandonment costs

Some forfeited sites will require only land capital expenditures, while others may require both land and water capital expenditures. The current model assumes that where water capital expenditures are incurred there also will be ongoing water treatment costs. The future reclamation capital costs are developed based on a projection of the forfeited acreage, the current status of each permit and the average reclamation cost amounts per permitted acre. With this treatment of costs as an overall average across permits, the water capital expenditures are projected for all forfeited permits, even though some sites may not require water treatment activities.

The future annual water treatment expenditures have been developed differently with this analysis from prior reports. The prior estimates were based on the total water treatment costs of forfeited permits where the water treatment process was fully completed. With the recent settlement agreement regarding compliance with the NPDES water quality standards, the prior costs are not reflective of future costs. We were provided with the increased annual water treatment costs for the forfeited permits currently in the process of treating water and those permits where the water treatment facilities are yet to be completed. These costs are from a study completed by Dr. Paul Ziemkiewicz and his colleagues at West Virginia University along with the members of the team in the Office of Special Reclamation.

As the treatment continues through time, it is expected that the nominal cost of treatment will decline by 2 percent per year before the application of normal cost inflation which is assumed to be 4 percent per year. Thus, the net annual change in water treatment costs is expected to be 2 percent.

We also have expanded the number of years in which the water treatment process is expected to operate. The previous studies assumed a 17 year timeframe for treatment. At that time, the water treatment facilities would be dismantled; incurring water abandonment costs. Based upon the recommendation of Michael Sheehan and his staff in the Office of Special Reclamation, we are now assuming the Water Treatment costs will continue to be required beyond the 35 year time horizon of our estimates. This assumption leaves the Water Abandonment costs outside of the study horizon and becomes an un-reflected cost within our estimates. Thus, all water abandonment costs related to forfeited permits requiring water treatment would be in addition to any numbers quoted in this report.

Our analysis includes a projection of the administration costs expected to be incurred in the oversight of the reclamation activities. We have assumed that the administration costs are independent of the reclamation expenditures and will increase into the future in line with price inflation. We have not made an explicit adjustment to administrative costs for the fact that as time passes, forfeited sites being handled will include permits not yet issued as of July 2011.

The actuarial model was applied to a database of all existing issued permits that have not yet been released or forfeited. The data on each permit included:

- Date of permit issue
- Status of permit (Active, Inactive or Phased Release)
- Type of permit (Underground, Surface, or Other)
- Number of permitted acres
- Total current bond amount

The model projects the number of permits/acres expected to be released or forfeited each year over the next 20+ years.

The projection of permit forfeiture is also used to determine the expected revenues from bond forfeiture and/or civil penalties and court settlements.

The actuarial model produced as output expected cash disbursements over the next 35 years. These disbursements were incorporated into a cash flow model that included projected tax receipts from coal production. The resulting fund balance, after consideration of administration costs, was assumed to earn investment rates roughly equal to the current Treasury rates based on varying investment horizons. The current Treasury rates are 0.125 percent for investments less than 2 years and increase up to a rate of 3.75 percent for investments 20 years or greater. The graduated rates, used in our estimates, project the expected investment rates into the future.

THE KEY MODEL COMPONENTS

The actuarial model used the following components, each of which was developed from an analysis of experience data.

- Rates of release of permits by type of permit
- Rates of forfeiture of permits by type of permit
- Disturbed acres as a percent of permitted acres
- Expected land capital costs per disturbed acre
- Expected water capital costs per disturbed acre
- Expected ongoing water treatment costs per disturbed acre
- Expected water abandonment costs per disturbed acre
- Administration costs

Expected Release and Forfeiture Rates

With this analysis, we have reviewed the historical release and forfeiture data of the West Virginia Program. We have revised the expected release rates for the surface mine, underground mine and other facilities permits. We have removed the distinction between permits issued before 1996 and permits issued after 1995 used in prior studies. Our selections relied primarily on the release activity over the past 10 fiscal calendar years. As such, much of the activity related to the older permits in the early years of operation is not considered. We did not observe an obvious difference in the release rate activity based upon year in which the permit was issued. The selected release rates are provided in Tables 4.1, 4.2 and 4.3 of the Exhibit package.

The projected forfeiture rates have been selected on a fiscal calendar year basis rather than based upon the year of permit issuance as previously used in studies of the Fund. With the sporadic nature of forfeitures and the high likelihood that there is correlation between permit forfeiture of multiple permits of one operator, we feel that this calendar year method of estimation is more appropriate for the West Virginia dynamics associated with this analysis. We reviewed the historical and recent forfeiture rates as a percent of open permits and selected a rate for each of surface mines, underground mines and other facility permits. The selected rates are shown in Tables 4.1, 4.2 and 4.3 of the Exhibit package. Note that we continue to expect that there will be no forfeitures during the first three years following this issuance of any permit in West Virginia.

Since inception of the Special Reclamation Trust Fund in 1977, nearly 6,000 coal-related permits have been issued in West Virginia, 1,773 of which were still in-force as of June 30, 2011. A summary of the in-force and forfeited permit information is found in Section 3.

Each permit in the open permit database had an associated status. We grouped the statuses into three main categories:

- active,
- inactive, and
- phased release.

We performed the analysis of costs based on disturbed acres of the previously forfeited permits. As not all of the permitted acres are disturbed in the current coal production process, adjustment factors have been developed based on the percent of permitted acres that are disturbed. The ratios of disturbed acres to permitted acres are displayed in Table 4.4. With the expansion of the analysis to project water treatment based upon forfeited permits that are currently or expected to treat water issues, we have expanded this table to develop ratios based upon the inventory of those permits.

Permits that have already entered a phased release status were deemed to be much less likely to be forfeited than those in active or inactive status. However, as a single mine operator may hold permits in all three statuses, even some permits in phased release status may be forfeited due to enterprise risk rather than reclamation cost risk. We therefore applied a factor to each permit based on these categories that reflected variations in the magnitude of potential forfeiture and liability to the Fund. The factors used are shown in Table 4.5.

Development of Cost per Acre

We performed an analysis of the land capital expenditures for the 1,905 permits that have been forfeited in West Virginia as of June 30, 2011.

Table 1.1 provides the development of Land Capital Expenditures per Acre and by Permit Type.

Table 1.2 provides the development of Water Capital Expenditures per Acre and by Permit Type. The estimate of Water Capital Costs has been adjusted due to the new NPDES requirements. In previous studies, this figure was developed based upon the water capital costs to construct treatment facilities based on the old standards.

We are including only the actual costs for permits currently treating water as we have been provided with the significant additional cost to upgrade these facilities to treat to the higher standards. For comparison purposes, the original cost of currently operating water treatment facilities was $4 million. Per the information from the Office of Special Reclamation, the cost to enhance these facilities to provide treatment up to the NPDES standards is an additional $17.2 million. There are 42 sites where the water treatment facilities are yet to be constructed. The cost of these new facilities is anticipated to be $30.4 million. These figures are provided in Appendix A, which is based upon the figures developed by the Office of Special Reclamation and the team from West Virginia University.

Based upon the percentage of previously forfeited permits with significant water treatment issues (shown on Tables 3.2, 3.3 and 3.4), we have adjusted the projected future costs per permitted acre to reflect the fact that not all future forfeitures are anticipated to have significant water treatment issues. We have assumed that permits classified as "Closed Not Water But With Water Costs" do not have significant water treatment issues but rather the costs incurred were to test for compliance prior to closure.

Table 1.3 displays the Water Abandonment Costs per Acre by Permit Type.

The valuation includes the anticipated costs for water capital equipment removal after testing indicates that water treatment is no longer needed. We are now assuming that all water treatment will continue over the next 35 years and thus, have not included any water abandonment costs within our projections.

Table 1.4 provides a summary of the expected reclamation costs per Forfeited Acre by Permit Type. The Table is provided here as well as in the exhibit package.

Table 1.4			
Reclamation Costs Summary			
(In 2011 Dollars)			
Based upon Forfeited Permits	***Surface***	***Underground***	***Other***
Land Capital Cost Per Permitted Acre	2,898.24	13,259.83	9,575.60
Water Capital Cost Per Permitted Acre	913.81	1,024.62	1,804.78
Water Abandonment Cost Per Permitted Acre	203.38	538.46	473.16
Total Capital Cost Per Permitted Acre	4,015.43	14,822.91	11,853.55

Based on the anticipated ongoing annual water treatment estimates developed by the Office of Special Reclamation in conjunction with Dr. Ziemkiewicz and his team at West Virginia University (displayed in Appendix A), we have developed the estimates of future water treatment costs per permitted acre. Table 1.5 summarizes the data for ongoing water treatment costs and shows the development of the initial year annual water treatment costs.

We have made a similar adjustment to the water treatment cost estimate as with the water capital estimate to reflect the assumption that not all future forfeited acres/permits will have water treatment issues. The ratio used in our analysis is based upon the historical ratio of forfeited permits with water treatment issues to the total number of forfeited permits. The development of these ratios is displayed in Tables 3.2, 3.3 and 3.4.

To show the impact of the new NPDES standards, we provide the prior expected annual expenditure for permits currently treating water.

We also note that the prior studies were based upon the annual costs from permits where the water treatment had been completed and the facilities dismantled. Even with an adjustment for inflation, we now see that this method seriously under-estimated the future annual water treatment costs.

Administration Costs

The Administration Costs are displayed and discussed further in the following section, Actuarial Valuation.

ACTUARIAL VALUATION

The actuarial model builds on the current cash projections developed by the Department of Environmental Protection for the expected reclamation costs on sites where permits have already been forfeited. The figures for permits forfeited prior to July 1, 2011 were provided by the Department of Environmental Protection in their Job Scheduling Report as of June 30, 2011. The following tables show the expected expenditures for the next 35 years in the following categories:

- **Table 1.6 - Land Capital Expenditures**
- **Table 1.7 - Water Capital Expenditures**
- **Table 1.8 –Water Abandonment Expenditures**
- **Table 1.9 - Water Treatment Expenditures**

Each table provides the estimated expenditures in the following categories:

- Permits forfeited prior to July 1, 2011 (from the Job Scheduling Report)
- Permits forfeited after July 1, 2011
- Total of the above

Fixed Pre-Existing (Legacy) Water Treatment Costs

In prior studies, the fixed pre-existing or legacy water treatment costs for five specific sites with multiple permits for which the Department of Environmental Protection took over responsibility from the federal Office of Surface Mining had been separately included in the analysis. We had assumed that the costs *($3.7 million annually)* would be those included by the Department of Environmental Protection in their Job Scheduling Report.

With the expansion of the water treatment costs to reflect the NPDES standards, we have included the water treatment cost of these sites as part of the water treatment estimates for currently forfeited permits. A major contributor to the future water treatment from these "legacy" sites is the permits of the DLM Coal Company which add $400,000 to the annual expected future water treatment costs.

Administration Costs

Generally, the administration costs are independent of the cost of the reclamation activities. The current DEP staffing levels may be adjusted over time as the inventory of older permit forfeitures is processed. We have assumed the current staffing levels will remain unchanged. Future administration costs were estimated by increasing the current administration costs by 1.5 percent per year. These expected costs by year are displayed in Table 1.11.

Coal Tax Revenues

Table 1.12 shows the projected coal production and the projected Coal Tax revenue by year and fund. These coal production figures have been taken from the "Consensus Coal Production Forecast for West Virginia 2010 Update" as prepared by George W. Hammond, PhD of West Virginia University's College of Business & Economics.

For the revenue projections included in our analysis, we have limited the expected coal tax revenues to the portion of the total expected coal tax revenues that are attributable to the permits issued prior to June 30, 2011. The expected coal tax to be paid from the permits issued prior to June 30, 2011 have been developed using the ratio of expected remaining surface and underground mining acres under permit to the total acres as of June 30, 2011. This ratio is provided in column (3) of this Table.

Bond Forfeiture, Civil Penalties, and Court Settlements

Based on the permit and acreage forfeiture projections along with the current bond values on the open permits issued in each year, we had developed an estimation of the expected bond forfeiture collections in each of the next 35 fiscal years. As might be expected, the amounts decline over time as the permits in-force today decline through attrition, and the expected number of permit forfeitures declines as well.

Table 1.13 provides the estimated bond collections from future forfeitures.

Investment Income

The investment income has been estimated by applying the investment rates to the fund balance at the beginning of the year plus one-half the current year income less one-half the current year expenditures.

We have selected investment rates of return based upon the recent returns available through investing in US Treasuries. The recent returns on Fund investments have declined significantly since the last study and the onset of the current global financial crisis. Our short term rate of 0.125% is slightly less than the 2010 return of 0.195% earned by the Funds. The use of the rates of return on US Treasuries also facilitates the gradual increase in expected rates of return to more historical levels.

As the SRF is prohibited from borrowing, when the projected fund balance is zero, there will be no investment income in the following year.

Given the long term nature of the liabilities and the short term nature of current investments, the Fund Board might wish to consider alternative investment strategies.

Table 1.14 provides the projected future investment rates.

Permit and Acreage Projections

As part of the analysis, we have developed projections of the permits and acreage into the future. While the most important pieces of information are the number of forfeited permits and number of forfeited acres, the number of (open) permits that remain to be closed via release or forfeiture is also interesting and useful. We have made separate projections of the active and inactive permits as well as permits in phased release status.

- Table 1.15 - projected number of permits in-force over time.
- Table 1.16 -the projection of the acreage of permits in force.
- Table 1.17 - projected acreage of in-force permits, forfeited permits, and released permits

Please note that these projections are only for the permits that had been issued on or before June 30, 2011.

We have also provided these tables separated by the type of permit.

SECTION 2

PROJECTION OF REQUIRED INCOME

As requested by the Special Reclamation Fund Advisory Council, we have also developed an estimate of the required coal tax rates needed to generate income sufficient for the Funds to cover the projected forfeiture reclamation of in-force permits through 2046. We also were requested to provide a cash flow projection assuming a Special Reclamation Water Trust Fund tax rate of 15 cents per ton of coal.

Alternate Tables D and E show the projected cash flow for the next 35 years with the goal of a positive cash balance at the end of fiscal year 2046.

Alternate Table D shows that under the current projections, the Special Reclamation Fund SRF tax would need to increase to 14.35 cents per ton of coal in order to balance the projected future income with the projected reclamation expenditures of permits in force as of June 30, 2011. The primary cause for the indicated tax increase is the anticipated additional cost of water capital and water treatment expenses to be covered by the SRF prior to the transfer of responsibility for these costs to the Water Trust Fund. Due to the requirements to comply with the NPDES standard, the SRF has additional water capital costs for currently forfeited permits of $37.9 million.

Due to the revised water capital cost and treatment assumptions, the anticipated annual costs in the Special Reclamation Water Trust Fund and the time horizon for these annual costs to be required, the required future revenue in this Fund is greatly increased. Alternate Table E shows that under the current projections the Special Reclamation Water Trust Fund would need to increase significantly to 20.56 cents per ton of coal in order to balance the projected future income with the projected reclamation expenditures of the permits in force as of June 30, 2011.

Alternate Tables D and E can be found in the Exhibits section of this report.

With all of the new information and assumptions included in this analysis, some level of increase appears to be required in the short term especially in the Water Trust Fund. We might suggest an incremental approach toward the adequacy target be taken to allow the various estimates and assumptions to be tested.

Using a tax rate of 15 cents per ton of coal for the Special Reclamation Water Trust Fund, we project that the Fund could cover the expenditures through 2037 prior to developing a deficit. This estimate continues to assume that the Water Trust Fund will be used for any expenditure until fiscal year 2019. This alternative cash flow is provided in Tables 2.7, 2.8 and 2.9.

SECTION 3

DATA UNDERLYING ANALYSIS

Data provided for this study are enumerated and discussed below. We did not audit or verify the data, although we did put them through some reasonability tests and found no obvious problems. In addition, we also used information provided for the prior evaluations of the Special Reclamation Fund and the Special Reclamation Water Trust Fund.

Data Provided By West Virginia for This Study

We were provided with a complete copy of the OSR (Office of Special Reclamation) database containing the forfeited permits as of June 30, 2011 in an Excel spreadsheet. The OSR also provided a detailed list of field definitions applicable to their database.

We also obtained a separate database from the Division of Mining and Reclamation that provided detailed information regarding permits issued for coal mining operations.

Following is a summary of the changes in the number of permits contained in the various databases and categories using information contained in the prior report and the current files.

Summary of Forfeited Permits in West Virginia			
	Total	***Active Reclamation***	***Completed Reclamation***
As of 6/30/2010	1,895	146	1,749
As of 6/30/2011	1,905	127	1,778
Change	10	(19)	29

Summary of Issued Permits in West Virginia			
	Total	***In Force***	***Released or Forfeited***
As of 6/30/2010	5,902	1,775	4,127
As of 6/30/2011	5,948	1,773	4,175
Change	46	(2)	48

We have utilized the "Consensus Coal Production Forecast for West Virginia 2010 Update" prepared by George W. Hammond, PhD of West Virginia University's College of Business & Economics. The most recent report was issued by Dr. Hammond in October 2011.

The forfeiture and release rates were reviewed using the available historical data updated through June of 2011. Based upon that data, we have revised the expected release rates for the surface mine, underground mine and other facilities permits. We have removed the distinction between permits issued before 1996 and permits issued after 1995 used in prior studies. Our selections relied primarily on the release activity over the past 10 fiscal calendar years. As such, much of the activity related to the older permits in the early years of operation is not considered. We did not observe an obvious difference in the release rate activity based upon year in which the permit was issued. The selected release rates are provided in Tables 4.1, 4.2 and 4.3 of the Exhibit package.

Using the historical data, the projected forfeiture rates have been selected on a fiscal calendar year basis rather than based upon the year of permit issuance. With the sporadic nature of forfeitures and the high likelihood that there is correlation between permit forfeiture of multiple permits of one operator, we feel that this method of estimation is more appropriate for the West Virginia dynamics associated with this analysis. We reviewed the historical and recent forfeiture rates as a percent of open permits and selected a rate for each of surface mines, underground mines and other facility permits. The selected rates are shown in Tables 4.1, 4.2 and 4.3 of the Exhibit package. Note that we continue to expect that there will be no forfeitures during the first three years following this issuance of any permit in West Virginia.

We were provided with a copy of the Job Scheduling Report (JSR) as of June 30, 2011. This report contains the Department of Environmental Protection estimates of work scheduled to be performed on sites for permits forfeited prior to June 30, 2011. The JSR contains the expected amount of payment for work in the next several quarters. This information was used for projecting costs for land capital and water capital costs for permits forfeited prior to June 30, 2011. In addition, data in the JSR providing estimates of future Bond Forfeitures, Civil Penalties & Court Settlements was used in the valuation.

More recently, we were provided with additional expected water capital costs required to bring the existing water treatment facilities in compliance with the NPDES standards and the expected additional operating and maintenance water treatment costs to meet the NPDES water quality standards. We have used this information in conjunction with the most recent JSR data to better reflect the water treatment costs for permits which have already been forfeited in West Virginia.

Using the OSR Data – Forfeited Permits

Taking the database of forfeited permits as provided by the Department of Environmental Protection, we split the forfeited permit data into three components: Other, Surface, and Underground. Within these categories, we had four types of forfeited permits: open water, closed water, closed not water but with water costs, and land only. We further split each of these twelve categories into open land and closed land.

This resulted in the following eight categories for each of Other, Surface, and Underground:

- Open water – open land;
- Open water – closed land;
- Closed water – open land;
- Closed water – closed land;
- Closed not water but with water costs – open land;
- Closed not water but with water costs – closed land;
- Land only – open water; and
- Land only – closed water.

The water claims were determined by the use of the acid mine drainage code. Next, we split out the open and closed water claims. Open water forfeited permits are those that have not yet had the capital water projects completed. They are labeled TBC (to be contracted) or UC (under contract) in the water status column. As we worked our way through the remaining sorts, we discovered that there are some open water claims with no code in water status column because they are only being monitored at this time.

The closed water forfeited permits are those that have had the capital water projects completed but are undergoing monitoring and/or treatment. They are labeled ACT (active) or P (passive).

The closed not water but with water cost forfeited permits are those that have some capital or ongoing water costs associated with them but are not considered water forfeited permits. This can arise from several situations.

- A closed water forfeited permit that has four consecutive quarters of untreated water monitoring that shows no problems will be reclassified as closed (C);
- An open water forfeited permit that has four consecutive quarters of untreated water monitoring that shows no problems will be reclassified as not applicable (NA); and
- Land capital costs are at times labeled as water capital costs if they involve a water source even if the water is not being treated.

In all three situations, we treated the water capital and ongoing costs as land capital costs. This is consistent with the treatment in the prior actuarial study.

The land only forfeited permits are those that have no capital water costs or ongoing water costs.

We then went through these four categories and split them into open land and closed land based on the land status column. The open land claims were assigned to one of the following status:

- TBC (to be contracted),
- TPL (tree planting),
- SSR (sediment structure removal), or
- RO (reopened).

The closed land claims were assigned to the following status codes:

- UCW (under contract warranty),
- RPM (re-permitted),
- OTR (others to reclaim), or
- C (closed).

The first three closed land categories were deemed closed for the purpose of this study because any additional funds spent on the sites' reclamation would not come from the Special Reclamation Fund.

The final model parameters based on the OSR and other data are shown in Section 4.

Forfeited Permits by Type of Mining Operation –

Total Forfeited and Forfeited Pending Reclamation Completion

Of the 1,905 forfeited permits at June 30, 2011, 127 permits were either in active reclamation or awaiting reclamation activity.

In Tables 3.1 through 3.4 of the Exhibit Package, we display the total number of forfeited permits and the number of open forfeited permits, the total number of forfeited permitted acres and the number of open forfeited permitted acres that formed the basis for the measurement

- Table 3.1 - Forfeitures - All Permit Types
- Table 3.2 - Forfeitures – Surface Permits
- Table 3.3 - Forfeitures – Underground Permits
- Table 3.4 - Forfeitures - All Other Permit Types

In-Force Permits

In a separate database, we have been provided information regarding permits issued before June 30, 2011 that are still in-force. The in-force designation means that the site is either

a. currently being mined,
b. inactive and not yet reclaimed, or
c. in the process of being reclaimed (phased release)

Tables 3.5 through 3.8, displayed in the Exhibits section of our report, summarize the in-force permits and acreage as of June 30, 2011 by year of issuance and type of permit:

- Table 3.5 - the total number of permits and acres in force
  - Surface Mine,
  - Underground Mine,
  - Other Permit.
- Table 3.6 - Surface Permits in-force and issued by year.
- Table 3.7 - Underground Permits in-force and issued by year.
- Table 3.8 - Other Permits (acres) in-force and issued by year.

SECTION 4

ACTUARIAL ASSUMPTIONS

This section summarizes the actuarial assumptions used in the measurement.

Since the model is one based upon a projection of the number of permits that will be forfeited and become the obligation of the Funds, the rates of permit forfeiture and release are the first key model assumptions. The selected rates of forfeiture and release are applied to the current in-force permit counts by year of issuance and years since issuance, and by type of permit. The selected release and forfeiture rates by type of permit are displayed on Tables 4.1, 4.2, 4.3 and 4.4. Also, the number of forfeited acres is determined in this part of the process.

Table 4.1 Forfeiture and Release Rates – Surface Permits

Table 4.2 Forfeiture and Release Rates – Underground Permits

Table 4.3 Forfeiture and Release Rates – Other Permits

Once the number of projected forfeitures is determined, the cost of reclamation is estimated by applying the estimated average land reclamation costs, water reclamation costs, water abandonment costs and annual on-going water treatment costs per acre by type of mining operation (permit). The average costs in 2011 dollars as developed from the previously forfeited permit data are displayed in Table 4.6, shown below. In adjusting the previous costs to 2011 dollars, we have used a 5 percent inflation rate for reclamation costs.

Table 4.6

Cost Per Acre by Permit Type

(in 2011 Dollars)

	Surface	*Underground*	*Other Types*
Land Capital	2,898.24	13,259.83	9,575.60
Water Capital	913.81	1,024.62	1,804.78
Water Abandonment	203.38	538.46	473.16
Annual Water Treatment	101.39	141.27	199.22

In development of the cash flow projections, the first item to determine is the timing of future payments. We have used the following assumptions as to the delay between permit forfeiture and the expenditure of land capital and water capital funds for reclamation. This expenditure delay is the same as used in previous reviews by the Hay Group and our previous study. We have not attempted to test these assumptions based upon the timing of actual expenditures.

Land Capital and Water Capital Expenditure Delay	
Forfeiture Fiscal Year	***Expenditure Fiscal Year***
2012	Half in FY 2015, half in FY 2016
2013	Half in FY 2016, half in FY 2017
2014	All in FY 2017
2015	All in FY 2018
2016	Half in FY 2018, half in FY 2019
2017	All in FY 2019
2018 and beyond	Completed in fiscal year 2 years after forfeiture

For the projection of annual on-going water treatment expenditures, we have assumed that there is no delay between the water capital expenditure and the commencement of the on-going water treatment. Thus, the table above applies to the origination of the water treatment.

The projection of administration costs assumes an annual increase of 1.5 percent.

In the cash flow projections, we have applied an inflation rate to historical actual reclamation costs to develop these costs in terms of 2011 dollars. The inflation rate applied to these reclamation costs is 4.0 percent annually.

The reflection of investment income on the Fund Balances and general net cash flow has been developed based upon investment rates from US Treasuries. While the longer term investment returns are typically about 4 to 5 percent, the current returns of the Funds are less than 0.2 percent. The investment rates provided in Table 1.14 assume the current environment will gradually return to more long term rates in the coming years. Interim annual periods have been interpolated to further smooth the transition of rates to the historical levels. Implicit Discount Factors based upon the Investment Rates are also displayed in Exhibit 1.14.

We have continued to utilize the adjustment factors for Bond Value Size and Permit Status as shown in Tables 4.5 and 4.7 below.

Table 4.5	
Adjustment Factors for Permit Status	
Permit Status	***Liability Factor***
Active	100.00%
Inactive	75.00%
Phased Release	50.00%

We note that during our review this year, we discovered that the factors in Table 4.7 were not completely reflected in the previous analysis. This oversight resulted in an over-estimation of the future land capital costs in 2010 and is the main driver of the change in the Funded Status of the Special Reclamation Fund between the studies.

Table 4.7 Adjustment Factors for Size of Permits	
Bond Value	Factor
Less than $10,000	2.50
Between $10,000 and $100,000	1.00
Over $100,000	0.38

As previously mentioned, since not all permitted acres are disturbed during the mining operations, in the case of forfeiture, only a portion of the permitted acres will require reclamation. The following table shows the development of the percentages used in our analysis based upon historical forfeiture information.

Table 4.4 Percent of Permitted Acres That Had Been Disturbed Prior to Forfeiture			
Based upon Forfeited Permits	**Surface**	**Underground**	**Other**
Forfeited Disturbed Acres	35,485.10	3,741.43	3,945.70
Forfeited Permitted Acres	50,453.48	5,153.62	5,021.56
Percent of Permitted Acres That Are Disturbed	70.33%	72.60%	78.58%
Forfeited Disturbed Acres with Open Water	9,282.55	446.62	812.01
Forfeited Permitted Acres with Open Water	13,259.49	513.21	1,007.55
Percent Disturbed with Open Water	70.01%	87.02%	80.59%
Forfeited Disturbed Acres with Closed Water	5,827.57	305.89	805.36
Forfeited Permitted Acres with Closed Water	7,934.50	339.89	1,007.90
Percent Disturbed with Closed Water	73.45%	90.00%	79.90%

A new variable considered in this year's analysis is the structure of the permit ownership. This potential variable has come into focus based upon work of Christine Risch at Marshall University in the Center for Business and Economic Research. During the operation of the Fund, we have a record of only one revoked permit from a publicly traded company. This permit did not appear to have been handled by the Office of Special Reclamation.

However, we do not yet have information with respect to the complete universe of permits (i.e. How many of the released permits were also held by public companies). This information is needed in order to determine an appropriate adjustment factor to apply to the forfeiture rates based on ownership structure.

We have built the following table into our model for possible future reflection of the impact of ownership structure on our projection of future permit forfeitures.

Adjustment Factors for Ownership Structure	
Ownership Structure	***Factor***
Sole Proprietor	100%
Partnership	100%
Multi-Corporation	100%
Public Corporation	100%
Private Corporation	100%

As can be seen, our current model sets all the adjustment factors to 100% (i.e., no impact in this year's analysis).

Table A-1 **Special Reclamation Fund** Liability as of June 30, 2011 for Known and Expected Forfeitures ***Limited to a 20-Year Cash Flow*** (Present Value in $ Millions)			
	Currently Forfeited	Projected Forfeited	Total Liabilities
(1) Land Capital	12.1	91.6	103.8
(2) Water Capital	62.8	7.5	70.3
(3) Water Abandonment	0.0	0.0	0.0
(4) Ongoing Water Treatment	35.2	1.8	37.0
(5) Legacy Water Treatment	0.0	0.0	0.0
(6) Administration			48.7
Total			259.7

Footnotes:

(1)	Table 1.6 Col (7)
(2)	Table 1.7 Col (7)
(3)	Table 1.8 Col (7)
(4)	Table 1.9 Col (7)
(5)	Table 1.10 Col (3)
(6)	Table 1.11 Col (3)

Table A-2 **Special Reclamation Fund** Liability as of June 30, 2011 for Known and Expected Forfeitures ***Cash Flow Projection through 2046*** (Present Value in $ Millions)			
	Currently Forfeited	Projected Forfeited	Total Liabilities
(7) Land Capital	12.1	123.2	135.4
(8) Water Capital	62.8	7.5	70.3
(9) Water Abandonment	0.0	0.0	0.0
(10) Ongoing Water Treatment	35.2	1.8	37.0
(11) Legacy Water Treatment	0.0	0.0	0.0
(12) Administration			78.2
Total			320.8

Footnotes:

(7)	Table 1.6 Col (8)
(8)	Table 1.7 Col (8)
(9)	Table 1.8 Col (8)
(10)	Table 1.9 Col (8)
(11)	Table 1.10 Col (3)
(12)	Table 1.11 Col (3)

Table A-3
Special Reclamation Water Trust Fund
Liability as of June 30, 2011 for Known and Expected Forfeitures
Limited to a 20-Year Cash Flow
(Present Value in $ Millions)

	Currently Forfeited	Projected Forfeited	Total Liabilities
(1) Land Capital	0.0	0.0	0.0
(2) Water Capital	0.0	15.9	15.9
(3) Water Abandonment	0.0	0.0	0.0
(4) Ongoing Water Treatment	93.5	27.5	120.9
(5) Legacy Water Treatment	0.0	0.0	0.0
(6) Administration			0.0
Total			136.8

Footnotes:

(1)
(2) Table 1.7 Col (7)
(3) Table 1.8 Col (7)
(4) Table 1.9 Col (7)
(5) Table 1.10 Col (3)
(6)

Table A-4
Special Reclamation Water Trust Fund
Liability as of June 30, 2011 for Known and Expected Forfeitures
Cash Flow Projection through 2046
(Present Value in $ Millions)

	Currently Forfeited	Projected Forfeited	Total Liabilities
(7) Land Capital	0.0	0.0	0.0
(8) Water Capital	0.0	23.6	23.6
(9) Water Abandonment	0.0	0.0	0.0
(10) Ongoing Water Treatment	186.5	82.4	268.9
(11) Legacy Water Treatment	0.0	0.0	0.0
(12) Administration			0.0
Total			292.5

Footnotes:

(7)
(8) Table 1.7 Col (8)
(9) Table 1.8 Col (8)
(10) Table 1.9 Col (8)
(11) Table 1.10 Col (3)
(12)

Table B-1 **<u>Special Reclamation Fund</u>** Revenue Projection as of June 30, 2011 for Known and Expected Forfeitures ***Limited to a 20-Year Cash Flow*** (Present Value in $ Millions)			
Coal Tax Current Permits	Bond, Forfeiture, Civil Penalties and Court Settlements	Interest Income	Total Income
(1)	(2)	(3)	(4)
161.7	45.5	9.4	216.7

<u>Footnotes:</u>

(1) Table 1.12 Col (7)
(2) Table 1.13 Col (3)
(3) Table D Revenue Col (3) x Table 1.14 Col (2)
(4) Sum of Col (1) through Col (3)

Table B-2 **<u>Special Reclamation Fund</u>** Revenue Projection as of June 30, 2011 for Known and Expected Forfeitures ***Cash Flow Projections through 2046*** (Present Value in $ Millions)			
Coal Tax Current Permits	Bond, Forfeiture, Civil Penalties and Court Settlements	Interest Income	Total Income
(5)	(6)	(7)	(8)
179.9	50.7	11.5	242.0

<u>Footnotes:</u>

(5) Table 1.12 Col (7)
(6) Table 1.13 Col (3)
(7) Table D Revenue Col (3) x Table 1.14 Col (2)
(8) Sum of Col (5) through Col (7)

Table B-3 **<u>Special Reclamation Water Trust Fund</u>** Revenue Projection as of June 30, 2011 for Known and Expected Forfeitures ***Limited to a 20-Year Cash Flow*** (Present Value in $ Millions)			
Coal Tax Current Permits	Bond, Forfeiture, Civil Penalties and Court Settlements	Interest Income	Total Income
(1)	(2)	(3)	(4)
18.8	0.0	0.9	19.7

<u>Footnotes:</u>

(1)	Table 1.12 Col (8)
(2)	
(3)	Table E Revenue Col (3) x Table 1.14 Col (2)
(4)	Sum of Col (1) through Col (3)

Table B-4 **<u>Special Reclamation Water Trust Fund</u>** Revenue Projection as of June 30, 2011 for Known and Expected Forfeitures ***Cash Flow Projections through 2046*** (Present Value in $ Millions)			
Coal Tax Current Permits	Bond, Forfeiture, Civil Penalties and Court Settlements	Interest Income	Total Income
(5)	(6)	(7)	(8)
20.9	0.0	0.9	21.8

<u>Footnotes:</u>

(5)	Table 1.12 Col (8)
(6)	
(7)	Table E Revenue Col (3) x Table 1.14 Col (2)
(8)	Sum of Col (5) through Col (7)

Table C-1 **Special Reclamation Fund** Funded Status as of June 30, 2011 (in $ Millions)		
	20 Years	Through 2046
(1) Present Value of Future Revenues	216.7	242.0
(2) Assets as of June 30, 2011	70.2	70.2
(3) Assets + Present Value of Future Revenues	286.8	312.2
(4) Present Value of Future Expenditures	259.7	320.8
(5) Funded Status	110.4%	97.3%
(6) Year Fund Balance Becomes Negative	2039	

Footnotes:

(1)	Table B-1 Col (4); Table B-2 Col (8)
(2)	Client Data
(3)	Row (1) + Row (2)
(4)	Table A-1 Total; Table A-2 Total
(5)	Row (3) / Row (4)
(6)	Table D Summary

Table C-2 **Special Reclamation Water Trust Fund** Funded Status as of June 30, 2011 (in $ Millions)		
	20 Years	Through 2046
(1) Present Value of Future Revenues	19.7	21.8
(2) Assets as of June 30, 2011	5.9	5.9
(3) Assets + Present Value of Future Revenues	25.6	27.7
(4) Present Value of Future Expenditures	136.8	292.5
(5) Funded Status	18.7%	9.5%
(6) Year Fund Balance Becomes Negative	2038	

Footnotes:

(1)	Table B-3 Col (4); Table B-4 Col (8)
(2)	Client Data
(3)	Row (1) + Row (2)
(4)	Table A-3 Total; Table A-4 Total
(5)	Row (3) / Row (4)
(6)	Table E Summary

Table D Summary

Special Reclamation Fund

Projected Cash Flow For 2012 to 2046

(in $ Thousands)

Fiscal Year Ending 6/30	Expenditures	Revenue	Projected Fund Balance
	(1)	(2)	(3)
2011	0	0	70,154
2012	13,629	21,004	77,529
2013	22,290	19,322	74,560
2014	18,439	17,829	73,950
2015	26,002	16,886	64,834
2016	41,286	16,020	39,568
2017	23,392	14,830	31,007
2018	23,514	13,693	21,186
2019	12,203	12,755	21,738
2020	8,818	12,131	25,050
2021	8,729	11,238	27,560
2022	8,637	10,584	29,506
2023	8,544	9,937	30,899
2024	8,450	9,388	31,836
2025	8,358	8,757	32,235
2026	8,265	8,214	32,184
2027	8,172	7,608	31,620
2028	8,081	7,062	30,601
2029	7,993	6,562	29,169
2030	7,907	6,123	27,385
2031	7,822	5,660	25,223
2032	7,740	5,217	22,700
2033	7,661	4,792	19,830
2034	7,587	4,380	16,624
2035	7,519	3,981	13,086
2036	7,457	3,590	9,218
2037	7,400	3,204	5,023
2038	7,348	2,822	497
2039	7,302	2,508	-4,297
2040	7,260	2,308	-9,250
2041	7,224	2,125	-14,349
2042	7,192	1,956	-19,585
2043	7,165	1,801	-24,948
2044	7,142	1,659	-30,431
2045	7,124	1,528	-36,027
2046	7,109	1,407	-41,729

Footnotes:

(1) Table D Expenditures Col (7)

(2) Table D Revenue Col (4)

(3) Prior Col (3) + (Col (2) - Col (1))

Table D Expenditures

Special Reclamation Fund

Projected Cash Flow For 2012 to 2046

(in $ Thousands)

Fiscal Year Ending 6/30	Land Capital	Water Capital	Water Abandonment	Ongoing Water	Fixed Water Treatment	Administration Costs	Total Expenditures
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
2011	0	0	0	0	0	0	0
2012	4,748	3,112	0	3,369	0	2,400	13,629
2013	7,401	8,793	0	3,659	0	2,436	22,290
2014	0	12,008	0	3,959	0	2,473	18,439
2015	3,265	15,698	0	4,530	0	2,510	26,002
2016	6,710	26,389	0	5,639	0	2,548	41,286
2017	10,160	2,603	0	8,044	0	2,586	23,392
2018	9,870	2,530	0	8,489	0	2,625	23,514
2019	9,539	**Cost covered by Water Trust Fund post 2018**				2,664	12,203
2020	6,114					2,704	8,818
2021	5,984					2,745	8,729
2022	5,852					2,786	8,637
2023	5,717					2,827	8,544
2024	5,580					2,870	8,450
2025	5,445					2,913	8,358
2026	5,308					2,957	8,265
2027	5,171					3,001	8,172
2028	5,035					3,046	8,081
2029	4,901					3,092	7,993
2030	4,769					3,138	7,907
2031	4,637					3,185	7,822
2032	4,507					3,233	7,740
2033	4,380					3,281	7,661
2034	4,256					3,331	7,587
2035	4,138					3,381	7,519
2036	4,025					3,431	7,457
2037	3,917					3,483	7,400
2038	3,813					3,535	7,348
2039	3,714					3,588	7,302
2040	3,619					3,642	7,260
2041	3,527					3,696	7,224
2042	3,440					3,752	7,192
2043	3,357					3,808	7,165
2044	3,277					3,865	7,142
2045	3,200					3,923	7,124
2046	3,127					3,982	7,109

Footnotes:

(1) Table 1.6 Col (6)
(2) Table 1.7 Col (6)
(3) Table 1.8 Col (6)
(4) Table 1.9 Col (6)
(5) Table 1.10 Col (1)
(6) Table 1.11 Col (1)
(7) Sum of Col (1) through (6)

Table D Revenue

Special Reclamation Fund

Projected Cash Flow For 2012 to 2046

(in $ Thousands)

Fiscal Year Ending 6/30	SRF Coal Tax	Bond, Penalties, etc.	Investment Income	Total Revenue
	(1)	(2)	(3)	(4)
2011	0	0	0	0
2012	16,676	4,236	92	21,004
2013	15,094	4,085	142	19,322
2014	13,749	3,894	185	17,829
2015	12,770	3,684	432	16,886
2016	12,047	3,453	519	16,020
2017	11,190	3,223	417	14,830
2018	10,336	3,001	356	13,693
2019	9,620	2,789	346	12,755
2020	9,107	2,590	435	12,131
2021	8,283	2,402	553	11,238
2022	7,736	2,225	623	10,584
2023	7,194	2,060	683	9,937
2024	6,750	1,903	734	9,388
2025	6,225	1,757	775	8,757
2026	5,788	1,621	805	8,214
2027	5,290	1,495	823	7,608
2028	4,857	1,378	827	7,062
2029	4,474	1,270	818	6,562
2030	4,158	1,169	796	6,123
2031	3,822	1,076	761	5,660
2032	3,514	991	713	5,217
2033	3,230	912	649	4,792
2034	2,969	841	571	4,380
2035	2,729	775	477	3,981
2036	2,509	714	367	3,590
2037	2,306	658	240	3,204
2038	2,120	607	95	2,822
2039	1,948	560	0	2,508
2040	1,791	517	0	2,308
2041	1,647	478	0	2,125
2042	1,515	441	0	1,956
2043	1,394	408	0	1,801
2044	1,282	377	0	1,659
2045	1,179	349	0	1,528
2046	1,085	323	0	1,407

Footnotes:

(1) Table 1.12 Col (4)

(2) Table 1.13 Col (1)

(3) Table D Summary Prior Col (3) + [0.5 x Col (1) + Col (2) - Table D Summary Col (1)] x Table 1.14 Col (1)

(4) Sum of Col (1) through (3)

Table E Summary

Special Reclamation Water Trust Fund

Projected Cash Flow For 2012 to 2046

(in $ Thousands)

Fiscal Year Ending 6/30	Expenditures	Revenue	Projected Fund Balance
	(1)	(2)	(3)
2011	0	0	5,893
2012	0	1,948	7,841
2013	0	1,772	9,613
2014	0	1,625	11,237
2015	0	1,560	12,797
2016	0	1,536	14,333
2017	0	1,479	15,812
2018	0	1,428	17,240
2019	11,384	1,315	7,171
2020	10,871	1,101	-2,598
2021	11,211	963	-12,846
2022	11,559	900	-23,505
2023	11,914	837	-34,583
2024	12,277	785	-46,075
2025	12,650	724	-58,001
2026	13,030	673	-70,359
2027	13,420	615	-83,163
2028	13,819	565	-96,418
2029	14,229	520	-110,126
2030	14,649	483	-124,292
2031	15,079	444	-138,927
2032	15,521	409	-154,040
2033	15,975	376	-169,639
2034	16,442	345	-185,736
2035	16,923	317	-202,342
2036	17,419	292	-219,469
2037	17,929	268	-237,130
2038	18,454	246	-255,337
2039	18,996	227	-274,107
2040	19,554	208	-293,452
2041	20,129	192	-313,390
2042	20,722	176	-333,936
2043	21,334	162	-355,107
2044	21,964	149	-376,922
2045	22,615	137	-399,400
2046	23,286	126	-422,560

Footnotes:

(1) Table E Expenditures Col (7)

(2) Table E Revenue Col (4)

(3) Prior Col (3) + (Col (2) - Col (1))

Table E Expenditures

Special Reclamation Water Trust Fund

Projected Cash Flow For 2012 to 2046

(in $ Thousands)

Fiscal Year Ending 6/30	Land Capital	Water Capital	Water Abandonment	Ongoing Water	Fixed Water Treatment	Administration Costs	Total Expenditures
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
2011							
2012							
2013							
2014							
2015							
2016							
2017							
2018				**Cost covered by Special Reclamation Fund until 2019**			
2019		2,445	0	8,939	0		11,384
2020		1,565	0	9,306	0		10,871
2021		1,529	0	9,682	0		11,211
2022		1,493	0	10,066	0		11,559
2023		1,456	0	10,458	0		11,914
2024		1,419	0	10,858	0		12,277
2025		1,383	0	11,267	0		12,650
2026		1,345	0	11,685	0		13,030
2027		1,308	0	12,112	0		13,420
2028		1,271	0	12,549	0		13,819
2029		1,234	0	12,995	0		14,229
2030		1,198	0	13,451	0		14,649
2031		1,161	0	13,918	0		15,079
2032		1,125	0	14,396	0		15,521
2033		1,090	0	14,885	0		15,975
2034		1,056	0	15,386	0		16,442
2035		1,023	0	15,900	0		16,923
2036		992	0	16,426	0		17,419
2037		962	0	16,966	0		17,929
2038		934	0	17,521	0		18,454
2039		906	0	18,090	0		18,996
2040		880	0	18,674	0		19,554
2041		854	0	19,275	0		20,129
2042		830	0	19,892	0		20,722
2043		807	0	20,526	0		21,334
2044		785	0	21,179	0		21,964
2045		764	0	21,851	0		22,615
2046		743	0	22,542	0		23,286

Footnotes:

(1)

(2) Table 1.7 Col (6)

(3) Table 1.8 Col (6)

(4) Table 1.9 Col (6)

(5) Table 1.10 Col (1)

(6)

(7) Sum of Col (1) through (6)

Table E Revenue

Special Reclamation Water Trust Fund

Projected Cash Flow For 2012 to 2046

(in $ Thousands)

Fiscal Year Ending 6/30	SRWTF Coal **Tax 1.5 cents**	Bond, Penalties, etc.	Investment Income	Total Revenue
	(1)	(2)	(3)	(4)
2011	0	0	0	0
2012	1,939	0	9	1,948
2013	1,755	0	16	1,772
2014	1,599	0	26	1,625
2015	1,485	0	75	1,560
2016	1,401	0	135	1,536
2017	1,301	0	178	1,479
2018	1,202	0	226	1,428
2019	1,119	0	197	1,315
2020	1,059	0	42	1,101
2021	963	0	0	963
2022	900	0	0	900
2023	837	0	0	837
2024	785	0	0	785
2025	724	0	0	724
2026	673	0	0	673
2027	615	0	0	615
2028	565	0	0	565
2029	520	0	0	520
2030	483	0	0	483
2031	444	0	0	444
2032	409	0	0	409
2033	376	0	0	376
2034	345	0	0	345
2035	317	0	0	317
2036	292	0	0	292
2037	268	0	0	268
2038	246	0	0	246
2039	227	0	0	227
2040	208	0	0	208
2041	192	0	0	192
2042	176	0	0	176
2043	162	0	0	162
2044	149	0	0	149
2045	137	0	0	137
2046	126	0	0	126

Footnotes:

(1) Table 1.12 Col (5)

(2)

(3) Table E Summary Prior Col (3) + [0.5 x Col (1) + Col (2) - Table E Summary Col (1)] x Table 1.14 Col (1)

(4) Sum of Col (1) through (3)

Table F

Cost Per Acre by Permit Type

Based on Forfeited Permits

(in 2011 Dollars)

	Surface	Underground	Other Types
(1) Land Capital	2,898.24	13,259.83	9,575.60
(2) Water Capital	913.81	1,024.62	1,804.78
(3) Water Abandonment	203.38	538.46	473.16
Total	4,015.43	14,822.91	11,853.55

Footnotes:

(1) Table 1.1 Row (9)

(2) Table 1.2 Row (9)

(3) Table 1.3 Row (3)

Table 2.1 Alternative Table D Summary
Special Reclamation Fund
Projected Cash Flow For 2012 to 2046
Using Coal Tax Rate of 14.35 Cents (in $ Thousands)

Fiscal Year Ending 6/30	Expenditures	Income	Projected Fund Balance
	(1)	(2)	(3)
2011	0	0	70,154
2012	13,629	22,879	79,404
2013	22,290	21,024	78,138
2014	18,439	19,385	79,084
2015	26,002	18,358	71,440
2016	41,286	17,447	47,601
2017	23,392	16,191	40,400
2018	23,514	14,992	31,878
2019	12,203	14,019	33,694
2020	8,818	13,388	38,264
2021	8,729	12,460	41,995
2022	8,637	11,781	45,139
2023	8,544	11,112	47,707
2024	8,450	10,554	49,811
2025	8,358	9,906	51,358
2026	8,265	9,357	52,450
2027	8,172	8,740	53,018
2028	8,081	8,192	53,128
2029	7,993	7,697	52,832
2030	7,907	7,273	52,197
2031	7,822	6,825	51,199
2032	7,740	6,402	49,862
2033	7,661	6,002	48,203
2034	7,587	5,622	46,238
2035	7,519	5,259	43,978
2036	7,457	4,909	41,430
2037	7,400	4,571	38,601
2038	7,348	4,242	35,495
2039	7,302	3,919	32,112
2040	7,260	3,600	28,451
2041	7,224	3,285	24,512
2042	7,192	2,951	20,271
2043	7,165	2,621	15,727
2044	7,142	2,293	10,877
2045	7,124	1,966	5,720
2046	7,109	1,639	249

Table 2.2 Alternative Table D Expenditures

Special Reclamation Fund

Projected Cash Flow For 2012 to 2046

Using Coal Tax Rate of 14.35 Cents (in $ Thousands)

Fiscal Year Ending 6/30	Land Capital	Water Capital	Water Abandonment	Ongoing Water	Fixed Water Treatment	Administration Costs	Total Expenditures
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
2011	0	0	0	0	0	0	0
2012	4,748	3,112	0	3,369	0	2,400	13,629
2013	7,401	8,793	0	3,659	0	2,436	22,290
2014	0	12,008	0	3,959	0	2,473	18,439
2015	3,265	15,698	0	4,530	0	2,510	26,002
2016	6,710	26,389	0	5,639	0	2,548	41,286
2017	10,160	2,603	0	8,044	0	2,586	23,392
2018	9,870	2,530	0	8,489	0	2,625	23,514
2019	9,539	**Cost covered by Water Trust Fund post 2018**				2,664	12,203
2020	6,114					2,704	8,818
2021	5,984					2,745	8,729
2022	5,852					2,786	8,637
2023	5,717					2,827	8,544
2024	5,580					2,870	8,450
2025	5,445					2,913	8,358
2026	5,308					2,957	8,265
2027	5,171					3,001	8,172
2028	5,035					3,046	8,081
2029	4,901					3,092	7,993
2030	4,769					3,138	7,907
2031	4,637					3,185	7,822
2032	4,507					3,233	7,740
2033	4,380					3,281	7,661
2034	4,256					3,331	7,587
2035	4,138					3,381	7,519
2036	4,025					3,431	7,457
2037	3,917					3,483	7,400
2038	3,813					3,535	7,348
2039	3,714					3,588	7,302
2040	3,619					3,642	7,260
2041	3,527					3,696	7,224
2042	3,440					3,752	7,192
2043	3,357					3,808	7,165
2044	3,277					3,865	7,142
2045	3,200					3,923	7,124
2046	3,127					3,982	7,109

Table 2.3 Alternative Table D Revenue

Special Reclamation Fund

Projected Cash Flow For 2012 to 2046

Using Coal Tax Rate of 14.35 Cents (in $ Thousands)

Fiscal Year Ending 6/30	SRF Coal Tax	Bond, Penalties, etc.	Investment Income	Total Revenue
	(1)	(2)	(3)	(4)
2011	0	0	0	0
2012	18,550	4,236	93	22,879
2013	16,791	4,085	148	21,024
2014	15,295	3,894	196	19,385
2015	14,206	3,684	469	18,358
2016	13,401	3,453	592	17,447
2017	12,448	3,223	519	16,191
2018	11,498	3,001	494	14,992
2019	10,701	2,789	528	14,019
2020	10,130	2,590	668	13,388
2021	9,214	2,402	844	12,460
2022	8,606	2,225	951	11,781
2023	8,003	2,060	1,050	11,112
2024	7,509	1,903	1,141	10,554
2025	6,924	1,757	1,224	9,906
2026	6,438	1,621	1,297	9,357
2027	5,884	1,495	1,360	8,740
2028	5,403	1,378	1,411	8,192
2029	4,977	1,270	1,450	7,697
2030	4,625	1,169	1,479	7,273
2031	4,252	1,076	1,497	6,825
2032	3,909	991	1,503	6,402
2033	3,593	912	1,497	6,002
2034	3,303	841	1,479	5,622
2035	3,036	775	1,448	5,259
2036	2,791	714	1,404	4,909
2037	2,565	658	1,347	4,571
2038	2,358	607	1,277	4,242
2039	2,167	560	1,191	3,919
2040	1,992	517	1,091	3,600
2041	1,832	478	975	3,285
2042	1,686	441	824	2,951
2043	1,550	408	663	2,621
2044	1,426	377	490	2,293
2045	1,312	349	305	1,966
2046	1,207	323	110	1,639

Table 2.4 Alternative Table E Summary
Special Reclamation Water Trust Fund
Projected Cash Flow For 2012 to 2046
Using Coal Tax Rate of 20.56 Cents (in $ Thousands)

Fiscal Year Ending 6/30	Expenditures	Income	Projected Fund Balance
	(1)	(2)	(3)
2011	0	0	5,893
2012	0	26,602	32,495
2013	0	24,141	56,636
2014	0	22,082	78,718
2015	0	20,909	99,627
2016	0	20,293	119,920
2017	0	19,365	139,285
2018	0	18,502	157,787
2019	11,384	17,928	164,332
2020	10,871	17,629	171,091
2021	11,211	16,858	176,738
2022	11,559	16,238	181,417
2023	11,914	15,611	185,114
2024	12,277	15,125	187,962
2025	12,650	14,492	189,804
2026	13,030	13,981	190,755
2027	13,420	13,349	190,684
2028	13,819	12,795	189,660
2029	14,229	12,295	187,727
2030	14,649	11,874	184,952
2031	15,079	11,393	181,265
2032	15,521	10,922	176,666
2033	15,975	10,457	171,147
2034	16,442	9,991	164,695
2035	16,923	9,518	157,290
2036	17,419	9,034	148,905
2037	17,929	8,531	139,507
2038	18,454	8,005	129,059
2039	18,996	7,450	117,513
2040	19,554	6,859	104,818
2041	20,129	6,228	90,916
2042	20,722	5,481	75,675
2043	21,334	4,701	59,043
2044	21,964	3,884	40,963
2045	22,615	3,027	21,375
2046	23,286	2,126	215

Table 2.5 Alternative Table E Expenditures

Special Reclamation Water Trust Fund

Projected Cash Flow For 2012 to 2046

Using Coal Tax Rate of 20.56 Cents (in $ Thousands)

Fiscal Year Ending 6/30	Land Capital	Water Capital	Water Abandonment	Ongoing Water	Fixed Water Treatment	Administration Costs	Total Expenditures
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
2011							
2012							
2013							
2014							
2015							
2016							
2017							
2018		Cost covered by Special Reclamation Fund until 2019					
2019		2,445	0	8,939	0		11,384
2020		1,565	0	9,306	0		10,871
2021		1,529	0	9,682	0		11,211
2022		1,493	0	10,066	0		11,559
2023		1,456	0	10,458	0		11,914
2024		1,419	0	10,858	0		12,277
2025		1,383	0	11,267	0		12,650
2026		1,345	0	11,685	0		13,030
2027		1,308	0	12,112	0		13,420
2028		1,271	0	12,549	0		13,819
2029		1,234	0	12,995	0		14,229
2030		1,198	0	13,451	0		14,649
2031		1,161	0	13,918	0		15,079
2032		1,125	0	14,396	0		15,521
2033		1,090	0	14,885	0		15,975
2034		1,056	0	15,386	0		16,442
2035		1,023	0	15,900	0		16,923
2036		992	0	16,426	0		17,419
2037		962	0	16,966	0		17,929
2038		934	0	17,521	0		18,454
2039		906	0	18,090	0		18,996
2040		880	0	18,674	0		19,554
2041		854	0	19,275	0		20,129
2042		830	0	19,892	0		20,722
2043		807	0	20,526	0		21,334
2044		785	0	21,179	0		21,964
2045		764	0	21,851	0		22,615
2046		743	0	22,542	0		23,286

Table 2.6 Alternative Table E Revenue **Special Reclamation Water Trust Fund** Projected Cash Flow For 2012 to 2046 Using Coal Tax Rate of 20.56 Cents (in $ Thousands)				
Fiscal Year Ending 6/30	SRWTF Coal Tax	Bond, Penalties, etc.	Investment Income	Total Revenue
	(1)	(2)	(3)	(4)
2011	0	0	0	0
2012	26,578	0	24	26,602
2013	24,057	0	83	24,141
2014	21,913	0	169	22,082
2015	20,353	0	556	20,909
2016	19,201	0	1,092	20,293
2017	17,835	0	1,530	19,365
2018	16,474	0	2,028	18,502
2019	15,332	0	2,596	17,928
2020	14,514	0	3,115	17,629
2021	13,202	0	3,657	16,858
2022	12,330	0	3,908	16,238
2023	11,466	0	4,145	15,611
2024	10,759	0	4,367	15,125
2025	9,921	0	4,572	14,492
2026	9,224	0	4,756	13,981
2027	8,431	0	4,918	13,349
2028	7,741	0	5,055	12,795
2029	7,131	0	5,165	12,295
2030	6,626	0	5,247	11,874
2031	6,092	0	5,301	11,393
2032	5,600	0	5,322	10,922
2033	5,148	0	5,309	10,457
2034	4,732	0	5,258	9,991
2035	4,350	0	5,168	9,518
2036	3,998	0	5,035	9,034
2037	3,675	0	4,856	8,531
2038	3,378	0	4,627	8,005
2039	3,105	0	4,345	7,450
2040	2,854	0	4,005	6,859
2041	2,625	0	3,602	6,228
2042	2,415	0	3,066	5,481
2043	2,221	0	2,479	4,701
2044	2,043	0	1,841	3,884
2045	1,880	0	1,147	3,027
2046	1,729	0	397	2,126

Table 2.7 Proposed Tax Table E Summary **Special Reclamation Water Trust Fund** Projected Cash Flow For 2012 to 2046 Using Coal Tax Rate of 15 Cents (in $ Thousands)			
Fiscal Year Ending 6/30	Expenditures	Income	Projected Fund Balance
	(1)	(2)	(3)
2011	0	0	5,893
2012	0	19,410	25,303
2013	0	17,615	42,919
2014	0	16,115	59,034
2015	0	15,264	74,298
2016	0	14,821	89,119
2017	0	14,147	103,267
2018	0	13,521	116,788
2019	11,384	13,082	118,487
2020	10,871	12,808	120,424
2021	11,211	12,174	121,387
2022	11,559	11,646	121,473
2023	11,914	11,103	120,663
2024	12,277	10,655	119,040
2025	12,650	10,088	116,478
2026	13,030	9,598	113,046
2027	13,420	9,009	108,636
2028	13,819	8,464	103,280
2029	14,229	7,943	96,995
2030	14,649	7,465	89,810
2031	15,079	6,926	81,657
2032	15,521	6,378	72,514
2033	15,975	5,814	62,353
2034	16,442	5,229	51,140
2035	16,923	4,618	38,835
2036	17,419	3,973	25,389
2037	17,929	3,290	10,751
2038	18,454	2,561	-5,142
2039	18,996	2,265	-21,873
2040	19,554	2,082	-39,344
2041	20,129	1,915	-57,558
2042	20,722	1,762	-76,518
2043	21,334	1,621	-96,231
2044	21,964	1,491	-116,705
2045	22,615	1,371	-137,948
2046	23,286	1,261	-159,972

Footnotes:

(1) Table 2.8 Proposed Tax Table E Expenditures Col (7)

(2) Table 2.9 Proposed Tax Table E Revenue Col (4)

(3) Prior Col (3) + (Col (2) - Col (1))

Table 2.8 Proposed Tax Table E Expenditures **Special Reclamation Water Trust Fund** Projected Cash Flow For 2012 to 2046 Using Coal Tax Rate of 15 Cents (in $ Thousands)							
Fiscal Year Ending 6/30	Land Capital	Water Capital	Water Abandonment	Ongoing Water	Fixed Water Treatment	Administration Costs	Total Expenditures
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
2011							
2012							
2013							
2014							
2015							
2016							
2017							
2018		**Cost covered by Special Reclamation Fund until 2019**					
2019		2,445	0	8,939	0		11,384
2020		1,565	0	9,306	0		10,871
2021		1,529	0	9,682	0		11,211
2022		1,493	0	10,066	0		11,559
2023		1,456	0	10,458	0		11,914
2024		1,419	0	10,858	0		12,277
2025		1,383	0	11,267	0		12,650
2026		1,345	0	11,685	0		13,030
2027		1,308	0	12,112	0		13,420
2028		1,271	0	12,549	0		13,819
2029		1,234	0	12,995	0		14,229
2030		1,198	0	13,451	0		14,649
2031		1,161	0	13,918	0		15,079
2032		1,125	0	14,396	0		15,521
2033		1,090	0	14,885	0		15,975
2034		1,056	0	15,386	0		16,442
2035		1,023	0	15,900	0		16,923
2036		992	0	16,426	0		17,419
2037		962	0	16,966	0		17,929
2038		934	0	17,521	0		18,454
2039		906	0	18,090	0		18,996
2040		880	0	18,674	0		19,554
2041		854	0	19,275	0		20,129
2042		830	0	19,892	0		20,722
2043		807	0	20,526	0		21,334
2044		785	0	21,179	0		21,964
2045		764	0	21,851	0		22,615
2046		743	0	22,542	0		23,286

Footnotes:

(1)
(2) Table 1.7 Col (6)
(3) Table 1.8 Col (6)
(4) Table 1.9 Col (6)
(5) Table 1.10 Col (1)
(6)
(7) Sum of Col (1) through (6)

Table 2.9 Proposed Tax Table E Revenue
Special Reclamation Water Trust Fund
Projected Cash Flow For 2012 to 2046
Using Coal Tax Rate of 15 Cents (in $ Thousands)

Fiscal Year Ending 6/30	SRWTF Coal Tax	Bond, Penalties, etc.	Investment Income	Total Revenue
	(1)	(2)	(3)	(4)
2011	0	0	0	0
2012	19,390	0	19	19,410
2013	17,552	0	64	17,615
2014	15,987	0	127	16,115
2015	14,849	0	415	15,264
2016	14,008	0	813	14,821
2017	13,012	0	1,136	14,147
2018	12,019	0	1,503	13,521
2019	11,186	0	1,896	13,082
2020	10,589	0	2,219	12,808
2021	9,632	0	2,542	12,174
2022	8,996	0	2,650	11,646
2023	8,365	0	2,738	11,103
2024	7,849	0	2,806	10,655
2025	7,238	0	2,850	10,088
2026	6,730	0	2,869	9,598
2027	6,151	0	2,858	9,009
2028	5,647	0	2,816	8,464
2029	5,202	0	2,741	7,943
2030	4,834	0	2,630	7,465
2031	4,444	0	2,482	6,926
2032	4,086	0	2,292	6,378
2033	3,756	0	2,059	5,814
2034	3,452	0	1,777	5,229
2035	3,174	0	1,444	4,618
2036	2,917	0	1,056	3,973
2037	2,681	0	608	3,290
2038	2,465	0	97	2,561
2039	2,265	0	0	2,265
2040	2,082	0	0	2,082
2041	1,915	0	0	1,915
2042	1,762	0	0	1,762
2043	1,621	0	0	1,621
2044	1,491	0	0	1,491
2045	1,371	0	0	1,371
2046	1,261	0	0	1,261

Footnotes:

(1) Table 1.12 Col (5) x (15 cents / 1.5 cents)

(2)

(3) Table 2.7 Proposed Tax Table E Summary Prior Col (3) + [0.5 x Col (1) + Col (2) -
Table 2.7 Proposed Tax Table E Summary Col (1)] x Table 1.14 Col (1)

(4) Sum of Col (1) through (3)

Table 1.1
Land Capital Expenditure Per Acre by Permit Type
Based on Forfeited Permits

	Surface	Underground	Other
(1) Total expenditure in actual dollars	65,373,486.17	30,551,113.53	21,497,166.45
(2) Total disturbed acreage under permit	35,485.10	3,741.43	3,945.70
(3) Average cost per acre in actual dollars	1,842.28	8,165.62	5,448.25
(4) Mid-point of experience data	1994.5	1994.5	1994.5
(5) Average annual increase in Land capital expenditures over experience period	5%	5%	5%
(6) Increase factor (1.05)^16.5	2.24	2.24	2.24
(7) Average cost per disturbed acre in 2011 dollars	4,120.78	18,264.71	12,186.54
(8) Percent of permitted acreage that is disturbed	70.33%	72.60%	78.58%
(9) Cost Per Permitted Acre in 2011 dollars	2,898.24	13,259.83	9,575.60

Footnotes:

(1)	Client Data
(2)	Table 4.4 Row (1)
(3)	Row (1) / Row (2)
(4)	Client Data
(5)	Selection
(6)	(Row (5) + 1) ^ (2011 - Row (4))
(7)	Row (3) x Row (6)
(8)	Table 4.4 Row (3)
(9)	Row (7) x Row (8)

Table 1.2

Water Capital Expenditure Per Acre by Permit Type

Based on Forfeited Permits

	Surface	Underground	Other
(1) Total expenditure in actual dollars for Open Water Forfeited Permits	3,000,175.19	107,743.00	955,600.00
(2) Mid-point of experience data	2005.5	2005.5	2005.5
(3) Average annual increase in Water capital expenditures over experience period	5%	5%	5%
(4) Increase factor (1.04)^5.5	1.31	1.31	1.31
(5) Total expenditure in 2011 dollars	3,923,627.41	140,906.23	1,249,733.14
(6) Additional expenditure for Currently Operating Permits	9,525,645.19	2,855,677.68	4,778,686.90
(7) Additional expenditure for To Be Contracted Permits	26,939,389.28	2,261,848.00	1,245,217.50
(8) Total Expenditure	40,388,661.88	5,258,431.91	7,273,637.54
(9) Total disturbed acreage under permits with open water	9,282.55	446.62	812.01
(10) Average cost per disturbed acre in 2011 dollars	4,351.03	11,773.84	8,957.57
(11) Percent of permitted acreage that is disturbed under permits with open water	70.01%	87.02%	80.59%
(12) Cost Per Permitted Acre in 2011 dollars	3,046.02	10,246.16	7,219.13
(13) Percent of forfeited acres with water issues	30.00%	10.00%	25.00%
(114) Cost Per Permitted Acre in 2011 dollars with water issues	913.81	1,024.62	1,804.78

Footnotes:

(1)	Client Data Forfeited Database
(2)	Client Data
(3)	Selection
(4)	(Row (3) + 1) ^ (2011 - Row (2))
(5)	Row (1) x Row (4)
(6)	Client Data Appendix A
(7)	Client Data Appendix A
(8)	Row (5) + Row (6) + Row (7)
(9)	Client Data
(10)	Row (8) / Row (9)
(11)	Table 4.4 Row (6)
(12)	Row (10) x Row (11)
(13)	Table 3.2, Table 3.3, Table 3.4 Col (6)
(14)	Row (12) x Row (13)

Table 1.3

Water Abandonment Expenditure Per Acre by Permit Type

Based on Forfeited Permits

	Surface	Underground	Other
(1) Total expenditure in actual dollars	5,379,176.00	1,830,178.00	1,907,605.00
(2) Total disturbed acreage under permits with closed water	5,827.57	305.89	805.36
(3) Average cost per disturbed acre in 2011 dollars	923.06	5,983.12	2,368.64
(4) Percent of permitted acreage that is disturbed under permits with closed water	73.45%	90.00%	79.90%
(5) Cost Per Permitted Acre in 2011 dollars	677.95	5,384.62	1,892.65
(6) Percent of forfeited acres with water issues	30.00%	10.00%	25.00%
(7) Cost Per Permitted Acre in 2011 dollars with water issues	203.38	538.46	473.16

Footnotes:

(1)	Client Data
(2)	Client Data
(3)	Row (1) / Row (2)
(4)	Table 4.4 Row (9)
(5)	Row (3) x Row (4)
(6)	Table 3.2, Table 3.3, Table 3.4 Col (6)
(7)	Row (5) x Row (6)

Table 1.4

Total Capital Expenditure Per Acre by Permit Type

Based on Forfeited Permits

(in 2011 Dollars)

	Surface	Underground	Other
(1) Land Capital Cost Per Permitted Acre	2,898.24	13,259.83	9,575.60
(2) Water Capital Cost Per Permitted Acre	913.81	1,024.62	1,804.78
(3) Water Abandonment Cost Per Permitted Acre	203.38	538.46	473.16
(4) Total Capital Cost Per Permitted Acre	4,015.43	14,822.91	11,853.55

Footnotes:

(1)	Table 1.1 Row (9)
(2)	Table 1.2 Row (12)
(3)	Table 1.3 Row (3)
(4)	Sum of Row (1) through Row (3)

Table 1.5

Ongoing Water Treatment Expenditure Per Acre by Permit Type

Based on Forfeited Permits that are Currently Treating or Scheduled to Treat Water

	Surface	Underground	Other
(1) Total Annual Expenditure in Actual Dollars for Open Water Forfeited Permits	4,481,385.40	725,027.34	802,915.89
(2) Total disturbed acreage under permits with open water	9,282.55	446.62	812.01
(3) Total cost per disturbed acre for open sites	482.78	1,623.37	988.80
(4) Percent of permitted acreage that is disturbed under permits with open water	70.01%	87.02%	80.59%
(5) Valuation Cost Per Permitted Acre	337.98	1,412.73	796.90
(6) Percent of forfeited acres with water issues	30.00%	10.00%	25.00%
(7) Valuation Cost Per Permitted Acre with water issues	101.39	141.27	199.22
Prior Total Annual Expenditure in Actual Dollars for Open Water Forfeited Permits	1,309,558.48	55,574.26	100,299.42

Footnotes:

(1)	Client Data Appendix A
(2)	Client Data Appendix A
(3)	Row (1) / Row (2)
(4)	Table 4.4 Row (6)
(5)	Row (3) x Row (4)
(6)	Table 3.2, Table 3.3, Table 3.4 Col (6)
(7)	Row (5) x Row (6)

Table 1.5

Ongoing Water Treatment Expenditure Per Permit by Permit Type

Based on Forfeited Permits

	Surface	Underground	Other
(1) Total Annual Expenditure in Actual Dollars for Open Water Forfeited Permits	4,481,385.40	725,027.34	802,915.89
(2) Number of permits	140	31	18
(3) Total cost per permit for open sites	32,009.90	23,387.98	44,606.44

Footnotes:

(1)	Client Data
(2)	Client Data
(3)	Row (1) / Row (2)

Table 1.6

Land Capital Expenditures

(in 2011 Dollars)

	Nominal			Inflated at 4%			Discounted Based on US Treasury Return		
Fiscal Year	Prior to 7-1-11	After 7-1-11	Total	Prior to 7-1-11	After 7-1-11	Total	Prior to 7-1-11	After 7-1-11	Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2012	4,656,086	-	4,656,086	4,748,294	-	4,748,294	4,745,330	-	4,745,330
2013	6,978,460	-	6,978,460	7,401,328	-	7,401,328	7,387,472	-	7,387,472
2014	-	-	-	-	-	-	-	-	-
2015		2,845,836	2,845,836		3,264,575	3,264,575		3,236,184	3,236,184
2016		5,624,177	5,624,177		6,709,791	6,709,791		6,597,843	6,597,843
2017		8,188,224	8,188,224		10,159,518	10,159,518		9,881,934	9,881,934
2018		7,648,795	7,648,795		9,869,831	9,869,831		9,478,720	9,478,720
2019		7,108,330	7,108,330		9,539,324	9,539,324		9,025,929	9,025,929
2020		4,380,964	4,380,964		6,114,390	6,114,390		5,685,822	5,685,822
2021		4,122,785	4,122,785		5,984,219	5,984,219		5,455,666	5,455,666
2022		3,876,335	3,876,335		5,851,556	5,851,556		5,221,640	5,221,640
2023		3,641,457	3,641,457		5,716,874	5,716,874		4,989,352	4,989,352
2024		3,417,679	3,417,679		5,580,177	5,580,177		4,759,251	4,759,251
2025		3,206,797	3,206,797		5,445,296	5,445,296		4,534,949	4,534,949
2026		3,005,866	3,005,866		5,308,271	5,308,271		4,313,401	4,313,401
2027		2,815,399	2,815,399		5,170,788	5,170,788		4,096,333	4,096,333
2028		2,636,195	2,636,195		5,035,327	5,035,327		3,885,922	3,885,922
2029		2,467,415	2,467,415		4,901,463	4,901,463		3,681,937	3,681,937
2030		2,308,530	2,308,530		4,769,273	4,769,273		3,484,526	3,484,526
2031		2,158,088	2,158,088		4,636,809	4,636,809		3,292,370	3,292,370
2032		2,016,975	2,016,975		4,506,964	4,506,964		3,107,624	3,107,624
2033		1,884,616	1,884,616		4,379,652	4,379,652		2,930,196	2,930,196
2034		1,761,162	1,761,162		4,256,469	4,256,469		2,761,066	2,761,066
2035		1,646,462	1,646,462		4,138,425	4,138,425		2,600,702	2,600,702
2036		1,539,869	1,539,869		4,025,320	4,025,320		2,448,740	2,448,740
2037		1,440,786	1,440,786		3,916,964	3,916,964		2,304,819	2,304,819
2038		1,348,661	1,348,661		3,813,171	3,813,171		2,168,590	2,168,590
2039		1,262,983	1,262,983		3,713,766	3,713,766		2,039,711	2,039,711
2040		1,183,280	1,183,280		3,618,577	3,618,577		1,917,849	1,917,849
2041		1,109,114	1,109,114		3,527,442	3,527,442		1,802,680	1,802,680
2042		1,040,082	1,040,082		3,440,204	3,440,204		1,694,552	1,694,552
2043		975,807	975,807		3,356,713	3,356,713		1,593,664	1,593,664
2044		915,946	915,946		3,276,824	3,276,824		1,499,504	1,499,504
2045		860,176	860,176		3,200,399	3,200,399		1,411,596	1,411,596
2046		808,201	808,201		3,127,302	3,127,302		1,329,499	1,329,499
Total	11,634,546	89,246,993	100,881,539	12,149,622	160,355,675	172,505,297	12,132,801	123,232,570	135,365,371
First 20 Years	11,634,546	69,452,873	81,087,419	12,149,622	104,057,481	116,207,103	12,132,801	91,621,780	103,754,581

Footnotes:

(1) Client Data
(2) Table 1.16
(3) Col (1) + Col (2)
(4) Col (1) x 4% inflation
(5) Col (2) x 4% inflation
(6) Col (4) + Col (5)
(7) Col (4) x Table 1.14 Col (2)
(8) Col (5) x Table 1.14 Col (2)
(9) Col (7) + Col (8)

Table 1.7
Water Capital Expenditures
(in 2011 Dollars)

	Nominal			Inflated at 4%			Discounted Based on US Treasury Return		
Fiscal Year	Prior to 7-1-11	After 7-1-11	Total	Prior to 7-1-11	After 7-1-11	Total	Prior to 7-1-11	After 7-1-11	Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2012	3,051,084	-	3,051,084	3,111,508	-	3,111,508	3,109,565	-	3,109,565
2013	8,290,712	-	8,290,712	8,793,096	-	8,793,096	8,776,635	-	8,776,635
2014	10,886,374	-	10,886,374	12,007,888	-	12,007,888	11,955,517	-	11,955,517
2015	12,957,803	726,506	13,684,309	14,864,423	833,405	15,697,828	14,735,154	826,157	15,561,310
2016	20,681,162	1,438,402	22,119,563	24,673,170	1,716,051	26,389,222	24,261,516	1,687,420	25,948,936
2017		2,097,698	2,097,698		2,602,713	2,602,713		2,531,601	2,531,601
2018		1,960,976	1,960,976		2,530,398	2,530,398		2,430,126	2,430,126
2019		1,821,577	1,821,577		2,444,542	2,444,542		2,312,980	2,312,980
2020		1,121,278	1,121,278		1,564,936	1,564,936		1,455,248	1,455,248
2021		1,053,707	1,053,707		1,529,455	1,529,455		1,394,366	1,394,366
2022		989,205	989,205		1,493,263	1,493,263		1,332,514	1,332,514
2023		927,717	927,717		1,456,461	1,456,461		1,271,114	1,271,114
2024		869,173	869,173		1,419,132	1,419,132		1,210,357	1,210,357
2025		814,186	814,186		1,382,527	1,382,527		1,151,395	1,151,395
2026		761,713	761,713		1,345,163	1,345,163		1,093,054	1,093,054
2027		711,910	711,910		1,307,500	1,307,500		1,035,810	1,035,810
2028		665,241	665,241		1,270,660	1,270,660		980,608	980,608
2029		621,185	621,185		1,233,969	1,233,969		926,947	926,947
2030		579,693	579,693		1,197,608	1,197,608		874,996	874,996
2031		540,383	540,383		1,161,052	1,161,052		824,406	824,406
2032		503,544	503,544		1,125,176	1,125,176		775,827	775,827
2033		469,058	469,058		1,090,042	1,090,042		729,290	729,290
2034		436,946	436,946		1,056,034	1,056,034		685,023	685,023
2035		407,171	407,171		1,023,435	1,023,435		643,155	643,155
2036		379,557	379,557		992,188	992,188		603,582	603,582
2037		353,943	353,943		962,241	962,241		566,202	566,202
2038		330,180	330,180		933,543	933,543		530,915	530,915
2039		308,129	308,129		906,043	906,043		497,626	497,626
2040		287,662	287,662		879,695	879,695		466,239	466,239
2041		268,661	268,661		854,454	854,454		436,664	436,664
2042		251,018	251,018		830,276	830,276		408,971	408,971
2043		234,632	234,632		807,119	807,119		383,195	383,195
2044		219,409	219,409		784,944	784,944		359,197	359,197
2045		205,264	205,264		763,711	763,711		336,849	336,849
2046		192,116	192,116		743,384	743,384		316,032	316,032
Total	55,867,135	22,547,837	78,414,972	63,450,085	40,241,119	103,691,204	62,838,386	31,077,868	93,916,253
Years 2012 - 2018	55,867,135	6,223,581	62,090,717	63,450,085	7,682,567	71,132,653	62,838,386	7,475,304	70,313,690
Years 2019 - 2031	-	11,476,966	11,476,966	-	18,806,267	18,806,267	-	15,863,795	15,863,795
Years 2019 - 2046	-	16,324,256	16,324,256	-	32,558,551	32,558,551	-	23,602,564	23,602,564

Footnotes:

(1) Client Data
(2) Table 1.16
(3) Col (1) + Col (2)
(4) Col (1) x 4% inflation
(5) Col (2) x 4% inflation
(6) Col (4) + Col (5)
(7) Col (4) x Table 1.14 Col (2)
(8) Col (5) x Table 1.14 Col (2)
(9) Col (7) + Col (8)

Table 1.8
Water Abandonment Expenditures
(in 2011 Dollars)

	Nominal			Inflated at 4%			Discounted Based on US Treasury Return		
Fiscal Year	Prior to 7-1-11	After 7-1-11	Total	Prior to 7-1-11	After 7-1-11	Total	Prior to 7-1-11	After 7-1-11	Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2012		-	-	-	-	-	-	-	-
2013		-	-	-	-	-	-	-	-
2014		-	-	-	-	-	-	-	-
2015		-	-		-	-		-	-
2016		-	-		-	-		-	-
2017		-	-		-	-		-	-
2018		-	-		-	-		-	-
2019		-	-		-	-		-	-
2020		-	-		-	-		-	-
2021		-	-		-	-		-	-
2022		-	-		-	-		-	-
2023		-	-		-	-		-	-
2024		-	-		-	-		-	-
2025		-	-		-	-		-	-
2026		-	-		-	-		-	-
2027		-	-		-	-		-	-
2028		-	-		-	-		-	-
2029		-	-		-	-		-	-
2030		-	-		-	-		-	-
2031		-	-		-	-		-	-
2032		-	-		-	-		-	-
2033		-	-		-	-		-	-
2034		-	-		-	-		-	-
2035		-	-		-	-		-	-
2036		-	-		-	-		-	-
2037		-	-		-	-		-	-
2038		-	-		-	-		-	-
2039		-	-		-	-		-	-
2040		-	-		-	-		-	-
2041		-	-		-	-		-	-
2042		-	-		-	-		-	-
2043		-	-		-	-		-	-
2044		-	-		-	-		-	-
2045		-	-		-	-		-	-
2046		-	-		-	-		-	-
Total	-	-	-	-	-	-	-	-	-
Years 2012 - 2018	-	-	-	-	-	-	-	-	-
Years 2019 - 2031	-	-	-	-	-	-	-	-	-
Years 2019 - 2046	-	-	-	-	-	-	-	-	-

Footnotes:

(1)	Client Data
(2)	Table 1.16
(3)	Col (1) + Col (2)
(4)	Col (1) x 4% inflation
(5)	Col (2) x 4% inflation
(6)	Col (4) + Col (5)
(7)	Col (4) x Table 1.14 Col (2)
(8)	Col (5) x Table 1.14 Col (2)
(9)	Col (7) + Col (8)

Table 1.9
Water Treatment Expenditures
(in 2011 Dollars) **Including Legacy Sites**

	Nominal			Inflated at 4%			Discounted Based on US Treasury Return		
Fiscal Year	Prior to 7-1-11	After 7-1-11	Total	Prior to 7-1-11	After 7-1-11	Total	Prior to 7-1-11	After 7-1-11	Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2012	3,303,317	-	3,303,317	3,368,736	-	3,368,736	3,366,632	-	3,366,632
2013	3,450,340	-	3,450,340	3,659,417	-	3,659,417	3,652,566	-	3,652,566
2014	3,588,964	-	3,588,964	3,958,698	-	3,958,698	3,941,433	-	3,941,433
2015	3,867,033	81,623	3,948,656	4,436,031	93,633	4,529,664	4,397,453	92,819	4,490,271
2016	4,485,379	241,567	4,726,946	5,351,175	288,196	5,639,371	5,261,895	283,388	5,545,282
2017	6,009,329	473,953	6,483,281	7,456,059	588,056	8,044,114	7,252,340	571,988	7,824,329
2018	5,889,142	689,480	6,578,623	7,599,215	889,690	8,488,905	7,298,082	854,434	8,152,516
2019	5,771,359	889,660	6,661,019	7,745,120	1,193,917	8,939,037	7,328,286	1,129,662	8,457,948
2020	5,655,932	1,011,515	6,667,447	7,893,826	1,411,743	9,305,569	7,340,536	1,312,791	8,653,327
2021	5,542,813	1,127,342	6,670,156	8,045,388	1,636,336	9,681,724	7,334,784	1,491,808	8,826,592
2022	5,431,957	1,236,043	6,668,000	8,199,859	1,865,880	10,065,739	7,317,150	1,665,019	8,982,170
2023	5,323,318	1,337,978	6,661,296	8,357,297	2,100,547	10,457,844	7,293,758	1,833,235	9,126,993
2024	5,216,852	1,433,471	6,650,323	8,517,757	2,340,484	10,858,241	7,264,669	1,996,165	9,260,833
2025	5,112,515	1,522,914	6,635,429	8,681,298	2,585,982	11,267,280	7,229,954	2,153,656	9,383,611
2026	5,010,264	1,606,583	6,616,848	8,847,978	2,837,178	11,685,157	7,189,701	2,305,438	9,495,139
2027	4,910,059	1,684,774	6,594,833	9,017,860	3,094,271	12,112,131	7,144,009	2,451,302	9,595,311
2028	4,811,858	1,757,831	6,569,689	9,191,003	3,357,586	12,548,589	7,092,989	2,591,156	9,684,145
2029	4,715,621	1,826,043	6,541,664	9,367,470	3,627,391	12,994,861	7,036,763	2,724,865	9,761,629
2030	4,621,308	1,889,693	6,511,001	9,547,325	3,903,983	13,451,309	6,975,467	2,852,328	9,827,795
2031	4,528,882	1,949,020	6,477,902	9,730,634	4,187,612	13,918,246	6,909,244	2,973,417	9,882,662
2032	4,438,304	2,004,299	6,442,603	9,917,462	4,478,637	14,396,099	6,838,250	3,088,093	9,926,343
2033	4,349,538	2,055,786	6,405,325	10,107,877	4,777,435	14,885,312	6,762,651	3,196,331	9,958,981
2034	4,262,548	2,103,745	6,366,292	10,301,949	5,084,440	15,386,389	6,682,618	3,298,150	9,980,768
2035	4,177,297	2,148,431	6,325,727	10,499,746	5,400,138	15,899,884	6,598,335	3,393,598	9,991,933
2036	4,093,751	2,190,083	6,283,833	10,701,341	5,725,024	16,426,365	6,509,990	3,482,727	9,992,717
2037	4,011,876	2,228,920	6,240,795	10,906,807	6,059,609	16,966,415	6,417,781	3,565,594	9,983,374
2038	3,931,638	2,265,146	6,196,784	11,116,218	6,404,417	17,520,635	6,321,909	3,642,259	9,964,168
2039	3,853,005	2,298,948	6,151,954	11,329,649	6,759,990	18,089,639	6,222,583	3,712,789	9,935,372
2040	3,775,945	2,330,502	6,106,448	11,547,178	7,126,885	18,674,063	6,120,015	3,777,255	9,897,271
2041	3,700,426	2,359,969	6,060,395	11,768,884	7,505,675	19,274,559	6,014,422	3,835,733	9,850,156
2042	3,626,418	2,387,497	6,013,915	11,994,847	7,896,954	19,891,801	5,908,337	3,889,826	9,798,163
2043	3,553,890	2,413,224	5,967,114	12,225,148	8,301,334	20,526,482	5,804,122	3,941,217	9,745,339
2044	3,482,812	2,437,280	5,920,091	12,459,870	8,719,446	21,179,317	5,701,746	3,990,095	9,691,841
2045	3,413,155	2,459,781	5,872,937	12,699,100	9,151,944	21,851,043	5,601,175	4,036,636	9,637,811
2046	3,344,892	2,480,838	5,825,731	12,942,923	9,599,501	22,542,424	5,502,379	4,081,002	9,583,380
Total	155,261,737	54,923,939	210,185,677	319,491,142	138,993,916	458,485,058	221,634,024	84,214,777	305,848,801
Years 2012 - 2018	30,593,504	1,486,623	32,080,127	35,829,331	1,859,574	37,688,905	35,170,401	1,802,629	36,973,029
Years 2019 - 2031	66,652,738	19,272,868	85,925,606	113,142,813	34,142,913	147,285,727	93,457,310	27,480,844	120,938,154
Years 2019 - 2046	124,668,234	53,437,316	178,105,550	283,661,811	137,134,342	420,796,153	186,463,623	82,412,149	268,875,772

Footnotes:

(1) Client Data
(2) Table 1.16
(3) Col (1) + Col (2)
(4) Col (1) x 4% inflation
(5) Col (2) x 4% inflation
(6) Col (4) + Col (5)
(7) Col (4) x Table 1.14 Col (2)
(8) Col (5) x Table 1.14 Col (2)
(9) Col (7) + Col (8)

Table 1.10

Legacy Water Treatment

NOW INCLUDED IN TABLE 1.9

Fiscal Year	Dollars	Discount Factors	Discounted Dollars
	(1)	(2)	(3)
2012	-	99.938%	-
2013	-	99.813%	-
2014	-	99.564%	-
2015	-	99.130%	-
2016	-	98.332%	-
2017	-	97.268%	-
2018	-	96.037%	-
2019	-	94.618%	-
2020	-	92.991%	-
2021	-	91.168%	-
2022	-	89.235%	-
2023	-	87.274%	-
2024	-	85.289%	-
2025	-	83.282%	-
2026	-	81.258%	-
2027	-	79.221%	-
2028	-	77.173%	-
2029	-	75.119%	-
2030	-	73.062%	-
2031	-	71.005%	-
2032	-	68.952%	-
2033	-	66.905%	-
2034	-	64.868%	-
2035	-	62.843%	-
2036	-	60.833%	-
2037	-	58.842%	-
2038	-	56.871%	-
2039	-	54.923%	-
2040	-	53.000%	-
2041	-	51.104%	-
2042	-	49.257%	-
2043	-	47.477%	-
2044	-	45.761%	-
2045	-	44.107%	-
2046	-	42.513%	-
Total	-		-
Years 2012 - 2018	-		-
Years 2019 - 2031	-		-
Years 2019 - 2046	-		-

Footnotes:

(1) Client Data

(2) Table 1.14 Col (2)

(3) Col (1) x Col (2)

Table 1.11

Administrative Expenditures

Fiscal Year	Dollars	Discount Factors	Discounted Dollars
	(1)	(2)	(3)
2012	2,400,339	99.938%	2,398,840
2013	2,436,344	99.813%	2,431,783
2014	2,472,889	99.564%	2,462,104
2015	2,509,983	99.130%	2,488,154
2016	2,547,632	98.332%	2,505,127
2017	2,585,847	97.268%	2,515,195
2018	2,624,634	96.037%	2,520,628
2019	2,664,004	94.618%	2,520,630
2020	2,703,964	92.991%	2,514,439
2021	2,744,524	91.168%	2,502,115
2022	2,785,691	89.235%	2,485,814
2023	2,827,477	87.274%	2,467,656
2024	2,869,889	85.289%	2,447,686
2025	2,912,937	83.282%	2,425,951
2026	2,956,631	81.258%	2,402,503
2027	3,000,981	79.221%	2,377,397
2028	3,045,995	77.173%	2,350,692
2029	3,091,685	75.119%	2,322,448
2030	3,138,061	73.062%	2,292,730
2031	3,185,132	71.005%	2,261,605
2032	3,232,909	68.952%	2,229,143
2033	3,281,402	66.905%	2,195,414
2034	3,330,623	64.868%	2,160,493
2035	3,380,583	62.843%	2,124,453
2036	3,431,291	60.833%	2,087,371
2037	3,482,761	58.842%	2,049,325
2038	3,535,002	56.871%	2,010,393
2039	3,588,027	54.923%	1,970,652
2040	3,641,848	53.000%	1,930,183
2041	3,696,475	51.104%	1,889,063
2042	3,751,922	49.257%	1,848,095
2043	3,808,201	47.477%	1,808,016
2044	3,865,324	45.761%	1,768,806
2045	3,923,304	44.107%	1,730,447
2046	3,982,154	42.513%	1,692,919
Total	109,436,466		78,188,270
First 20 Years	55,504,640		48,693,497

Footnotes:

(1) Client Data
(2) Table 1.14 Col (2)
(3) Col (1) x Col (2)

Table 1.12								
Projected Coal Tax Revenues								
Fiscal Year	Production (Millions of Tons)	Total Tax	Pre 7-1-2011 Ratio	SRF	SRWTF	Discount Factors	Discounted SRF	Discounted SRWTF
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
2012	135.80	19,555,200	95.2%	16,675,795	1,939,046	99.938%	16,665,383	1,937,835
2013	129.50	18,648,000	90.4%	15,094,332	1,755,155	99.813%	15,066,074	1,751,869
2014	124.60	17,942,400	85.5%	13,749,174	1,598,741	99.564%	13,689,209	1,591,768
2015	122.50	17,640,000	80.8%	12,770,136	1,484,899	99.130%	12,659,079	1,471,986
2016	122.70	17,668,800	76.1%	12,047,218	1,400,839	98.332%	11,846,219	1,377,467
2017	121.40	17,481,600	71.5%	11,190,217	1,301,188	97.268%	10,884,472	1,265,636
2018	119.70	17,236,800	66.9%	10,336,257	1,201,890	96.037%	9,926,663	1,154,263
2019	119.10	17,150,400	62.6%	9,619,891	1,118,592	94.618%	9,102,159	1,058,391
2020	120.70	17,380,800	58.5%	9,106,596	1,058,907	92.991%	8,468,300	984,686
2021	117.70	16,948,800	54.6%	8,283,139	963,156	91.168%	7,551,535	878,086
2022	117.90	16,977,600	50.9%	7,736,296	899,569	89.235%	6,903,490	802,731
2023	117.80	16,963,200	47.3%	7,194,169	836,531	87.274%	6,278,649	730,075
2024	118.90	17,121,600	44.0%	6,750,268	784,915	85.289%	5,757,203	669,442
2025	118.00	16,992,000	40.9%	6,224,535	723,783	83.282%	5,183,914	602,781
2026	118.20	17,020,800	38.0%	5,787,587	672,975	81.258%	4,702,884	546,847
2027	116.50	16,776,000	35.2%	5,289,806	615,094	79.221%	4,190,620	487,281
2028	115.50	16,632,000	32.6%	4,856,779	564,742	77.173%	3,748,131	435,829
2029	115.00	16,560,000	30.2%	4,474,075	520,241	75.119%	3,360,887	390,801
2030	115.60	16,646,400	27.9%	4,157,503	483,431	73.062%	3,037,555	353,204
2031	115.00	16,560,000	25.8%	3,822,072	444,427	71.005%	2,713,865	315,566
2032	114.40	16,473,600	23.8%	3,513,615	408,560	68.952%	2,422,694	281,709
2033	113.80	16,387,200	22.0%	3,229,969	375,578	66.905%	2,161,003	251,279
2034	113.20	16,300,800	20.3%	2,969,144	345,249	64.868%	1,926,010	223,955
2035	112.60	16,214,400	18.8%	2,729,310	317,362	62.843%	1,715,175	199,439
2036	112.00	16,128,000	17.4%	2,508,782	291,719	60.833%	1,526,178	177,463
2037	111.40	16,041,600	16.0%	2,306,012	268,141	58.842%	1,356,903	157,779
2038	110.80	15,955,200	14.8%	2,119,572	246,462	56.871%	1,205,423	140,165
2039	110.20	15,868,800	13.7%	1,948,153	226,529	54.923%	1,069,984	124,417
2040	109.60	15,782,400	12.7%	1,790,548	208,203	53.000%	948,992	110,348
2041	109.10	15,710,400	11.7%	1,647,157	191,530	51.104%	841,770	97,880
2042	108.60	15,638,400	10.8%	1,515,220	176,188	49.257%	746,356	86,786
2043	108.10	15,566,400	10.0%	1,393,825	162,073	47.477%	661,745	76,947
2044	107.60	15,494,400	9.2%	1,282,130	149,085	45.761%	586,714	68,223
2045	107.10	15,422,400	8.5%	1,179,363	137,135	44.107%	520,180	60,486
2046	106.60	15,350,400	7.9%	1,084,812	126,141	42.513%	461,182	53,626
Total		584,236,800		206,383,457	23,998,076		179,886,601	20,917,047
First 20 Years		345,902,400		175,165,845	20,368,121		161,736,292	18,806,546

Footnotes:

(1) Client Data

(2) Col (1) x 1,000,0000 x Coal Tax of 14.4 cents / 100

(3) Ratio of current year Table 1.16 Col (1) surface and underground to all subsequent years Table 1.16 Col (1) surface and underground

(4) Col (2) x Col (3) x Coal Tax of (12.9 / 14.4)

(5) Col (2) x Col (3) x Coal Tax of (1.5 / 14.4)

(6) Table 1.14 Col (2)

(7) Col (4) x Col (6)

(8) Col (5) x Col (6)

Table 1.13
Projected Bond Forfeiture Collection

Fiscal Year	Projected Collection	Discount Factors	Discounted Projected Collection
	(1)	(2)	(3)
2012	4,235,516	99.938%	4,232,871
2013	4,085,370	99.813%	4,077,722
2014	3,894,485	99.564%	3,877,500
2015	3,683,886	99.130%	3,651,849
2016	3,453,448	98.332%	3,395,830
2017	3,223,472	97.268%	3,135,398
2018	3,000,704	96.037%	2,881,796
2019	2,789,018	94.618%	2,638,916
2020	2,589,783	92.991%	2,408,261
2021	2,402,143	91.168%	2,189,975
2022	2,224,662	89.235%	1,985,179
2023	2,059,502	87.274%	1,797,412
2024	1,903,331	85.289%	1,623,323
2025	1,757,014	83.282%	1,463,276
2026	1,621,447	81.258%	1,317,558
2027	1,495,245	79.221%	1,184,543
2028	1,378,231	77.173%	1,063,625
2029	1,269,553	75.119%	953,677
2030	1,168,951	73.062%	854,059
2031	1,076,214	71.005%	764,166
2032	990,840	68.952%	683,200
2033	912,492	66.905%	610,501
2034	840,582	64.868%	545,265
2035	774,572	62.843%	486,763
2036	713,970	60.833%	434,332
2037	658,324	58.842%	387,371
2038	607,220	56.871%	345,332
2039	560,280	54.923%	307,723
2040	517,158	53.000%	274,094
2041	477,536	51.104%	244,042
2042	441,122	49.257%	217,285
2043	407,651	47.477%	193,540
2044	376,878	45.761%	172,463
2045	348,580	44.107%	153,748
2046	322,551	42.513%	137,125
Total	58,261,732		50,689,719
First 20 Years	49,311,976		45,496,936

Footnotes:

(1)	Client Data
(2)	Table 1.14 Col (2)
(3)	Col (1) x Col (2)

Table 1.14

Projected Investment Rates

Based on US Treasury Returns in Fall 2011

Fiscal Year	Investment Return (%)	Discount Factors
	(1)	(2)
2012	**0.125**	99.938%
2013	0.188	99.813%
2014	**0.250**	99.564%
2015	0.625	99.130%
2016	**1.000**	98.332%
2017	1.188	97.268%
2018	**1.375**	96.037%
2019	1.625	94.618%
2020	1.875	92.991%
2021	**2.125**	91.168%
2022	2.206	89.235%
2023	2.288	87.274%
2024	2.369	85.289%
2025	2.450	83.282%
2026	2.531	81.258%
2027	2.613	79.221%
2028	2.694	77.173%
2029	2.775	75.119%
2030	2.856	73.062%
2031	2.938	71.005%
2032	3.019	68.952%
2033	3.100	66.905%
2034	3.181	64.868%
2035	3.263	62.843%
2036	3.344	60.833%
2037	3.425	58.842%
2038	3.506	56.871%
2039	3.588	54.923%
2040	3.669	53.000%
2041	**3.750**	51.104%
2042	3.750	49.257%
2043	3.750	47.477%
2044	3.750	45.761%
2045	3.750	44.107%
2046	3.750	42.513%

Footnotes:

(1) Based on US Treasury Returns in Fall 2011

(2) Based on Col (1)

Table 1.15

Projected Number of Permits In-Force

(All Permit Types Combined)

Fiscal Year Ending 6/30	Active	Inactive	Phase Released	Total
	(1)	(2)	(3)	(4)
2011	1,336	150	287	1,773
2012	1,276	143	268	1,686
2013	1,216	135	250	1,601
2014	1,157	128	233	1,518
2015	1,099	121	217	1,437
2016	1,042	115	201	1,359
2017	987	109	187	1,283
2018	934	103	174	1,211
2019	883	97	162	1,142
2020	834	91	151	1,076
2021	787	86	140	1,013
2022	742	81	130	953
2023	699	77	121	897
2024	659	72	113	844
2025	620	68	105	793
2026	584	64	97	746
2027	550	60	91	701
2028	518	57	84	659
2029	488	54	79	620
2030	459	50	73	583
2031	433	48	68	549
2032	408	45	64	516
2033	384	42	60	486
2034	362	40	56	458
2035	342	38	52	432
2036	323	36	49	407
2037	305	34	45	384
2038	289	32	43	363
2039	273	30	40	343
2040	258	29	37	324
2041	245	27	35	307
2042	232	26	33	291
2043	220	24	31	275
2044	209	23	29	261
2045	198	22	27	247
2046	188	21	26	235

Footnotes:

(1) Table 3.6 through Table 3.8 x Table 4.1 through Table 4.3

(2) Table 3.6 through Table 3.8 x Table 4.1 through Table 4.3

(3) Table 3.6 through Table 3.8 x Table 4.1 through Table 4.3

(4) Sum of Col (1) through Col (3)

Table 1.15

Projected Number of Permits In-Force

Surface Permits

Fiscal Year Ending 6/30	Active	Inactive	Phase Released	Total
	(1)	(2)	(3)	(4)
2011	431	20	130	581
2012	408	19	120	548
2013	386	18	111	515
2014	363	17	102	483
2015	341	16	94	452
2016	319	15	87	421
2017	298	14	80	392
2018	277	13	73	364
2019	258	12	67	337
2020	239	11	62	312
2021	221	11	57	288
2022	204	10	52	266
2023	189	9	48	245
2024	174	8	44	226
2025	160	8	40	208
2026	148	7	37	191
2027	136	7	33	176
2028	125	6	31	161
2029	114	5	28	148
2030	105	5	26	135
2031	96	5	23	124
2032	88	4	21	113
2033	80	4	20	104
2034	73	4	18	95
2035	67	3	16	87
2036	62	3	15	79
2037	56	3	14	73
2038	51	2	13	67
2039	47	2	12	61
2040	43	2	11	56
2041	39	2	10	51
2042	36	2	9	47
2043	33	2	8	43
2044	30	1	7	39
2045	28	1	7	36
2046	25	1	6	33

Footnotes:

(1) Table 3.6 x Table 4.1

(2) Table 3.6 x Table 4.1

(3) Table 3.6 x Table 4.1

(4) Sum of Col (1) through Col (3)

Table 1.15

Projected Number of Permits In-Force

Underground Permits

Fiscal Year Ending 6/30	Active	Inactive	Phase Released	Total
	(1)	(2)	(3)	(4)
2011	510	86	119	715
2012	484	81	111	676
2013	459	76	103	637
2014	433	71	96	600
2015	408	67	89	564
2016	384	62	83	529
2017	361	58	77	496
2018	339	54	71	464
2019	318	51	66	434
2020	298	47	61	405
2021	278	44	56	378
2022	259	41	52	352
2023	241	38	48	327
2024	225	35	45	304
2025	208	32	41	282
2026	194	30	38	262
2027	180	28	35	243
2028	167	26	33	225
2029	155	24	30	209
2030	143	22	28	193
2031	132	20	26	179
2032	122	19	24	165
2033	113	17	22	153
2034	105	16	20	141
2035	97	15	19	131
2036	90	14	17	121
2037	83	13	16	112
2038	77	12	15	104
2039	71	11	14	96
2040	66	10	13	89
2041	61	9	12	82
2042	56	9	11	76
2043	52	8	10	70
2044	48	7	9	65
2045	44	7	9	60
2046	41	6	8	55

Footnotes:

(1) Table 3.7 x Table 4.2

(2) Table 3.7 x Table 4.2

(3) Table 3.7 x Table 4.2

(4) Sum of Col (1) through Col (3)

Table 1.15
Projected Number of Permits In-Force
Other Permits

Fiscal Year Ending 6/30	Active	Inactive	Phase Released	Total
	(1)	(2)	(3)	(4)
2011	395	44	38	477
2012	383	43	37	463
2013	372	41	36	449
2014	360	40	34	435
2015	349	39	33	421
2016	339	38	32	408
2017	328	36	31	395
2018	318	35	30	383
2019	307	34	29	370
2020	298	33	28	358
2021	288	32	27	347
2022	278	31	26	335
2023	269	30	25	324
2024	260	29	24	313
2025	251	28	23	303
2026	243	27	23	292
2027	235	26	22	282
2028	227	25	21	273
2029	219	24	20	264
2030	211	23	20	255
2031	204	23	19	246
2032	197	22	18	238
2033	191	21	18	230
2034	184	20	17	222
2035	178	20	17	214
2036	172	19	16	207
2037	166	18	16	200
2038	160	18	15	193
2039	155	17	14	186
2040	150	17	14	180
2041	145	16	14	174
2042	140	15	13	168
2043	135	15	13	162
2044	130	14	12	157
2045	126	14	12	152
2046	122	13	11	146

Footnotes:
(1) Table 3.8 x Table 4.3
(2) Table 3.8 x Table 4.3
(3) Table 3.8 x Table 4.3
(4) Sum of Col (1) through Col (3)

Table 1.16

Projected Acreage of Permits In-Force

(All Permit Types Combined)

Fiscal Year Ending 6/30	Active	Inactive	Phase Released	Total
	(1)	(2)	(3)	(4)
2011	265,234	15,654	38,649	319,536
2012	253,279	14,946	35,914	304,139
2013	241,265	14,239	33,320	288,824
2014	229,322	13,527	30,899	273,748
2015	217,595	12,817	28,633	259,045
2016	205,963	12,130	26,504	244,597
2017	194,449	11,456	24,514	230,419
2018	183,268	10,813	22,673	216,754
2019	172,540	10,202	20,973	203,715
2020	162,283	9,629	19,401	191,313
2021	152,490	9,076	17,938	179,504
2022	143,273	8,546	16,572	168,391
2023	134,446	8,045	15,309	157,800
2024	126,077	7,561	14,143	147,780
2025	118,204	7,108	13,066	138,379
2026	110,770	6,681	12,073	129,524
2027	103,759	6,280	11,156	121,196
2028	97,127	5,901	10,311	113,339
2029	90,887	5,548	9,531	105,966
2030	85,028	5,218	8,812	99,058
2031	79,560	4,910	8,149	92,619
2032	74,476	4,623	7,537	86,636
2033	69,747	4,355	6,973	81,074
2034	65,348	4,104	6,452	75,904
2035	61,254	3,870	5,971	71,095
2036	57,444	3,651	5,527	66,621
2037	53,895	3,446	5,117	62,459
2038	50,591	3,255	4,739	58,584
2039	47,512	3,075	4,390	54,977
2040	44,642	2,908	4,068	51,617
2041	41,967	2,750	3,770	48,487
2042	39,472	2,603	3,495	45,570
2043	37,145	2,465	3,241	42,850
2044	34,972	2,335	3,006	40,314
2045	32,944	2,214	2,789	37,947
2046	31,050	2,099	2,589	35,738

Footnotes:

(1) Client data x Table 4.1 through Table 4.3

(2) Client data x Table 4.1 through Table 4.3

(3) Client data x Table 4.1 through Table 4.3

(4) Sum of Col (1) through Col (3)

Table 1.16
Projected Acreage of Permits In-Force
Surface Permits

Fiscal Year Ending 6/30	Active	Inactive	Phase Released	Total
	(1)	(2)	(3)	(4)
2011	200,337	8,527	33,995	242,858
2012	190,962	8,144	31,531	230,637
2013	181,482	7,748	29,200	218,430
2014	172,004	7,331	27,020	206,356
2015	162,648	6,910	24,984	194,542
2016	153,285	6,488	23,072	182,845
2017	143,980	6,075	21,288	171,342
2018	134,910	5,680	19,641	160,232
2019	126,217	5,312	18,122	149,651
2020	117,904	4,969	16,719	139,592
2021	109,985	4,633	15,415	130,033
2022	102,568	4,318	14,197	121,083
2023	95,465	4,015	13,072	112,552
2024	88,741	3,720	12,036	104,497
2025	82,458	3,446	11,080	96,985
2026	76,531	3,189	10,200	89,919
2027	70,954	2,950	9,390	83,294
2028	65,690	2,725	8,644	77,058
2029	60,754	2,517	7,957	71,228
2030	56,141	2,325	7,325	65,791
2031	51,860	2,148	6,743	60,751
2032	47,906	1,984	6,208	56,097
2033	44,253	1,832	5,715	51,800
2034	40,878	1,692	5,261	47,832
2035	37,761	1,563	4,843	44,168
2036	34,882	1,444	4,459	40,785
2037	32,223	1,334	4,105	37,661
2038	29,766	1,232	3,779	34,777
2039	27,496	1,138	3,479	32,114
2040	25,400	1,051	3,203	29,654
2041	23,463	971	2,949	27,383
2042	21,674	897	2,715	25,286
2043	20,021	829	2,500	23,350
2044	18,495	765	2,302	21,562
2045	17,085	707	2,119	19,911
2046	15,782	653	1,951	18,386

Footnotes:
(1) Client data x Table 4.1
(2) Client data x Table 4.1
(3) Client data x Table 4.1
(4) Sum of Col (1) through Col (3)

Table 1.16

Projected Acreage of Permits In-Force

Underground Permits

Fiscal Year Ending 6/30	Active	Inactive	Phase Released	Total
	(1)	(2)	(3)	(4)
2011	24,349	3,533	3,241	31,124
2012	22,919	3,317	3,019	29,255
2013	21,534	3,112	2,802	27,448
2014	20,192	2,921	2,605	25,717
2015	18,922	2,731	2,419	24,073
2016	17,728	2,564	2,243	22,534
2017	16,569	2,398	2,078	21,045
2018	15,492	2,241	1,923	19,656
2019	14,467	2,089	1,779	18,336
2020	13,508	1,946	1,646	17,100
2021	12,591	1,813	1,523	15,927
2022	11,722	1,681	1,409	14,812
2023	10,906	1,564	1,303	13,773
2024	10,143	1,454	1,206	12,802
2025	9,419	1,351	1,115	11,886
2026	8,753	1,256	1,031	11,040
2027	8,132	1,164	954	10,250
2028	7,551	1,079	882	9,513
2029	7,009	1,001	816	8,826
2030	6,501	928	755	8,183
2031	6,028	860	698	7,586
2032	5,590	797	646	7,033
2033	5,183	739	597	6,520
2034	4,806	685	553	6,044
2035	4,457	635	511	5,603
2036	4,133	589	473	5,194
2037	3,832	546	437	4,815
2038	3,554	506	404	4,464
2039	3,295	469	374	4,138
2040	3,056	435	346	3,836
2041	2,833	403	320	3,557
2042	2,627	374	296	3,297
2043	2,436	346	274	3,057
2044	2,259	321	253	2,834
2045	2,095	298	234	2,627
2046	1,943	276	217	2,435

Footnotes:

(1) Client data x Table 4.2

(2) Client data x Table 4.2

(3) Client data x Table 4.2

(4) Sum of Col (1) through Col (3)

Table 1.16

Projected Acreage of Permits In-Force

Other Permits

Fiscal Year Ending 6/30	Active	Inactive	Phase Released	Total
	(1)	(2)	(3)	(4)
2011	40,548	3,594	1,412	45,554
2012	39,397	3,485	1,365	44,247
2013	38,249	3,379	1,318	42,946
2014	37,126	3,276	1,274	41,676
2015	36,024	3,176	1,230	40,430
2016	34,950	3,079	1,189	39,217
2017	33,900	2,983	1,148	38,032
2018	32,865	2,891	1,109	36,865
2019	31,856	2,801	1,072	35,729
2020	30,871	2,714	1,035	34,621
2021	29,914	2,630	1,000	33,544
2022	28,984	2,547	966	32,497
2023	28,076	2,466	933	31,475
2024	27,193	2,387	901	30,481
2025	26,327	2,311	871	29,508
2026	25,487	2,237	841	28,565
2027	24,673	2,166	813	27,652
2028	23,886	2,097	785	26,768
2029	23,124	2,030	758	25,912
2030	22,386	1,965	732	25,084
2031	21,672	1,903	708	24,282
2032	20,981	1,842	683	23,506
2033	20,311	1,783	660	22,755
2034	19,663	1,726	638	22,028
2035	19,036	1,671	616	21,323
2036	18,429	1,618	595	20,642
2037	17,841	1,567	575	19,982
2038	17,271	1,517	555	19,343
2039	16,720	1,468	537	18,725
2040	16,187	1,421	518	18,127
2041	15,671	1,376	501	17,547
2042	15,171	1,332	484	16,987
2043	14,687	1,290	467	16,444
2044	14,218	1,249	451	15,918
2045	13,764	1,209	436	15,409
2046	13,325	1,170	421	14,917

Footnotes:

(1) Client data x Table 4.3

(2) Client data x Table 4.3

(3) Client data x Table 4.3

(4) Sum of Col (1) through Col (3)

Table 1.17

Projected Acreage of Permits Issued On Or Before June 30, 2011

(All Permit Types Combined)

Fiscal Year Ending 6/30	Acreage of In Force Permits	Acreage of Forfeited Permits	Acreage of Released Permits	End of Year In Force Acreage
	(1)	(2)	(3)	(4)
2011	319,536	-	-	319,536
2012	304,139	1,692	13,705	288,741
2013	288,824	1,649	13,666	273,509
2014	273,748	1,596	13,480	258,673
2015	259,045	1,525	13,178	244,342
2016	244,597	1,441	13,007	230,149
2017	230,419	1,356	12,822	216,241
2018	216,754	1,273	12,392	203,089
2019	203,715	1,192	11,846	190,677
2020	191,313	1,116	11,287	178,911
2021	179,504	1,043	10,766	167,694
2022	168,391	974	10,139	157,278
2023	157,800	909	9,682	147,209
2024	147,780	848	9,172	137,760
2025	138,379	789	8,612	128,977
2026	129,524	735	8,120	120,670
2027	121,196	684	7,644	112,868
2028	113,339	636	7,221	105,482
2029	105,966	590	6,783	98,593
2030	99,058	548	6,360	92,150
2031	92,619	508	5,931	86,180
2032	86,636	471	5,512	80,652
2033	81,074	437	5,124	75,513
2034	75,904	406	4,765	70,733
2035	71,095	377	4,432	66,286
2036	66,621	350	4,124	62,148
2037	62,459	325	3,838	58,296
2038	58,584	302	3,573	54,710
2039	54,977	280	3,327	51,370
2040	51,617	260	3,099	48,258
2041	48,487	242	2,888	45,357
2042	45,570	225	2,692	42,653
2043	42,850	209	2,510	40,130
2044	40,314	195	2,342	37,777
2045	37,947	181	2,185	35,581
2046	35,738	169	2,040	33,530

Footnotes:

(1) Table 1.16 Col (4)

(2) Table 1.16 Col (4) x Table 4.1 through Table 4.3

(3) Table 1.16 Col (4) x Table 4.1 through Table 4.3

(4) Col (1) - Col (2) - Col (3)

Table 1.17

Projected Acreage of Permits Issued On Or Before June 30, 2011

Surface Permits

Fiscal Year Ending 6/30	Acreage of In Force Permits	Acreage of Forfeited Permits	Acreage of Released Permits	End of Year In Force Acreage
	(1)	(2)	(3)	(4)
2019	242,858	-	-	242,858
2020	230,637	1,518	10,704	218,415
2021	218,430	1,481	10,726	206,223
2022	206,356	1,432	10,642	194,282
2023	194,542	1,368	10,447	182,727
2024	182,845	1,291	10,406	171,149
2025	171,342	1,213	10,290	159,839
2026	160,232	1,136	9,974	149,122
2027	149,651	1,062	9,520	139,070
2028	139,592	991	9,068	129,533
2029	130,033	924	8,635	120,474
2030	121,083	861	8,089	112,133
2031	112,552	801	7,729	104,022
2032	104,497	745	7,311	96,441
2033	96,985	692	6,821	89,473
2034	89,919	642	6,424	82,854
2035	83,294	595	6,031	76,668
2036	77,058	551	5,685	70,823
2037	71,228	509	5,321	65,397
2038	65,791	471	4,966	60,354
2039	60,751	435	4,605	55,711
2040	56,097	401	4,253	51,443
2041	51,800	370	3,927	47,503
2042	47,832	342	3,626	43,864
2043	44,168	316	3,348	40,505
2044	40,785	291	3,092	37,402
2045	37,661	269	2,855	34,538
2046	34,777	248	2,636	31,893
2047	32,114	229	2,434	29,450
2048	29,654	211	2,248	27,195
2049	27,383	195	2,076	25,112
2050	25,286	180	1,917	23,189
2051	23,350	166	1,770	21,414
2052	21,562	154	1,634	19,774
2053	19,911	142	1,509	18,260
2054	18,386	131	1,394	16,862

Footnotes:

(1) Table 1.16 Col (4)

(2) Table 1.16 Col (4) x Table 4.1

(3) Table 1.16 Col (4) x Table 4.1

(4) Col (1) - Col (2) - Col (3)

Table 1.17

Projected Acreage of Permits Issued On Or Before June 30, 2011

Underground Permits

Fiscal Year Ending 6/30	Acreage of In Force Permits	Acreage of Forfeited Permits	Acreage of Released Permits	End of Year In Force Acreage
	(1)	(2)	(3)	(4)
2027	31,124	-	-	31,124
2028	29,255	87	1,781	27,387
2029	27,448	83	1,724	25,641
2030	25,717	80	1,651	23,986
2031	24,073	76	1,568	22,429
2032	22,534	71	1,468	20,995
2033	21,045	66	1,423	19,555
2034	19,656	62	1,326	18,268
2035	18,336	58	1,263	17,015
2036	17,100	54	1,181	15,865
2037	15,927	51	1,123	14,754
2038	14,812	47	1,068	13,696
2039	13,773	44	995	12,734
2040	12,802	41	930	11,831
2041	11,886	38	878	10,969
2042	11,040	35	811	10,194
2043	10,250	33	757	9,461
2044	9,513	30	707	8,775
2045	8,826	28	659	8,139
2046	8,183	26	617	7,540
2047	7,586	24	573	6,989
2048	7,033	22	531	6,479
2049	6,520	21	492	6,006
2050	6,044	19	456	5,568
2051	5,603	18	423	5,162
2052	5,194	17	392	4,785
2053	4,815	15	364	4,436
2054	4,464	14	337	4,113
2055	4,138	13	312	3,813
2056	3,836	12	290	3,535
2057	3,557	11	269	3,277
2058	3,297	10	249	3,038
2059	3,057	10	231	2,816
2060	2,834	9	214	2,611
2061	2,627	8	198	2,420
2062	2,435	8	184	2,244

Footnotes:

(1) Table 1.16 Col (4)

(2) Table 1.16 Col (4) x Table 4.2

(3) Table 1.16 Col (4) x Table 4.2

(4) Col (1) - Col (2) - Col (3)

Table 1.17

Projected Acreage of Permits Issued On Or Before June 30, 2011

Other Permits

Fiscal Year Ending 6/30	Acreage of In Force Permits	Acreage of Forfeited Permits	Acreage of Released Permits	End of Year In Force Acreage
	(1)	(2)	(3)	(4)
2035	45,554	-	-	45,554
2036	44,247	87	1,220	42,940
2037	42,946	85	1,216	41,645
2038	41,676	84	1,186	40,405
2039	40,430	82	1,163	39,185
2040	39,217	80	1,133	38,005
2041	38,032	77	1,108	36,846
2042	36,865	75	1,092	35,698
2043	35,729	73	1,064	34,593
2044	34,621	70	1,038	33,513
2045	33,544	68	1,009	32,467
2046	32,497	66	981	31,449
2047	31,475	64	958	30,453
2048	30,481	62	932	29,488
2049	29,508	60	913	28,535
2050	28,565	58	885	27,622
2051	27,652	56	857	26,739
2052	26,768	54	830	25,884
2053	25,912	53	803	25,057
2054	25,084	51	777	24,256
2055	24,282	49	753	23,481
2056	23,506	48	728	22,730
2057	22,755	46	705	22,004
2058	22,028	45	683	21,300
2059	21,323	43	661	20,619
2060	20,642	42	640	19,960
2061	19,982	41	619	19,322
2062	19,343	39	599	18,705
2063	18,725	38	580	18,107
2064	18,127	37	562	17,528
2065	17,547	36	544	16,968
2066	16,987	34	526	16,426
2067	16,444	33	510	15,901
2068	15,918	32	493	15,393
2069	15,409	31	478	14,901
2070	14,917	30	462	14,424

Footnotes:

(1) Table 1.16 Col (4)

(2) Table 1.16 Col (4) x Table 4.3

(3) Table 1.16 Col (4) x Table 4.3

(4) Col (1) - Col (2) - Col (3)

Summary of Forfeited Permits			
	Total	Active Reclamation	Completed Reclamation
As of 6/30/2010	1,895	146	1,749
As of 6/30/2011	1,905	127	1,778
Change	10	(19)	29

Summary of Issued Permits			
	Total	In Force	Released or Forfeited
As of 6/30/2010	5,902	1,775	4,127
As of 6/30/2011	5,948	1,773	4,175
Change	46	(2)	48

Table 3.1

Number of Forfeited Permits and Acres for All Permits

Site Type	Total Number of Forfeited Permits	Open Number of Forfeited Permits	Total Forfeited Permitted Acres	Open Forfeited Permitted Acres	Percent of Forfeited Permitted Acres are Water Only	Selected Percentage
	(1)	(2)	(3)	(4)	(5)	(6)
Open Water - Open Land	29	29	4,818	4,818		
Open Water - Closed Land	20	20	1,965	1,965		
Open Water - Total	49	49	6,784	6,784		
Closed Water - Open Land	5	5	706	706		
Closed Water - Closed Land	139	-	8,576	-		
Closed Water - Total	144	5	9,282	706		
Closed Not Water But With Water Costs - Open Land	43	43	4,103	4,103		
Closed Not Water But With Water Costs - Closed Land	738	-	25,477	-		
Closed Not Water But With Water Costs - Total	781	43	29,579	4,103		
Open Land - Land Only	30	30	1,974	1,974		
Closed Land - Land Only	901	-	13,010	-		
Land Only - Total	931	30	14,983	1,974		
Total	1,905	127	60,629	13,566	26.50%	

Footnotes:

(1)	Table 3.2, Table 3.3, Table 3.4 Col (1)
(2)	Table 3.2, Table 3.3, Table 3.4 Col (2)
(3)	Table 3.2, Table 3.3, Table 3.4 Col (3)
(4)	Table 3.2, Table 3.3, Table 3.4 Col (4)
(5)	Col (3) ratio of water only acres and total acres
(6)	Selection

Table 3.2

Number of Forfeited Permits and Acres for Surface Mines

Site Type	Total Number of Forfeited Permits	Open Number of Forfeited Permits	Total Forfeited Permitted Acres	Open Forfeited Permitted Acres	Percent of Forfeited Permitted Acres are Water Only	Selected Percentage
	(1)	(2)	(3)	(4)	(5)	(6)
Open Water - Open Land	23	23	4,630	4,630		
Open Water - Closed Land	17	17	1,899	1,899		
Open Water - Total	40	40	6,529	6,529		
Closed Water - Open Land	4	4	694	694		
Closed Water - Closed Land	97	-	7,241	-		
Closed Water - Total	101	4	7,935	694		
Closed Not Water But With Water Costs - Open Land	18	18	3,375	3,375		
Closed Not Water But With Water Costs - Closed Land	377	-	20,422	-		
Closed Not Water But With Water Costs - Total	395	18	23,798	3,375		
Open Land - Land Only	14	14	1,677	1,677		
Closed Land - Land Only	635	-	10,516	-		
Land Only - Total	649	14	12,192	1,677		
Total	1,185	76	50,453	12,275	28.67%	30.00%

Footnotes:

(1) Client data

(2) Client data

(3) Client data

(4) Client data

(5) Col (3) ratio of water only acres and total acres

(6) Selection

Table 3.3

Number of Forfeited Permits and Acres for Underground Mines

Site Type	Total Number of Forfeited Permits	Open Number of Forfeited Permits	Total Forfeited Permitted Acres	Open Forfeited Permitted Acres	Percent of Forfeited Permitted Acres are Water Only	Selected Percentage
	(1)	(2)	(3)	(4)	(5)	(6)
Open Water - Open Land	4	4	41	41		
Open Water - Closed Land	2	2	36	36		
Open Water - Total	6	6	78	78		
Closed Water - Open Land	1	1	12	12		
Closed Water - Closed Land	25	-	328	-		
Closed Water - Total	26	1	340	12		
Closed Not Water But With Water Costs - Open Land	15	15	309	309		
Closed Not Water But With Water Costs - Closed Land	282	-	3,000	-		
Closed Not Water But With Water Costs - Total	297	15	3,309	309		
Open Land - Land Only	7	7	114	114		
Closed Land - Land Only	152	-	1,313	-		
Land Only - Total	159	7	1,427	114		
Total	488	29	5,154	513	8.11%	10.00%

Footnotes:

(1) Client data
(2) Client data
(3) Client data
(4) Client data
(5) Col (3) ratio of water only acres and total acres
(6) Selection

Table 3.4

Number of Forfeited Permits and Acres for Other Mines

Site Type	Total Number of Forfeited Permits	Open Number of Forfeited Permits	Total Forfeited Permitted Acres	Open Forfeited Permitted Acres	Percent of Forfeited Permitted Acres are Water Only	Selected Percentage
	(1)	(2)	(3)	(4)	(5)	(6)
Open Water - Open Land	2	2	147	147		
Open Water - Closed Land	1	1	30	30		
Open Water - Total	3	3	177	177		
Closed Water - Open Land	-	-	-	-		
Closed Water - Closed Land	17	-	1,008	-		
Closed Water - Total	17	-	1,008	-		
Closed Not Water But With Water Costs - Open Land	10	10	419	419		
Closed Not Water But With Water Costs - Closed Land	79	-	2,054	-		
Closed Not Water But With Water Costs - Total	89	10	2,473	419		
Open Land - Land Only	9	9	183	183		
Closed Land - Land Only	114	-	1,181	-		
Land Only - Total	123	9	1,364	183		
Total	232	22	5,022	778	23.59%	25.00%

Footnotes:

(1) Client data
(2) Client data
(3) Client data
(4) Client data
(5) Col (3) ratio of water only acres and total acres
(6) Selection

Table 3.5
Number of In Force Permits by Type and Year of Issuance

Issue Year	Surface Permits In Force	Underground Permits In Force	Other Permits In Force	Total Permits In Force
	(1)	(2)	(3)	(4)
1977	4	4	2	10
1978	5	8	4	17
1979	6	14	8	28
1980	14	16	20	50
1981	18	29	57	104
1982	10	25	31	66
1983	8	50	71	129
1984	8	15	18	41
1985	15	13	18	46
1986	14	8	17	39
1987	9	27	9	45
1988	24	17	13	54
1989	27	20	16	63
1990	7	13	8	28
1991	13	19	10	42
1992	17	16	11	44
1993	12	22	18	52
1994	16	31	14	61
1995	22	28	9	59
1996	26	27	9	62
1997	32	28	13	73
1998	12	26	7	45
1999	9	22	4	35
2000	14	26	7	47
2001	31	17	7	55
2002	14	28	7	49
2003	30	17	12	59
2004	26	19	5	50
2005	14	19	4	37
2006	30	18	11	59
2007	23	21	7	51
2008	24	23	11	58
2009	19	16	6	41
2010	17	24	10	51
2011	11	9	3	23
Total	581	715	477	1,773
After 1995	332	340	123	795
Before 1996	249	375	354	978

Footnotes:

(1) Client data

(2) Client data

(3) Client data

(4) Sum of Col (1) through Col (3)

Table 3.5

Number of In Force Acres by Type and Year of Issuance

Issue Year	Surface Acres In Force	Underground Acres In Force	Other Acres In Force	Total Acres In Force
	(1)	(2)	(3)	(4)
1977	1,971	120	103	2,194
1978	2,588	194	116	2,898
1979	1,382	943	186	2,511
1980	3,334	496	1,154	4,984
1981	5,457	1,255	6,148	12,859
1982	3,423	975	2,095	6,493
1983	2,130	8,232	7,602	17,964
1984	2,317	1,869	2,294	6,480
1985	5,914	533	2,423	8,871
1986	5,380	160	1,611	7,151
1987	2,361	745	433	3,539
1988	8,172	529	720	9,422
1989	8,389	475	1,172	10,036
1990	3,024	484	511	4,020
1991	6,468	929	556	7,953
1992	8,123	368	973	9,464
1993	4,639	1,193	2,603	8,435
1994	7,971	1,118	1,922	11,011
1995	12,068	740	1,816	14,625
1996	16,204	683	1,361	18,248
1997	17,436	1,012	1,589	20,037
1998	6,121	912	1,265	8,298
1999	3,485	907	397	4,789
2000	7,428	861	877	9,165
2001	13,383	299	371	14,053
2002	5,238	1,050	683	6,971
2003	19,268	408	1,244	20,920
2004	13,166	665	387	14,219
2005	3,962	302	398	4,662
2006	10,012	540	292	10,844
2007	8,145	691	334	9,169
2008	10,597	470	587	11,654
2009	6,443	286	329	7,059
2010	4,973	560	898	6,430
2011	1,886	118	102	2,107
Total	242,858	31,124	45,554	319,536
After 1995	147,748	9,764	11,115	168,626
Before 1996	95,111	21,360	34,439	150,910

Footnotes:

(1) Client data

(2) Client data

(3) Client data

(4) Sum of Col (1) through Col (3)

Table 3.6

Number of Surface Permits by Year of Issuance

Issue Year	Number of Permits Issued	Number Still In Force as of June 30, 2011	Percent Still In Force
	(1)	(2)	(3)
1977	128	4	3%
1978	126	5	4%
1979	100	6	6%
1980	121	14	12%
1981	141	18	13%
1982	160	10	6%
1983	162	8	5%
1984	109	8	7%
1985	130	15	12%
1986	133	14	11%
1987	133	9	7%
1988	125	24	19%
1989	135	27	20%
1990	57	7	12%
1991	63	13	21%
1992	65	17	26%
1993	39	12	31%
1994	44	16	36%
1995	33	22	67%
1996	42	26	62%
1997	44	32	73%
1998	21	12	57%
1999	17	9	53%
2000	18	14	78%
2001	34	31	91%
2002	19	14	74%
2003	33	30	91%
2004	26	26	100%
2005	16	14	88%
2006	30	30	100%
2007	24	23	96%
2008	24	24	100%
2009	19	19	100%
2010	17	17	100%
2011	11	11	100%
Total	2,399	581	
After 1995	395	332	
Before 1996	2,004	249	

Footnotes:

(1) Client data

(2) Client data

(3) Col (2) / Col (1)

Table 3.6
Number of Surface Acres by Year of Issuance

Issue Year	Number of Acres Issued	Number Still In Force as of June 30, 2011	Percent Still In Force
	(1)	(2)	(3)
1977	4,579	1,971	43%
1978	4,542	2,588	57%
1979	4,795	1,382	29%
1980	8,914	3,334	37%
1981	9,860	5,457	55%
1982	9,506	3,423	36%
1983	6,222	2,130	34%
1984	6,193	2,317	37%
1985	10,846	5,914	55%
1986	13,955	5,380	39%
1987	8,204	2,361	29%
1988	14,657	8,172	56%
1989	17,289	8,389	49%
1990	8,273	3,024	37%
1991	10,945	6,468	59%
1992	11,687	8,123	70%
1993	7,611	4,639	61%
1994	11,388	7,971	70%
1995	13,862	12,068	87%
1996	17,580	16,204	92%
1997	19,688	17,436	89%
1998	7,302	6,121	84%
1999	4,424	3,485	79%
2000	7,626	7,428	97%
2001	13,639	13,383	98%
2002	5,919	5,238	88%
2003	19,645	19,268	98%
2004	13,166	13,166	100%
2005	4,290	3,962	92%
2006	10,012	10,012	100%
2007	8,153	8,145	100%
2008	10,597	10,597	100%
2009	6,443	6,443	100%
2010	4,973	4,973	100%
2011	1,886	1,886	100%
Total	338,675	242,858	
After 1995	155,345	147,748	
Before 1996	183,330	95,111	

Footnotes:
(1) Client data
(2) Client data
(3) Col (2) / Col (1)

Table 3.7

Number of Underground Permits by Year of Issuance

Issue Year	Number of Permits Issued	Number Still In Force as of June 30, 2011	Percent Still In Force
	(1)	(2)	(3)
1977	83	4	5%
1978	80	8	10%
1979	76	14	18%
1980	134	16	12%
1981	148	29	20%
1982	213	25	12%
1983	274	50	18%
1984	118	15	13%
1985	87	13	15%
1986	103	8	8%
1987	159	27	17%
1988	155	17	11%
1989	90	20	22%
1990	43	13	30%
1991	52	19	37%
1992	45	16	36%
1993	45	22	49%
1994	61	31	51%
1995	46	28	61%
1996	44	27	61%
1997	42	28	67%
1998	37	26	70%
1999	24	22	92%
2000	34	26	76%
2001	20	17	85%
2002	33	28	85%
2003	22	17	77%
2004	21	19	90%
2005	21	19	90%
2006	19	18	95%
2007	21	21	100%
2008	26	23	88%
2009	16	16	100%
2010	24	24	100%
2011	9	9	100%
Total	2,425	715	
After 1995	413	340	
Before 1996	2,012	375	

Footnotes:

(1) Client data

(2) Client data

(3) Col (2) / Col (1)

Table 3.7

Number of Underground Acres by Year of Issuance

Issue Year	Number of Acres Issued	Number Still In Force as of June 30, 2011	Percent Still In Force
	(1)	(2)	(3)
1977	455	120	26%
1978	314	194	62%
1979	1,496	943	63%
1980	1,380	496	36%
1981	2,016	1,255	62%
1982	2,238	975	44%
1983	9,957	8,232	83%
1984	2,506	1,869	75%
1985	1,027	533	52%
1986	919	160	17%
1987	1,634	745	46%
1988	3,094	529	17%
1989	1,197	475	40%
1990	867	484	56%
1991	1,347	929	69%
1992	776	368	47%
1993	1,501	1,193	79%
1994	1,762	1,118	63%
1995	1,095	740	68%
1996	868	683	79%
1997	1,209	1,012	84%
1998	1,094	912	83%
1999	932	907	97%
2000	1,025	861	84%
2001	332	299	90%
2002	1,147	1,050	92%
2003	463	408	88%
2004	723	665	92%
2005	340	302	89%
2006	556	540	97%
2007	691	691	100%
2008	527	470	89%
2009	286	286	100%
2010	560	560	100%
2011	118	118	100%
Total	46,451	31,124	
After 1995	10,871	9,764	
Before 1996	35,580	21,360	

Footnotes:

(1) Client data

(2) Client data

(3) Col (2) / Col (1)

Table 3.8

Number of Other Permits by Year of Issuance

Issue Year	Number of Permits Issued	Number Still In Force as of June 30, 2011	Percent Still In Force
	(1)	(2)	(3)
1977	19	2	11%
1978	18	4	22%
1979	20	8	40%
1980	44	20	45%
1981	113	57	50%
1982	101	31	31%
1983	215	71	33%
1984	56	18	32%
1985	59	18	31%
1986	46	17	37%
1987	62	9	15%
1988	59	13	22%
1989	30	16	53%
1990	17	8	47%
1991	17	10	59%
1992	31	11	35%
1993	44	18	41%
1994	18	14	78%
1995	13	9	69%
1996	12	9	75%
1997	17	13	76%
1998	9	7	78%
1999	7	4	57%
2000	8	7	88%
2001	7	7	100%
2002	7	7	100%
2003	13	12	92%
2004	5	5	100%
2005	4	4	100%
2006	13	11	85%
2007	8	7	88%
2008	13	11	85%
2009	6	6	100%
2010	10	10	100%
2011	3	3	100%
Total	1,124	477	
After 1995	142	123	
Before 1996	982	354	

Footnotes:

(1) Client data

(2) Client data

(3) Col (2) / Col (1)

Table 3.8
Number of Other Acres by Year of Issuance

Issue Year	Number of Acres Issued	Number Still In Force as of June 30, 2011	Percent Still In Force
	(1)	(2)	(3)
1977	210	103	49%
1978	184	116	63%
1979	297	186	63%
1980	1,388	1,154	83%
1981	7,428	6,148	83%
1982	2,634	2,095	80%
1983	8,787	7,602	87%
1984	3,115	2,294	74%
1985	2,832	2,423	86%
1986	1,782	1,611	90%
1987	1,364	433	32%
1988	1,219	720	59%
1989	2,086	1,172	56%
1990	919	511	56%
1991	849	556	66%
1992	1,841	973	53%
1993	3,154	2,603	83%
1994	2,196	1,922	88%
1995	1,958	1,816	93%
1996	1,429	1,361	95%
1997	1,736	1,589	92%
1998	1,275	1,265	99%
1999	740	397	54%
2000	877	877	100%
2001	371	371	100%
2002	683	683	100%
2003	1,259	1,244	99%
2004	387	387	100%
2005	398	398	100%
2006	296	292	99%
2007	339	334	99%
2008	592	587	99%
2009	329	329	100%
2010	886	898	101%
2011	102	102	100%
Total	55,944	45,554	
After 1995	11,699	11,115	
Before 1996	44,245	34,439	

Footnotes:
(1) Client data
(2) Client data
(3) Col (2) / Col (1)

Table 4.1

Valuation Rates of Forfeiture and Release for Surface Permits

Year Since Issuance	Forfeiture	Release
	(1)	(2)
1	0.00%	0.00%
2	0.00%	0.00%
3	0.00%	0.00%
4	1.25%	0.50%
5	1.25%	0.50%
6	1.25%	1.00%
7	1.25%	1.00%
8	1.25%	2.00%
9	1.25%	3.00%
10	1.25%	5.00%
11	1.25%	5.00%
12	1.25%	5.00%
13	1.25%	5.00%
14	1.25%	5.00%
15	1.25%	5.00%
16	1.25%	5.00%
17	1.25%	5.00%
18	1.25%	5.00%
19	1.25%	5.00%
20+	1.25%	7.00%

Footnotes:

(1) Selection

(2) Selection

Table 4.2

Valuation Rates of Forfeiture and Release for Underground Permits

Year Since Issuance	Forfeiture	Release
	(1)	(2)
1	0.00%	0.00%
2	0.00%	1.00%
3	0.00%	1.00%
4	0.50%	1.00%
5	0.50%	1.00%
6	0.50%	4.00%
7	0.50%	4.00%
8	0.50%	3.00%
9	0.50%	2.00%
10	0.50%	2.00%
11	0.50%	4.00%
12	0.50%	4.00%
13	0.50%	4.00%
14	0.50%	4.00%
15	0.50%	9.00%
16	0.50%	5.00%
17	0.50%	5.00%
18	0.50%	5.00%
19	0.50%	5.00%
20+	0.50%	7.00%

Footnotes:

(1) Selection

(2) Selection

Table 4.3

Valuation Rates of Forfeiture and Release for Other Permits

Year Since Issuance	Forfeiture	Release
	(1)	(2)
1	0.00%	0.00%
2	0.00%	0.00%
3	0.00%	1.25%
4	0.40%	1.25%
5	0.40%	1.25%
6	0.40%	1.25%
7	0.40%	1.25%
8	0.40%	1.25%
9	0.40%	1.25%
10	0.40%	1.50%
11	0.40%	1.50%
12	0.40%	1.50%
13	0.40%	1.50%
14	0.40%	1.50%
15	0.40%	3.00%
16	0.40%	3.00%
17	0.40%	3.00%
18	0.40%	3.00%
19	0.40%	3.00%
20+	0.40%	3.00%

Footnotes:

(1) Selection

(2) Selection

Table 4.4

Percent of Permitted Acres That Had Been Disturbed

Based on Forfeited Permits

	Surface	Underground	Other
(1) Forfeited Disturbed Acres	35,485.10	3,741.43	3,945.70
(2) Forfeited Permitted Acres	50,453.48	5,153.62	5,021.56
(3) Percent of Permitted Acres That Are Disturbed	70.33%	72.60%	78.58%
(4) Forfeited Disturbed Acres for Permits with Open Water	9,282.55	446.62	812.01
(5) Forfeited Permitted Acres for Permits with Open Water	13,259.49	513.21	1,007.55
(6) Percent of Permitted Acres That Are Disturbed	70.01%	87.02%	80.59%
(7) Forfeited Disturbed Acres for Permits with Closed Water	5,827.57	305.89	805.36
(8) Forfeited Permitted Acres for Permits with Closed Water	7,934.50	339.89	1,007.90
(9) Percent of Permitted Acres That Are Disturbed	73.45%	90.00%	79.90%

Footnotes:

(1)	Client Data
(2)	Table 3.2, Table 3.3, Table 3.4 Col (3)
(3)	Row (1) / Row (2)
(4)	Client Data Appendix A
(5)	Client Data Appendix A
(6)	Row (4) / Row (5)
(7)	Client Data
(8)	Client Data
(9)	Row (7) / Row (8)

Table 4.5 **Adjustment Factors for Permit Status**	
Permit Status	Liability Factor
	(1)
Active	100.00%
Inactive	75.00%
Phased Release	50.00%

Footnotes:

(1) Selection

Table 4.6

Valuation Costs Per Acre by Permit Type

(in 2011 Dollars)

	Surface	Underground	Other
(1) Land Capital	2,898.24	13,259.83	9,575.60
(2) Water Capital	913.81	1,024.62	1,804.78
(3) Water Abandoment	203.38	538.46	473.16
(4) Annual Water Treatment	101.39	141.27	199.22

Footnotes:

(1) Table 1.1 Row (9)

(2) Table 1.2 Row (12)

(3) Table 1.3 Row (3)

(4) Table 1.5 Row (7)

Table 4.7 **<u>Adjustment Factors for Size of Permits</u>**	
Bond Value	Factor
	(1)
Less than $10,000	2.50
Between $10,000 and $100,000	1.00
Above $100,000	0.38

<u>Footnotes:</u>

(1) Selection

Table 4.8
Adjustment Factors for Permit Ownership

Ownership	Factor
	(1)
Private Corporation	1.00
Public Corporation	1.00
Multi Corporation	1.00

Footnotes:
(1) Selection

WATER CAPITAL AND WATER TREATMENT COSTS
Estimates Reflecting NPDES Standards

Site Name	Permit Number	Water Status	Newly Estimated Capital Costs	Prior Estimated Liability Costs	Final Capital Const. Cost	Current Annual O&M	New Post-Construction Annual O&M		*PERMIT TYPE*	Distrubed Acres	*Permitted Acres*
A S & K, INC.	S-1011-89	TBC	$91,150.00	$243,000.00	-$151,850.00		$4,075.41		Surface	26	24
ALPHAINE CORP.	S-6032-86	C	$0.00		$0.00				Surface	0	0
AMANDA NICOLE FUELS, INC.	S-1018-88	UC	$0.00		$0.00		$48,465.00		Surface	30	28
B & S Contracting Inc.	U-3055-87	P	$88,530.00		$88,530.00	$4,221.35	$6,721.35		Underground	12	10
B & S CONTRACTING, INC.	O-3086-87	P	$0.00		$0.00				Other	0	0
B & S CONTRACTING, INC.	R-668	P	$3,360.00		$3,360.00	$3,265.60	$5,765.60		Other	26	26
BARRENSHE COAL CO.	UO-694	P	$83,782.00		$83,782.00	$288.42	$9,877.00		Underground	2	4
BARRETT FUEL CORP.	R-737	P	$10,200.00		$10,200.00	$1,680.23	$4,180.23		Other	200	175
BELLE CONTRACTING, INC.	S-6020-87	P	$116,377.69		$116,377.69	$5,040.94	$10,623.00		Surface	5	108
BENHAM GROUP	120-79	ACT	$8,960.00		$8,960.00	$17,326.62	$19,826.62		Surface	33	180
BJORKMAN MINING	S-37-81	P	$8,960.00		$8,960.00	$1,833.60	$4,333.60		Surface	35	35
BLACK DIAMOND MINING CO.	13-79	P	$2,800.00		$2,800.00	$1,231.28	$3,731.28		Surface	31	34
BOLINGREEN MINING COMPANY	S-1024-88	ACT	$8,990.41		$8,990.41	$4,464.00	$6,964.00		Surface	16	21
Borgman	EM-32	ACT	$451,555.00		$451,555.00	$12,862.53	$15,362.53		Other	9	6
BRADY CLINE	EM-97	ACT	$506,785.00		$506,785.00	$14,922.51	$17,422.51		Surface	2	11
BRENKEE COAL CO.	UO-435	NA							Underground	0	0
BUFFALO COAL	S-2003-88	TBC	$2,098,037.50		$2,098,037.50		$135,402.00		Surface	342	356
BUFFALO COAL COMPANY, INC.	S-122-80	ACT	$15,400.00		$15,400.00	$23,036.16	$25,536.16		Surface	270	306
BUFFALO COAL COMPANY, INC.	S-2001-86	TBC	$1,377,127.50	$401,939.00	$975,188.50		$66,769.00		Surface	505	595
BUFFALO COAL COMPANY, INC.	S-2003-03	TBC	$113,052.50	$577,878.00	-$464,825.50		$30,728.00		Surface	55	266
BUFFALO COAL COMPANY, INC.	S-2006-86	UC	$0.00		$0.00		$57,400.00		Surface	230	272
BUFFALO COAL COMPANY, INC.	S-2011-92	TBC	$0.00		$0.00				Surface	0	0
BUFFALO COAL COMPANY, INC.	S-52-80	TBC	$1,375,155.00	$944,494.00	$430,661.00		$107,233.00		Surface	190	191
BUFFALO COAL COMPANY, INC.	S-53-80	TBC	$1,190,250.00	$863,838.00	$326,412.00		$80,857.00		Surface	365	375
C. C. CONLEY & SONS, INC.	S-3046-91	P	$309,285.00		$309,285.00	$4,913.30	$14,010.00		Surface	170.24	195
CHAFIN COAL CO.	O-69-82	P	$0.00		$0.00	$1,095.39	$3,595.39		Other	1	8
CHESTNUT RIDGE COAL CORP.	S-28-83	ACT	$92,001.91		$92,001.91	$4,817.01	$61,930.00		Surface	29	30
CHEYENNE COAL SALES	S-2009-96	TBC	$570,725.00	$411,100.00	$159,625.00		$67,181.00		Surface	40.2	48.28
Cheyenne Sales	O-11-83	TBC	$133,365.00	$21,387.00	$111,978.00		$77,357.00		Other	22.1	22.1
Chicopee Coal Co. Inc.	S-3006-99	TBC	$3,602,677.50	$1,564,000.00	$2,038,677.50		$95,442.00		Surface	131.98	257.41
CHICOPEE COAL CO., INC.	S-3002-98	TBC	$104,460.00	$85,500.00	$18,960.00		$8,500.00		Surface	127.96	124.52
CHICOPEE COAL COMPANY, INC.	O-6013-88	UC	$0.00		$0.00		$5,442.00		Other	124.55	124.55
CLASSIC RES., INC.	S-55-81	TBC	$130,900.00	$175,000.00	-$44,100.00		$8,266.00		Surface	15	20
COAL X, INC.	UO-396	ACT	$0.00		$0.00	$2,224.34	$4,724.34		Underground	18	18
COWACO, INC.	R-3022-87	P	$0.00		$0.00	$3,245.62	$5,745.62		Other	63	63
CRADDOCK & SONS COAL CO.	S-68-83	P	$10,161.58		$10,161.58	$3,042.59	$5,542.59		Surface	45	94
CRANE COAL CO., INC.	S-27-83	P	$5,160.00		$5,160.00	$1,558.95	$4,058.95		Surface	8	8
DAUGHERTY COAL CO.	65-77	ACT	$504,013.51		$504,013.51	$13,873.99	$60,457.00		Surface	92	92
DAUGHERTY COAL CO.	S-1009-86	ACT	$9,520.00		$9,520.00	$30,199.45	$23,220.99		Surface	50	50
DAUGHERTY COAL COMPANY, INC.	124-79	NA	$0.00		$0.00				Surface	0	0

WATER CAPITAL AND WATER TREATMENT COSTS
Estimates Reflecting NPDES Standards

Site Name	Permit Number	Water Status	Newly Estimated Capital Costs	Prior Estimated Liability Costs	Final Capital Const. Cost	Current Annual O&M	New Post-Construction Annual O&M		*PERMIT TYPE*	Distrubed Acres	*Permitted Acres*
DAUGHERTY COAL COMPANY, INC.	17-81	NA	$0.00		$0.00				Surface	0	0
DAUGHERTY COAL COMPANY, INC.	192-77	ACT	$0.00		$0.00				Surface	0	0
DAUGHERTY COAL COMPANY, INC.	246-74	NA	$0.00		$0.00				Surface	0	0
DAUGHERTY COAL COMPANY, INC.	S-73-83	NA	$0.00		$0.00				Surface	0	0
DECONDOR COAL CO.	U-147-82	TBC	$387,027.50	$400,000.00	-$12,972.50		$35,521.00		Underground	7.25	7.25
Delta Mining/Pierce Coal	U-2024-87/71-80	ACT	$163,500.00		$163,500.00	$10,146.46	$12,646.46	Multi	Surface	47	47
DLM COAL CO.	12-78	ACT	$0.00		$0.00	$11,205.35	$11,205.35		Surface	0	0
DLM COAL CO.	135-78	ACT	$0.00		$0.00	$14,883.12	$14,883.12		Surface	56	56
DLM COAL CO.	138-74	ACT	$0.00		$0.00	$27,641.67	$27,641.67		Surface	227	227
DLM COAL CO.	164-77	ACT	$0.00		$0.00	$4,222.87	$4,222.87		Surface	44	44
DLM COAL CO.	1-78	ACT	$0.00		$0.00	$12,167.98	$12,167.98		Surface	61	61
DLM COAL CO.	23-76	ACT	$0.00		$0.00	$35,560.52	$35,560.52		Surface	165	165
DLM COAL CO.	2-80	ACT	$15,340.00		$15,340.00	$24,077.43	$26,577.43		Surface	97	97
DLM COAL CO.	58-77	ACT	$0.00		$0.00	$14,929.83	$14,929.83		Surface	0	0
DLM COAL CO.	71-75	ACT	$0.00		$0.00	$9,507.84	$9,507.84		Surface	90	90
DLM COAL CO.	P-426					$236,325.20	$236,325.20		Surface	0	0
DLM COAL CO.	R-423					$11,821.97	$11,821.97		Surface	0	0
DUSTY COALS., INC.	S-119-85	P	$271,565.00		$271,565.00	$4,922.25	$12,104.00		Surface	30	71
E. J. & L. CO., INC.	S-3041-87	P	$62,787.50		$62,787.50	$1,543.35	$4,997.00		Surface	11	50
EASTERN ENERGY INVEST.	U-6012-88	P	$0.00		$0.00	$899.79	$3,399.79		Underground	5.35	5.35
EASTERN ENERGY INVESTMENTS	S-6029-86	ACT	$15,200.00		$15,200.00	$12,986.18	$15,486.18		Surface	124	297
Ed-E Development	S-1032-86	ACT	$336,917.00		$336,917.00	$15,367.06	$17,867.06		Surface	42	80
Ed-E Development	S-10-81	ACT	$284,510.00		$284,510.00	$95,556.49	$100,556.49		Surface	64	64
EDWARD E. THOMPSON	S-1041-89	ACT	$700,696.00		$700,696.00	$5,278.22	$61,140.00		Surface	20	26
F & M COAL CO.	46-79	P	$5,320.00		$5,320.00	$1,530.02	$4,030.02		Surface	116	130
F & M COAL CO.	S-1026-87	P	$5,260.00		$5,260.00	$5,511.71	$8,011.71		Surface	167	167
F & M COAL CO.	S-1073-86	NA	$0.00		$0.00				Surface	0	0
F&M Coal Co.	S-1044-87	ACT	$873,600.00		$873,600.00	$180,800.98	$183,300.98		Surface	102	87
F&M Coal Co.	S-57-84	ACT	$742,500.00		$742,500.00	$89,456.15	$96,956.15		Surface	72	96
FALCON LAND COMPANY	P-656	ACT	$150,814.95		$150,814.95	$27,428.25	$29,928.25		Other	0	132
FARKAS COAL CO.	34-81	ACT	$54,635.00		$54,635.00	$13,837.38	$16,337.38		Surface	10	10
FREEPORT MINING CORPORATION	S-1005-95	UC	$0.00		$0.00		$135,042.00		Surface	40	107
FRUSH ENTERPRISES	S-1008-89	TBC	$508,622.50		$508,622.50		$23,702.00		Surface	86	76
GAULEY COAL SALES CO.	O-43-84	ACT	$2,360.00		$2,360.00	$2,053.68	$4,553.68		Other	3	15
GLADE RUN MINING CO.	3-72	P	$2,800.00		$2,800.00	$1,951.03	$4,451.03		Surface	50	50
GLADY FORK MINING, INC.	D-35-82	UC	$0.00		$0.00	$121,261.23	$24,312.00		Underground	12.25	12.25
GLORY COAL CO., INC.	UO-744	P	$14,480.00		$14,480.00	$2,398.93	$4,898.93		Underground	1	3
GOLD STAR MINING CORP.	S-121-85	NA	$0.00		$0.00				Surface	0	0
GOLDEN PRODUCTS	S-1009-88	P	$1,800.00		$1,800.00	$2,543.69	$5,043.69		Surface	30	30
GREEN MOUNTAIN ENERGY	U-4013-91	P	$4,140.00		$4,140.00	$2,004.64	$4,504.64		Underground	15.23	15.23

WATER CAPITAL AND WATER TREATMENT COSTS
Estimates Reflecting NPDES Standards

Site Name	Permit Number	Water Status	Newly Estimated Capital Costs	Prior Estimated Liability Costs	Final Capital Const. Cost	Current Annual O&M	New Post-Construction Annual O&M		*PERMIT TYPE*	Distrubed Acres	*Permitted Acres*
GREENDALE COAL CO.	S-75-83	TBC	$2,969,995.00	$2,257,490.20	$712,504.80		$287,952.00		Surface	200	224
Hallelujah Mining	40-81	ACT	$209,261.00		$209,261.00	$17,114.30	$19,614.30		Surface	52	55
Harvey Energy	S-11-82	P	$47,000.00		$47,000.00	$5,594.71	$8,094.71		Surface	25	41
HARVEY ENERGY CORP.	S-3030-89	P	$22,343.75		$22,343.75	$2,204.29	$6,461.00		Surface	44	44
HARVEY ENERGY CORP.	S-35-81	P	$245,565.00		$245,565.00	$3,393.70	$13,013.00		Surface	12	22
HAWKS NEST MINING CO.	O-1-81	ACT	$12,000.00		$12,000.00	$3,018.58	$5,518.58		Other	14	48
HIDDEN VALLEY COAL CO.	S-60-84	ACT	$11,688.82		$11,688.82	$4,921.84	$7,421.84		Surface	47	47
HUNT COAL, INC.	U-5071-86	ACT	$0.00		$0.00	$1,006.61	$3,506.61		Underground	10	10
INTERSTATE LUMBER CO	S-39-82	TBC	$718,210.00	$766,500.00	-$48,290.00		$43,254.00		Surface	20.18	31
INTER-STATE LUMBER CO.	176-77	ACT	$153,850.84		$153,850.84	$4,064.80	$6,564.80		Surface	57	110
INTER-STATE LUMBER COMPANY, INC.	S-112-80	P	$320,856.25		$320,856.25	$1,185.10	$24,923.00		Surface	97	100
INTER-STATE LUMBER COMPANY, INC.	S-52-83	ACT	$6,380.00		$6,380.00	$1,305.96	$3,805.96		Surface	20	48
INTER-STATE LUMBER COMPANY, INC.	S-96-82	P	$0.00		$0.00	$42.47	$2,542.87		Surface	7	25
J & N PROCESSING COMPANY, LLC	O-58-83	P	$294,800.22		$294,800.22	$6,961.12	$30,433.00		Other	202.9	202.9
J.A.L. COAL CO., INC.	S-23-82	P	$376,447.50		$376,447.50	$475.79	$2,975.79		Surface	31	40
J.E.B. Inc.	S-61-82	ACT	$119,100.00		$119,100.00	$5,802.60	$8,302.60		Surface	18	18
JINKS MINING COMPANY	U-3031-93	P	$7,720.00		$7,720.00	$3,056.67	$5,556.67		Underground	9	15
JOCARR RESOURCES, INC.	U-3059-86	TBC	$27,167.50	$175,500.00	-$148,332.50		$3,461.00		Underground	12	10
JOHN GALT	D-76-82	P	$0.00		$0.00	$1,344.39	$3,844.39		Underground	4	8
JONES COAL INC	S-1030-86	P	$3,480.00		$3,480.00	$2,108.70	$4,608.70		Surface	23	23
JONES COAL INC	S-9-83	TBC	$273,432.50	$120,000.00	$153,432.50		$13,422.00		Surface	46	46
Keister Coal	184-77	ACT	$7,840.00		$7,840.00	$82,134.17	$84,634.17		Surface	13	27
KEYSTONE COAL, INC.	S-84-83	TBC	$0.00	$162,000.00	-$162,000.00				Surface	0	0
KEYSTONE COAL, INC.	U-186-83	TBC	$281,698.00	$162,000.00	$119,698.00		$11,593.00		Underground	14	19
KODIAK LAND CO., INC.	S-3052-87	P	$168,252.50		$168,252.50	$1,950.90	$8,307.00		Surface	6	32
LAKEVIEW COAL COMPANY	S-55-84	P	$28,753.27		$28,753.27	$182.26	$4,398.00		Surface	2	27
LANDMARK CORP.	S-34-82	TBC	$732,433.00	$180,162.00	$552,271.00		$48,822.00		Surface	12	95
LANDMARK CORPORATION	S-5069-88	TBC	$0.00		$0.00				Surface	0	0
LAROSA FUEL COMPANY	S-1051-86	TBC	$1,206,222.50	$943,450.00	$262,772.50		$106,717.00		Surface	181.71	196.79
LEVEL LAND MINING CORPORATION	S-3031-90	P	$4,480.00		$4,480.00	$2,023.92	$4,523.92		Surface	24	24
LILLYBROOK COAL CO.	S-86-85	ACT	$114,590.00		$114,590.00	$11,735.78	$14,235.78		Surface	34	34
LOBO CAPITOL, INC.	UO-204	TBC	$448,895.00	$47,631.00	$401,264.00		$47,631.00		Underground	0	6
LODESTAR ENERGY, INC.	R-5-84	P	$222,666.73		$222,666.73	$1,365.62	$15,639.00		Other	31.46	34
LODESTAR ENERGY, INC.	S-19-85	P	$0.00		$0.00	$9,346.24	$11,846.24		Surface	53.53	98
LODESTAR ENERGY, INC.	S-3006-89	TBC	$674,825.00	$199,000.00	$475,825.00		$46,794.00		Surface	34	122.79
LODESTAR ENERGY, INC.	S-3083-86	TBC	$196,525.00	$167,000.00	$29,525.00		$10,088.00		Surface	8.5	74
LOW ASH COAL CO.	UO-389	P	$70,782.50		$70,782.50	$1,137.83	$5,166.00		Underground	3.18	3.18
M & T MINING CO.	S-3026-89	P	$5,600.00		$5,600.00	$8,219.09	$10,719.09		Surface	114	171
MANGUS COAL COMPANY	S-1036-91	TBC	$754,750.00	$437,100.00	$317,650.00		$54,102.00		Surface	32	32
MAURICE JENNINGS	53-78	TBC	$812,287.50	$165,566.00	$646,721.50		$37,295.00		Surface	65	65

WATER CAPITAL AND WATER TREATMENT COSTS
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Maurice Jennings	S-61-83	TBC	$339,992.50	$422,042.00	-$82,049.50		$32,337.00		Surface	45	52
MOHIGAN MINING CO.	U-109-83	P	$82,909.97		$82,909.97	$3,049.71	$34,525.00		Underground	23	18
MORGANTOWN ENERGY EXPORT CO.	U-8-83	P	$53,642.50		$53,642.50	$1,263.80	$4,631.00		Underground	12	12
MOUNTAINEER FUELS, INC.	U-3083-87	P	$15,000.00		$15,000.00	$4,265.52	$6,765.52		Underground	2	10
NATIONAL CONSTRUCTION COMPANY, INC	S-2004-86	P	$73,121.62		$73,121.62	$2,821.80	$7,598.00		Surface	64.9	54
Omega	D-79-82	ACT	$1,452,655.00		$1,452,655.00	$337,987.10	$340,487.10		Underground	20	24
PIERCE COAL & CONSTRUCTION, INC.	252-76	NA	$0.00		$0.00				Surface	0	0
PIERCE COAL & CONSTRUCTION, INC.	71-80	P	$0.00		$0.00	$4,008.96	$4,008.96		Surface	37	37
PINNACLE CREEK MINING CORP.	R-721	P	$77,466.00		$77,466.00	$2,343.53	$4,843.53		Other	24	32
Preston Energy	O-1035-87	ACT	$6,800.00		$6,800.00	$49,052.60	$51,552.60		Other	30	54
PRESTON ENERGY, INC.	O-43-85	ACT	$0.00		$0.00	$3,400.30	$8,400.30		Surface	13	13
PRESTON ENERGY, INC.	O-86-82	ACT	$0.00		$0.00	$1,113.05	$1,113.05		Surface	16	18
PRIMROSE COAL, INC.	7-81	TBC	$381,142.50	$501,700.00	-$120,557.50		$32,019.00		Surface	147	190
PRINCESS CINDY MINING, INC.	30-79	P	$52,424.00		$52,424.00	$443.53	$4,470.00		Surface	137	137
PRINCESS SUSAN COAL CO.	S-6033-86	UC	$0.00		$0.00		$3,571.00		Surface	118	200
PRINCESS SUSAN COAL CO.	S-6-85	UC	$0.00		$0.00		$7,046.00		Surface	34	216
PRINCESS SUSAN COAL CO.	S-76-82	C	$0.00		$0.00				Surface	0	0
PUPS CREEEK COAL	S-3006-94	TBC	$689,117.50	$330,680.00	$358,437.50		$11,120.00		Surface	213.72	221.31
RALEIGH COMMERICAL DEVELOPMENT CO	149-79	P	$0.00		$0.00	$817.68	$3,317.68		Surface	20	70
ROBLEE COAL CO.	U-2001-00	TBC	$453,017.50	$38,380.00	$414,637.50		$16,975.00		Underground	0	9.19
Rockville Mining Co.	237-76	ACT	$146,700.00		$146,700.00	$18,141.19	$25,641.19		Surface	44	50
Rockville Mining Co.	65-78	ACT	$125,880.00		$125,880.00	$46,964.69	$49,464.69		Surface	145	158
Rockville Mining Co.	S-1035-86	ACT	$178,972.00		$178,972.00	$10,634.91	$15,634.91		Surface	93	120
Rockville Mining Co.	S-65-82	ACT	$57,000.00		$57,000.00	$50,626.29	$55,626.29		Surface	310	475
ROCKVILLE MINING CO.	S-91-85	TBC	$952,586.28	$351,000.00	$601,586.28		$48,309.00		Surface	50	125
ROYAL COAL CO.	R-676	TBC	$1,111,852.50	$243,000.00	$868,852.50		$61,971.00		Other	30	30
Royal Scot Minerals, Inc.	31-72	ACT	$395,000.00		$395,000.00	$486,447.26	$488,947.26		Surface	235	400
ROYAL SCOT MINERALS, INC.	56-81	P	$13,198.92		$13,198.92	$848.48	$3,452.00		Surface	120	300
ROYAL SCOT MINERALS, INC.	D-32-81	ACT	$42,900.00		$42,900.00	$9,341.88	$11,841.88		Underground	8.44	8.44
ROYAL SCOT MINERALS, INC.	R-3078-86	ACT	$717,660.00		$717,660.00	$11,875.99	$18,870.00		Other	26	30
ROYAL SCOT MINERALS, INC.	S-65-76	TBC			$0.00		$2,795.42		Surface	107.23	160
ROYAL SCOT MINERALS, INC.	S-90-82	P	$14,312.00		$14,312.00	$1,658.43	$4,158.43		Surface	92	154
ROYAL SCOT MINERALS, INC.	S-99-83	P	$7,220.00		$7,220.00	$5,936.21	$8,436.21		Surface	10	11
ROYAL SCOT MINERALS, INC.	U-3046-88	TBC	$477,532.50	$224,000.00	$253,532.50		$11,577.00		Underground	26	26.4
ROYAL SCOT MINERALS, INC.	U-40-85	P	$4,160.00		$4,160.00	$4,957.28	$7,457.28		Underground	23	23
S. Kelly Industries	51-78	ACT	$104,135.00		$104,135.00	$72,846.66	$75,346.66		Surface	40	40
SALYERS LEASING CORP.	U-5066-87	P	$0.00		$0.00	$761.73	$3,261.73		Underground	9	19
SAN SUE COAL CO.	19-75	P	$8,520.00		$8,520.00	$4,668.16	$7,168.86		Surface	14	14
SMITH & STOVER	EM-29	TBC	$377,772.50	$54,000.00	$323,772.50		$31,970.00		Surface	25	25
SOLITAIRE COAL CORP.	S-87-85	TBC	$139,377.50	$398,250.00	-$258,872.50		$31,907.00		Surface	85	138

WATER CAPITAL AND WATER TREATMENT COSTS **Appendix A**

Estimates Reflecting NPDES Standards

Site Name	Permit Number	Water Status	Newly Estimated Capital Costs	Prior Estimated Liability Costs	Final Capital Const. Cost	Current Annual O&M	New Post-Construction Annual O&M		*PERMIT TYPE*	Distrubed Acres	*Permitted Acres*
SOUTHERN EAGLE MINING CORPORATION	U-32-84	P	$0.00		$0.00	$2,558.78	$5,058.78		Underground	12	11
STAR INDUSTRIES, INC.	R-3-81	ACT	$20,799.35		$20,799.35	$14,088.96	$25,062.00		Surface	38	38
STEWARTOWN COAL CORP	67-78	ACT	$17,920.00		$17,920.00	$5,547.69	$8,047.69		Surface	4	80
SUMMERSVILLE FIVE BLOCK	S-3051-88	TBC	$4,290,212.50	$243,000.00	$4,047,212.50		$231,065.00		Surface	175	604
T & J COAL, INC.	P-177-85	UC	$0.00		$0.00		$41,315.00		Surface	5	5
T & T FUELS, INC.	U-125-83	ACT	$78,574.21		$78,574.21	$17,565.94	$20,065.94		Underground	14	14
T&T	EM-113	ACT	$2,829,004.00		$2,829,004.00	$459,657.88	$462,157.88		Other	5	5
TEMPLEMAN CONST. CO., INC.	151-75	P	$4,200.00		$4,200.00	$1,469.65	$3,969.65		Surface	25	25
The Masteller Coal Co.	S-125-82	TBC	$136,257.50	$92,500.00	$43,757.50		$36,861.00		Surface	49	49
THE MASTELLER COAL COMPANY	S-10-85	TBC	$186,510.00	$113,419.00	$73,091.00		$9,908.00		Underground	122	142
Triple A Coals	S-96-85	P	$259,480.00		$259,480.00	$10,246.80	$12,746.80		Surface	58.4	262
TRIPLE A COALS, INC.	S-3028-87	P	$52,760.00		$52,760.00	$6,832.47	$9,332.47		Surface	96	121
TRIPLE A COALS, INC.	U-3046-87	P	$52,760.00		$52,760.00	$1,687.81	$4,187.81		Underground	25	25
VALLEY MINING CO.	S-17-82	ACT	$59,575.23		$59,575.23	$3,425.12	$5,944.00		Surface	45	62
VALLEY MINING CO.	S-64-83	ACT	$174,512.50		$174,512.50	$28,192.83	$30,692.83		Surface	161	160
VICKIE ENERGY, INC.	U-53-85	P	$61,247.50		$61,247.50	$1,667.93	$4,935.00		Underground	14	14
Viking Coal	UO-519	ACT	$742,394.00		$742,394.00	$66,132.58	$68,632.58		Underground	10.92	10.92
VMS, LIMITED	S-1045-87	ACT	$54,626.00		$54,626.00	$28,625.86	$31,125.86		Surface	87	162
W & E LOGGING & COAL	S-20-82	P	$5,040.00		$5,040.00	$1,922.20	$4,422.20		Surface	50	70
WERNER MINING CO., INC.	S-2003-86	P	$25,600.00		$25,600.00	$2,652.95	$5,152.95		Surface	43	43
WETER Co	S-71-79	P	$0.00		$0.00	$393.99	$2,893.99		Surface	57	56
WINCHESTER COALS, INC.	O-52-83	C	$0.00		$0.00				Surface	0	0
Wocap Energy	S-26-85	ACT	$268,993.00		$268,993.00	$24,898.42	$27,398.42		Surface	25	40
X W CORP.	S-6013-87	P	$0.00		$0.00	$2,443.57	$4,943.57		Surface	22	25
Z & F DEVELOPMENT CO.	S-21-84	ACT	$383,287.50		$383,287.50	$19,314.08	$50,791.00		Surface	28	28
ZINN COAL CO.	60-79	P	$11,320.00		$11,320.00	$2,569.25	$5,069.25		Surface	10	75
ZY COAL CO	S-6028-88	TBC	$132,092.50		$132,092.50		$7,526.00		Surface	150	190.39
ZY COAL CO.	91-79	P	$30,713.54		$30,713.54	$610.20	$3,237.00		Surface	64	64
ZY COAL CO.	S-30-80	C	$0.00		$0.00				Surface	0	0
TOTAL - Currently Operating Permits Table 1.2 Row (6)					17,160,009.77						
TOTAL - To Be Contracted Permits Table 1.2 Row (7)			30,446,454.78								
TOTAL - Table 1.5 Row (1)						3,175,444.29	6,009,328.63				
TOTAL - Table 1.2 Row (9) and Table 1.5 Row (2)										10,541.18	

Consensus Coal Production And Price Forecast For West Virginia: 2011 Update

Prepared for the
West Virginia Department of Environmental Protection
Office of Special Reclamation

By

George W. Hammond, Ph.D.
Bureau of Business and Economic Research
College of Business and Economics
West Virginia University

December 2011

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Executive Summary

Coal production in West Virginia declined drastically in 2009. The state produced just 137.2 million short tons of coal in 2009, which was a 13.1 percent decrease from 2008. State coal production fell again in 2010, to 135.7 million tons. That was an additional 1.1 percent decline, which left state production 14.0 percent below 2008 (pre-recession) levels. The drop in state production during the past two years was likely related to a number of factors, including the economic downturn, lost production due to the Upper Big Branch mine explosion, as well as rising costs due increasingly challenging geologic conditions and new safety regulations, a shortage of skilled workers, and increasing scrutiny of surface mine permits.

Coal production in both northern and southern West Virginia decreased in 2009, but the drop was more severe in the south. Coal production in the southern region declined to 98.8 million short tons of coal in 2009 from 116.7 million short tons in 2008. This translated into a 15.3 percent decrease in production from 2008 to 2009. Coal production also decreased in the northern region from 2008 (41.1 million tons) to 2009 (38.4 million tons), which was a 6.6 percent decline.

Production trends within West Virginia diverged in 2010, with the northern region posting an increase of 7.9 percent, while production in the southern region declined by an additional 4.6 percent. These trends have continued into the first nine months of 2011, with northern coal production up by 8.3 percent compared to the same period in 2010. In contrast, southern coal production is up just 0.1 percent compared to the first nine months of 2010. This likely reflects a number of factors, including the loss of production due to the Upper Big Branch mine explosion, increasingly challenging geologic conditions, increasing regulatory scrutiny of surface mining permits (which primarily impacts the southern coal fields), and the impact of installation of pollution control equipment at power plants that allows the burning of higher sulfur coals produced in northern Appalachia and elsewhere.

The consensus forecast calls for state coal production to rise from 135.7 million tons in 2010 to 138.4 million tons in 2011, an increase of 2.0 percent. Rising coal production in 2011 is partly driven by strong export demand, particularly for metallurgical coal. Coal production declines in 2012 to 135.8 million tons and again in 2013 to 129.5 million tons. Thereafter, coal production continues to decline through the forecast period, reaching 115.6 million tons by 2030.

Declining coal production during the forecast period reflects the cumulative effect of a number of factors weighing on production in the state. These include demand-side factors that tend to make coal produced in the state a less attractive choice as a fuel to generate electricity. These include additional restrictions on SO_2, NO_x, and mercury (and hazardous air pollutants more generally) and the related investments in pollution control equipment by electric power producers. These investments tend to make coal produced in the southern part of the state less attractive relative to coal produced in Northern Appalachia and other regions of the country. In addition, the forecast reflects the perception that natural gas will be a more potent competitor for coal in the generation of electricity in the future, as well as efforts by electricity producers to start positioning themselves for the eventual regulation of greenhouse gases (including generation from renewables). These forces contribute to the expectation that utilities will phase out less efficient coal-fired plants in favor of those with fewer problematic emissions (such as scrubbed coal-fired plants and plants that burn natural gas and other non-coal fuels, such as biomass). This includes coal-fired plants located in West Virginia (Kanawha River, Phillip Sporn, and Kammer) slated for shut-down by AEP.

These adverse demand-side trends are exacerbated by supply-side issues. These include the increasingly challenging geologic conditions that tend to raise production costs, particularly in southern West Virginia. In addition, the increasing scrutiny of surface mining permits by the U.S. Environmental Protection Agency (EPA) is also expected to contribute to declining productivity at surface mines, and thus rising production costs, in southern West Virginia.

In contrast, the consensus forecast calls for nominal coal prices to rise during the forecast period. Nominal coal prices, which are an average of contract and spot prices, are forecast to rise by 3.1 percent in 2011. Nominal prices continue rising during the forecast period, with the price rising from \$75.93 in 2011 to \$118.05 by 2030. That translates into a growth rate of 2.4 percent per year.

The consensus coal forecast calls for production to decline and prices to rise during the 2011-2030 period. However, it is important to understand that the forecast depends on a number of assumptions that have important impacts on the outlook for coal production in the state. These assumptions include the expected rate of growth of the U.S. and world economies, the competitive and regulatory environment, and the magnitude of the impact of the competitive and regulatory environment on power generation, industrial activity, and mining operations. The potential impact of these assumptions on the forecast is both uncertain and huge, which in turn means that the outlook for coal production and prices in the state is uncertain and may deviate to an unknown extent from the consensus forecast.

In addition, there are up-side risks to the consensus forecast. For instance, the U.S. Energy Information Administration (EIA) assumes that the price of imported crude oil rises from \$92.57 in 2008 to \$181.43 by 2035. If oil prices rise faster than expected, this may present an opportunity for additional investment in coal-to-liquids (CTL) capacity, which would in turn generate increased demand for coal. Likewise, additional development of electric power generation that employs carbon capture and sequestration (CCS) technology may support higher levels of coal production in the future.

Finally, West Virginia coal competes in an increasingly global marketplace. Indeed, the state has seen significant increases in coal exports recently. This likely reflects strong demand for metallurgical coal, as well as supply disruptions internationally (Australian floods), which combine to support continued high metallurgical coal prices. If West Virginia coal producers are more effective than expected in maintaining and opening foreign markets for metallurgical and steam coal, then actual coal production may exceed the consensus forecast. Indeed, the continued consolidation in the industry (like the recent acquisition of Massey Energy by Alpha Natural Resources and the acquisition of ICG by Arch Coal) may make international marketing efforts more effective in the future.

This report proceeds as follows: the Recent Developments section describes in more detail updated trends in coal production, prices, employment, and productivity; the updated consensus coal production and price forecast for West Virginia is summarized next; followed by an analysis of risks. Appendix I contains the details of the construction of the consensus forecast and Appendix II summarizes each of the updated component forecasts individually.

Recent Developments

With Jordan Hantz, Undergraduate Research Assistant

Coal Production

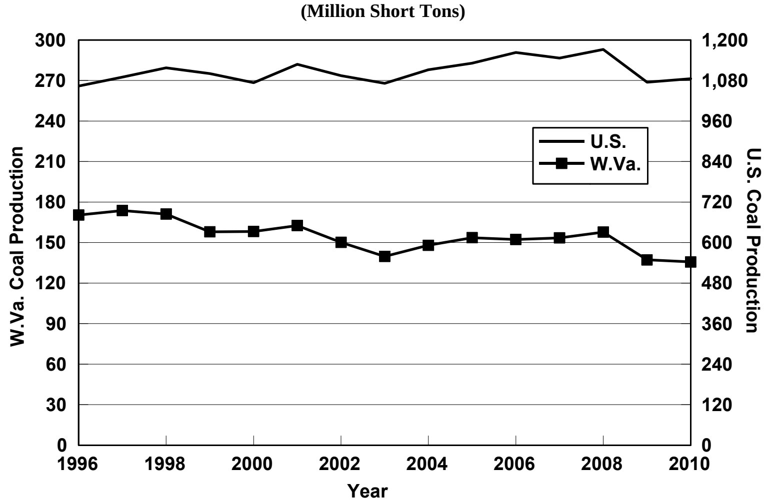
Figure 1 displays the annual production of coal in the United States and West Virginia from 1996 to 2010, according to preliminary data. Coal production in West Virginia to declined drastically in 2009. The state produced just 137.2 million short tons of coal in 2009, which was a 13.1 percent decrease from 2008. State coal production fell again in 2010, to 135.7 million tons. That was an additional 1.1 percent decline, which left state production 14.0 percent below 2008 (pre-recession) levels.

The drop in state production in 2010 was likely related to a number of factors, including lost production due to the Upper Big Branch mine explosion, as well as rising costs due to increasingly challenging geologic conditions and new safety regulations, a shortage of skilled workers, and increased scrutiny of surface mining permits. Rising world demand for coal likely softened the blow in 2010.

National coal production rose in 2010, to a level of 1,085.3 million short tons, according to preliminary estimates. That was a 1.0 percent increase over 2009 and reflects rebounding U.S. and world demand for electricity and steel. However, national coal production remained 7.4 percent below pre-recession (2008) levels.

Even with recent declines, West Virginia accounted for a significant share of national coal production. In 2010, the state produced 12.5 percent of the nation's coal. However, West Virginia's share of national coal production declined since 1996, when it accounted for 16.0 percent of coal produced in the U.S.

Figure 1
Annual Coal Production
W.Va. And U.S.
(Million Short Tons)



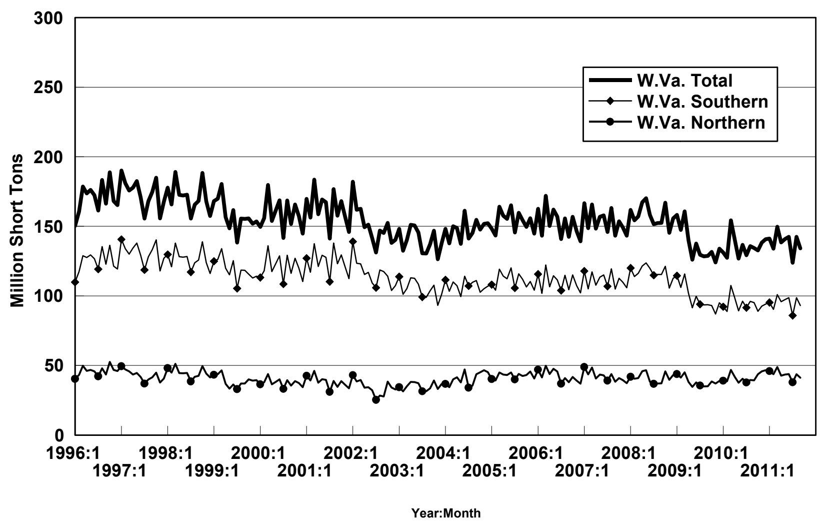
Source: Energy Information Administration

As seen in Figure 2, the preliminary monthly data suggest that West Virginia coal production has begun to gradually increase in recent months. Indeed, state coal production rose by 4.5 percent on average from the second half of 2009 to the second half of 2010. Data through September of 2011 suggest that state coal production has continued to rise so far this year, with total coal production up 2.5 percent compared to the first nine months of 2010.

Figure 2 also shows that the production of coal in the state is heavily concentrated in the southern region with significantly less coal produced in the north.[1] In 2010, the southern region produced 69.5 percent of West Virginia's coal, while the northern region produced 30.5 percent.

Coal production declined in both northern and southern West Virginia, but the drop was more severe in the south in 2009. Coal production in the southern region declined to 98.8 million short tons of coal in 2009 from 116.7 million short tons in 2008. This translated into a 15.3 percent decrease in production from 2008 to 2009. Coal production also decreased in the northern region from 2008 (41.1 million short tons) to 2009 (38.4 million short tons), which was a 6.6 percent decline.

Figure 2
W.Va. Monthly Coal Production By Region
(Non-seasonally Adjusted, Annualized In Million Tons)



Source: Energy Information Administration

Production trends within West Virginia diverged in 2010, with the northern region posting an increase of 7.9 percent, while production in the southern region declined by an additional 4.6 percent. These trends have continued into the first nine months of 2011, with northern coal production up by 8.3 percent compared to the same period in 2010. In contrast, southern coal production is up just 0.1 percent compared to the first nine months of 2010. This likely reflects a number of factors, including the loss of production due to the Upper Big Branch mine explosion,

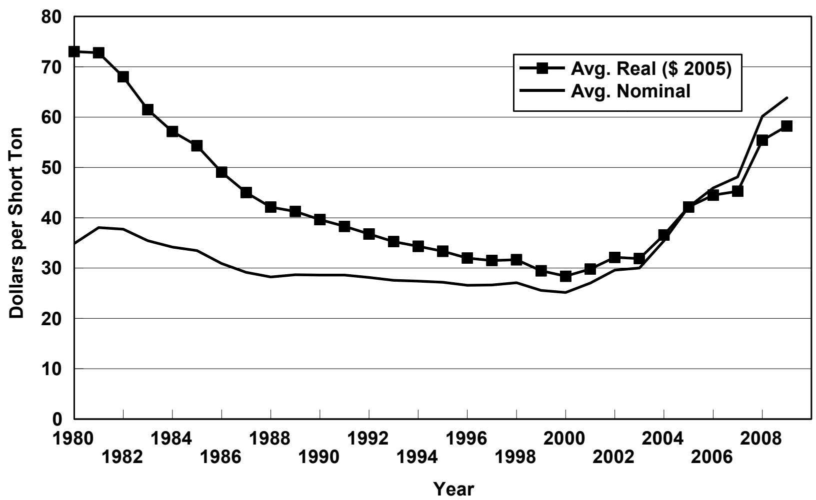
[1] The northern region includes the counties of: Barbour, Braxton, Brooke, Calhoun, Doddridge, Gilmer, Grant, Harrison, Jackson, Lewis, Marion, Marshall, Mineral, Monongalia, Ohio, Pleasants, Preston, Randolph, Ritchie, Roane, Taylor, Tucker, Tyler, Upshur, Webster, Wetzel, Wirt, Wood, and Hancock. The southern region includes the counties of: Boone, Cabell, Clay, Fayette, Greenbrier, Kanawha, Lincoln, Logan, Mason, McDowell, Mercer, Mingo, Nicholas, Pocahontas, Putnam, Raleigh, Summers, Wayne, and Wyoming. This was obtained from the Energy Information Administration (EIA).

increasingly challenging geologic conditions, increasing regulatory scrutiny of surface mining permits (which primarily impacts the southern coal fields), and the impact of installation of pollution control equipment at power plants that allows the burning of higher sulfur coals produced in northern Appalachia.

Coal Prices

As seen in Figure 3, coal prices increased rapidly during the past decade in West Virginia, which was unusual considering that prices consistently declined since 1981. Nominal coal prices hit bottom in 2000, at $25.17 per short ton. From 2000 to 2009, nominal coal prices rose at an average annual rate of 10.9 percent per year. The real price of coal (adjusted for inflation, using the GDP deflator) also increased during this time period. Indeed, the real price increased by 8.3 percent per year from 2000 to 2009. This indicated that nominal prices of coal rose faster than the rate of inflation.

Figure 3
Average Mine Price Of W.Va. Coal
(Nominal And Real Dollars Per Short Ton)



Source: Energy Information Administration

Figure 4 shows monthly coal spot prices for the Central and Northern Appalachian regions from April 4, 2008 until September 16, 2011.[2] Spot coal prices have been very volatile during the past three years and have followed a similar pattern in both regions. Spot coal prices peaked in the summer/fall of 2008 in the $145 per ton range in part because of strong world growth, which increased demand for steel and electricity and thus coal. During the same period, the industry experienced declining productivity and thus rising costs, due in part to increasingly challenging geologic conditions.

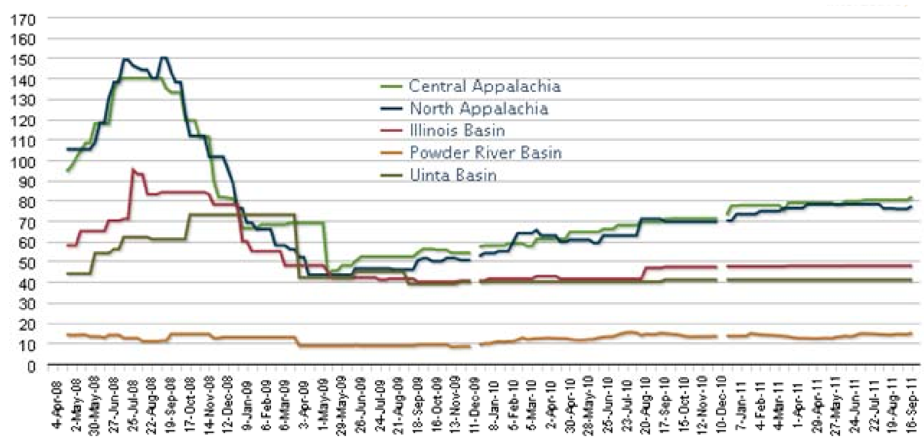
However, demand declined during 2008 and into 2009 due to the Great Recession, which lead to falling spot prices during 2009. Prices eventually fell to lows in the $45 per short ton range in

[2] The Central Appalachian region includes Virginia, eastern Kentucky, northern Tennessee, and southern West Virginia. The Northern Appalachian region includes Pennsylvania, Maryland, Ohio, and northern West Virginia.

May 2009 in both regions. This translated into roughly a 70.0 percent decrease in spot coal prices for both the Central and Northern Appalachian regions.

With the end of the Great Recession in 2009, demand for steel and electricity rose, and spot coal prices began to gradually increase. The spot price at the end of May 2011 for the Central Appalachian region was $78.85. Spot coal prices in the Northern Appalachian region were similar by the end of May 2011, at $78.15. Although spot prices have increased since June 2009, they have not yet reached pre-recession levels ($145 per ton range).

Figure 4
Historical Average Weekly Coal Commodity Spot Prices
($ Per Short Ton)



Source: With permission, selected from listed prices in Platts Coal Outlook, "Weekly Price Survey."
Note: The historical data file of spot prices is proprietary and cannot be released by EIA; see Coal News and Prices .

Metallurgical coal export prices have increased rapidly during the past year, rising from $120.70 per ton in March 2010 to $178.99 in March 2011, according to data from the EIA. That likely reflects continued strong international demand, as well as international supply constraints (Australian floods).

Coal Mining Employment

Both the U.S. and West Virginia experienced major employment declines in coal mining from 1990 to 2000. Indeed, employment dropped during these years by 60,118 in the U.S. and by 11,883 in West Virginia. This translated into a total percentage decline of 45.7 percent and a 44.3 percent decrease in coal mining employment in the nation and the state, respectively. Coal mining employment trends for the nation and the state are displayed in Figure 5.

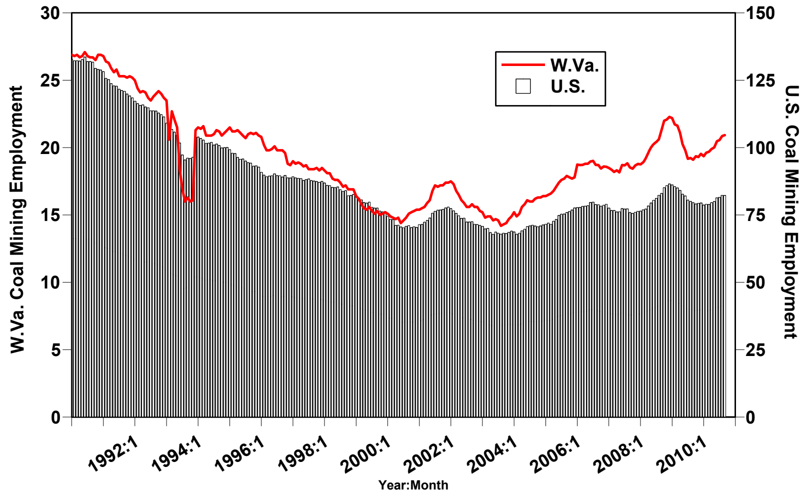
In contrast to the job losses suffered during the 1990s, coal mining employment has risen significantly since 2000. Indeed, the state added 5,300 jobs from 2000 to 2009, which translated into a percentage increase of 35.3 percent. Nationally, coal mining jobs have risen by 14.8 percent since 2000.

However, this overall growth trend has been interrupted by recessions and by regulatory uncertainty. In particular, the state experienced coal mining job losses during the 2002-2003 period, due to the aftermath of the U.S. recession of 2001 and regulatory uncertainty related to surface mining. The state also experienced significant mining job losses during the Great

Recession, with employment falling by 12.3 percent from December 2008 to December 2009. Coal mining jobs declined by 8.2 percent nationally during that period.

As with coal production and prices, employment began to rebound during the past year. Indeed, state coal mining jobs increased by 9.6 percent from September 2009 to September 2010 (the most recent coal mining employment data available from the U.S. Bureau of Labor Statistics). National coal mining employment rose by 3.4 percent during the same period.

Figure 5
Coal Mining Employment
W.Va. And U.S.
(Non-seasonally Adjusted, In Thousands)



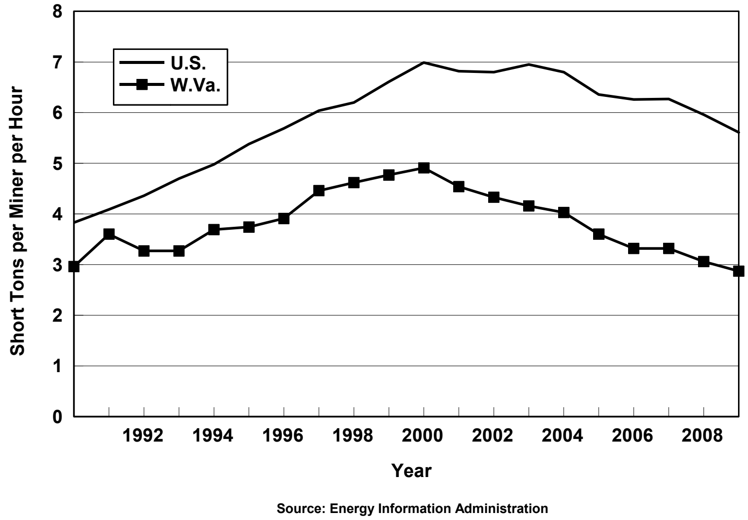
Source: Bureau of Labor Statistics

Coal Productivity

Coal productivity can be measured by coal production per miner per hour, which is displayed annually in Figure 6 for the U.S. and West Virginia. Coal productivity has declined gradually after a peak in 2000 in West Virginia. Coal productivity fell from 4.9 short tons of coal per miner per hour in 2000 to 2.9 in 2009. This translated into an average decrease of 5.7 percent per year. This was also the lowest coal productivity in the state since 1990 (3.0 short tons of coal per miner per hour). This likely reflects the increasing share of coal production in northern West Virginia (which is primarily underground mining) and the increasingly challenging geologic conditions being encountered in the southern coal fields.

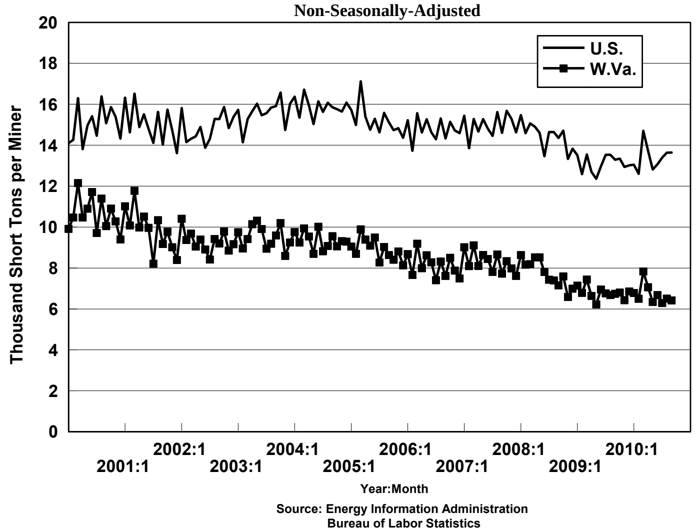
Coal productivity was higher for the U.S. than for West Virginia in 2009, which reflects the large surface mines located in the West. However, national coal mining productivity peaked in 2000 as well, at 7.0 short tons of coal per miner per hour. Like West Virginia, the nation’s coal productivity also decreased since 2000. It fell to 5.6 short tons of coal per miner in 2009, which translated into a 2.4 percent annual decrease.

Figure 6
Annual Coal Mining Productivity
W.Va. And U.S.
(Short Tons Of Coal Per Miner Per Hour)



West Virginia showed a steady decline in monthly coal productivity since a peak in March 2000. This is displayed in Figure 7 measured in thousands of short tons per miner. Coal productivity was just over 12 thousand short tons per miner in West Virginia in March 2000. It declined by 35.5 percent by March 2010. The U.S. followed a similar path in monthly coal productivity. After a peak in March 2005, monthly coal productivity declined until January 2010 for the nation.

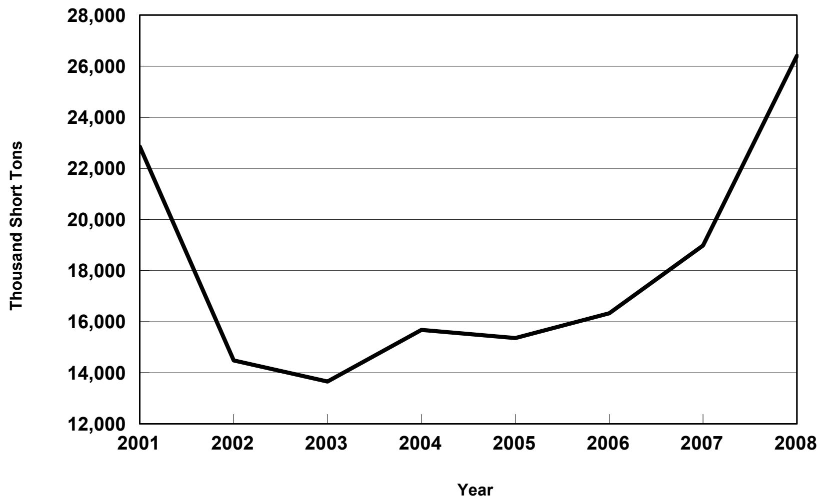
Figure 7
Monthly Coal Mining Productivity
W.Va. And U.S.
Annualized Coal Production In Thousand Short Tons Per Miner
Non-Seasonally-Adjusted



Coal Exports

Coal is one of the most important commodity exports from West Virginia. According to data from the U.S. Energy Information Agency (EIA), the volume of coal exports from the state decreased from 2001 to 2003, but rose by 93.3 percent from 2003 to 2008. This is shown in Figure 8, which displays the volume of exports of West Virginia coal in short tons.

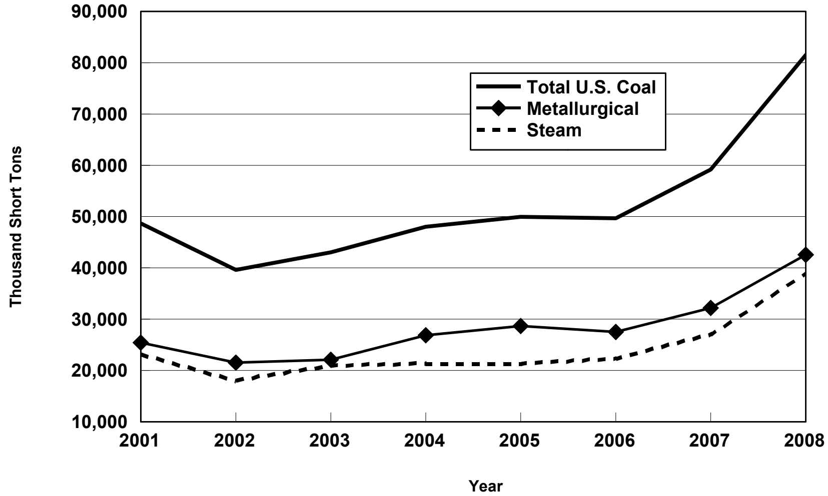
Figure 8
Foreign Distribution Of West Virginia Coal
2001-2008



Source: U.S. Energy Information Administration

The U.S. also experienced a sharp increase in coal exports during the past decade, although the surge began in 2002, as Figure 9 shows. In fact, U.S. coal exports rose by 105.8 percent from 2002 to 2008, as strong world growth drove demand for electricity and steel, and thus coal.

Figure 9
U.S. Coal Exports By Type
2001-2008



Source: U.S. Energy Information Administration

U.S. coal exports include both metallurgical and steam coal. The U.S. has exported more metallurgical coal than steam coal in recent years, as Table 1 and Figure 9 show. Indeed, the nation exported 42,549 thousand short tons of metallurgical coal and 38,971 thousand short tons of steam coal in 2008. Metallurgical and steam coal comprised 52.2 and 47.8 percent of the nation's coal exports in 2008, respectively.

Table 1
U.S. And W.Va. Coal Exports
(Thousand Short Tons)

	2001	2002	2003	2004	2005	2006	2007	2008
U.S. Metallurgical	25,412	21,535	22,090	26,841	28,661	27,498	32,185	42,549
U.S. Steam	23,254	18,066	20,924	21,157	21,281	22,149	26,978	38,971
Total U.S. Coal	48,666	39,601	43,014	47,998	49,942	49,647	59,163	81,519
U.S. Percent Metallurgical	52.2	54.4	51.4	55.9	57.4	55.4	54.4	52.2
U.S. Percent Steam	47.8	45.6	48.6	44.1	42.6	44.6	45.6	47.8
W.Va. Coal Exports	22,855	14,480	13,660	15,677	15,358	16,327	18,981	26,404
W.Va. Coal Export Share	47.0	36.6	31.8	32.7	30.8	32.9	32.1	32.4

Source: U.S. Energy Information Administration

West Virginia is responsible for a significant share of total U.S. coal exports. Indeed, 47.0 percent of the coal exported from the nation originated from West Virginia in 2001. However, the state's share of U.S. coal exports decreased since 2001 to 32.4 percent in 2008.

Table 2 displays the top countries to which West Virginia exported coal, by volume. The EIA has discontinued this dataset, and only data for 2001 through 2003 are available. For these years, West Virginia exported the most coal to Canada. Indeed, Canada accounted for 20.6 percent of West Virginia's coal exports during this period. Italy, France, Brazil, the U.K., and the Netherlands also accounted for large shares of state coal exports.

Table 2
Top Ten Rankings And Tonnage By Destination Of W.Va. Coal Exports
(Thousand Short Tons)

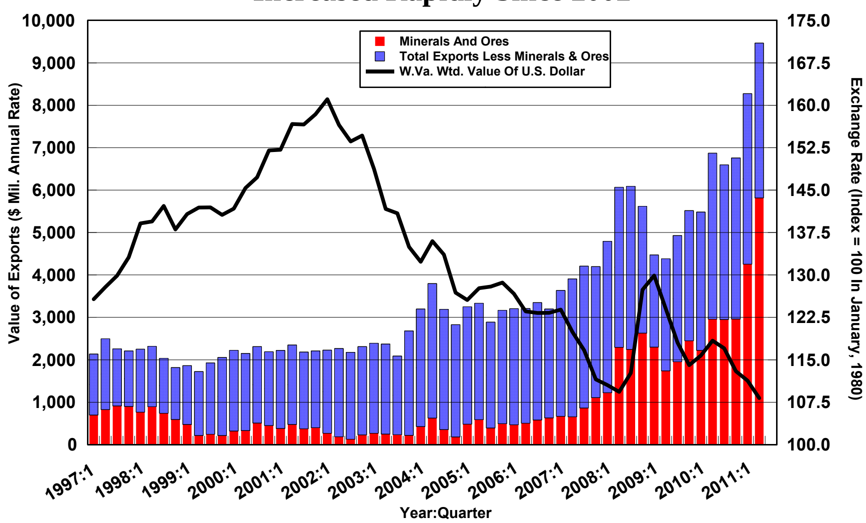
	2001		2002		2003	
Ranking	**Country**	**Tonnage**	**Country**	**Tonnage**	**Country**	**Tonnage**
1	Canada	4,974	Canada	4,515	Canada	2,808
2	Italy	4,257	Italy	2,276	Italy	2,095
3	France	2,287	France	1,277	France	1,608
4	Brazil	2,040	Brazil	1,016	Netherlands	1,061
5	United Kingdom	1,858	Netherlands	877	Brazil	967
6	Netherlands	1,372	Spain	691	Spain	846
7	Sweden	728	United Kingdom	642	United Kingdom	735
8	Spain	635	Sweden	403	Egypt	604
9	Turkey	323	Algeria	303	Turkey	532
10	Bulgaria	305	Turkey	262	Algeria	506

Source: U.S. Energy Infromation Administration

Part of the surge in coal exports since 2003 is related to a major drop in the value of the U.S. dollar during the period. As the value of the U.S. dollar drops, it buys fewer units of foreign currency (and foreign currencies tend to buy more U.S. dollars). This, in turn, tends to make U.S. goods and services cheaper for foreign consumers. Thus, when the dollar falls against most other currencies, we expect that to spur U.S. exports, other things constant.

As Figure 10 shows, the West Virginia export-weighted value of the U.S dollar has depreciated significantly since 2002. Indeed, after peaking in the first quarter of 2002, the state's weighted-average value of the U.S. dollar declined by 32.8 percent by the second quarter of 2011. This depreciation likely played a large role in the surge in the value of commodity exports from West Virginia during the 2002 to 2010 period.

Figure 10
The Value Of W.Va. Commodity Exports Increased Rapidly Since 2002



Source: WISERTrade & Author Calculations

As Figure 10 also shows, the value of West Virginia commodity exports has risen significantly since 2002. Indeed, the value of state commodity exports rose from $2,246.5 million in 2002 to $6,449.2 million in 2010, an increase of 187.1 percent. Data on the value of state commodity exports comes from WISERTrade, which begins with raw trade-flow data from the U.S. Census Bureau.

As the figure also shows, state exports of minerals and ores (primarily coal) have risen dramatically since 2002 as well, likely driven by increased metallurgical coal exports. Indeed, the value of West Virginia mineral and ore exports rose from $203.2 million in 2002 to $2,771.7 million in 2010, which is an increase of more than an order of magnitude. This is similar to previous results from the overall volume of state coal exports, in tons. However, it is important to keep in mind that the data on the value of minerals and ores exports reflects both the physical volume and the price of coal.

The WISERTtrade (and U.S. Census) data allow us to analyze the value of commodity exports across industries and destination countries. Table 3 shows the top ten state export industries, ranked by the value of commodity exports in 2010. As the table shows, exports of minerals and ores were the largest (by value) export industry in the state in 2010. Indeed, in 2010, exports of minerals and ores accounted for 43.0 percent of total state exports. The next largest industry in 2010 was chemical products, which accounted for 24.3 percent of state exports.

Table 3
Top Ten W.Va. Export Industries
Ranked By Value Of Commodity Exports In 2010
(Millions of Dollars)

Rank	NAICS	Industry	2008	2009	2010
1	212	Minerals And Ores	2,098.2	2,110.0	2,771.7
2	325	Chemicals	1,540.7	1,181.7	1,568.1
3	336	Transportation Equipment	667.8	416.1	629.3
4	331	Primary Metal Manufacturing	345.8	170.6	231.4
5	339	Miscellaneous Manufactured Commodities	90.9	108.0	126.3
6	327	Nonmetallic Mineral Products	86.1	90.6	151.4
7	333	Machinery, Except Electrical	375.9	364.0	532.1
8	334	Computer And Electronic Products	66.3	54.1	69.4
9	324	Petroleum And Coal Products	56.3	44.2	53.8
10	326	Plastics And Rubber Products	25.3	29.6	44.1
		Total all Industries	5,643.5	4,825.6	6,449.2

Source: WISERTrade

As Table 4 shows, the largest export market (again by value) for West Virginia exports of minerals and ores in 2010 was India, which accounted for 10.9 percent of state exports of minerals and ores. As the table also shows, the European Union is a very large market for state exports of minerals and ores, accounting for 48.7 percent of state exports in 2010.

Table 4
Top Ten W.Va. Mineral And Ores Export Destinations
Ranked By Value Of Commodity Exports In 2010
(Millions of Dollars)

Rank	Country/Region	2008	2009	2010
1	India	258.2	173.9	302.8
2	Brazil	232.7	312.9	280.4
3	Ukraine	97.3	50.2	245.1
4	Italy	122.8	139.9	224.2
5	United Kingdom	149.4	189.0	221.3
6	Netherlands	134.7	212.4	202.8
7	Turkey	144.4	44.5	154.6
8	France	236.1	257.9	150.8
9	Belgium	129.7	178.5	127.3
10	Spain	28.3	101.3	112.1
	European Union (27)	1,014.2	1,304.9	1,349.0
	Pacific Rim, including China	37.2	60.8	73.5
	Mexico, Latin America, Caribbean	259.6	381.8	350.1
	Total Mineral And Ores	2,098.2	2,110.0	2,771.7

Source: WISERTrade

Consensus Coal Production And Price Forecast For West Virginia

The consensus coal production and price forecast for West Virginia arises from the combination of four forecasts from three forecast providers (two providers for the price forecast). The consensus forecast is a weighted average of the component forecasts, where the weights reflect the relative accuracy of past forecasts from each provider. See Appendix I for the derivation of the weights used to combine forecasts.

The component forecasts included in the consensus production forecast come from the Energy Information Administration (EIA reference case forecast), West Virginia University Bureau of Business and Economic Research (WVU BBER), and Energy Ventures Analysis (EVA). Coal price forecasts come from EIA and EVA. See Appendix II for summaries of each component forecast.

Forecasts were chosen to reflect a variety of models and forecasts. These vary from short-run forecasts designed to reflect business cycle influences to long-run forecasts derived from firm-level modeling exercises. The WVU BBER and EIA forecasts were produced in late 2010 or early 2011. The EVA forecast was produced in October 2011.

The consensus forecast calls for state coal production to rise from 135.7 million tons in 2010 to 138.4 million tons in 2011, an increase of 2.0 percent. Rising coal production in 2011 is partly driven by strong export demand, particularly for metallurgical coal. Coal production declines in 2012 to 135.8 million tons and again in 2013 to 129.5 million tons. Thereafter, coal production continues to decline through the forecast period, reaching 115.6 million tons by 2030. The consensus coal production forecast is summarized in Table 5 and Figure 11.

Declining coal production during the forecast period reflects the cumulative effect of a number of factors weighing on production in the state. These include demand-side factors that tend to make coal produced in the state a less attractive choice as a fuel to generate electricity. These include additional restrictions on SO_2, NO_x, and mercury (and hazardous air pollutants, more generally) and the related investments in pollution control equipment by electric power producers. These investments tend to make coal produced in the southern part of the state less attractive relative to coal produced in Northern Appalachia and other regions of the country. In addition, the forecast reflects the perception that natural gas will be a more potent competitor for coal in the generation of electricity in the future, as well as efforts by electricity producers to start positioning themselves for the eventual regulation of greenhouse gases (including increasing generation from renewables). These forces contribute to the expectation that utilities will phase out less efficient coal-fired plants in favor of those with fewer problematic emissions (such as scrubbed coal-fired plants and plants that burn natural gas and other non-coal fuels, such as biomass). This includes coal-fired plants located in West Virginia (Kanawha River, Phillip Sporn, and Kammer) slated for shut-down by AEP.

These demand-side trends are exacerbated by supply-side issues. These include the increasingly challenging geologic conditions that tend to raise production costs, particularly in the southern part of the state. In addition, the increasing scrutiny of surface mining permits by the U.S. Environmental Protection Agency (EPA) is also expected to contribute to declining productivity at surface mines, and thus rising production costs, in southern West Virginia.

In contrast, the consensus forecast calls for nominal coal prices to rise during the forecast period, as Figure 12 and Table 5 show. Nominal coal prices, which are an average of contract and spot prices, are forecast to rise by 3.1 percent in 2011. Nominal prices continue rising during the forecast period, with the price rising from $75.93 in 2011 to $118.05 by 2030. That translates into a growth rate of 2.4 percent per year. Stronger price growth in the short-run reflects continued strong demand combined with a limited supply response.

Figure 11
W.Va. Consensus Forecast
Coal Production

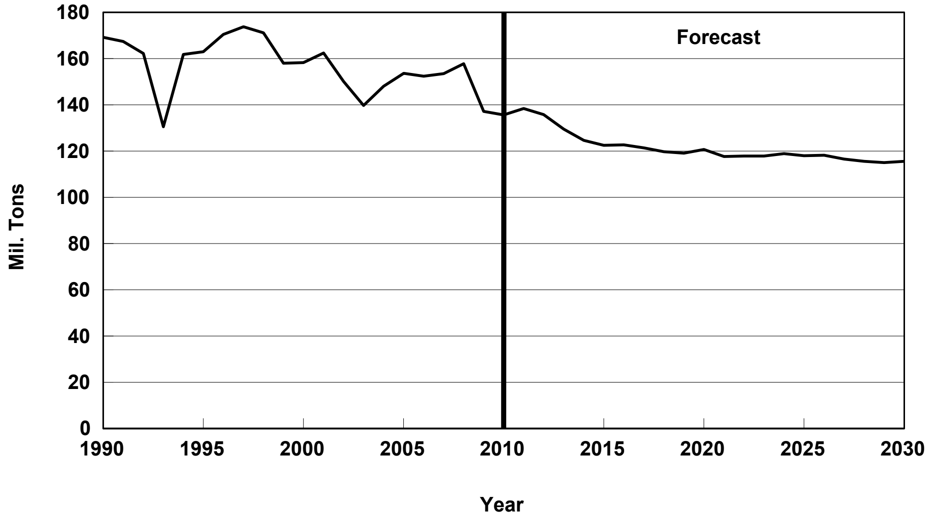


Figure 12
W.Va. Consensus Forecast
Nominal Coal Prices

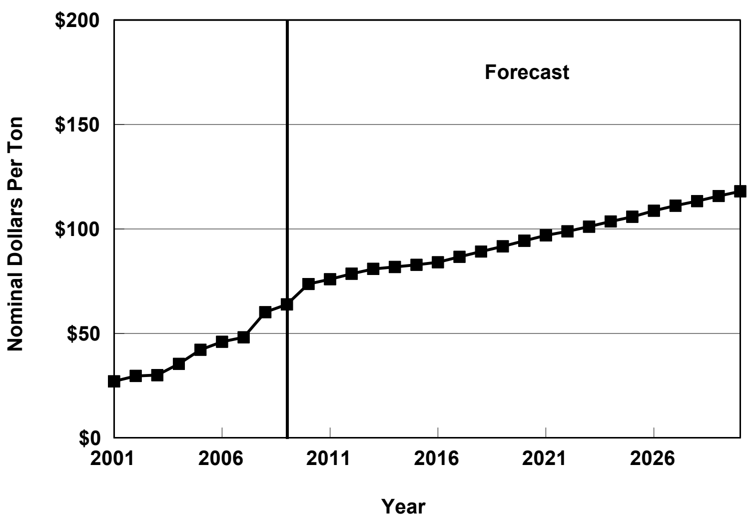


Table 5
W.Va. Coal Production And Prices
Consensus Forecast
(Millions Of Tons And Nominal Price Per Ton*)

	Actual						
	2005	**2006**	**2007**	**2008**	**2009**	**2010**	**Ann.Gr.(%)**
W.Va. Coal Production	153.7	152.4	153.5	157.8	137.1	135.7	-2.5
W.Va. Nominal Coal Price	42.14	45.94	48.12	60.16	63.83	73.65f	11.8

	Forecast						
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**Ann.Gr.(%)**
W.Va. Coal Production	138.4	135.8	129.5	124.6	122.5	122.7	-2.4
W.Va. Nominal Coal Price	75.93	78.56	80.84	81.80	82.80	84.06	2.1

	Forecast						
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**Ann.Gr.(%)**
W.Va. Coal Production	121.4	119.7	119.1	120.7	117.7	117.9	-0.6
W.Va. Nominal Coal Price	86.67	89.19	91.66	94.32	96.93	98.84	2.7

	Forecast						
	2023	**2024**	**2025**	**2026**	**2027**	**2028**	**Ann.Gr.(%)**
W.Va. Coal Production	117.8	118.9	118.0	118.2	116.5	115.5	-0.4
W.Va. Nominal Coal Price	101.14	103.61	105.86	108.72	111.16	113.32	2.3

	Forecast		
	2029	**2030**	**Ann.Gr.(%)**
W.Va. Coal Production	115.0	115.6	0.5
W.Va. Nominal Coal Price	115.79	118.05	2.0

*The coal price for 2010 is forecast. Coal prices are an average of contract and spot prices.

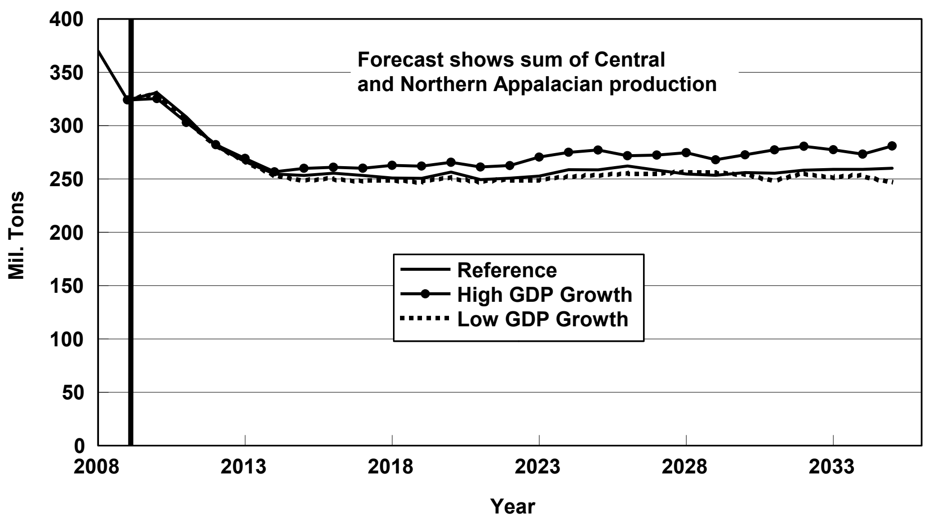
Risks To The Forecast

The consensus coal forecast calls for production to decline and prices to rise during the 2011-2030 period. However, it is important to understand that the forecast depends on a number of assumptions that have important impacts on the outlook for coal production in the state. These assumptions include the expected rate of growth of the U.S. and world economies, the competitive and regulatory environment, and the magnitude of the impact of the competitive and regulatory environment on power generation, industrial activity, and mining operations. The potential impact of these assumptions on the forecast is huge, which in turn means that the outlook for coal production in the state is uncertain and may deviate to an unknown extent from the consensus forecast.

One important assumption built into all of the component forecasts is the assumption regarding future economic growth, typically summarized by real GDP growth. This matters because overall economic growth is an important driver of the demand for electricity and steel, which in turn are important drivers of the demand for coal. Overall, slower economic growth tends to reduce the demand for coal, while faster economic growth increases the demand for coal. The reference case forecast from the Energy Information Administration (EIA) assumes that U.S. real GDP growth averages 2.7 percent per year during the forecast. That growth rate is significantly below the average U.S. growth rate during the 1970-2010 period, which was 2.9 percent per year.

Figure 13 shows the impact of two different growth cases on Central and Northern Appalachian coal production. The high growth case assumes that real GDP, labor force, and productivity growth exceed reference case assumptions. For instance, U.S. real GDP growth averages 3.2 percent per year in the high growth case. As the figure shows, this results in significantly higher coal production by 2035, when production is 20.9 million (or 8.0 percent) above the reference case.

Figure 13
EIA Forecasts For Central And Northern Appalachian Coal Production Under Alternative Growth Scenarios



The low GDP growth case illustrates possible results if real GDP, labor force, and productivity growth falls below the reference case assumptions (with real GDP growth at 2.1 percent per year). In this case, Central and Northern Appalachia production ends the forecast 12.0 million tons (4.6 percent) below the reference case.

Each of the component forecasts also includes an assessment of the future regulatory environment and its impact on power generation, industrial activity, and mining operations. The EIA reference case forecast assumes that the U.S. Environmental Protection Agency (EPA) continues to implement its interim permit review guidelines regarding surface mining. EIA estimates that this reduces productivity at Central Appalachian surface mines by 15-20 percent during the forecast. To the extent that these estimates are too optimistic (i.e. the productivity falls more than expected), then Central Appalachian coal production may be below the reference case forecast. The opposite would occur if EIA estimates are too pessimistic (i.e. productivity falls less than expected).

There are a wide variety of additional regulatory risks to the forecast. These include additional restrictions on emissions of SO_2, NO_x, and mercury (and hazardous air pollutants, more generally). Including these restrictions would likely reduce the EIA forecast for Appalachian coal production below reference case levels.

Natural gas is expected to be a formidable competitor for coal in the electricity generation market. The EIA reference case forecast assumes that natural gas production rises quickly during the forecast and that natural gas prices remain low. The lower 48 wellhead price of natural gas is projected to rise by 4.0 percent per year, from $3.62 per million BTU in 2009 to $9.99 per million BTU by 2035. If natural gas prices rise faster than expected (relative to coal prices) then that will likely result in higher than expected coal production. If natural gas prices rise slower than expected, this coal production will likely be lower than expected in the reference case.

None of the component forecasts include a cap-and-trade style plan to reduce the emissions of green house gases. The adoption of such a plan would likely result in lower coal production than expected in the consensus forecast.

There are up-side risks to the consensus forecast. For instance, EIA assumes that the price of imported crude oil rises from $92.57 in 2008 to $181.43 by 2035. If oil prices rise faster than expected, this may present an opportunity for additional investment in coal-to-liquids (CTL) capacity, which would in turn generate increased demand for coal. Likewise, additional development of electric power generation that employs carbon capture and sequestration (CCS) technology may support higher levels of coal production in the future.

Finally, West Virginia coal competes in an increasingly global marketplace. Indeed, the state has seen significant increases in coal exports recently. If West Virginia coal producers are more effective than expected in maintaining and opening foreign markets for metallurgical and steam coal, then actual coal production may exceed the consensus forecast.

Appendix I

Assessment Of Forecast Accuracy And Forecast Weights

A forecast is a prediction about the future. In the simplest terms, evaluating a forecast means comparing forecast values to actual realizations. In theory, this is simple; in practice, it gets complicated. The purpose of this appendix is to systematically compare coal production and price forecasts from EIA, Energy Ventures Analysis (EVA), and the West Virginia University Bureau of Business and Economic Research, to actual realizations and summarize the results.

Keep in mind that most forecasts differ from what we eventually observe. It is a fact of life that the future is uncertain and economic models cannot fully surmount that. In addition, the current economic situation is uncertain. Even preliminary production data are released at least one month after the fact and sometimes take years to become "final." Thus, we find ourselves in the position of evaluating what the future may bring, while in possession of only incomplete information about what has just happened. Indeed, this uncertainty contributes to the importance of timely analysis of current trends and forecasting.

Comparing Forecasts To Actual Values

Forecast Horizon

To summarize the forecasting performance of the models, we focus on forecasts that are one, two, three, and four years ahead. Now, what is the meaning of a one-year-ahead forecast? A practical example using an actual forecast from the BBER West Virginia State Econometric Model will be used to illustrate basic concepts. This model is used twice per year to forecast the state economy.

In the Fall of 2007, the BBER used its econometric model to generate an annual forecast of West Virginia coal production. In the Fall of 2007, we knew that coal production in West Virginia was about 152 million tons in 2006 and we had six of months of coal production data for 2007. In the Fall of 2007, a one-year-ahead forecast of state coal production from the BBER West Virginia Econometric Model was for annual production in 2007 (the model predicted that state coal production would be 152 million tons). Similarly, a two-year-ahead forecast was for 153 million tons for 2009, and so on. In a similar fashion, each forecast from the BBER West Virginia Econometric Model generates forecasts of coal production one, two, three, four, and up to 10 years ahead.

Forecast Difference

To measure how a forecast differs from the actual results, at each forecast horizon, I will use the term “forecast difference.” A forecast difference is measured simply as a forecast value minus the actual value. A percentage forecast difference is just the forecast difference divided by the actual value, multiplied by 100, as shown in the equations below,

$$\text{Forecast Difference}_t = \text{Forecast}_t - \text{Actual}_t$$

$$\text{Percent Forecast Difference}_t = \frac{\text{Forecast Difference}_t}{\text{Actual}_t} \times 100 = \frac{\text{Forecast}_t - \text{Actual}_t}{\text{Actual}_t} \times 100$$

Thus, a positive forecast difference tells us that the forecast exceeds the current estimate, whereas a negative difference tells that the forecast falls short of the current estimate. Specifically, the one-year-ahead forecast difference for the West Virginia coal production forecast produced in the spring of 2007 was -2 million tons (the actual value for 2007 turned out to be 154 million tons). The one-year-ahead percent forecast difference for this forecast was -1.3 percent.

For each forecast provider, I report the average percentage forecast differences for all available forecasts at the four forecast horizons (a measure of the bias of the forecasts). Since the forecast difference from each release could be positive or negative, an average of forecast differences will allow positive forecast differences to be canceled by negative forecast differences.

However, a forecast accuracy measure based on a simple average of positive and negative forecast differences is not sufficient. In order to see why, suppose we are comparing the one-step-ahead forecast accuracy of two models, each of which has produced two forecasts. Suppose that for model 1, the percent forecast differences are +1 percent and -1 percent. Thus, the average percent forecast difference is 0.0 percent. Suppose that for model 2, the percent forecast differences are +10 percent and -10 percent. The average percent forecast difference for model 2 is 0.0 percent as well. It is obvious, however, that model 1 has produced the superior forecasts, coming closer to actual values each time. (The forecast from model 1 is more efficient in the sense that its variance around the actual value is lower.) We can account for this issue by averaging the absolute percent differences for each model. Thus, for model 1 the average absolute percent difference is 1 percent, while for model 2 the average is 10 percent.

Evaluating The Internal Accuracy Of Coal Production And Price Forecasts

Table 6 shows the ability of forecast providers to predict the coal production level and nominal coal price level for their chosen geography (Northern Appalachia, Central Appalachia, or West Virginia). The table shows the average percentage forecast differences as well as average absolute percentage forecast differences, by forecast horizon, for each forecast provider. In each case, the target variable corresponds to the variable forecasted. For example, EIA generates coal production forecasts for Northern Appalachia. In order to evaluate the performance of this forecast, we compare forecast coal production for Northern Appalachia to actual coal production for Northern Appalachia. The results of this analysis tell us about the performance of each forecast providers model, relative to the geography and coal price they are trying to predict.

The table also provides information on the number of one-step-ahead forecasts available from each forecast provider. A larger number of forecasts available for evaluation tends to make the average forecast difference a more robust indicator of overall forecast performance. The number of forecasts available ranges from 20 for West Virginia University to four for Energy Ventures Analysis. All forecasts evaluated were produced during the 1998 to 2009 period. Coal price forecasts are available only from EIA and EVA.

At the one-year-ahead horizon, average absolute percentage differences for coal production range from 1.78 percent to 6.24 percent. At the three-year-ahead horizon, average absolute percentage differences range from 2.52 percent to 14.97 percent. As the table shows, forecast differences generally rise with the length of the forecast horizon. This is a standard result in forecast evaluation and arises because of the increasing uncertainty associated with forecasts at longer horizons.

As Table 6 shows, I evaluated 11 coal price forecasts from EIA, which forecasts the average of spot and contract prices. This tends to make the price data less volatile, since contract prices reset gradually. The one-year-ahead average absolute forecast differences for EIA range from 4.27 percent for Northern Appalachia to 5.26 percent for Central Appalachia. Forecast differences tend to rise as the forecast horizon increases, as expected.

I evaluated four coal price forecasts from EVA, which forecasts spot prices. The one-year-ahead average absolute forecast differences range from 5.05 percent for Central Appalachia to 7.36 percent for Northern Appalachia. The forecast differences rise significantly at the two year horizon, to 51.79 percent for Northern Appalachia and 57.34 percent for Central Appalachia. This reflects the high volatility of spot prices in Northern and Central Appalachia during 2008 and 2009. Overall, average forecast differences for coal prices tend to be higher for EVA than for EIA. This occurs because EVA forecasts spot prices, which are much more volatile, and because I have fewer coal price forecasts from EVA to evaluate. In addition, the forecasts that are available happen to include a period of very high volatility in spot prices.

Table 6
Forecast Performance With Respect To The Coal Production And Price Level By Geography And Coal Type
Average Percentage Differences and Average Absolute Percentage Differences

Forecast Provider / Forecast Geography	Coal Type	One Step Forecasts	Average Percentage Differences* Annual Steps Ahead: One	Two	Three	Four	Average Absolute Percentage Differences Annual Steps Ahead: One	Two	Three	Four
Coal Production										
Energy Information Admin.										
Northern Appalachian Region	All	13	3.06	7.46	11.01	18.02	6.24	8.89	12.27	18.02
Central Appalachian Region	All	13	-1.12	-0.76	1.83	2.72	3.53	6.20	8.37	7.05
Energy Ventures Analysis										
Northern Appalachian Region	All	4	2.01	6.90	14.97	NA	2.25	6.90	14.97	NA
Central Appalachian Region	All	4	-0.34	4.63	2.52	NA	1.78	13.19	2.52	NA
West Virginia University										
West Virginia	All	20	0.48	4.37	5.68	6.13	4.06	6.53	7.39	8.84
Nominal Coal Prices										
Energy Information Admin.**										
Northern Appalachian Region	All	11	-1.84	-5.34	-9.53	-13.09	4.27	7.17	11.55	15.34
Central Appalachian Region	All	11	-3.85	-10.15	-16.55	-24.22	5.26	10.96	16.81	24.22
Energy Ventures Analysis**										
Northern Appalachian Region	All	4	-3.49	8.62	13.93	NA	4.40	52.15	17.83	NA
Central Appalachian Region	All	4	2.25	17.11	19.08	NA	5.00	57.80	26.71	NA

*Positive (negative) values indicate over (under) prediction on average.
**EIA forecasts an average of spot and contract prices. EVA forecasts spot prices.
Forecasts Evaluated:
EIA: Annual Energy Outlook 1997-2010 for production, 1999-2010 for prices.
EVA: Long-Term Forecast: 2006-2009
West Virginia University: West Virginia Economic Outlook 1998-2010, Mid-Year Review 1999, 2001, Long-Term Forecast 1998, 2000, 2002, 2004, 2006

Evaluating The Accuracy Of External Forecasts For West Virginia Coal Production And Prices

The analysis so far tells us a great deal about the relative performance of the forecasts I combine. However, our ultimate goal is to produce forecasts for West Virginia coal production and prices, by combining forecasts for West Virginia and Northern and Central Appalachia. Since EIA and EVA generate forecasts for geographies that extend beyond West Virginia's borders, we need to evaluate the ability of these forecasts to predict West Virginia coal production and prices.

To evaluate these forecasts, I will compare forecast coal production and price **growth rates** from each provider to actual West Virginia coal production and price **growth rates**. The forecast growth rates are computed using exactly the same coal production and price forecasts evaluated above. I follow the same procedure as above, except that I focus on forecast differences only and do not compute percentage forecast differences.

The results of this exercise are presented in Table 7 below. The average forecast differences provide information on how close forecast growth rates are to actual West Virginia coal production and price growth rates. For instance, to construct the one-step-ahead forecast differences for Northern Appalachian coal production (from EIA), I compare the forecast growth rate for Northern Appalachian coal production (one step ahead) to the actual West Virginia coal production growth rate. The results of this analysis tell us how useful the EIA forecasts of Northern Appalachia coal production are in forecasting West Virginia coal production growth. As shown in the table, average absolute one-year-ahead growth rate differences for the Northern Appalachian forecast from EIA were 3.97 percent. This means that on average, the one-year-ahead forecast of the Northern Appalachian coal production growth rate was 3.97 percentage points above/below the actual West Virginia coal production growth rate.

Table 7
Forecast Performance With Respect To The W.Va. Coal Production And Price Growth Rate
Average And Average Absolute Growth Rate Differences In Percent

Forecast Provider			Average Growth Rate Differences*				Average Absolute Growth Rate Differences				
		One Step	Annual Steps Ahead				Annual Steps Ahead				
Forecast Geography	Coal Type	Forecasts	One	Two	Three	Four	One	Two	Three	Four	Average
Coal Production											
Energy Information Admin.											
Northern Appalachian Region	All	13	2.50	4.18	3.02	5.57	3.97	5.56	6.16	6.92	5.65
Central Appalachian Region	All	13	-2.34	0.37	1.59	-0.03	4.02	4.95	5.38	3.99	4.59
Energy Ventures Analysis											
Northern Appalachian Region	All	4	2.14	8.05	17.08	NA	2.51	8.76	17.08	NA	9.45
Central Appalachian Region	All	4	-1.78	3.24	6.54	NA	3.89	11.00	6.54	NA	7.14
West Virginia University											
West Virginia	All	20	0.62	3.75	1.53	0.47	2.73	4.74	4.16	5.06	4.17
Nominal Coal Prices											
Energy Information Admin.**											
Northern Appalachian Region	All	11	-3.69	-7.08	-8.80	-9.03	5.70	8.30	9.61	9.03	8.16
Central Appalachian Region	All	11	-4.32	-7.69	-8.71	-10.45	5.26	8.89	9.23	10.45	8.46
Energy Ventures Analysis**											
Northern Appalachian Region	All	4	-1.90	-13.72	-1.13	NA	39.39	13.72	1.13	NA	18.08
Central Appalachian Region	All	4	4.67	-12.73	-1.43	NA	52.12	12.73	1.43	NA	22.09

Growth rate differences show the difference between the predicted growth rate (for each geography and coal type) and the West Virginia coal production growth rate.
*Positive (negative) values indicate over (under) prediction on average. NA: not available
**EIA forecasts an average of spot and contract prices. EVA forecasts spot prices.
Forecasts Evaluated:
EIA: Annual Energy Outlook 1997-2010
Energy Venturea Analysis: Long-Term Outlook: 2006-2009
West Virginia University: West Virginia Economic Outlook 1998-2010, Mid-Year Review 1999, 2001, Long-Term Forecast 1998, 2000, 2002, 2004, 2006

As the table shows, the results are generally similar to the internal forecast evaluation results. The forecast differences rise as the forecast horizon rises, as is usually the case. At the one-year-ahead horizon, average absolute growth rate differences for coal production range from 2.51 percent to 4.02 percent. At the three-year-ahead horizon, average absolute growth rate differences range from 4.16 percent to 17.08 percent. The forecast differences for West Virginia coal production during the time period considered are a bit lower for the forecasts produced by West Virginia University and EIA than are those produced by EVA. The average absolute growth rate differences (averaged across forecast horizons) are used to construct the weights required to compute the final West Virginia coal production forecast.

Table 7 also summarizes the results for coal prices. Forecast differences again tend to be lower for EIA than for EVA. This occurs because EVA forecasts spot prices, which tend to be more volatile, and because the forecasts that are available include a period of unusual volatility in spot prices.

Construction Of The Consensus Forecast

The West Virginia consensus coal production forecast is constructed as the linear combination of seven coal production forecasts from three forecast providers (following Granger (1989)). This linear combination amounts to computing a weighted average of the forecast growth rates, where the weights are computed as functions of average absolute forecast differences. The average absolute forecast differences are drawn from Table 7 above and are the average across the four forecast horizons. The consensus coal price forecast is constructed in a similar manner.

For instance, the forecast of the growth rate for West Virginia coal production in year (t) is computed as follows:

$$\text{West Virginia Coal Production Growth Rate}_t = \sum_i \omega_i * \text{Coal Production Growth Rate}_{i,t},$$

where i indexes the seven forecasts to be combined and ω_i is the weight applied to the coal production growth rate for forecast i.

The weights (ω_i) are constructed from the average absolute growth rate differences (averaged across horizons) shown in Table 7. They are constructed as follows:

$$\omega_i = \frac{1/\mathrm{d}_i}{\sum_i 1/\mathrm{d}_i},$$

where d_i is the average absolute growth rate forecast difference (averaged across horizons). Thus, by definition, the weights sum to 1.0 and the forecast provider with the smallest (largest) average absolute growth rate differences gets the largest (smallest) weight in the combined forecast.

Using this formula and the data from Table 7, the weights (ω_i) used to combine forecasts are shown in Table 8.

Table 8
Weights Used to Combine
Coal Production And Price Growth Rate Forecasts

Forecast Provider Geography	Weight (ωi)*	Last Year Forecast
Coal Production		
Energy Information Admin.		
Northern Appalachian Region	0.20	2030
Central Appalachian Region	0.25	2030
Energy Ventures Analysis		
Northern Appalachian Region	0.12	2030
Central Appalachian Region	0.16	2030
West Virginia University		
West Virginia	0.27	2015
Nominal Coal Prices		
Energy Information Admin.		
Northern Appalachian Region	0.36	2030
Central Appalachian Region	0.35	2030
Energy Ventures Analysis		
Northern Appalachian Region	0.16	2030
Central Appalachian Region	0.13	2030

*These are the weights when all forecasts are available. When forecast data for a provider are exhausted the weights are re-adjusted to sum to one for the remaining forecasts.

Finally, the consensus forecast for West Virginia coal production growth rates generate forecast coal production levels using the following:

$$\text{W.Va. Coal Production Level}_t = \text{W.Va. Coal Production Level}_{t\text{-}1} * (1 + \text{W.Va. Coal Production Growth Rate}_t).$$

The consensus forecast for coal prices is constructed in a similar manner, using data from Tables 7 and 8.

Appendix II

Summary Of Component Forecasts

Energy Information Agency (EIA)

Publication: Annual Energy Outlook 2011
Publication Date: April 2011
Coal Type: All
Geography: Northern Appalachia, Central Appalachia[3]
Forecast Horizon: 2010-2035
Scenario: Reference Case

Assumptions:

Macroeconomic Growth:

U.S. real GDP grows at an average rate of 2.7 percent per year during the 2009-2035 period.

Environmental:

Current law and enforcement practices in effect as of the end of January 2011 are assumed to continue. This includes an effort to model the new EPA guidelines for monitoring the compliance of surface coal mining operation in Appalachia with the provisions of the Clean Water Act, the National Environmental Policy Act, and the environmental justice Executive Order (E.O. 12989). This results in significantly lower productivity in Central Appalachia, which reduces competitiveness.

Natural Gas Prices:

The lower 48 wellhead price of natural gas is projected to rise by 4.0 percent per year, from $3.62 per million BTU in 2009 to $9.99 per million BTU by 2035.

Electricity Growth:

Electricity sales are forecast to grow an average of 0.9 percent per year through 2035. Coal's share of electricity generation falls from 44.5 percent in 2009 to 42.9 percent in 2035.

---

[3] Northern Appalachia includes Pennsylvania, Maryland, Ohio, and Northern West Virginia. Northern West Virginia includes all mines in the following counties (formerly defined as Coal-Producing Districts 1, 3, & 6): Barbour, Brooke, Braxton, Calhoun, Doddridge, Gilmer, Grant, Hancock, Harrison, Jackson, Lewis, Marion, Marshall, Mineral, Monongalia, Ohio, Pleasants, Preston, Randolph, Ritchie, Roane, Taylor, Tucker, Tyler, Upshur, Webster, Wetzel, Wirt, and Wood.

Central Appalachia includes Southern West Virginia, Virginia, Eastern Kentucky, Northern Tennessee. Southern West Virginia includes all mines in the following counties (formerly defined as Coal-Producing Districts 7 & 8): Boone, Cabell, Clay, Fayette, Greenbrier, Kanawha, Lincoln, Logan, Mason, McDowell, Mercer, Mingo, Nicholas, Pocahontas, Putnam, Raleigh, Summers, Wayne, and Wyoming.

Coal Mining Productivity:

Growth in coal mining productivity declines from an annual average rate of 5.9 percent per year during the 1980-2002 period to 0.3 percent per year during the 2009-2035 period. This is attributed to higher stripping ratios and the additional labor needed to maintain underground mines, which offsets productivity gains from improved equipment and technology. In addition, regulatory restrictions on surface mining techniques, increasingly challenging geologic conditions, and fragmentation of underground reserves limit productivity gains in Appalachia.

Summary Coal Production And Price Forecast For Central And Northern Appalachia

Figures 14 and 15 and Tables 9 and 10 summarize the EIA coal production forecast for Central and Northern Appalachia. The forecast calls for the two regions to experience very different production trends during the next 26 years. The outlook calls for production in Central Appalachia to decline significantly during the forecast period. Indeed, production in Central Appalachia is forecast to drop from 196.7 million tons in 2009 to 100.5 million tons by 2035, which translates into a decline of 48.9 percent.

As Figure 14 shows, the bulk of the decline is expected to occur within the next decade. The drop in Central Appalachian production is driven by the depletion of easily mineable coal reserves, increased regulatory scrutiny of surface mining practices, and the ability of coal-fired power plants that have been retrofitted with flue-gas desulfurization (FGD) equipment to use higher sulfur coals. The outlook is also affected by the development of natural gas shale plays, which have the potential to bring large amounts of natural gas to the market at reasonable prices, which affects the long-term prospects of coal-powered electricity generation.

Northern Appalachian coal production rises during the forecast period, from 127.5 million tons in 2009 to 159.7 million tons in 2035. That translates into an increase of 25.3 percent. Production in Northern Appalachia benefits from investments to retrofit coal-fired power plants with FGD equipment.

In contrast, nominal price trends are more similar during the forecast, with prices rising for both Central and Northern Appalachia during the period. Coal prices in Northern Appalachia are forecast to rise by 2.1 percent per year during the 2010-2035 period, while prices in Central Appalachia rise by 1.9 percent per year. Stronger price growth in Northern Appalachia than Central Appalachia reflects stronger demand growth in that region during the forecast.

Figure 14
EIA Forecast
Regional Coal Production
Annual Energy Outlook 2011

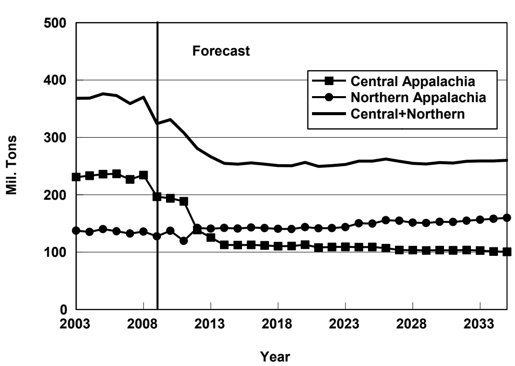


Figure 15
EIA Forecast
Regional Coal Prices
Annual Energy Outlook 2011

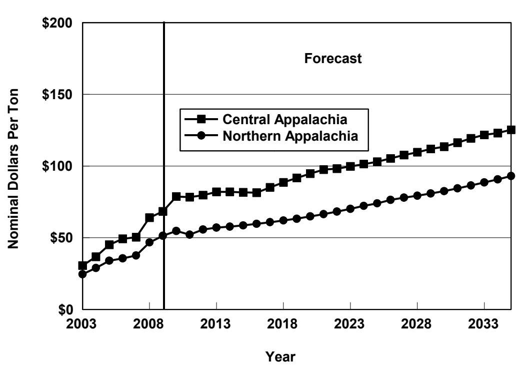


Table 9
EIA Forecast
Regional Coal Production
Annual Energy Outlook 2011
(Millions of Tons)

Actual	2004	2005	2006	2007	2008	2009	Ann.Gr.(%)
Central Appalachia	233.2	235.8	236.5	226.7	234.4	196.7	-3.4
Northern Appalachia	135.1	140.1	136.4	132.3	135.7	127.5	-1.2
Central + Northern	368.3	375.9	372.9	359.0	370.1	324.2	-2.5

Forecast	2010	2011	2012	2013	2014	2015	Ann.Gr.(%)
Central Appalachia	193.9	188.6	138.6	125.4	112.7	112.4	-10.3
Northern Appalachia	137.1	119.6	142.2	140.8	142.1	141.0	0.6
Central + Northern	331.0	308.2	280.8	266.2	254.8	253.4	-5.2

Forecast	2016	2017	2018	2019	2020	2021	Ann.Gr.(%)
Central Appalachia	112.6	111.6	110.4	110.5	112.9	108.0	-0.8
Northern Appalachia	142.9	141.9	140.6	140.2	143.6	141.5	-0.2
Central + Northern	255.5	253.5	251.0	250.7	256.5	249.5	-0.5

Forecast	2022	2023	2024	2025	2026	2027	Ann.Gr.(%)
Central Appalachia	109.0	109.2	108.7	109.0	106.8	103.7	-1.0
Northern Appalachia	141.8	143.6	150.1	149.6	155.5	154.6	1.7
Central + Northern	250.8	252.8	258.8	258.6	262.3	258.3	0.6

Forecast	2028	2029	2030	2031	2032	2033	Ann.Gr.(%)
Central Appalachia	103.4	103.4	103.0	103.6	102.7	101.1	-0.5
Northern Appalachia	151.3	152.7	152.4	154.7	156.4	158.0	0.9
Central + Northern	254.7	256.1	255.4	258.3	259.1	259.1	0.3

Forecast	2034	2035	Ann.Gr.(%)
Central Appalachia	101.1	100.5	-0.6
Northern Appalachia	158.0	159.7	1.1
Central + Northern	259.1	260.2	0.4

Table 10
EIA Forecast
Regional Coal Prices
Annual Energy Outlook 2011
(Nominal Dollars Per Ton)

Actual	2004	2005	2006	2007	2008	2009	Ann.Gr.(%)
Central Appalachia	36.8	45.1	49.2	50.3	64.0	68.3	13.2
Northern Appalachia	28.9	34.0	35.7	37.6	46.7	51.4	12.2

Forecast	2010	2011	2012	2013	2014	2015	Ann.Gr.(%)
Central Appalachia	78.7	78.3	79.7	82.0	82.0	81.6	0.7
Northern Appalachia	54.7	52.1	55.7	57.0	57.7	58.6	1.4

Forecast	2016	2017	2018	2019	2020	2021	Ann.Gr.(%)
Central Appalachia	81.4	85.1	88.5	91.7	94.7	97.5	3.7
Northern Appalachia	59.7	60.9	62.0	63.2	64.9	66.5	2.2

Forecast	2022	2023	2024	2025	2026	2027	Ann.Gr.(%)
Central Appalachia	98.2	99.7	101.4	103.0	105.3	107.7	1.9
Northern Appalachia	68.2	70.1	72.2	74.0	76.4	77.9	2.7

Forecast	2028	2029	2030	2031	2032	2033	Ann.Gr.(%)
Central Appalachia	109.6	113.5	116.3	119.3	121.7	123.0	2.3
Northern Appalachia	79.3	82.5	84.4	86.4	88.5	90.7	2.7

Forecast	2034	2035	Ann.Gr.(%)
Central Appalachia	123.0	125.3	1.9
Northern Appalachia	90.7	93.0	2.5

Energy Ventures Analysis

Publication: Long-Term US Coal Outlook 2011
Publication Date: October 2011
Coal Type: All
Geography: Northern Appalachia and Central Appalachia
Forecast Horizon: 2011-2030

Assumptions:

Macroeconomic Growth:

The forecast calls for U.S. real GDP growth to average 2.8 percent per year during the 2011-2015 period. Growth slows during the rest of the forecast, averaging 1.73 percent per year during the 2016-2020 period and falling further to 1.64 percent per year during the 2016-2030 period.

Environmental:

The EPA Cross States Air Pollution Rule Phase 1 is assumed to be implemented in 2012, with Phase 2 implemented in 2014. The EPA Air Toxics Standards is implemented by the end of 2015. Firms are assumed to comply with EPA regulations on cooling water intakes and combustion residuals by 2018.

Natural Gas Prices:

Natural gas prices are assumed to increase during the forecast, rising from the $4.19-$5.22 range during the 2011-2015 period to the $6.84-$6.90 range during the 2026-2030 period.

Electricity:

Total electricity demand is assumed to grow by 0.70 percent per year during the 2011-2015 period. Demand growth declines gradually through the remaining forecast years, falling from 0.68 percent per year during the 2016-2020 period to 0.60 percent during the 2026-2030 period.

Coal Mining Productivity:

The forecast assumes that coal mining productivity declines during the 2011-2030 period for both Northern and Central Appalachian producers. Productivity falls at an average annual rate of 0.8 percent per year in the Northern Appalachian region, compared to a decline of 1.2 percent per year in the Central Appalachian region.

Summary Coal Production and Price Forecast For Central And Northern Appalachia

Figures 16 and 17 and Tables 11 and 12 summarize the EVA forecast for regional coal production and spot prices. The forecast calls for a rapid decline in coal production in Central Appalachia during the 2011-2015 period, with production falling from 200.4 million tons in 2011 to 143.2 million tons in 2015. That translates into a decline of 28.5 percent in just four years. Production in Central Appalachia continues to decline during the 2016-2030 period, but at a slower pace. By 2030, the end of the forecast period, Central Appalachian coal production hits 112.2 million tons. This reflects the impact of high costs and increasingly challenging geologic conditions in the region, as well as the responses of utilities to increasing environmental regulation and requirements to increase energy production from renewables. It also reflects increasing competitive pressure from natural gas.

Northern Appalachian coal production also declines during the 2011-2015 period, but at a much slower pace. Indeed, Northern Appalachian coal production declines by 8.5 percent during the period. Northern Appalachian coal production remains relatively stable during the 2016-2030 period, stabilizing in the neighborhood of 122 million tons, as lower costs help to sustain production in the region.

In contrast to falling production during the forecast, nominal spot coal prices are expected to increase during the 2011-2030 period. For Central Appalachia, spot coal prices rise by 16.3 percent in 2011, to $75.06 dollars per ton. Prices also rise rapidly in Northern Appalachia in 2001, with growth expected to hit 17.4 percent. On average during the 2011 to 2030 period, nominal spot coal prices in Central Appalachia rise at an average annual rate of 3.0 percent per year. Spot coal prices in Northern Appalachia also rise during the forecast, although at a slower rate (2.4 percent per year).

Figure 16
EVA Forecast
Regional Coal Production
Long-Term U.S. Coal Outlook 2011

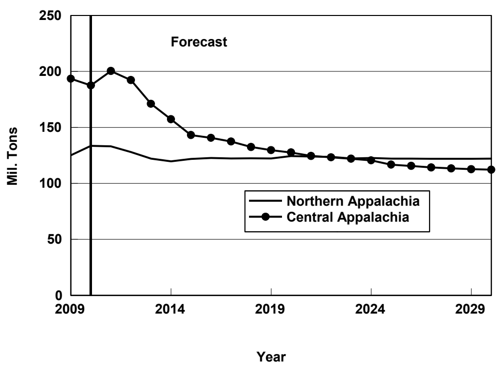


Figure 17
EVA Forecast
Regional Coal Prices
Long-Term U.S. Coal Outlook 2011

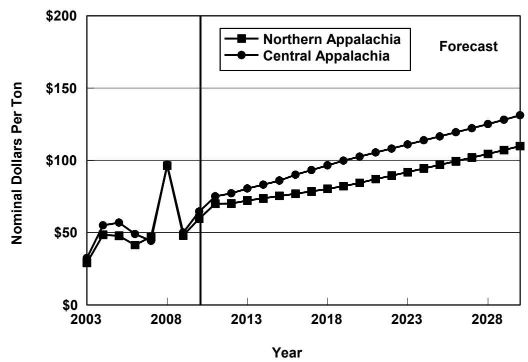


Table 11
EVA Forecast
Regional Coal Production
Long Term U.S. Coal Outlook 2011
(Millions of Tons)

Actual	2005	2006	2007	2008	2009	2010	Ann.Gr.(%)
Central Appalachia	235.3	236.5	226.3	234.2	193.5	187.5	-4.4
Northern Appalachia	138.2	133.9	131.2	134.5	125.2	133.6	-0.7

Forecast	2011	2012	2013	2014	2015	2016	Ann.Gr.(%)
Central Appalachia	200.4	192.3	171.1	157.3	143.2	140.7	-6.8
Northern Appalachia	133.1	128.1	122.1	119.7	121.8	122.7	-1.6

Forecast	2017	2018	2019	2020	2021	2022	Ann.Gr.(%)
Central Appalachia	137.4	132.5	129.7	127.6	124.4	123.3	-2.2
Northern Appalachia	122.3	122.3	122.3	124.4	124.0	123.7	0.2

Forecast	2023	2024	2025	2026	2027	2028	Ann.Gr.(%)
Central Appalachia	122.0	120.5	116.7	115.6	114.2	113.4	-1.5
Northern Appalachia	122.2	122.7	122.2	122.1	122.0	122.0	0.0

Forecast	2029	2030	Ann.Gr.(%)
Central Appalachia	112.6	112.2	-0.3
Northern Appalachia	122.0	122.0	0.0

Table 12
EVA Forecast
Regional Coal Prices
Long-Term U.S. Coal Outlook 2011
(Nominal Dollars Per Ton)

Actual	2005	2006	2007	2008	2009	2010	Ann.Gr.(%)
Central Appalachia	56.9	49.0	44.3	96.9	50.0	64.6	2.6
Northern Appalachia	47.8	41.4	47.1	96.3	48.1	59.6	4.5

Forecast	2011	2012	2013	2014	2015	2016	Ann.Gr.(%)
Central Appalachia	75.1	77.1	80.5	83.1	86.0	90.0	3.7
Northern Appalachia	70.0	70.1	72.3	73.7	75.4	76.8	1.9

Forecast	2017	2018	2019	2020	2021	2022	Ann.Gr.(%)
Central Appalachia	93.3	96.5	99.8	102.6	105.5	108.2	3.0
Northern Appalachia	78.4	80.3	82.2	84.4	87.0	89.4	2.6

Forecast	2023	2024	2025	2026	2027	2028	Ann.Gr.(%)
Central Appalachia	111.0	113.9	116.6	119.4	122.2	125.1	2.4
Northern Appalachia	91.9	94.4	96.9	99.4	101.9	104.4	2.6

Forecast	2029	2030	Ann.Gr.(%)
Central Appalachia	128.1	131.2	2.4
Northern Appalachia	107.2	109.9	2.6

West Virginia University BBER

Publication: West Virginia Economic Outlook 2011
Publication Date: November 2010
Coal Type: All
Geography: State of West Virginia
Forecast Horizon: 2010-2015
Scenario: Baseline

Assumptions:

Macroeconomic Growth:

The West Virginia forecast is based on a national forecast, produced by IHS Global Insight, Inc., completed in September 2010. U.S. real GDP growth is forecast to average 2.6 percent per year during the 2010-2015 period, with painfully slow gains during 2010-2011 gradually giving way to trend growth of about 3.0 percent by 2012.

Environmental:

Laws on the books at the time of the forecast are observed.

Natural Gas Prices:

After falling by 53.3 percent from 2008 to 2009, natural gas prices (as measured by the U.S. average well-head price) are forecast to gradually rise from $3.61 per million BTU in 2009 to $5.03 per million BTU by 2015. That translates into an increase of 5.7 percent per year.

Electricity:

Electricity sales fell by 4.2 percent from 2008 to 2009, but are forecast to rebound strongly in 2010, rising by 5.0 percent. Thereafter, electricity sales growth settles down, averaging 1.2 percent per year from 2011 to 2015. Coal's share of electric utility fuel use falls from 48.5 percent in 2008 to 47.4 percent by 2015.

Coal Mining Productivity:

After falling during the 2000-2010 period, coal mining productivity is expected to stabilize during the next five years. This is well below the average growth rate posted during the 1990s, when coal mining productivity growth averaged 5.4 percent per year.

Summary Coal Production Forecast For West Virginia

The WVU BBER forecast for West Virginia coal production is summarized in Figure 18 and Table 13. The forecast calls for coal production to stabilize in 2010, after a huge decline in 2009. As rebounding U.S. and world growth drive increased demand for electricity and steel, West Virginia coal production gradually rises from 138.3 million tons in 2010 to 145.4 million tons by 2012. Coal production stabilizes between 146-143 million tons during the 2012-2015 period, as production gains in the northern West Virginia coal fields are offset by production declines in the southern part of the state.

Figure 18
West Virginia University BBER Forecast
W.Va. Coal Production
West Virginia Economic Outlook 2011

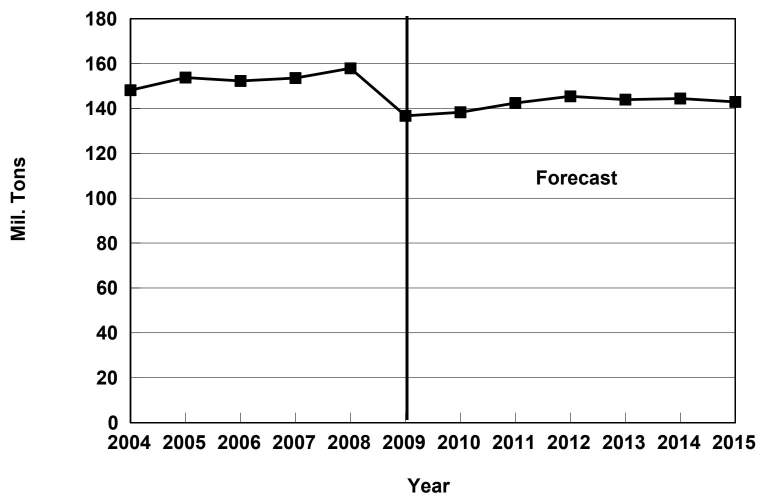


Table 13
West Virginia University BBER Forecast
W.Va. Coal Production
West Virginia Economic Outlook 2011
(Millions of Tons)

Actual

	2005	2006	2007	2008	2009	2010	Ann.Gr.(%)
W.Va. Coal Production	153.8	152.3	153.6	157.9	136.7	138.3	-2.1

Forecast

	2011	2012	2013	2014	2015	Ann.Gr.(%)
W.Va. Coal Production	142.5	145.4	144.0	144.5	143.0	0.1

References

Energy Ventures Analysis, *Long-Term U.S. Coal Outlook*, October 2011.

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West Virginia University, Bureau of Business and Economic Research. *West Virginia Economic Outlook 2011.* Morgantown, West Virginia, November 2010.

DATE: June 16, 2011

Status Report on Ongoing Work for the Special Reclamation Fund Advisory Council

Submitted by Christine Risch - Center for Business and Economic Research (CBER), Marshall University

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As part of its contracted work to improve the ability to anticipate future forfeitures to the SRF, MU CBER is currently adding two data fields to the forfeited permits database.

1. Ownership Type Field: Using the US OSM Applicant/Violator System (AVS) database we have completed the field titled "Ownership Type" for which one of five classifications was assigned: multi-corporation, private corporation, private corporation/partnership, partnership and sole proprietor. Of the 1,901 permits in the database 1,264 were forfeited recently enough to have a record in the AVS database and were classified.

Count of Permits with Assigned Ownership Type

Ownership Type	Usable Permits	All Permits
Multi-Corporation	17	17
Partnership	177	177
Private Corp.	832	832
Private Corp./ Partnership	25	25
Sole Proprietor	213	213
Older Unusable Entries		637
# of Permits	**1264**	**1901**

This field will be provided to the actuary for the next round of analysis.

2. Number of permit transfers: This field is also based on the AVS database. We are in the process of collecting permit-level data on the number of times a permit was transferred to another firm. For example, if a permit was never transferred the field value is 0. If a permit was transferred twice the field value is 2. This field is not expected to be used by the actuary. It will be used for regression analysis and will correlate this value with likelihood of forfeiture for open/closed vs. forfeited permits.

MU CBER also compiled a comparison of various forecasts of forfeited acreage over the past five years. While the timeframe for which a comparison is possible is short (2006 to 2010) is shows that some very realistic forecasts have been made.

A Retrospective Look at Forecasted vs. Actual Acreage Forfeited

FY	Acres Forecast to be Forfeited					Actual Forfeited Acres
	CBER 2006	Hay 2005	Hay 2008 (1st)	Hay 2008 (2nd)	Pinnacle 2010	
2005		1,958				622
2006	1,527	1,821				680
2007	1,562	1,663				5,702
2008	1,585	1,515	3,406	1,610		314
2009	1,599	1,370	3,058	1,538		233
2010	1,595	1,260	2,777	1,453		499
2011	1,571	1,175	2,512	1,387	3,754	
2012	1,556	1,094	2,272	1,318	3,446	
2013	1,531	1,019	2,069	1,252	3,158	
2014	1,512	948	1,885	1,173	2,882	
2015	1,486	883	1,720	1,116	2,645	
2016	1,464	823	1,575	1,053	2,396	
2017	1,442	766	1,442	1,007	2,172	
2018	1,440	713	1,322	964	1,965	
2019	1,430	664	1,215	922	1,787	
2020	1,424	617	1,115	883	1,631	
2021	1,418	576	1,026	847	1,495	
2022	1,417	537	942	812	1,370	
2023	1,415	500	868	777	1,256	
2024	1,413	465	801	746	1,152	
2025	1,410	433	738	717	1,056	
2006-2010	1,574	1,526	3,080	1,534		1,485

DATE: October 12, 2011

SUBJECT: Ownership Type Data Summary

Submitted by Christine Risch - Center for Business and Economic Research (CBER), Marshall University

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The following tables describe the results of the ownership type classification for open and forfeited permits. As of October 12, 2011 these assignments are currently being reviewed by WVDEP personnel.

OPEN PERMITS: Count of Permits with Assigned Ownership Type

PERMITEE OWNERSHIP	# of Permits	% of Total
Multi-Corporation	43	2%
Partnership	67	4%
Private Corporation	198	11%
Public Corporation	1,366	75%
Sole Proprietor	141	8%
Total	1,815	

FORFEITED PERMITS: Count of Usable Permits with Assigned Ownership Type

PERMITEE OWNERSHIP	# of Permits	% of Total
Multi-Corporation	35	3%
Partnership	177	14%
Private Corp.	839	66%
Sole Proprietor	213	17%
Public Corporation	0	0%
Total	1,264	

The following three pages provide lists of permittees by assigned ownership type for open permits.

Open Permits as of 6 30 11: Ownership Classification

Multi-Corp. (9 permittees)	# Permits
AMERICAN BITUMINOUS POWER PARTNERS	6
APPALACHIAN FUELS, LLC.	6
CALDWELL TRAILBLAZER, LLC	1
DOCKS CREEK LLC	1
FRASURE CREEK MINING, LLC	21
KANAWHA RIVER TERMINALS LLC	2
SIATA, LLC	2
WINIFREDE DOCK LLC	1
WWMV, LLC	3

Partnership (10 permittees)	# Permits
ANGEL COAL COMPANY INC	1
ARGUS ENERGY WV LLC	45
BETTY COAL COMPANY	3
BURES CORP	1
COAL VALLEY, LLC.	1
D. & L. COAL COMPANY, INC.	12
HIDDEN VALLEY ESTATES GOLF COURSE INC.	1
M & J COAL COMPANY INC	1
RAYLE COAL CO.	1
TEN-A-COAL COMPANY	1

Private Corp. (68 permittees)	# Permits
AMERICAN DISPOSAL SERVICES OF WV INC	1
AMERIKOHL MINING INC	2
AMHERST INDUSTRIES INC	1
ASSET MINING, LLC	2
BEAVER ELKHORN COAL INC	1
BLACK STALLION COAL COMPANY, LLC	1
BLACK WALNUT COAL COMPANY	1
BLUE RIDGE MINING LLC	1
BUCKEYE COAL COMPANY INC	1
CARTER ROAG COAL COMPANY	14
CLUB COAL INC	1
CNP PROPERTIES LLC	2
COAL RIVER MINING, LLC	15
CORESCO LLC	6
D D S LEASING INC	3
DANA MINING COMPANY LLC	5
DAYSPRING CAMP & CONFERENCE CENTER,	1
DEEPGREEN WEST VIRGINIA INC	1
DMV MANAGEMENT LLC	1
DOUBLE H MINING CO., INC.	1
DUCKWORTH COAL, INC.	1
EAGLE MINING LLC	2
EAGLE RIDGE DEVELOPMENT GROUP, LLC	5
FMC SERVICES INC	2

Private Corp. cont'd	# Permits
GARY PARTNERS LLC	1
GATLING, LLC	3
GAULEY EAGLE HOLDINGS INC	6
GREENBRIER SMOKELESS COAL MINING, LLC	9
H & S COAL CO	1
ISLAND FORK CONSTRUCTION, LTD.	2
JMAC LEASING INC	3
KANAWHA CRANE AND CONSTRUCTION INC	1
KEY POINT MINING, LLC	1
L E A D COAL AND LAND CORPORATION	2
LAW RIVER COMPANY LLC	1
LCC WEST VIRGINA, LLC	7
LDH ENERGY CYRUS RIVER TERMINAL LLC	1
LOWER HUTCHINSON MINERALS LLC	1
LP MINERAL LLC	2
LUKE PAPER COMPANY	3
LYONSOUTH LLC	1
M & W CONTRACTORS, INC	1
MAJESTIC MINING INC	7
MCDOWELL POCAHONTAS COAL COMPANY	1
MEPCO, LLC	1
MET RESOURCES, LLC	3
MILBURN COLLIERY CO	1
MYRTLE D. CORPORATION	1
OMEGA MINING CO INC	1
ORCHARD COAL CO	1
OXFORD MINING COMPANY LLC	1
PEACHTREE RIDGE MINING COMPANY INC	3
PERIAMA HANDLING LLC	1
POCAHONTAS COAL COMPANY LLC	16
PRESTON COUNTY COAL AND COKE CORPOR/	2
RIVER POINT LLC	1
ROCK N ROLL COAL CO INC	2
ROLLING S AUGERING LLC	2
SHAFER BROTHERS CONSTRUCTION, INC.	5
SHANE COAL COMPANY	5
SOUTHERN MINERALS INC	12
SPRING CREEK ENERGY COMPANY, LLC	2
STOLLINGS TRUCKING CO INC	6
TEN-A COAL CO., INC.	2
TYLER MORGAN, L.L.C.	2
WEIRTON ICE & COAL SUPPLY COMPANY	1
WESTCHESTER COAL LIMITED PARTNERSHIP	1
WHITE RIDGE COAL CO INC	1

Public Corp. (119 permittees)	# Permits
ALEX ENERGY INC	44
APOGEE COAL COMPANY LLC	18
ARACOMA COAL COMPANY INC	24
ATLANTIC LEASECO, LLC	15
BANDMILL COAL CORPORATION	9
BIG BEAR MINING COMPANY	4
BLACK WOLF MINING COMPANY	20
BLUESTONE COAL CORPORATION	51
BROOKS RUN MINING COMPANY, LLC	50
CATENARY COAL COMPANY LLC	33
CENTRAL APPALACHIA MINING, LLC	11
CHAFIN BRANCH COAL CO LLC	7
CLEAR FORK COAL COMPANY	7
CLIFFS LOGAN COUNTY COAL LLC	14
COAL-MAC, INC. DBA PHOENIX COAL-MAC N	35
COBRA NATURAL RESOURCES LLC	21
COLONY BAY COAL CO	5
CONSOL OF KENTUCKY INC	50
CONSOL PENNSYLVANIA COAL COMPANY, LI	1
CONSOLIDATION COAL COMPANY	35
COYOTE COAL CO LLC	19
DAKOTA LLC	2
DELBARTON MINING COMPANY	5
DUCHESS COAL COMPANY	1
DYNAMIC ENERGY, INC.	5
EAGLE ENERGY INC	3
EASTERN ASSOCIATED COAL, LLC	42
ELK RUN COAL COMPANY INC	29
FOLA COAL COMPANY LLC	27
GOALS COAL COMPANY	2
GREEN VALLEY COAL COMPANY	13
GREYEAGLE COAL COMPANY	2
HAMPDEN COAL COMPANY LLC	29
HAWTHORNE COAL COMPANY INC	2
HERNDON PROCESSING COMPANY, LLC	3
HIGHLAND MINING COMPANY	7
HILLSIDE MINING COMPANY	6
HOBET MINING LLC	30
ICG BECKLEY LLC	3
ICG EASTERN, LLC	25
ICG TYGART VALLEY, LLC	2
INDEPENDENCE COAL COMPANY INC	35
ISLAND CREEK COAL COMPANY	15
JACKS BRANCH COAL COMPANY	24
JARRELL'S BRANCH COAL COMPANY	2
JULIANA MINING COMPANY INC	9
JUSTICE HIGHWALL MINING, INC.	1
KANAWHA COAL LLC	1

Public Corp. cont'd	# Permits
KANAWHA EAGLE COAL LLC	17
KANAWHA ENERGY COMPANY	27
KENTUCKY FUEL CORPORATION	6
KEPLER PROCESSING COMPANY, LLC	3
KING KNOB COAL CO INC	1
KINGSTON RESOURCES INC	9
KINGWOOD MINING COMPANY, LLC	6
LAUREL CREEK COMPANY INC	1
LAUREL RUN MINING COMPANY	3
LITTLE CREEK LLC	1
LITTLE EAGLE COAL COMPANY LLC	4
LITWAR PROCESSING COMPANY LLC	5
LOADOUT, LLC	16
LOGAN FORK COAL COMPANY	1
LYNN BRANCH COAL COMPANY INC	1
MAPLE COAL CO.	15
MARFORK COAL COMPANY INC	20
MARTINKA COAL COMPANY LLC	4
MCELROY COAL COMPANY	4
METTIKI COAL (WV), LLC	3
METTIKI COAL, LLC	3
MIDLAND TRAIL RESOURCES, LLC	10
MID-VOL COAL SALES, INC.	22
MINGO LOGAN COAL COMPANY	39
MOUNTAIN VIEW COAL COMPANY, LLC	17
NEWEAGLE MINING CORP	2
NUFAC MINING COMPANY INC	1
OMAR MINING COMPANY	12
PANTHER LLC	4
PATRIOT MINING COMPANY INC	32
PAY CAR MINING INC	3
PAYNTER BRANCH MINING INC	5
PEERLESS EAGLE COAL CO	10
PERFORMANCE COAL COMPANY	10
PINE RIDGE COAL COMPANY, LLC	13
PINNACLE MINING COMPANY, LLC	8
PIONEER FUEL CORPORATION	15
PIONEER MINING INC	2
POWELLTON COAL COMPANY LLC	5
POWER MOUNTAIN COAL COMPANY	6
PREMIUM ENERGY LLC	4
RAVEN CREST CONTRACTING LLC	9
RAWL SALES & PROCESSING CO	11
REMINGTON LLC	3
RHINO EASTERN LLC	12
RIVERS EDGE MINING, INC.	1
RIVERSIDE ENERGY COMPANY, LLC	37
ROAD FORK DEVELOPMENT COMPANY INC	4

Public Corp. cont'd	# Permits
ROCKHOUSE CREEK DEV LLC	6
ROCKSPRING DEVELOPMENT INC	3
RUM CREEK COAL SALES INC	4
SECOND STERLING CORP.	3
SHANNON POCAHONTAS MINING COMPAN\	1
SNAP CREEK MINING LLC	4
SPARTAN MINING COMPANY	8
STIRRAT COAL COMPANY	3
TERRY EAGLE COAL COMPANY LLC	9
THE SYCAMORE GROUP, LLC	1
TRACE CREEK COAL COMPANY	16
TUNNEL RIDGE, LLC	4
TWIN STAR MINING INC	2
UPSHUR PROPERTY, INC.	10
VANSANT COAL CORPORATION	4
VINDEX ENERGY CORPORATION	20
WHITE FLAME ENERGY INC	2
WILDCAT LLC	4
WINDSOR COAL COMPANY	3
WOLF RUN MINING COMPANY	9
WOLFPEN KNOB DEVELOPMENT COMPANY	2
HIGHLAND MINING COMPANY, LLC	1
KANAWHA RIVER TERMINALS INC	2

Sole Proprietor (48 permittees)	# Permits
92 COAL CORP	1
ALI CO	1
BAYSTAR COAL COMPANY INC	6
BEACON RESOURCES INC	1
BINGAMON CORPORATION	1
BL & S COAL CO INC	1
BLACK WOLF MINING COMPANY	1
BULLSKIN STONE & LIME LLC	1
CARETTA MINING INC	4
COALBURG CORP	1
COALEX INC	3
DB COAL MINING, LLC	1
DFM COAL, LLC	1
DOUGLAS COAL COMPANY	2
ENERGY MARKETING COMPANY INC	6
ERUN COAL SALES, INC	1
GOLD RESOURCES, LLC	2
GS ENERGY, LLC	1
HAZZARD'S EXCAVATING AND TRUCKING COI	1
HUTCHINSON MINERALS LLC	3
JERRY STALNAKER COAL COMPANY INC	3
JUPITER HOLDINGS, LLC	5
KANAWHA DEVELOPMENT CORP	3
KEYSTONE INDUSTRIES LLC DBA KEYSTONE DI	2
KWV OPERATIONS LLC	14
MARION DOCKS, INC.	11
MARY RUTH CORPORATION	1
MCCM LLC	1
MEADOW CREEK MINERALS LLC	1
NATIONAL RESOURCES, INC.	5
NESCO, INC.	3
NEW LAND LEASING COMPANY INC	4
POWDERMILL PROCESSING INC	2
PRITCHARD MINING COMPANY, INC.	7
RAVEN HOCKING COAL CORP	1
REBEKAH COAL COMPANY INC	1
RED OAK, INC	1
RESOURCES LIMITED, LLC	4
RICK JOHNSON MINING LLC	1
SAN-WEST COAL CO., INC.	1
STANLEY INDUSTRIES INC	3
TOM L. SCHOLL	1
UNITED COALS, INC.	5
UNITED INTERNATIONAL, INC	1
UPPER KANAWHA VALLEY DEVELOPMENT CO	6
WEST VIRGINIA PROPERTIES INC	4
WESTWOOD MINING CO, INC	5
WIND RIVER RESOURCES CORP	6

Estimated Cost of Selenium Treatment at West Virginia Active Mining sites Using Zero Valent Iron and Fluidized Bed Reactor Technology

Paul Ziemkiewicz, PhD, Director
West Virginia Water Research Institute

3 Oct 2010

Introduction

Currently in West Virginia, abandoned mine lands are divided into two categories: those mines abandoned before 1977 and mines abandoned after 1977. Mines abandoned before 1977 are regulated by the Surface Mining Control and Reclamation Act and are overseen by the WV Division of Abandoned Mine Lands, while mines abandoned after 1977 are regulated by the WV Division of Special Reclamation. This study estimates additional treatment liabilities that would accrue to the Special Reclamation Fund in the event that costs associated with treatment of selenium to a standard of 4.7 µg/L cause wholesale forfeiture of existing permits. This study follows the guidance in the ruling by Federal District Judge Robert Chambers that fluidized bed bioreactor (FBR) technology be installed on Patriot Coal property to treat selenium per the recommendation of CH2M Hill Corporation.

Methods

In order to develop a basis for evaluating potential liabilities to the Special Reclamation Fund, this study made use of a recent study for the North American Metals Council (CH2M Hill 2010) that reviewed available selenium treatment technologies. This report also includes operational cost data for zero valent iron (ZVI) acquired in constructing selenium treatment systems in southern West Virginia. Four technologies were evaluated:

- FBR: Fluidized bed bioreactor
- RO: Reverse osmosis
- ZVIc: Zero valent iron (steel wool) per CH2M Hill
- ZVIa: Zero valent iron (steel wool) per actual installations

ZVIc differs from ZVIa in that the latter is a much simpler design. For example, ZVIa replaces the highly mechanized systems for aeration, clarification and iron removal from the effluent with a simple settling pond. This substantially reduces the capital and operating costs. Therefore, since ZVIa has been installed and has operated successfully, those costs were used in the analysis. In application, it has generally been limited to smaller discharges (< 200 gpm) due to the area requirements.

The economic costs associated with abandoned coal mines can be significant. This research intends to study the economic costs of the treatment of all active mining sites in WV that discharge a significant amount of selenium. The two methods of treatment to be compared are: zero valent iron (ZVI) and a fluidized bed bioreactor (FBR).

The basis of the cost estimates used by WVWRI come from the document titled "Review of Available Technologies for the Removal of Selenium from Water" by CH2M Hill. This document was prepared for the North American Metals Council (NAMC) and detailed many different types of selenium removal systems, including ZVI and FBR. The cost estimates used for equipment, direct costs, and construction costs were defined by the American Association of Cost Engineers International. CH2M Hill determined the costs of treating Patriot Coal's Ruffner Mine outfall. However, CH2M Hill could not determine if the costs detailed in their report could be applied to other selenium-producing sites because they did not detail the cost of flow diversion/equalization equipment. This was not done because there is a large degree of variability between sites and CH2M Hill only had data for one site.

We expanded the applicability of these cost formulas by using flow and (in the case of ZVIa) selenium concentrations for specific ourfalls. The cost analysis determined selenium treatment costs for 180 outfalls, identified as potentially out of compliance, in West Virginia. The minimum, average, and maximum values for flow and selenium concentrations were determined from data collected by the West Virginia Division of Mining and Reclamation. This was performed by using the capital and O&M costs from the NAMC report (CH2M Hill 2010). The 180 sites were then divided up into flow regimes of 30, 60, 100, 300, and 1,000 gallons per minute. Regression curves were fitted through the data to create a continuously variable relationship between flow and cost. Two types of curves yielded good fits: polynomial equations were used for the CH2M Hill cost data and power curves were uses for the ZVIa cost data.

These values were used to determine the cost of treatment for each site. The final costs were expressed in dollars per 1,000 gallons treated over a nominal, 20 year life cycle.

Zero Valent Iron Description

A ZVI remediation system utilizes ZVI media (elemental iron) to chemically reduce selenate and selenite to elemental selenium. The elemental form of selenium is neither soluble nor mobile and will not be discharged with the treated effluent water. Instead, it remains embedded in the ZVI treatment medium. During the treatment process, the elemental iron is oxidized to its soluble ferrous form and is discharged with the effluent water. The iron may then be oxidized further to the ferric form in an aeration tank and precipitated in a settling pond (CH2M Hill, 2009).

Other compounds can affect the efficiency of the ZVI treatment system. Influent water with large nitrate concentrations can slow down the reduction of selenium because nitrate is reduced before selenium. The reaction kinetics will also be very slow at low selenium concentrations and may require longer hydraulic retention time (i.e., contact time) in the reaction tank to achieve a selenium concentration <4.7 µg/L. Temperature and pH are also important in the reaction kinetics. Lower temperatures will slow down the reduction reaction that converts selenate to elemental selenium. The optimum pH range for this reaction is 7.0 to 9.0 (CH2M Hill, 2009).

ZVI treatment systems typically consist of tanks or chambers that hold a type of elemental iron. The elemental iron may come in several forms such as filings, steel wool, or iron impregnated foam. Tanks may also be in series, allowing for several coinciding trains of selenium treatment. The tanks may also be positioned at varying elevations so that differences in hydraulic pressure will move the water by gravity through the ZVI system. This would allow the treating entity to eliminate intermediate pumping. The effluent from these reactor tanks can be aerated to oxidize the iron in an aeration tank (similar to an aeration pond) prior to discharging to the outfall (CH2M Hill, 2009).

Previous Treatment with ZVI

Some pilot studies have been performed using ZVI technology. Golder (2009) used steel wool ZVI to treat low levels of selenium. Over a 250 day period, influent selenium concentrations ranged from 5 and 14 µg/L. Effluent concentrations were not consistently below the regulatory limit of 4.7 µg/L. The system required a five hour residence time. Other agents used to reduce selenate to selenite have been used, including zinc powder and ferrous sulfate (CH2M Hill, 2010). ZVI technology used in conjunction with biological reduction also showed promising results (Zhang, 2005).

ZVI was also used at the Richmond Hill mine to reduce selenate to selenite. This system treated influent water with a selenium concentration of 100 µg/L down to 12-22 µg/L (Sobolewski, 2005). Reverse Osmosis was used as a polishing step to ensure that selenium concentrations met regulatory requirements.

Actual Costs (ZVI a)

The cost basis for ZVI a was based on the following parameters. These have been the basis on ongoing construction on sites in southern West Virginia. They do not include road construction, power distribution to site or flow equalization. The later is generally not an important consideration since the flows are generally small (< 200 gpm) and the systems are fed from existing sedimentation ponds.

- **Direct Capital Cost**
    - Tanks
    - Iron/pH controls
    - Site Preparation
    - Limestone
    - Shipping

- **Indirect Capital Costs**
    - Interest during construction
    - Contingencies
    - A&E fees, Project management
    - Working capital

- **O&M**
    - Insurance costs
    - Gasses
    - Routine maintenance labor
    - Insert replacements
    - Shipping
    - Labor
    - Replacement and repair
    - General maintenance
    - Disposal cost

Fluidized Bed Reactor Description

In an FBR, fluid (contaminated water) is passed through a granular, solid media (sand or GAC) at a high velocity. If the velocity is great enough, the media will become suspended and will act as a fluid. The biological treatment mechanism for selenium removal consist of a reduction of selenate and selenite to elemental selenium under anoxic (absence of dissolved oxygen) conditions. Heterotrophic facultative bacteria that are suited for nitrate and selenium removal are seeded in the FBR. These bacteria use the oxygen in the nitrate and selenate as the electron acceptor for their respiration and energy requirements. A carbon substrate and phosphorus nutrient is used as the electron donor. The mine water will be pumped from the feed tank to a covered FBR for nitrate and selenium removal. A fluidization and effluent collection system is integrated into the FBR to promote uniform flow distribution. The water is then pumped into the bottom of the FBR, creating upflow to suspend the sand or GAC media. If necessary, the pH may be adjusted upstream of the FBR to meet optimal growth conditions. The effluent from the FBR will be aerated in a small polishing tank to increase the dissolved oxygen. The effluent from the polishing tank will be discharged to the stream after TSS removal in a settling pond. If a pond cannot be used, multimedia filters can be installed to remove these solids. The expected TSS level leaving the aeration tank will be approximately 30 mg/L (CH2M Hill, 2009).

Previous Treatment with FBR

FBR was used for the removal of selenium in the San Joaquin Valley at the Adams Avenue Agricultural Drainage Research Center. The reactor was operated continuously for two years at a flow rate of one gallon per minute. As a result of the FBR, total selenium decreased from a concentration of 520 µg/L to an average effluent concentration of 380 µg/L (State of California Department of Water Resources, 2004).

Six bench-scale bioreactors were constructed by Brienne et al. (2009) to establish the ability of a FBR to remove selenium from a mining-influenced water. A variety of flow rates and nutrient combinations were used to determine what type of FBR would best treat the water. The greatest selenium removal occurred with the reactor configured in an upflow pattern using ethanol as the nutrient. ORP was also found to be an important control parameter in this system.

Cost basis for Fluidized Bed Bioreactor

Costs for the FBR were determined for a system that reduced selenium concentrations to <5 µg/L (Table 1). Determined costs have an accuracy of +100%/-50% based on 2009-2010 market conditions. The system is a grass roots/green field selenium reduction system.

Total Installed Cost (TIC). The costs for stand-alone utilities (electricity) and an equipment/control room have been included in the cost estimate. All other capital costs, including equipment and labor to complete the construction of the system, have also been included. Because flow and selenium concentrations vary from site to site, the TIC estimate does not include flow equalization or diversion equipment. Once the flow trends and the selenium concentrations have been determined for a specific site, flow equalization and/or diversion equipment will likely be needed.

Operational costs (OpX) include maintenance, labor, energy, media replacement, cleaning and chemical and residual disposal costs. All residual substances were assumed to be non-hazardous and were disposed in a non-hazardous landfill. Estimated costs do not include wholesale periodic replacement costs for all the media. This cost could not be determined as it is site specific and will be a function of water quality and quantity that the system must treat (CH2M Hill, 2010).

Reverse Osmosis

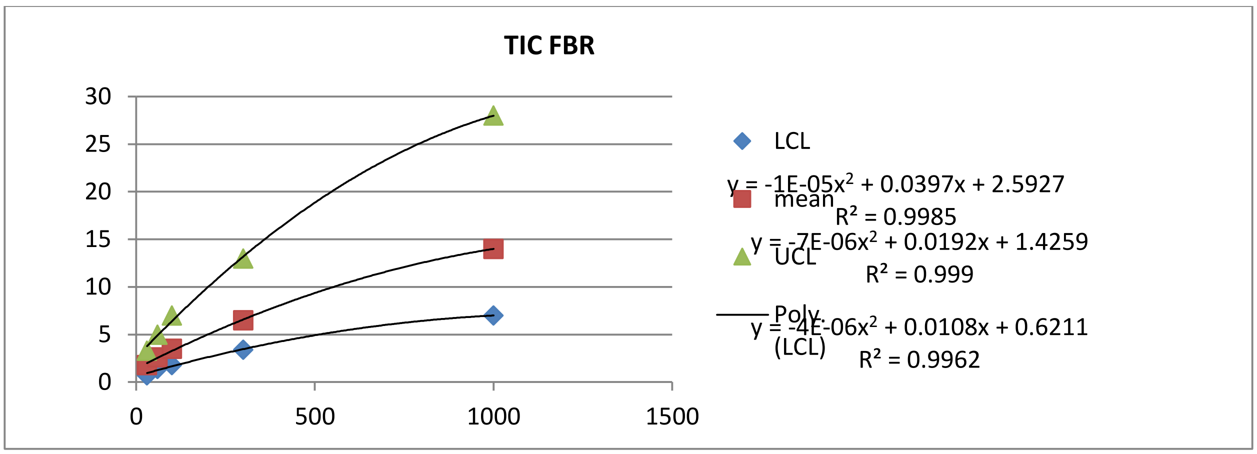
CH2M Hill 2010 also evaluated the costs associated with reverse osmosis. These cost data were used to estimate costs and are subject to many of the same restraints as indicated above for FBR.

Not included in cost estimates

Cost estimates do not include site access, site preparation, construction of flow equalization ponds, water diversions and bringing power into the site. These costs are highly site specific and could substantially increase the installed costs beyond those given in this report.

Results

Examples of polynomial models developed for this project are given in figure 1. Polynomial models were much better predictors than linear models, particularly at low flows. Note that the polynomial curves extend to about 1,000 gpm, the limit of cost estimates in the NAMC (CH2M Hill) report. For values greater than 1,250 gpm, the curves became negative for the four high flow outlets. For these, the estimates pertaining at a flow of 1,250 gpm were used to estimate TIC and OpX.



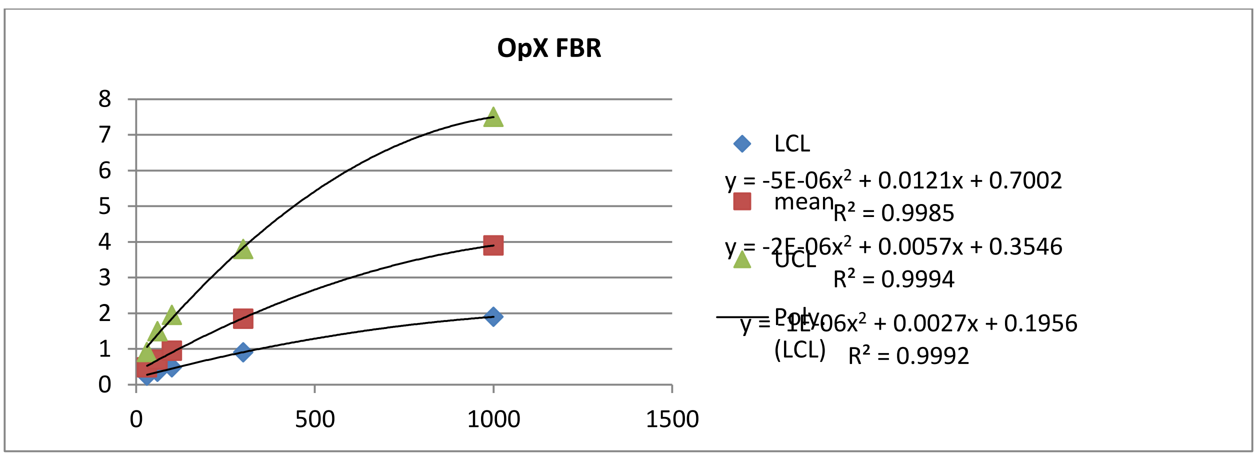


Figure 1. Polynomial models developed for FBR costs. Line equations and respective R^2 values are included.

Cost estimates are presented in table 1. They include costs dimensioned as:

1. $/1,000 gallon
2. TIC + 1 yr OpX: total installed costs plus one year of operating expense
3. TIC + 20 yrs OpX: total installed costs plus twenty years of operating expense

These cost estimates are based on constant, 2010 dollars.

Table 1. Estimated costs for four treatment options. ZVI actual and FBR CH2M Hill were considered for the entire 180 outlets identified by WVDEP. Costs of ZVI CH2M Hill and RO are given below. LCL and UCL represent lower and upper confidence limits based on the mean value plus or 50 or 100% respectively.

Technology/ Cost basis		LCL 50%	mean	UCL 100%
ZVI actual	$/1000 gal	2.06	4.11	8.23
< 200 gpm, 125 units	TIC + 1 yr OpX	$15 million	$30 million	$60 million
	TIC + 20 yrs OpX	$133 billion	$267 billion	$534 billion
FBR CH2MHill	$/1000 gal	5.11	10.55	21.26
> 200 gpm, 55 units	TIC + 1 yr OpX	$366 million	$697 million	$1.525 billion
	TIC + 20 yrs OpX	$1.792 trillion	$3.697 trillion	$7.449 trillion
Total cost	TIC + 20 yrs OpX	$1.191 trillion	$2.528 trillion	$4.639 trillion

Other technologies				
ZVI CH2M Hill	$/1000 gal	12.55	25.43	50.78
< 200 gpm, 125 units	TIC + 1 yr OpX	$191 million	$396 million	$798 million
	TIC + 20 yrs OpX	$814 billion	$1.652 billion	$3.298 billion
RO CH2M Hill	$/1000 gal	8.16	14.20	29.93
> 200 gpm, 55 units	TIC + 1 yr OpX	$1.191 billion	$2.087 billion	$4.202 billion
	TIC + 20 yrs OpX	$2.859 trillion	$4.976 trillion	$10.490 trillion

ZVI	Zero valent iron-steel wool
RO	Reverse osmosis
FBR	Fluidized bed bioreactor

Conclusions

The actual costs developed for operational installation of ZVI were much less expensive than those reported for more complex ZVI systems in the NAMC report (CH2M Hill, 2010). Those costs were used in this analysis for discharges less than 200 gpm. FBR was substantially less expensive than RO. Given the technical advantages listed in the NAMC report (CH2M Hill, 2010) FBR was identified as the technology of choice for discharges in excess of 200 gpm.

Final technology selection will be based on site factors and it remains to be seen whether FBR performs adequately under operational, field conditions.

The objective of this study was to develop a first-pass cost estimate of the liabilities that may accrue to the Special Reclamation Fund if currently active permits with selenium discharges in excess of 4.7 ug/L forfeit. It is clear that the liabilities, even with the most efficient technologies, are huge.

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Project WV 304:

Natural Attenuation of Major Mine Pollutants

January 2012 Status Report

Prepared for the
West Virginia Special Reclamation Advisory Council

5 Jan 2012

Ben Mack and Paul Ziemkiewicz

West Virginia Water Research Institute

West Virginia University

Introduction

Previous research has estimated the longevity of specific mine pollutants. Investigations of surface mine discharges have shown that acidic water may be released at a consistent level for 10 to 20 years (Meek, 1996), while Wood et al. (1999) determined that surface mines attenuated much more quickly than underground mines. However, underground mine discharges are more difficult to predict. Younger (1997) estimated that acidic drainage may continue for 10 to 100 years, dependent upon hydrologic factors, pyrite reaction rate, and amount of pyrite. Other researchers have found that the worst pollution occurs within the first 40 years after mine closure (Wood et al., 1999) and that several decades must elapse before water quality will improve significantly (Jones et al., 1994).

Research by West Virginia University has studied the longevity of mine water pollutants from underground mines in the Pittsburgh and Upper Freeport coal seams. Mack et al. (2010) found that acidity decreased, on average, 80% over 40 years (Figure 1). Demchak (2006) studied 20 underground mines and found that acidity, metals, and sulfate decreased 50-80% over 32 years. A partially flooded Pittsburgh seam mine was also studied by Demchak (2006). She found that sulfate concentrations showed a very rapid rate of exponential decline (Figure 2).

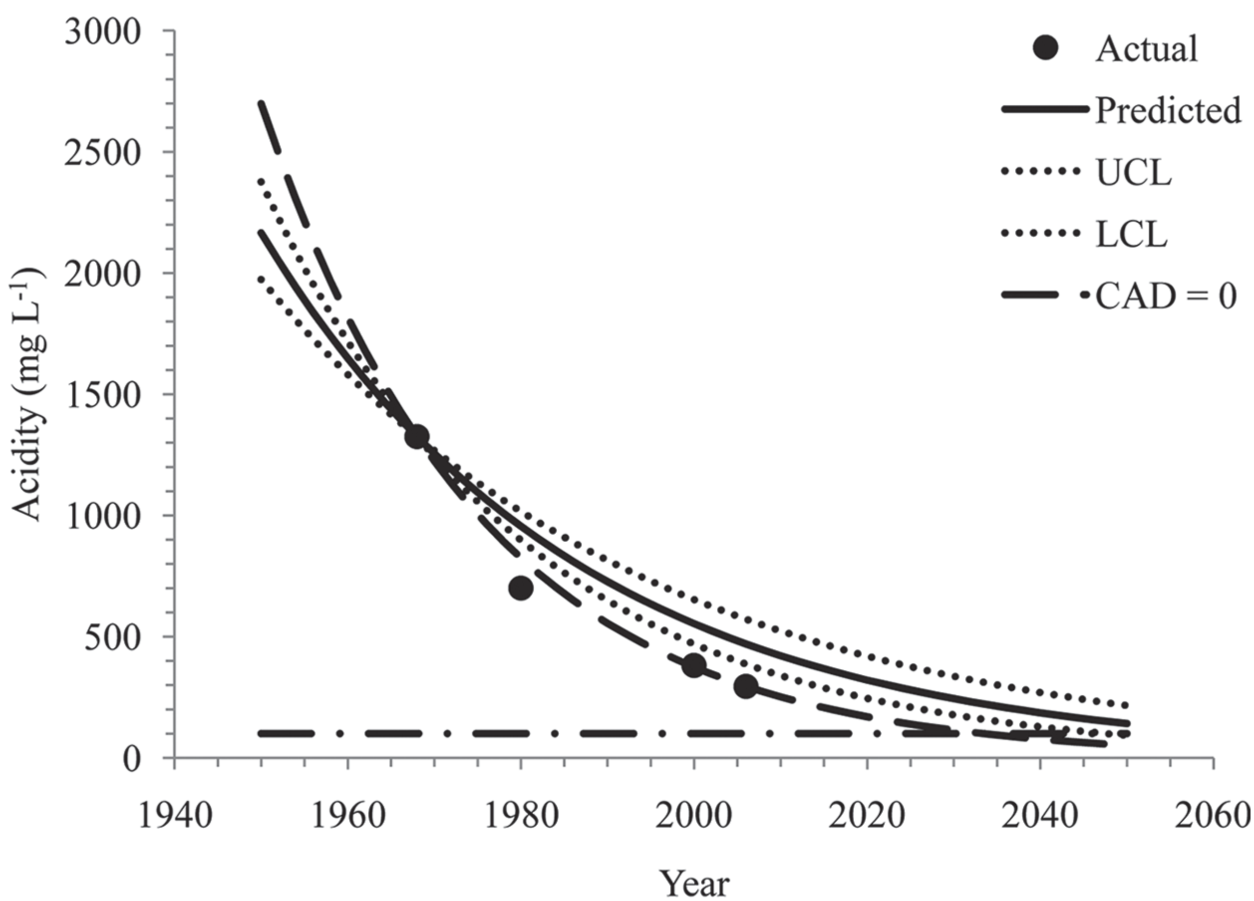


Figure 1. Acidity (mg L^{-1}) for the Upper Freeport sites, best-fit first-order decay function (*k* =0.0273), upper and lower confidence intervals, and, when adjusted so that mean cumulative difference = 0 (*k* = 0.0395), extrapolated to the year 2050. Horizontal dashed line represents the cutoff acidity to begin passive treatment (100 mg L^{-1}). CAD, cumulative average difference; LCL, lower confidence limit; UCL, upper confidence limit.

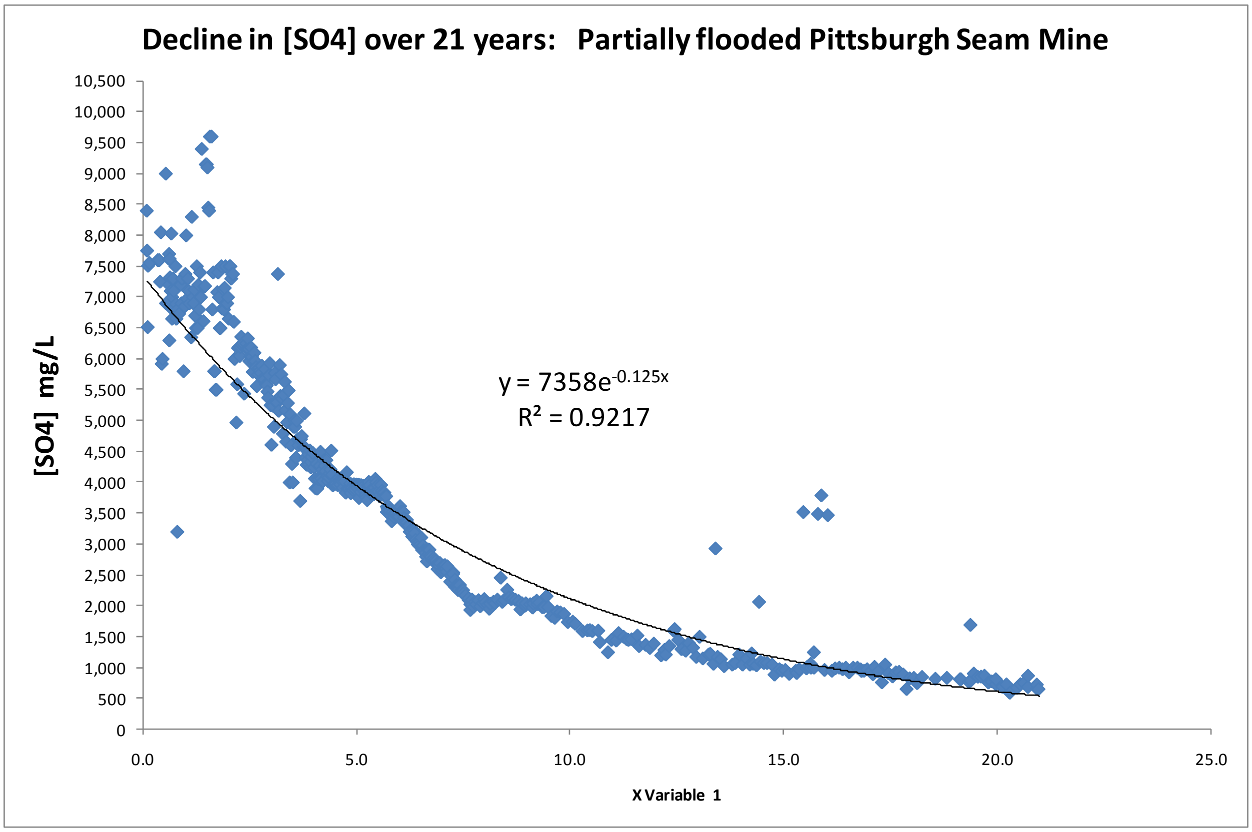


Figure 2. Flooding of underground coal mines releases acid forming salts that have accumulated since over the mine's life. Early flooding releases these largely sulfate salts. As the mine floods, pyrite oxidation is restricted and salts are flushed out of the mine. The above figure shows the effects of sulfate decline during the 21 years after flooding.

Other research by the WV Water Research Institute has estimated the rate of decline for mine drainage parameters, including sulfate, acidity, and selenium. Figures 3 and 4 show changes in acidity and sulfate over time as a function of the amount of sulfur found in the mine water, while Figure 5 shows changes in selenium concentrations over time.

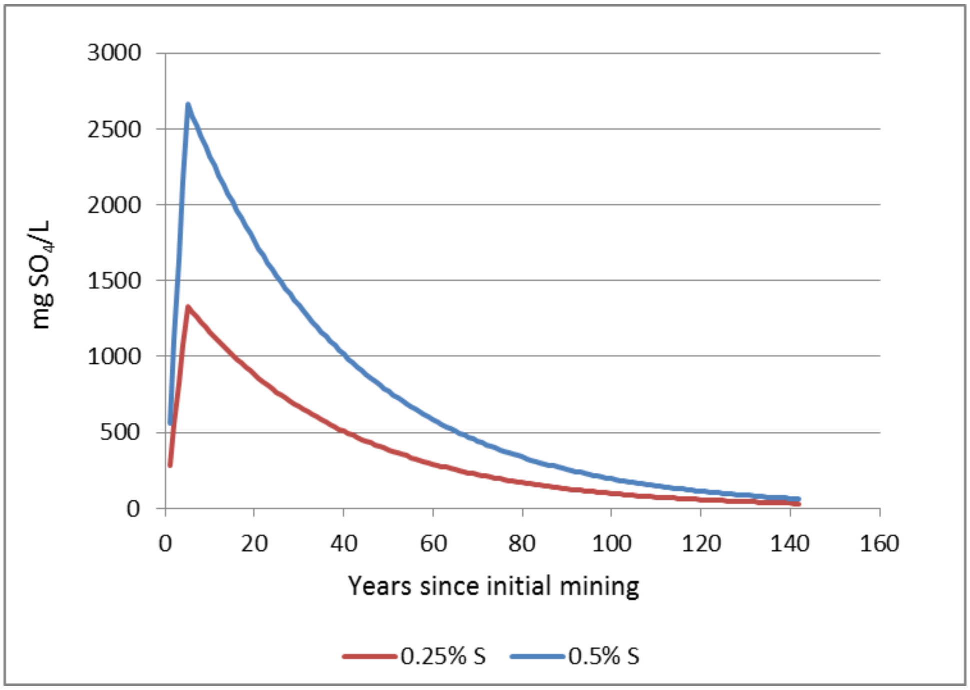


Figure 3. Decrease in sulfate over time as a function of %S.

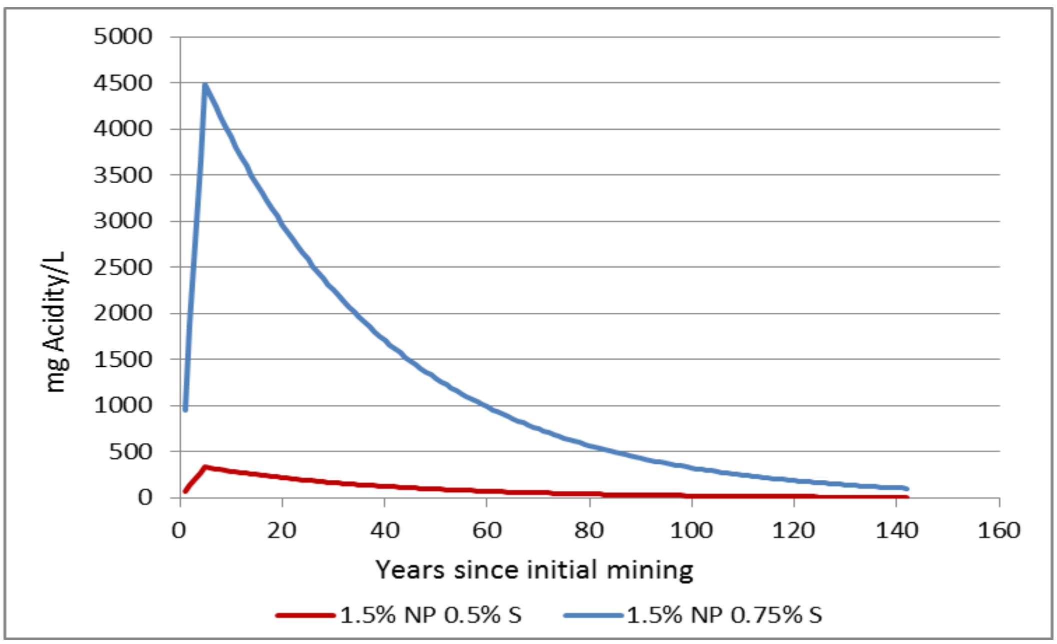


Figure 4. Decrease in acidity over time as a function of %S.

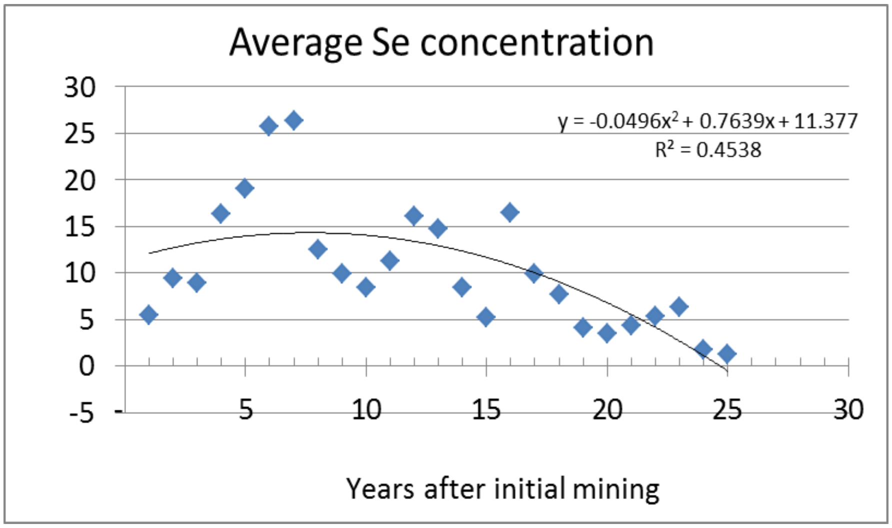


Figure 5. Average Se concentrations over time.

Similar decreases are expected to be observed in other parameters. The goal of this project is to identify attenuation rates of various parameters for surface and underground mines, as well as refuse sites. Attenuation rates will be categorized by geology, fill volume, fill type, and age. These results will be used to determine the decay rate of various TDS constituents within the mined watershed. The natural attenuation of these pollutants will positively influence the estimated liability of the Special Reclamation Fund.

Project Methods

Data will be collected from Discharge Monitoring Reports (DMRs). DMRs from two surface mines (one from Upper Kanawha to lower Allegheny coals and one from mid-Kanawha to earlier coals) and two underground mines (one from Upper Kanawha to lower Allegheny coals and one from mid-Kanawha to earlier coals) will be gathered and analyzed for relevant data. Parameters of interest will include: Ca, Mg, Na, HCO_3, SO_4, Cl, and TDS. Selected DMRs will cover a variety of fill ages, fill volumes, and fill types. If not enough relevant data can be obtained from DMRs, previously collected data will be used to supplement DMR data. Table 1 details the ideal distribution of surface mine sites.

Table 1. Matrix to be used for comparison of surface mines.

Lower Allegheny/Upper Kanawha

	Fill type					
	a	a	a	b	b	b
	Volume class					
Age class	1	2	3	1	2	3
A	A1a	A2a	A3a	A1b	A2b	A3b
B	B1a	B2a	B3a	B1b	B2b	B3b
C	C1a	C2a	C3a	C1b	C2b	C3b
D	D1a	D2a	D3a	D1b	D2b	D3b

Middle to lower Kanawha

	Fill type					
	a	a	a	b	b	b
	Volume class					
Age class	1	2	3	1	2	3
A	A1a	A2a	A3a	A1b	A2b	A3b
B	B1a	B2a	B3a	B1b	B2b	B3b
C	C1a	C2a	C3a	C1b	C2b	C3b
D	D1a	D2a	D3a	D1b	D2b	D3b

Project Progress – Surface Mines

Data has been collected from both DMRs and previous research. As detailed in the last report, nine DMRs from the Ruffner/Wylo complex have been gathered. Table 2 details what type of data is available from the Wylo/Ruffner DMRs. Fill ages range from 1-19 years old. Data on fill volumes and types are still being analyzed. Permit # WV1022792 had the most water quality data, including conductivity, SO_4, and TDS. However, only one sample for each of these parameters was taken.

Table 2. Sampled parameters from various NPDES permits at the Ruffner/Wylo mine complex. T=Total. D=Dissolved.

NPDES #	pH	TSS	Fe (T)	Al (D)	Al (T)	Mn (T)	Flow	Settleable solids	Se (T)	Sp. Conduc	SO_4	TDS
WV0099767	X	X	X	X		X	X	X				
WV0092991	X	X	X	X		X	X	X				
WV1010921	X	X	X	X	X	X	X	X	X			
WV1013530	X	X	X	X	X	X	X	X	X			
WV1020510	X	X	X	X	X	X	X	X				
WV1022792	X	X	X	X	X	X	X	X	X	X	X	X
WV1013599	X	X	X	X	X	X	X	X	X			
WV0099520	X	X	X	X	X	X	X	X	X			
WV1008331	X	X	X		X	X	X	X				

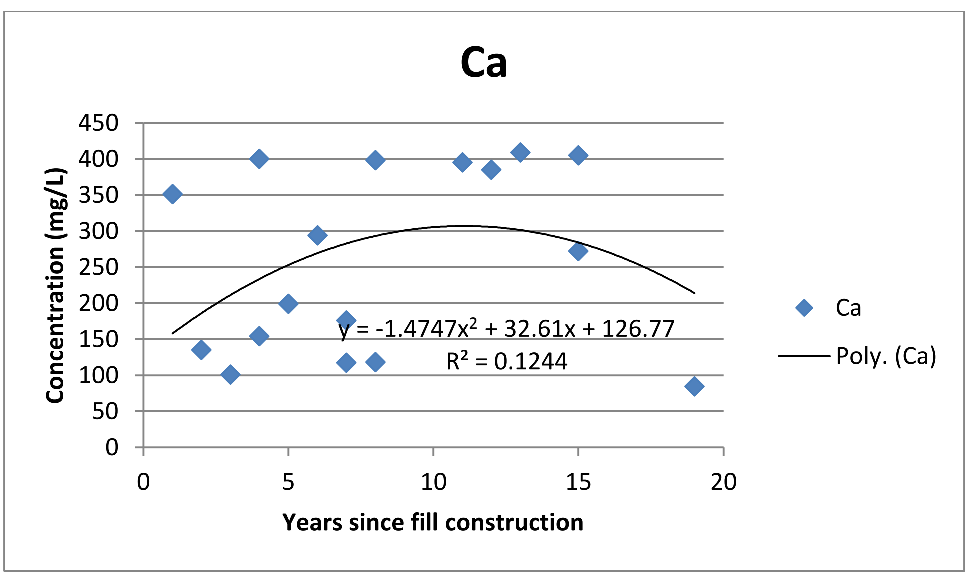
The Mid-Vol mine complex was selected as the representative mine for the middle to lower Kanawha coal seams. Similar to the Wylo/Ruffner mine, not all needed data were found in the DMRs (Table 3).

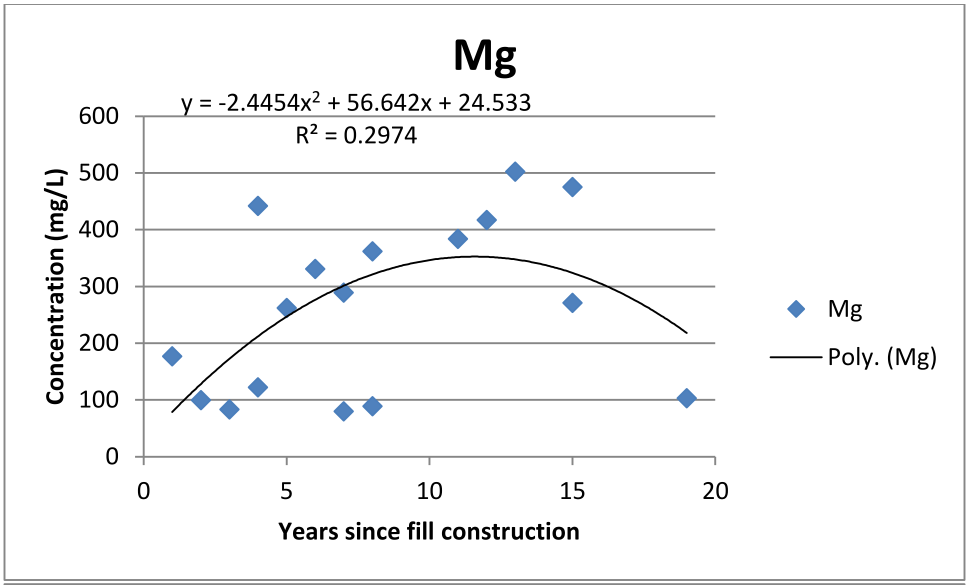
Table 3. Sampled parameters from various NPDES permits at the Mid-Vol mine complex. T=Total. D=Dissolved.

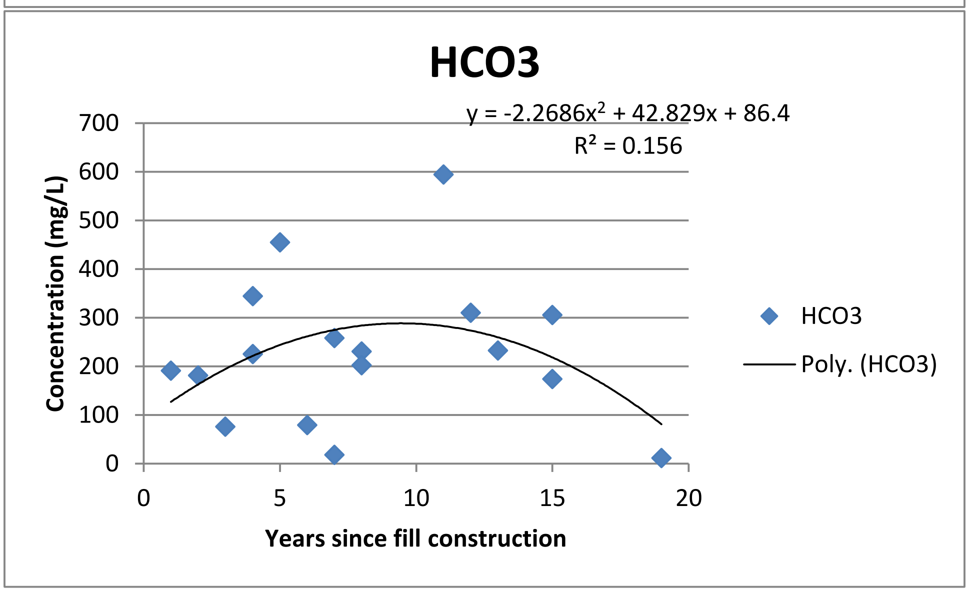
NPDES #	pH	TSS	Fe (T)	Al (D)	Al (T)	Mn (T)	Flow	Settleable solids	Se (T)	Sp. Conduc	SO_4	TDS
WV1005758	X	X	X	X	X	X	X	X				
WV0069701	X	X	X	X	X	X	X					

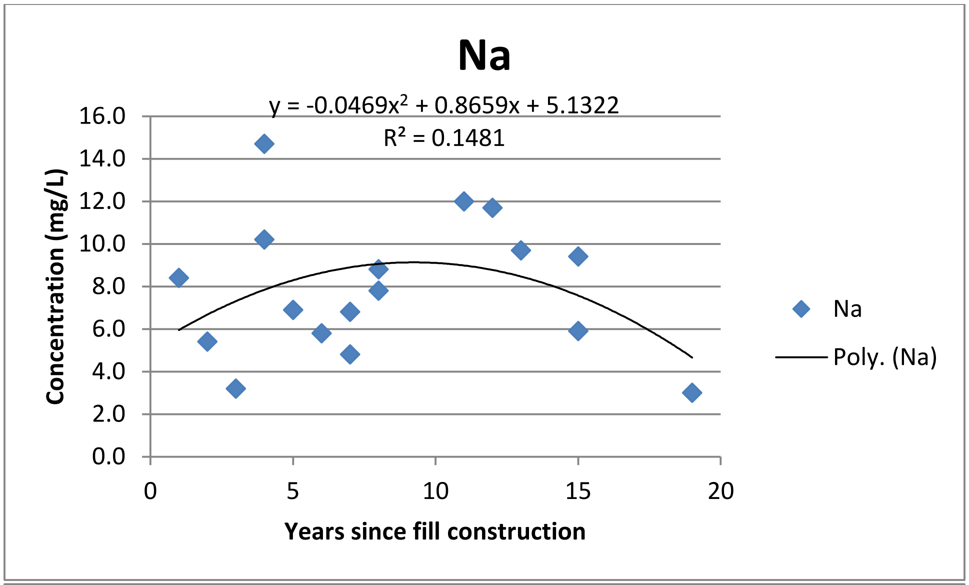
WV1008781	X	X	X	X	X	X	X				
WV1012193	X	X	X	X	X	X	X				
WV1018574	X	X	X	X	X	X	X				
WV1018850	X	X	X	X	X	X	X				
WV1019023	X		X	X	X	X	X				

As seen in Tables 3 and 4, the data available in the DMRs is not sufficient to meet the objectives of the project. To remedy this issue, valley fill data from the Mid-Vol and Wylo/Ruffner complexes will be combined with previously collected data from other mines. Valley fills will be grouped by fill age, as well as fill construction technique and fill volume (if possible). Figure 6 shows the preliminary graphs of concentrations of various parameters related to years since fill construction. These parameters were chosen because they are the main constituents of TDS in southern WV. All constituents show a similar polynomial trend of increased concentrations from 5-15 years from fill construction. All parameters then begin to decrease after 15 years. As more valley fills are included in this analysis, the amount of variance in the data, especially on the extreme ends of the time since fill construction, will likely be reduced. Reduction in the variance of the data will enable the model to be a more accurate predictor of parameter concentrations over time.




Mg
y = -2.4454x² + 56.642x + 24.533
R² = 0.2974
Concentration (mg/L)
600
500
400
300
200
100
0
0
5
10
15
20
Years since fill construction
Mg
Poly. (Mg)


HCO3
y = -2.2686x² + 42.829x + 86.4
R² = 0.156
Concentration (mg/L)
700
600
500
400
300
200
100
0
0
5
10
15
20
Years since fill construction
HCO3
Poly. (HCO3)


Na
y = -0.0469x² + 0.8659x + 5.1322
R² = 0.1481
16.0
14.0
12.0
10.0
8.0
6.0
4.0
2.0
0.0
0
5
10
15
20
Concentration (mg/L)
Years since fill construction
Na
Poly. (Na)


SO4
y = -9.1795x² + 221.44x + 370.97
R² = 0.1876
3000
2500
2000
1500
1000
500
0
0
5
10
15
20
Concentration (mg/L)
Years since fill construction
SO4
Poly. (SO4)

Figure 6. Effects of fill age on concentrations of select constituents.

Project Progress - Underground mines

DMRs have also been obtained for two underground mines. The Aracoma Coal company (10 discharges) and the Highland Mining Company (9 discharges) are both in the Upper Kanawha coals. Similar to the Wylo/Ruffner and the Mid-Vol surface mines, the DMRs for these two underground mines do not have all the water quality data that is required. A similar approach to the one used for surface mines will also be used for underground mine data. The same chemical parameters will be gathered and grouped by refuse pile age. Underground mine data collection is currently ongoing.

Future Project Plans

The project team will continue to gather data from both DMRs and other data sources. Data will be organized by fill age and if possible, fill volume and fill construction type.

Once all data has been collected and organized, decay curves will be constructed for all parameters of interest. From these decay curves, estimations will be made of how long TDS constituents will be expected to impact water quality.

References

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Younger, P.L. 1997. The Longevity of Minewater Pollution: a Basis For Decision-Making. The Science of the Total Environment. 194-195: 457-466.

Capital Cost	**$33,122,958.35**					
O & M	**$5,547,227.85**					
Site Name	**Permit Number**	**Water Status**	**Newly Estimated Capital Costs**	**Estimated Liability Costs**	**Final Capital Const. Cost**	**Newly Estimated Annual O&M**
A S & K, INC.	S-1011-89	TBC	$91,150.00	$243,000.00	-$151,850.00	$4,075.41
ALPHAINE CORP.	S-6032-86	C	$0.00		$0.00	
AMANDA NICOLE FUELS, INC.	S-1018-88	UC	$0.00		$0.00	$48,465.00
B & S Contracting Inc.	U-3055-87	P	$88,530.00		$88,530.00	$6,721.35
B & S CONTRACTING, INC.	O-3086-87	P	$0.00		$0.00	
B & S CONTRACTING, INC.	R-668	P	$3,360.00		$3,360.00	$5,765.60
BARRENSHE COAL CO.	UO-694	P	$83,782.00		$83,782.00	$9,877.00
BARRETT FUEL CORP.	R-737	P	$10,200.00		$10,200.00	$4,180.23
BELLE CONTRACTING, INC.	S-6020-87	P	$116,377.69		$116,377.69	$10,623.00
BENHAM GROUP	120-79	ACT	$8,960.00		$8,960.00	$19,826.62
BJORKMAN MINING	S-37-81	P	$8,960.00		$8,960.00	$4,333.60
BLACK DIAMOND MINING CO.	13-79	P	$2,800.00		$2,800.00	$3,731.28
BOLINGREEN MINING COMPANY	S-1024-88	ACT	$8,990.41		$8,990.41	$6,964.00
BRADY CLINE	EM-97	ACT	$506,785.00		$506,785.00	$17,422.51
BRENKEE COAL CO.	UO-435	NA	$424,143.65		$ -	
BUFFALO COAL	S-2003-88	TBC	$2,098,037.50		$2,098,037.50	$135,402.00
BUFFALO COAL COMPANY, INC.	S-53-80	TBC	$1,190,250.00	$863,838.00	$326,412.00	$80,857.00
BUFFALO COAL COMPANY, INC.	S-52-80	TBC	$1,375,155.00	$944,494.00	$430,661.00	$107,233.00
BUFFALO COAL COMPANY, INC.	S-2006-86	UC	$0.00		$0.00	$57,400.00
BUFFALO COAL COMPANY, INC.	S-2001-86	TBC	$1,377,127.50	$401,939.00	$975,188.50	$66,769.00
BUFFALO COAL COMPANY, INC.	S-2003-03	TBC	$113,052.50	$577,878.00	-$464,825.50	$30,728.00
BUFFALO COAL COMPANY, INC.	S-2011-92	TBC	$0.00		$0.00	
BUFFALO COAL COMPANY, INC.	S-122-80	ACT	$15,400.00		$15,400.00	$25,536.16
C. C. CONLEY & SONS, INC.	S-3046-91	P	$309,285.00		$309,285.00	$14,010.00
CHAFIN COAL CO.	O-69-82	P	$0.00		$0.00	$3,595.39
CHESTNUT RIDGE COAL CORP.	S-28-83	ACT	$92,001.91		$92,001.91	$61,930.00
CHEYENNE COAL SALES	S-2009-96	TBC	$570,725.00	$411,100.00	$159,625.00	$67,181.00
Cheyenne Sales	O-11-83	TBC	$133,365.00	$21,387.00	$111,978.00	$77,357.00
Chicopee Coal Co. Inc.	S-3006-99	TBC	$3,602,677.50	$1,564,000.00	$2,038,677.50	$95,442.00
CHICOPEE COAL CO., INC.	S-3002-98	TBC	$104,460.00	$85,500.00	$18,960.00	$8,500.00
CHICOPEE COAL COMPANY, INC.	O-6013-88	UC	$0.00		$0.00	$5,442.00
CLASSIC RES., INC.	S-55-81	TBC	$130,900.00	$175,000.00	-$44,100.00	$8,266.00
COAL X, INC.	UO-396	ACT	$0.00		$0.00	$4,724.34

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	O & M	$5,547,227.85					
Site Name	Permit Number		Water Status	Newly Estimated Capital Costs	Estimated Liability Costs	Final Capital Const. Cost	Newly Estimated Annual O&M
COWACO, INC.	R-3022-87		P	$0.00		$0.00	$5,745.62
CRADDOCK & SONS COAL CO.	S-68-83		P	$10,161.58		$10,161.58	$5,542.59
CRANE COAL CO., INC.	S-27-83		P	$5,160.00		$5,160.00	$4,058.95
DAUGHERTY COAL CO.	65-77		ACT	$504,013.51		$504,013.51	$60,457.00
DAUGHERTY COAL CO.	S-1009-86		ACT	$9,520.00		$9,520.00	$23,220.99
DAUGHERTY COAL COMPANY, INC.	192-77		ACT	$0.00		$0.00	
DAUGHERTY COAL COMPANY, INC.	124-79		NA	$0.00		$0.00	
DAUGHERTY COAL COMPANY, INC.	17-81		NA	$0.00		$0.00	
DAUGHERTY COAL COMPANY, INC.	246-74		NA	$0.00		$0.00	
DAUGHERTY COAL COMPANY, INC.	S-73-83		NA	$0.00		$0.00	
DECONDOR COAL CO.	U-147-82		TBC	$387,027.50	$400,000.00	-$12,972.50	$35,521.00
DLM COAL CO.	164-77		ACT	$0.00		$0.00	
DLM COAL CO.	1-78		ACT	$0.00		$0.00	
DLM COAL CO.	71-75		ACT	$0.00		$0.00	
DLM COAL CO.	138-74		ACT	$0.00		$0.00	
DLM COAL CO.	135-78		ACT	$0.00		$0.00	
DLM COAL CO.	58-77		ACT	$0.00		$0.00	
DLM COAL CO.	12-78		ACT	$0.00		$0.00	
DLM COAL CO.	23-76		ACT	$0.00		$0.00	
DLM COAL CO.	2-80		ACT	$15,340.00		$15,340.00	$26,577.43
DUSTY COALS., INC.	S-119-85		P	$271,565.00		$271,565.00	$12,104.00
E. J. & L. CO., INC.	S-3041-87		P	$62,787.50		$62,787.50	$4,997.00
EASTERN ENERGY INVEST.	U-6012-88		P	$0.00		$0.00	$3,399.79
EASTERN ENERGY INVESTMENTS	S-6029-86		ACT	$15,200.00		$15,200.00	$15,486.18
EDWARD E. THOMPSON	S-1041-89		ACT	$700,696.00		$700,696.00	$61,140.00
F & M COAL CO.	S-1073-86		NA	$0.00		$0.00	
F & M COAL CO.	S-1026-87		P	$5,260.00		$5,260.00	$8,011.71
F & M COAL CO.	46-79		P	$5,320.00		$5,320.00	$4,030.02
FALCON LAND COMPANY	P-656		ACT	$150,814.95		$150,814.95	$29,928.25
FARKAS COAL CO.	34-81		ACT	$54,635.00		$54,635.00	$16,337.38
FREEPORT MINING CORPORATION	S-1005-95		UC	$0.00		$0.00	$135,042.00
FRUSH ENTERPRISES	S-1008-89		TBC	$508,622.50		$508,622.50	$23,702.00
GAULEY COAL SALES CO.	O-43-84		ACT	$2,360.00		$2,360.00	$4,553.68

	Capital Cost	$33,122,958.35					
	O & M	$5,547,227.85					
Site Name	**Permit Number**		**Water Status**	**Newly Estimated Capital Costs**	**Estimated Liability Costs**	**Final Capital Const. Cost**	**Newly Estimated Annual O&M**
GLADE RUN MINING CO.	3-72		P	$2,800.00		$2,800.00	$4,451.03
GLADY FORK MINING, INC.	D-35-82		UC	$0.00		$0.00	$24,312.00
GLORY COAL CO., INC.	UO-744		P	$14,480.00		$14,480.00	$4,898.93
GOLD STAR MINING CORP.	S-121-85		NA	$0.00		$0.00	
GOLDEN PRODUCTS	S-1009-88		P	$1,800.00		$1,800.00	$5,043.69
GREEN MOUNTAIN ENERGY	U-4013-91		P	$4,140.00		$4,140.00	$4,504.64
GREENDALE COAL CO.	S-75-83		TBC	$2,969,995.00	$2,257,490.20	$712,504.80	$287,952.00
HARVEY ENERGY CORP.	S-35-81		P	$245,565.00		$245,565.00	$13,013.00
HARVEY ENERGY CORP.	S-3030-89		P	$22,343.75		$22,343.75	$6,461.00
HAWKS NEST MINING CO.	O-1-81		ACT	$12,000.00		$12,000.00	$5,518.58
HIDDEN VALLEY COAL CO.	S-60-84		ACT	$11,688.82		$11,688.82	$7,421.84
HUNT COAL, INC.	U-5071-86		ACT	$0.00		$0.00	$3,506.61
INTERSTATE LUMBER CO	S-39-82		TBC	$718,210.00	$766,500.00	-$48,290.00	$43,254.00
INTER-STATE LUMBER CO.	176-77		ACT	$153,850.84		$153,850.84	$6,564.80
INTER-STATE LUMBER COMPANY, INC.	S-112-80		P	$320,856.25		$320,856.25	$24,923.00
INTER-STATE LUMBER COMPANY, INC.	S-96-82		P	$0.00		$0.00	$2,542.87
INTER-STATE LUMBER COMPANY, INC.	S-52-83		ACT	$6,380.00		$6,380.00	$3,805.96
J & N PROCESSING COMPANY, LLC	O-58-83		P	$294,800.22		$294,800.22	$30,433.00
J. E. B., INC.	S-61-82		ACT	$0.00		$0.00	
J.A.L. COAL CO., INC.	S-23-82		P	$376,447.50		$376,447.50	$2,975.79
JINKS MINING COMPANY	U-3031-93		P	$7,720.00		$7,720.00	$5,556.67
JOCARR RESOURCES, INC.	U-3059-86		TBC	$27,167.50	$175,500.00	-$148,332.50	$3,461.00
JOHN GALT	D-76-82		P	$0.00		$0.00	$3,844.39
JONES COAL INC	S-9-83		TBC	$273,432.50	$120,000.00	$153,432.50	$13,422.00
JONES COAL INC	S-1030-86		P	$3,480.00		$3,480.00	$4,608.70
Keister Coal	184-77		ACT	$7,840.00		$7,840.00	$84,634.17
KEYSTONE COAL, INC.	U-186-83		TBC	$281,698.00	$162,000.00	$119,698.00	$11,593.00
KEYSTONE COAL, INC.	S-84-83		TBC	$0.00	$162,000.00	-$162,000.00	
KODIAK LAND CO., INC.	S-3052-87		P	$168,252.50		$168,252.50	$8,307.00
LAKEVIEW COAL COMPANY	S-55-84		P	$28,753.27		$28,753.27	$4,398.00
LANDMARK CORP.	S-34-82		TBC	$732,433.00	$180,162.00	$552,271.00	$48,822.00
LANDMARK CORPORATION	S-5069-88		TBC	$0.00		$0.00	
LAROSA FUEL COMPANY	S-1051-86		TBC	$1,206,222.50	$943,450.00	$262,772.50	$106,717.00

Capital Cost	**$33,122,958.35**					
O & M	**$5,547,227.85**					
Site Name	**Permit Number**	**Water Status**	**Newly Estimated Capital Costs**	**Estimated Liability Costs**	**Final Capital Const. Cost**	**Newly Estimated Annual O&M**
LEVEL LAND MINING CORPORATION	S-3031-90	P	$4,480.00		$4,480.00	$4,523.92
LILLYBROOK COAL CO.	S-86-85	ACT	$114,590.00		$114,590.00	$14,235.78
LOBO CAPITOL, INC.	UO-204	TBC	$448,895.00	$47,631.00	$401,264.00	$47,631.00
LODESTAR ENERGY, INC.	S-3006-89	TBC	$674,825.00	$199,000.00	$475,825.00	$46,794.00
LODESTAR ENERGY, INC.	S-3083-86	TBC	$196,525.00	$167,000.00	$29,525.00	$10,088.00
LODESTAR ENERGY, INC.	R-5-84	P	$222,666.73		$222,666.73	$15,639.00
LODESTAR ENERGY, INC.	S-19-85	P	$0.00		$0.00	$11,846.24
LOW ASH COAL CO.	UO-389	P	$70,782.50		$70,782.50	$5,166.00
M & T MINING CO.	S-3026-89	P	$5,600.00		$5,600.00	$10,719.09
MANGUS COAL COMPANY	S-1036-91	TBC	$754,750.00	$437,100.00	$317,650.00	$54,102.00
Maurice Jennings	S-61-83	TBC	$339,992.50	$422,042.00	-$82,049.50	$32,337.00
MAURICE JENNINGS	53-78	TBC	$812,287.50	$165,566.00	$646,721.50	$37,295.00
MOHIGAN MINING CO.	U-109-83	P	$82,909.97		$82,909.97	$34,525.00
MORGANTOWN ENERGY EXPORT CO.	U-8-83	P	$53,642.50		$53,642.50	$4,631.00
MOUNTAINEER FUELS, INC.	U-3083-87	P	$15,000.00		$15,000.00	$6,765.52
NATIONAL CONSTRUCTION COMPANY, INC.	S-2004-86	P	$73,121.62		$73,121.62	$7,598.00
PIERCE COAL & CONSTRUCTION, INC.	252-76	NA	$0.00		$0.00	
PIERCE COAL & CONSTRUCTION, INC.	71-80	P	$0.00		$0.00	
PINNACLE CREEK MINING CORP.	R-721	P	$77,466.00		$77,466.00	$4,843.53
PRESTON ENERGY, INC.	O-86-82	ACT	$0.00		$0.00	
PRESTON ENERGY, INC.	O-43-85	ACT	$0.00		$0.00	
PRIMROSE COAL, INC.	(Z)-7-81	TBC	$381,142.50	$501,700.00	-$120,557.50	$32,019.00
PRINCESS CINDY MINING, INC.	30-79	P	$52,424.00		$52,424.00	$4,470.00
PRINCESS SUSAN COAL CO.	S-76-82	C	$0.00		$0.00	
PRINCESS SUSAN COAL CO.	S-6033-86	UC	$0.00		$0.00	$3,571.00
PRINCESS SUSAN COAL CO.	S-6-85	UC	$0.00		$0.00	$7,046.00
PUPS CREEEK COAL	S-3006-94	TBC	$689,117.50	$330,680.00	$358,437.50	$0.00
RALEIGH COMMERICAL DEVELOPMENT CORP.	149-79	P	$0.00		$0.00	$3,317.68
ROBLEE COAL CO.	U-2001-00	TBC	$453,017.50	$38,380.00	$414,637.50	$16,975.00
ROCKVILLE MINING CO.	S-91-85	TBC	$952,586.28	$351,000.00	$601,586.28	$48,309.00
ROYAL COAL CO.	R-676	TBC	$1,111,852.50	$243,000.00	$868,852.50	$61,971.00
ROYAL SCOT MINERALS, INC.	56-81	P	$13,198.92		$13,198.92	$3,452.00
ROYAL SCOT MINERALS, INC.	U-3046-88	TBC	$477,532.50	$224,000.00	$253,532.50	$11,577.00

Capital Cost	$33,122,958.35					
O & M	$5,547,227.85					
Site Name	**Permit Number**	**Water Status**	**Newly Estimated Capital Costs**	**Estimated Liability Costs**	**Final Capital Const. Cost**	**Newly Estimated Annual O&M**
ROYAL SCOT MINERALS, INC.	R-3078-86	ACT	$717,660.00		$717,660.00	$18,870.00
ROYAL SCOT MINERALS, INC.	D-32-81	ACT	$42,900.00		$42,900.00	$11,841.88
ROYAL SCOT MINERALS, INC.	S-90-82	P	$14,312.00		$14,312.00	$4,158.43
ROYAL SCOT MINERALS, INC.	S-65-76	TBC			$0.00	$2,795.42
ROYAL SCOT MINERALS, INC.	S-99-83	P	$7,220.00		$7,220.00	$8,436.21
ROYAL SCOT MINERALS, INC.	U-40-85	P	$4,160.00		$4,160.00	$7,457.28
S. Kelly Industries	51-78	ACT	$104,135.00		$104,135.00	$75,346.66
SALYERS LEASING CORP.	U-5066-87	P	$0.00		$0.00	$3,261.73
SAN SUE COAL CO.	19-75	P	$8,520.00		$8,520.00	$7,168.86
SMITH & STOVER	EM-29	TBC	$377,772.50	$54,000.00	$323,772.50	$31,970.00
SOLITAIRE COAL CORP.	S-87-85	TBC	$139,377.50	$398,250.00	-$258,872.50	$31,907.00
SOUTHERN EAGLE MINING CORPORATION	U-32-84	P	$0.00		$0.00	
STAR INDUSTRIES, INC.	R-3-81	ACT	$20,799.35		$20,799.35	$25,062.00
STEWARTOWN COAL CORP	67-78	ACT	$17,920.00		$17,920.00	$8,047.69
SUMMERSVILLE FIVE BLOCK	S-3051-88	TBC	$4,290,212.50	$243,000.00	$4,047,212.50	$231,065.00
T & J COAL, INC.	P-177-85	UC	$0.00		$0.00	$41,315.00
T & T FUELS, INC.	U-125-83	ACT	$78,574.21		$78,574.21	$20,065.94
TEMPLEMAN CONST. CO., INC.	151-75	P	$4,200.00		$4,200.00	$3,969.65
The Masteller Coal Co.	S-125-82	TBC	$136,257.50	$92,500.00	$43,757.50	$36,861.00
THE MASTELLER COAL COMPANY	S-10-85	TBC	$186,510.00	$113,419.00	$73,091.00	$9,908.00
TRIPLE A COALS, INC.	U-3046-87	P	$52,760.00		$52,760.00	$4,187.81
TRIPLE A COALS, INC.	S-3028-87	P	$52,760.00		$52,760.00	$9,332.47
VALLEY MINING CO.	S-64-83	ACT	$174,512.50		$174,512.50	$30,692.83
VALLEY MINING CO.	S-17-82	ACT	$59,575.23		$59,575.23	$5,944.00
VICKIE ENERGY, INC.	U-53-85	P	$61,247.50		$61,247.50	$4,935.00
VMS, LIMITED	S-1045-87	ACT	$54,626.00		$54,626.00	$31,125.86
W & E LOGGING & COAL	S-20-82	P	$5,040.00		$5,040.00	$4,422.20
WERNER MINING CO., INC.	S-2003-86	P	$25,600.00		$25,600.00	$5,152.95
WETER Co	S-71-79	P	$0.00		$0.00	$2,893.99
WINCHESTER COALS, INC.	O-52-83	C	$0.00		$0.00	
X W CORP.	S-6013-87	P	$0.00		$0.00	$4,943.57
Z & F DEVELOPMENT CO.	S-21-84	ACT	$383,287.50		$383,287.50	$50,791.00
ZINN COAL CO.	60-79	P	$11,320.00		$11,320.00	$5,069.25

Capital Cost	**$33,122,958.35**					
O & M	**$5,547,227.85**					
Site Name	**Permit Number**	**Water Status**	**Newly Estimated Capital Costs**	**Estimated Liability Costs**	**Final Capital Const. Cost**	**Newly Estimated Annual O&M**
ZY COAL CO	S-6028-88	TBC	$132,092.50		$132,092.50	$7,526.00
ZY COAL CO.	91-79	P	$30,713.54		$30,713.54	$3,237.00
ZY COAL CO.	S-30-80	C	$0.00		$0.00	
PREVIOUS LAWSUITS:						
Borgman	EM-32	ACT			$451,555.00	$15,362.53
Delta Mining/Pierce Coal	U-2024-87/70-81	ACT			$163,500.00	$1,665.42
Ed-E Development	S-1032-86	ACT			$336,917.00	$17,867.06
Ed-E Development	S-10-81	ACT			$284,510.00	$100,556.49
F&M Coal Co.	S-1044-87	ACT			$873,600.00	$183,300.98
F&M Coal Co.	S-57-84	ACT			$742,500.00	$96,956.15
Hallelujah Mining	40-81	ACT			$209,261.00	$19,614.30
J.E.B. Inc.	S-61-82	ACT			$119,100.00	$8,302.60
Omega	D-79-82	ACT			$1,452,655.00	$340,487.10
Preston Energy	O-43-85	ACT			$6,800.00	$8,400.30
Rockville Mining Co.	65-78 Site 1	ACT			$125,880.00	$49,464.69
Rockville Mining Co.	S-65-82 Site 4	ACT			$32,280.00	$55,626.29
Rockville Mining Co.	S-65-82 Site 10	ACT			$24,720.00	
Rockville Mining Co.	S-1035-86 Site 4	ACT			$162,172.00	$15,634.91
Rockville Mining Co.	S-1035-86 Site 5	ACT			$16,800.00	
Rockville Mining Co.	237-76 Site 1	ACT			$75,180.00	
Rockville Mining Co.	237-76 Site 2	ACT			$50,520.00	$25,641.19
Rockville Mining Co.	237-76 Site 3	ACT			$21,000.00	
T&T	EM-113	ACT			$2,829,004.00	$462,157.88
Viking Coal	UO-519	ACT			$742,394.00	$68,632.58
Wocap Energy	S-26-85	ACT			$268,993.00	$27,398.42
Triple A Coals	S-96-85	P			$259,480.00	$12,746.80
Harvey Energy	S-11-82	P			$47,000.00	$8,094.71
Royal Scot Minerals, Inc.	31-72	ACT			$395,000.00	$488,947.26