WRI 50: Strategies for Cooling Electric Generating Facilities Utilizing Mine Water: Technical and Economic Feasibility Project

Final Report

Reporting period start date: November 1, 2003
Reporting period start date: September 30, 2004

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Date Report was issued: November 2004
DOE Award Number DE-FC26-03NT41908

Submitted to:

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Abstract

Power generation and water consumption are inextricably linked. Because of this relationship DOE / NETL has funded a competitive research and development initiative to address this relationship. This report is part of that initiative and is in response to DOE / NETL solicitation DE-PS26-03NT41719-0.

Thermal electric power generation requires large volumes of water to cool spent steam at the end of the turbine cycle. The required volumes are such that new plant siting is increasingly dependent on the availability of cooling circuit water. Even in the eastern U.S., large rivers such as the Monongahela may nolonger be able to support additional, large power stations due to subscription of flow to existing plants, industrial, municipal and navigational requirements.

Earlier studies conducted by West Virginia Unviersity (WV 132, WV 173 phase I, WV 173 Phase II, WV 173 Phase III, and WV 173 Phase IV in review) have identified that a large potential water resource resides in flooded, abandoned coal mines in the Pittsburgh Coal Basin, and likely elsewhere in the region and nation. This study evaluates the technical and economic potential of the Pittsburgh Coal Basin water source to supply new power plants with cooling water.

Two approaches for supplying new power plants were evaluated. Type A employs mine water in conventional, evaporative cooling towers. Type B utilizes earth-coupled cooling with flooded underground mines as the principal heat sink for the power plant reject heat load.

Existing mine discharges in the Pittsburgh Coal Basin were evaluated for flow and water quality. Based on this analysis, eight sites were identified where mine water could supply cooling water to a power plant. Three of these sites were employed for pre-engineering design and cost analysis of a Type A water supply system, including mine water collection, treatment, and delivery. This method was also applied to a “base case” river-source power plant, for comparison. Mine-water system cost estimates were then compared to the base-case river source estimate.

We found that the use of net-alkaline mine water would under current economic conditions be competitive with a river-source in a comparable-size water cooling system. On the other hand, utilization of net acidic water would be higher in operating cost than the river system by 12 percent. This does not account for any environmental benefits that would accrue due to the treatment of acid mine drainage, in many locations an existing public liability. We also found it likely that widespread adoption of mine-water utilization for power plant cooling will require resolution of potential liability and mine-water ownership issues. In summary, Type A mine-water utilization for power plant cooling is considered a strong option for meeting water needs of new plant in selected areas.

Analysis of the thermal and water handeling requirements for a 600 megawatt power plant indicated that Type B earth coupled cooling would not be feasible for a power plant of this size. It was determined that Type B cooling would be possible, under the right conditions, for power plants of 200 megawatts or less. Based on this finding the feasibility of a 200 megawatt facility was evaluated.

A series of mines were identified where a Type B earth-coupled 200 megawatt power plant cooling system might be feasible. Two water handling scenarios were designed to distribute heated power-plant water throughout the mines. Costs were developed for two different pumping scenarios employing a once-through power-plant cooling circuit. Thermal and groundwater flow simulation models were used to simulate the effect of hot water injection into the mine under both pumping strategies and to calculate the return-water temperature over the design life of a plant. Based on these models, staged increases in required mine-water pumping rates are projected to be part of the design, due to gradual heating and loss of heat-sink efficiency of the rock sequence above the mines.

Utilizing pumping strategy #1 (two mines) capital costs were 25 percent lower and operating cost 19 percent higher than a conventional river-water cooling water scheme. Utilizing pumping strategy #2 (three mines), capital costs were 20 percent lower and operating costs 192 percent higher. Major capital cost advantages are obtained by using earth-coupled cooling, due in large part to elimination of need for cooling towers. In addition, the lack of cooling towers and of thermal-pollution considerations may be positive factors in power plant permitting. However, application of Type B earth-coupled cooling will be technically feasible limited at a much smaller number of sites than than Type A systems due to requirements involving mine size, geometry, and hydraulic conditions. Innovations such as directional drilling may be required to create mine interconnections across barriers where none presently exist.

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Introduction

Power generation and water consumption are inextricably linked. Because of this relationship DOE / NETL has funded a competitive research and development initiative to address this relationship. This report is part of that initiative and is in response to DOE / NETL solicitation DE-PS26-03NT41719-0.

The purpose and scope of this study is to evaluate the technical and economic feasibility of using water from abandoned underground coal mines to supply cooling water to power plants. Environmental regulations (316(b)) related to the Clean Water Act of 1972 (CWA) have substantially limited the use of once-through cooling due to the thermal load that it places on the receiving surface water, and the potential it has for impingment and entrainment of aquatic organizims. This has led to the widespread use of cooling towers to transfer reject heat from the power plant to the atmosphere. However, even this approach has negative environmental impacts related to water consumption. The use of mine water for power plant cooling would have the benefit of treating the heat-dissipation problem while reducing or eliminating consumptive use of surface water. The approach also has the potential to improve the efficiency of the electric generating facility. While some power plants in the anthracite region of Pennsylvania currently use mine water for cooling (Veil *et al.* 2003) the feasibility of this approach has not been demonstrated in a single-seam bituminous coal basin supporting large (>600 MW) generating facilities. Notwithstanding, Donovan *et al.* (2004, in review) have demonstrated the widespread availability of mine water in the Pittsburgh Coal Basin that would be available for this use.

In Section 1 of this report, a feasibility analysis was performed on the use of a mine water for cooling-tower makeup water in a conventional 600 megawatt (MW) plant, deemed Type A mine-water cooling. Two methods of water utilization were evaluatd. In case one, mine water is treated and released to a surface water body from which it is later removed by the power plant. In case two, the power plant is located close to the mine water discharge and the treated mine water is pumped directly to the power plant. We identified potential water sources, designed water collection systems, and performed economic / environmental analysis utilizing a "base case" scenario of a conventional river water-source cooling tower plant for comparison. To do this, locations are identified within the Pittsburgh Coal Basin of southwestern Pennsylvania/northern West Virginia where mine water is available in sufficient quantity to meet cooling water needs. This basin has a reported availability of at least 86,000 gallons per minute (gpm) (Donovan *et al.* 2004, in review). Three mine complexes were used for case study and cost comparison, involving realistic sites with potential for use under differing water chemical and site conditions.

In Section 2 of this report, the feasibility and economics of earth-coupled cooling using underground mines for heat dissipation, deemed Type B mine-water cooling, was examined. This concept involves "once-through" cooling of power plant condensers with mine water, subsequently cooled by recirculation through a series of underground mines. This design would eliminate construction of a cooling tower, but would require considerably more water than for a conventional plant. The scope includes thermal/groundwater flow modeling to estimate temperature differentials and required mine area/volumes; more detailed site-specific groundwater modeling to determine mine hydraulics required for a water collection/distribution system; and economic/environmental analysis. A series of three mines were used for case study, involving a realistic site with potential for Type B cooling in the Pittsburgh Coal Basin.

Since many of the operations at a power plant - for example, the turbine, boiler, scrubber, smokestack, and fuel handling facilities, as well as substations - are not affected by the heat rejection side of the facility, they are not considered in any of these economic analyses. This allows a direct cost comparison of the alternative cooling options. Also considered separately are the costs of obtaining and treating the mine water.

Executive Summary

Power generation and water consumption are inextricably linked. Because of this relationship DOE / NETL has funded a competitive research and development initiative to address this relationship. This report is part of that initiative and is in response to DOE / NETL solicitation DE-PS26-03NT41719-0.

This project investigates the potential for using mine water in power plant cooling. The study is organized in two parts. Part 1 investigates the potential for Type A cooling: use of mine water as makeup to new power plants with cooling towers. Part 2 investigates the potential for Type B cooling: use of flooded underground mines as a heat sink for recirculating "once-through" heated water used for condenser cooling, without cooling towers. Type A represents consumptive use (all water is either evaporated or discharged) while Type B represents non-consumptive use (water is recirculated).

Large volumes of metals-contaminated mine water are currently discharging into rivers and streams of the Pittsburgh Coal Basin. Only 29 percent of this water is currently treated. Over time, the flooded mines in the Pittsburgh seam have improved in water quality. At a number of locations water is discharging in sufficient volume to provide makeup water to power plants that utilize cooling towers. This study evaluates the physical, regulatory, and economic potential for mine water utilization in power plant cooling.

Part 1:

Eight sites were identified in the Pittsburgh Coal Basin where water is, or is expected to be, available in sufficient supply to support power plant operations. Three of these with rail access to fuelstock were used for cost comparison with variations between locations in mine water chemistry and other site factors. Costs of water system construction were within ± 7% of the river-source case for all three systems. Operating costs were very similar in two of the three systems, and were 28% higher in the third. In summary, the cost of using net-alkaline mine water for Type A cooling is on a par with traditional river-water sources. However, there are site and water-source factors that will make some locations more favorable than others.

Environmental and regulatory factors relevant to Type A cooling will not include recently-promulgated Clean Water Act regulations on cooling water intake structures provided that the water is withdrawn for the mine and not a surface water body. It will also provide environmental benefits related to treatment of acid mine drainage (AMD). Investment in mine-source power plants may be limited by uncertainties regarding liability for the mine discharge and ownership of the mine water source.

Part 2:

Thermal modeling was performed to determine mine volume/area requirements to cool a 600 MW plant heat output. In addition, more detailed hydraulic modeling was performed to examine the hydraulic characteristics of a single site (3 large mines) in the Pittsburgh Coal Basin for their potential use in a Type B earth-coupled power plant design

The thermal and isothermal models were constructed with the U.S. Geological Survey's HST3D and MODFLOW computer programs. The thermal groundwater model consisted of injection and extraction wells at either end of a rectangular domain. Initially 1.77 m^3/s (28,000 gpm) was pumped through the thermal model. As the temperature of the extracted water started to increase, the pumping rate had to be increased to satisfy the cooling rate requirements of the power plant. After 12.3 years, the pumping rate had to be increased to 1.89 m^3/s (30,000 gpm), and after 23.3 years, the pumping rate had to be increased again to 2.02 m^3/s (32,000 gpm).

HST3D does not have the boundary condition capability to construct a site-specific flow model, so an isothermal model was constructed using MODFLOW to test the hydraulics of two pumping strategies. The first pumping strategy involved injecting hot water from the power plant into the Vesta mine, and extracting the cooled water from the Clyde mine. The median travel time with pumping strategy #1 was approximately 206 days. The second pumping strategy involved injecting hot water from the power plant into the Vesta mine, extracting the cooled water from the Clyde mine, reinjecting the cooled water into Marianna 58, and extracting the still cooler water from the upper part of Marianna 58. The median travel time with pumping strategy #2 was approximately 291 days, but because this pumping strategy involves reinjecting the cooled water extracted from Clyde, additional cooling that is not reflected in the median travel time should be observed. The results of the MODFLOW models indicate that it should be possible to install a mine water cooling system in the Clyde, Vesta, and Marianna 58 mines with sufficient travel time between injection and extraction wells to permit sufficient cooling.

Pumping strategy #1 had capital costs that were 25% lower and operating cost 19% higher than the base case. Pumping strategy #2 was 20% lower and 92 % higher, respectively.

Type B cooling shows promise, largely due to the large reduction in capital cost associated with cooling towers. However, its use will be very site specific, and will be especially favorable in areas where the non-consumptive water use is an attractive option.

1 Use of Mine Water Source for Cooling Tower Makeup Water in a 600 MW Plant

1.1 Experimental

1.1.1 Characteristics of water from underground coal mines

Underground mine mapping of the Pittsburgh Coal Basin was taken from the files of the investigators at the West Virginia Water Research Institute. Earlier versions of these maps were presented in Donovan *et al*. (2004, in review) and are also available on the web site of the Hydrogeology Research Center at WVU (www.hrc.wvu.edu).

Data for mine water availability were compiled from the results of Dzombak *et al*. and Donovan *et al*. (2004, in review). These included discharges measured from underground mines in 1999-2003 as well as either estimated or reported pumping rates at AMD tretament plants.

Data on water chemistry were compiled from the results of Dzombak *et al*. Donovan *et al.* (2004, in review). For these chemical analyses, total acidities were calculated as the sum of equivalent concentrations of Fe (2 equivalents per mole), aluminum (3 equivalents per mole), manganese (2 equivalents per mole), and hydrogen ion (molar concentration = equivalent concentration). The equivalent concentrations were divided by 1000 and multiplied by 50 to be expressed in mg/L as $CaCO_3$ equivalents. This acidity was subtracted from the actual measured alkalinity (if any) from field measurement to yield a variable entitled "net alkalinity". This yields a value (in mg/L as $CaCO_3$ equivalents) that is positive if net alkaline, negative if net acidic, and exactly zero if neutral. These results for net alkalinity were compiled into three different nominal categories: net alkaline (>50 mg/L); net acidic (<-50 mg/L); and near-neutral (between -50 mg/L and +50 mg/L).

Based on analyses of these data, the approach taken included the following steps:

> 1- screen existing mines with known or anticipated water discharges to compile locations where both water withdrawal/collection and plant sites would be within 3 miles of each other,
>
> 2- select 3 of these water collection sites for more detailed analysis of technical/economic feasibility.

The criteria used to screen and identify these water collection sites included the following:

- availability of 8000 gpm or more within a 1 mile radius of all other water collection sites for this plant facility,

- proximity of a rail line or barge unloading facility where a power plant could be constructed within an upper limit of 3 miles from the most distant water collection facility.

Table 1-1 shows power plant water consumption data from a number of sources. These data were used to support the water consumption estimates used in the design of the base case. In particular, emphasis was placed on the data from EPRI as it is believed to represent a broad evaluation of water consumption at coal fired power plants.

1.1.2 Design of a collection system

In case one, a collection system must be built to convey the mine water to the AMD treatment plant(s) where it is treated and released to a surface water body. In case two, the same collection system must be constructed; in addition, a pipeline from the treatment plant to the power plant must also be constructed. The advantage of case one is that the mine discharges sufficient in volume to meet the power plant needs do not have to be located near to each other or the power plant. In case two the advantage is that the constant temperature of the mine water can be used to decrease the initial capital cost as well as to reduce the variations in plant operation due to high summer temperatures.

Any system for mine-water utilization would require a collection system, involving one or more pumping wells, surface collection intakes, and a transfer pipeline. The design of the collection system affects both the capital and the operating costs of the overall project.

Water collection systems were designed for the three "detailed-analysis" mine discharges, identified according to Section 1.1.1. As part of this process, a prospective site was selected for the location of the power plant, based on both proximity to the water source (<3 miles) and access to coal transportation. Access to the electric distribution grid was not a factor in the site selection although, where present, the grid was mapped and plotted along with the mine water sites. Water collection sites were selected that tended to minimize pumping head requirements, both static and dynamic, by allowing pipelines to be sited along valley locations as much as possible.

For cost purposes, pipe material employed in all applications was high density polyethylene (HDPE), which is favored due to its resistance to corrosion and relative smoothness (Hazen-Williams C value 150-155). Pipe size was selected to minimize dynamic head over long pipe runs, although higher friction loss was tolerated over short pipe runs to reduce cost. Although most pumping pressures are less than 30 psi, a pressure rating of DR 11 (160 psi) was selected due to its ability to resist collapse under negative pressure up to one atmosphere.

All collection systems were designed with internal redundancy; as an example, pump installations requiring two pumps for operation were designed using three.

1.1.3 Determining Treatment Needs

Water treatment operations were designed to (a) remove metals by addition of hydrated lime, and (b) reverse osmosis, to remove all solutes to the level required for boiler feed water. In addition to lime addition, the potential for using hydrogen peroxide to remove metals was evaluated. Cost estimates for metals removal were based on results of *AMDTreat* (OSM, 2003), a standard source for sizing and costing of mine drainage metals removal facilities. Raw water data from selected mines were used as imput data to AMDtreat. Geochemical modeling to estimate post-treatment water chemistry was performed using *PHREEQC* (Parkhurst *et al.* 1999).

1.1.4 Environmental Factors and Permitting

All new power plants must comply with a number of environmental laws and regulations. For existing plants these include the 316(a) and 316(b) sections of the Clean Water Act (CWA) as well as all relevant National Pollution Discharge Elimination System (NPDES) requirements. In addition, the Safe Drinking Water Act (SDWA) would be relevant if any injection of water into the mines is proposed.

1.1.4.1 316(a)(b)

Regulations under section 316(a) and (b) of CWA restrict withdrawals from surface water for the protection aquatic life. These regulations address the protection of aquatic life that may be entrained in the intake water as well as placing restrictions on the thermal load that may be delivered to the receiving stream. These regulations favor the use of cooling towers over once through cooling schemes that discharge directly to a stream.

The following regulations and legal considerations will be evaluated with regard to the use of mine water for makeup water to a cooling tower operation. Some of the regulations relate to environmental aspects of discharge of cooling water; others relate to the legal aspects of mine water withdrawal and use.

1.1.4.2 NPDES

The National Pollution Discharge Elimination System (NPDES) applies to all point-source discharges. These regulations are applicable to any power plant discharge to surface water. Similarly, all acid mine drainage treatment plants are required to obtain an NPDES permit. However, if all water generated at an AMD treatment facility is utilized at a power plant or other facility, then the AMD plant would not have a discharge and hence would not be required to have an independent NPDES permit.

If a power plant were to direct all of its cooling-water discharge into closed mines, then no NPDES permit would be required, but in its place a Underground Injection Control (UIC) permit would be needed.

1.1.4.3 Underground Injection Control

The UIC program under the SWDA regulates the sub-surface placement of fluids through any opening that is deeper than it is wide. The purpose of this regulation is to protect potential future drinking water sources. These potential future drinking water sources include all waters that contain less than 10,000 mg/L total dissolved solids. Permits would be required for any injection into underground mines; typically these would be class V permits. This would include blowdown water and, in the earth-coupled case, the injection of high-temperature once-through water. As currently written, the regulations would address contaminants in the blowdown water, but not thermal changes within or above the mine.

1.1.4.4 Water Rights

For the base case economic analysis, it was assumed that river water will continue to be available without cost for appropriation as a consumptive use for power plant cooling.

Water rights for subsurface water are administered on a state-by-state basis. Water rights in both Pennsylvania and West Virginia are largely based on English common law. Under this standard, beneficial users may withdraw as much groundwater from their property as they need without regard to adjacent landowners or concurrent users. Therefore, English common law will be used as the basis for determining mine water availability and the right to withdraw water.

1.1.4.5 Environmental Benefits

The use of mine water for power plant cooling has several environmental benefits. Water discharging from underground mines in Pennsylvania and West Virginia is, in many cases, of unsuitable quality for direct discharge to streams, and has polluted thousands of miles of streams. Over 70% of this discharge is polluted with dissolved metals and is currently untreated because the mines from which they issue were closed prior to implementation of the 1977 Surface Mining Control and Reclamation Act (SMCRA). The use of mine water for cooling of power plants would require removal of nearly all of its metals prior to utilization in order to prevent the formation of deposits on the condensers. Therefore, the discharge of cooling water would be largely metal-free. This reduction in metal loads will reduce the impact of these legacy discharges on the receiving streams of the region. In the event that the case one method of mine water utilization is used the mine water will be treated and discharged to a surface water body thus improving the water quality of the receiving stream and sustaining flow during low flow periods. In this report, no "benefit value" will be ascribed to this treatment, although it will be an intangible asset in the development of power plants employing such designs.

1.1.5 Economic Analysis

Economic analysis of construction and operation of a 600-MW power plant will be limited to costs related to the cooling system. For example, this analysis will not incorporate the cost of a 600-MW turbine as this cost will be identical for all scenarios evaluated. In contrast, the cost of cooling towers is expected to vary from one design to another and hence their cost will be included in the analysis.

A "base case" for cost consideration was developed for a hypothetical 600-MW power plant using a river source for cooling water. This source services two cooling towers, the typical design for a new, modern facility. The purpose of this base case is to compare alternative mine water cooling strategies. Although some new, modern power plants are being designed for once-through cooling, it is believed that such a design would not be permitted on even the larger rivers in the mid-Appalachian region, due to existing environmental requirements.

In addition to the "base case", prospective hypothetical power plants were sited near the three mine water sources identified in section 1.1.1. Each site had to be reasonably close (3 miles) to rail or barge transportation, and have access to sufficient mine water to support a power plant operation. Access to transmission lines was not a primary consideration in site select due to the long term cost associated with moving water versus moving electricity. However, where possible, sites were selected in proximity to the grid.

Two power plant designs were developed and applied to these sites. In one design, cooling tower blowdown water is discharged to the local stream. In the other, uncooled water from the condenser, equal in volume to the cooling tower blowdown, was injected into a mine adjacent to the source mine. The cost of these power plant options were calculated and compared to the base case.

Cost analysis was also performed on the capture and treatment of the mine water. The cost of conventional hydrated lime treatment was evaluated as well as the cost of hydrogen peroxide treatment. These costs were combined with the other water system costs and the total was then compared to the base case.

1.2 Results and Discussion

1.2.1 Characteristics of water from underground coal mines

Recent USDOE-NETL-sponsored research conducted at West Virginia University identified mine discharge flows and chemistry throughout the Pittsburgh Coal Basin; some of these results are summarized in Figure 1-1. This project estimated that a minimum 171 million cubic meters/year (86,000 gpm) of mine water are discharged from the Pittsburgh Coal Basin, and mine discharges are still being added to this estimate (Donovan *et al.* 2004, in review). In excess of 70% of this water is not currently treated. Mined area in the Pittsburgh Basin includes 379,000 hectares in Pennsylvania and West Virginia. We estimate that about 159,000 hectares are flooded. This is equivalent to approximately 1.2 billion cubic meters of water in storage. Additional flooded mines are still being identified within the basin, as nine large underground mines are still in the process of flooding. Once these mines fully flood, additional discharge, volume of water in storage, and flooded mine area will be added to the basin total.

The quality of water from underground coal mines in the Pittsburgh coal seam varies widely. Iron values of current discharges can range from less than 10 mg/L to more than 1,000 mg/L. Acidity can range from net alkaline water to acidities greater than 2,000 mg/L. Indeed, one pumped sample from a flooding mine was found to have an acidity of 12,000 mg/L, a pH of 4.1, an iron content of 2,435 mg/L; and a sulfate content of 21,500 mg/L. However, the occurrence of such strongly acidic waters is relatively uncommon.

While the water quality of newly flooded mines can be very poor, it is also known that this quality will improve over time as the acid-laden water is removed from the system either by treatment or discharge and is replaced by net-alkaline groundwater. Depending on the portion of the mine that is flooded, within 10 years after flooding is complete and water begins to discharge, a pH of 6.5 to 7.0; iron of less than 150 mg/L; alkalinity of 200 to 600 mg/L; sulfate between 2,000 and 6,000 mg/L; and very low aluminum and manganese levels are attained. Long-closed mines in the basin have much improved water qualities. In these mines, the pH ranges from 6.8 to 7.4; the iron is less than 10 mg/L; sulfate is between 100 and 400 mg/L; and aluminum and manganese are less than 1.0 mg/L.

Figure 1-1 shows a GIS mapping view of mine-discharge net alkalinity and mine discharge magnitude; each discharge represents a single mine. There are many more discharges in the basin than those shown; this figure includes only those with water chemistry data. Acidic discharges are shown as "pies" in red, alkaline discharges in blue, and near neutral discharges in green. The diameter of each circle is proportional to the average flow rate from each mine. These data demonstrate that the large majority of these discharges are net alkaline. Acidic discharges occur in newly flooded mines and mines with large un-flooded areas. Near-neutral discharges are rare and either represent a transitional phase between net-acidic and net-alkaline conditions, or they are in dynamic equilibrium between acid generation and alkaline mobility. The preponderance of net-alkaline discharges from mines within the Pittsburgh Coal Basin suggests a potential for low cost water treatment for power plant utilization.

Four sites were identified as sufficient to support the makeup water requirements of a 600 MW power plant, based on the screening requirements outlined in

Section 1.1.1. These sites are mapped along with the existing power plant and electrical grid in Figure 1-2. They are also tabulated in Table 1-2.

From these four sites, three were selected for additional analysis based on availability and reliability of water supply at the site as well as its raw (untreated) water quality. One site was selected for each of the three main water chemistry categories: Flaggy Meadows (net-acidic), Irwin (near-neutral) and Uniontown (net-alkaline).

1.2.2 Design of a collection system

The three sites selected were Flaggy Meadows, Irwin and Uniontown. Flaggy Meadows represents a site where the water quality is relatively poor, but there is an existing AMD treatment plant. Irwin is a borderline net-alkaline water with a substantial discharge that is contaminating Brush Creek. The Uniontown discharge is a net-alkaline discharge that is contaminating Redstone Creek.

In addition, the upstream treatment / downstream utilization approach was evaluated allowing for AMD treatment at the mine discharge with the power plant located on a major river. Because any point downstream of the AMD treatment can be used for the power plant location a specific site was not selected. Rather it is assumed that a number of sites exist that meet the requirements for rail or barge transportation of coal as well as access to the power distribution grid as evidenced by the number of power plants currently located on the Monongahela and Ohio rivers.

1.2.2.1 Flaggy Meadows

The Flaggy Meadows treatment plant is a modern high-density sludge facility. Although it was designed for 6,000 gpm, it is currently only treating about 3,000 gpm. An additional 3,500 gpm is expected to report to this plant as three large adjacent mines fill with water. 2,000 gpm is currently being pumped from another adjacent mine known as Jordan. This water is currently treated at the Dogwood Lakes treatment plant, but it could be pumped into Arkwright where it can be withdrawn and treated at the existing Sears AMD treatment plant. From there it can be pumped to the power plant. Hence, sufficient water will be available to support a 600-MW power plant. The Flaggy Meadows site is shown in Figure 1-3.

Because of the existing AMD treatment plants, it is only necessary to construct a pipeline and pumping system to the hypothetical power plant. The power plant site selected is located on a hilltop overlooking the Monongahela River. This site is in close proximity to the transmission grid, but not to any nodes on the grid. Rail service for coal delivery is present, adjacent to the river. It is assumed, for the purpose of cost analysis, that coal delivery to this site will be equivalent to that for the other sites.

A pipeline would extend from the clarifier overflow to the plant cooling towers and would be 2100 meters in length. Twenty-two-inch diameter DR 11 HDPE pipe was selected for this application. This pipe size is capable of handling additional flow up to 6,000 gpm if needed. A second pipeline from the Sears AMD plant would be 4,900 meters in length and constructed of 16 inch DR 11 HDPE pipe.

The power plant configuration for this site is shown in Figure 1-4. In this configuration, the blow-down water that would normaly report to the cooling tower (2,260 gpm) is pumped into the Jordan mine. This allows for the injection of hot blow-down water from the condensers before it reports to the cooling towers. This removes 0.75 percent of the thermal load from the cooling towers and directs it into the mine. While this reduction in thermal load is an insufficient basis to reduce the size of the cooling towers it is expected to reduce the evaporative loss by some 36 gallons per minute, while at the same time using the mine for limited earth-coupled cooling. It is expected that the heat from the blow-down water will be fully dissipated before the water returns to the Flaggy Meadows mine pumps. For additional information on earth-coupled cooling, refer to section 2 of this report.

1.2.2.2 Irwin

The mine discharge in Irwin (11,300 gpm) is the largest single discharge that has been observed in the Pittsburgh Coal Basin and more than sufficient to meet the need for makeup water for a 600-MW power plant. The discharge occurs as two pipelines that flow from the mine to a tributary of Brush Creek. Because the flow so greatly exceeds the needs of the plant, it is not necessary to usee the mine pool as a reservoir by pumping the water from the mine. Instead, the current mine discharge pipelines could be intercepted and diverted into a concrete in-ground tank, for pumping to a new AMD treatment plant. Because of the quality of this water, a conventional hydrated-lime plant has been selected, although it may be possible to substitute hydrogen peroxide for lime as the treatment chemical.

Once treated, the water will be pumped to the power plant site some 11,775 feet away as shown in figure 1-5. This site was selected for its access to rail transportation, its generally flat topography. The HDPE water pipeline is 26 inches in outside diameter; 11,775 feet in length and is designed to follow existing rights-of-way to the extent possible. The pipeline is to be buried to avoid accidental damage and elongation / contraction due to temperature variations.

Using the Hazen-Williams formula and a friction coefficient of 150 for the pipe (I.D. 20.988 inches), the friction loss is computed to be 72.8 feet of head. The static head for this system is about -60 feet, resulting in a total dynamic head of 12.8 feet.

The power plant configuration for this site is shown in figure 1-6. In this configuration the blow-down water is discharged to Brush Creek because there is no readily available mine in which to inject the water. In addition, the closest mine into which the water could be injected is the mine from which the water is being withdrawn. While such injection is possible, it was rejected because of the cost of the pipeline and the fact that the blow-down water would raise the temperature of the mine water source, which should remain as cold as possible.

1.2.2.3 Uniontown

Seven discharges occur at different elevations in the vicinity of this site, representing a total of 8,460 gpm flowing into Redstone Creek (figure 1-7). Wells are proposed at this site to collect the water and diminish the flow from the discharges. Because the average discharge is only slightly greater than the power plant water requirement it will be necessary to lower the water level in the mine under dry weather conditions.

This seasonal fluctuation in the mine pool has the potential to cause renued AMD formation in those parts of the mine that are exposed to oxygen infiltration as a result of the dewatering. Other proceses such as the exolving of dissolved carbon dioxide from the mine water may diminish the the oxygen concentration in the mine atmosphere. For the purposes of this analysis the pH and metal content of the mine water was not modified to account for any renued AMD formation.

The well locations selected focus on the lower four discharges that are closest to the proposed power plant, representing 6,760 gpm of the total discharge from this area, and an additional well in the vicinity of the up stream discharge yielding 1,700 gpm on a long term average. The four pumps are designed to deliver 2,700 gpm each, meeting the plant's water needs with only three pumps in operation. An additional pump is provided for system redundancy / maintenance. The mine pool water levels will have to be monitored in order to balace the water delivery from the various mine pools.

Four pipelines would extend from the wells to the AMD treatment plant. These pipelines would be 1,800, 1,980, 2,340, and 5,035 feet in length. The pipes are designed to be 16-inch outside diameter DR 11 HDPE pipe (ID 12.915 inches; friction losses 15.5, 17.1, 20.1, and 43.3 feet respectively in each of the four lines). The AMD treatment plant would be at about the same elevation as the wells so there is no change in head from this transfer. However, due to an anticipated drawdown in the mine of 20 feet the total dynamic heads are increased to 35.5, 37.1, 40.1 and 63.3 feet for the purpose of calculating pump operational costs.

AMD treatment is anticipated to be identical to the Irwin case with the potential for use of hydrogen peroxide instead of hydrated lime.

The pipeline from the AMD plant to the power plant would be 3,140 feet in length with an outside diameter of 22 inches. The static head would be 40 feet and the friction loss would be 25.1 feet resulting in a total dynamic head of 65.1 feet.

The power plant configuration for this site is shown in Figure 1-6. In this configuration, the cooling tower blow down water is discharged to Redstone Creek because there is no readily available mine for injection except for the source-water mine. As with the Irwin case, injection into the source mine was rejected.

1.2.2.4 Mine Site Treatment - Downstream Utilization

An alternate use of mine water in power plant cooling involves treatment of the mine water at or near the discharge location, discharging the treated water to surface stream and then building the power plant at a convenient site downstream of the treatment and withdrawing water from the river at that point. This approach could be applied to all of the preceeding examples including Flaggy Meadows, Irwin and Uniontown. In fact, this method of mine water utilization is currently employed at the Limerick power plant in Montgomery County, Pennsylvania.

The advantage of this approach is that the power plant siting requirements do not have to be met at the mine discharge location. This approach can also be applied to existing power plants that are facing water use restrictions on their current water supply. In this case the treatment of the mine water and the improved water quality in the stream would be used to offset any water use restruictions that may be applied to the power plant withdrawal. In order to obtain this resource management trade it may be necessary to treat more mine water than the power plant requires so that a net improvement can be documented.

There are also disadvantages to this approach. For example, all thermal advantage would be lost; EPA regulations on surface water withdrawals would be applicable; and, water treatment facilities, particularly the clarifiers would have to be built at both the AMD treatment site and the power plant site.

1.2.3 Determining Treatment Needs

1.2.3.1 Treatment Plant Design

For high volume discharges, hydrated-lime neutralization is the least expensive process for AMD treatment. In this process, raw water is pumped from the mine and initially pre-aerated to outgas as much dissolved carbon dioxide as practical, minimizing carbonic acid, and increasing pH. This step reduces the hydrated lime required in the process by avoiding its reaction with the carbon dioxide to form calcite. This process is shown in Figure 1-8.

Once the carbon dioxide has been outgassed, hydrated lime is added to raise the pH to about 9.0. The water is then aerated to drive the oxidation of ferrous to ferric iron and, at this pH, readily form ferric hydroxide. This step produces acidity and lowers pH in an amount that varies from site to site due to factors such as metals and alkalinity concentration in the raw water.

AMD treatment plant designs vary from compact highly controlled tank-based operations to large minimally-controlled pond/lake systems. Since the goal of a treatment plant in this context is to deliver cold water to the cooling towers, the smaller tank-based designs are preferred, offering less surface area and residence time for heat gain during summer months.

An alternative process can be applied for treating net-alkaline mine water. This uses hydrogen peroxide instead of mechanical aeration, reducing electrical and capital costs, the potential for scaling, and the volume of reject water from the reverse osmosis system due to lower dissolved solid levels. In addition, the small temperature rise associated with aeration could be eliminated. These cost savings and operational advantages would be offset by the higher cost of hydrogen peroxide compared to lime.

Raw water quality data from Dzombak *et al*. (2001) and Donovan *et al*. (2004, in review) for the three selected sites are presented in tabular form as Table 1-3. Although the Irwin discharge is classified as a borderline source with regard to net alkalinity, it can be seen from Table 1-3 that the chemistries of both Irwin and Uniontown are very similar, particularly with respect to iron and manganese. In addition, the field alkalinity values are also similar between the two sites. Therefore, the Irwin discharge was selected as representative of both water chemistries in the PHREEQC analysis.

Table 1-4 shows the results of the PHREEQC analysis estimating water chemistry resulting from hydrated lime treatment.

1.2.3.2 Hydrogen Peroxide

In net-alkaline mine drainages, hydrogen peroxide may have both cost and operational benefits over lime. In net-alkaline mine drainage, there is sufficient alkalinity to offset the acidity released when the iron, manganese and aluminum precipitate. Unfortunately, this reaction is slow if the pH is below 7. The addition of hydrated lime increases the pH of the water and also provides floc centers which aid in the settling of the precipitate. In contrast, iron precipitation in the presence of hydrogen peroxide is nearly instantaneous at a pH above 4. An additional benefit is that it does not increase total dissolved solids as is the case with hydrated lime. This can be of particular concern to power plant operators because high TDS levels can lead to mineral deposition on the condensers or in the cooling tower.

The use of hydrogen peroxide is more easily accomplished than mechanical aeration used in traditional hydrated lime plants. Since hydrogen peroxide is a liquid, it is only necessary to meter it into the flow of mine water and provide for some static mixing. In contrast, hydrated lime must be delivered by pneumatic trucks, is difficult to store in lime silos and feed due to bridging or "clumping", and is not readily soluble without constant agitation. Hydrogen peroxide use can eliminate the need for mechanical aerators, aeration basins, and lime silos reducing power needs.

1.2.3.3 Temperature Rise due to Treatment

Water treatment is known to affect the temperature of the mine water due to retention time in the plant. On warm days the temperature may rise, and on cold days it may fall. Treatment plant design can also affect the amount of temperature change experienced in the process. For example, treatment plants that are based upon large open-air ponds can experience greater temperature change due to their exposed surface area and retention time than would a plant design based on small tanks.

In order to minimize temperature rise in the summer, a small-area, short-retention-time plant is preferred. One such plant has been recently constructed to treat the water from the Shannopin Mine. Water temperature was measured at several locations throughout the process. In this treatment plant raw water is pumped from the mine at 2,700 gallons per minute. The water is first pre-aerated to drive off dissolved carbon dioxide gas; the aerated water is then mixed with hydrated lime slurry to raise the pH, and the mixture is then aerated for a second time to enhance iron oxidation. The aerated water is then sent to a clarifier to settle the iron hydroxide. The clarified water is pumped approximately two miles in a buried high-density polyethylene pipeline. The temperatures observed through out this process are shown in Table 1-5. A temperature rise of only 0.6 ^oC was observed.

It is clear from Table 1-5 that lime treatment can have only a very limited effect on the temperature of the mine water. A greater temperature effect was observed due to long distance pumping. Should hydrogen peroxide be utilized instead of mechanical aeration, temperature rise due to treatment should be reduced by at least 0.3 ^oC.

1.2.4 Environmental Factors and Permitting

1.2.4.1 316(b)

Considerable concern has been raised relative to the new regulations that have been promulgated recently by the US EPA. These regulations apply to both new and exisiting withdrawls of water from surface water sources for use in power plant cooling.

This differentiation between new and existing facilities may be found by comparing 40 CFR 122.21 (r), as contained in the currently applicable rule, that states that new facilities must comply with paragraphs (r)(2), (3), and (4) and section 125.86. However, Phase II existing facilities must submit the information required under sections (r)(2), (3), and (5) as well as section 125.95.

Based on the definitions contained in these regulations, the proposed 600-MW cooling tower plant is a new facility that has a point source; it has a cooling water intake structure and withdraws more than 25 percent of its water use for cooling purposes; and it has a design flow greater than ten million gallons per day, but less than 50 million gallons per day. The proposed 600-MW earth-coupled plant is also a new facility but it will use greater than 10 million gallons per day. Regulation for this facility will be discussed later in this report.

The requirements of 40 CFR 122.21 (r) (2) and (3) are the same for both new and existing facilities and are not viewed as generating any significant cost differences for surface water based intakes as opposed to mine water based intakes. Hence no financial analysis will be performed relative to these two regulations.

As a new facility, the proposed power plant must comply with 40 CFR 122.21(r)(4) which requires a baseline biological characterization. This characterization can be both expensive and time consuming for a surface-water source, and must be performed if the permit is ultimately issued or not issued. While this requirement also applies to intake structures for mine derived water, the number of species normally found in mine water renders the regulation moot. This being the case, the cost of compliance with this regulation will be relatively small compared with an equivalent permit application for a surface water body.

New facilities must also comply with the provisions of 40 CFR 125.86. This regulation separates applicants into Track 1 and Track 2. Tracks 1 and 2 are only available for withdrawals of 50 million gallons per day or less. Track 1 is further broken down into withdrawals of 2 to 10 million gallons per day and withdrawals greater than 10 million gallons per day. Nevertheless, the requirements of 125.86 (b)(1), (2), (3), and (4) must be meet. These regulations may be found in the Appendix.

The provisions of 40 CFR 125.86 may be problematical with regard to power plant cooling based on mine water. For example, provision (b)(1) of this section requires the applicant to “demonstrate that you have reduced your flow to a level commensurate with that which can be attained by a closed-cycle recirculation cooling water system.” However, in the earth-coupled case the goal is to eliminate the need for a cooling tower which may be viewed as incompatible with this provision.

Provision (b)(2) of this section requires the applicant to demonstrate that the intake velocity has been designed to be less than 0.5 feet per second. Such an inlet velocity is completely inappropriate for any mine water withdrawal. Inlet velocities to mine pumps can be 20 or more times the 0.5 feet per second standard.

Provision (b)(3) of this section references 40 CFR 125.84 (b)(3) and (c)(2), and then goes on to require descriptions of the water body from which the cooling water will be withdrawn. These descriptions refer to (i) freshwater rivers and streams, (ii) estuaries or tidal rivers, and (iii) lakes or reservoirs. A mine water source for power plant cooling water does not fit into any of these categories. However, if the 40 CFR 125.84 (b)(3) and (c)(2) apply to cooling water withdrawals of greater than 10 MGD and between 2 and 10 MGD respectively. In either case the requirements are identical.

Sub-paragraph (i) requires that any withdrawal from a fresh water river be less than five percent of the source water annual mean flow. This sub-paragraph is not applicable to mine water withdrawals for two reasons: one, the mine is not a river, and two, the amount of water withdrawn from the mine may exceed, in some years, the total annual mean flow.

Sub-paragraph (ii) prohibits the disruption of the thermal stratification in lakes and reservoirs. Again, a mine water source is not a lake or reservoir and hence this section would appear to be inapplicable. However, if a mine water source were deemed to be equivalent to a lake or reservoir then any thermal discharge to the mine would change the thermal characteristics of the mine pool. Whether this constitutes a violation under this provision is not clear. But it is clear that applying this provision to mine water would be very tortured and inappropriate.

Sub-paragraph (iii) requires that any thermal discharge to an estuary or tidal pool be limited to one percent of the volume of water defined in the sub-paragraph. Based on the reference to estuaries and tidal pools this sub-paragraph is also inappropriate to mine water utilization. Consequently, permitting a mine pool for power plant cooling under this sub-paragraph is also inappropriate.

Clearly, utilization of water from mines for makeup cooling water, or the utilization of flooded mines a heat sink is not anticipated by the current regulations.

The earth-coupled option that is being evaluated in this study would not qualify for any of the Track I options provided in 40CFR125.84(b) or (c) because the required water withdrawal for cooling would in all cases exceed the 10 MGD ceiling established in the regulations. However, the earth-coupled option could benefit from the Track II provisions contain in 40CFR125.84(d) printed above. This provision allows the applicant to demonstrate to the director that the proposed withdrawal will use technologies that will provide equivalent protection to the provisions contained under Track I. Because the earth-coupled design does not incorporate any withdrawal from surface water, this demonstration can be made easily.

Having overcome the withdrawal limitation of 10 MGD through the implementation of the Track II requirements, the earth-coupled option is still burdened with the provisions of (d)(2) which places limits on the intake structures in fresh water rivers and streams, lakes and reservoirs, and estuaries or tidal rivers. None of these scenarios is applicable to the earth-coupled case. Therefore, it is unknown how the regulatory authority may react in this circumstance.

Even if the 600-MW cooling tower power plant, that is the subject of this study, were to be an existing facility it would still not be subject to the new existing facility regulations because the water withdrawal of 8,170 gallons per minute is only equivalent to 11.76 million gallons per day. The new regulation only affects facilities that withdraw in excess of 50 million gallons per day.

1.2.4.2 National Pollution Discharge Elimination System (NPDES)

The NPDES program under the Clean Water Act regulates point source discharges to receiving streams so that established water quality standards are not exceeded. The location of power plants on large rivers accomplishes two functions. Not only is water available for power plant cooling, but the large volumes of water in the river can provide dilution for the dissolved constituents in the plant discharge that are not removed by conventional treatment. Pennsylvania has established an osmotic pressure standard which must be met by NPDES dischargers within the Commonwealth. For discharges that are high in total dissolved solids this has meant that the discharge must be located near a large stream or river, or that the discharge must be curtailed during low flow periods (treated AMD discharge from the Clyde mine).

This regulation has implications for the use of mine water for power plant cooling. Because it is necessary to locate the power plant near the mine water source the selected site is likely to be near a stream rather than a river. With less water available for dilution the potential for exceeding the osmotic pressure limits is increased. In order to comply with this regulation it may be necessary to adopt higher levels of water treatment, higher levels of water reuse, alternate discharge methods, or discharge elimination. Compliance with this requirement has not been monitarized in this study.

The NPDES program has been applied to the mining industry since its inception. Over the years compliance with these regulations has been required of a mine operator even if he is not the person originally responsible for the pollution. This is known in the industry as the “touch it and it’s yours” aspect of the law. The application of this requirement can impart perpetual liability for a discharge to the new operator. This aspect of the law is a serious impediment to power plant investors and lending institutions. Several options exist for dealing with this problem.

Option 1) the power plant owner could assume perpetual liability, and set aside money during the operation of the power plant to pay for any perpetual care obligations.

Option 2) if there is a responsible party already treating the water, then the power plant operator could contract with that responsible party for water delivery. While feasible this option takes control of the plants cooling water out of the hand of the plant operator.

Option 3) a separate entity could be established (including non profit 501(c)(3) entities) for the purpose of treating the water from the mine, the sale of which is contracted to the power plant.

Option 4) the Clean Water Act could be modified to allow for the use of mine water for other purposes without incurring the obligation of perpetual liability.

Although option 3 is less satisfactory in that the power plant operator does not have control over the plants cooling water it is the option currently being considered by power plant developers.

1.2.4.3 Underground Injection Control

One alternate discharge method would be to inject the plant's treated waste water into an underground mine. This method avoids the NPDES requirements but is instead regulated under the UIC provisions of the Safe Drinking Water Act. Injection of high TDS and high TSS water into mines has been approved by state regulatory authorities for the disposal of AMD treatment sludge in the mines. This is true for the mine from which the water is being pumped for treatment. Approval has also been granted for disposal into adjacent mines although in this case a demonstration may have to be made that the injection will not result in a new surface discharge or the degradation of an existing surface discharge.

The cost of injecting power plant waste water into a mine is included in the design of the Flaggy Meadows site.

1.2.4.4 Water Rights

A significant potential impediment to the use of mine water for power plant cooling is the establishment of a right to the water. Water law in the eastern United States does not establish an absolute ownership of the right to withdraw water as is the case in the western United States. Instead, eastern water law is based on a modification of English common law which allows a property owner to withdraw water for a beneficial use without regard to the effect of the withdrawal on other users.

This approach to water rights means that if a power plant were to use mine water, another user could pump water from the same mine for their own purposes to the extent that there could be insufficient water for the power plant. Although this scenario is currently unlikely, as available water resources become increasingly scarce the potential for conflicting water withdrawals will increase. Because mine water resources could be over subscribed, investors and lending institutions are not likely to invest in power plants based on mine water cooling unless assurances are provided by government. There is currently no established mechanism for assuring that over subscription will not occur.

1.2.4.5 Effect of mine water withdrawal on AMD production

Many of the mines that are suitable as water sources for power plant cooling have water quality that has improved dramatically since the mine was initially flooded. There is increasing evidence that AMD formation in these mines has ceased and that eventually these mines may improve to discharge quality without the need for treatment. A potential impediment to the use of mine water for power plant cooling would be the possibility that mine water utilization might cause the acid forming reaction to begin anew.

AMD forms when water, oxygen and the mineral pyrite (FeS_2) react to form sulfuric acid and iron in solution. Flooding is known to stop the pyrite oxidation process, so it is not unusual to find improving water quality from mines that are fully flooded. However, improving water quality has also been found in mines that are not fully flooded. This suggests that another mechanism is at work. It is believed that oxygen may be depleted in these partially flooded mines thus stopping the acid forming reaction. The concern that water withdrawal from the mines might reactivate AMD formation centers on the potential for reintroduction of oxygen into the unflooded portions of these mines, and for the creation of additional unflooded area due to the lowering of the water level in the mine.

Only anecdotal evidence is available to address this concern. It is known that pumping from the Clyde mine must stop for at least several months each year to protect the receiving stream from excessive levels of osmotic pressure. During this period the mine is allowed to fill with water. During the remainder of the year the water level is pumped down in preparation for the next period of non-pumping. To date the water quality at Clyde continues to improve. Similarly, Montour #4 is pumped at 3,500 gpm for eleven months out of the year. However, this is not enough pumping to maintain a stable water level so the water level rises during those eleven months. During the twelfth month a second 3,500 gpm pump is operated bringing the total pumping rate to 7,000 gpm. This extra pumping reduces the water level in the mine so that single pump operation can resume. Despite this annual fluctuation in the mine pool the raw water quality of the Montour #4 discharge has continued to improve from a high value of over 1,000 mg/L Fe to current values that range from 25 to 35 mg/L.

Despite these encouraging examples it is still possible that lowering of the mine pool might induce AMD formation. Consequently, the siting and design of the mine water systems in this study focused on those locations where mine water was available in excess so that the mine pool would not have to be lowered. This is particularly true of the Irwin site and the Flaggy Meadows site. On average, mine water is available in excess at the Uniontown site, however, this may not be true during extended dry periods. During these periods the mine pool may have to be lowered in order to support the design withdrawal. Should this occur it would create a situation similar to the Montour #4 example cited above.

1.2.4.6 Mine Subsidence

Some mine subsidence events have been observed to be coincident in time with the initial flooding of a portion of the mine. Flooding is not believed, in and of itself, to cause subsidence. But it may play a role in hastening the collapse in the mine roof. Concern has been expressed that fluctuations in the level of mine water due to pumping for power plant use may result in increased incidence of mine subsidence. Here again only anecdotal evidence is available. As stated previously, both the Montour #4 and Clyde mines have seasonal variations in mine pool level without any reported additional mine subsidence.

1.2.5 Economic Analysis

1.2.5.1 Base Case: Cooling Tower System Using River Water as Source

The base case assumes that sufficient water is available for a surface water source, such as the Monongahela River. It is also assumed that both river-source and mine water-source sites have equal access to the power grid, although clearly some sites (e.g., the Uniontown location) may have higher costs than others to construct a transmission line. This cost will be considered after the initial data are compared.

For the river-source base case (Figure 1-8), approximately 8,170 gpm will be required as makeup water for the cooling towers, the FGD scrubber and service water for the deionization (DI) and ash sluice systems. A worst-case supply temperature of 90°F was used for the river source. The intake structure was specified as a series of traveling screens and spray systems to gently wash fish into a recovery trough and to screen/remove particulate debris.

Following the intake structure, the water supply is split into two separate systems, service water and makeup water. The service water system is supplied by two 650 gpm variable-speed pumps, one operating and one for standby. Of the 610 gpm, approximately 360 gpm is used for the deionized (DI) water system and approximately 250 gpm is used for the ash sluice system.

The DI system will be made up of a lamella clarifier, clearwell, filters, prefilters, reverse osmosis (RO) membranes, polishers, and a 250,000 gallon DI storage tank. The RO-reject waste stream (110 gpm) will be directed to either the settling ponds or to the zero discharge facility.

Approximately 7,060 gpm will be used for cooling tower makeup water and 500 gpm will be used by the FGD scrubber. These water needs will be supplied by three 3,800 gpm pumps. This will allow two pumps to handle the full load when maintenance is required on the third pump. This system will flow through a lamella clarifier and be stored in two 500,000 gallon storage tanks prior to entering the cooling towers.

The heat rejection system of the steam cycle consists of a surface condenser with two shells, a circulating water system, and cooling towers. The surface condenser receives exhaust steam from the low-pressure section of the steam turbine generator and condenses it to liquid for return to the heat recovery steam generator. The heat rejected from the steam will be absorbed by approximately 310,400 gpm of circulating water that exits the condenser approximately 15 ^{o}F warmer than when it entered.

The circulating water system will supply approximately 320,400 gpm to the surface condenser and other miscellaneous heat exchangers used for equipment cooling. The circulating water system will be supplied by three 165,000 gpm variable speed pumps. This will allow two pumps two handle the full load when maintenance is required on the third pump.

The warm circulating water from the surface condenser and other miscellaneous heat exchangers used in the plant will be directed to two mechanical draft cooling towers. The warm circulating water will be distributed among multiple cells of the plant cooling towers, cascading from the top, through the towers, where it contacts a high airflow drawn through the tower by fans. Cooling occurs primarily through partial evaporation of the falling water and contact cooling of the water by the cooler air. The cooled water will collect in a large collecting basin beneath the tower.

Circulating water will be lost in the process by evaporation, drift, and blowdown. Evaporation from the cooling tower will constitute the main water loss (approximately 4,800 gpm). As water evaporates in the cooling tower, the total dissolved solids increase and, at excessive levels, could precipitate on the cooling-tower heat-transfer surfaces. The resulting scale on these surfaces would reduce heat transfer and degrade the performance of the cooling tower. To counteract these effects, approximately 2,260 gpm of the basin water must be continuously removed and processed as cooling tower blowdown to the wastewater settling ponds.

The final stage in the water system will be the settling ponds. The discharge water from the ash sluice system and the cooling tower blowdown will collect in the wastewater settling ponds prior to being discharged back into the river. Approximately 3,120 gpm will return to the river at approximately 105 ^{o}F.

The capital cost of this alternative is $55,277,400, and the operating cost is estimated to be $5,451,660. A breakdown of this cost is shown in Tables 1-6.

1.2.5.2 Mine Water Case A: Cooling Tower System Using the Irwin Mine Water Source and Discharging to a Stream

The makeup water for this hypothetical power plant cooling system will be drawn from a mine water source at the Irwin site, located west of Irwin, Pennsylvania. Water discharging from this mine represents the largest single discharge in the study area. The flow is in excess of 11,000 gallons per minute, far in excess of the 8,170 gpm required for the cooling towers, the FGD scrubber, and the service water for the DI and ash sluice systems. Because of this excess, it is not necessary to use the mine pool as a reservoir. Mine water is currently being discharged through two buried pipes. The design proposes that a pre-aeration tank be installed in the ground to intercept the pipelines. Hydrated lime will then be added to the mine water before it flows to the aeration basin. Once aerated, the treated water will flow to the clarifier where the metal hydroxide flocs can settle. Three pumps, accounted for in the power plant cost analysis, transfer the treated mine water to the cooling tower sump. Table 1-7 shows the estimated capital and operating costs of this operation. Because mine pumps are not needed at this location, the cost is reduced by over $1,184,000 when compared to the Uniontown site.

A worst-case mine-water supply temperature of 65 ^{o}C was used. The mine water will be directed to an AMD treatment system for pretreatment of the power plant service water. The total cost of the AMD treatment plant is estimated to be $4,318,000. The operating cost is $575,000 per year. Amortized over twenty years, this results in a cost for treated water of $0.186 per 1000 gallons or $0.00015 per kWh.

Following the AMD treatment plant, the water supply will be split into two separate systems, service water and makeup water. The service water system will be supplied by two 650 gpm variable speed pumps, one operating and one for standby. Of the 610 gpm, approximately 360 gpm will be used for the deionized (DI) water system and approximately 250 gpm will be used for the ash sluice system.

The DI system will be made up of filters, prefilters, reverse osmosis (RO) membranes, polishers, and a 250,000 gallon DI storage tank. The RO reject waste stream (110 gpm) will be directed to the settling ponds (or zero discharge facility).

Approximately 7,060 gpm will be used for cooling tower makeup water. The makeup water system will be supplied by three 3,800 gpm pumps. This will allow two pumps two handle the full load when maintenance is required on the third pump. The makeup system water will be stored in two 500,000 gallon storage tanks prior to entering the cooling towers.

The heat rejection system of the steam cycle consists of a surface condenser with two shells, a circulating water system, and cooling towers. The surface condenser receives exhaust steam from the low pressure section of the steam turbine generator and condenses it to liquid for return to the heat recovery steam generator. The heat rejected from the steam will be absorbed by approximately 300,000 gpm of circulating water that exits the condenser approximately 15.5 degrees Fahrenheit warmer than when it entered. This increase in temperature differential is due to the effect of the cool mine water as compared to the warm river water.

The circulating water system will supply approximately 305,000 gpm to the surface condenser and other miscellaneous heat exchangers used for equipment cooling. The circulating water system will be supplied by three 155,000 gpm variable speed pumps. This will allow two pumps two handle the full load when maintenance is required on the third pump.

The warm circulating water from the surface condenser and other miscellaneous heat exchangers used in the plant will be directed to a plant mechanical draft cooling towers. The warm circulating water will be distributed among multiple cells of the plant cooling towers, cascading from the top, through the towers, where it contacts a high airflow drawn through the tower by fans. Cooling occurs primarily through partial evaporation of the falling water and contact cooling of the water by the cooler air. The cooled water will collect in a large collecting basin beneath the tower.

Circulating water will be lost in the process by evaporation, drift, and blowdown. Evaporation from the cooling tower will constitute the main loss of water for the project and will be approximately 4,800 gpm. As water evaporates in the cooling tower, the total dissolved solids will increase. At excessive levels, these solids could precipitate on the cooling tower heat transfer surfaces. The resulting scale on these surfaces would increase the resistance to the transfer of heat and degrade the performance of the cooling tower. To counteract these effects, approximately 2,260 gpm of the basin water must be continuously removed and processed as cooling tower blowdown to the wastewater settling ponds.

The final stage in the water system will be the settling ponds. The discharge water from the ash sluice system and the cooling tower blowdown will collect in the wastewater settling ponds prior to being discharged to the river. Approximately 3,120 gpm will return to a surface source at approximately 95 degrees Fahrenheit.

The capital and operating cost of the Irwin water collection system may be found in Table 1-8. The combined capital cost of the AMD treatment plant and the cooling side of the power plant at the Irwin site is $54,241,300 which is 98.1 percent of the base case capital cost of $55,277,400. Operating costs at the power plant are reduced from the base case by $562,260 due to savings in plant operations. However this is entirely offset by treatment cost at the Irwin site of $574,940.

Hydrogen peroxide use is feasible at the Irwin and Uniontown sites. Based on 8,100 gallons per minute of net alkaline water containing 70 mg/L dissolved iron, it is calculated that 225 gallons per day of 30 percent hydrogen peroxide would be required. A 30 to 35 percent technical grade product is available for about $1.41 per gallon, this yields and annual cost of $115,875. This is compared the annual lime cost calculated by AMD Treat of $225,442. Elimination of the lime silo, one 30 hp aerator and the aeration basin would reduce the capital cost of the AMD plant by $229,000. In addition, the plant would save $11,770 per year on the cost of electricity based on $0.06 per kilowatt hour. Combining the chemical and electrical savings, the operation and maintanence cost of the AMD treatment plant can be reduced by $121,337.

1.2.5.3 Mine Water Case B: Cooling Tower System Using the Flaggy Meadows Mine Water Source with Discharge Injected into a Mine

This cooling system will be drawn from a mine water source at the Flaggy Meadows site, West Virginia. Approximately 8,135 gpm will be required as makeup water for the cooling towers, DI, and ash sluice systems. The existing treatment plant on this site has a capacity of 6,000 gpm. Its construction costs are historic and believed to be about $5,000,000. An expansion of this plant would be required to meet the design requirements. A 2,500 gpm expansion is estimated to cost $885,000 primarily for an additional clarifier, and $888,000 for additional pump capacity

Additional capital for the pumping and pipeline installation to the power plant would be $1,196,360, plus an additional $27,000 for a blowdown injection well and piping. Including a 20 percent contingency this brings the total capital cost for AMD treatment to $10,528,900. Amortized over 20 years using a 8,100 gpm plant load, the capital cost of the facility is estimated at $0.12 per 1,000 gallons. Operating costs are estimated at about $0.29 per 1,000 gallons, leading to a total cost of about $0.41 per 1,000 gallonsor $0.00033 per kWh.

A worst-case supply temperature of 65 degrees Fahrenheit was used for the mine water.

Following AMD treatment, the water supply will be split into two separate systems, service water and makeup water. The service water system will be supplied by two 650 gpm variable speed pumps, one operating and one for standby. Of the 610 gpm, approximately 360 gpm will be used for the DI water system and approximately 250 gpm will be used for the ash sluice system.

The DI system will be made up of filters, prefilters, RO membranes, polishers, and a 250,000 gallon DI storage tank. The RO reject waste stream (110 gpm) will be directed to the settling ponds (or zero discharge facility).

Approximately 7,025 gpm will be used for cooling tower makeup water. The makeup water system will be supplied by three 3,800 gpm pumps. This will allow two pumps two handle the full load when maintenance is required on the third pump. The makeup system water will be stored in two 300,000 gallon storage tanks prior to entering the cooling towers.

The heat rejection system of the steam cycle consists of a surface condenser with two shells, a circulating water system, and cooling towers. The surface condenser receives exhaust steam from the low pressure section of the steam turbine generator and condenses it to liquid for return to the heat recovery steam generator. The heat rejected from the steam will be absorbed by approximately 300,000 gpm of circulating water that exits the condenser approximately 15.5 degrees Fahrenheit warmer than when it entered.

The circulating water system will supply approximately 305,000 gpm to the surface condenser and other miscellaneous heat exchangers used for equipment cooling. The circulating water system will be supplied by three 155,000 gpm variable speed pumps. This will allow two pumps two handle the full load when maintenance is required on the third pump.

The warm circulating water from the surface condenser and other miscellaneous heat exchangers used in the plant will be directed to a plant mechanical draft cooling towers. The warm circulating water will be distributed among multiple cells of the plant cooling towers, cascading from the top, through the towers, where it contacts a high airflow drawn through the tower by fans. Cooling occurs primarily through partial evaporation of the falling water and contact cooling of the water by the cooler air. The cooled water will collect in a large collecting basin beneath the tower.

Circulating water will be lost in the process by evaporation and drift, and blowdown. Evaporation from the cooling tower will constitute the main loss of water for the project and will be approximately 4,765 gpm. As water evaporates in the cooling tower, the total dissolved solids increase. At excessive levels, these solids could precipitate on the cooling tower heat transfer surfaces. The resulting scale on these surfaces would increase the resistance to the transfer of heat and degrade the performance of the cooling tower. To counteract these effects, approximately 2,260 gpm of the recirculating cooling water must be continuously removed (prior to the cooling towers) and processed as cooling tower blowdown to the wastewater settling ponds.

The final stage in the water system will be the settling ponds. The discharge water from the ash sluice system and the cooling tower blowdown will collect in the wastewater settling ponds prior to being discharged back into the mine.

Approximately 3,120 gpm will return to a mine water source at approximately 95 degrees Fahrenheit.

Table 1-9 shows the estimated capital and operating costs for the power plant at the Flaggy Meadows site. The capital cost is estimated to be $49,751,940 and the annual operating cost is estimated to be $4,875,000. Combining these estimates with the estimates for water acquisition the total capital cost is $60,281,000. The total operating cost is estimated to be $6,111,000. This represents 109 percent of the base case capital cost and 112 percent of the combined estimated operating cost. The reason for this variation from the other sites studied is the higher elevation of the Flaggy Meadows site, the poorer quality of its water, and the over-design of the Flaggy Meadows plant (High density sludge) compared to the other treatment facilties (standard design).

1.2.5.4 Mine Water Case C: Cooling Tower System Using the Uniontown Mine Water Source and Discharging to a Stream

Economically, the Uniontown case is very similar to the Irwin case. Both use the same AMD and power plant configuration. The principal difference in these two sites is the cost of acquiring the water. Table 1-10 shows the cost of water acquisition and treatment at the Uniontown site. The cost at Uniontown is increased by the need to drill pump boreholes and install vertical turbine mine pumps. However, this is more than offset by the reduction in the cost of the pipeline. Capital cost for this design is estimated to be $ 5,898,670 which if amortized over 20 years is equal to $ 0.069 per 1,000 gallons. The annual operating cost of $ 433,421 is equal to $ 0.153 per 1,000 gallons. Combined the water acquisition cost is estimated to be $ 0.221 per 1,000 gallons or $0.0018 per kWh.

The combined capital cost of the AMD treatment plant and the cooling side of the power plant at the Uniontown site is $55,822,000 which is 101 percent of the base case capital cost of $55,277,400. Operating costs at the power plant are reduced from the base case by $562,260 due to savings in plant operations. However, this is more than offset by treatment cost at the Uniontown site of $649,938 resulting in an operating cost that is 101.6 percent of the base case.

The Uniontown site is not located close to the distribution grid. The cost of this interconnection has been excluded until this point so that the effects of using mine water could be evaluated independently. The nearest transmission line is 5,500 meters (3.45 miles) to the west. Based on recent construction costs it is estimated that connecting the Uniontown site to the grid would cost an additional $4,140,000.

1.2.5.5 Mine Site Treatment - Downstream Utilization

In the prior analysis only the water needed for the power plant was treated. This approach may also be possible where mine site treatment and downsatream utilization are employed. However, this would alow some untreated water to discharge to the streams when the mine flow is greater than the power plant water requirement. It is more reasonable to assume that all of the mine water must be treated so that the water quality of the receiving stream could improve. This requires that the treatment plant be designed on the basis of the maximum anticipated mine discharge. At Irwin the maximum observed flow from all discharges is 25,066 gallons per minute in late January of 1999. It is usually impractical to design for these flow conditions when the average flow is 8,400 gpm. Mine pool managers solve this problem by maintaining void space in the mine to accommodate these high inflow events and treating the water during dry weather conditions. For the purpose of this analysis the AMD plant will be designed at 125 percent of average flow, and the plant will be supplied by mine pumps to keep the water level low enough to accommodate high inflow events. The existing pumping design is adequate to meet these requirements but the AMD plant itself would have to be enlarged from 8,500 gpm capacity to 10,500 gpm. This will result in a total capital cost of $5,259,500 and an annual operating cost of $702,840.

The downstream power plant would follow the base case design because there would not be any thermal advantage in sizing the plant equipment. The capital cost for the base case facility is estimated to be $55,277,400 with an operating cost of $5,451,660. Combined the capital cost of the AMD treatment with the capital cost of the power plant the Mine Site Treatment / Downstream Utilization configuration is 109.5 percent of the base case and the operating cost is 112.9 percent of the base case at this site. Similar to higher costs are anticipated for the Irwin site due to a similar water chemistry but higher flow volume. Costs for Flaggy Meadows were not evaluated.

1.3 Conclusions

Significant findings of this study include:

- Eight sites were identified in the Pittsburgh Coal Basin where conditions may be suitable for application of this technology,
- Current laws and regulations do not contemplate the use of mine water for power plant cooling,
- The use of mine water for power plant cooling is economically viable for net alkaline mine water,
- The use of hydrogen peroxide has the potential to reduce capital and operating costs in AMD treatment,
- Water collection systems can be designed to avoid the potential for new AMD generation for sites with excess available flow,
- Non-monetary factors may influence the use of mine water for power plant cooling.

Water from underground mines is available in sufficient quantity at a number of locations through out the Pittsburgh Coal Basin. Water quality is often net alkaline and is believed to be improving over time. A number of mines are currently flooding and are expected to increase the water availability from mines in the future. Four sites have been identified where sufficient mine water is available for power plant cooling.

The current regulatory framework is geared toward the protection of surface water from excessive thermal loads, and the protection of the aquatic habitat from entrainment in the power plant water intakes. The use of mine water for power plant cooling avoids many of these regulations which may encourage development based on mine water cooling. However, uncertainties remain with regard to long term liability for the mine water discharge, and appropriation of the mine water for the power plant's use.

The use of water from underground mines as makeup cooling water is economically on a par with existing river water sources in the Pittsburgh Coal Basin. Savings derived in the power plant design are offset by the increased cost of mine water acquisition and treatment. Acidic mine water is more costly to treat as evidenced by the Flaggy Meadows site. Operating costs at these sites are expected to be higher than river water sourced power plants.

Although anecdotal information suggests that mine pumping does not induce AMD formation or mine subsidence, additional research into these areas is indicated before a design that relies on mine dewatering can be fully assessed.

Until this issue is fully resolved, water collection systems should be designed to avoid the potential for new AMD generation by selecting those sites where mine dewatering in not required.

Because the cost of using mine water is similar to the cost of a more traditional power plant design, non-monetary factors and factors that have not been monetized in this study may influence decision making on the use of mine water for power plant cooling. These factors include the reduction or elimination of the environmental studies that are required under the 316 (a)(b) regulations; environmental improvement to miles of presently contaminated streams; and the consumptive use of an environmentaly damaged resource as opposed to a comparatively clean environmentally resource; and governmental incentives that promote the long term utilization of mine water.

1.4 References

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1.5 Figures and Tables

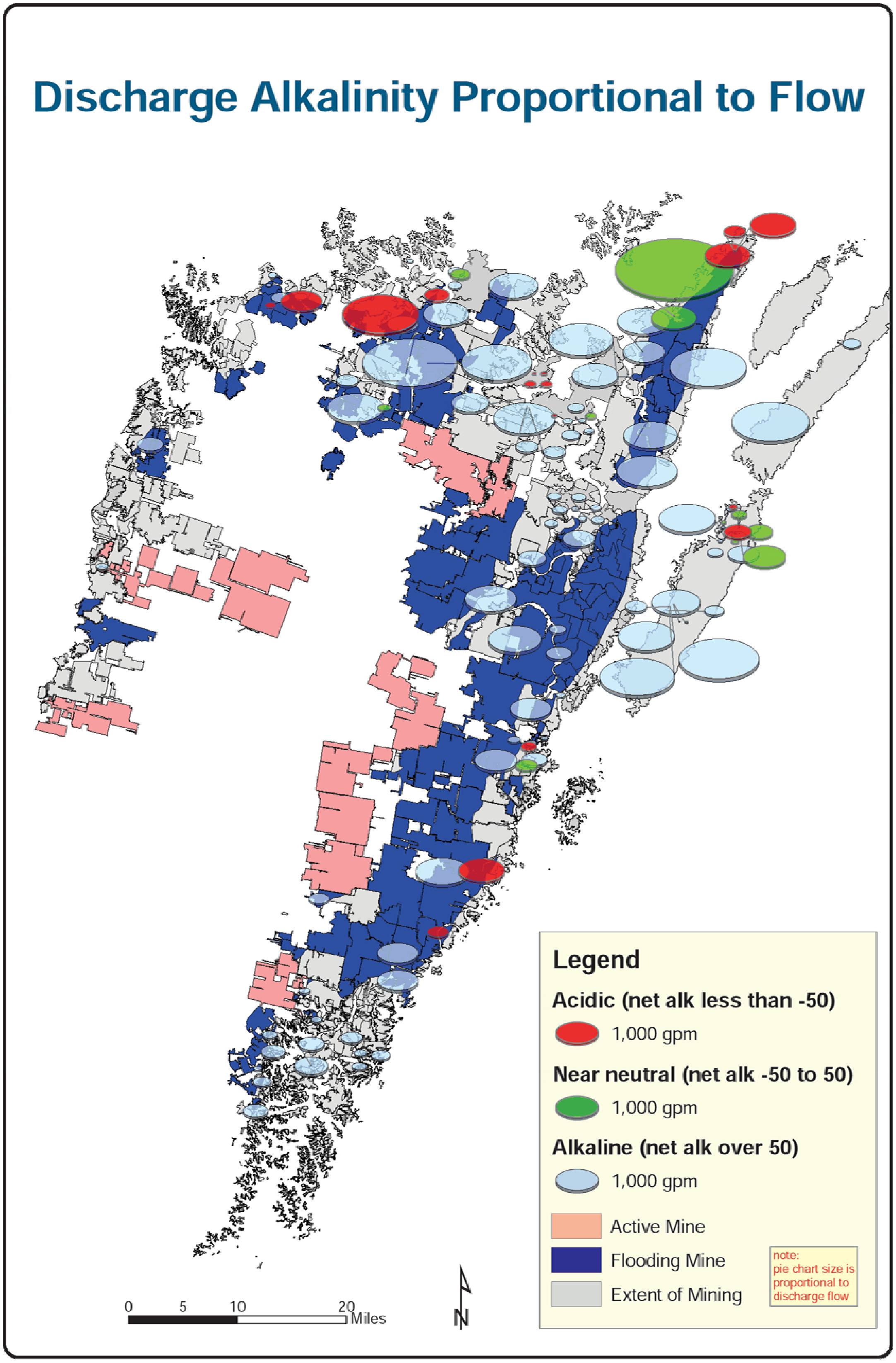

Figure 1-1. Location and alkalinity of mine discharges with known chemical character.

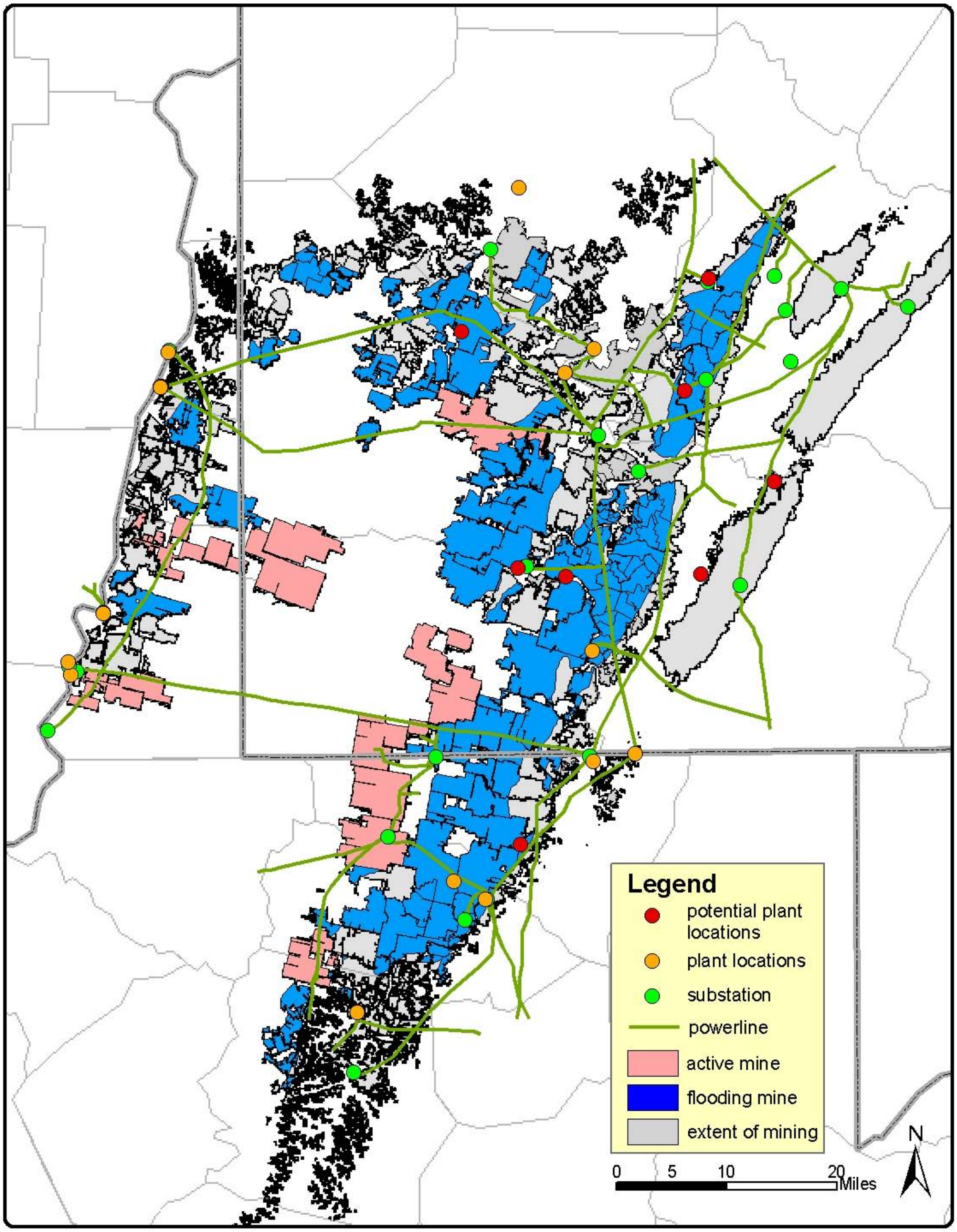

Figure 1-2. Overview map of Pittsburgh Coal Basin showing mining status, electric power system, and potential plant locations.

Flaggy Meadows Site

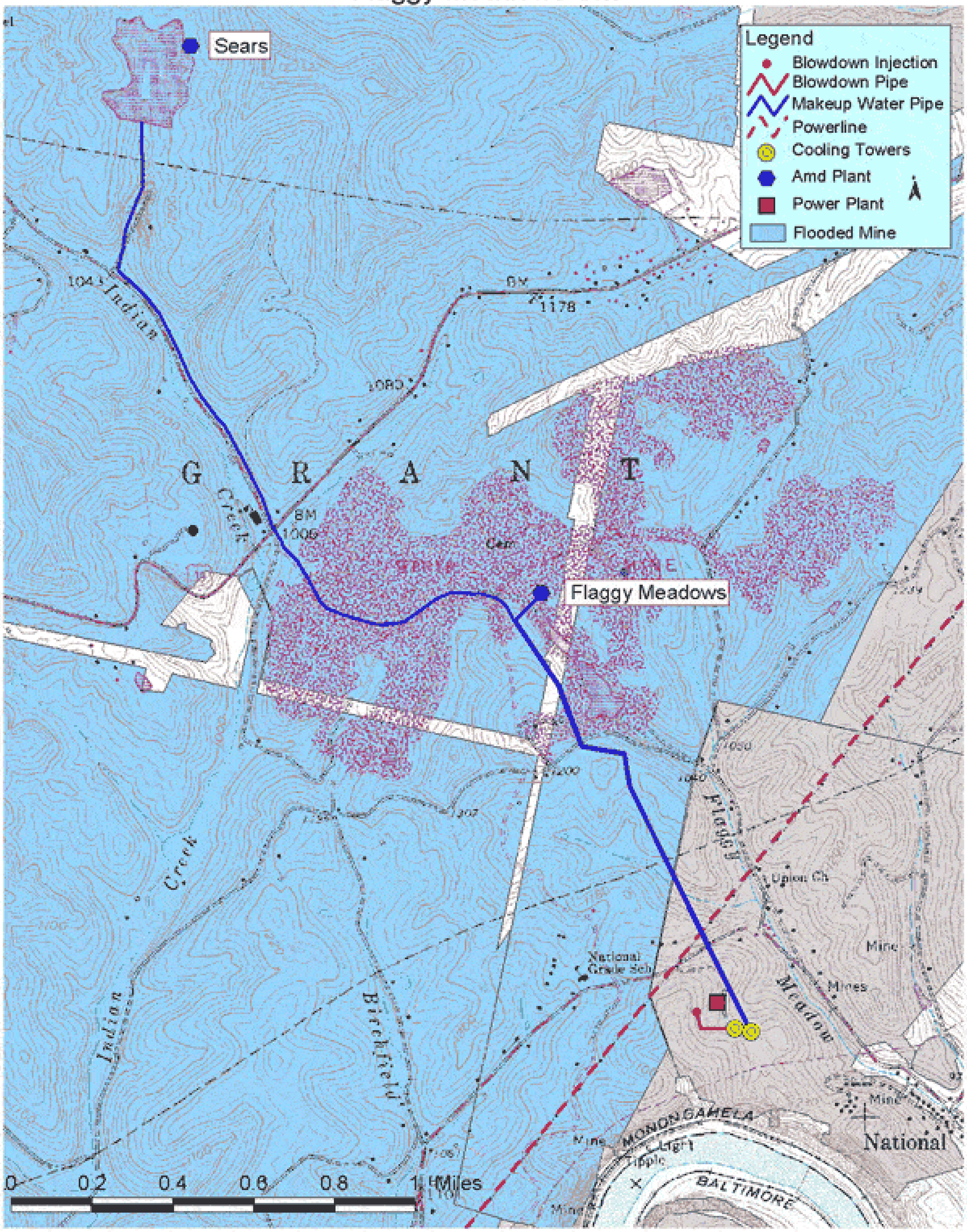

Figure 1-3. Location map for the Flaggy Meadows case.

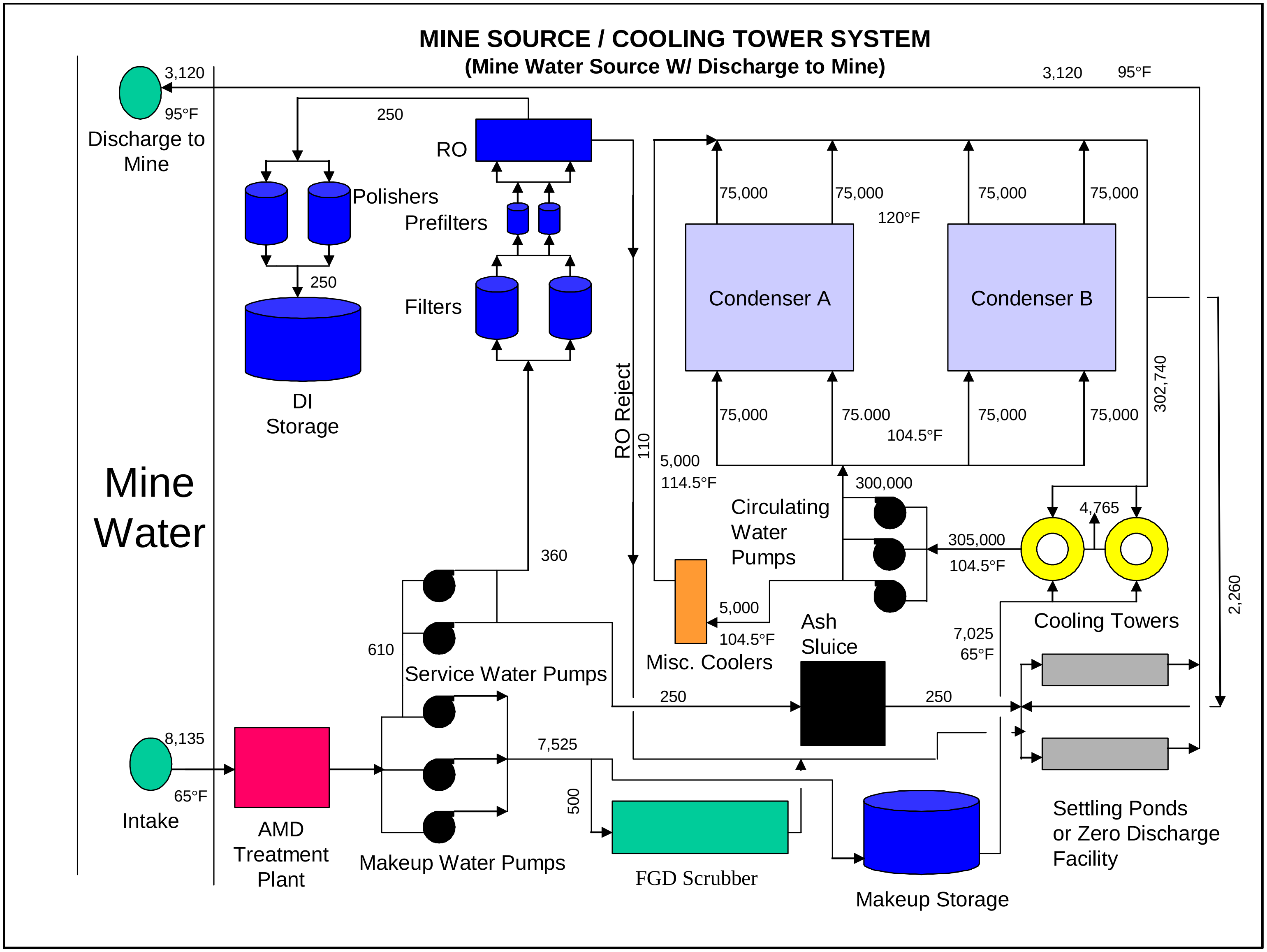

Figure 1-4. Power plant cooling circuit diagram for the Flaggy Meadows case.

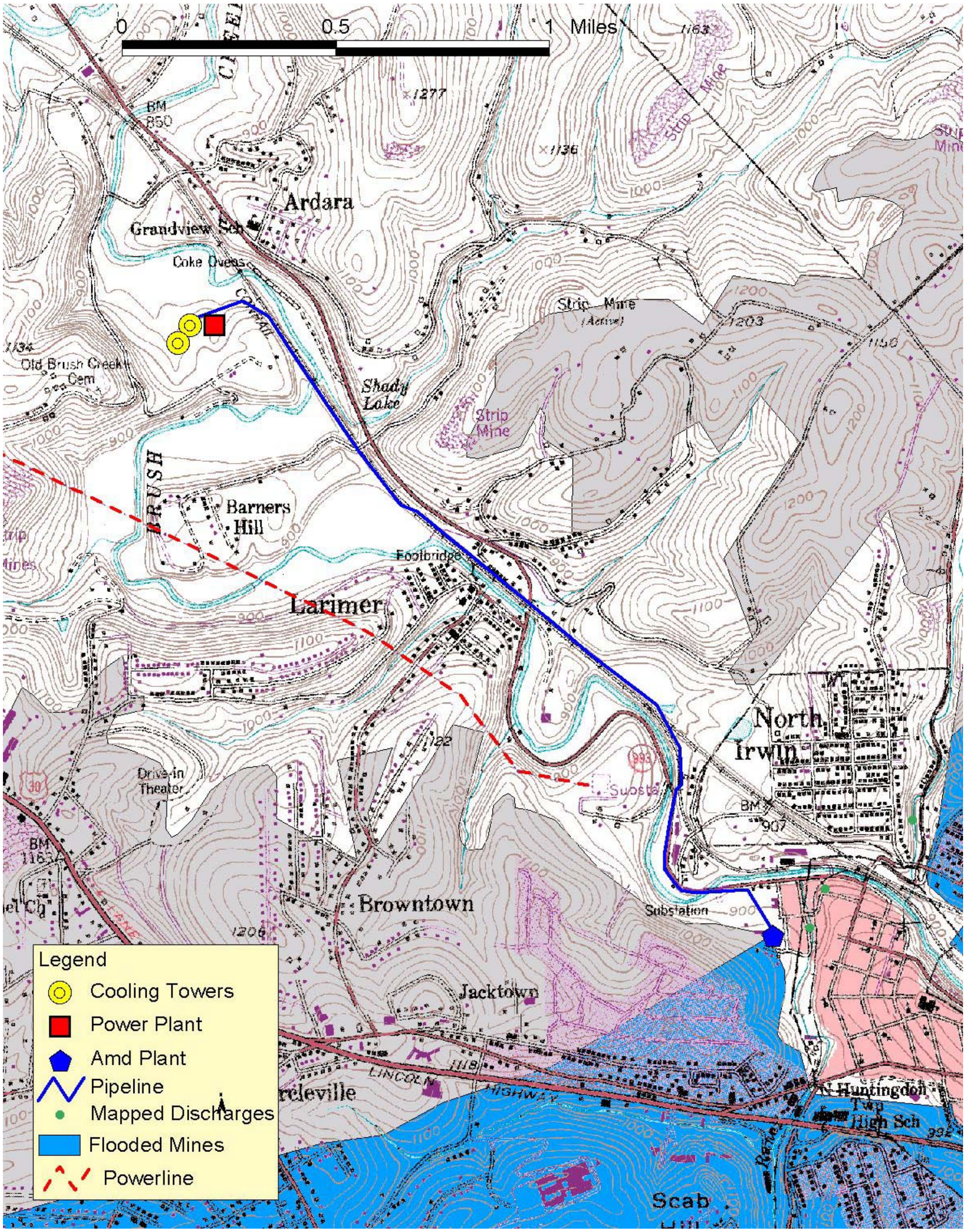

Figure 1-5. Location map for the Irwin case.

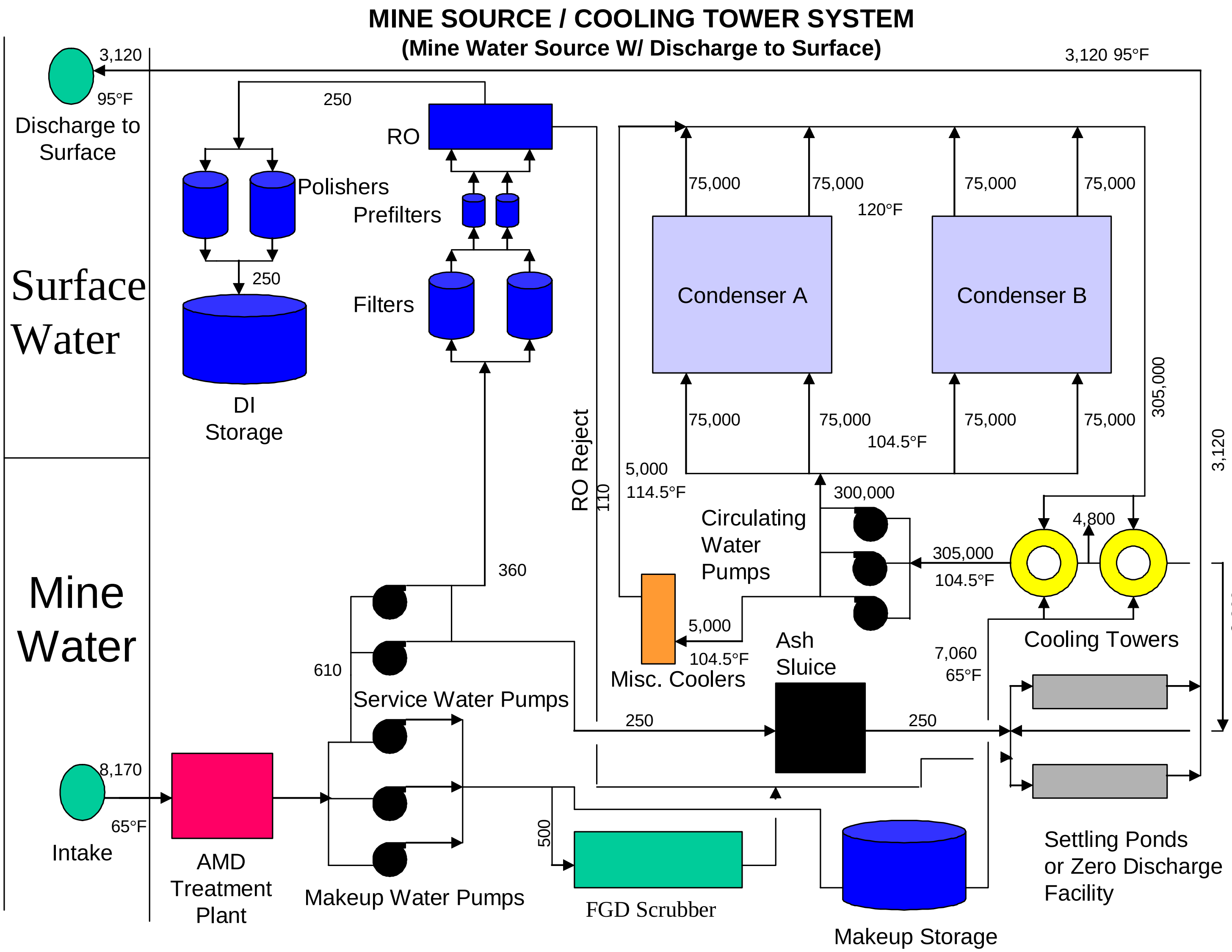

Figure 1-6. Power plant cooling circuit diagram for the Irwin case.

Uniontown Site

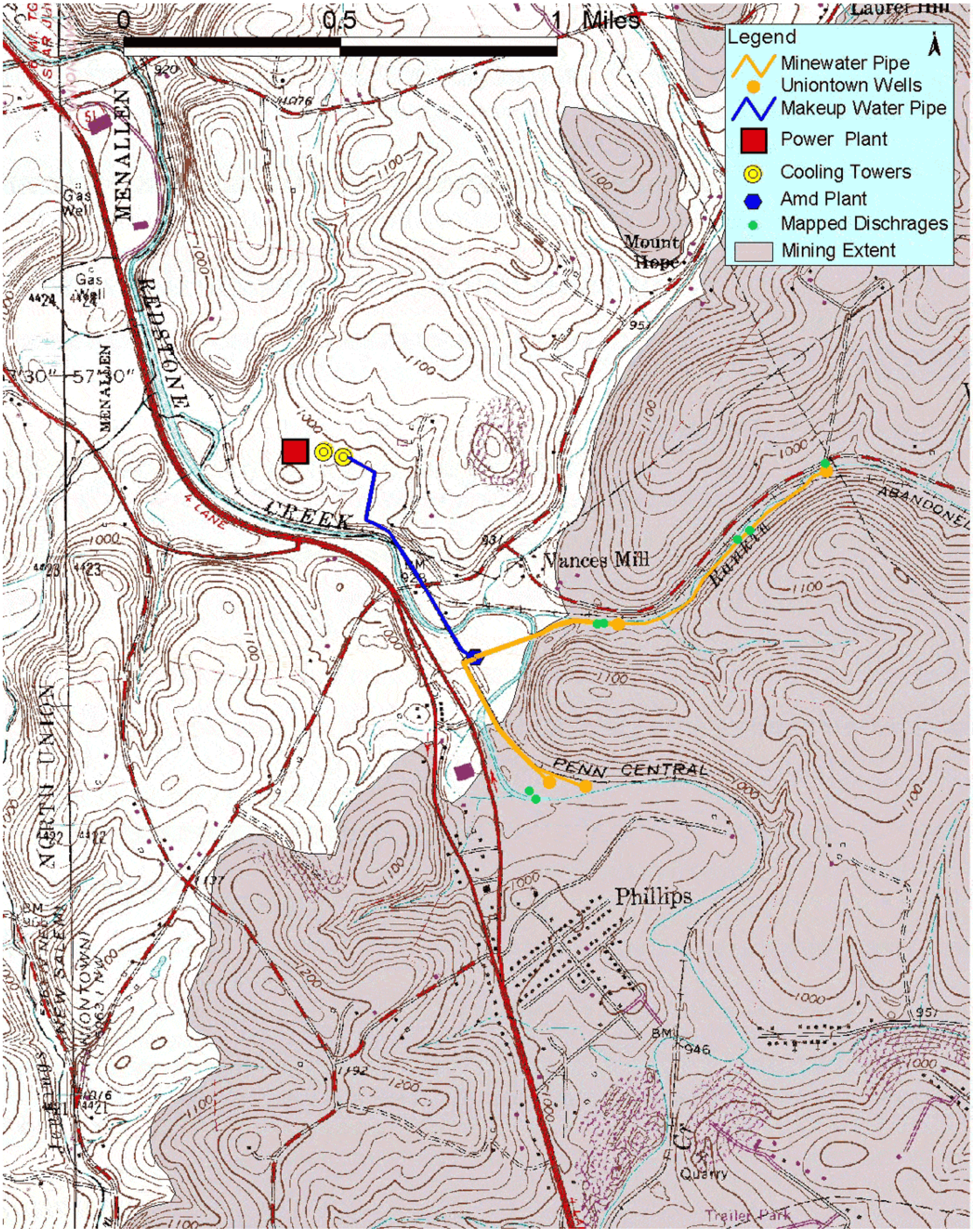

Figure 1-7. Location map for the Uniontown case.

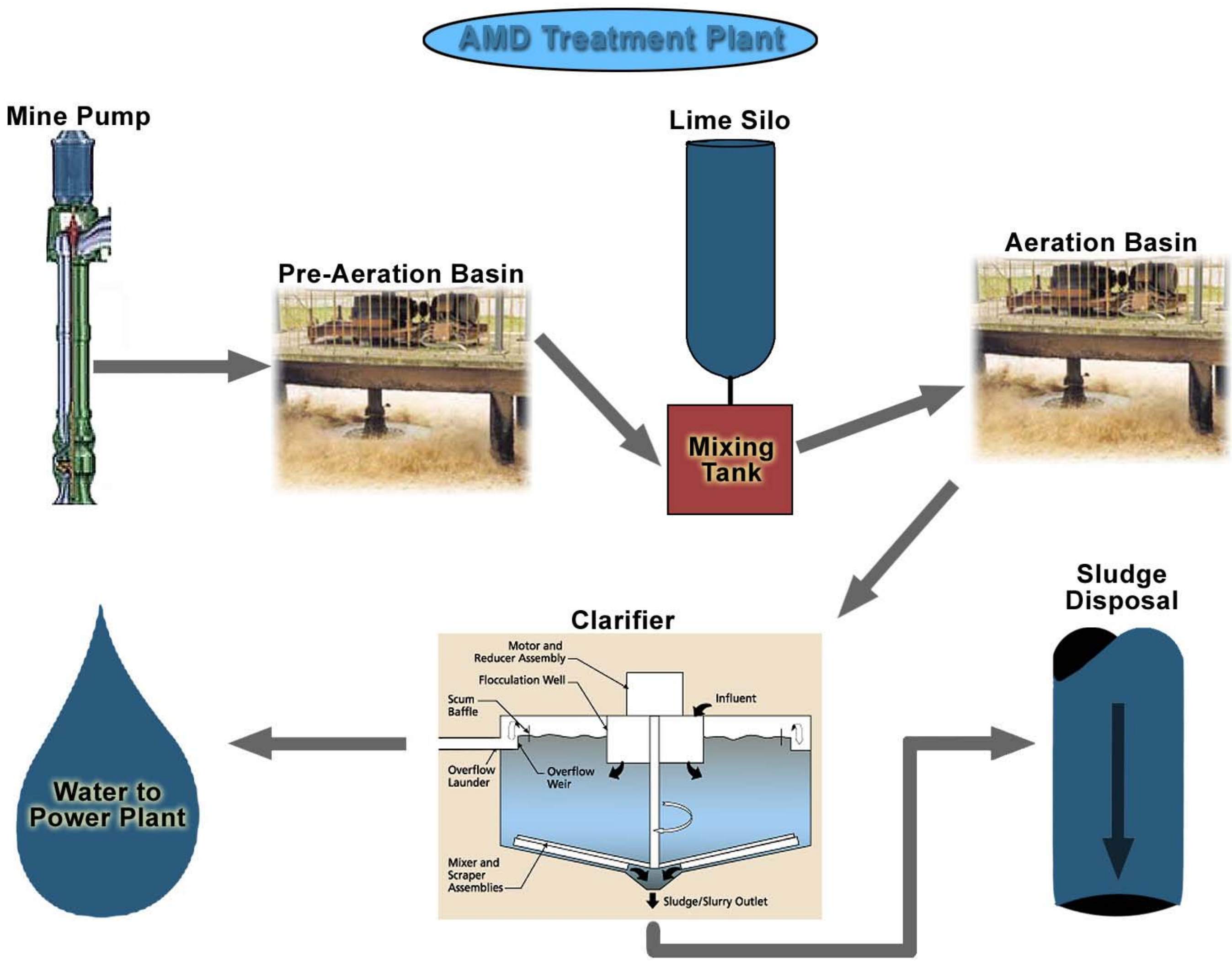

Figure 1-8. AMD treatment plant flow diagram.

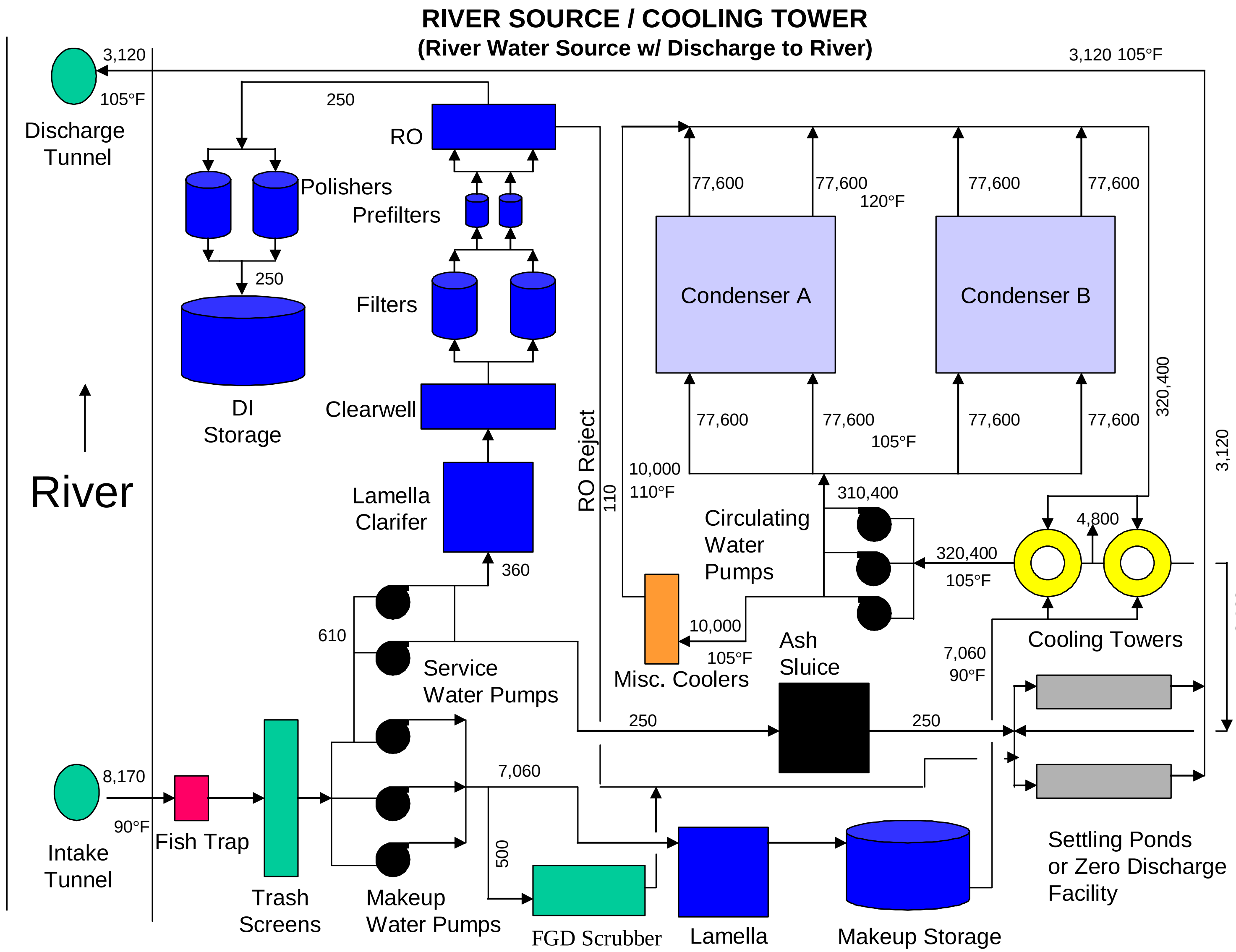

Figure 1-9. Power plant cooling circuit diagram for the base case.

Table 1-1. Power plant water consumption.

Source	Capacity MWh	Water Consumption gallons per MWh	Water Consumption gallons per minute	Heat Rejection MBTU/hr
EPRI	600	480	4,800	
Bruce Mansfield Avg.	850	459	6,500	
Mount Storm Unit 1	533	506	4,500 est.	2,038
Mount Storm Unit 2	533	458	4,070 est.	1,975
Mount Storm Unit 3	521	528	4,585 est.	2,226

Table 1-2. Prospective power plant locations.

Prospective Power Plant Locations							
Site	Water Availability		Water Quality	Coal Transportation		Grid Connection Difficulty	Estimated Population Density
	GPM	Confidence		Method	Dificulty		
West Newton	4,650	high	Net Alkaline	Rail	moderate	low	moderate
McMurray	7,500	high	Net Alkaline	Rail	low	high	high
Uniontown	8,460	high	Net Alkaline	Rail	low	moderate	moderate
Clarksville	4,300 est.	moderate	Near Neutral	Rail, Barge	low, moderate	low	moderate
Crucible	4,000 est.	low	Near Neutral	Rail, Barge	low, low	moderate	low
Flaggy Meadow	3,000 - 8,500	moderate	Net Acidic	Rail, Barge	mod, mod	low	low
Irwin	11,300	high	Net Alkaline	Rail	mod	moderate	high
Adelaid	4,745	high	mixed	Rail	low	moderate	low

Table 1-3. Raw chemical water quality for selected sites.

Site	pH	Sc	Alk mg/L	Na mg/L	K mg/L	Si mg/L	Fe mg/L	Mn mg/L	Al mg/L	Ca mg/L	Mg mg/L	SO_4 mg/L	Cl mg/L
Flaggy Meadows	5.14		28.0	379.9	17.5	9.0	155.0	8.3	4.21	472.8	165.0	2775	12.6
Irwin	5.58	1784	135.0	34.2	3.6	10.8	66.9	1.9	0.29	122.5	38.6	494	97.4
Uniontown	5.90	1800	171.6	103.0			69.9	2.8		213.0	81.1	1120	26.9

Table 1-4. Results of PHREEQC analysis.

Site		Moles Lime	pH	pe	Na mg/L	K mg/L	Si mg/L	Fe mg/L	Mn mg/L	Al mg/L	Ca mg/L	Mg mg/L	SO_4 mg/L	Cl mg/L
Flaggy Meadows	Raw		5.14	16.0	381.3	57.3	4.4	155.	8.3	4.2	475	165.	2775	12.6
	Treated	237.1	7.86	8.10	381.3	57.3	4.4	0.0	2.2	1.6	492	165	2635	12.7
Irwin	Raw		5.58	16.0	34.2	389	5.1	66.9	1.9	0.3	123	38.6	797.	97.5
	Treated	92.6	8.07	13.5	34.2	389	5.1	0.0	0.0	0.3	127	38.6	797	97.5

Table 1-5. Treatment plant temperature profile.

Source	Temperature ^{o}C
Pre Aeration	12.2
Aeration	12.5
Clarifier Overflow	12.8
Stream Discharge	14.5

Table 1-6. Base case cost analysis.

PROJECT TITLE:			
DOE	**River Water Cooling Tower**		
600MW Power Plant Cooling Circuit	**Order of Magnitude Estimate of Probable Cost**		**Jan-05**
Conceptual Design Study			
Equipment	**Description**	**Capital Cost**	**O&M Cost**
Intake Structure	Concrete intake structure, fish trap, & screens	$ 262,500	$ 20,100
Makeup Water Pumps	(3) 3,750 gpm with VFD's	$ 169,500	$ 46,250
Makeup Water Lamella	7,560 gpm - 10.88 mgd	$ 2,250,000	$ 210,000
Makeup Water Storage Tank	(2) 500,000 gallon steel tanks	$ 1,200,000	$ 15,000
Cooling Towers	Concrete cooling towers (2 x 160,500 gpm)	$ 20,000,000	$ 1,780,000
Circulating Water Pumps	(3) 165,000 gpm with VFD's	$ 1,950,000	$ 1,984,000
Misc. Coolers	10,000 gpm Turbine heat exchangers	$ 500,000	$ 5,000
Condensers	1 Condenser - 2 Shells	$ 4,900,000	$ 185,000
Settling Ponds	3,120 gpm	$ 900,000	$ 55,500
Discharge Structure	Concrete discharge	$ 32,000	$ -
Service Water Pumps	(2) 650 gpm with VFD's	$ 54,250	$ 11,500
DI Lamella	360 gpm - 0.52 mgd	$ 131,250	$ 13,200
Clearwell	50,000 gal	$ 75,000	$ -
Multi-Media Filters	360 gpm	$ 100,000	$ 7,500
RO System	360 gpm	$ 940,000	$ 125,000
Polishing Mixed Bed Ion Exchange	250 gpm	$ 450,000	$ 35,000
DI Storage Tank	250,000 gallon stainless steel tank	$ 625,000	$ -
Piping	1,000 ft 84" S.S.	$ 1,585,000	$ -
Fittings & Valves	84" S.S. (200% of piping)	$ 3,170,000	$ -
Piping	1,000 ft 18" S.S.	$ 480,000	$ -
Fittings & Valves	18" S.S. (200% of piping)	$ 960,000	$ -
Piping	1,000 ft 6" S.S.	$ 110,000	$ -
Fittings & Valves	6" S.S. (200% of piping)	$ 220,000	$ -
Electrical		$ 2,000,000	$ -
Controls		$ 3,000,000	$ 50,000
	Total	**$ 46,064,500**	**$ 4,543,050**
	20% Contingency	**$ 9,212,900**	**$ 908,610**
	New Total	**$ 55,277,400**	**$ 5,451,660**

Table 1-7. Cost analysis for mine to surface case (Irwin and Uniontown).

PROJECT TITLE: **DOE** **600MW Power Plant Cooling Circuit** **Conceptual Design Study**	**Mine Source Cooling Tower (Surface Discharge)** **Order of Magnitude Estimate of Probable Cost**		**Jan-05**
Equipment	**Description**	**Capital Cost**	**O&M Cost**
Makeup Water Pumps	(3) 3,750 gpm with VFD's	$ 169,500	$ 46,250
Makeup Water Storage Tank	(2) 500,000 gallon steel tanks	$ 1,200,000	$ 15,000
Cooling Towers	Concrete cooling towers (2 x 152,500 gpm)	$ 19,000,000	$ 1,691,000
Circulating Water Pumps	(3) 155,000 gpm with VFD's	$ 1,832,000	$ 1,889,000
Misc. Coolers	5,000 gpm Turbine heat exchangers	$ 375,000	$ 3,750
Condensers	1 Condenser - 2 Shells	$ 4,800,000	$ 148,000
Settling Ponds	3,120 gpm	$ 900,000	$ 55,500
Discharge Structure	Concrete discharge	$ 32,000	$ -
Service Water Pumps	(2) 650 gpm with VFD's	$ 54,250	$ 11,500
Multi-Media Filters	360 gpm	$ 100,000	$ 7,500
RO System	360 gpm	$ 940,000	$ 125,000
Polishing Mixed Bed Ion Exchange	250 gpm	$ 450,000	$ 35,000
DI Storage Tank	250,000 gallon stainless steel tank	$ 625,000	$ -
Piping	1,000 ft 84" S.S.	$ 1,585,000	$ -
Fittings & Valves	84" S.S. (200% of piping)	$ 3,170,000	$ -
Piping	1,000 ft 18" S.S.	$ 480,000	$ -
Fittings & Valves	18" S.S. (200% of piping)	$ 960,000	$ -
Piping	1,000 ft 6" S.S.	$ 110,000	$ -
Fittings & Valves	6" S.S. (200% of piping)	$ 220,000	$ -
Electrical		$ 2,000,000	$ -
Controls		$ 2,600,000	$ 47,000
	Total	**$ 41,602,750**	**$ 4,074,500**
	20% Contingency	**$ 8,320,550**	**$ 814,900**
	New Total	**$ 49,923,300**	**$ 4,889,400**

Table 1-8. Cost analysis for water aquisition at Irwin.

PROJECT TITLE:	**Irwin**		
DOE	**Mine Source Cooling Tower (Surface Discharge)**		
8100 gpm Treatment Facility	**Order of Magnitude Estimate of Probable Cost**		**Sep-04**
Conceptual Design Study			
Equipment	**Description**	**Capital Cost**	**O&M Cost**
AMD Plant	Complete with pre-aeration, clarifier and sludge disposal	$ 2,401,952	$ 479,115
Piping to Power Plant	26" DR11 11,775 feet	$ 1,196,360	$ -
	Total	**$ 3,598,312**	**$ 479,115**
	20% Contingency	**$ 719,662**	**$ 95,823**
	New Total	**$ 4,317,975**	**$ 574,938**

Table 1-9. Cost analysis for Flaggy Meadows power plant cooling system.

PROJECT TITLE: **DOE** **600MW Power Plant Cooling Circuit** **Conceptual Design Study**	**Mine Source Cooling Tower (Mine Discharge)** **Order of Magnitude Estimate of Probable Cost**		**5-Jan**
Equipment	**Description**	**Capital Cost**	**O&M Cost**
Makeup Water Pumps	(3) 3,800 gpm with VFD's	$ 169,500	$ 46,250
Makeup Water Storage Tank	(2) 500,000 gallon steel tanks	$ 1,200,000	$ 15,000
Cooling Towers	Concrete cooling tower 2 x 151,370 gpm	$ 18,862,000	$ 1,679,000
Circulating Water Pumps	(3) 155,000 gpm with VFD's	$ 1,832,000	$ 1,889,000
Misc. Coolers	Turbine heat exchangers	$ 375,000	$ 3,750
Condensers	1 Condenser - 2 Shells	$ 4,800,000	$ 148,000
Settling Ponds	3,120 gpm	$ 900,000	$ 55,500
Discharge Structure	Injection Well	$ 27,200	$ -
Service Water Pumps	(2) 650 gpm with VFD's	$ 54,250	$ 11,500
Multi-Media Filters	360 gpm	$ 100,000	$ 7,500
RO System	250 gpm	$ 940,000	$ 125,000
Polishing Mixed Bed Ion Exchange	250 gpm	$ 450,000	$ 35,000
DI Storage Tank	200000 gallon stainless steel tank	$ 625,000	$ -
Piping	1000 ft 84" S.S.	$ 1,585,000	$ -
Fittings & Valves	84" S.S. (200% of piping)	$ 3,170,000	$ -
Piping	1000 ft 18" S.S.	$ 480,000	$ -
Fittings & Valves	18" S.S. (200% of piping)	$ 960,000	$ -
Piping	1000 ft 6" S.S.	$ 110,000	$ -
Fittings & Valves	6" S.S. (200% of piping)	$ 220,000	$ -
Electrical		$ 2,000,000	$ -
Controls		$ 2,600,000	$ 47,000
	Total	**$ 41,459,950**	**$ 4,062,500**
	20% Contingency	**$ 8,291,990**	**$ 812,500**
	New Total	**$ 49,751,940**	**$ 4,875,000**

Table 1-10. Cost analysis for water acquisition for Uniontown site.

PROJECT TITLE:	**Uniontown**				
DOE	**Mine Source Cooling Tower (Surface Discharge)**				
8100 gpm Treatment Facility	**Order of Magnitude Estimate of Probable Cost**				**Sep-04**
Conceptual Design Study					
Equipment	**Description**	**Capital Cost**		**O&M Cost**	
Mine Water Pumps	(4) 2,700 gpm	$	1,184,000	$	62,500
Piping to AMD Plant	4 pipes 16" DR 11 total = 11,160 feet	$	767,606	$	-
AMD Plant	Complete with pre-aeration, clarifier and sludge disposal	$	2,401,952	$	479,115
Piping to Power Plant	26" DR11 3140	$	319,000	$	-
Pump Boreholes	(4) 20" diameter Cased boreholes	$	243,000	$	-
	Total	**$**	**4,915,558**	**$**	**541,615**
	20% Contingency	**$**	**983,112**	**$**	**108,323**
	New Total	**$**	**5,898,670**	**$**	**649,938**

2 Conceptual design of earth-coupled power plant cooling using flooded underground mines

2.1 Experimental

2.1.1 Site selection and water transfer system design

Based on preliminary results from the HST3D thermal model described below a determination was made as to the scale of the underground mine area that would be required to support the heat rejection requirements identified in the model. Figure-1 shows the relationship between the discharge flow rate required to maintain the heat rejection from a 600 MW power plant through time. Based on this analysis it was determined that it would not be possible to move the required volumes of water through the mines. An alternate plan was adoped to apply the conceptual design to 200 MW power plant.

Mine flooding information generated by Donovan *et al*. (2004, in review) was used to identify mine and surface geometries that meet the requirements. One important criterion was the presence of an underground barrier opening between two mines that would allow the return of injected water back to the water withdrawal point. Another consideration was the ability to distribute the heated water broadly across the heat-sink mine for maximum heat dissipation.

2.1.1.1 Design of a collection system / distribution system

The primary criterion in designing the collection / distribution system was (a) minimization of both static and dynamic head, and (b) widespread distribution of the water so that the maximum mine area could be included in the flow path with the minimum pipe length. Water injection into gob areas (areas of collapsed overburden), as opposed to main haulages that are linear openings with long-term roof support, was considered essential to achieve efficient distribution of water within the mine without "short-circuiting". Mine-water transfers were limited to less than 3,000 gpm per well in gob areas. Higher withdrawal and injection rates were permitted in mains as needed. For the purpose of this simulation, it was assumed that a connection exists between the Vesta #5 and Clyde mines allowing high water flow without excessive head loss. This situation precludes the water level in Vesta #5 from rising above surface discharge elevation.

2.1.2 Fluid and heat flow modeling

Experimental work for this task consisted of constructing a conceptual thermal groundwater model of a mine water cooling system and a detailed isothermal model of a cooling system installed in the Clyde, Vesta, and Marianna 58 mines in the Pittsburgh seam.

2.1.2.1 Thermal Model

The conceptual thermal model of a mine-water cooling system was constructed with the U.S. Geological Survey's HST3D computer program. HST3D is a mesh-centered, finite-difference computer program designed to simulate non-isothermal flow of water in porous media. Because the definition of piezometric head is dependent upon the assumption of uniform, constant fluid density, the primary dependent variables for HST3D models are pressure and temperature, and permeability is employed instead of hydraulic conductivity. HST3D also allows one to simulate contaminant transport, but this feature was not employed for the models developed by this research.

Table 2-1 lists the basic parameters of the models, and the discretization of the model domain is shown in Figures 2-2 and 2-3. Because HST3D is a mesh centered finite difference computer program, material properties are assigned to the volumes between the model nodes, and the dependent variables simulated by the model are calculated at the model nodes. Since this is a conceptual model, material properties are assigned to the volumes between the mesh layers (element layers), which are listed in Tables 2-2 and 2-3. Table 2-4 lists the elevation, initial pressure, and initial temperature of each model mesh layer.

Element layers 1 and 2 each have a thickness of 1 m and a porosity of 25% and represent the mine aquifer formed by the collapse of a room and pillar mined area. The permeability assigned to those layers (10^{-7} m^2) was estimated from the reported permeabilities (10^{-15} to 10^{-9} m^2) of aquifers formed by lignite mining in Texas (Mace, Smyth, Xu, and Liang, 1999) with an allowance for the larger void space and higher permeability expected with the collapse of harder bituminous coal.

Element layer 3 has a thickness of 10 m and a porosity of 10% in order to represent the fractured zone that would result from the collapse of the lower mine voids. A permeability of 10^{-8} m^2 was assigned to this layer to account for the creation of the tension fractures in the overburden. Element layers 4 through 6 each have a thickness of 10 m and a porosity of 0.1% because the overburden at these depths has not been impacted by the collapse of the lower mine voids. The permeability of these layers decreases by one order of magnitude to represent the increasing resistance to groundwater flow without introducing the numerical errors associated with larger changes in permeability between adjacent model units.

Element layers 7 through 16 each have a thickness of 10 m, a porosity of 0.1%, and a permeability of 10^{-11} m^2 to represent the undisturbed overburden. The permeability of the undisturbed overburden layers was chosen to represent relatively undisturbed, near surface rock strata (Domenico and Schwartz, 1990). Because very little fluid flow takes place in these layers, the permeability of these element layers has very little impact on the results of the simulation. Element layer 17 is the identical to layers 7 through 16 except for a thickness of 12 m.

Layers 7 through 17 were included in the model because thermal HST3D models cannot simulate phreatic conditions. Atmospheric cooling of the top layer (ground surface) was simulated using a constant temperature boundary at the top of element layer 17 (mesh layer 18).

Figure 2-2 also shows the locations of the injection and extraction wells. During the mine water cooling process, hot water at 40 °C is pumped into the injection well, which is on the left side of the model domain, and cool water is pumped from the extraction well, on the right side of the model domain. The properties of these wells are shown in Table 2-5. HST3D allows the user to specify some sophisticated techniques for modeling the well extraction and injection process, but this model only used method (WQMETH) #11, which uses a specified volumetric flow rate and calculates the pressure drop between the well and the porous media from the effective permeability around the well.

As the mine-water cooling simulation progressed, the cool water being pumped from the extraction well became warmer and the pumping rate had to be increased to maintain the required cooling rate for a 200 MW power plant. This minimum cooling rate is approximately 217 MW. Stress periods are defined by the HST3D program as being those periods where the well pumping rate changes. The duration and pumping rates for the simulated stress periods in the model are listed in Table 2-6.

Increasing the pumping rate for the injection and extraction wells increases the mean pore water velocity between the wells and decreases the average amount of time the water remains in the mine aquifer. Since the hot water is 30 °C warmer than the initial temperature of the aquifer, this decrease in travel time will tend to reduce the cooling rate for the injected water. The mean travel times for the simulated stress periods are listed in Table 2-7.

2.1.2.2 Isothermal Model

This isothermal model constructed for this task was generated with the USGS MODFLOW-96 computer program. MODFLOW-96 is designed to simulate the three-dimensional, isothermal flow of water in a porous media (McDonald and Harbaugh, 1996). This computer program was selected because of the wide variety of boundary conditions that may be simulated and the program’s history of widespread use.

The general parameters of the MODFLOW model are listed in Table 2-8, and the model grid is shown in Figure 2-4. The Clyde, Vesta, and Marianna 58 mines are separated by mine barriers. The barrier separating sections of the Vesta mine, the northern mines, has several breaks, which are also regions of high hydraulic conductivity.

The outline of the model domain shown in Figure 2-4 was derived from maps of the Pittsburgh coal seam elevation and known piezometric head values for the simulated mines. While this system is known to be unconfined in small portions of the mines, attempts to simulate existing conditions with the model layer produced unrealistic results, and the decision was made to assume confined conditions.

The mine barriers are simulated with the horizontal flow barrier package with the conductivity and thickness parameters listed in Table 2-9. The selection of these values for the barrier parameters was based upon the experience of the investigators with mine barriers in the Pittsburgh coal seam and the reasonable results generated from their application in initial models without a mine water cooling system that were constructed to test parameter values.

The preconditioned conjugate-gradient solver (PCG2; Hill, 1990) was used to solve the finite difference equations generated by MODFLOW's body centered flow package (BCF). This package was employed for these models because it has been shown to provide stable convergence for models of underground mine voids.

The east-west barrier that separates Marianna 58 and Clyde mines from the Vesta mine has a single break that is represented by three constant head cells. This break is represented by the constant head cells because it is believed that a subsurface broad crested weir separates the two mine pools. Because a package simulating this kind of boundary is not available with either MODFLOW-88 (McDonald and Harbaugh, 1988) or MODFLOW-96 (McDonald and Harbaugh, 1996), the effect of this weir on upstream and downstream piezometric head was best simulated by a constant head boundary.

Figure 2-5 shows the zones of hydraulic conductivity for the model. Those regions where the mine maps show a passageway are assumed relatively open areas and are given the highest hydraulic conductivity in the model, 5.787 m/s. Those transitional areas 100 meters on each side of the passageways are given an intermediate hydraulic conductivity of 1.157 m/s. The cells around the constant head boundary cells are also given a hydraulic conductivity of 1.157 m/s. The other areas of the mine are assumed fully extracted room and pillar areas that have undergone some degree of collapse. These areas were assigned a hydraulic conductivity of 0.069 m/s.

The assignment of the hydraulic conductivity values for the passageways and fully extracted areas were assigned by applying known recharge rates to the simulated mines and determining the minimum hydraulic conductivity values required to replicate the observed values of hydraulic head and hydraulic head gradient reported by Donovan *et al.* (2004). The passageways were assigned a much higher conductivity value because of the large (5 m x 2 m) open areas. The conductivity of the transitional regions was selected to avoid the numerical errors associated with large changes in conductivity in adjacent model cells.

Figure 2-6 shows the annual recharge rates for the simulated mines. These rates were estimated from the 0.0934 m^3/s (1,480 gpm) pumping rate of the existing well in the southeastern portion of the Clyde mine. Along with the hydraulic conductivity values shown in Figure 2-5, the annual recharge rates shown in Figure 2-6 allowed the model to generate reasonable values of piezometric head for the mine pools with the existing pumping from the Clyde mine.

Two pumping strategies were tested with the isothermal model. Pumping strategy #1 consisted of 10 new injection wells and 4 new extraction wells. Pumping strategy #2 employed a larger portion of the simulated mine for cooling and consists of 21 new injection wells and 13 new extraction wells. These basic parameters for these pumping strategies are listed in Tables 2-10 and 2-11.

2.1.3 Water treatment and chemistry

2.1.3.1 Determining Treatment Needs

Data for the Clyde Mine from Donovan *et al.* (2004, in review) are used as input to the AMD Treat design model for the purpose of designing a water treatment plant and determining the amount of reagents that are needed for the treatment process.

2.1.3.2 Geochemical analysis of treated mine water

Using equilibrium geochemical techniques, simulation was performed of the changes in chemistry that are anticipated to occur accompanying withdrawal of mine water, chemical treatment to remove metals, and heating/reinjecting of the mine water in the plant condenser cycle. The mine water chemistry chosen for the analysis is a sample taken from the Clyde water treatment plant in Clarksville, PA, operated by the Pennsylvania DEP. The sample was collected on June 25, 2001, after 4 years of operation of the plant following completion of mine flooding. The plant operates at a discharge of 2500 gpm 9 months of the year. This is a typical discharge for a large flooded mine but much lower than the pumping rate required for once-through cooling of a power plant using cool (10^{o}C) mine water. The chemistry of the Clyde plant on that date is shown in Table 2-12.

To remove metals from this water, a lime treatment cycle would normally be employed, as is used at Clyde. The goal of this analysis was to examine the water chemistry at 3 phases in the water utilization process:

1) Raw water, cool (in this case, 15ºC, the temperature of the water at Clyde)

2) Treated water, still cool

3) Treated water heated to 40^{o}C and re-injected into the aquifer.

To perform the analysis, the equilibrium modeling code PHREEQC was employed (Parkhurst *et al.* 1999). PHREEQC uses equilibrium thermodynamic data and calculations based on user-specified assumptions. The methodology employed for the three geochemical steps above are as follows

1) Speciate raw water at subsurface temperature and CO_2 pressure conditions indicated at the time of sampling; calculate saturation indices of relevant phases,

2) Add a quantity of lime hydrate (the mineral portlandite) sufficient to remove most of the metals present in solution, plus a slight excess of lime to maintain an alkalinity buffer in the treated water. A large excess of alkalinity is undesirable due to the prospect for fouling of the condensers and plumbing by calcite or aragonite ($CaCO_3$) precipitation. Saturation phases will be set to force precipitation of mineral phases deemed likely to form, at equilibrium or supra-equilibrium values commonly observed in plant effluent. Also, the pCO_2 of the treated water will be reduced to atmospheric levels by aeration, in a step designed to force as much calcite as possible to form in the AMD treatment plant rather than in the cooling cycle,

3) Water heated to $40^{o}C$ and re-injected into the aquifer at atmospheric CO_2 pressure will be allowed to react with the mineral chalcedony, a relatively soluble form of SiO_2. This dissolved silica load is dependent on temperature alone. The impact of the silica in solution would likely be in pumps that are down gradient of the first re-injection point of the heated cooling water. The assumption is that such silica would dissolve into solution at elevated temperature more readily than it would precipitate during cooling.

2.1.4 Environmental Factors and Permitting

2.1.4.1 316(a)(b)

Since a surface water source is not involved, the regulations promulgated under the Clean Water Act are not applicable.

2.1.4.2 Underground Injection Control

The UIC program is expected to be the most significant regulatory process affecting the earth-coupled design. Even though large quantities of water are being injected, the quality of injected water is better than the existing water quality in the mine itself.

2.1.4.3 NPDES

No NPDES new discharges are anticipated. However, changes in water quality are expected at the existing Clyde AMD treatment plant.

2.1.4.4 Water Rights

The water rights issues raised by the earth-coupled case include the concerns raised previously in this report but also go beyond the issues previously considered. Specifically, does one water user have the right to increase the temperature of, or for that matter, improve the quality of the groundwater that underlies other potential users?

2.1.4.5 AMD

Because the overall water level in the mines is expected to be unchanged, no new AMD is expected to be created. However, large quantities of AMD will be treated and injected into the mines; this is expected to have a significant, beneficial effect on water quality in the mines.

2.1.4.6 Mine Subsidence

Since water levels are not being lowered, changes in subsidence frequency are not anticipated.

2.1.5 Economic Analysis

A power plant was designed for once through cooling utilizing a 36.8°C temperature rise. The estimated cost of this design is combined with the estimated cost of the pumping and distribution system to generate a total system cost. This value is then compared with the cost of building a conventional river source cooling tower plant. It is assumed for this analysis that additional once-through cooling plants are unlikely in the Monongahela River system.

2.2 Results and Discussion

2.2.1 Site selection and water transfer system design

Based on the preliminary result from the HST3D model, it was determined that only large flooded mines would be capable of providing a satisfactory heat sink, and then only for a 200-MW power plant. Other essential criteria were an existing subsurface barrier opening between two mines and a relatively low pumping lift from both mines. This requires that a stream valley cross a barrier between two mines known to be interconnected. Further, this stream valley would need to be located as far way from the mine interconnection as possible, to maximize residence time.

Within the restraints of our pre existing database we were able to locate only one pair of mines where these conditions were met. These mines are Vesta #4-5 and Clyde. The Vesta complex is the largest flooded mine in the basin. The Clyde mine lies south of the Vesta complex in the east and south of Marianna #58 in the west. Clyde receives all of Vesta's mine water, and water is currently being pumped and treated near the town of Clarksville, Pennsylvania.

Ten Mile Creek is the major drainage over the area of interest. It flows east and then southeast from the town of Marianna to the town of Clarksville, eventually joining the Monongahela River. Daniels Run and Little Daniels Run flow southeast across the Vesta Mines before joining Ten Mile Creek at Marianna. These stream valleys provide the route for the piping system that will deliver the mine water to and from the power plant without the need to pump the water over the tops of the hills.

2.2.1.1 Pumping Strategy #1

A closed mine site in the Town of Marianna was selected for the power plant location. From this point, injection piping could be laid up Daniels Run providing access to the bulk of Vesta 4 and Vesta 5 mines. Mine pumps were sited over Clyde mine along Ten Mile Creek.

Four deep-well pumps were located near main entries of the Clyde mine. These pumps were separated from each other to reduce well-to-well interference. At a 36.8°C temperature rise it was determined that 1.77 m^3/s (28,000 gpm) must be pumped from Clyde. This requires 0.44 m^3/s (7,000 gpm) per well. Each well is provided with a discharge pipe to the AMD treatment plant. The pipe is designed to accommodate 0.50 m^3/s (8,000 gpm)

The AMD treatment plant is designed to treat 2.02 m^3/s (32,000 gpm) to accommodate future pumping requirements resulting from a temperature increase in the mine water returning to the power plant. Treated water is then pumped from the treatment plant to water storage at the power plant.

Once the treated water has been heated by the power plant it is pumped into a distribution network for injection into the Vesta Complex. HDPE DR 11 pipe was selected for this application. Even at the anticipated discharge temperature, DR 11 pipe exceeds the anticipated pressure requirements, and is strong enough to resist collapse under a negative pressure of one atmosphere. The distribution network contains 39,426 feet of HDPE pipe ranging from 12 to 36 inches in diameter. Ten injection holes are utilized to provide aerial distribution and to reduce the volume of water injected at each hole. By doing so, the local ability of the Vesta mine to accept the water is not exceeded.

The injected water flows through the Vesta complex and overflows into Clyde. From this overflow point, the water flows back to the four deepwell pumps thus completing the circuit.

2.2.1.2 Pumping strategy #2

Water is pumped from the Marianna mine located beneath the power plant and it is treated adjacent to the power plant. The treated water flows to the power plant and the heated water is pumped through the same injection network, previously described, into the Vesta complex. The water flows through Vesta and overflows to Clyde. Eight deep-well pumps in Clyde, located along the Clyde-Marianna barrier, pump the water across the coal barrier into Marianna and hence back to the Marianna Pumps. This pumping strategy adds the Marianna mine to the cooling circuit and more fully utilizes the Clyde mine as a heat sink.

2.2.2 Fluid and heat flow modeling

2.2.2.1 Thermal Model

Figure 2-10 is a contour plot of the temperature calculated by the model in the middle of the two element layers representing the abandoned mine at the end of the first stress period (4,500 days). While the water being taken by the extraction well is cooler than 12°C, the increase in temperature was enough to require an addition to the pumping rate to maintain the minimum system-cooling rate. Figure 2-11 is a contour plot of the pressure for the same mesh layer and shows symmetric curvature of pressure contours around the injection and extraction wells.

Figures 2-12 and 2-13 are contour plots of the temperature and pressure for the middle of the abandoned mine at the end of the second stress period (8,500 days). The 12°C contour line remains away from the extraction well, but an increase in pumping rate was required by the warming of the extracted water. The pressure contour plot resembles the pressure contour plot at the end of the first stress period.

Figures 2-14 and 2-15 are contour plots of the temperature and pressure for the middle of the abandoned mine at the end of the simulation (9,250 days). The 12°C contour line is very close to the extraction well, but the extracted water remains cooler than 12°C. The simulated cooling system could have maintained the minimum cooling rate beyond this point, but it was decided to end all of the transient simulation models shortly after the end of the 25 year (9,131 days) expected lifetime for the plant.

Figures 2-16 and 2-17 are contour plots of the temperature and pressure calculated by the model at the end of the first stress period (4,500 days) for a vertical slice defined by the Y coordinates of the injection and extraction wells. The locations of the injection and extraction wells are indicated on these contour plots by the crosses on the left (injection) and right (extraction) sides of the model domain.

As expected, Figure 2-16 shows warmer contours around the injection well. However, both the pressure and temperature contour plots show “fingers” that indicate the presence of instability caused by warmer and lighter water being injected below cooler and heavier water. In groundwater, as well as in ordinary fluids, thermal heating from below can result in the formation of Rayleigh convection cells. During this simulation, the maximum Rayleigh number was 7 x 10^{-8}, low enough to prevent free convection cell formation. These observed “fingers” are more pronounced in the top and bottom regions of the model domain. Some of this natural instability is probably damped by the lower permeability of the upper layers, but the instability was such that the triangular-factorization direct solver was required by HST3D to solve the finite difference equations, which requires substantially greater computational time per simulation.

Figures 2-18 and 2-19 are contour plots of the temperature and pressure calculated by the model at the end of the second stress period (8,500 days) for the same vertical slice. With the exception of the larger thermal mound around the injection well, these contour plots are similar to the contour plots for the end of the first stress period. Figures 2-20 and 2-20 are contour plots of the temperature and pressure calculated by the model at the end of the simulation (9,250 days). Like the previous pair of contour plots, the thermal mound around the injection well has grown during the last stress period, and the contour plots show “fingers,” which are more pronounced in the top and bottom regions of the model domain.

Figure 2-22 contain plots of the thermal profile above the injection well at the end of the first, second, and third stress periods (4,500, 8,500, and 9,250 days), respectively. These plots show a nearly uniform temperature distribution in the bottom 32 meters of the column and abrupt changes in thermal gradient at elevations -140 and -130 m. These abrupt changes in thermal gradient correspond to the upper two changes in layer permeability.

Figure 2-23 contains plots of the thermal profile above the extraction well at the end of the first, second, and third stress periods (4,500, 8,500, and 9,250 days), respectively. The thermal profile at the end of the first stress period is nearly uniformly equal to the initial temperature of the simulation, 10°C. Because the magnitude of the deviations in this profile from the initial temperature is rather small, one can safely conclude that any influence of the injection process on the thermal profile above the extraction well before 4,500 days is an artifact of the simulation model.

The other profiles in Figure 2-23 show the thermal profile over the extraction well to be evolving in shape during the simulation towards the profiles observed over the injection well. However, the overall thermal gradient above the extraction well at the end of the simulation is much less than the thermal gradient above the injection well.

Figure 2-24 is a time series plot of the power plant cooling rate and difference in temperature between the injection and extraction wells. The cooling rate curve in this plot was calculated with the following equation and the results of the HST3D model.

$$\frac{dC}{dt} = \frac{\rho_i \quad Q \quad c \quad T_i - \rho_e \quad Q \quad c \quad T_e}{1000} \tag{1}$$

Where: $\frac{dC}{dt}$ = Cooling rate, MW.

ρ_i = Density of injected water, kg/m^3.
ρ_e = Density of extracted water, kg/m^3.
T_i = Absolute temperature of the injected water, K.
T_e = Absolute temperature of the extracted water, K.
Q = Pumping rate of the injection and extraction wells, m^3/s.
c = Specific heat of water, 4.184 kJ/kg.

Twice during the simulation, it was necessary to increase the pumping rate to maintain the minimum required cooling rate of 217 MW. These increases in pumping rate correspond to the end of the first and second stress periods. Figure 2-25 is a time series plot of the cooling rate and the pumping rate of the injection and extraction wells. At the beginning of the simulation, the pumping rate was 1.77 m^3/s (28,000 gpm). After 4,500 days of operation, the pumping rate was increased to 1.89 m^3/s (30,000 gpm), and after 8,500 days, the pumping rate was increased again to 2.02 m^3/s (32,000 gpm). These pumping rates were chosen to correspond to the capacities of widely available pumps. The mass balance for the HST3D simulation is shown in Table 2-8.

2.2.2.2 Isothermal Model

Table 2-10 shows the pumping rates for the injection and extraction wells for pumping strategy #1, and Figure 2-26 shows both the location of the wells and the resulting piezometric head distribution generated by the pumping strategy. With the exception of the recharge mounds and cones of depression around the injection and extraction wells and the constant head boundary cells, the piezometric head is little different from the simulations executed without the new injection and extraction wells.

In addition to showing the calculated piezometric head, Figure 2-27 shows the flow paths from the injection wells to the extraction wells for pumping strategy #1. The flow paths were calculated from the results of the MODFLOW model with the U.S. Geological Survey computer program, MODPATH (Pollock, 1994). Ten particles were released from each of the injection wells for the MODPATH calculations. From the calculated flow paths, it is easy to see how the hydraulic conductivity, size, and location of the passageways in the mine would affect the average travel time between the injection and extraction wells.

In the absence of a site-specific thermal model, the surface area of the flow fields between the wells is a reasonable guide for making comparisons of cooling rate. Table 2-13 lists the surface area of the flow field for the MODFLOW and HST3D models. Because the flow path lines for the HST3D model passed through the entire horizontal extent of the model's domain, the total surface area of the HST3D model should be compared against the surface area of the flow path lines for the MODFLOW models.

Figure 2-28 shows the observed cumulative distribution function for the travel time calculated by MODPATH for pumping strategy #1. Also shown on Figure 2-28 is the cumulative distribution function for the exponential distribution fitted to the travel time data. The sample statistics for the travel time data and the fitted exponential distribution function parameters are listed in Table 2-14.

Table 2-15 shows the water balance for the pumping strategy #1 MODFLOW simulation. With a relative discrepancy less than 0.02% and a difference between what is entering and leaving the constant head boundary cells of less than 0.1%, it appears that the results calculated by MODFLOW are reasonable.

Table 2-11 shows the range in pumping rates for the injection and extraction wells for pumping strategy #2, and Figure 2-29 shows the location of the wells and the resulting piezometric head distribution generated by the pumping strategy. With this pumping strategy, the calculated range in piezometric head is less, and the general distribution of piezometric head is different than with pumping strategy #1.

Figure 2-30 shows the flow paths for pumping strategy #2. The hydraulic conductivity, size, and location of the passageways appear to be even more important for this simulation than with the previous model. This pumping strategy spreads the injected water over a greater portion of the computational domain than pumping strategy #1, so a greater cooling rate should be expected.

Figure 2-31 shows the observed and fitted exponential distribution functions for the travel time calculated by MODPATH for pumping strategy #2, and the sample statistics for the travel time data and the fitted exponential distribution function parameters are listed in Table 2-16. Like the travel time data for pumping strategy #1, the exponential distribution function is a good fit for the travel time data. This ability to fit an exponential distribution to the MODPATH calculated travel time data suggests that the groundwater system is performing like a plug flow reactor with segregation.

Table 2-17 is the volume balance for the pumping strategy #2 MODFLOW simulation. Like the volume balance for pumping strategy #1, the relative discrepancy is less than 0.02%, and the difference between what is entering and leaving the constant head boundary cells is less than 0.1%. While the discrepancy with this model is slightly higher than with the previous model, it is still small enough to allow the investigators to believe that this model's results are reasonable.

The major difference between the volume balance for the pumping strategy #2 simulation and the simulation for pumping strategy #1 is that an additional 1.5263 x 10^5 m^3 is entering and leaving the model via the injection and extraction wells. This is expected because pumping strategy #2 is taking the hot water from the power plant and injecting into the Vesta mine. This water moves to the Clyde mine through openings known to exist in the mine barrier. At ten locations, water is pumped from the Clyde mine and injected into Marianna 58. Cool water is then extracted from Marianna 58 and treated before being cycled back to the power plant. Because this simulation is injecting and extracting the same water twice in the model, the volume balance in Table 2-17 shows the additional 1.5263 x 10^5 m^3 of water entering and leaving the model via the wells.

2.2.3 Water treatment and chemistry

2.2.3.1 Determining Treatment Needs

Water quality data obtained from Clyde was used to establish the water treatment requirements. These data were input into the computer program AMD Treat. Hydrated lime treatment was selected for this high volume discharge. The treatment plant is designed for 2.02 m^3/s (32,000 gpm) capacity but is evaluated economically at an initial flow of 1.77 m^3/s (28,000 gpm). Based on these data the hydrated lime requirement for this plant would be 8,830 tons per year.

The mine water chemistry is expected to change over time. Natural improvements are normal, but the water quality improvements anticipated under these pumping conditions should be dramatic. Initially, the water quality may deteriorate as poor quality water is moved toward the mine pumps due to the injection process. However, once this water has been processed the effect of the clean water injection should be felt throughout the mine complex. This should significantly reduce the cost of hydrated lime.

2.2.3.2 Geochemical analysis of treated mine water

Results of PHREEQC geochemical simulation are given in Table 2-12 for water chemistry and in Table 2-18 for saturation indices of relevant minerals. Discussion follows.

2.2.3.2.1 <u>Step 1: Raw water</u>

The raw water has 241 mg/L iron, 5.2 mg/L Mn, and minor (0.41) mg/L Al, for a total of 8.87 milliequivalents/liter calculated metal acidity, under the assumption that nearly all Fe and Mn are present in reduced form in the raw water. The water has considerable alkalinity in dissolved form (603 mg/L, or 12.06

milliequivalents/liter), and thus the water is “net alkaline”, with sufficient alkalinity to neutralize all metals present.

2.2.3.2.2 Step 2: Cool treated water

Despite the net alkalinity of the raw water, in practice, some lime would be added to this water, to elevate pH, needed to promote rapid metals removal, and to encourage floc development for settling of sludge. By experience, a lime dose of 2.88 millimoles/liter (5.76 milliequivalents/liter) of portlandite was added in this step of the reaction, to simulate conditions in a working lime treatment facility.

The treated water was then constrained to precipitate under the following conditions:

phase	**Saturation Index**
Calcite	0.3
$Al(OH)_3$ (amorphous)	0.0
$Fe(OH)_3$ (amorphous)	0.0
Pyrolusite	0.0
Gypsum	0.0

The amorphous phases are relatively soluble mineral phases commonly produced in AMD treatment. Pyrolusite is a common manganese oxide (tetravalent) found in soils. Gypsum is a common reaction product in high-sulfate waters treated with lime. Calcite was designated as the likely calcium carbonate to precipitate in these waters following lime addition. Its slight rate of supersaturation (SI=+0.30) is in deference to the fact that calcite is kinetically slower to form than the other phases.

Results (Tables 2-12 and 2-18) show that metal concentrations were reduced to <0.01 mg/L for iron, but neither aluminum nor manganese reaction products were formed under these conditions. For aluminum, this is ascribed to the $Al(OH)_4^-$ complex at the treated water pH (8.17), which retains the aluminum in soluble form. For manganese, this is ascribed to the pH of the water being too low to remove manganese. Therefore, barring further chemical treatment, these minor concentrations of Al and Mn are likely to be present in the cooling water despite treatment. It would be possible to remove Mn by raising pH further by lime addition, but this would also increase the potential for calcite scale.

The treated water is greatly lowered in alkalinity (to 121 mg/L, due to neutralization of oxidation generated acidity and to formation of calcite. In addition, it is about 40% lower in Ca than the raw water (165 mg/L, from 272), from calcite precipitation. Gypsum did not form.

2.2.3.2.3 Step 3: Hot treated water

The heated water (40^{o}C) is allowed to react with chalcedony assumed present in the mine environment, to equilibrium. This is the only reaction constraint applied.

The only changes from cool treated water are in pH (7.87 from 8.17) and dissolved silica (24.3 mg/L from 10.0). The pH shift is due simply to enthalpy effects on equilibrium constants for water and for the Henry's Law constant for CO_2, causing re-carbonation of the water to a slight degree. This causes a slight shift in charge balance and lowering of pH. The additional dissolved silica is a relatively minor load, but one that may entail some risk of re-precipitation as chalcedony in the mine aquifer or power plant plumbing system. Some periodic maintenance of pumps may be required to keep silica scale from accumulation. No large-scale plugging of the aquifer is anticipated to be likely from such a small load.

Gypsum is not formed in any step of the treatment process. The concentrations of sulfate are too low for this to be a concern at the level of lime addition employed.

2.2.4 Environmental Factors and Permitting

2.2.4.1 NPDES

The concept of "touch it and it's yours" is somewhat less applicable in the earth-coupled case than in the makeup water case. In this example, the discharge has not been touched and should continue to flow at its pre-power plant level. A responsible party, in this case the State of Pennsylvania using the trust fund derived from the bankruptcy of the mine operator to pay for the water treatment, is in place. All of the actions taken by the power plant during its operation benefit the responsible party. Although these points do not invalidate the Clean Water Act, they do argue against its application under these circumstances.

2.2.4.2 Underground Injection Control

The UIC regulations would appear to be the only federal environmental law that could regulate the injection of power plant water into the mines. However, because the proposed injection represents an improvement to the existing water quality in the mine there does not appear to be any basis for regulation. The concept of thermal pollution does not seem to apply because there is no biological community impacted by the rise in temperature, and there is no groundwater standard for temperature.

2.2.4.3 Water Rights

The issue of water rights remains the most serious obstacle to implementation of the earth-coupled concept. Even though water is still available and perhaps cleaner than before it will have a higher temperature. A landowner could argue that the increase in temperature under his land represents a trespass on the part of the power plant operator. Before a power plant operator would agree to build an earth-coupled systems as described in this study he would have to have legal protection.

2.2.4.4 Environmental Benefits

If a power plant were to be built utilizing an earth-coupled design a number of benefits would accrue to society.

- The mine pool from which the cooling water is pumped would be treated and would not be a burden to the taxpayers or the environment. It is expected that after plant closure this improvement would continue.

- There would be no loss of available water to evaporation as is the case with cooling tower designs. In the case of a 200-MW plant, that represents 1525 gpm that would be available for other purposes.

- A large area of heated mine water would be created. This could be used to support residential and light industrial heating needs with groundwater heat pumps.

2.2.5 Economic Analysis

For both pumping strategy #1 and pumping strategy #2, the same earth-coupled power plant design is used, with a mine water source/sink. Figure 2-32 shows the flow diagram for this plant design. Data on the final power plant design arrived after all water handling and groundwater simulation programs had been completed. Therefore, the need for auxiliary cooling water was not included in these calculations.

Approximately 32,110 gpm will be required for the plant to supply makeup water for the cooling system and service water for the DI and ash sluice systems. A worst-case supply temperature of 65°F was used for the mine water temperature. The mine water withdrawal will be directed to an AMD treatment system for pretreatment of the power plant service water.

Following the AMD treatment plant, the water supply will be split into two separate systems: service water and makeup/condenser feed water. The service water system will be supplied by two 650-gpm variable speed pumps, one operating and one for standby. Of the 610 gpm, approximately 360 gpm will be used for the deionized (DI) water system and approximately 250 gpm will be used for the ash sluice system.

The DI system will be made up of filters, prefilters, RO membranes, polishers, and a 200,000-gallon DI storage tank. The RO reject waste stream (110 gpm) will be directed to the settling ponds (or zero discharge facility).

Approximately 31,500 gpm will be used for the cooling water systems. The makeup water/condenser feed system will be supplied by three 16,000-gpm pumps. This will allow two pumps two handle the full load when maintenance is required on the third pump.

The heat rejection system of the steam cycle consists of a surface condenser with two shells, a circulating water system, and cooling towers. The surface condenser receives exhaust steam from the low-pressure section of the steam turbine generator and condenses it to liquid for return to the heat recovery steam generator. The heat rejected from the steam will be absorbed by approximately 28,000 gpm of once through cooling water that exits the condenser approximately 55°F warmer than when it entered.

The warm once through cooling water from the surface condenser and other miscellaneous heat exchangers used in the plant will be directed back to the mine water source.

The final stage in the water system will be the settling ponds. The discharge water from the ash sluice system and the RO reject water will collect in the wastewater settling ponds prior to being discharged back into the river. Approximately 360 gpm will return to a mine water source.

Table 2-19 shows the estimated cost for the once through cooling circuit. There are considerable savings within the power plant as compared to the 200 MW base case: $16,686,276 vs. $43,776,230 for a potential savings of $27,089,954. However, this is exclusive of the mine water handling and treatment requirements.

Table 2-20 shows the estimated cost for pumping strategy #1. Under this scenario, a $16,103,700 investment is required in the water-handling infrastructure. This raises the capital investment required to $32,789,976. This is still less than the capital cost of the base case plant by $10,986,254. Operating cost of the combined water handling system and the power plant is $4,188,531 as compared to the base case design operating cost of $3,509,412. This represents a $679,119 increase. The $679,119 increase in operating cost is less than the amount of money that is estimated for the cost of hydrated lime. As the mine water quality improves, the cost of lime and sludge removal is expected to decrease as well. This decrease may well offset the initial higher operating cost.

Table 2-21 shows the estimated cost for pumping strategy #2. Capital investment under this approach is estimated to be $18,379,200. This still leaves the invested capital less than the base case. However, the operating cost of the water handling system alone escalates rapidly to $5,895,831 per year, for a combined annual operating cost of $6,759,291 per year. This represents a $3,249,879 increase in operating cost over the base case.

2.3 Conclusions

The conclusions of this study for Type B cooling are:

- we were able to identify one favorable site in the study area where such cooling is technically feasible and attractive in terms of capital costs.

- Flow and thermal modeling is required to establish design parameters for earth-coupled cooling, and techniques are available to accomplish plausible results. Thermal modeling establishes the area of the mine needed to achieve the required cooling, while flow modeling produces average mine residence times (206 and 291 days for pumping strategies # 1 and #2, respectively) that must be known to assure cooling performance.

- The capital cost of pumping strategy #1 is 75 percent of the base case with operating costs that are 119 percent of the base case.

- The capital cost of pumping strategy #2 is 80 percent of the base case with operating costs that are 193 percent of the base case.

Pumping over barriers as illustrated in pumping strategy #2 adds substantial cost to the process. Alternative methods to increase mine interconnections, such as directional drilling, might be an attractive though untried option to reduce operational costs.

The results of the thermal and flow modeling indicated that groundwater modeling can be employed to establish the design parameters for the earth-coupled cooling. Thermal modeling was used by this project to establish the acceptable ranges for the following parameters to maintain the required cooling rate: mine surface area, overburden depth, groundwater travel time between injection and extraction wells, and total pumping rate. Flow modeling was used to determine the acceptable ranges for the following parameters: mine gob and passageway hydraulic conductivity, mine barrier conductance and configuration, and pumping strategy.

The thermal model simulated an earth-coupled cooling system installed in a mine with a surface area of 8.570×10^7 m^2, an average groundwater travel time between 204 and 233 days, and an overburden depth of 152 m. The total pumping rate was initially 1.77 m^3/s and increased to 1.89 m^3/s and 2.02 m^3/s at 4,500 and 8,500 days after the start of the simulation to maintain the required cooling rate of 217 MW.

The first investigated pumping strategy involved injecting hot water from the power plant into the Vesta mine, and extracting the cooled water from the Clyde mine. The median travel time with the first pumping strategy was approximately 206 days.

The second pumping strategy involved injecting hot water from the power plant into the Vesta mine, extracting the cooled water from the Clyde mine, reinjecting the cooled water into Marianna 58, and extracted the still cooler water from the upper part of Marianna 58. The median travel time with the second pumping strategy was approximately 291 days, but because this pumping strategy involves reinjecting the cooled water extracted from Clyde, additional cooling that is not reflected in the median travel time should be observed. This additional cooling that this pumping strategy should provide is reflected by the 81% additional surface area of the MODPATH calculated flow field with the pumping strategy.

Significant savings can be achieved on the capital cost of the power plant if an earth-coupled system can be designed by minimizing operating costs identified in this study. If two mines could be linked at the deepest part of their extent then the plant could be located near the shallow cover where the pumping cost would not be as great.

2.4 References

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2.5 Figures and Tables

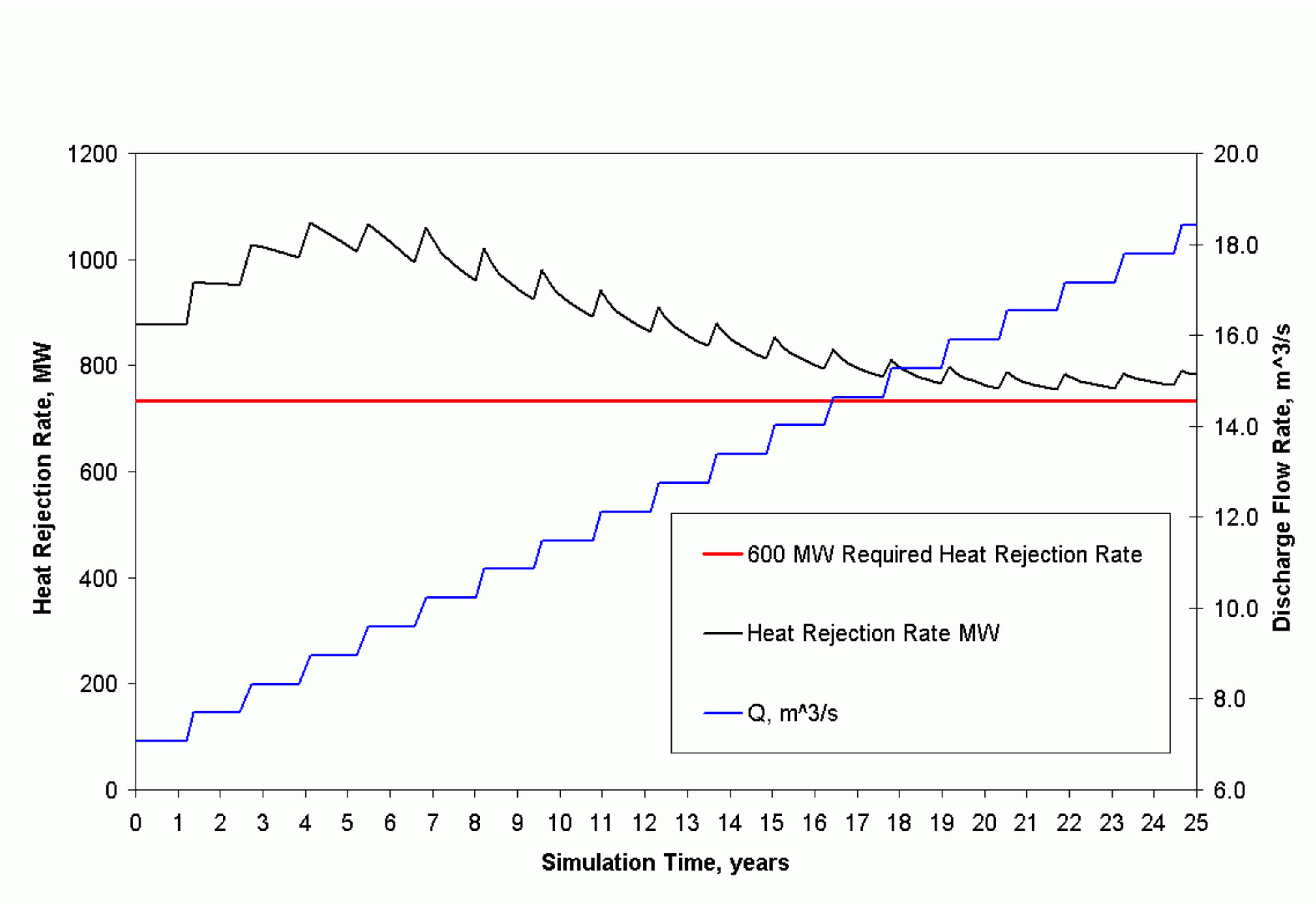

Figure 2-1 Pumping rates needed to meet heat rejection requirements

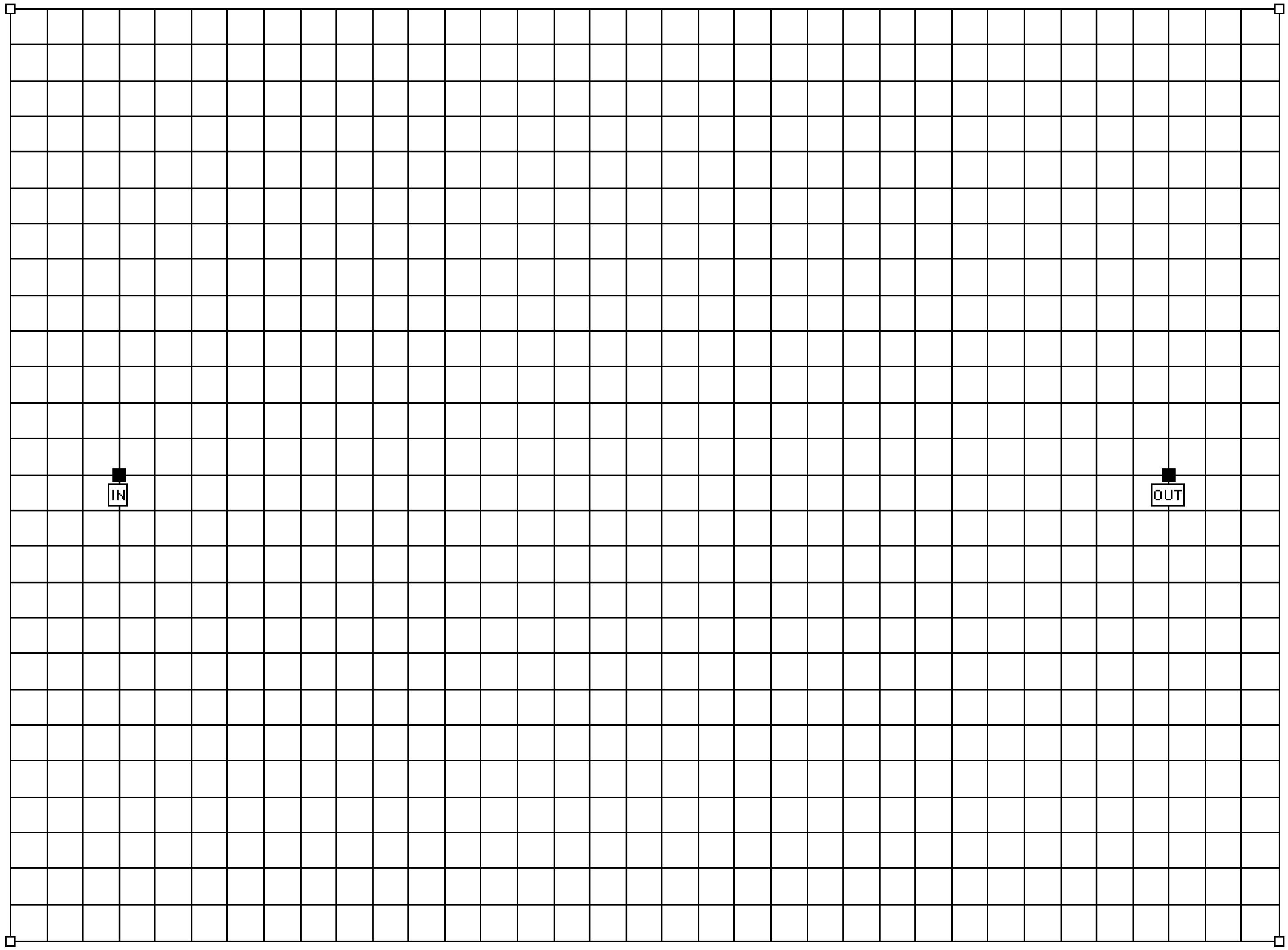

Figure 2-2. Computational grid for the HST3D simulations.

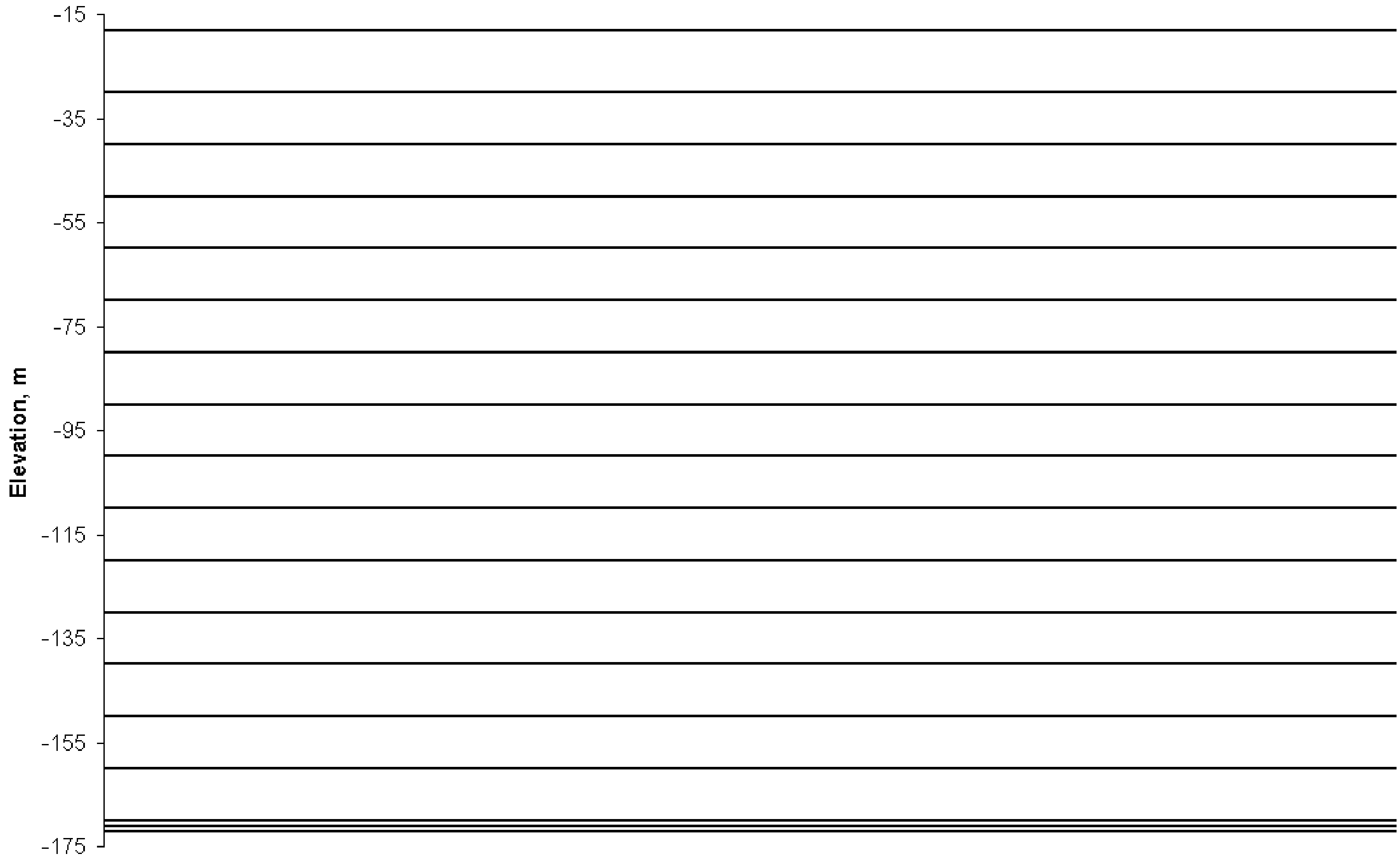

Figure 2-3. Computational layers for the HST3D simulations.

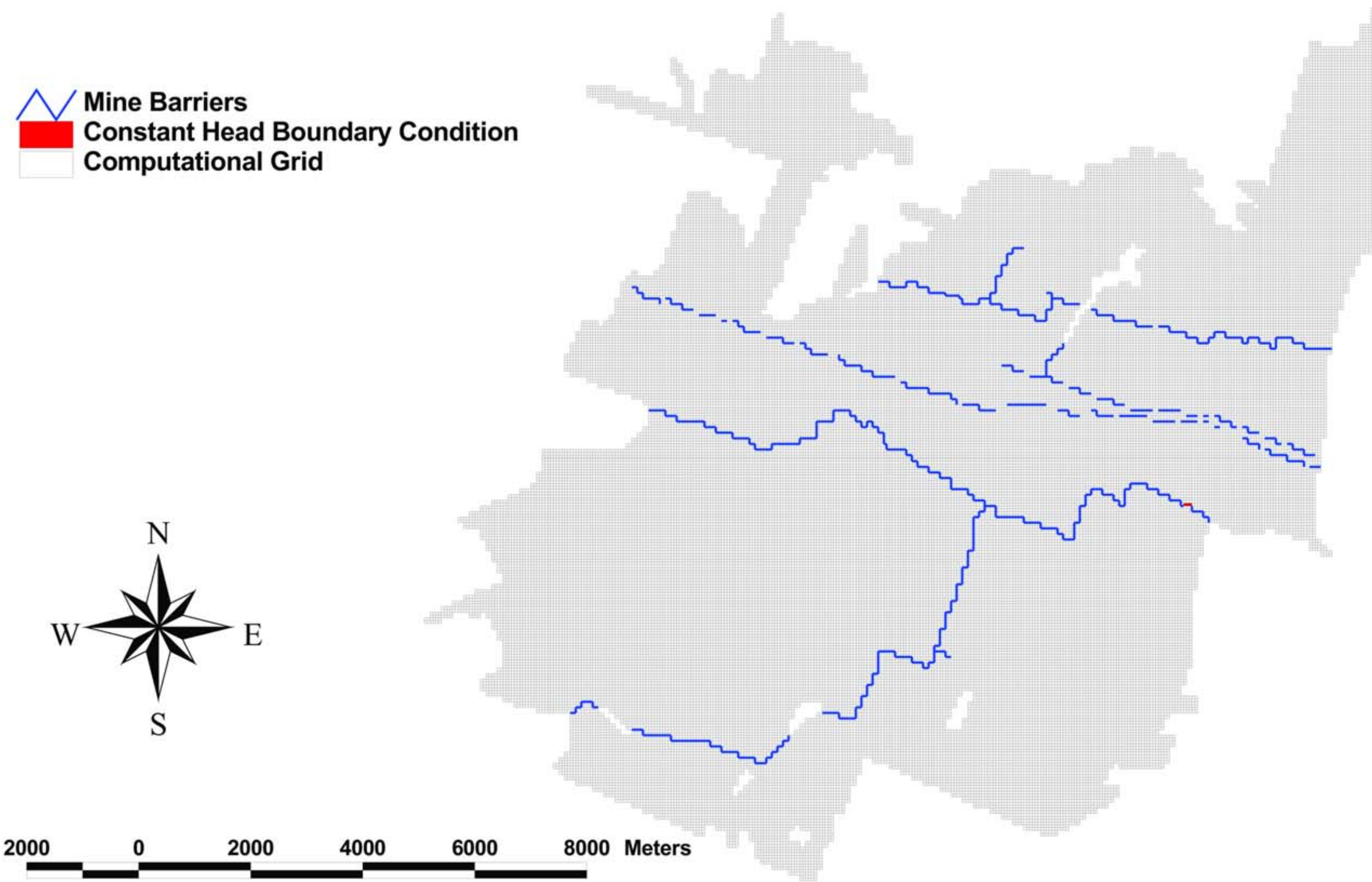

Figure 2-4. Computational grid for the MODFLOW simulations.

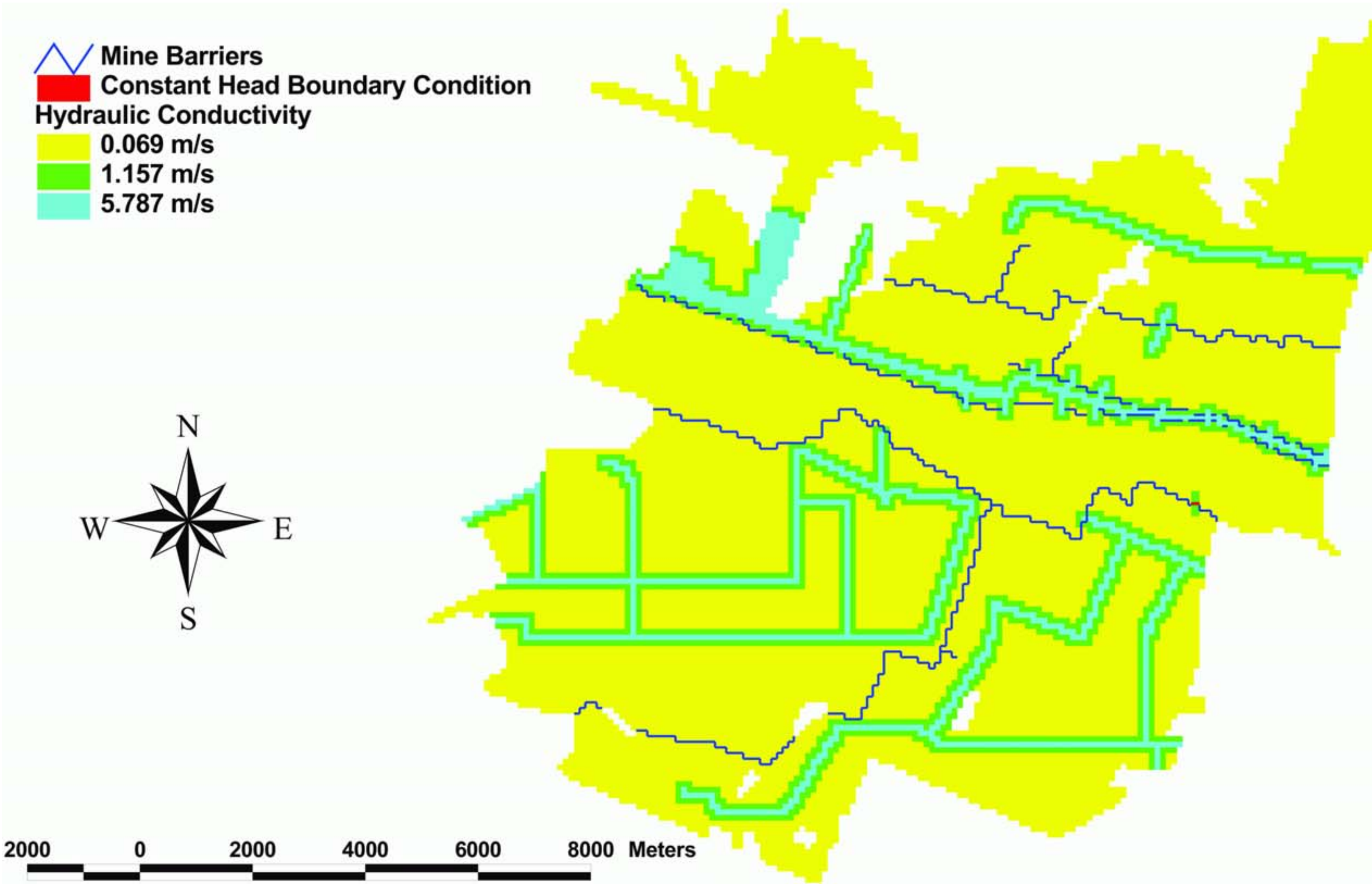

Figure 2.5. Hydraulic conductivity zones for the MODFLOW simulations.

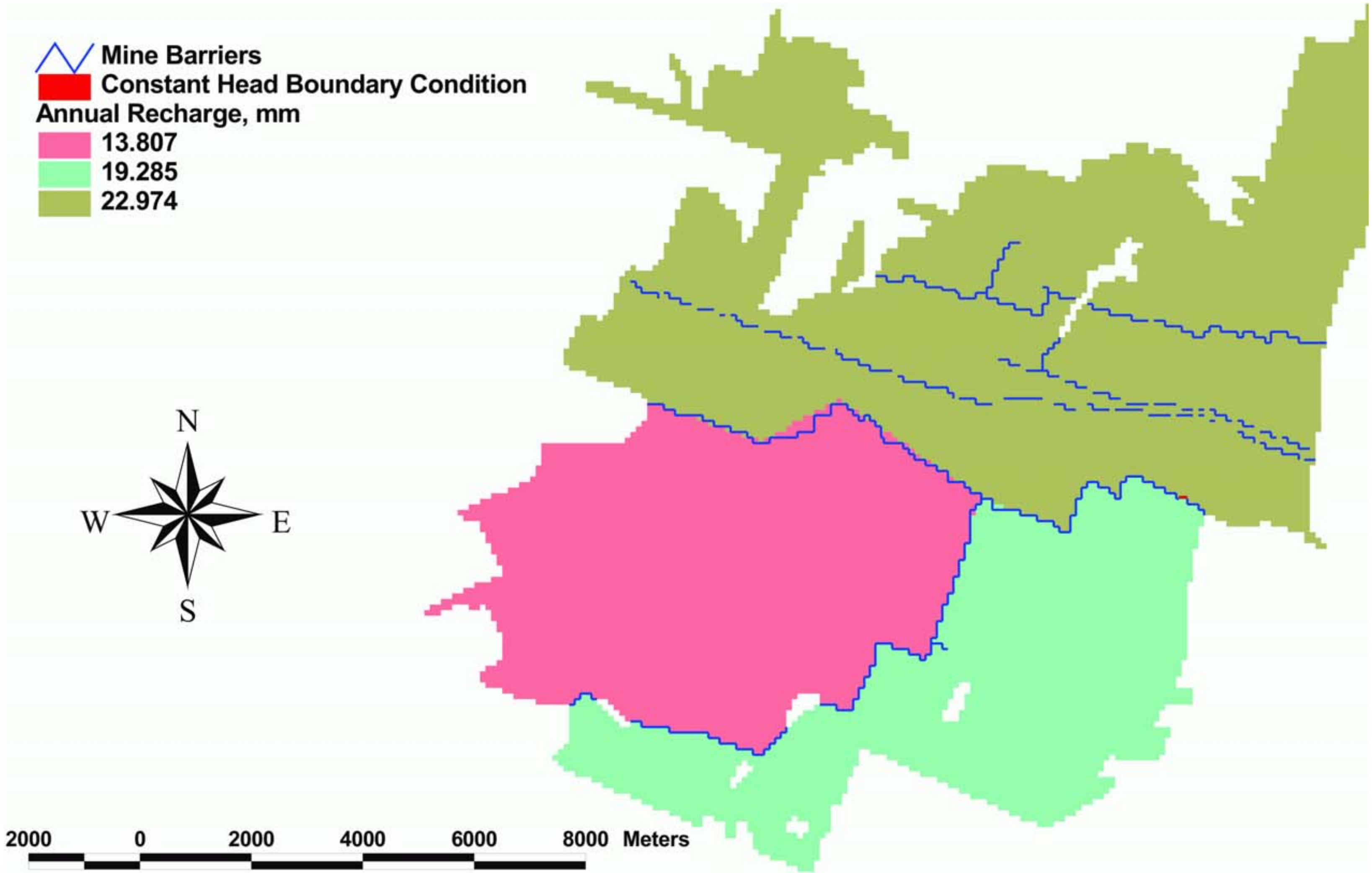

Figure 2-6. Recharge zones for the MODFLOW simulations.

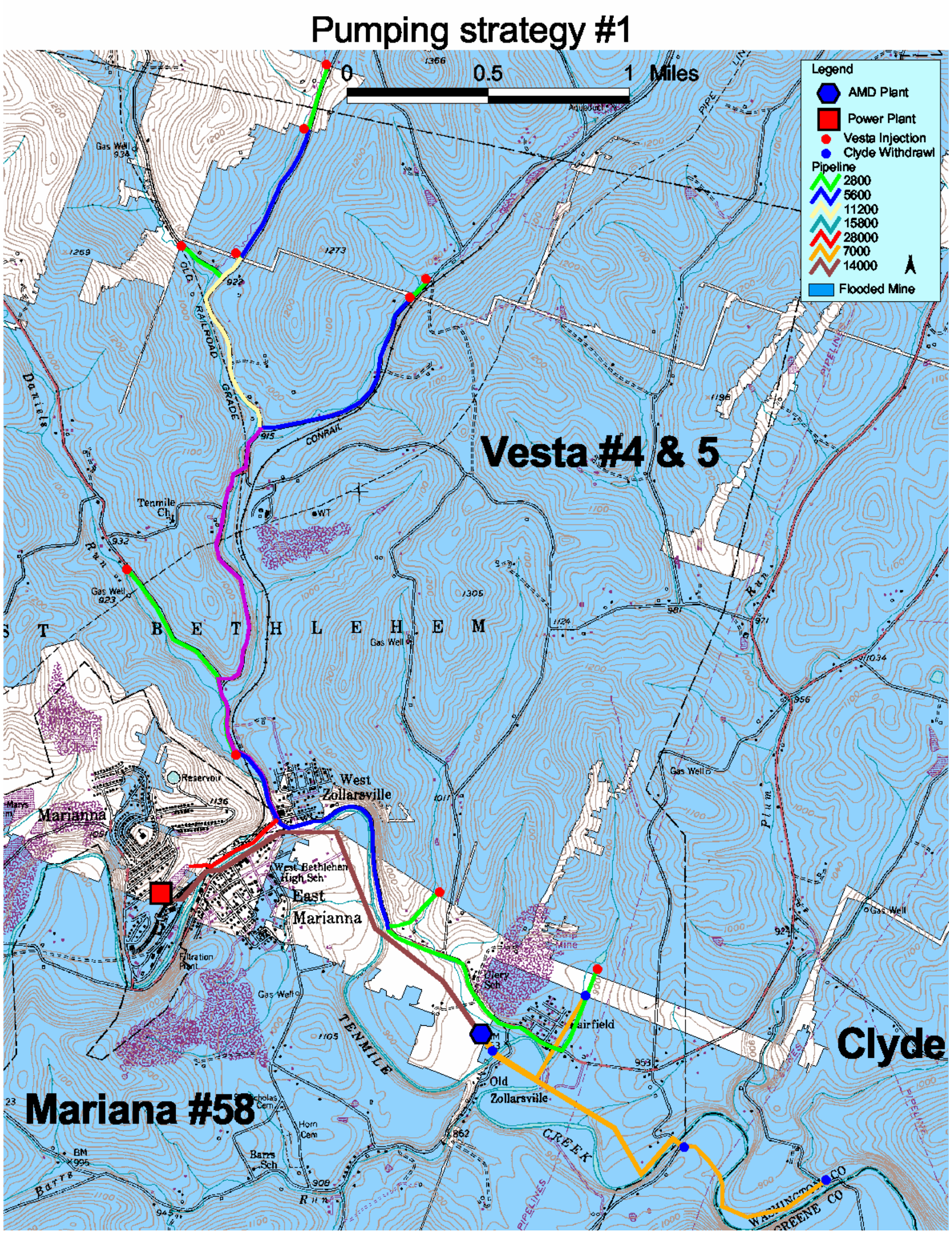

Figure 2-7. Pumping strategy #1 map showing configuration of mines and pipeline systems.

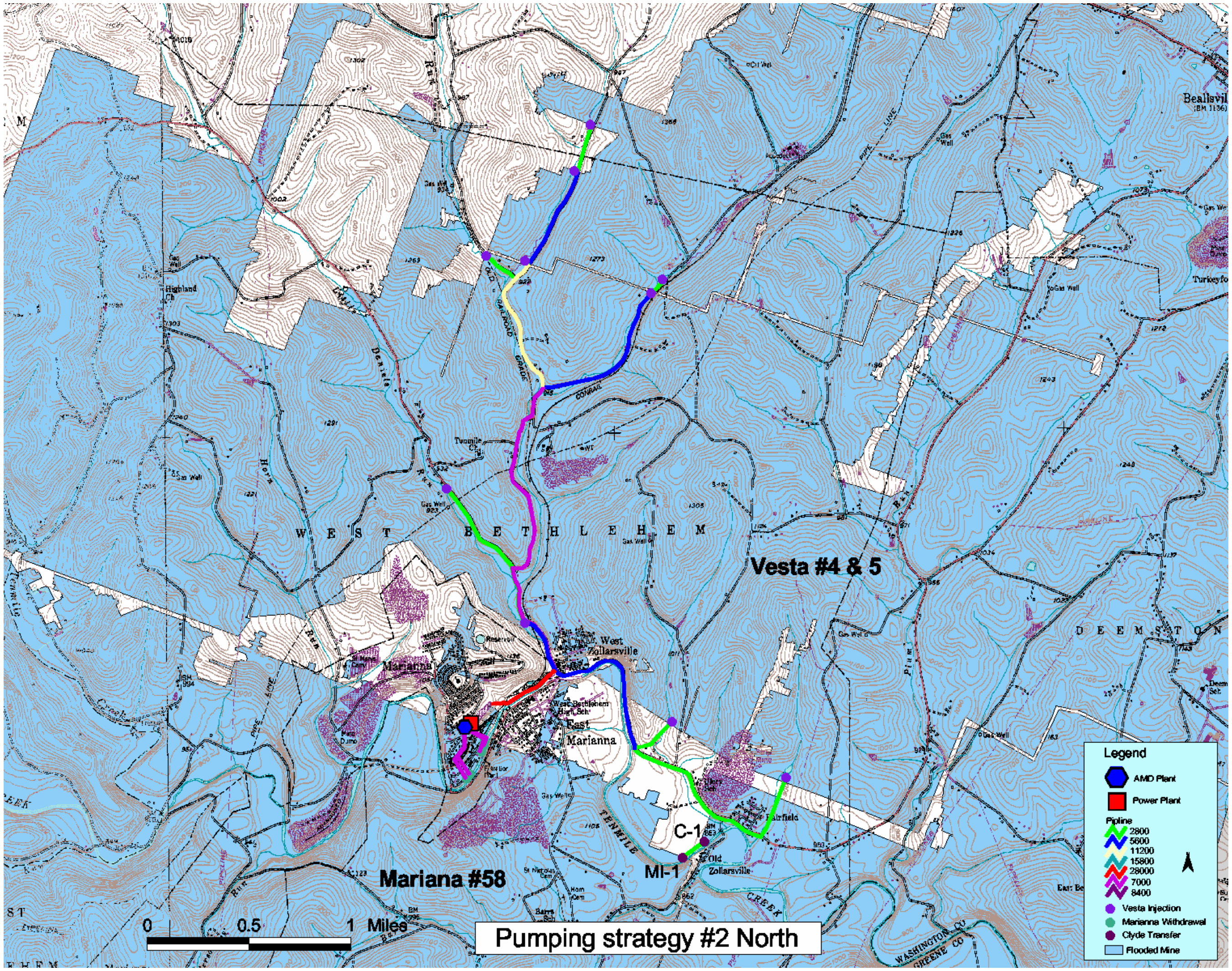

Figure 2-8. Pumping strategy #2 map (northern portion) showing configuration of mines and pipeline systems.

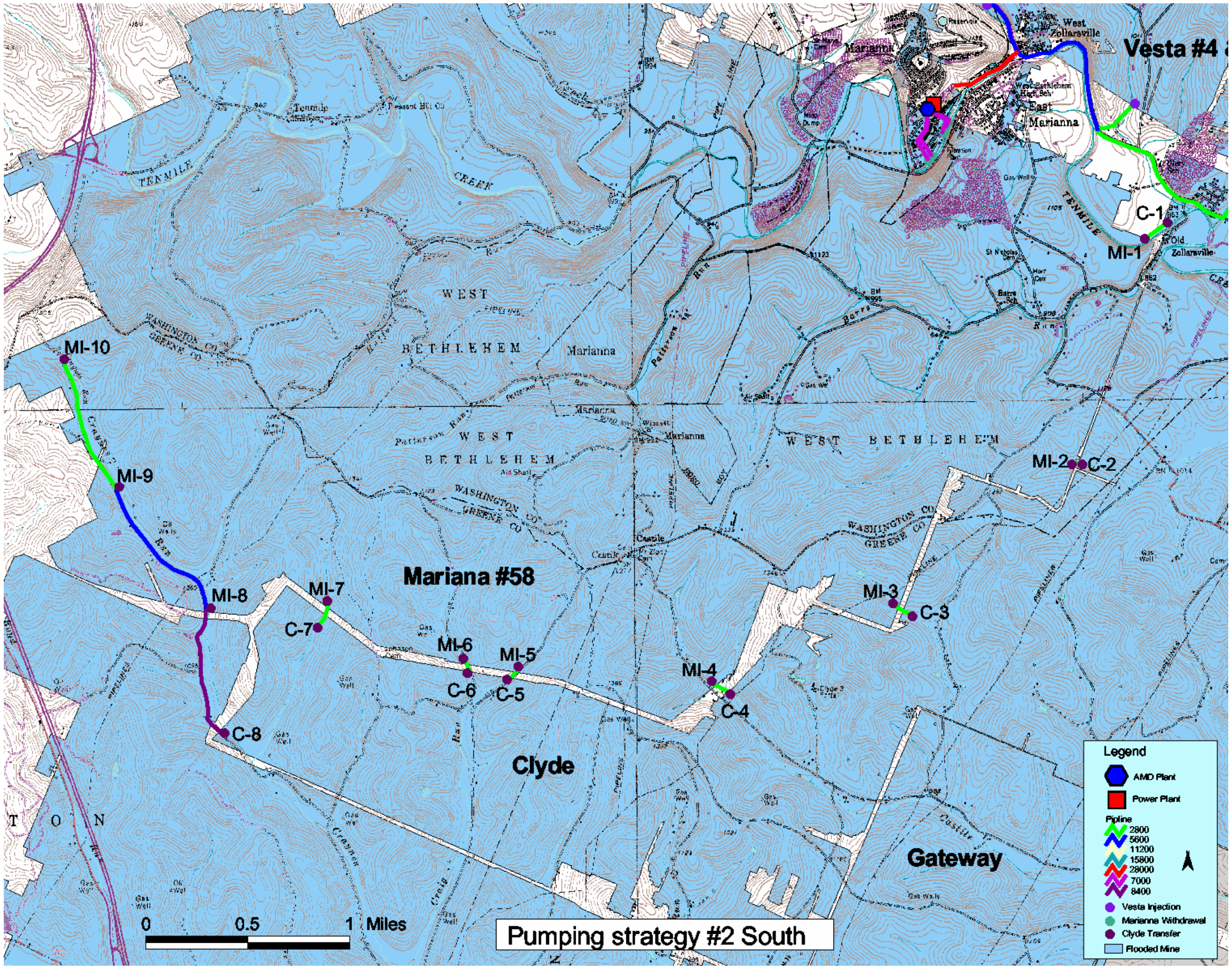

Figure 2-9. Pumping strategy #2 map (southern portion) showing configuration of mines and pipeline systems.

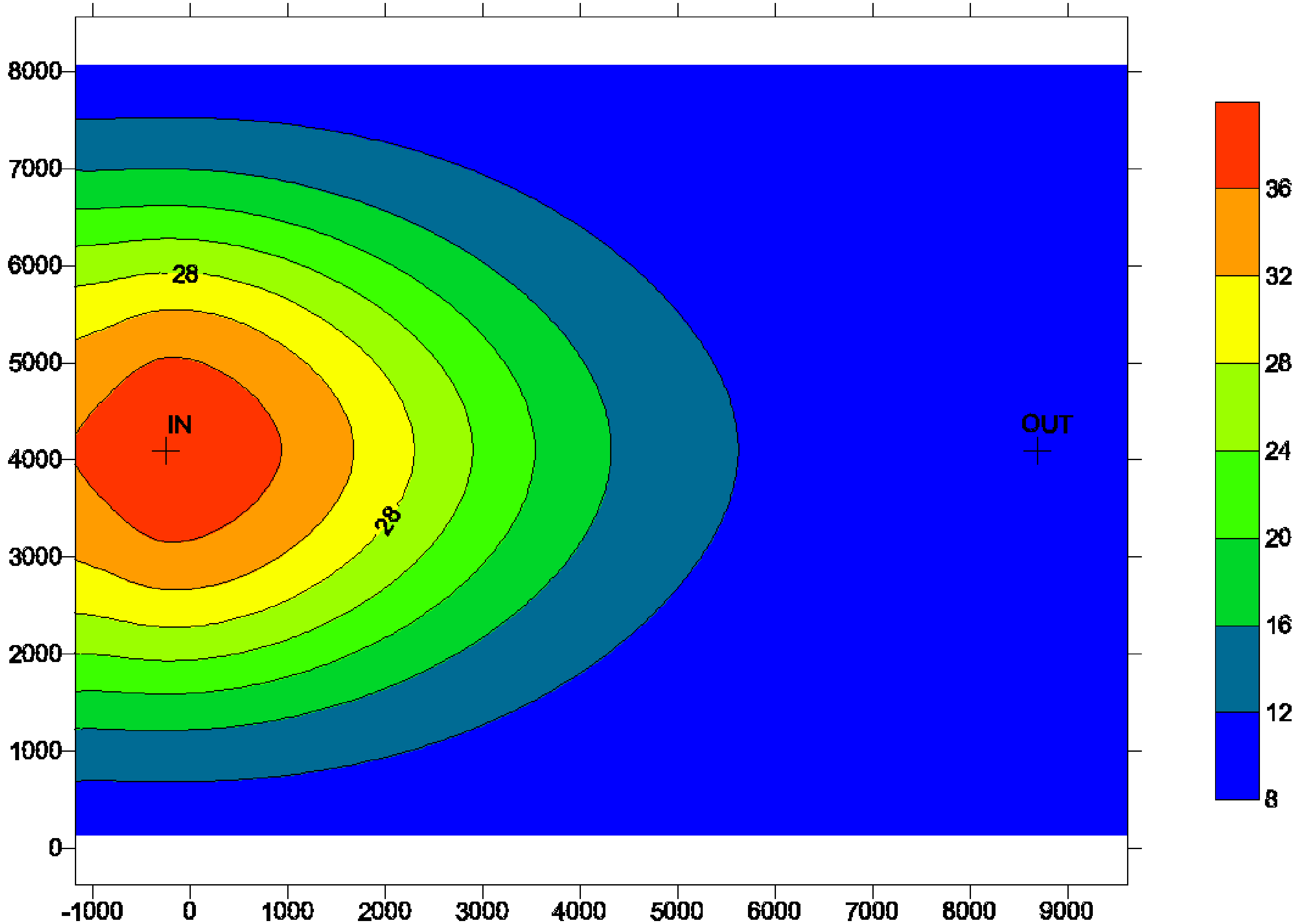

Figure 2-10. Simulated temperature (°C) for the mine layer (layer 2, elevation -171 m) at 4,500 days.

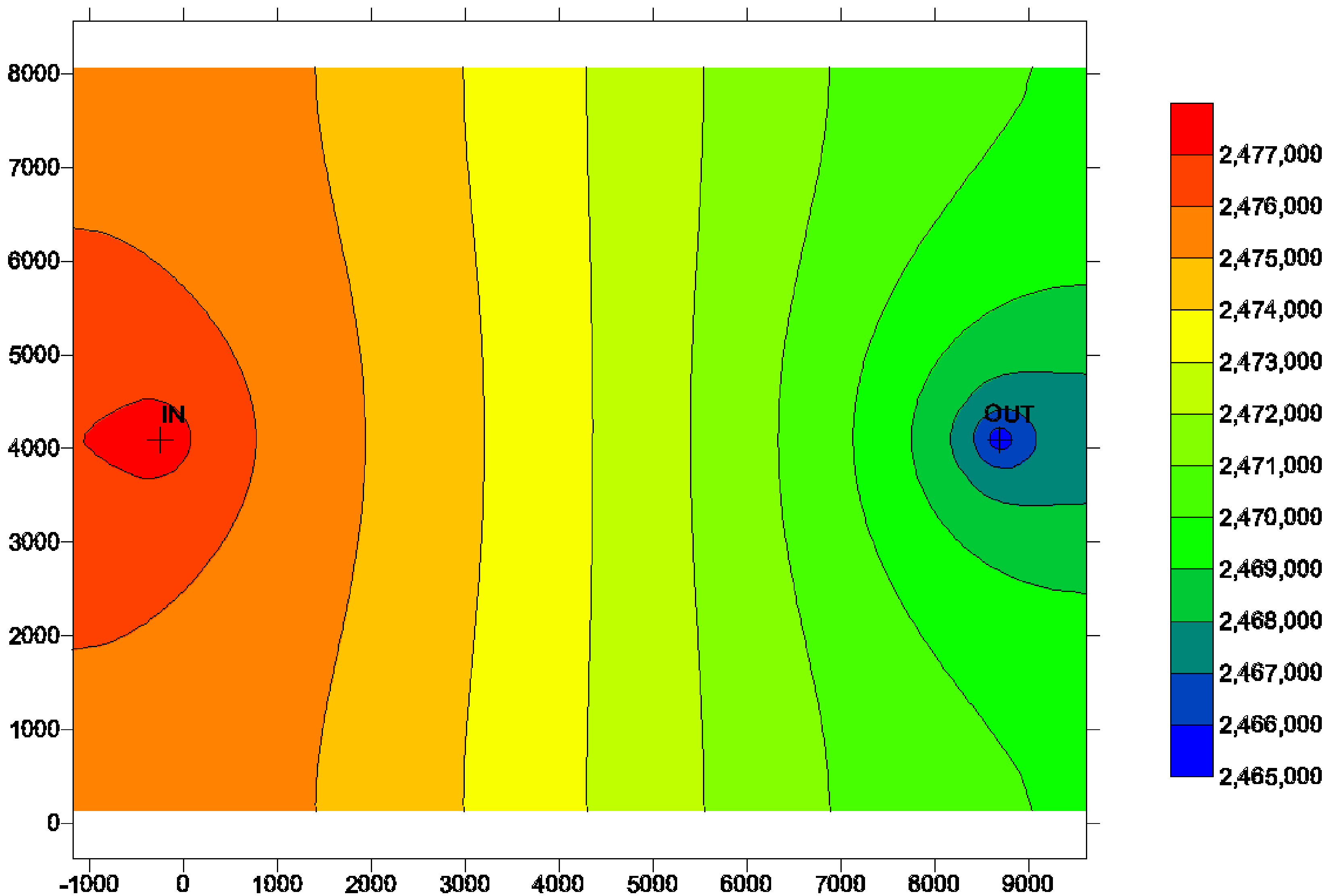

Figure 2-11. Simulated pressure (Pa) for the mine layer (layer 2, elevation -171 m) at 4,500 days.

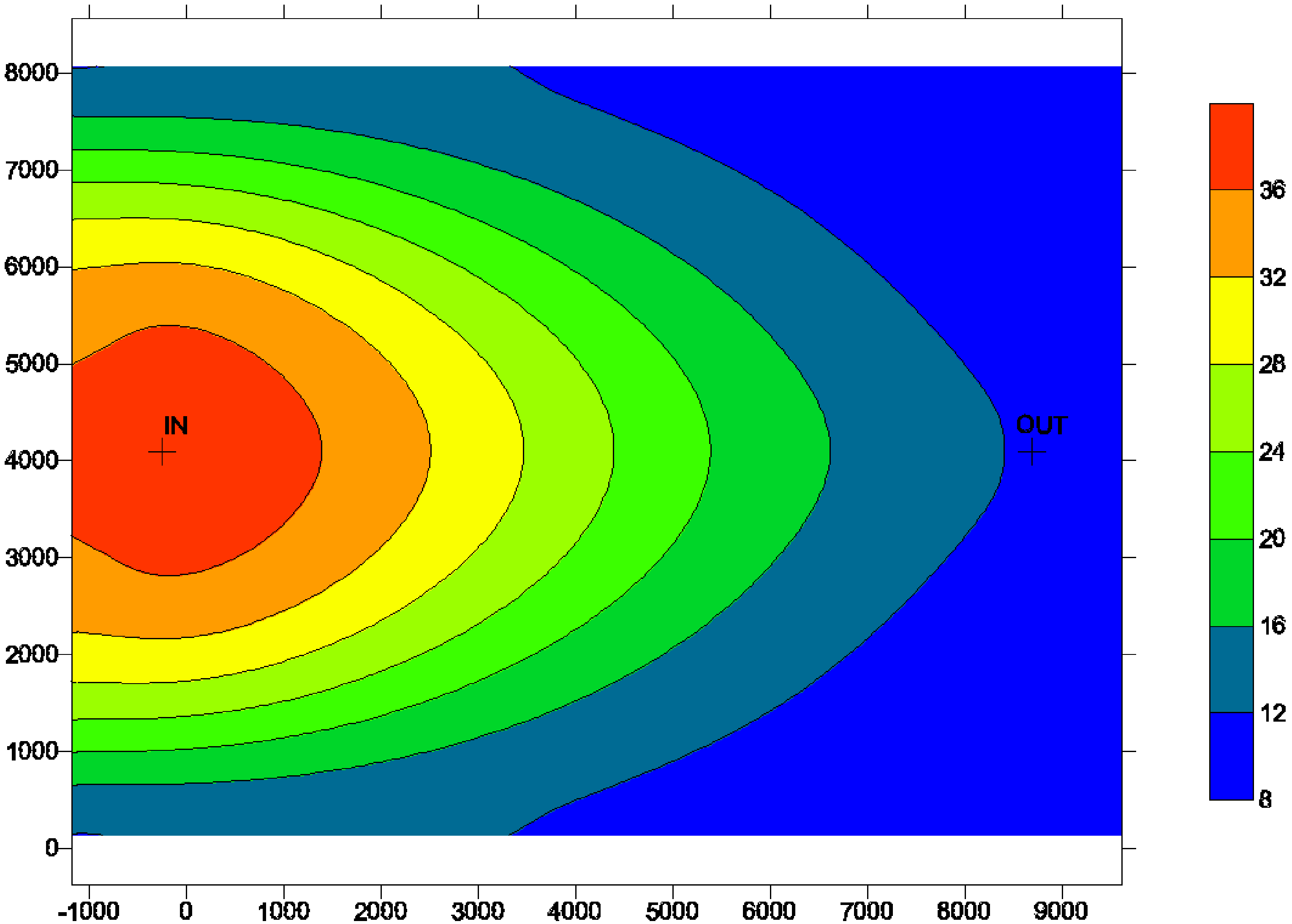

Figure 2-12. Simulated temperature (°C) for the mine layer (layer 2, elevation -171 m) at 8,500 days.

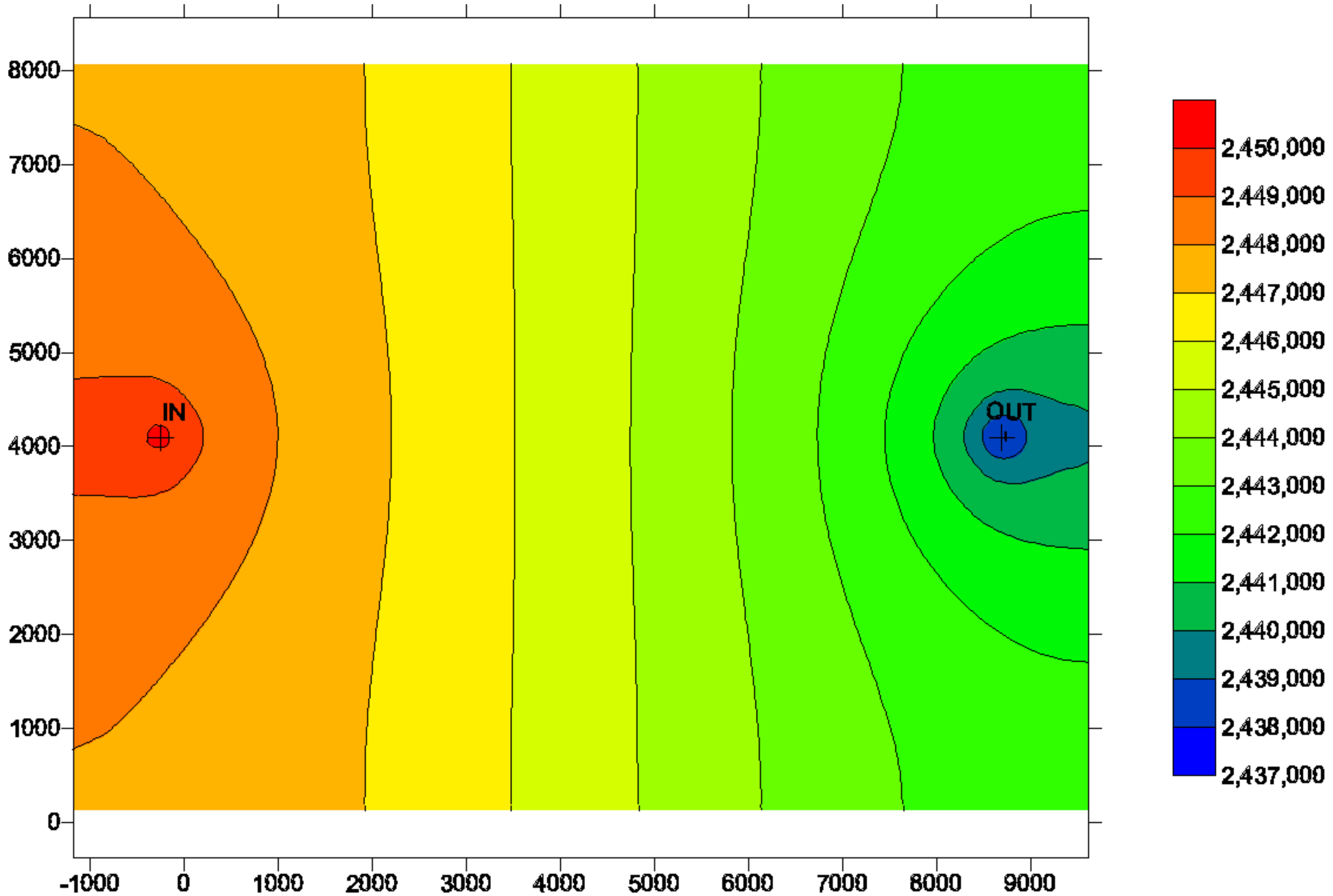

Figure 2-13. Simulated pressure (Pa) for the mine layer (layer 2, elevation -171 m) at 8,500 days.

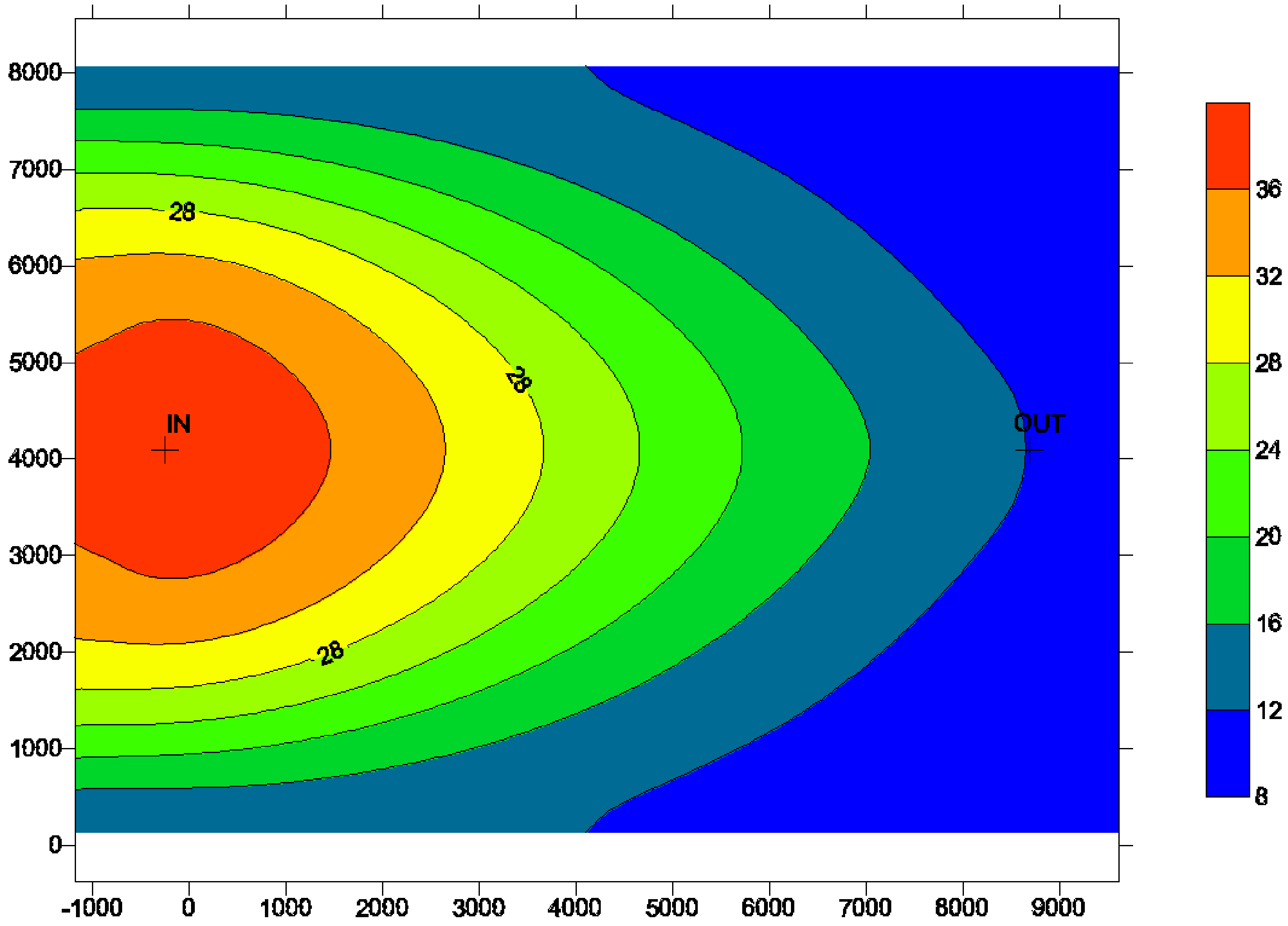

Figure 2-14. Simulated temperature (°C) for the mine layer (layer 2, elevation -171 m) at 9,250 days.

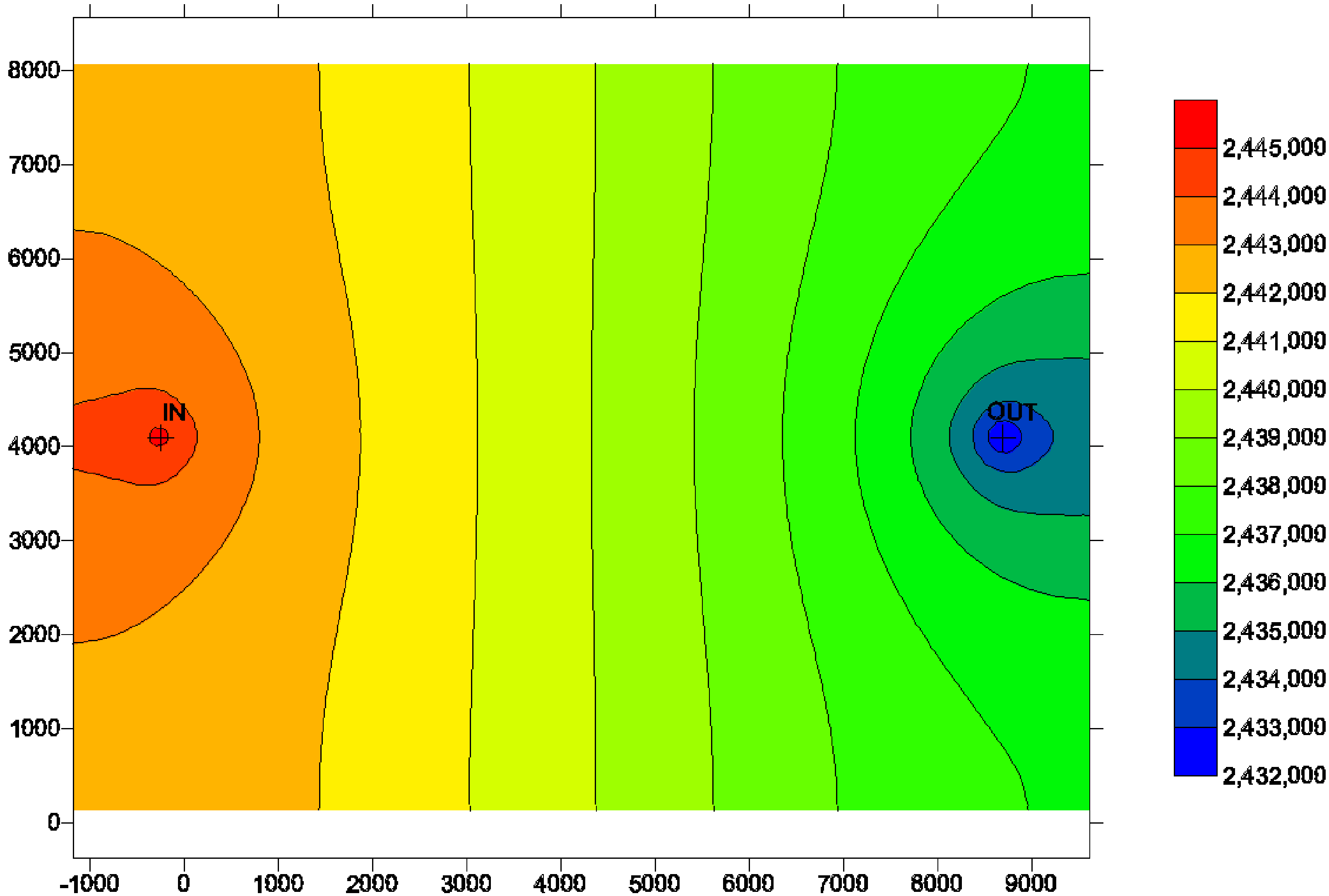

Figure 2-15. Simulated pressure (Pa) for the mine layer (layer 2, elevation -171 m) at 9,250 days.

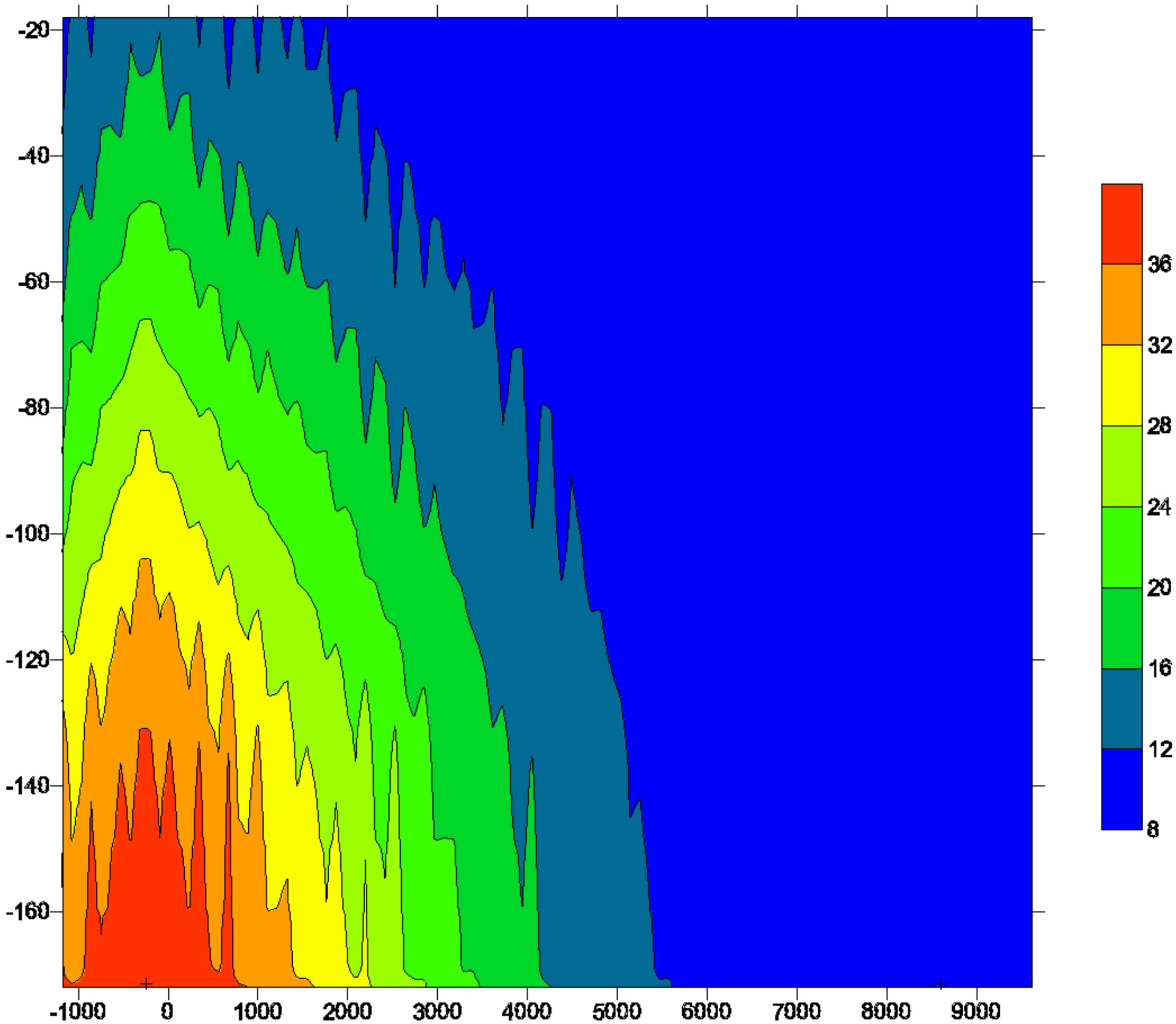

Figure 2-16. Simulated temperature (°C) for the middle of the model (row 14) at 4,500 days.

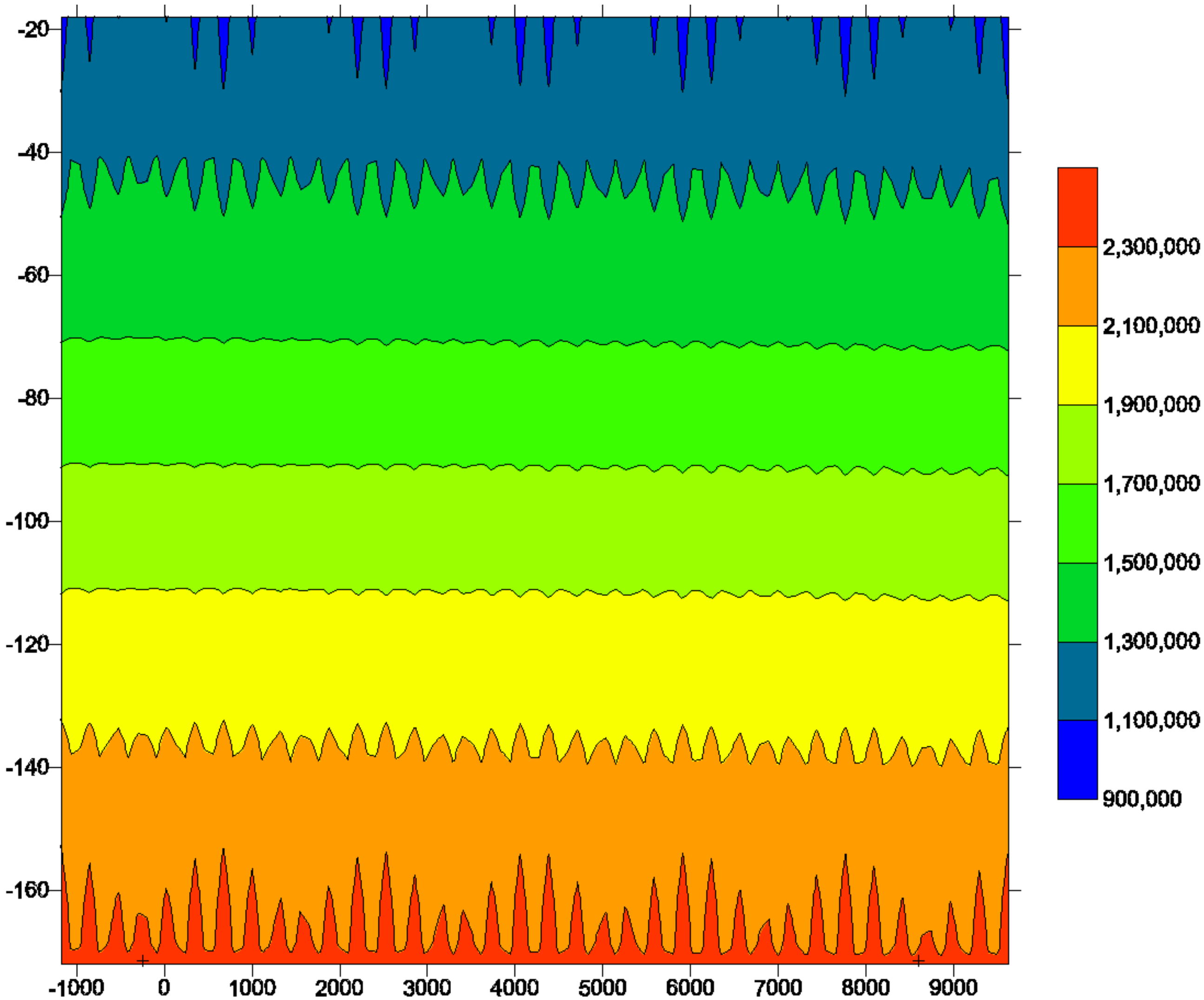

Figure 2-17. Simulated pressure (Pa) for the middle of the model (row 14) at 4,500 days.

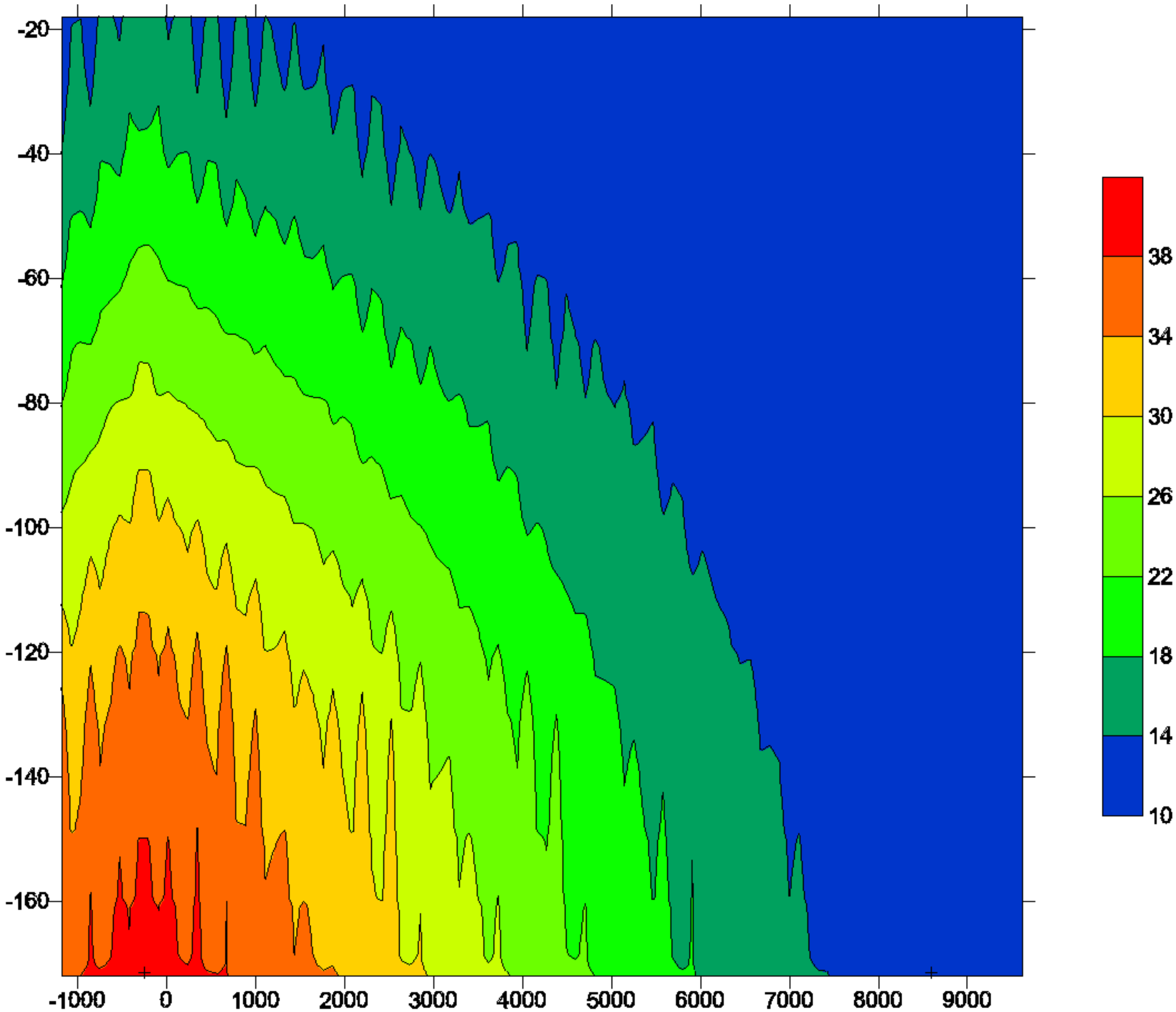

Figure 2-18. Simulated temperature (°C) for the middle of the model (row 14) at 8,500 days.

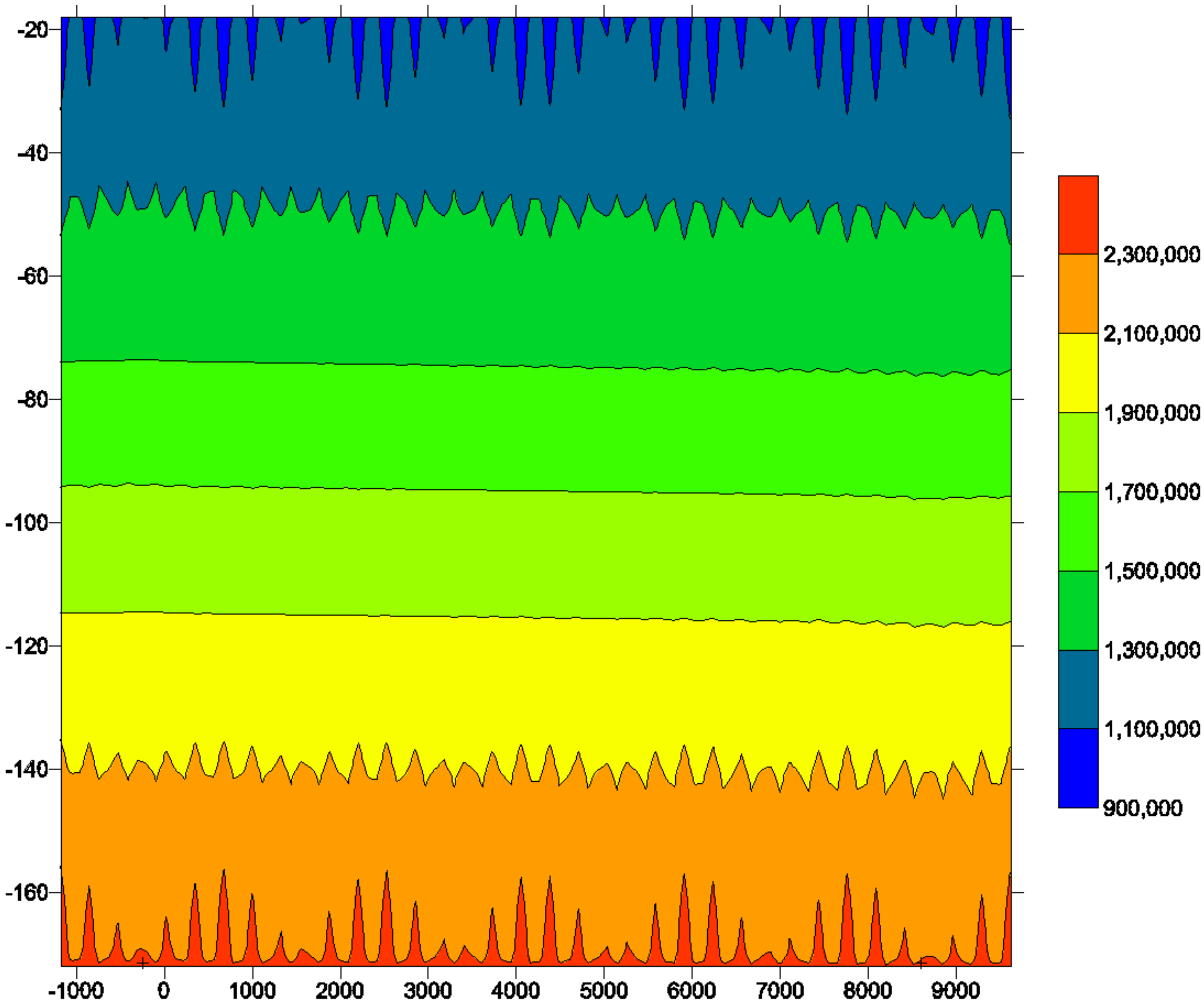

Figure 2-19. Simulated pressure (Pa) for the middle of the model (row 14) at 8,500 days.

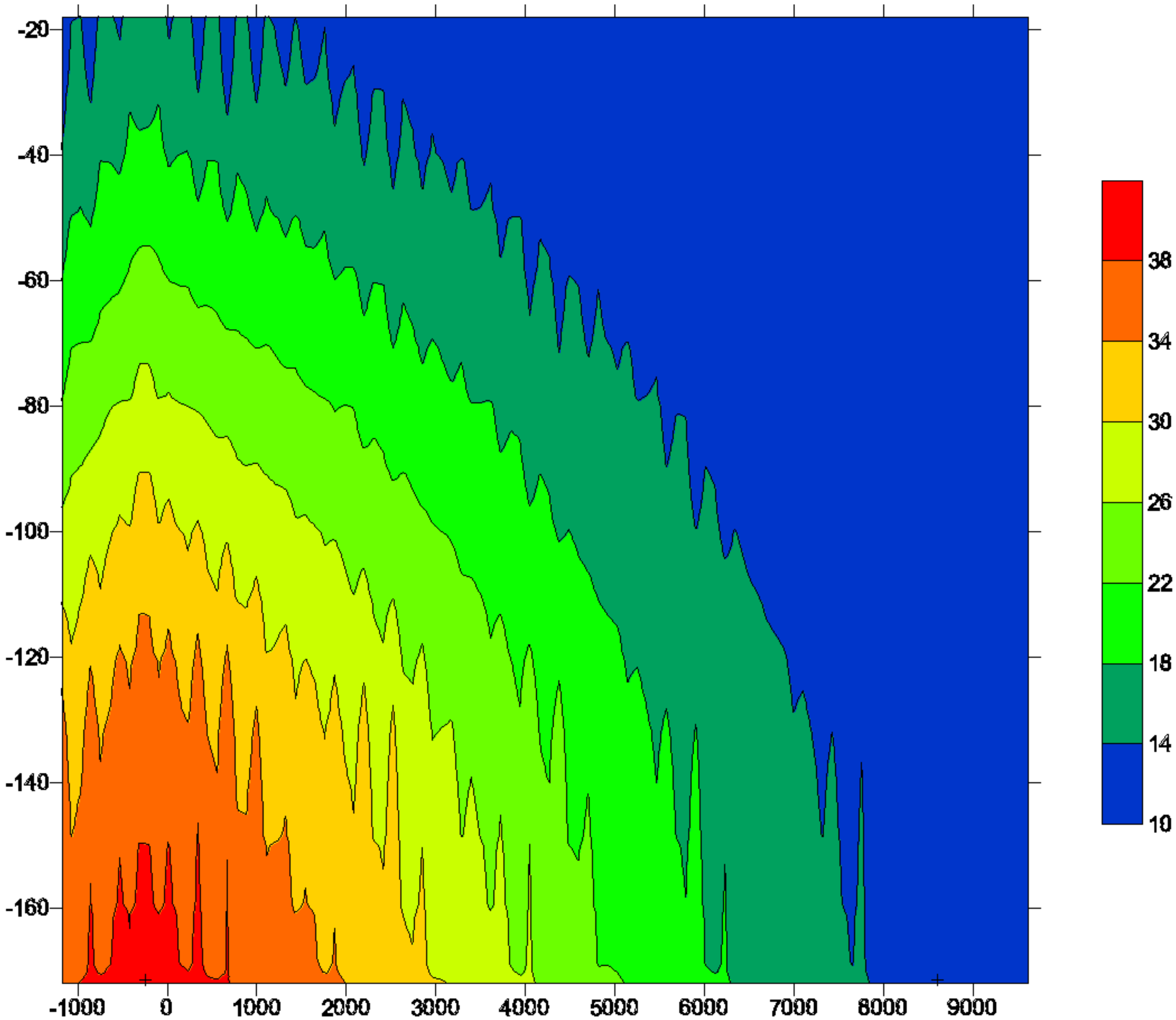

Figure 2-20. Simulated temperature (°C) for the middle of the model (row 14) at 9,250 days.

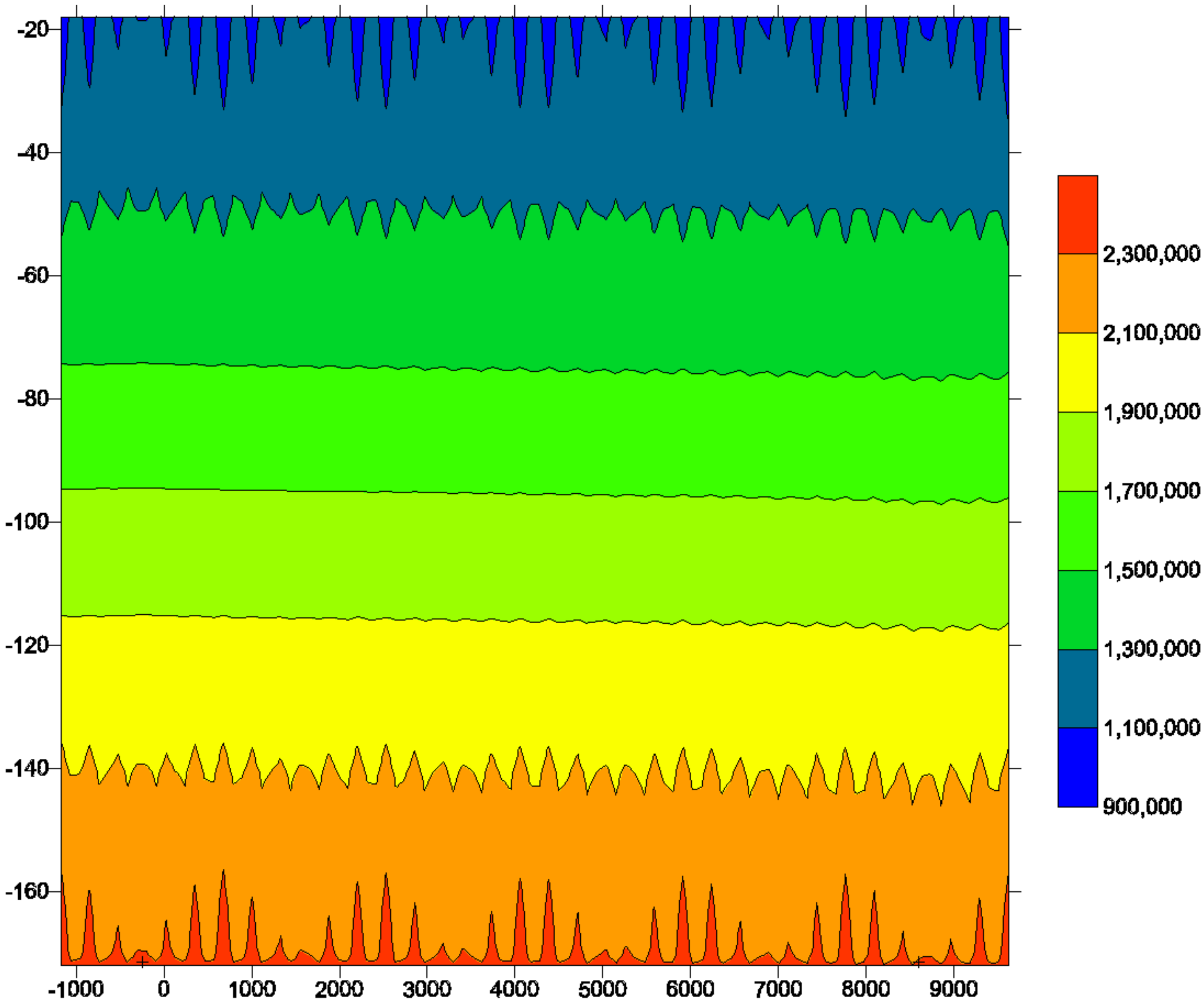

Figure 2-21. Simulated pressure (Pa) for the middle of the model (row 14) at 9,250 days.

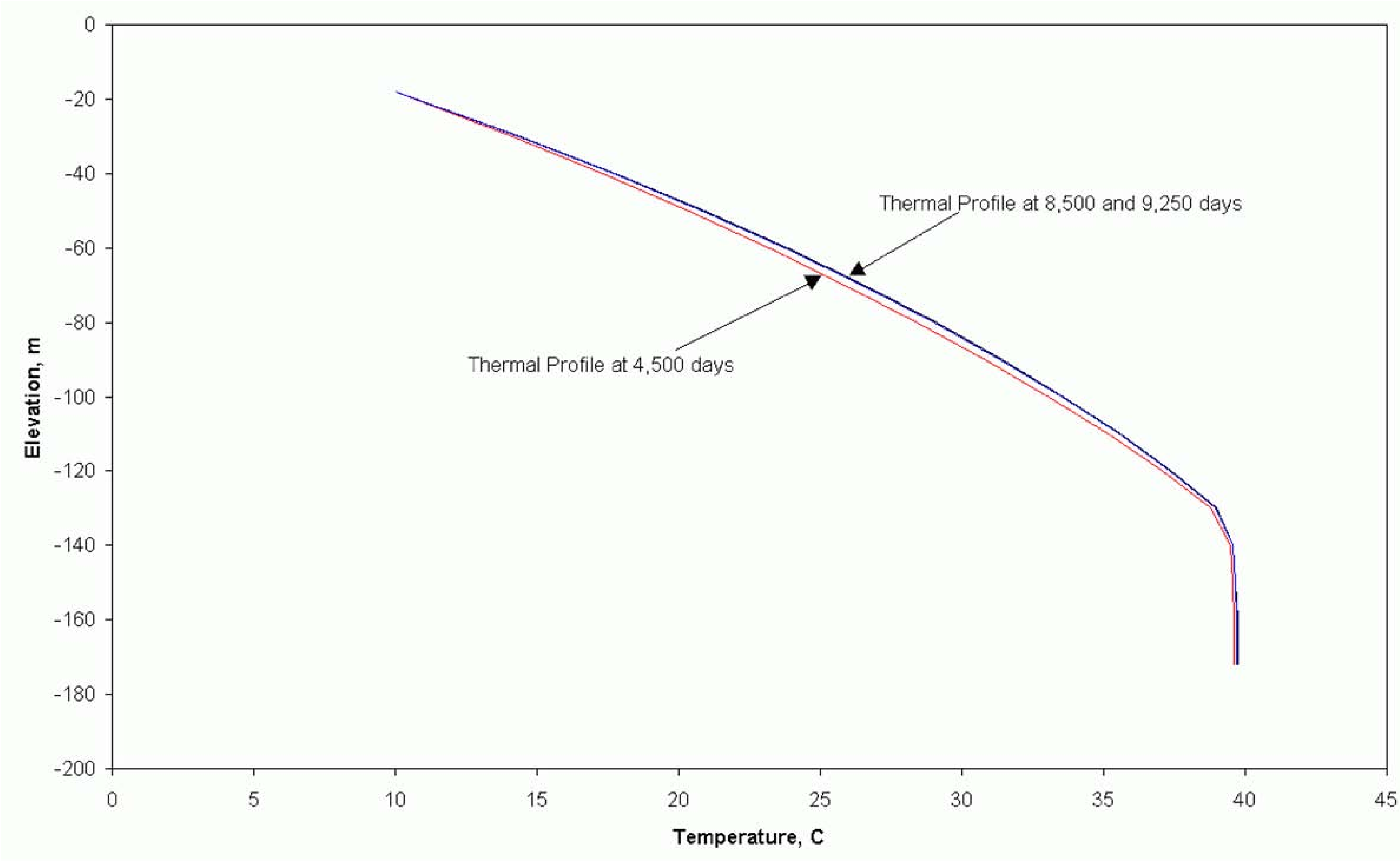

Figure 2-22. Vertical thermal profile above the injection well at 4,500, 8,500, and 9,250 days.

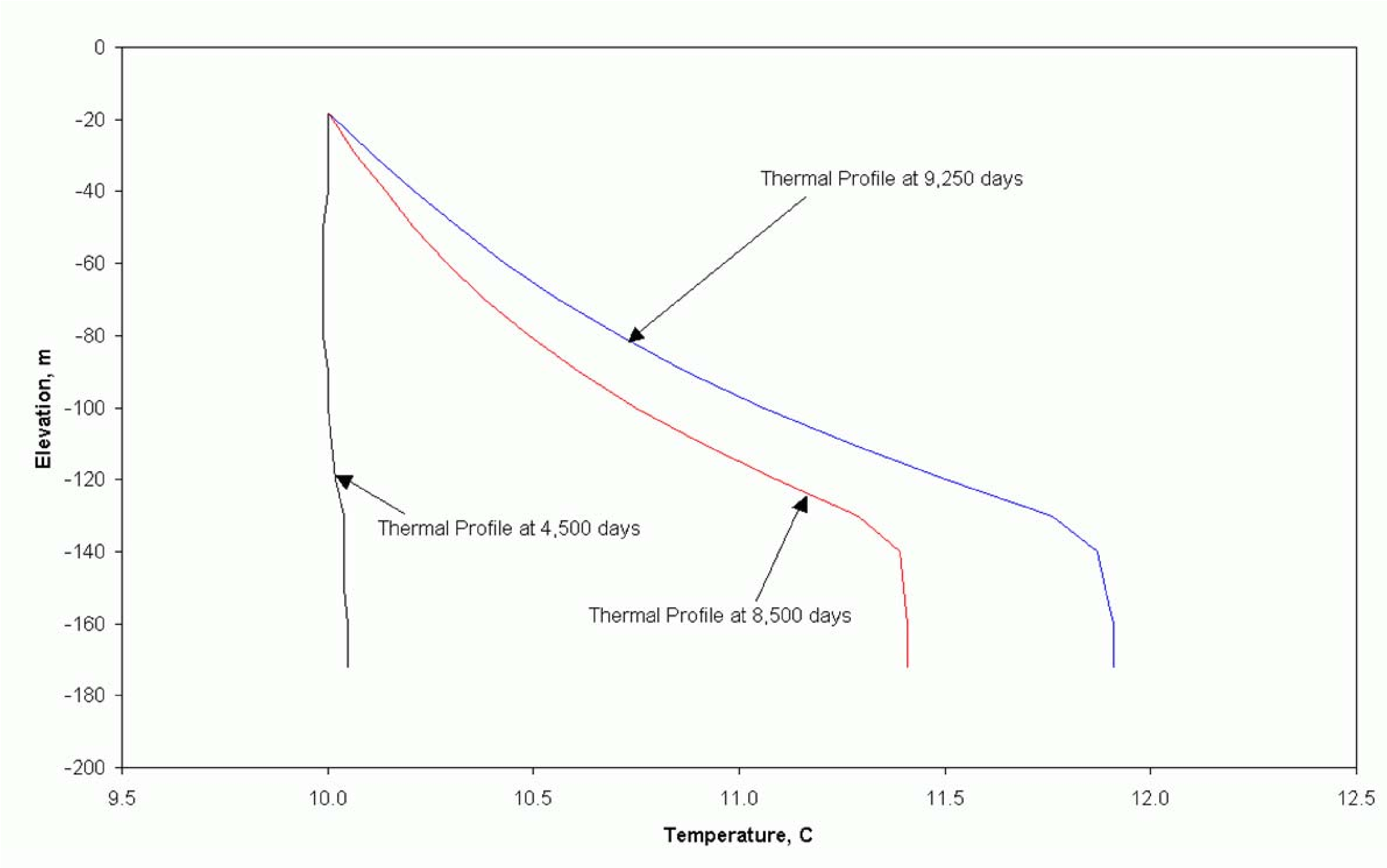

Figure 2-23. Vertical thermal profile above the extraction well at 4,500, 8,500, and 9,250 days.

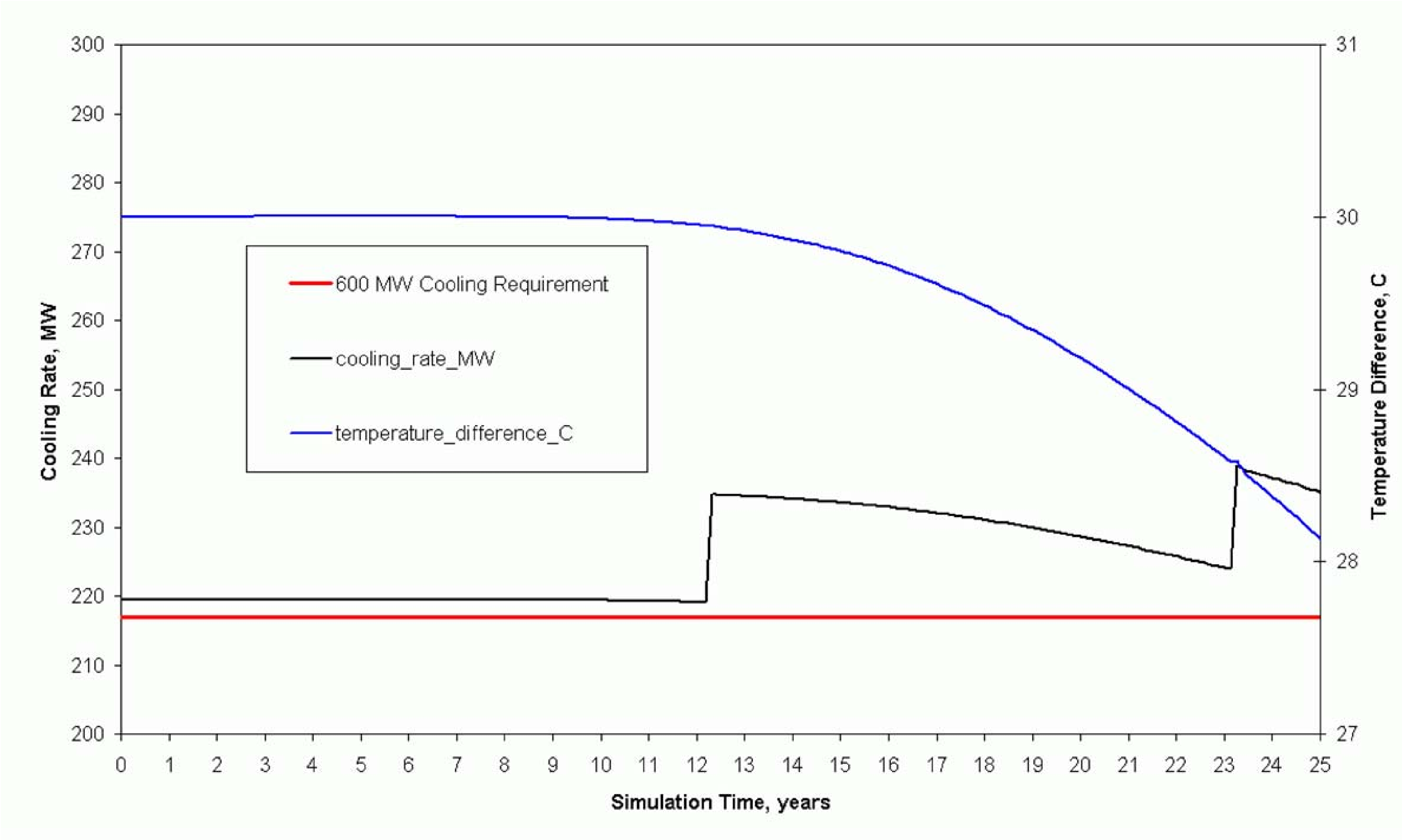

Figure 2-24. Time series plot of the power plant cooling rate and injection / extraction well thermal difference.

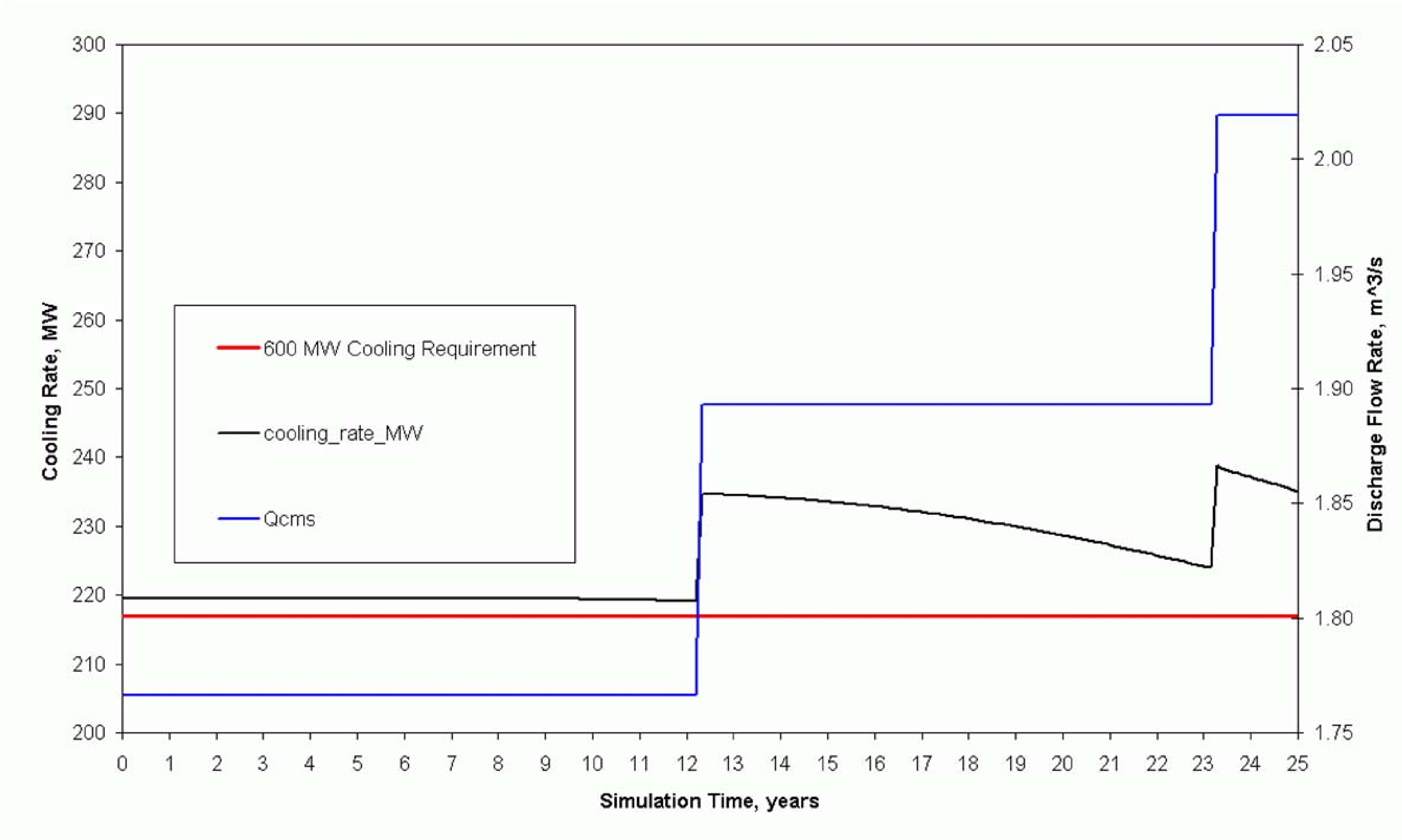

Figure 2-25. Time series plot of the power plant cooling rate and injection / extraction pumping rate.

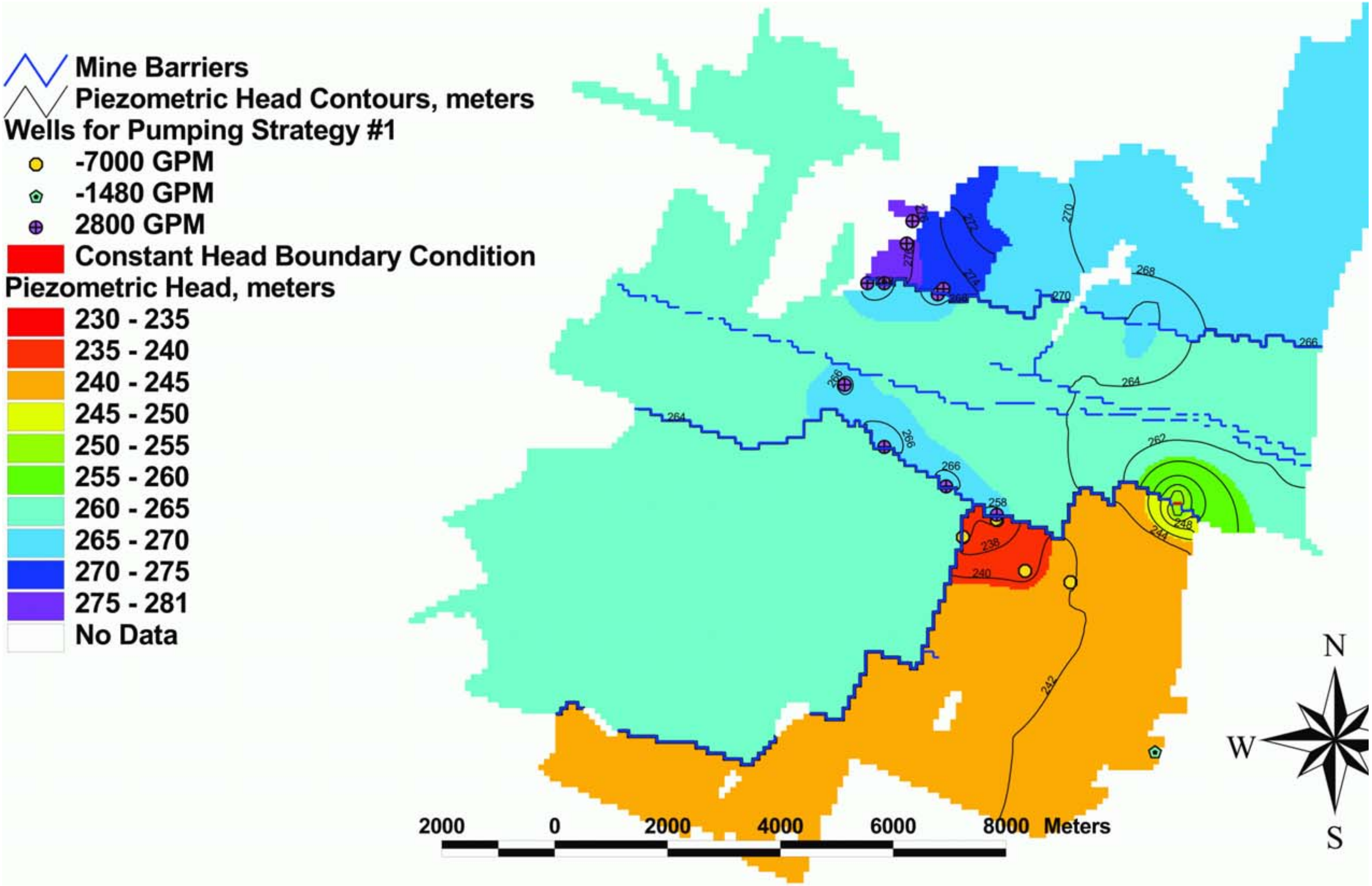

Figure 2-26. Calculated piezometric heads for pumping strategy #1.

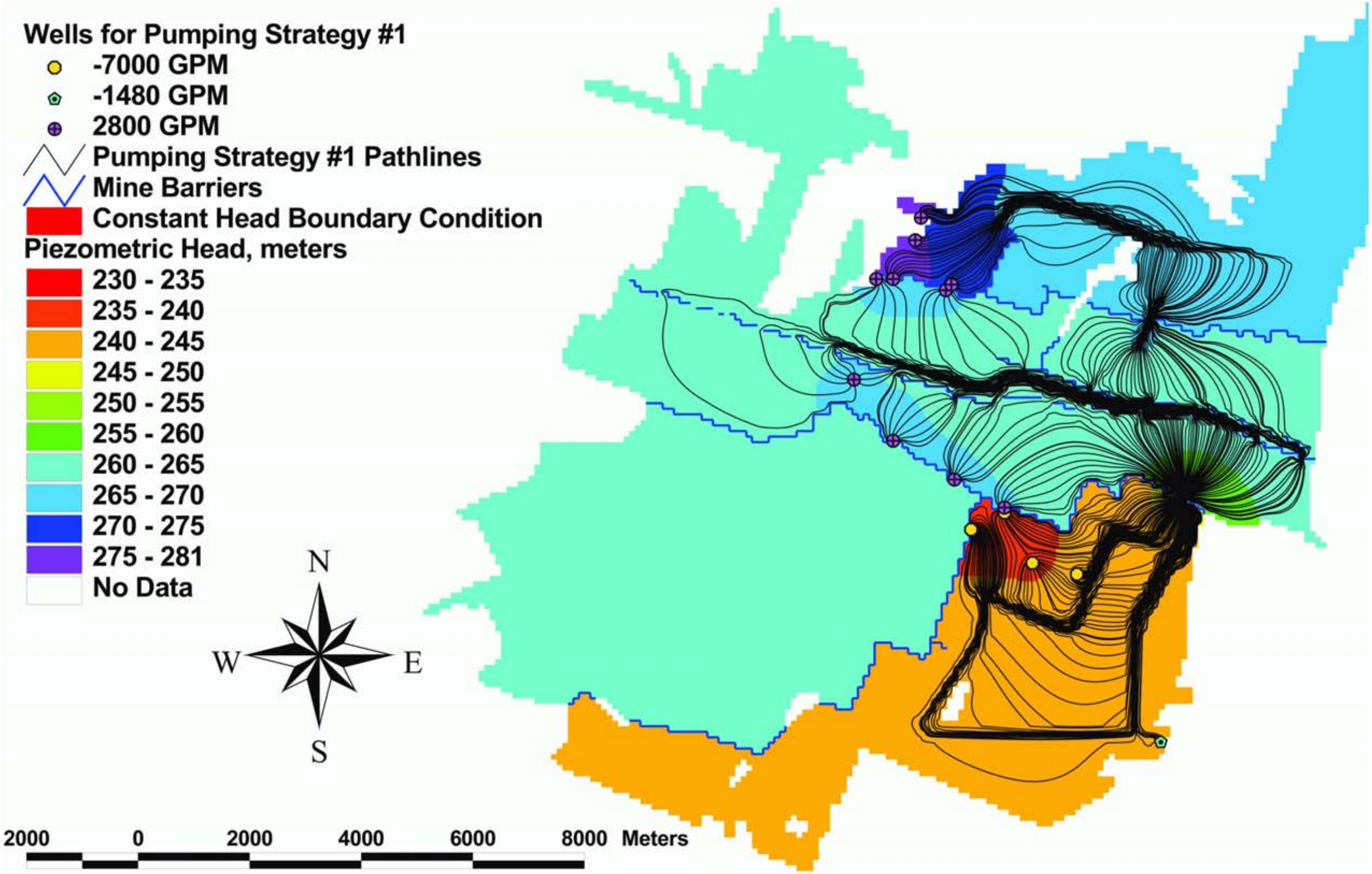

Figure 2-27. Calculated flow paths for pumping strategy #1.

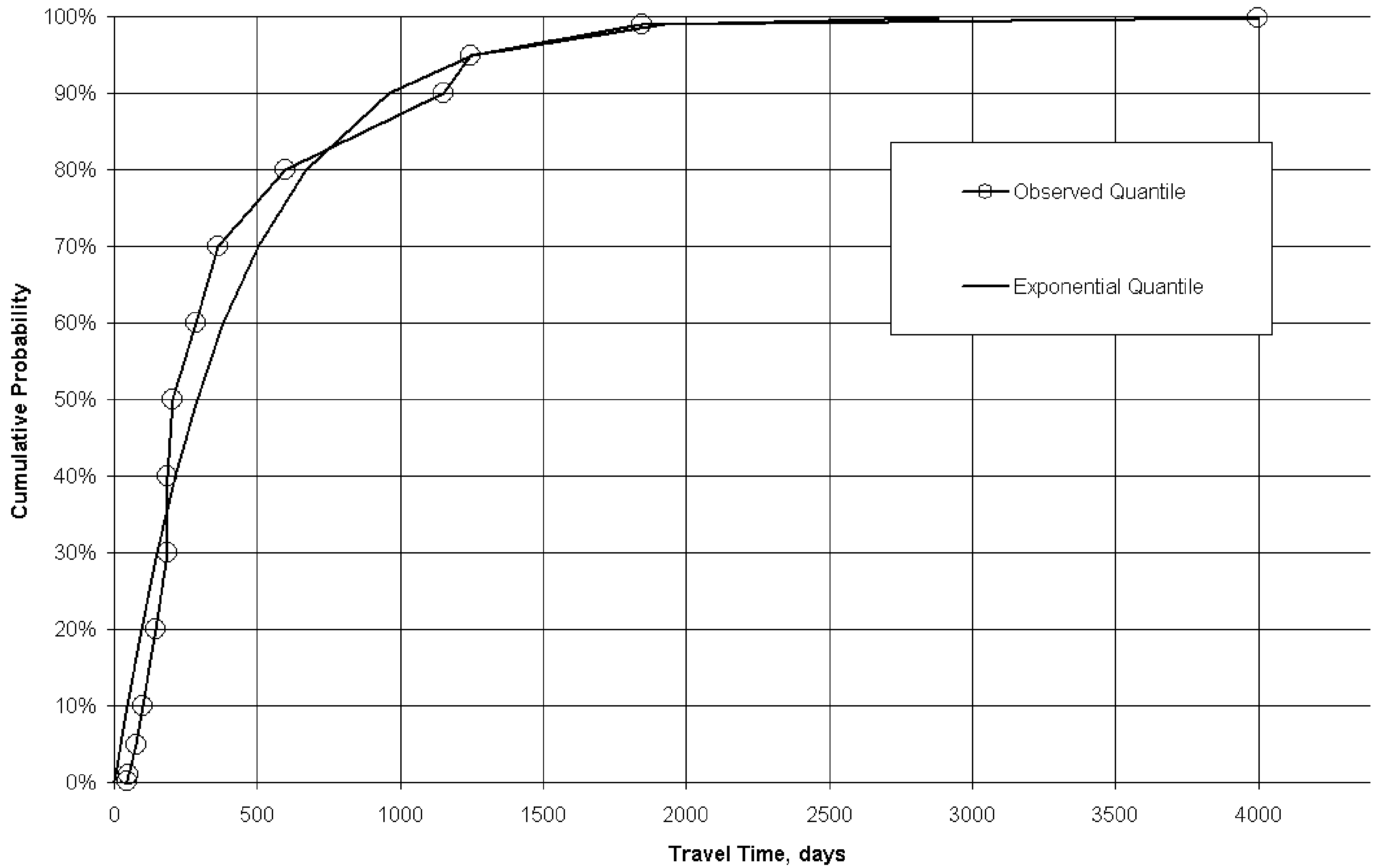

Figure 2-28. Cumulative distribution function for the flow path travel time with pumping strategy #1.

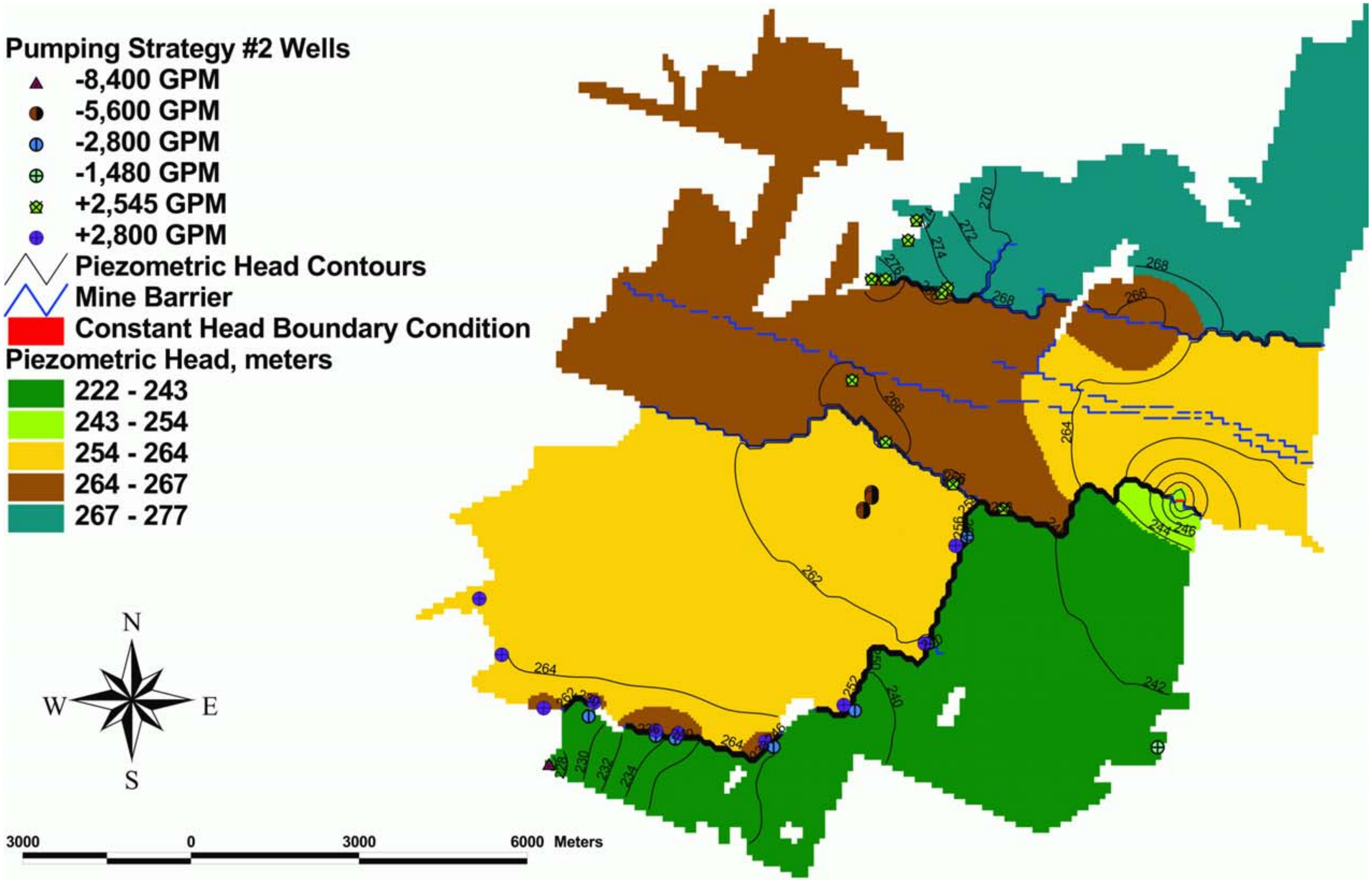

Figure 2-29. Calculated piezometric heads for pumping strategy #2.

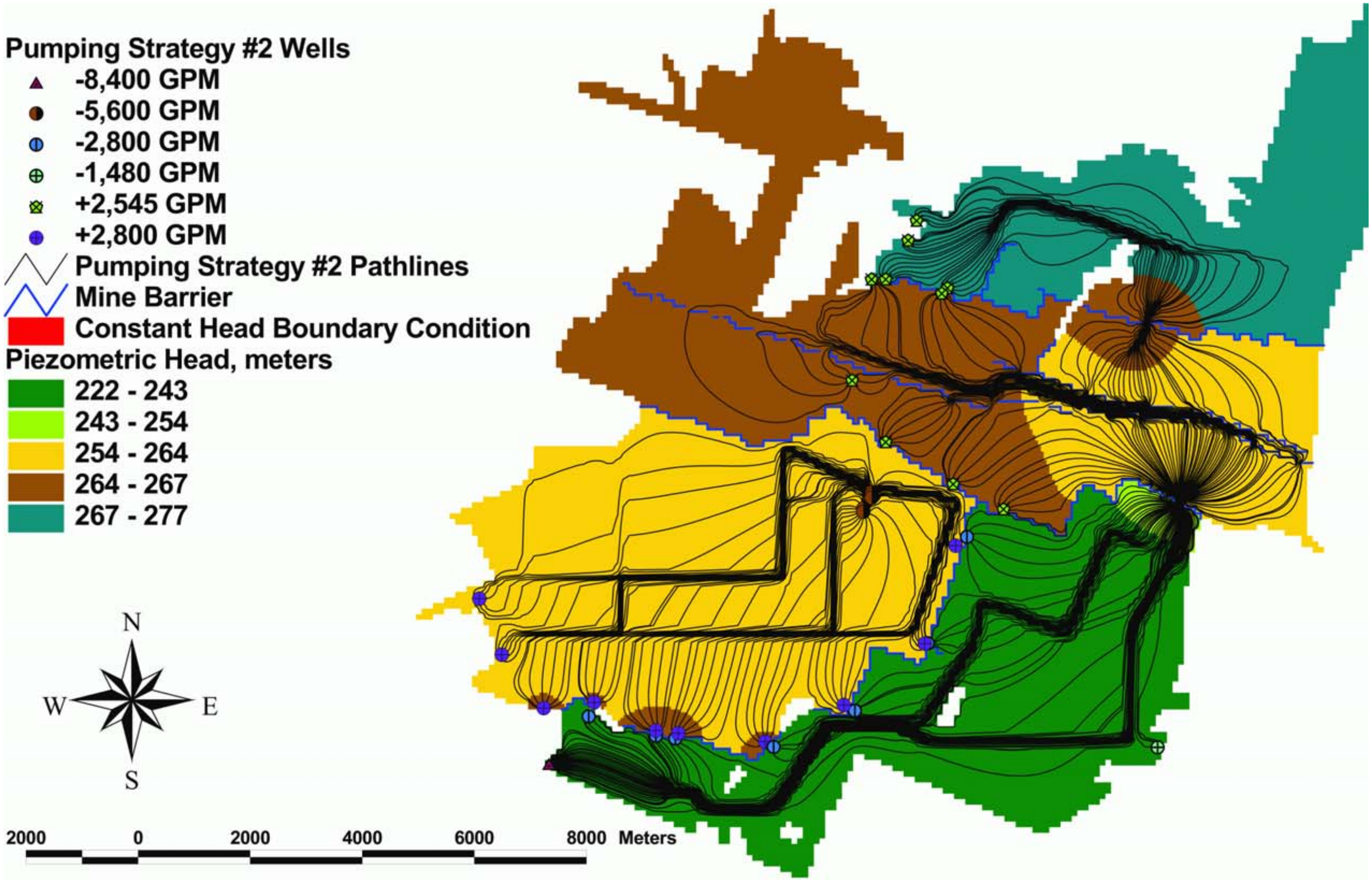

Figure 2-30. Calculated flow paths for pumping strategy #2.

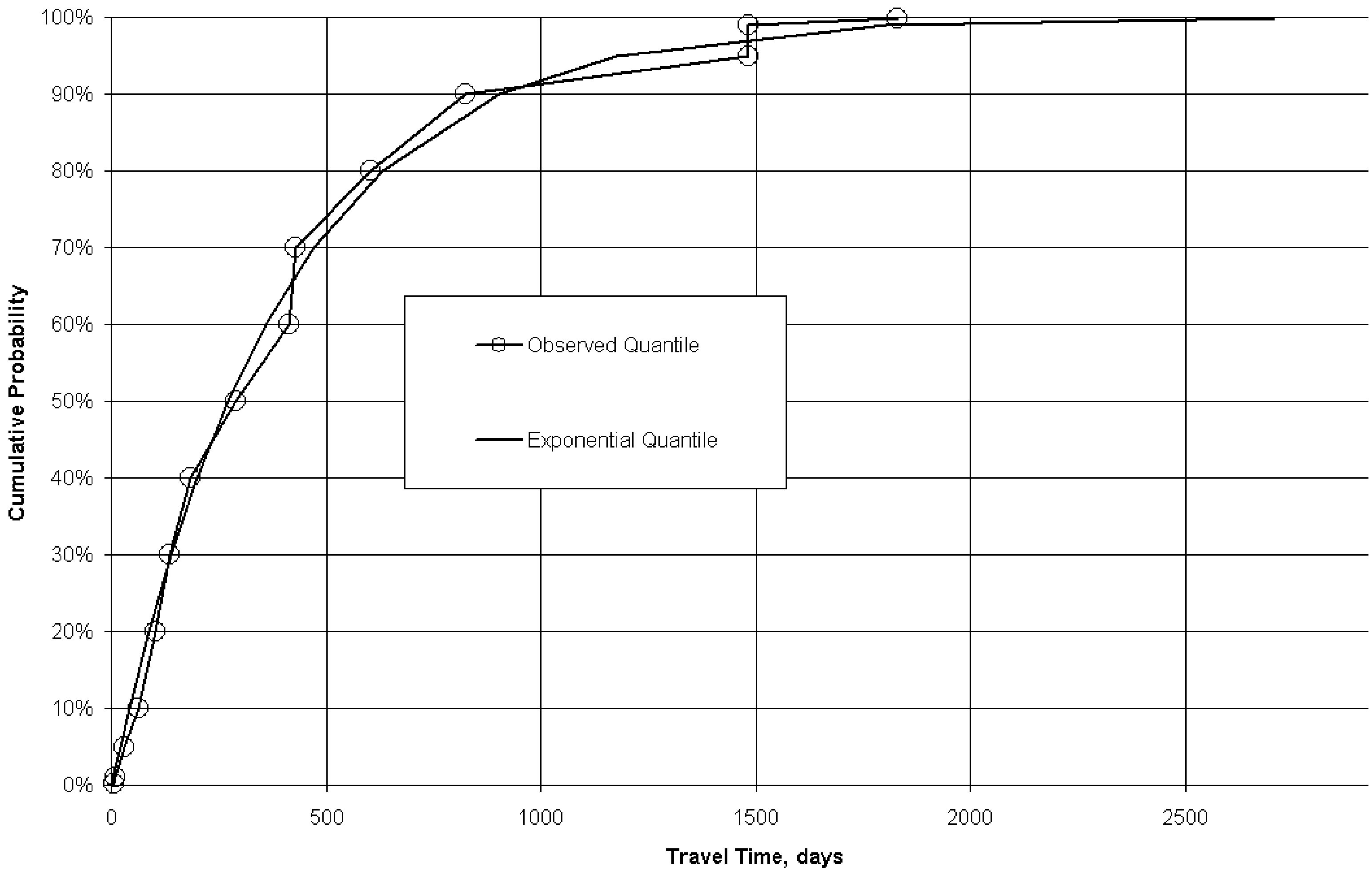

Figure 2-31. Cumulative distribution function for the flow path travel time with pumping strategy #2.

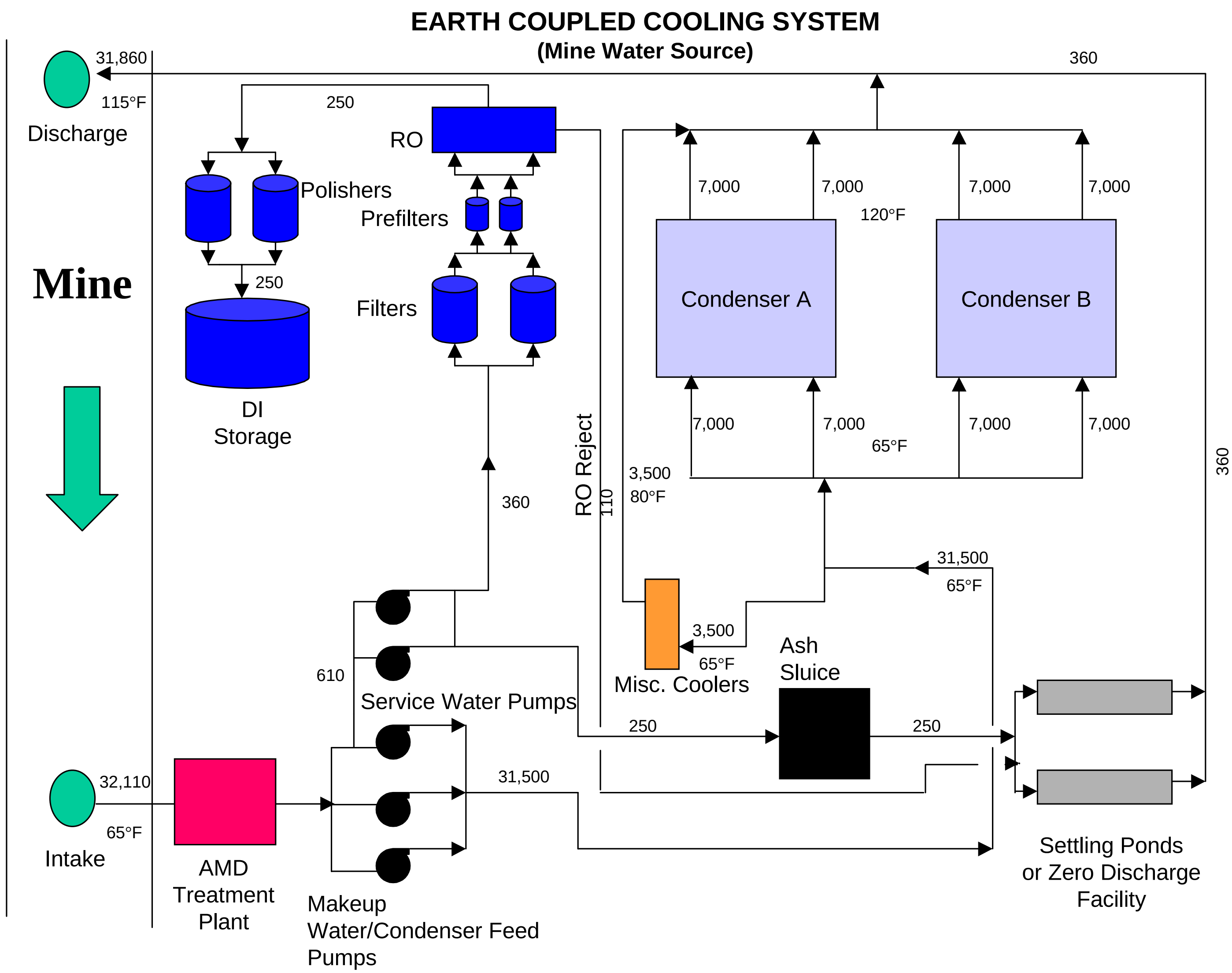

Figure 2-32. Power plant cooling system earth-coupled design.

Table 2-1. General parameters of HST3D simulation.

Parameter	Variable Name	Value	Units
Node spacing in the X direction	None	308.36	m
Node spacing in the Y direction	None	305.41	m
Number of model nodes in the X direction	NX	36	
Number of model nodes in the Y direction	NY	27	
Number of model nodes in the Z direction	NZ	18	
Fluid compressibility	BP	4.4×10^{-10}	Pa^{-1}
Reference pressure for density	PO	0	Pa
Reference temperature for density	TO	20	C
Fluid density at reference conditions	DNEFO	998.23	kg/m^3
Atmospheric absolute-pressure	PAATM	0	Pa
Reference pressure for enthalpy variations	TOH	10	C
Fluid heat capacity at constant pressure	CPF	4182	J/(kg - C)
Fluid thermal conductivity	KTHF	0.6	W/(m - C)
Fluid coefficient of thermal expansion	BT	2.0×10^{-4}	C^{-1}
Spatial-discretization factor	FDSMTH	0	
Temporal-discretization factor	FDTMTH	1	
Fractional density change convergence criterion	TOLDEN	0.01	
Maximum number of iterations per cycle	MAXITN	50	
Minimum time step	DTIMMN	0.01	days
Maximum time step	DTIMMX	50	days

Table 2-2. General material properties of the mine and overburden layers.

Parameter	Variable Name(s)	Value	Units
Vertical compressibility	ABPM	1×10^{-8}	Pa^{-1}
Heat capacity	RCPPM	2.24×10^{6}	$J/(m^3 - C)$
Thermal conductivity	KTHXPM, KTHYPM, KTHZPM	6.0	W/(m - C)
Thermal dispersivity	ALPHL, ALPHT	127.	m

Table 2-3. Material properties of specific overburden and mine layers.

Element Layer	Permeability, m^2	Effective Porosity
1	$1. \times 10^{-7}$	0.25
2	$1. \times 10^{-7}$	0.25
3	$1. \times 10^{-8}$	0.1
4	$1. \times 10^{-9}$	01
5	$1. \times 10^{-10}$	01
6	$1. \times 10^{-11}$	01
7	$1. \times 10^{-11}$	01
8	$1. \times 10^{-11}$	01
9	$1. \times 10^{-11}$	01
10	$1. \times 10^{-11}$	01
11	$1. \times 10^{-11}$	01
12	$1. \times 10^{-11}$	01
13	$1. \times 10^{-11}$	01
14	$1. \times 10^{-11}$	01
15	$1. \times 10^{-11}$	01
16	$1. \times 10^{-11}$	01
17	$1. \times 10^{-11}$	01

Table 2-4. Initial pressure and temperature for the mine and overburden layers.

Mesh Layer	Elevation, m	Initial Pressure, kPa	Initial Temperature, C
1	-172	2,510.74	10
2	-171	2,500.93	10
3	-170	2,491.12	10
4	-160	2,393.02	10
5	-150	2,294.92	10
6	-140	2,196.82	10
7	-130	2,098.72	10
8	-120	2,000.62	10
9	-110	1,902.52	10
10	-100	1,804.42	10
11	-90	1,706.32	10
12	-80	1,608.22	10
13	-70	1,510.12	10
14	-60	1,412.02	10
15	-50	1,313.92	10
16	-40	1,215.82	10
17	-30	1,117.72	10
18	-18	1,000	10

Table 2-5. General parameters for the injection and extraction wells.

Parameter	Variable Name	Numerical Value	Units
Top Completion Elevation	ZWT	-171	m
Bottom Completion Elevation	ZWB	-172	m
Outside Diameter	WBOD	1	m
Method	WQMETH	11	
Well Completion	WCF	1	
Well Skin Factor	WSF	0	
Injection Temperature	TWSRKT	40	°C

Table 2-6. Well injection and extraction flow rates for the various stress periods.

Stress Period Start, days	Stress Period End, days	Pumping Rate, m^3/day	Pumping Rate, m^3/s
0	4,500	152,628	1.77
4,500	8,500	163,530	1.89
8,500	9,250	174,432	2.02

Table 2-7. Travel time between the injection and extraction wells for each stress period.

Start of Stress Period, days	Start of Stress Period, years	Travel Time, days
0	0	233
4,500	12.32	217
8,500	23.27	204

Table 2-8. Mass and energy balance at the end of the HST3D simulation.

Parameter	Value	Units
Fluid inflow	1.46×10^{12}	kg
Fluid outflow	1.47×10^{12}	kg
Change in fluid in region	-8.60×10^{9}	kg
Fluid in region	3.64×10^{11}	kg
Fluid volume in region	3.64×10^{8}	m^3
Absolute discrepancy	8.53×10^{7}	kg
Relative discrepancy	0.01	%
Heat inflow	2.49×10^{17}	J
Heat outflow	8.80×10^{16}	J
Change in heat in region	1.60×10^{17}	J
Heat in region	4.69×10^{17}	J
Absolute discrepancy	-5.29×10^{14}	J
Relative discrepancy	-0.21	%

Table 2-9. General parameters of the MODFLOW simulations.

Parameter	Value	Units
Rows	316	
Columns	372	
Layers	1	
Rows spacing	50	m
Column spacing	50	m
Layer type	Confined	
Stress periods	1	
Active cells	59932	
Constant head boundary cells	3	
Barrier wall cells	1201	
Barrier wall thickness	10	m
Barrier hydraulic conductivity	0.03	m/day
Solver Package	PCGC2	

Table 2-10. Well parameters for the MODFLOW simulation of pumping strategy #1.

Parameter	Value	Units
New injection wells	10	
New extraction wells	4	
Mine drainage wells currently in operation	1	
Pumping rate of new extraction wells	0.0934	m^3/s
Pumping rate of existing mine drainage wells	0.4416	m^3/s
Pumping rate of new injection wells	0.1767	m^3/s

Table 2-11. Well parameters for the MODFLOW simulation of pumping strategy #2.

Parameter	Value	Units
New injection wells	21	
New extraction wells	13	
Mine drainage wells currently in operation	1	
Pumping rate of new extraction wells	0.1767 – 0.5300	m^3/s
Pumping rate of existing mine drainage wells	0.4416	m^3/s
Range of pumping rates of new injection wells	0.1606 – 0.1767	m^3/s

Table 2-12. Clyde Mine raw water chemistry and PHREEQC simulation chemistry.

Constituents		molar concentration Step 1 untreated cool	molar concentration Step 2 treated cool	molar concentration Step 3 treated hot	concentration, mg/L Step 1 untreated cool	concentration, mg/L Step 2 treated cool	concentration, mg/L Step 3 treated hot
Al	26.98	1.55E-05	1.55E-05	1.55E-05	0.41	0.41	0.41
Alkalinity	50.00	1.22E-02	2.41E-03	2.41E-03	603	121	121
Ca	40.08	6.78E-03	4.11E-03	4.11E-03	269	165	165
Cl	35.45	1.60E-02	1.60E-02	1.60E-02	563	563	563
F	19.00	3.07E-05	3.07E-05	3.07E-05	0.57	0.57	0.57
Fe	55.85	4.32E-03	1.96E-08	1.96E-08	239	0.0011	0.0011
K	39.10	1.25E-02	1.25E-02	1.25E-02	6	*489 **	489 *
Mg	24.31	4.89E-03	4.89E-03	4.89E-03	118	118	118
Mn	54.94	9.47E-05	9.47E-05	9.47E-05	5.2	5.2	5.2
Na	22.98	9.70E-02	9.70E-02	9.70E-02	2210	2210	2210
SO4	96.00	5.46E-02	5.46E-02	5.46E-02	5197	5197	5197
SiO2	60.00	1.66E-04	1.66E-04	4.04E-04	10.0	10.0	24.3
pH					6.24	8.17	7.87
calculated acidity (milliequivalents/liter)					8.79	0.23	0.23
CO2 partial pressure (log atmospheres)					-0.55	-3.20	-2.73

* K was used to charge balance water to correct for analysis error -- these numbers irrelevant

Table 2-13. Flow field surface area for the MODFLOW and HST3D simulations.

Parameter	Value	Units
Total surface area of the MODFLOW simulations	149,830,000	m^2
Surface area bounded by flow path lines for pumping strategy #1 simulation	59,636,343	m^2
Surface area bounded by flow path lines for pumping strategy #2 simulation	108,172,264	m^2
Releative surface area bounded by flow field for pumping strategy #1 simulation	0.3980	
Relative surface area bounded by flow field for pumping strategy #2 simulation	0.7220	
Surface area of the HST3D simulation	85,700,267	m^2

Table 2-14. Travel time statistics for pumping strategy #1 MODFLOW simulation.

Statistic	Value	Units
Sample mean	408.57	days
Sample standard deviation	484.27	days
Sample maximum	4523.47	days
Sample minimum	43.56	days
Sample median	206.05	days
Sample skew	4.06	
Sample kurtosis	26.71	
Exponential fit parameter (λ)	2.40×10^{-3}	1/days
Sum of the square of the error (SSE)	1.15×10^{4}	$days^2$

Table 2-15. Cumulative volume balance for pumping strategy #1 MODFLOW simulation.

Parameter	Value	Units
In		
Constant Head	1.5641×10^{5}	m^3
Wells	1.5263×10^{5}	m^3
Recharge	8.0676×10^{3}	m^3
Total	3.1711×10^{5}	m^3
Out		
Constant Head	1.5643×10^{5}	m^3
Wells	1.6070×10^{5}	m^3
Total	3.1713×10^{5}	m^3
Absolute Discrepancy	-1.9469×10^{1}	m^3
Relative Discrepancy	-0.01	%

Table 2-16. Travel time statistics for pumping strategy #2 MODFLOW simulation.

Statistic	Value	Units
Sample mean	389.06	days
Sample standard deviation	381.10	days
Sample maximum	1940.93	days
Sample minimum	6.34	days
Sample median	291.33	days
Sample skew	1.73	
Sample kurtosis	2.87	
Exponential fit parameter (λ)	2.55×10^{-3}	1/days
Sum of the square of the error (SSE)	5.12×10^{2}	$days^2$

Table 2-17. Cumulative volume balance for pumping strategy #2 MODFLOW simulation.

Parameter	Value	Units
In		
Constant Head	1.5628×10^{5}	m^3
Wells	3.0526×10^{5}	m^3
Recharge	8.0676×10^{3}	m^3
Total	4.6961×10^{5}	m^3
Out		
Constant Head	1.5635×10^{5}	m^3
Wells	3.1333×10^{5}	m^3
Total	4.6967×10^{5}	m^3
Absolute Discrepancy	-6.5656×10^{1}	m^3
Relative Discrepancy	-0.01	%

Table 2-18. Clyde mine saturation indices from PHREEQC simulation

Mineral Phase	**saturation index**		
	Step 1 untreated cool	**Step 2 treated cool**	**Step 3 treated hot**
Al(OH)3(a)	-0.45	-0.85	-1.49
Ca-smectite	4.65	4.31	2.79
Calcite	**-0.73**	**0.30**	**0.29**
Chalcedony	-0.09	-0.10	0.00
CO2(g)	**-0.55**	**-3.20**	**-2.73**
Dolomite	**-1.60**	**0.68**	**0.84**
Fe(OH)3(a)	4.92	0.00	-1.50
Gibbsite	2.33	1.94	1.07
Goethite	10.45	5.52	4.90
Gypsum	**-0.19**	**-0.39**	**-0.45**
Illite	4.10	5.30	3.66
Kaolinite	6.19	5.39	3.80
Melanterite	-8.18	-8.11	-8.51
Portlandite	-14.01	-10.33	-9.13
Pyrolusite	3.13	-10.70	-10.22
Quartz	0.37	0.36	0.38
Rhodochrosite	0.04	1.29	1.20
Siderite	-4.07	-2.78	-2.82
SiO2(a)	-0.96	-0.97	-0.79

Table 2-19. Cost analysis for earth-coupled power plant cooling system.

PROJECT TITLE: **DOE** **200MW Power Plant Cooling Circuit** **Conceptual Design Study**	**Mine Water Earth Coupled** **Order of Magnitude Estimate of Probable Cost**		**Sep-04**
Equipment	**Description**	**Capital Cost**	**O&M Cost**
Makeup Water Pumps	(3) 16,000 gpm with VFD's	$ 485,500	$ 526,500
Misc. Coolers	Turbine heat exchangers	$ 300,000	$ 2,500
Condensers	1 Condenser - 2 Shells	$ 1,495,000	$ 40,000
Settling Ponds	360 gpm	$ 355,000	$ 18,000
Discharge Structure	Concrete discharge	$ 20,000	$ -
Service Water Pumps	(2) 650 gpm with VFD's	$ 4,550	$ 7,550
RO System	250 gpm	$ 750,000	$ 100,000
DI Storage Tank	200000 gallon stainless steel tank	$ 500,000	$ -
Piping	1000 ft 84" S.S.	$ 1,582,260	$ -
Fittings & Valves	84" S.S. (200% of piping)	$ 3,164,520	$ -
Piping	1000 ft 18" S.S.	$ 476,800	$ -
Fittings & Valves	18" S.S. (200% of piping)	$ 953,600	$ -
Piping	1000 ft 6" S.S.	$ 106,000	$ -
Fittings & Valves	6" S.S. (200% of piping)	$ 212,000	$ -
Electrical		$ 2,000,000	$ -
Controls		$ 1,500,000	$ 25,000
	Total	**$ 13,905,230**	**$ 719,550**
	20% Contingency	**$ 2,781,046**	**$ 143,910**
	New Total	**$ 16,686,276**	**$ 863,460**

Table 2-20. Cost analysis for water acquisition for earth-coupled pumping strategy #1.

PROJECT TITLE:			
DOE	**Mine Water Earth Coupled Pumping Strategy #1**		
200 MW Power Plant Cooling Circuit	**Order of Magnitude Estimate of Probable Cost**		**Sep-04**
Conceptual Design Study			
Equipment	**Description**	**Capital Cost**	**O&M Cost**
(5) Production Wells	24 inch dia steel lined 1,370 feet	$ 274,000	$ -
Piping to Treatment Plant	34,250 feet HDPE DR 11 22 - 28 inch dia	$ 1,235,000	$ -
Treatment Plant	Complete with claifier and sludge disposal	$ 4,334,000	$ 1,219,500
Piping to Power Plant	16,190 feet HDPE DR 11 22 - 24 inch	$ 2,095,000	$ -
Distibution Piping to Injection Wells	39,426 feet HDPE DR 11 12 - 36 inch dia	$ 3,413,000	$ -
Injection Wells	(10) wells drilled and cassed 4,165 feet	$ 208,250	$ -
(5) deepwell turbine pumps	8,000 gpm	$ 1,375,000	$ 780,000
Injection Pumps	(3) 16,000 gpm with VFD's	$ 485,500	$ 771,393
	Total	**$ 13,419,750**	**$ 2,770,893**
	20% Contingency	**$ 2,683,950**	**$ 554,179**
	New Total	**$ 16,103,700**	**$ 3,325,071**

Table 2-21. Cost analysis for water acquisition for earth-coupled pumping strategy #2.

PROJECT TITLE:

DOE

200 MW Power Plant Cooling Circuit

Conceptual Design Study

Mine Water Earth Coupled Pumping Strategy #2

Order of Magnitude Estimate of Probable Cost

Sep-04

Equipment	Description	Capital Cost		O&M Cost	
(5) Production Wells (Marianna)	24 inch dia steel lined 1,370 feet	$	460,000	$	707,800
Piping to Treatment Plant	5215 feet HDPE DR 11 20 inch dia	$	396,400	$	-
Treatment Plant	Complete with claifier and sludge disposal	$	4,334,000	$	1,219,500
(5) Deepwell Turbine Pumps	8,000 gpm	$	1,375,000	$	780,000
Distibution Piping to Injection Wells	39,426 feet HDPE DR 11 12 - 36 inch dia	$	3,413,000	$	-
Injection Wells	(10) wells drilled and cassed 4,165 feet	$	208,250	$	-
(8) Production Wells (clyde)	24 inch dia steel lined 4,800 feet	$	960,000	$	-
(10) Injection Wells (Marianna)	12 inch dia steel lined 6315 feet	$	315,750	$	-
Piping to Marianna	19,600 feet HDPE DR 11 12 - 24 inch	$	1,064,900	$	-
3 Phase Power to Pumps	41,080 feet	$	883,200	$	-
(8) Deepwell Turbine Pumps	(7) 3,000 gpm (1) 9,000 gpm	$	1,420,000	$	1,434,500
Injection Pumps	(3) 16,000 gpm with VFD's	$	485,500	$	771,393
	Total	**$**	**15,316,000**	**$**	**4,913,193**
	20% Contingency	**$**	**3,063,200**	**$**	**982,639**
	New Total	**$**	**18,379,200**	**$**	**5,895,831**

Appendix

40 CFR 122.21

(r) *Application requirements for facilities with cooling water intake structures*—(1)(i) *New facilities with new or modified cooling water intake structures.* New facilities with cooling water intake structures as defined in part 125, subpart I, of this chapter must submit to the Director for review the information required under paragraphs (r)(2), (3), and (4) of this section and § 125.86 of this chapter as part of their application. Requests for alternative requirements under § 125.85 of this chapter must be submitted with your permit application.

(ii) *Phase II existing facilities.* Phase II existing facilities as defined in part 125, subpart J, of this chapter must submit to the Director for review the information required under paragraphs (r)(2), (3), and (5) of this section and all applicable provisions of § 125.95 of this chapter as part of their application except for the Proposal for Information Collection which must be provided in accordance with § 125.95(b)(1).

From 40 CFR new facilities include:

§ 125.81 Who is subject to this subpart?

(a) This subpart applies to a new facility if it:

(1) Is a point source that uses or proposes to use a cooling water intake structure;

(2) Has at least one cooling water intake structure that uses at least 25 percent of the water it withdraws for cooling purposes as specified in paragraph (c) of this section; and

(3) Has a design intake flow greater than two (2) million gallons per day (MGD).

(b) Use of a cooling water intake structure includes obtaining cooling water by any sort of contract or arrangement with an independent supplier (or multiple suppliers) of cooling water if the supplier or suppliers withdraw(s) water from waters of the United States. Use of cooling water does not include obtaining cooling water from a public water system or the use of treated effluent that otherwise would be discharged to a water of the U.S. This provision is intended to prevent circumvention of these requirements by creating arrangements to receive cooling water from an entity that is not itself a point source.

(c) The threshold requirement that at least 25 percent of water withdrawn be used for cooling purposes must be measured on an average monthly basis. A new facility meets the 25 percent cooling water threshold if, based on the new facility’s design, any monthly average over a year for the percentage of cooling water withdrawn is expected to equal or exceed 25 percent of the total water withdrawn.

(d) This subpart does not apply to facilities that employ cooling water intake structures in the offshore and coastal subcategories of the oil and gas extraction point source category as defined under 40 CFR 435.10 and 40 CFR 435.40.

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(4) *Source water baseline biological characterization data*. This information is required to characterize the biological community in the vicinity of the cooling water intake structure and to characterize the operation of the cooling water intake structures. The Director may also use this information in subsequent permit renewal proceedings to determine if your Design and Construction Technology Plan as required in § 125.86(b)(4) of this chapter should be revised. This supporting information must include existing data (if they are available). However, you may supplement the data using newly conducted field studies if you choose to do so. The information you submit must include:
(i) A list of the data in paragraphs (r)(4)(ii) through (vi) of this section that are not available and efforts made to identify sources of the data;
(ii) A list of species (or relevant taxa) for all life stages and their relative abundance in the vicinity of the cooling water intake structure;
(iii) Identification of the species and life stages that would be most susceptible to impingement and entrainment.
Species evaluated should include the forage base as well as those most important in terms of significance to commercial and recreational fisheries;
(iv) Identification and evaluation of the primary period of reproduction, larval recruitment, and period of peak abundance for relevant taxa;
(v) Data representative of the seasonal and daily activities (e.g., feeding and water column migration) of biological organisms in the vicinity of the cooling water intake structure;
(vi) Identification of all threatened, endangered, and other protected species that might be susceptible to impingement and entrainment at your cooling water intake structures;
(vii) Documentation of any public participation or consultation with Federal or State agencies undertaken in development of the plan; and
(viii) If you supplement the information requested in paragraph (r)(4)(i) of this section with data collected using field studies, supporting documentation for the Source Water Baseline Biological Characterization must include
a description of all methods and quality assurance procedures for sampling, and data analysis including a description of the study area; taxonomic identification of sampled and evaluated biological assemblages (including all life stages of fish and shellfish); and sampling and data analysis methods. The sampling and/or data analysis methods you use must be appropriate for a quantitative survey and based on consideration of methods used in other biological studies performed within the same source water body. The study area should include, at a minimum, the area of influence of the cooling water intake structure.

40 CFR 125.86

(b) Track I application requirements. To demonstrate compliance with Track I requirements in Sec. 125.84(b) or (c), you must collect and submit to the Director the information in paragraphs (b)(1) through (4) of this section.

(1) Flow reduction information. If you must comply with the flow reduction requirements in Sec. 125.84(b)(1), you must submit the following information to the Director to demonstrate that you have reduced your flow to a level commensurate with that which can be attained by a closed-cycle recirculation cooling water system:

(i) A narrative description of your system that has been designed to reduce your intake flow to a level commensurate with that which can be attained by a closed-cycle recirculation cooling water system and any engineering calculations, including documentation demonstrating that your make-up and blowdown flows have been minimized; and

(ii) If the flow reduction requirement is met entirely, or in part, by reusing or recycling water withdrawn for cooling purposes in subsequent industrial processes, you must provide documentation that the amount of cooling water that is not reused or recycled has been minimized.

(2) Velocity information. You must submit the following information to the Director to demonstrate that you are complying with the requirement to meet a maximum through-screen design intake velocity of no more than 0.5 ft/s at each cooling water intake structure as required in Sec. 125.84(b)(2) and (c)(1):

(i) A narrative description of the design, structure, equipment, and operation used to meet the velocity requirement; and

(ii) Design calculations showing that the velocity requirement will be met at minimum ambient source water surface elevations (based on best professional judgment using available hydrological data) and maximum head loss across the screens or other device.

(3) Source waterbody flow information. You must submit to the Director the following information to demonstrate that your cooling water intake structure meets the flow requirements in Sec. 125.84(b)(3) and (c)(2):

(i) If your cooling water intake structure is located in a freshwater river or stream, you must provide the annual mean flow and any supporting documentation and engineering calculations to show that your cooling water intake structure meets the flow requirements;

(ii) If your cooling water intake structure is located in an estuary or tidal river, you must provide the mean low water tidal excursion distance and any supporting documentation and engineering calculations to show that your cooling water intake structure facility meets the flow requirements; and

(iii) If your cooling water intake structure is located in a lake or reservoir, you must provide a narrative description of the water body thermal stratification, and any supporting documentation and engineering calculations to show that the natural thermal stratification and turnover pattern will not be disrupted by the total design intake flow. In cases where the disruption is determined to be beneficial to the management of fisheries for fish and shellfish you must provide supporting documentation and include a written concurrence from any fisheries management agency(ies) with responsibility for fisheries potentially affected by your cooling water intake structure(s).

(4) Design and Construction Technology Plan. To comply with Sec. 125.84(b)(4) and (5), or (c)(3) and (c)(4), you must submit to the Director the following information in a Design and Construction Technology Plan:

(i) Information to demonstrate whether or not you meet the criteria in Sec. 125.84(b)(4) and (b)(5), or (c)(3) and (c)(4);

(ii) Delineation of the hydraulic zone of influence for your cooling water intake structure;

(iii) New facilities required to install design and construction technologies and/or operational measures must develop a plan explaining the technologies and measures you have selected based on information collected for the Source Water Biological Baseline Characterization required by 40 CFR 122.21(r)(3). (Examples of appropriate technologies include, but are not limited to, wedgewire screens, fine mesh screens, fish handling and return systems, barrier nets, aquatic filter barrier systems, etc. Examples of appropriate operational measures include, but are not limited to, seasonal shutdowns or reductions in flow, continuous operations of screens, etc.) The plan must contain the following information:

(A) A narrative description of the design and operation of the design and construction technologies, including fish-handling and return systems, that you will use to maximize the survival of those species expected to be most susceptible to impingement. Provide species-specific information that demonstrates the efficacy of the technology;

(B) A narrative description of the design and operation of the design and construction technologies that you will use to minimize entrainment of those species expected to be the most susceptible to entrainment. Provide species-specific information that demonstrates the efficacy of the technology; and

(C) Design calculations, drawings, and estimates to support the descriptions provided in paragraphs (b)(4)(iii)(A) and (B) of this section.

Sec. 125.84 As an owner or operator of a new facility, what must I do to comply with this subpart?

(a)(1) The owner or operator of a new facility must comply with either:

(i) Track I in paragraph (b) or (c) of this section; or

(ii) Track II in paragraph (d) of this section.

(2) In addition to meeting the requirements in paragraph (b), (c), or (d) of this section, the owner or operator of a new facility may be required to comply with paragraph (e) of this section.

(b) Track I requirements for new facilities that withdraw equal to or greater than 10 MGD. You must comply with all of the following requirements:

(1) You must reduce your intake flow, at a minimum, to a level commensurate with that which can be attained by a closed-cycle recirculating cooling water system;

(2) You must design and construct each cooling water intake structure at your facility to a maximum through-screen design intake velocity of 0.5 ft/s;

(3) You must design and construct your cooling water intake structure such that the total design intake flow from all cooling water intake structures at your facility meets the following requirements:

(i) For cooling water intake structures located in a freshwater river or stream, the total design intake flow must be no greater than five (5) percent of the source water annual mean flow;

(ii) For cooling water intake structures located in a lake or reservoir, the total design intake flow must not disrupt the natural thermal stratification or turnover pattern (where present) of the source water except in cases where the disruption is determined to be beneficial to the management of fisheries for fish and shellfish by any fishery management agency(ies);

(iii) For cooling water intake structures located in an estuary or tidal river, the total design intake flow over one tidal cycle of ebb and flow must be no greater than one (1) percent of the volume of the water column within the area centered about the opening of the intake with a diameter defined by the distance of one tidal excursion at the mean low water level;

(4) You must select and implement design and construction technologies or operational measures for minimizing impingement mortality of fish and shellfish if:

(i) There are threatened or endangered or otherwise protected federal, state, or tribal species, or critical habitat for these species, within the hydraulic zone of influence of the cooling water intake structure; or

(ii) There are migratory and/or sport or commercial species of impingement concern to the Director or any fishery management agency(ies), which pass through the hydraulic zone of influence of the cooling water intake structure; or

(iii) It is determined by the Director or any fishery management agency(ies) that the proposed facility, after meeting the technology- based performance requirements in paragraphs (b)(1), (2), and (3) of this section, would still contribute unacceptable stress to the protected species, critical habitat of those species, or species of concern;

(5) You must select and implement design and construction technologies or operational measures for minimizing entrainment of entrainable life stages of fish and shellfish if:

(i) There are threatened or endangered or otherwise protected federal, state, or tribal species, or critical habitat for these species, within the hydraulic zone of influence of the cooling water intake structure; or

(ii) There are or would be undesirable cumulative stressors affecting entrainable life stages of species of concern to the Director or any fishery management agency(ies), and it is determined by the Director or any fishery management agency(ies) that the proposed facility, after meeting the technology-based performance requirements in paragraphs (b)(1), (2), and (3) of this section, would contribute unacceptable stress to these species of concern;

(6) You must submit the application information required in 40 CFR 122.21(r) and Sec. 125.86(b);

(7) You must implement the monitoring requirements specified in Sec. 125.87;

(8) You must implement the record-keeping requirements specified in Sec. 125.88.

(c) Track I requirements for new facilities that withdraw equal to or greater than 2 MGD and less than 10 MGD and that choose not to comply with paragraph (b) of this section. You must comply with all the following requirements:

(1) You must design and construct each cooling water intake structure at your facility to a maximum through-screen design intake velocity of 0.5 ft/s;

(2) You must design and construct your cooling water intake structure such that the total design intake flow from all cooling water intake structures at your facility meets the following requirements:

(i) For cooling water intake structures located in a freshwater river or stream, the total design intake flow must be no greater than five (5) percent of the source water annual mean flow;

(ii) For cooling water intake structures located in a lake or reservoir, the total design intake flow must not disrupt the natural thermal stratification or turnover pattern (where present) of the source water except in cases where the disruption is determined to be beneficial to the management of fisheries for fish and shellfish by any fishery management agency(ies);

(iii) For cooling water intake structures located in an estuary or tidal river, the total design intake flow over one tidal cycle of ebb and flow must be no greater than one (1) percent of the volume of the water column within the area centered about the opening of the intake with a diameter defined by the distance of one tidal excursion at the mean low water level;

(3) You must select and implement design and construction technologies or operational measures for minimizing impingement mortality of fish and shellfish if:

(i) There are threatened or endangered or otherwise protected federal, state, or tribal species, or critical habitat for these species, within the hydraulic zone of influence of the cooling water intake structure; or

(ii) There are migratory and/or sport or commercial species of impingement concern to the Director or any fishery management agency(ies), which pass through the hydraulic zone of influence of the cooling water intake structure; or

(iii) It is determined by the Director or any fishery management agency(ies) that the proposed facility, after meeting the technology- based performance requirements in paragraphs (c)(1) and (2) of this section, would still contribute unacceptable stress to the protected species, critical habitat of those species, or species of concern;

(4) You must select and implement design and construction technologies or operational measures for minimizing entrainment of entrainable life stages of fish and shellfish;

(5) You must submit the application information required in 40 CFR 122.21(r) and Sec. 125.86(b)(2), (3), and (4);

(6) You must implement the monitoring requirements specified in Sec. 125.87;

(7) You must implement the recordkeeping requirements specified in Sec. 125.88.

(d) Track II. The owner or operator of a new facility that chooses to comply under Track II must comply with the following requirements:

(1) You must demonstrate to the Director that the technologies employed will reduce the level of adverse environmental impact from your cooling water intake structures to a comparable level to that which you would achieve were you to implement the requirements of paragraphs (b)(1) and (2) of this section.

(i) Except as specified in paragraph (d)(1)(ii) of this section, this demonstration must include a showing that the impacts to fish and shellfish, including important forage and predator species, within the watershed will be comparable to those which would result if you were to implement the requirements of paragraphs (b)(1) and (2) of this section. This showing may include consideration of impacts other than impingement mortality and entrainment, including measures that will result in increases in fish and shellfish, but it must demonstrate comparable performance for species that the Director, in consultation with national, state or tribal fishery management agencies with responsibility for fisheries potentially affected by your cooling water intake structure, identifies as species of concern.

(ii) In cases where air emissions and/or energy impacts that would result from meeting the requirements of paragraphs (b)(1) and (2) of this section would result in significant adverse impacts on local air quality, significant adverse impact on local water resources not addressed under paragraph (d)(1)(i) of this section, or significant adverse impact on local energy markets, you may request alternative requirements under Sec. 125.85.

(2) You must design and construct your cooling water intake structure such that the total design intake flow from all cooling water intake structures at your facility meet the following requirements:

(i) For cooling water intake structures located in a freshwater river or stream, the total design intake flow must be no greater than five (5) percent of the source water annual mean flow;

(ii) For cooling water intake structures located in a lake or reservoir, the total design intake flow must not disrupt the natural thermal stratification or turnover pattern (where present) of the source water except in cases where the disruption is determined to be beneficial to the management of fisheries for fish and shellfish by any fishery management agency(ies);

(iii) For cooling water intake structures located in an estuary or tidal river, the total design intake flow over one tidal cycle of ebb and flow must be no greater than one (1) percent of the volume of the water column within the area centered about the opening of the intake with a diameter defined by the distance of one tidal excursion at the mean low water level.

(3) You must submit the application information required in 40 CFR 122.21(r) and Sec. 125.86(c).

(4) You must implement the monitoring requirements specified in Sec. 125.87.

(5) You must implement the record-keeping requirements specified in Sec. 125.88.

(e) You must comply with any more stringent requirements relating to the location, design, construction, and capacity of a cooling water intake structure or monitoring requirements at a new facility that the Director deems are reasonably necessary to comply with any provision of state law, including compliance with applicable state water quality standards (including designated uses, criteria, and antidegradation requirements).