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## SOLUTION MINING OF NAHCOLITE AT THE AMERICAN SODA PROJECT, PICEANCE CREEK, COLORADO

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### ABSTRACT

American Soda, LLP has commissioned the first solution mine for recovery of naturally formed sodium bicarbonate (nahcolite) from low-grade deposits using high-pressure, high-temperature injection fluid. This project, known as the Yankee Gulch Project, was commissioned 33 years after discovery of the deposit and followed an intensive four-year feasibility study that included a full-scale pilot test. The nahcolite is co-mingled with oil shale and is impermeable. Solution mining is achieved by a combination of thermo-mechanical cracking and dissolution. Elevated temperatures are required to initiate the thermally induced cracking and to enhance solubility of the nahcolite, which is highly temperature dependent. This paper will provide an overview of the development of the project from discovery, characterization, pilot testing, permitting and commissioning, with emphasis on the solution mining aspects.

### INTRODUCTION

The Yankee Gulch Sodium Minerals Project (YGP), operated by American Soda, LLP (American Soda), initiated commercial operations in November 2000. The YGP has its origins following discovery of the nahcolite mineralization by Irv Nielsen in 1964 at the location where the pilot plant is now located near the Piceance Creek in Rio Blanco County, Colorado (Nielsen, 1969). Development of the project accelerated after Williams Corporation of Tulsa, Oklahoma, joined with American Alkali, LLP, in 1996 to initiate the pilot testing, which led to permitting, plant design, construction, and startup of the YGP. Figure 1 shows the location of the American Soda leases and the location of the upper and lower plant sites.

Public information regarding the project is available from articles published by Kurt Nielsen (2001) and in permit applications and submissions to the U. S. Bureau of Land Management (BLM) and the Environmental Protection Agency (EPA). The Commercial Mine Plan was prepared by American Soda and submitted to the BLM, and the Environmental Impact Statement (EIS) was prepared by the BLM from that plan and other documents submitted to the BLM by American Soda and others. Resource data and general geologic and hydrologic information on the Piceance Creek Basin are found in the Rocky Mountain Association of Geologists 25th Field Conference (1974) and in numerous volumes of oil shale symposiums sponsored by the Colorado School of Mines published between 1970 and 1990. The solution mining and processing of nahcolite is covered by Patent Application Number 09/540,658.

### GEOLOGIC SETTING AND RESOURCE

The geologic setting of the nahcolite resource of the Piceance Basin is documented by Beard et al. (1974) and Dyni (1974). The nahcolite is co-mingled with oil shale. The oil shale of Colorado is an immense resource that has been extensively studied because of its

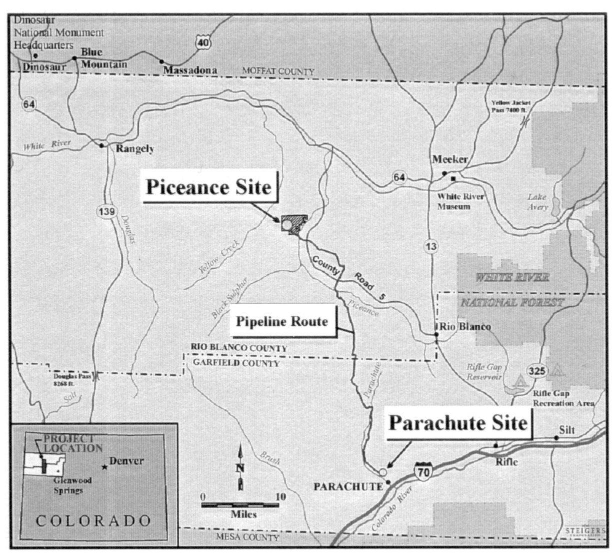


**Figure 1. Site Map**

 

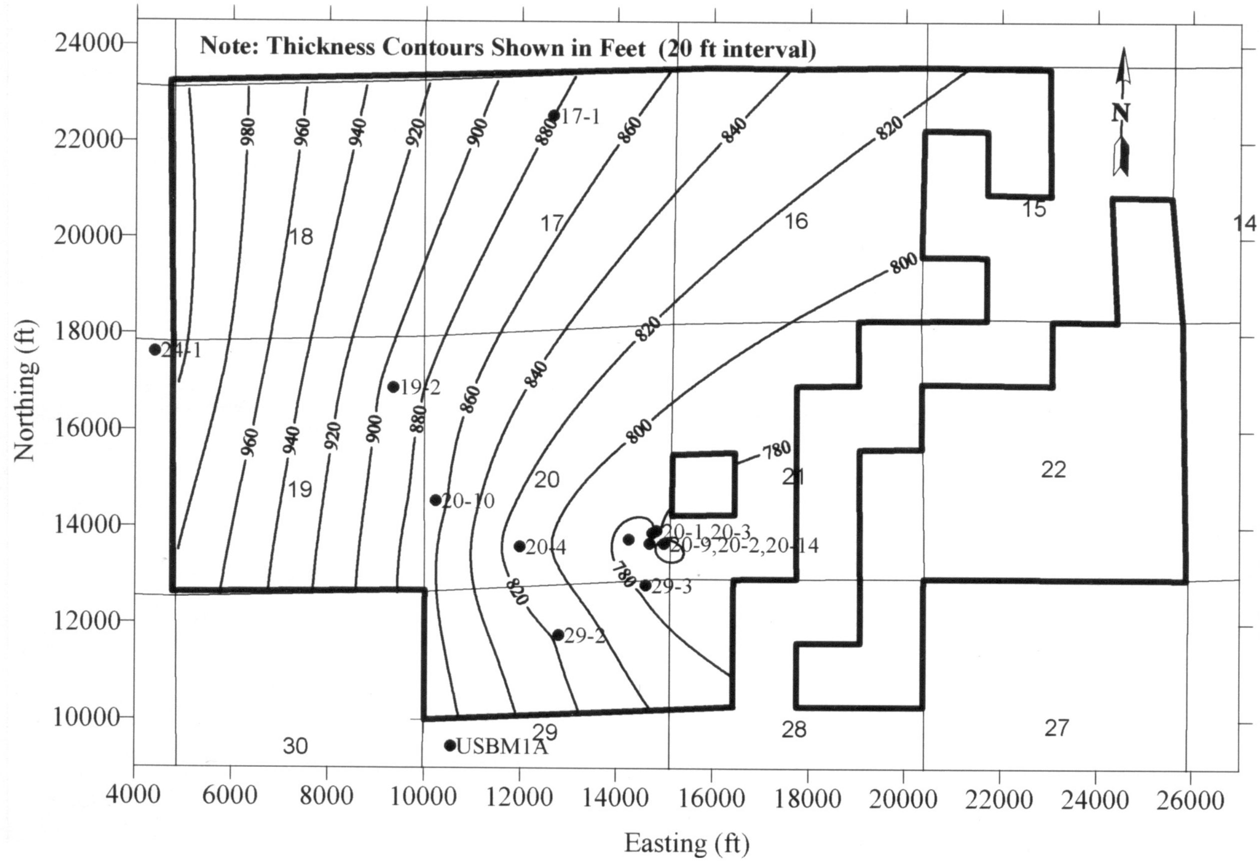


**Figure 2. Contour of Saline Zone Thickness at the American Soda Lease**

potential to supply oil to the nation. Adjacent to the leases held by American Soda is a nahcolite producer, White River Nahcolite Minerals Ltd. (White River Nahcolite), solution mines nahcolite from a high-grade nahcolite bed using horizontal holes (Day, 1994). The White River Nahcolite leases were extensively drilled in the early 1980s to confirm both the nahcolite and oil shale resources. On the American Soda leases, two holes were cored in the 1960s and 1970s, and an additional six holes were cored in 1997. Additional holes that were drilled for resource, gas, or hydrology characterization surround the leases and offer confirmation of resource continuity.

The nahcolite resource in the center of the Piceance Basin is present in beds of high-grade crystalline nahcolite and as disseminated nahcolite in oil shales of the Green River Formation, and has a thickness of up to 1000 ft. Figure 2 shows the thickness contour of the Saline Zone below the Dissolution Surface at the American Soda lease. Individual beds of high-grade nahcolite (<80%) are present with thicknesses of up to 30 ft. In some parts of the basin, halite is present in the upper horizons of the nahcolite. The nahcolite is leached and brecciation has occurred above the Dissolution Surface, presumably as a result of collapse following leaching (Gulliver et al., 1985). Over the full column of nahcolite-rich oil shale in the center of the basin, the average nahcolite grade is 20% to 30%.

Solution mining at American Soda is limited to below the Lower Salt Bed or 150 to 200 ft below the Dissolution Surface. The Lower Salt Bed is halite rich in portions of the American Soda lease, and in some parts rich in nahcolite and devoid of halite. The target zone for solution mining at American Soda has a thickness of 500 to 650 ft and has an average nahcolite grade of 20% to 25%, with halite less than 1%.

Figure 3 shows a cross section through the American Soda lease. Corehole Nielsen 20-1 is the nahcolite discovery well located on the American Soda controlled lease. The figure shows the Lower Salt Bed, the stratification of nahcolite and oil shale, and the Love, Greeno, and TI Beds. This north–south cross section traverses the lease area. The Upper Salt Bed and the Boise Bed are leached over much of the American Soda lease area.

The richest oil shale in the area is in the Mahogany Zone between the A and B Groove beds (see Figure 3) some 400 to 500 ft above the Dissolution Surface. The Mahogany Zone can average over 35 gallons per ton oil content (the oil shale contains kerogen, that when retorted will yield over 35 gallons per ton). In the Saline Zone below the Dissolution Surface, the oil yield from the oil shale is below 25 gallons per ton.

The nahcolite-rich oil shale below the Dissolution Surface is generally devoid of joints, fractures, or faults. The nahcolite-rich oil shale is very impermeable and can maintain high fluid pressures with minimal bleed off. Above the Dissolution Surface, the oil shales are fractured and brecciated, and in some horizons are water bearing. The water quality is low at the Dissolution Surface and can be potable at higher elevations.

The resource available for solution mining within the American Soda lease is significant. The geologic nahcolite resource estimate for

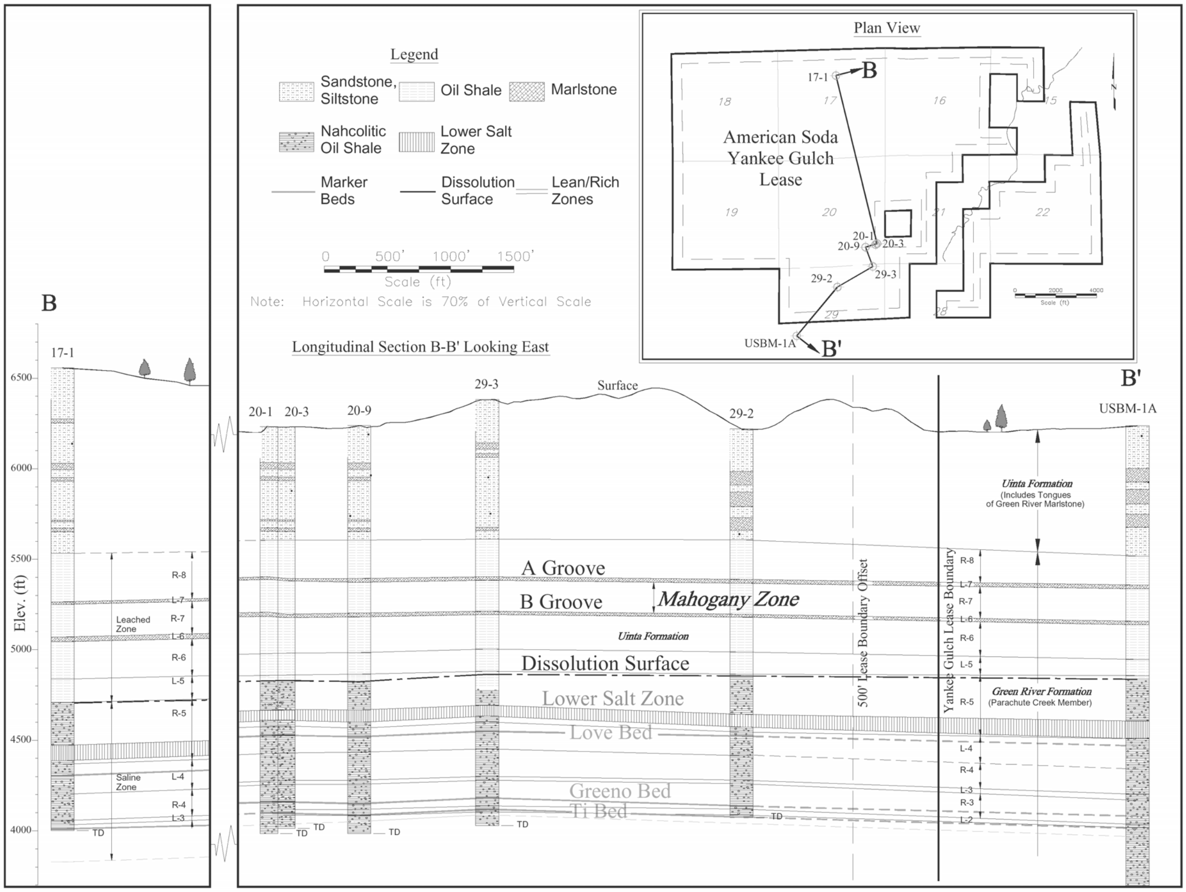


**Figure 3. North-South Cross Section Through the American Soda Lease**

the American Soda lease below the Dissolution Surface, based on the two original core holes, the six core holes completed in 1997, and the surrounding core holes, is approximately 1.9 billion tons. The probable reserve estimated after factoring in losses due to the mine height, well spacing, topography, and geologic and hydrologic anomalies is approximately 250 million tons.

## SOLUTION MINING CONCEPT

The solution mining concept proposed by American Soda was based on field tests conducted by Shell in the early 1970s and reported in Prats et al. (1977). Shell undertook field testing of a concept to recover oil by injecting high-temperature steam into the nahcolite-rich oil shale below the Dissolution Surface at a location near the southeast corner of the American Soda lease. As part of that field test, Shell injected steam at 300°F and produced significant quantities of nahcolite. They then increased the steam temperature to 600°F in an attempt to produce oil. The oil production did not meet their expectations, so they abandoned the field test.

American Soda proposed to inject pressurized water at temperatures sufficient to fracture the rock and to produce high-concentration liquor. The high-temperature injection fluid was needed for two reasons: (1) to fracture the oil shale and provide access for the fluid to contact the nahcolite, and (2) the high temperature was required to raise the solubility of nahcolite. The saturation of nahcolite in water is highly temperature dependent. Concentrations of over 35% by weight are possible at temperatures over 350°F, whereas concentrations of less than 20% are possible at 200°F. The growth rate of the cavern, which is dependent on the nahcolite grade as well as the extent of the thermally induced cracking, is accelerated at higher temperatures.

Issues of concern in the design of the well field included:

• The maximum extent of the cavern and resource recovery per well, essentially the size and shape of the cavern.

• The impact of solution mining on overlying aquifers.

• The potential for subsidence and the impact of subsidence on the overlying aquifers and on mining of overlying oil shale resources.

• The impact of solution mining on the oil shale resources at the horizons of solution mining.

• The hydraulic conductivity of the host rock and the ability of the host rock to contain the high fluid pressures within the cavern without leakage.

• Well design to minimize drilling and completion costs while satisfying the operational requirements of the well.

• The location of the injection and production strings to optimize recovery without producing adverse contaminants such as halite.

• Selection of injection temperatures and target flow rates to establish the number of wells to meet the production targets.

 

**Figure 4. Pilot Plant Area**

To provide answers to these and other questions and concerns related to design and permitting of the proposed solution mining concept, laboratory testing, analysis, and pilot testing were undertaken. The process of collecting data, pilot testing, and permitting the project was completed in four years. The core holes drilled in 1997 were pressure tested over the interval of interest for solution mining to evaluate the hydraulic conductivity of the formation and to confirm that the formation would contain pressurized fluid without leakage. Five of the six core holes successfully completed the pressure test, but with the sixth core hole, difficulties were encountered with packer seating and the test was abandoned. The hydraulic conductivity indicated from these tests was in the $10^{-7}$ to $10^{-8}$ cm/sec range, indicating very tight conditions with minimal leakage at the planned operating pressures.

## LABORATORY TESTING AND ANALYSIS

Core recovered from the 1997 coring program was assayed and tested for thermomechanical properties. Tests were completed on the influence of temperature on strength, deformation properties, and thermal expansion coefficient of the oil shale, nahcolite, and nahcolitic oil shale. The thermal conductivity of selected samples from the core was determined as a function of temperature. This data was used to predict the temperature field around the cavern, the projected heat losses from the cavern, and the extent of fracturing around the cavern. This analysis was also used to assess the potential interaction between caverns and to select the spacing between caverns.

Thermal cracking is induced because of the high thermally induced stresses developed around the cavern and the reduction in strength of the nahcolitic oil shales at elevated temperature. The reduction of strength of oil shale is well documented, see for example Miller et al. (1979). Tests on core from the American Soda site confirmed the reduction in strength of the nahcolitic oil shale at elevated temperatures. Oil shale also has a high thermal expansion coefficient, in the range of 6 to 200 microstrains per degree F. The combination of reduced strength and increased thermally induced stress results in cracking, fracturing, and/or yielding of the rock at the perimeter of the cavern, and allows fluid to penetrate the fractured rock and dissolve the nahcolite. This process is confined to a local area adjacent to the cavern. The low thermal conductivity of the nahcolitic oil shale results in relatively high temperature gradients around the cavern and limits the heat loss to the host rock.

## PILOT TESTING

Because this mining method had not been demonstrated on a commercial scale, American Soda (originally American Alkali), recognized that a full-scale pilot test would be required prior to design of the commercial plant. Williams Companies became a partner and formed American Soda to develop the pilot test and to design and build the plant. Issues to be resolved in the pilot testing phase were to verify plant feed concentration, chemical quality, and production rate. Associated issues, such as energy consumption and cavern growth rate, could be demonstrated and well designs could be tested.

Pilot testing was initiated in early 1997, with the first test well (20-3) coming on stream in mid-1997. Figure 4 shows the pilot test area, with the first well (20-3) in the foreground, the plant, and the ponds in the background. In all, three wells were developed and produced brine that was discharged to a pond or to a disposal well. Heated pressurized water with temperatures up to 400°F was injected for over two-and-a-half years. Injection rates of up to 100 gallons per minute (gpm) were achieved, but because of water supply and plant boiler limitations, the injection rate was typically 50 to 75 gpm. The water supply was augmented by recirculated cooled liquor from the ponds.

Over the two-and-a-half years of operation, approximately 25,000 tons of sodium bicarbonate was produced and caverns of equivalent diameter of 33 and 35 ft were developed. The pilot test confirmed product quality and cavern growth rates. The well design matured and demonstrated a preferred well design. Two of the pilot test wells (20-2 and 20-14) were reactivated in November 2000 and have continued in operation through November 2002.

## COMMERCIAL MINE PLAN

The well field proposed by American Soda was based on a well field spacing of 300 ft to allow growth of the caverns to up to 200 ft in diameter. The caverns are each about 515-ft high, with the roof at a depth of approximately 1800 ft. First-stage mining would develop every other well on a spacing of 600 ft, with infill wells developed later between the first-stage mining. Figure 5 shows the planned well field layout, the location of the pilot plant, and the pilot test wells. A goal for economic planning was for each cavern to develop to the equivalent diameter of 135 ft. Figure 6 shows a schematic three-dimensional sketch of the well field.

The well field is designed for long-term stability. The spacing of wells is such that the remaining undisturbed nahcolitic oil shale between caverns is able to support the overlying strata. The caverns after solution mining will be filled with the residual undissolved oil shale, and this fill material will resist deformation of the walls and immediate roof of the cavern. The term “cavern” is a misnomer, as the solution-mined volume is more correctly described as a leached zone. The impact to the overlying aquifers is expected to be undetectable, and no impact to the overlying Mahogany Zone is expected. An extensive array of groundwater monitoring wells is part of the mine plan. The oil shale at the horizon of solution mining will remain in the cavern in an enhanced state because of its improved permeability. At a later stage, recovery of oil or other minerals such as dawsonite are possible.

The proposed mine plan included development of 26 wells to support a plant capable of producing 896,000 tons per year of soda ash equivalent. The plant is designed to produce soda ash and

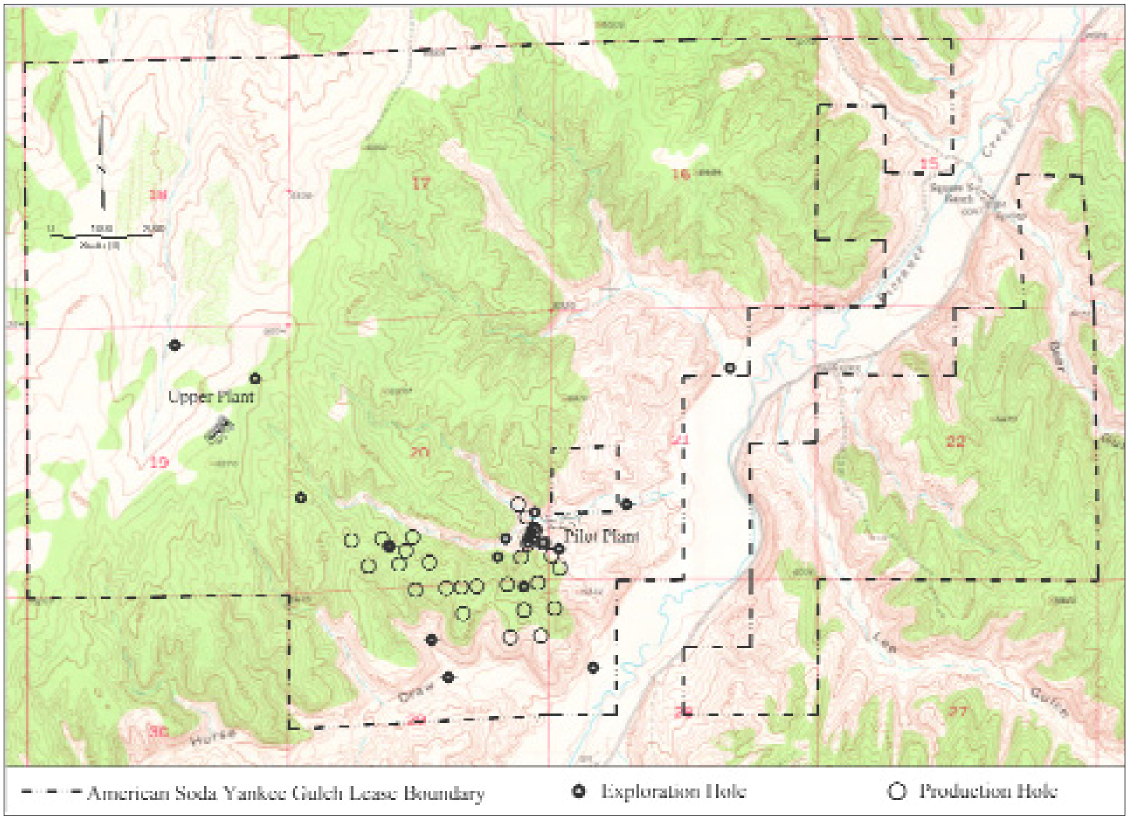


**Figure 5. Well Field Layout**

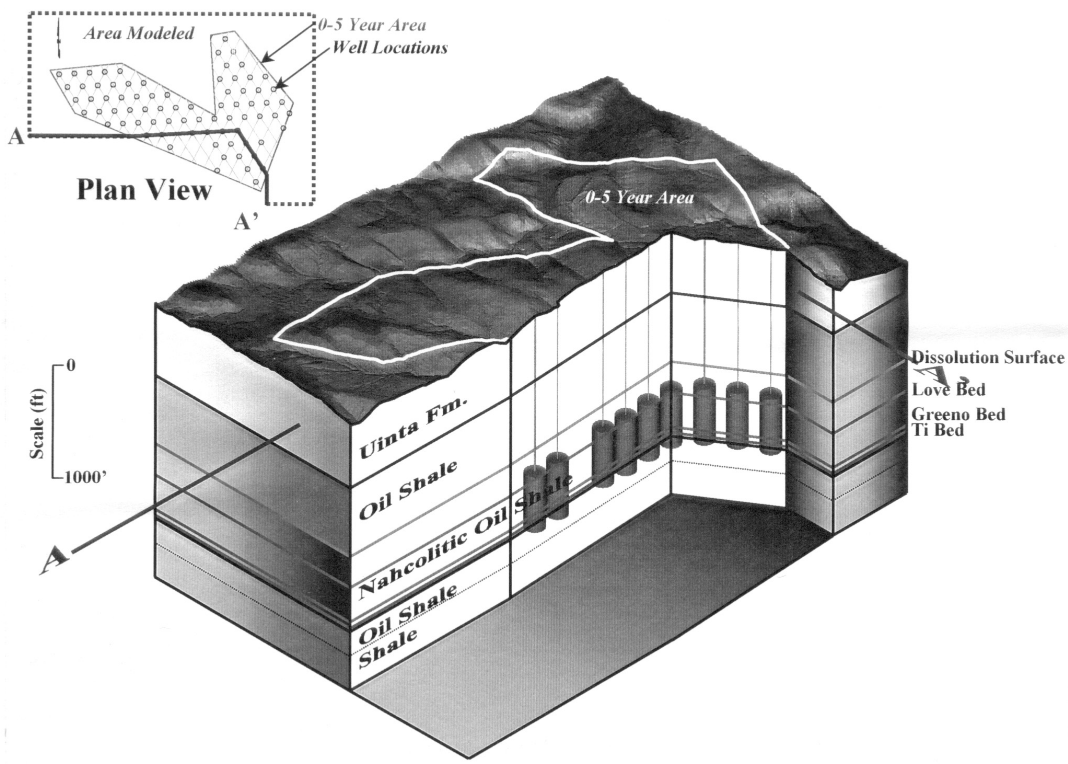


**Figure 6. Schematic Three-dimensional Sketch of the Well Field**

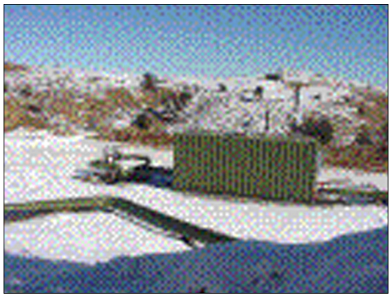

**Figure 7. Well Head**

**Figure 8. Upper Plant**

**Figure 9. Lower Plant**

sodium bicarbonate. After the first year of injection, it was thought that production could be sustained from fewer wells, possibly as few as 13 wells. Replacement of wells was scheduled at 15 wells per year; a well life of three years was anticipated.

Each wellhead is instrumented to monitor temperature, pressure, and mass flow rate for both the injection stream and the production stream. Figure 7 shows a typical wellhead and the skid containing the instrumentation and the valving. The instrumentation was selected so that leakage from a cavern can be detected and to determine the tonnage of nahcolite produced from each well.

Pressurized nitrogen is provided at each wellhead for development of a gas cap on top of each cavern. The gas cap inhibits upward cavern growth and can be used to focus solution mining to specific horizons.

Surface features of the well field include roads, well pads, and piping. The access roads and pipeline routings were carefully selected to minimize surface disturbances. Some potential well locations were avoided to protect tree stands, archeology sites, or raptor habitat.

**Figure 10. Pipeline Construction**

The commercial plan included an upper plant and a lower plant, as shown in Figures 8 and 9, respectively. The upper plant is located in the center of the lease at a remote location at Piceance Creek. The lower plant is located near Parachute in Garfield County on a site purchased from Unocal and the former site of an oil shale upgrade facility. Two insulated pipelines, one for product and the other for return water, connect the two plants. The upper plant receives high-temperature pressurized liquor from the well field and strips the liquor-producing sodium carbonate brine. In the stripping process, the liquor is depressurized and cooled. Carbon dioxide and water, in addition to sodium carbonate, are produced from the stripping of the sodium bicarbonate. Some carbon dioxide is collected and trucked to the lower plant for use in reconstituting sodium bicarbonate.

The buried insulated pipeline delivers an intermediate brine of sodium carbonate to the lower plant where sodium carbonate is crystallized and a limited quantity of sodium bicarbonate is produced. The pipeline is approximately 44 miles long. Figure 10 shows the construction of the pipeline. The solubility of sodium carbonate is essentially insensitive to temperature and can be piped long distances in insulated pipe. The pipeline avoided a potential problem in trucking product out of the Piceance Basin. The return pipeline provides a source of water for the upper plant from the Colorado River and water rights secured from Unocal. Product is shipped from the lower plant via rail.

## CURRENT STATUS

The well field has operated for over two years with production increasing each year. Start-up difficulties associated with the plant and well field have been overcome, and production is nearing plant design capacity. Cavern growth has been near what was projected, with caverns of over 130 ft in diameter developed as of November 2002. Production from each well has been variable, reflecting differing injection flow histories and local geologic variability. As of November

2002, some of the best producing wells in terms of production (tons per day) and concentration were some of the largest caverns, suggesting that these wells will be able to produce beyond the economic cavern diameter goal of 135 ft, and could produce up to and beyond the 200-ft-diameter design limit. Concentrations from the well field were projected to be low during startup and to increase as wells mature. This trend has been observed, although the initial concentrations from the well field were lower than projected. An additional three wells were drilled in late 2002, with an additional 13 wells planned for construction in 2003.

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