40-8943

FERRET EXPLORATION COMPANY OF NEBRASKA, INC.

216 Sixteenth Street Mall, Suite 810
Denver, Colorado 80202

(303) 825-2266
(303) 825-1544 - FAX

X61150

RETURN ORIGINAL TO PDR, HQ.

December 3, 1993

'93 DEC -7 A9 55
URFO RECEIVED

DOCKETED
DEC 07 1993
USNRC
MAIL SECTION
DOCKET CLERK

Mr. Ramon Hall
U.S. Nuclear Regulatory Commission
Uranium Recovery Field Office
P.O. Box 25325
Denver, CO 80225

RE: Docket No. 40-8943
SUA No. 1534

Dear Mr. Hall:

Enclosed is a copy for your information of FEN responses to questions from the State of Nebraska regarding our Class I injection well for disposal of waste water. The state is progressing well with their review and is preparing a draft permit. I trust the NRC will determine their policy on deep wells in the near future prior to State permit issuance.

If you have any questions regarding these responses, please contact me.

Sincerely,

Stephen P. Collings

Stephen P. Collings
President

Enclosure

9402220224 931203
PDR ADOCK 04008943
C PDR

180043

DESIGNATED ORIGINAL
Certified by Mary C. Hood

DF02
Addl Info
94-0107

RESPONSE TO COMMENTS
FROM
STATE OF NEBRASKA
DEPARTMENT OF ENVIRONMENTAL QUALITY
REVIEW LETTER DATED NOVEMBER 1, 1993

State Comment:

One small error on Figure 1-1 should be corrected. The "townships" listed on the right-hand side of the map have been located incorrectly. They should be adjusted so as not to create confusion with subsequent maps in the text.

FEN Response:

The labeling on Figure 1-1 has been corrected. Please replace Figure 1-1 in the text with the enclosed corrected copy.

State Comment:

The Department's long form application was submitted by FEN along with the supporting text. The application must be signed and dated on page 11. The application form is enclosed for your convenience.

FEN Response:

A copy of the application form, which has been signed and dated, is enclosed.

State Comment:

Hydraulic conductivity is an important component in many of the calculations used to determine Radius of Pressure Response, Zone of Endangering Influence, and the Area of Review, etc. Transmissivity and Storativity are some additional components that will need to be established. The Department would like to know exactly how these components are going to be measured or derived.

FEN Response:

Hydraulic properties of the proposed injection formation will be assessed during one or more pumping tests. Data from the tests will be analyzed by conventional hydrogeologic methods, such as Theis and Jacob, to assess the hydraulic conductivity and transmissivity of the Sundance Formation.

The equation used to calculate storativity includes a value for the radial distance between the pumping and observation well(s). As such, published storativity values are typically based on data from multiple well tests. Storativity can be calculated from a single well test, however an "effective wellbore radius" must be assumed. Determination of effective wellbore radius is quite subjective, and since the square of the radius is used in the storativity equation, variation in the assumed effective radius has a large effect on calculated storativity.

Storativity can also be estimated from properties of the fluid (density and compressibility) and the formation (thickness, compressibility and porosity). FEN will estimate storativity based on data from the drilling and testing phases of the proposed well. The resultant storativity will be compared to published values and the results presented to the Department.

Dependent on borehole conditions, the pumping test(s) will be either (1) open-hole with an inflatable packer, or (2) cased-hole without a packer. A brief description of the two test methods follows:

Open-hole Test

- An open-hole packer will be run into the hole on drill pipe to the point where the packer is located at the top of the basal Sundance Formation. A submersible pump and pump chamber will be placed in the drillstring at an approximate depth of 1500 feet; a pressure transducer will be placed at the bottom of the drill string. The packer will be inflated at approximately 3700 feet, which will isolate the basal Sundance Formation.
- The pump will be turned on at an estimated rate of 5 to 10 gallons per minute (gpm) until formation fluid is recovered at the surface.
- Pumping will be stopped and the drillstring bailed until the fluid level (head) inside the drill pipe is approximately equal to the head of the Sundance Formation.
- A pumping test or tests will be performed at rates which, depending on formation properties, may vary from 5 to 100 gpm; duration of the tests may range from 4 to 24 hours. Drawdown in the well will be measured with the pressure transducer. Drawdown data will be analyzed and transmissivity and hydraulic conductivity calculated.

Cased-hole Test

- Production casing (7" diameter) will be run in hole and cemented.
- The drillstring will be run to the bottom of the casing, and drilling mud displaced with completion fluid.
- Completion fluid will be bailed from the well and the casing across the Sundance Formation perforated "underbalanced"

(e.g., the head inside the casing will be less than the head in the Sundance Formation). Perforating in this manner will clean the perforation debris from the formation and remove some of the wall cake deposited by the drilling mud.

- A submersible pump will be placed in the hole (suspended on the drillstring) at an approximate depth of 1500 feet. A pressure transducer will be placed on the outside of the drill string at approximately 1450 feet.

- A pumping test or tests will be performed at rates which, depending on formation properties, may vary from 5 to 100 gpm; duration of the tests may range from 4 to 24 hours. Drawdown in the well will be measured with the pressure transducer. Drawdown data will be analyzed and transmissivity and hydraulic conductivity calculated.

State Comment:

Formation Porosity is another component that will need to be accurately measured. The Department agrees that a compensated Neutron/Density log (CNL/FDC) should be run to establish the porosity. This log must be run on a sandstone matrix to coincide with the proposed injection horizon.

FEN Response:

FEN will instruct the logging operator to set up the CNL/FDC logging tool for a sandstone matrix.

State Comment:

From the maps enclosed in the application it would appear that the Area of Review for the proposed injection well does not intersect the White River Fault. The Department requests all information from FEN regarding structural displacement that may be associated with this fault or fault system. Specifically, the Department would like to know if there are any other subsurface structural anomalies or faults located within the area of review.

FEN Response:

FEN identified the White River Fault during exploratory drilling at the Crow Butte Project. The fault is located northwest of the mine permit area and approximately 4.5 miles from the proposed injection well. The vertical displacement across the fault is estimated to be 200 to 400 feet. The fault plane dips to the north-northwest at approximately 75°. As such, the fault dips away from, and will not intersect the Sundance Formation within the Area of Review.

No wells in the Area of Review penetrate the Sundance Formation. However, based on review of logs from oil and gas exploration wells in the area and discussions with the Nebraska Conservation and Survey (Hal DeGraw; personal communication; 11-16-93), no structural displacement has been observed in the Lower Cretaceous or Jurassic sections. After completion of logging operations on the proposed injection well, FEN will correlate the injection well logs to logs from surrounding wells in the Area of Review (e.g., Roby #1, Heckman #1, and Arner #1). The Department will be notified if any structural anomalies or faults are identified within the Area of Review from this analysis or other analyses.

State Comment:

Appendix F includes estimated costs for plugging and abandonment. This section does not include any costs for reclamation of the well site, or removal and disposal of the uppermost portion of the surface casing. These costs should be accounted for and listed in the Restoration/Reclamation Surety Cost Estimate document. In addition, there may be some costs associated with abandonment and reclamation of equipment or property associated with land application activities. Any potential costs associated with either of these activities should be listed in the Surety Cost Estimate document. The revision of the Surety Cost Estimate document may be handled as a separate issue, but will need to be completed prior to public notice of the draft permit.

FEN Response:

FEN annually updates the Restoration/Reclamation Surety Cost Estimate document. Upon permit approval for the injection well, costs for plugging and abandonment (P&A), reclamation of the well site, and removal and disposal of the uppermost portion of the surface and production casings will be included in that document.

Estimated P&A, restoration and reclamation costs are attached as a revision to Appendix F of the original report. Please replace Appendix F of the report with the revised Appendix F.

Additional costs that would be incurred by NDEQ in the unlikely event that FEN were unable to continued operation of the injection well are also included. These costs include a total of $4,600 which consists of administrative charges, injection pump rehabilitation, and performance of a Mechanical Integrity Test (MIT).

To further clarify proposed P&A and reclamation plans, step-by-step procedures are presented below:

P&A Procedures

1. Obtain regulatory approvals, as required, to plug and abandon the well.

2. Flush well with three (3) wellbore volumes of buffer fluid.

3. Perform annulus pressure test for mechanical integrity.

4. Move in and rig up the plug and abandonment (P&A) rig and associated equipment.

5. Nipple down wellhead and install blowout preventers (if necessary).

6. Release injection packer. Remove packer and 3 ½" injection tubing. If packer does not release, leave in place. Rig up slickline unit and make internal cut above the top of the packer to recover injection string.

7. Set wireline (or tubing set) cement retainer above the injection packer.

8. Pick up workstring and run in hole. Sting into cement retainer. Pressure annulus to assure proper set of retainer.

9. Establish injection rate down workstring. Squeeze cement into injection zone with premium cement and additives.

10. Close cement retainer. Pressurize wellbore to assure proper closure of cement retainer.

11. Release workstring from cement retainer leaving approximately 100 feet of cement on top of the retainer. Reverse circulate clean and pull out of the hole to approximately 900 feet.

12. Spot 200 foot balanced plug (premium cement) across the surface casing shoe from approximately 700 to 900 feet. Pull out of the hole and wait for cement to set.

13. Go in the hole and tag cement plug with workstring to assure cement has set.

14. Pull out of the hole to 200 feet.

15. Spot a balanced plug from 200 feet back to 10 feet with premium cement. Rinse out blowout preventers.

16. Remove blowout preventers. Cut surface and production casings off approximately 5 feet below grade and close all casings

with steel plate.

17. Rig down P&A rig and release same.

18. Erect a permanent well location marker. Marker is to be inscribed with the operators name, well class and number, serial number, section-township-range, county, and date plugged and abandoned.

19. Prepare and file closure and post closure report with NDEQ.

Site Restoration Procedures

1. Perform radiation survey and collect soil samples, if needed. Soil samples will be collected if radiation is significantly above background levels.

2. Remove gravel (approximately 6" thick) from the location.

3. Rip the location with a grader to a depth of 1 foot.

4. Replace topsoil.

5. Revegetate the location, including soil preparation (grade and contour topsoil, disk and harrow), seeding and mulching.

State Comment:

The application should address whether or not there are any potential adverse byproducts that may occur as a result of mixing the injection fluids with the formation water of the Sundance Formation. Include(d) with this analysis should be an assessment of the potential for such things as scale buildup to occur in the injection well. A contingency plan for handling potential problems associated with the injection well should be developed, including a worst case scenario in the unlikely event of a catastrophic occurrence.

FEN Response:

As stated in the application text, insufficient water quality data are available for the Sundance Formation to allow quantitative analysis of the compatibility of the injection and formation fluids. Formation water samples will be collected during the testing phase of the injection well construction and analyzed to further assess fluid compatibility.

In the event that this analysis indicates possible compatibility problems, two alternatives will be considered: (1) pre-treatment of the injection fluid to remove or reduce concentrations of constituents of concern, and/or (2) use of a "pad" or buffer to be injected prior to any wastes. This pad would probably consist of sodium chloride water that would be used to: (1) reduce concentrations of sulfates which, on contact with the injection fluid, could precipitate out calcium sulfate as a scale deposit, and (2) provide a physical buffer between the injection fluid and the native formation and formation fluid.

FEN does not consider that a "catastrophic failure" could occur which would endanger life or human health. However, potential injection problems could include scale or bacterial deposits which reduce the injectivity of the well and/or formation.

FEN will monitor the condition of the well based on injection pressure and volume. If monitoring indicates a significant decline in the injectivity of the well or formation, remedial treatment options could include: (1) treatment of the well with a biocide to remove bacteria deposits, and/or (2) treatment of the well with acid to remove scale and precipitates. A common and generally accepted acid treatment method follows:

Inject a buffer or pad, typically consisting of ammonium chloride.

Inject hydrochloric acid to remove calcium carbonate scale.

If necessary, inject mixture of hydrochloric and hydrofluoric acid to remove wall cake and clay materials.

Inject a "flush" of ammonium chloride to displace the acids away from the wellbore.

Produce (by bailing or pumping) a volume equivalent to 90% of the total acid volume to remove deposits and spent acid from the formation and well. Produced fluids from the acid treatment will be disposed to existing Crow Butte Project evaporation ponds.

To monitor surface piping and prevent failures, piping from the treatment facility to the injection well will be equipped with flow and pressure alarms. In addition, the injection line will be inspected periodically to monitor for corrosion, visual leaks, etc.

FEN has evaluated potential impacts from a surface release, such as a pipeline break, in the report "Impact Analysis and Incident Response Release Plan for Wellfield Release" (Resource Technologies Group, Inc.; March 1993). This plan addresses release flow rates of 1000 to 2000 gallons per minute (gpm), whereas the anticipated flow rates in the injection line are 20 to 100 gpm. However, the Incident Response Plan included in Section 3.0 of this report is applicable to the operation of the proposed injection well.

State Comment:

Figure 7-1 and supporting text indicate that the proposed injection well will not be cemented from a depth of approximately 800 feet to 2100 feet (Base of Chadron Formation to Base of Niobrara Formation). The reasons listed for not running cement in this interval are listed on page 61, and include: "(1) the pressure induced by 3750 feet of cement would exceed the formation fracture pressure, (2) the cement will be high enough to isolate all of the lower sand intervals (i.e., from the "D" Sand through the basal Sundance), and (3) shallow freshwater zones (i.e., the Brule and Chadron Formations) will already be isolated by the 10¾" surface casing and associated cement". Department staff have reviewed this section of the application, and determined that the proposed cementation completion may need to be altered. For example, oil and gas wells are commonly completed by running cement through the entire long string interval from the base of the surface casing to total depth. The Department is unaware of completion problems associated with this practice and the potential to exceed formation fracture pressure. Another factor that may complicate the proposed construction is the water quality within the Dakota Formation. Since the water quality of the Dakota Formation has not yet been established at the site, the proposed injection well may need to be cemented through the Dakota interval in order to satisfy requirements in Nebraska Title 122, Chapter 15, part 002.01B. In consideration of the life expectancy of the proposed injection well, it would be prudent to seal the annulus from total depth to surface so as to minimize any potential for vertical migration of fluids.

FEN Response:

The cementing program presented in the text was designed to place premium cement from the Sundance Formation up as high as possible (in this case, to the base of the Niobrara Formation) without fracturing the Sundance Formation. Discussions with Paul Roberts (Director, Oil and Gas Conservation Commission; 11-8-93) indicate that the cementing program as presented in the text is customary and accepted for oil and gas wells in the State of Nebraska.

If the proposed premium cement (Class G or H) were to be placed throughout the entire annulus (from ground surface to 3750 feet), the head imposed by the cement would exceed the estimated formation fracture pressure by approximately 800 psi. For this reason, the cement design specified that the cement would be limited to the interval from the base of the Niobrara Formation through the Sundance Formation.

The cementing program described in the text will provide approximately 1400 feet of isolation between the Dakota and the Niobrara Formations. If the cement bond log (CBL) results show adequate bond, this amount of cement should be more than adequate to prevent migration into or between underground sources of drinking water (USDWs) as required under Title 122 (specifically, Chapter 15, part 002.01B). However, to address concerns of the Department, alternative cementing programs are presented below.

Alternative cementing programs for the long string that merit consideration are: (1) stage cementing with a diverter (DV) tool, (2) stage cementing by casing perforations, and (3) altering the cement mixture to utilize lighter cements in general, especially with regard to the lead cement.

Due to the potential operational problems associated with stage cementing (DV tool plugging, compromising casing integrity, etc.), the use of lighter cements is the preferred alternative. A preliminary example of one cementing combination that could be used is presented below:

- Lead Cement: 250 Sacks Class G or H "lite" mixed at 11.4 #/gallon with a yield of 2.95 ft^3/sx. This amount of cement would extend from the ground surface to approximately 2700 feet.

- Tail Cement: 200 Sacks 50/50 Pozmix mixed at 14.3 #/gallon with a yield of 1.27 ft^3/sx. This amount of cement would extend from 2700 feet to the bottom of the hole (3750 feet).

  Note: This cementing design is preliminary, and based on expected formation type, chemistry, depth, and temperature. Final cementing design may vary with respect to additives, yield, and density. Cement volumes are based on a gauge hole; the amount of cement in excess of the volume presented here will be determined based on an open-hole caliper log.

The cement design presented herein would provide a full annulus of cement but would impose a head approximately equal to the formation fracture pressure. One method to reduce the head imposed during cementing (by approximately 400 psi) would be to bring the cement only 100 feet up into the surface casing. However, designing for cementing back to a known point is complicated by a variable hole ameter (due to washouts), even if an open-hole caliper log is . Hence, if the program is designed to bring cement only to the ace casing shoe, it is quite possible that the top of cement may actually be higher (in which case the cement head could approach fracture pressure) or lower (below the casing shoe).

The location of the top of cement can be determined from the cement bond log (CBL), which will be run after the cement job. If the top of cement is inside the casing shoe, no additional cementing would be performed. However, based on the Department's comments, if the cement is below the casing shoe, additional cementing might be necessary. Alternatives at this point would be a top job or a squeeze job.

FEN considers both of these options undesirable. Performing a top job at depths of 800 feet or more is an inefficient method of cement placement, and due to bridging in the annulus, obtaining a good cement bond is difficult. Performing a squeeze job would require perforating the production casing which could potentially compromise the integrity of the casing.

In summary, FEN prefers the cementing program presented in the original text. However, to address concerns expressed by the Department, the alternate cement design discussed above has been presented. This design will fill the annulus from total depth to 100 feet inside the surface casing shoe, as shown on a the attached revision of Figure 7-1 (wellbore schematic).

State Comment:

Upon completion of cementation of the proposed injection well, a certain period of time will be required to allow the concrete to cure. A Mechanical Integrity Test (MIT) will need to be performed once the construction of the well is completed. FEN needs to indicate what kind of MIT will be performed, and what measures will be used to determine if the well has passed or failed the MIT.

FEN Response:

In accordance with EPA guidance documents and accepted oil and gas standards, and based on recommendations from the Nebraska Oil and Gas Conservation Commission (Paul Roberts, Director; personal communication; 11-8-93), three separate tests to determine mechanical integrity will be performed, as described below:

- Surface Casing: While cementing the 10 ¾" surface casing, positive pressure of approximately 500 psi will be used to "bump" the top cementing plug. Pressure will be held for 15 to 30 minutes and recorded on a pressure chart to demonstrate the mechanical integrity of the casing. A significant pressure decrease (e.g., more than 10 percent) over this time period could indicate that the integrity of the casing is questionable.

If more than a 10% pressure decrease occurs, the cement will be allowed to cure (12 to 48 hours after the cement is in place). A packer will be run into the hole and positive pressure tests (300 psi for 15 to 30 minutes) will be performed at various depths.

If a casing leak is identified, it will be corrected by placement of a casing patch or with a cement squeeze job, and the casing retested.

- Production Casing: While cementing the 7" production casing, positive pressure of approximately 1000 psi will be used to "bump" the top cementing plug. Pressure will be held for 15 to 30 minutes and recorded on a pressure chart to demonstrate the mechanical integrity of the casing. A significant pressure decrease (i.e., more than 10 percent) over this time period could indicate that the integrity of the casing is questionable.

  If more than a 10% pressure decrease occurs, the cement will be allowed to cure (12 to 48 hours after the cement is in place). A packer will be run into the hole and positive pressure tests (300 psi for 15 to 30 minutes) will be performed at various depths.

  If a casing leak is identified, it will be corrected by placement of a casing patch or with a cement squeeze job, and the casing retested.

- Tubing and Packer: After a successful MIT on the production casing, 3 ½" diameter tubing and a packer will be run in the hole, and the packer set above the Sundance Formation. Positive pressure of 300 psi will be applied to the casing/tubing annulus, held for 15 to 30 minutes, and recorded on a pressure chart to demonstrate the mechanical integrity of the casing, tubing and packer. A significant pressure decrease (e.g., more than 10 percent) over this time period could indicate that the integrity of the tubing or packer is questionable.

  If a leak is detected, the packer will be reset, and the test performed again. If the packer continues to leak, it will be pulled out of the hole, replaced, and the test re-run.

  If a tubing leak is discovered, the tubing will be retested internally to identify the leak location. The tubing will then be pulled, the leaking joint(s) replaced, run back in the hole, and retested.

As per Oil and Gas Conservation Commission regulations, cement would be allowed to cure till it develops a compressive strength of at least 500 psi. This curing time depends on the final cement mixture used, but is estimated to be 12 to 48 hours.

As per Title 122 requirements (Chapter 16, 002.1C) annular pressure (approximately 100 to 200 psi) will be maintained and recorded over operational life of the injection well.

State Comment:

The operation of the proposed injection well will require the use of an approvable packer fluid. FEN should identify the chemical and physical characteristics of the proposed packer fluid.

FEN Response:

FEN proposes to drill the well with bentonite drilling mud. After running and cementing the 7" diameter casing, a cement bond log (CBL) will be run to assess cement bond. Based on adequate bond, the drilling mud will then be displaced with freshwater completion fluid. This water will be obtained locally; one acceptable source may be the Chadron Formation.

Freshwater completion fluid is commonly used for oil and gas operations in the State. If necessary, additives such as sodium and potassium chloride may be mixed with the freshwater completion fluid to control swelling clays.

After the 3 ½" diameter tubing and packer are in place, completion fluid will remain between the tubing and 7" casing. This fluid will be treated with some or all of the following additives to reduce corrosion: (1) oxygen scavengers - to react with oxygen before corrosion occurs; (2) bases - to neutralize all acids; (3) biocides - to kill bacteria that would degrade fluid additives to form organic acids, hydrogen sulfide, or carbon dioxide; and (4) corrosion inhibitor - to slow or eliminate corrosion caused by corrodents remaining in the fluid. This fluid, referred to as the "packer fluid", will remain in place for the life of the well.

RESPONSE TO COMMENTS
FROM
STATE OF NEBRASKA
DEPARTMENT OF ENVIRONMENTAL QUALITY
REVIEW LETTER DATED NOVEMBER 12, 1993

FEN has reviewed the November 12, 1993 letter from the Nebraska Department of Environmental Quality that lists requirements for the Notice of Intent to Operate for the proposed Class I injection well.

Following the construction of the well and completion of the testing phases, FEN will submit the requested information to the Department as part of the Notice of Intent to Operate.

RESPONSE TO COMMENTS
FROM
STATE OF NEBRASKA
DEPARTMENT OF ENVIRONMENTAL QUALITY
PHONE CONVERSATION ON DECEMBER 1, 1993

In a phone conversation with Hal Demuth (Harlan, Casey & Associates, Inc. - consultant to FEN) on December 1, 1993, Frank Mills (NDEQ) requested additional information regarding determination of formation fracture pressure.

FEN Response:

The fracture pressure for the Sundance Formation presented in Appendix D of the report was based on (1) estimated vertical stress and formation pore pressure (P. Dickey, Petroleum Development Geology; p. 302) , and (2) discussions with Paul Roberts (Director, Nebraska Oil and Gas Conservation Commission) regarding fracture gradients in northwestern Nebraska. When formation pore pressure is determined during the testing phase of well construction, this calculation will be validated.

In addition, fracture pressure will be estimated based on (1) resistivity and density logs, and (2) pumping test data. Accepted methods such as Mathews & Kelly[1] or Eaton[2] will be used. The resultant values will be correlated with regional fracture pressure information and the results presented to the Department.

[1] Mathews, W.R. and J. Kelly, 1967, How to Predict Formation Pressure and Fracture Gradient; Oil and Gas Journal, February 20, 1967.

[2] Eaton, Ben A., Fracture Gradient Prediction and It's Application in Oilfield Operations, SPE Journal, October, 1969.

APPENDIX F

ESTIMATED PLUGGING & ABANDONMENT RESTORATION AND RECLAMATION COSTS

(Revised 12-1-93)

FEN ESTIMATED PLUGGING, ABANDONMENT, and RECLAMATION COSTS
Proposed Injection Well - Crow Butte Project

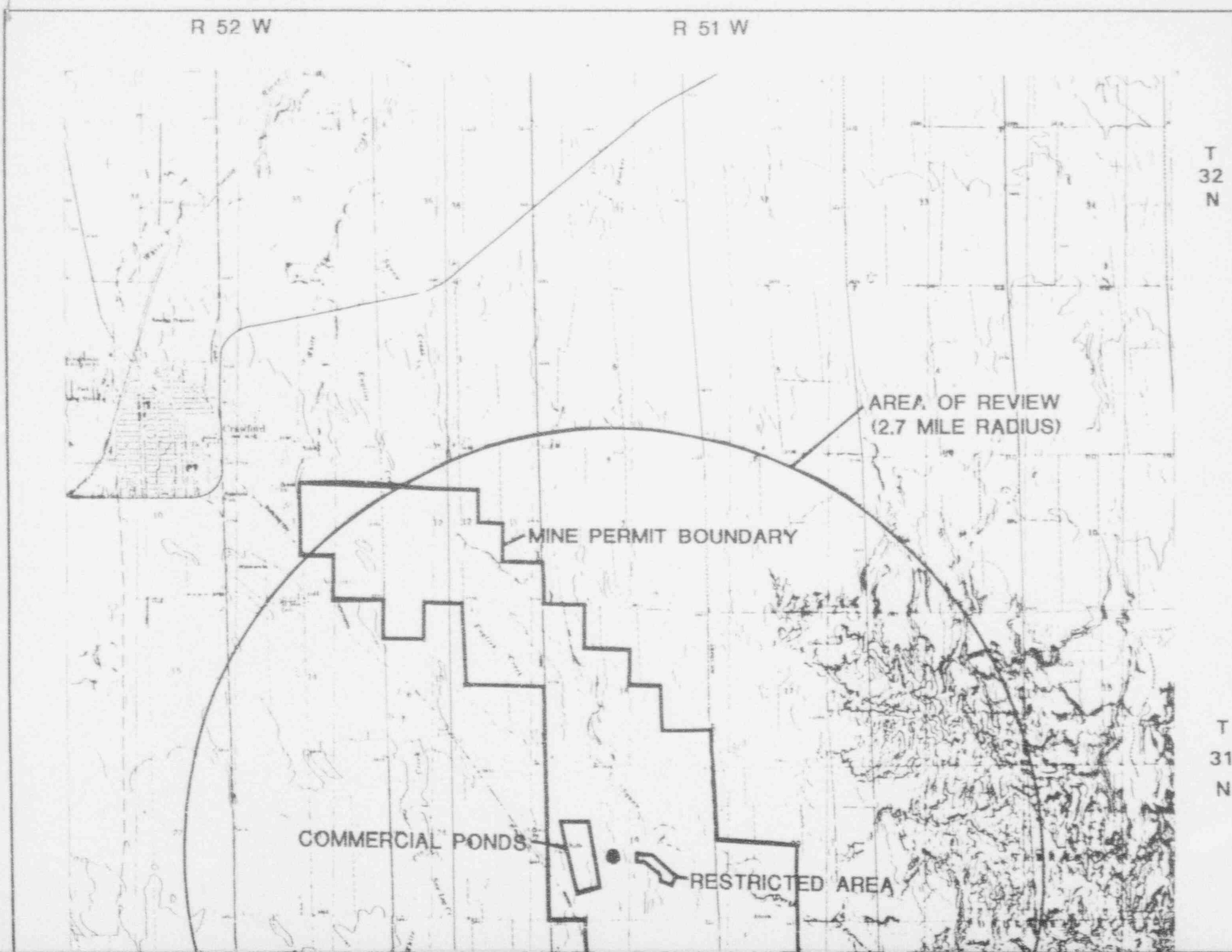
CEMENT	Total Units	Unit Cost	Total Cost ($)
300 Foot Bottom Plug (3750'-3450') 70 sx. Class H or G Cement	70	7.80	546
7" Bridge Plug	1	1000	1000
200 Foot Bottom Plug (900'-700') 50 sx. Class H or G Cement	50	7.80	390
200 Foot Bottom Plug (200'-surface) 50 sx. Class H or G Cement	50	7.80	390
Pumping Charges	1	3000	3000
OPERATIONS			
Rig Cost (4 days)	4	1500	6000
Circulating Pump & Tank (2 days)	2	500	1000
Power Swivel (1 day)	1	300	300
Water Hauling (2 days)	2	300	600
Frac Tank Rental (4 days)	4	125	500
Slickline Services (2 days)	2	400	800
Mud Materials	1	500	500
2 7/8" Tubing Rental ($0.25/ft)	4000	0.25	1000
Tubing Inspection (125 joints)	125	10	1250
Welder, Dirtwork, Roustabouts (4 days)	4	600	2400
Trucking	1	1000	1000
Removal, Disposal of Wellhead, Piping & E	1	2000	2000
Supervision (6 days)	6	450	2700
Miscellaneous Costs	1	1000	1000
SUBTOTAL			26376
CONTINGENCY (@ 10%)			2638
TOTAL ESTIMATED P&A COST ($)			29014

ESTIMATED SITE RESORATION COSTS
Proposed Injection Well - Crow Butte Project

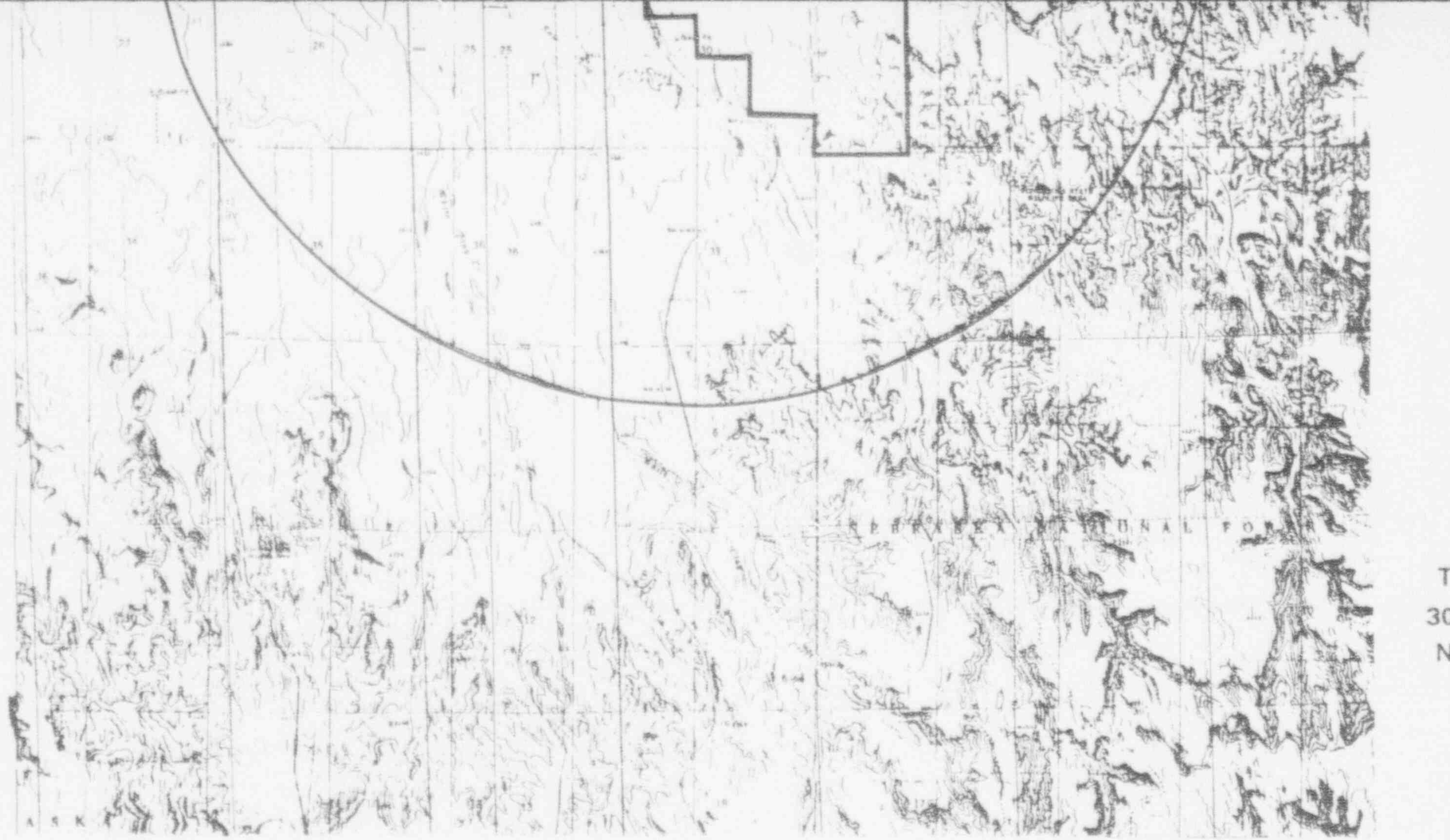
	Total Units	Unit Cost	Total Cost ($)
Radiation Survey - 1 day			
Labor Crew (8 hours)	8	30	240
Soil Sampling (5 samples)	5	50	250
Gravel Removal (6" thickness)			
21780 cu. ft. = 806 cu. yd.	806	1.00	806
Ripping - Rip with Motor Grader to 1' depth			
1 acre @ 4 acres/hr ==> 1/2 d	4	80	320
Topsoil Replacement			
1 acre @ 8 acres/hr ==> 1/2 d	4	80	320
Revegetate 1 Acre			
Grade & Contour Topsoil; per ac	1	80	80
Preparation (Disk & Harrow)	1	20	20
Drill Seed	1	160	160
Mulch @ 2 tons/acre; $50/ton	2	50	100
Mulch & Crimp	1	50	50
SUBTOTAL			2346
CONTINGENCY @ 10%			235
TOTAL ESTIMATED SITE RESTORATION COST ($)			2581

P&A and SITE RESTORATION COSTS
IF NDEQ ASSUMES OPERATIONS FROM FEN
Proposed Injection Well - Crow Butte Project

	Total Units	Unit Cost	Total Cost ($)
ADMINISTRATIVE			
Review well construction, history, etc	40	65	2600
OPERATIONS			
Initial MIT (1 day rig time)	1	1500	1500
Pump Rehabilitation	1	500	500
P&A			
(as decribed above)	1	29014	29014
SITE RESTORATION			
(as decribed above)	1	2581	2581
TOTAL ESTIMATED COST($)			36194



R 52 W
R 51 W
T
32
N
T
31
N
AREA OF REVIEW
(2.7 MILE RADIUS)
MINE PERMIT BOUNDARY
COMMERCIAL PONDS
RESTRICTED AREA



EXPLANATION

- *LOCATION OF PROPOSED INJECTION WELL*
- *CROW BUTTE MINE PERMIT BOUNDARY*
- *AREA OF REVIEW (2.7 MILES)*

0 2000 4000 8000

SCALE IN FEET

N
W E

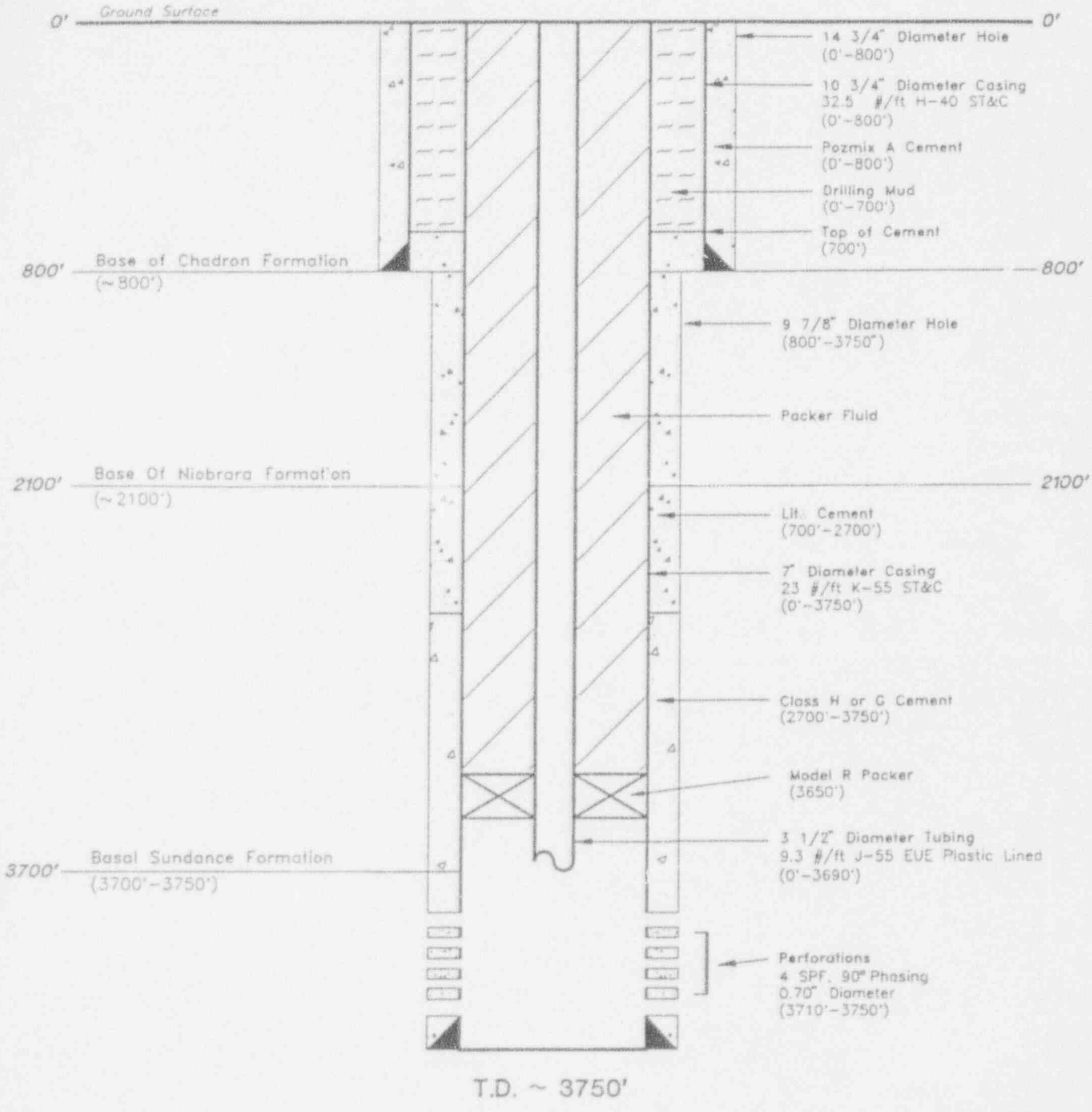
Ferret Exploration Company
of Nebraska, Inc.

FIGURE 1-1
CROW BUTTE PROJECT
DAWES COUNTY, NEBRASKA
SITE LOCATION MAP

PROJECT: 0108-002	DATE: April, 1993
REV: 0	BY: HPD CHECKED: RLH

HARLAN, CASEY & ASSOCIATES, INC.
Consulting Engineers and Hydrogeologists

12/93 FERRET07.DWG



NOTE:
ALL DEPTHS IN FEET BELOW GROUND SURFACE.

NOT TO SCALE

Ferret Exploration Company
of Nebraska, Inc.
Crow Butte Facility

FIGURE 7-1

INJECTION WELL SCHEMATIC-
ALTERNATE CEMENT DESIGN

PROJECT: 0108-002	DATE: December, 1993	
REV: 0	BY: HPD	CHECKED: RLH

HARLAN, CASEY & ASSOCIATES, INC.
Consulting Engineers and Hydrogeologists