Potential for Fluid Flows From Oil and/or Gas Wells And The Effects on Trona Mining In Southwestern Wyoming

Prepared for
Tg Soda Ash, Inc.

May 16, 1998

By:

Craig W. Van Kirk

Craig W. Van Kirk
10463 E. Chinook Trail
Parker, CO. 80138
Phone (303) 841-1049 Fax (303) 841-4107

May 16, 1998

Mr. Paul W. Hynes
Staff Engineer
Tg Soda Ash, Inc.
P.O. Box 100
Granger, WY 82934

Re: Report on the Potential for Fluid Flows from
Oil and/or Gas Wells and the Effects on Trona Mining
in Southwestern Wyoming

Dear Mr. Hynes:

It is my pleasure to submit this report addressing the potential for fluid flows from oil and/or gas wells and the effects on trona mining in southwestern Wyoming. This natural gas migration study responds to your authorization correspondence dated October 16, 1997 and focuses on the two major tasks you requested to be conducted at this time.

This phase of the project has been completed in both of the focus areas, as follows:

1. A literature search has identified examples where oil or gas has migrated from wells.

2. A computer simulation model has been developed which demonstrates how fluids could leak from wells within the Known Sodium Leasing Area.

A summary of results is presented herein, along with details of the work and findings. If you have any questions or would like further information or clarification, do not hesitate to contact me at your convenience. I look forward to assisting you again in the near future.

Sincerely,

Craig W. Van Kirk

Craig W. Van Kirk

TABLE OF CONTENTS

	Page
Letter of Transmittal	
Executive Summary	1
Overview	3
Geology	4
Potential for Fracturing	5
Technical Analysis	8
Methodology	9
Gas Injection	12
Wellbore Crossflow	13
Water Injection	14
Literature Search and Example Case Histories	15
Examples of Migration without Fracturing	15
Examples of Migration with Fracturing	16
Examples of Geologic Formation Collapse	17

Figures

1. Green River Basin Area Map
2. Southwestern Wyoming
3. Extent of Trona
4. Structure Map – Second Frontier
5. Stratigraphic Correlation
6. Trona Bed Log Character
7. Well Log – Montana Power 1-16 State
8. Map – Simulator Area and Mining Area
9. Pressure versus Depth
10. Simulation Grid
11. Simulator Stratigraphic Column
12. Wellbore Diagram
13. Wellbore Diagram
14. Wellbore Diagram
15. Wellbore Diagram
16. Proposed Wellbore Diagram
17. Proposed Wellbore Diagram

Tables

I. Simulator Geologic Parameters
II. Oil and Gas Fields Near Trona Mining Area
III. Simulation Results

3. The worst case scenario estimates that if high-pressured gas within a gas well were to find its way to the trona mining level, approximately 1,800 feet below ground level, the gas would fracture the rocks and flow out of control laterally a distance of two miles and break into a working trona mine in a matter of 1.5 to 3 days. This would be a life threatening catastrophic event.

4. A more moderate scenario would not be life threatening if the high-pressure gas (or water) in a well were to enter one of the sandstone beds within the thicker trona interval and pressure up the natural waters which occupy the natural pore system within the sandstone rocks. This increased pressure would force the water within the sandstone to flow at rates higher than any observed in the past, requiring much higher expenditures for dewatering the trona mining operation. This could double the maximum historical water flow rates into the mines and greatly reduce the amount of trona which could be mined commercially.

5. Suggested tentative plans to (1) set surface casing deeper, below the trona beds, (2) run production casing cement higher, within the trona beds, and (3) consolidate multiple wells into drilling islands contained in the mines by pillars of unmined trona constitute steps in the right direction in an attempt to reduce risk and increase safety. However, the new well designs will not completely eliminate the risks.

OVERVIEW

The overlapping of trona mining at shallow depths and natural gas (or oil) well drilling and production from deeper depths creates a situation which has led to a controversy over the economics and safety of simultaneous development. Several geologic formations are productive of oil and/or gas in or near the area of interest, but it is the deeper Frontier formation which generates the most deserved safety concern for mining operations. At depths of approximately 12,000 feet and initial reservoir pressures exceeding 6,000 psia, this high-pressured source of gas has the potential to cause life-threatening catastrophies within trona mines.

Since natural gas has a very low density, its high pressure existing at great depths can readily be transmitted to much shallower depths with very little loss in pressure. Therefore, it is possible for the deep Frontier formation to deliver gas to the trona mining levels at pressures exceeding 5,000 psia. At the trona mining depths of approximately 2,000 feet below ground level, gas pressures in the range of 1,500 to 2,000 psia would be sufficient to fracture rocks and create catastrophic consequences in a trona mine. The potential for a disaster in a mine clearly exists.

The trona beds being mined are contained within a layer cake of different rock types, dominated by trona, but with sandstone beds of significant thickness and areal extent, and numerous other layers of a variety of other sedimentary rock types. The significance of this heterogeneous geologic setting is two-fold:

1. The bedding planes, or points of contact between trona beds and adjacent layers of other rock types, generally are the weakest links in the chain, and fractures tend to be created there more easily than within a homogeneous single rock type layer. Pressures at depth of only 0.75 to 0.80 psi per foot of depth could be sufficient to create fractures at the bedding planes. These fractures provide conduits with migration rates approximating one mile per day.
2. The thick sandstone layers provide a naturally porous and permeable pathway for gas or water to flow from a wellbore into a mine without the higher pressures required for

the proximity of wells drilled west of the mining area and also shows the western boundary of the KSLA.

The trona beds are within the Wilkins Peak Member of the Green River formation. The trona covers an area of approximately 1,300 square miles. The depths of these beds range from 400 to 3,500 feet below ground level. The major beds underlie an area of approximately 850 square miles. Shown in Figure 5 is a stratigraphic correlation chart, with the Wilkins Peak formation shown in the Bridger Basin, which is part of the Greater Green River Basin.

The trona is interbedded with sandstones, mudstones, oil shale, and marlstones as clearly shown in Figure 6. For this study an actual well was utilized, and shown in Figure 7 is the well's log header and the log section below surface casing for the trona interval. The well, Montana Power 1-16 State (MP16), was located in Section 16, Township 18 North, Range 111 West and was drilled in November 1980 within the boundary of the KSLA. The stratigraphic sequence of this well was used in constructing the simulation model. The well data were translated north approximately 8 miles, closer to the actual Tg mining area, to a location in Section 5, Township 19 North, Range 111 West. The location of the simulator well in relation to the mining area is shown in Figure 8 and also in Figure 4.

The translation of this well's log character, formation tops, and formation thickness northward was done because no logs were in our possession on the actual wells which have been drilled in the area just west of Tg's mining operations. Structure maps and cross-sectional maps based on numerous wells in the area were incorporated to ensure that formation tops and thickness were accurately input into the simulation model.

Potential for Fracturing

The high-pressured natural gas existing in the deep Frontier formation is one of the more significant sources of cause for mine safety concern. The data shown on Figure 9 demonstrate graphically the relationship between pressures, depths, and rock-fracturing potential.

The Frontier formation typical conditions are indicated on this Figure at a depth of 12,351 feet with a corresponding initial pressure of approximately 6,793 psia. This chart shows that if a continuous column of gas existed from the Frontier formation all the way to ground

level, the surface pressure would be approximately 5,500 psia. Any other pressures between 5,500 and 6,793 psia can be read directly from the line labeled "Frontier Formation Gas Gradient" for any depth of interest.

If instead of natural gas existing from the Frontier formation to the surface the fluid was a liquid, such as oil or water, the pressures would decrease more rapidly at shallow depths. This is simply because liquid densities are much higher than the density of natural gas. The relationship of pressure versus depth for oil is labeled "Frontier Formation Oil Gradient" and indicates a surface pressure of approximately 2,000 psia. If instead of gas or oil the fluid was water, then the surface pressure would be approximately 1,400 psia as shown by the line labeled "Frontier Formation Water Gradient". It is more likely that natural gas would be the fluid in the wells of concern, but any combination of gas, oil, or water is possible.

The three other lines on the Figure labeled "Fracture Gradients" indicate the range of pressures required to fracture the geologic formations at various depths. Based on data and reports of measurements made on rocks in this area of interest, the minimum fluid pressures required to fracture the rock formations result in a fracture pressure gradient of approximately 0.75 psi per foot of depth; while the upper limits of rock strength indicate a higher pressure required for fracturing, approximately 1.0 psi per foot of depth. These two relationships are shown and labeled on the Figure and form an envelope of possible fracture pressure gradients existing between 0.75 and 1.0 psi per foot.

The solid line within this envelope, labeled "Estimated Fracture Gradient South Moxa Arch Green River Basin", was published by the Gas Research Institute in March of 1995 in their final report titled "Successful Drilling Practices Study Greater Green River Basin". This fracture gradient line resulted from GRI's study of numerous actual wells and data within the Green River Basin.

This Figure demonstrates the depths which are vulnerable to fracturing. For example, notice the gas gradient line intercepts the fracture gradient envelope at depths between approximately 6,000 feet and 8,500 feet. This means that at depths below approximately 8,500 feet the gas should not fracture the rocks. Also, at depths shallower than 6,000 feet the gas

would almost certainly fracture the rocks, and the shallower the depth, the more certain the fracturing.

At the trona mining depths of approximately 2,000 feet the gas pressure could be approximately 5,500 psia, greatly exceeding the pressures required to fracture the rocks, which would be as low as 1,500 to 2,000 psia. Even oil or water in a well would exert sufficient pressures at 2,000 feet to cause fracturing of the formations. This Figure demonstrates the clear danger faced by the trona miners at 2,000 feet.

TECHNICAL ANALYSIS

Initially a small model, 5x2x3, was used to test some of the reservoir characteristics that were to be incorporated in a larger model. The small model allowed for faster runs when testing for modeling of reservoir characteristics. The testing was done to insure that flow barriers could be set up within the model to simulate the natural resistance of rocks to fracture. These flow barriers would act as barriers to flow until a specified threshold pressure was surpassed. Another important area for this simulation study was crossflow between geologic horizons. The smaller model helped set up the crossflow criteria for the large-scale model. The small model incorporated geological data such as porosity and permeability that matched data for wells in the area. Once all of the testing was done, the larger model was constructed that more closely matched the geological strata for wells in the Known Sodium Leasing Area.

The large-scale model was 20x5x13, a total of 1,300 cells. A schematic of the model is shown in Figure 10. Figure 11 shows the simulator stratigraphic column with associated depths utilized in the model. The model covered a surface area of two miles by one mile, simulating a well two miles from an active trona mine. The 13 vertical layers incorporated the main geological formations found in wells within the area. Of prime importance were the trona layers and the Frontier formation. Table I lists the geologic parameters input into the simulator. In this area the Frontier is a major contributor to the gas production. The Dakota and the Morrison have also contributed to oil and/or gas production within the area, however, for this simulation only the Frontier was utilized as a producing formation. Based upon cross-sections through the area these thirteen geological layers can be correlated for long distances in the Known Sodium Leasing Area.

Within the trona layers (layers two through five) two layers were used extensively during the simulation. These two layers were the conduits for transporting fluids from the well over the two-mile distance to the mine. Layer three (3) was a porous and permeable sandstone within the trona layers. This sandstone had characteristics such that it was of considerable reservoir volume and could be an unfractured conduit for gas, oil, or water. Layer five (5) was a thin layer used to model a fracture. The fracture was utilized in the simulation to demonstrate more rapid fluid

The Water Injection Cases can be assumed to simulate actual water injection conducted purposefully by the operator of a well, or it can be assumed that the source of the water (or gas) is an underground geologic formation. These cases are similar to the Gas Injection Cases described above, except that the fluid entering the trona mine would be water instead of gas.

The object of the simulation was to verify how quickly gas or water could move through the conduit layers, how much fluid was transported, and at what rate. These methods were utilized to simulate conditions which could happen in real wells. Shown in Figures 12 through 15 are wellbore schematics which demonstrate how fluid could find its way from one section of the wellbore to a different section of the wellbore. The wellbore schematics are typical of completions utilized in the past in this area. Shown in Figures 16 and 17 are schematics of the proposed drilling and completions for new wells within the KSLA. The major difference is, the newer wells would have the surface casing set deeper and would have cement behind the production casing that is designed to prevent flow in the production casing annulus.

Refer to Figure 12 as a schematic demonstrating how high-pressured fluid could migrate from a deep producing formation through or around the cement, uphole to shallower depths, and into the trona mining interval. This scenario could occur in several possible ways, as follows:

1. Original cement job was inadequate, poor quality or poor design. Poor bonding between the casing, cement, and rock.
2. Hydraulic frac job conducted on the well to stimulate production from the producing formation applies very high pressures inside the casing, causing the casing to expand and balloon outward, and compressing the cement outside the casing. When the frac job is completed and the pressure is relieved, the casing returns to its original diameter, but the cement does not completely expand back to its original thickness, thereby leaving a small opening or passageway, called a "micro-annulus". This micro-annulus is a pathway for high-pressured fluid to migrate outside the casing from the producing formation upward to the trona mining level.

Figure 13 presents another possible scenario for uncontrolled fluid migration. In this example the migration path is provided by a hole in the casing near the trona interval.

1. Hole in casing caused by corrosion.

2. Hole through incompetent threads at casing joint.
3. Slip planes within the trona interval permit lateral movement of rocks, compressing well casing, deforming well casing, accelerating corrosion.
4. Even if the well had a packer installed near the bottom of the tubing (as shown in Figure 12) designed to prevent fluid from migrating upward as the arrows show in Figure 13, oftentimes packers leak. For example, a 1994 survey by both BLM and Wyoming State Oil and Gas Commission inspectors noted numerous cases where surface pressures revealed leaks in packers and/or casing and/or cement.

Figure 14 demonstrates another example of how uncontrolled migration could occur. In this case a hole in the casing (or connection joint threads) has been created deeper in the well, opening a pathway for migration. Figures 13 and 14 are very similar in causes and effects.

Figure 15 is similar to Figure 12 in that the fluid migrates through incompetent cement, however, the difference in the two scenarios is that in Figure 15 the source of the high-pressured fluid is not the producing formation. Instead, a shallower formation above the intended producing zone supplies fluid into the wellbore and upward to the trona level. This case is practically the same as Figure 12 for all intents and purposes, and it exposes the necessary concern for all potentially porous and permeable formations exposed in the wellbore even if they are not the primary formation targeted for production. For example, the common practice of disposing of produced waters into porous but non-productive formations could contribute to this potential problem.

Figures 16 and 17 were provided by Union Pacific Resources at a meeting in Green River, Wyoming on March 26, 1998. These two figures were part of a document titled "Draft Proposed KSLA Drilling Procedures". The major points to note are:

1. The surface casing is run deeper, to a depth of 3,000 feet, below the trona mining interval.
2. Cement is placed higher in the well, up to the mine level.

Earlier discussions throughout this report address the potential risks associated with the hazards of drilling and the causes and consequences of leaks in packers, casing, and cement.

One final note on Figures 12 through 17; they all show wells which have been completed and are operational for production or injection purposes. Another area of concern for safety exists in wells which have been abandoned after commercial production has ceased. In this case the tubing and packer are removed from the well, and perhaps some of the casing is removed also. According to governmental regulations, competent cement plugs should be placed in the well, and the wellhead will be cut off. Figures 12 through 17 can be reviewed to appreciate how fluids could leak into and migrate through an improperly plugged and abandoned wellbore and ultimately enter the trona level.

Gas Injection

Gas was injected into layer three (sandstone) or five (fracture). The controlling factor for the amount of gas that was injected was a specified bottom-hole injection pressure. For the fracture layer, gas injection was set at 1,800 psia. Under this scenario, Case 1, the gas moved the two-mile distance in approximately three days at an average flow rate of 400 Mcfd. See Table III for a summary of results. The 1,800 psia bottom-hole injection pressure approximates a pressure gradient of 1.0 psi/ft. In real life under this scenario it is highly likely that a horizontal fracture would be created. It is highly unlikely that anyone would purposely inject at these kinds of pressures, however, it is important to note that the pressure gradient would be greater than 1.0 psi/ft at the level of the trona beds if gas from the Frontier communicated directly with the shallow beds associated with the trona mining. As stated previously the three days that it takes to cover the two miles is a result of the small volume associated with the thin fracture layer. It is a worst case scenario for transporting gas the two-mile distance.

Another gas injection case, Case 2 in Table III, was run using a bottom-hole injection pressure of 1,200 psia, representing a pressure gradient of 0.67 psi/ft at the trona mine depth of approximately 1,800 feet. This 1,200 psia pressure is less extreme than the 1,800 psia pressure in Case 1 discussed above, but still shows significant potential problems for miners. The gas moved from the well to the trona mine in one week at an average flow rate of 100 Mcfd. This lower pressure case with a pressure gradient of 0.67 psi per foot of depth would less likely

actually fracture rocks in the trona interval, whereas Case 1 with the higher pressure certainly would.

Also, gas was injected into the sandstone layer within the trona beds. As with the fracture layer, the injection pressure was limited to 1,800 psia bottom hole, and the gas traveled the two miles in 1.75 years at an average rate of 1,954 Mcfd, Case 3. This rate resulted from only the matrix porosity and permeability, whereas in real life probably a fracture would have been created that would have permitted the gas to travel the two miles in a much shorter time period.

Table III shows the results for Case 4, in which the injection pressure is lowered to 1,200 psia, the time for gas breakthrough to the mine is delayed to 4.1 years, and the average rate of flow is 488 Mcfd.

Wellbore Crossflow

This scenario would be the most likely candidate for actual communication between the deep Frontier gas producing horizon and the shallow trona beds. The Frontier sandstone was allowed to crossflow first with the fracture layer of the trona beds and then with the sandstone layer within the trona beds. When Case 5 allowed gas to crossflow with the fracture layer, gas traveled the two-mile distance in approximately 1.5 days at an average rate of 1,400 Mcfd. Again, it is pointed out that this is a worst case scenario, modeling a conduit of small volume and high permeability. When the Frontier was allowed to crossflow with the sandstone interval within the trona beds (Case 6) it took 9 years for gas to travel the two-mile distance. The average rate during this time period was 806 Mcfd. For this run the Frontier formation matrix permeability was set to 1 md. This run demonstrated that the gas would flow the two-mile distance, but took a considerable amount of time. As part of the sensitivity runs the matrix permeability of the Frontier sandstone was changed to 5 md and 10 md. When these changes were made the amount of time and average flow rate changed dramatically. For the 5-md case, Case 7, the travel time was 1.3 years with an average rate of 4,508 Mcfd. For the 10-md case, Case 8, the time for the gas to travel the two miles was 6 months and the average rate was 8,791 Mcfd.

Water Injection

Water was injected in the well into either the fracture layer or the sandstone interval at bottom-hole pressures of 1,200 psia. This was done to compare the relative times it took for the trona mine to see a response to the water. The injection of water caused a much quicker pressure response as compared to gas as one would expect. For the fracture layer, Case 9, the response time was 4 hours. When water was injected into the sandstone layer with a bottom-hole injection pressure of 1,200 psia, Case 10, the response time was approximately 8 hours. Case 9, with water creating and flowing through a fracture, predicts a water flow rate of 280 barrels per day. The case where water flows through the sandstone layer, Case 10, simulates an induced pressure on the water already existing within the sandstone, resulting in an increased water flow rate into a working trona mine. Whatever actual historical water flow rates have been experienced in the mines would be increased significantly by higher pressures in wellbores acting on the water-bearing sandstone interval. The expected increase in the water rates above and beyond the maximum water rates ever observed in the past would be 50 percent if the induced wellbore pressure were 1,200 psia, and 100 percent if the induced pressure were 1,600 psia.

LITERATURE SEARCH AND EXAMPLE CASE HISTORIES

This portion of the project was conducted in order to identify examples throughout the world which document the causes and consequences of uncontrolled fluid migration. Some of the examples were not catastrophic or life threatening, while some clearly were.

An abundance of literature exists which addresses the need for safe well control during drilling, completion, stimulation, production, injection, and abandonment. The literature clearly explains why safe control is essential, the causes and consequences of loss of control, and how to reduce the risk. The examples truly are too numerous to mention in total, so some representative case histories are presented below.

Examples of Migration Without Fracturing

These examples address lateral migration of fluids within the same formation through natural matrix permeability without fracturing, that is, pressures were never high enough to fracture the formation.

1. Jormar Field, Southwest Nebraska, Denver Basin, "J Sand" formation.
   a. Production from an older neighboring field in the same geologic formation created a pressure sink, causing water, oil, and gas to migrate away from the Jormar Field.
   b. Not catastrophic, but example of fluid flowing approximately one mile laterally during a period of a few years.
2. Huntsman Storage Field, near Jormar Field presented above, same geologic formation.
   a. Gas injected into Huntsman for storage was drawn two miles away by production from a neighboring field.
   b. Example of significant lateral migration caused by injection in one place and production at another place; gas, oil, and water migrated approximately 2 miles during a period of a few years. Some migration rates approached a few million cubic feet of gas per day.

successful in preventing fluid migration. and built in safety features and guidelines cannot ensure against fluid migration.

2. Denver Basin, 30 miles north of Denver, hydraulic frac job on gas well to stimulate production rate created a fracture one-mile long. The new fracture created in one well penetrated another well one mile away, demonstrating the great distances fractures can travel during frac jobs in just a few hours.
   a. Good example of the lack of control of "frac job" fracture direction and length.
3. Underground blowouts during drilling, northeast Utah, fluids from deep (13,000 feet) zones flowing uphole, leaving the wellbore at shallower depths, and moving laterally one mile to intersect another well.
   a. Example of accidental loss of control during drilling operations due to human error. Deep high-pressured fluids travelling up the wellbore, fracturing the vulnerable formation at shallower depths, travelling laterally one mile in less than 24 hours, and entering the neighboring well.
   b. Lots of examples of underground blowouts like this both onshore and offshore around the world.

Examples of Geologic Formation Collapse

The examples presented below demonstrate that significant subsidence or collapse of rocks can be caused by human activity.

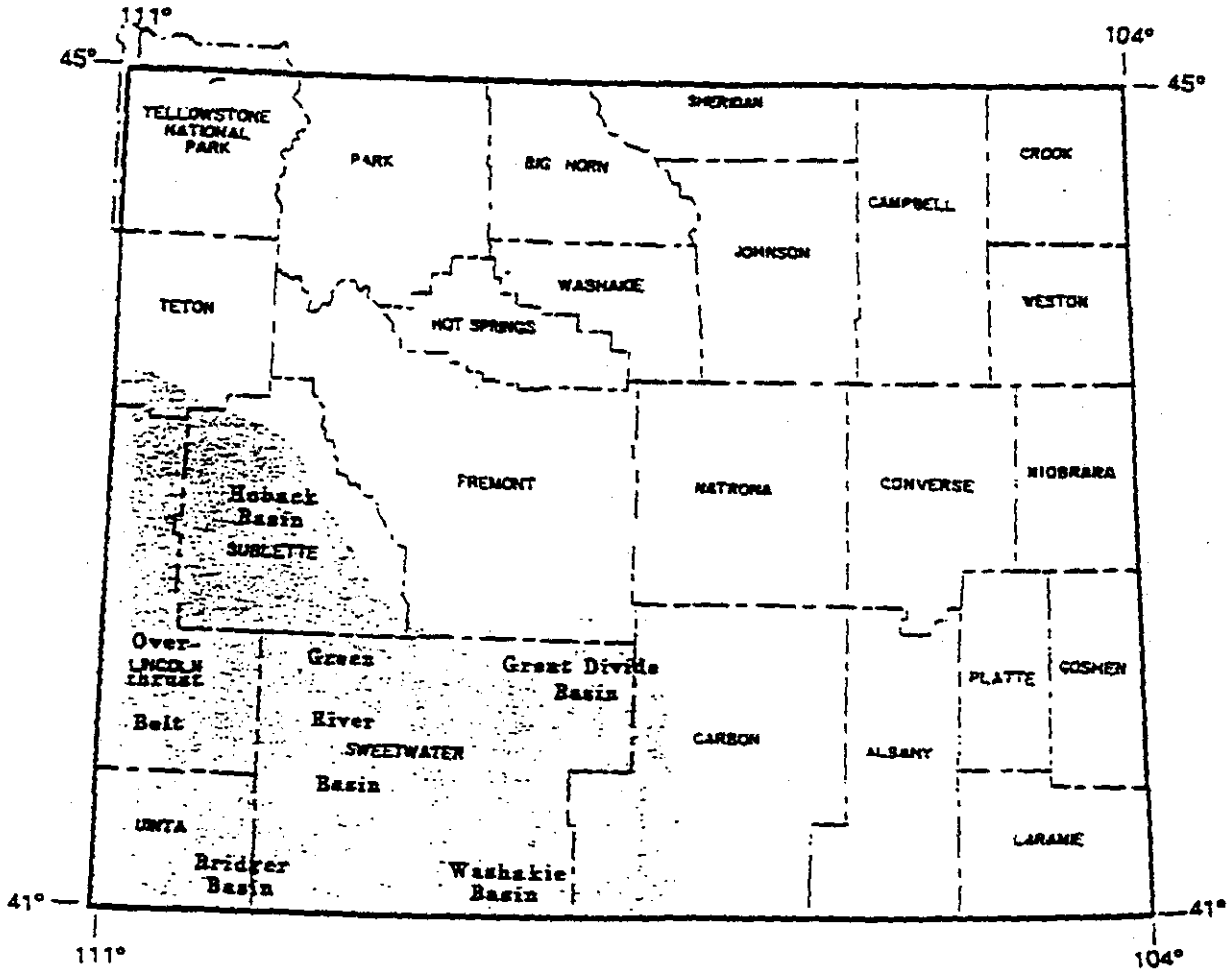
1. Wilmington Field; Long Beach, California. Production from the field caused compaction and surface subsidence of 45 feet.
   a. Fluid removal from the producing formation lowered the fluid pressure within the reservoir, causing the reservoir to compact due to the weight of the overburden sediments. This reservoir compaction removed the support for the shallower sediments, causing subsidence of the overlying formations, resulting in damaging land surface subsidence of 45 feet over a period of a few years. This compaction and subsidence was transmitted over a vertical thickness of several thousand feet, from the producing formation to the ground surface. Numerous references in the

literature over the past 40 years. Other examples of surface subsidence resulting from subsurface production of fields are the (1) the North Sea between England and Norway, (2) northern Italy.

2. Wink Sink, west Texas, improperly abandoned oil well permitted deeper waters to migrate up hole dissolving evaporite rocks and creating a solution cavity, causing overhead collapse, creating an open sink hole at the surface.
   a. Vertical movement of fluids, and height of cavity approximately 2,000 feet. Sink hole at the surface approximately 350 feet in diameter.
   b. Same geologic formation as the other example in Southeast New Mexico discussed above.
   c. Several references in the literature, with the most recent one as part of an article in the January 1998 issue of the American Scientist titled "Sinkholes in Evaporite Rocks". The article addresses numerous surface sinkholes around the world, some of them caused by natural phenomena, with others caused accidentally by human error in oil well activities.

Green River Basin

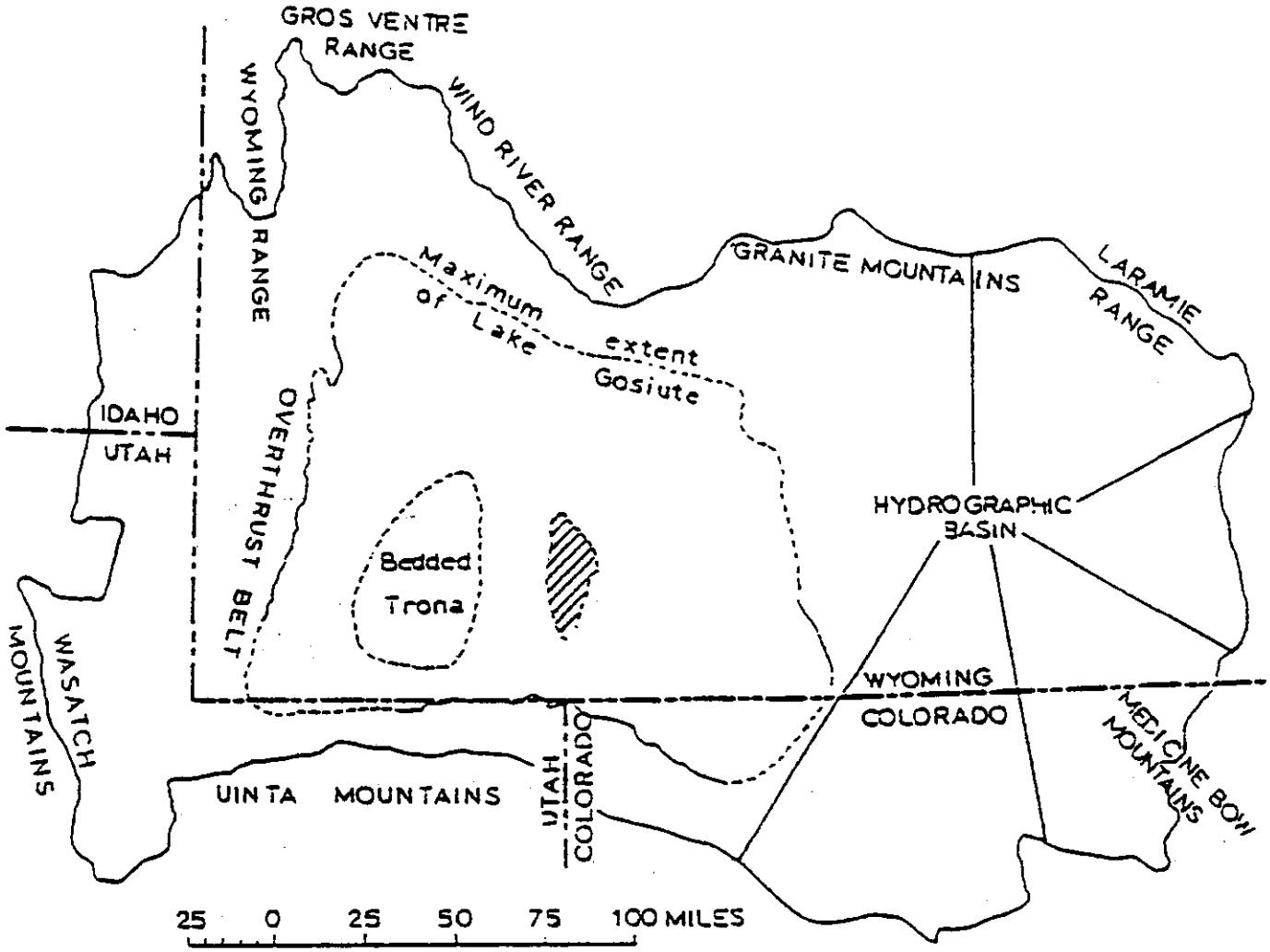
Area Map



Gas Research Institute. Successful Drilling Practices Study, Greater Green River Basin, 1995.

Figur-

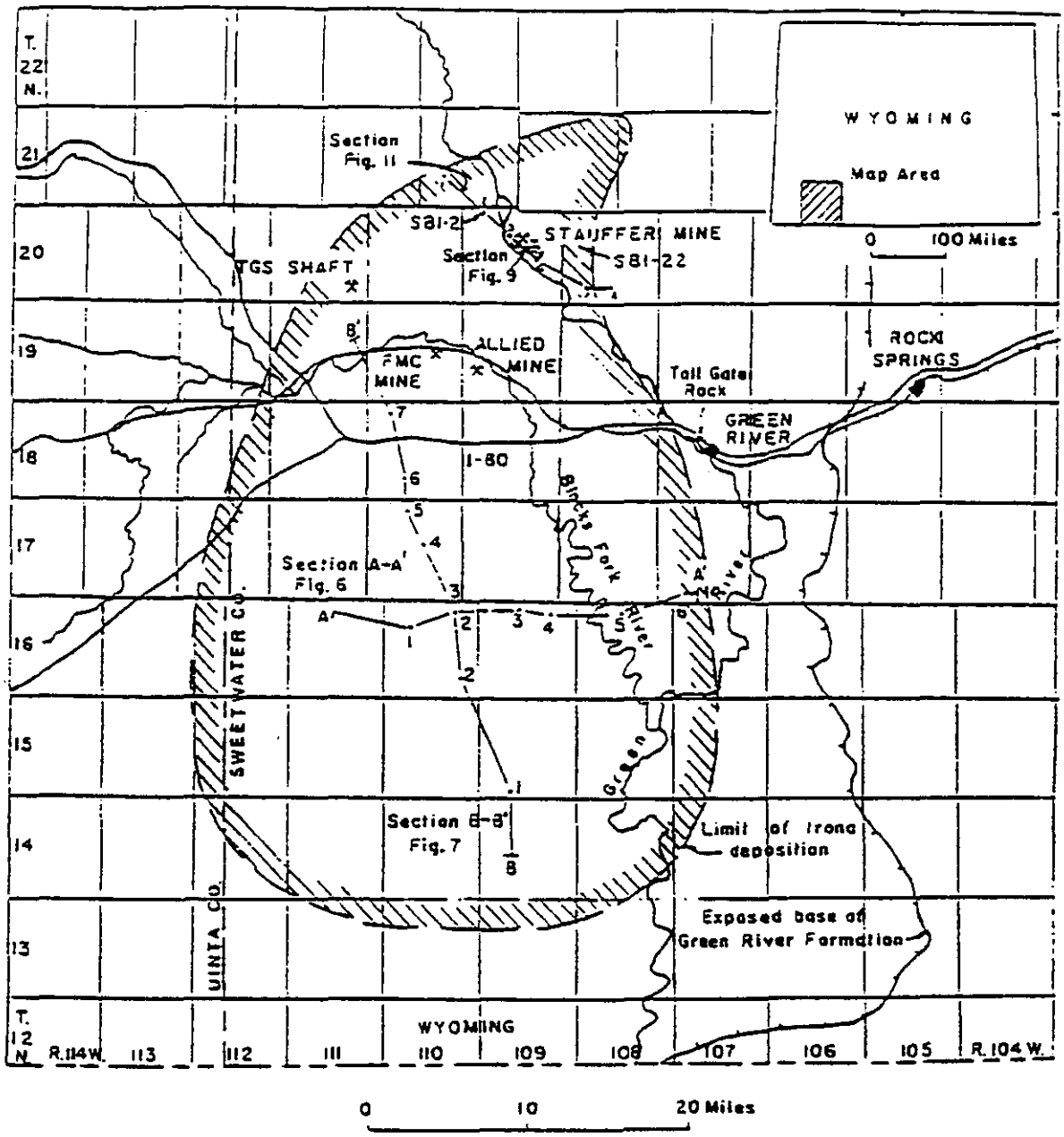
SOUTHWESTERN WYOMING



Inferred outline of the hydrographic basin of Lake Gosiute. Ruled area shows the location of the Rock Springs uplift (Bradley, 1964).

Article by Claudia A. Wolffbauer, Contributions to Geology. 1971 Field Conference of Wyoming trona deposits.

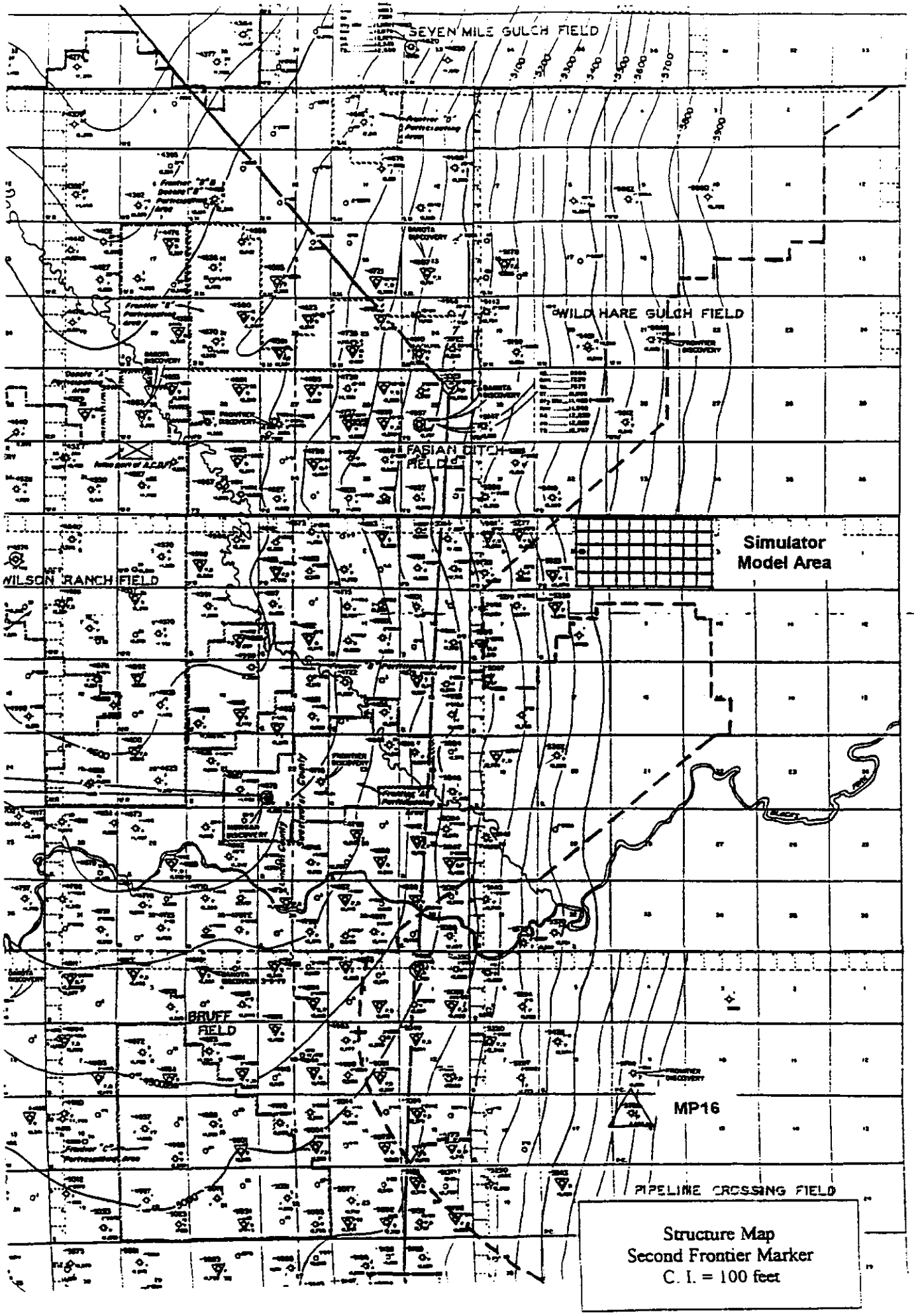
Figure 2



Map of part of southwestern Wyoming showing approximate extent of trona deposition in the Green River Basin. Also indicated are locations of existing underground workings, plus cross sections and sites referred to in the text.

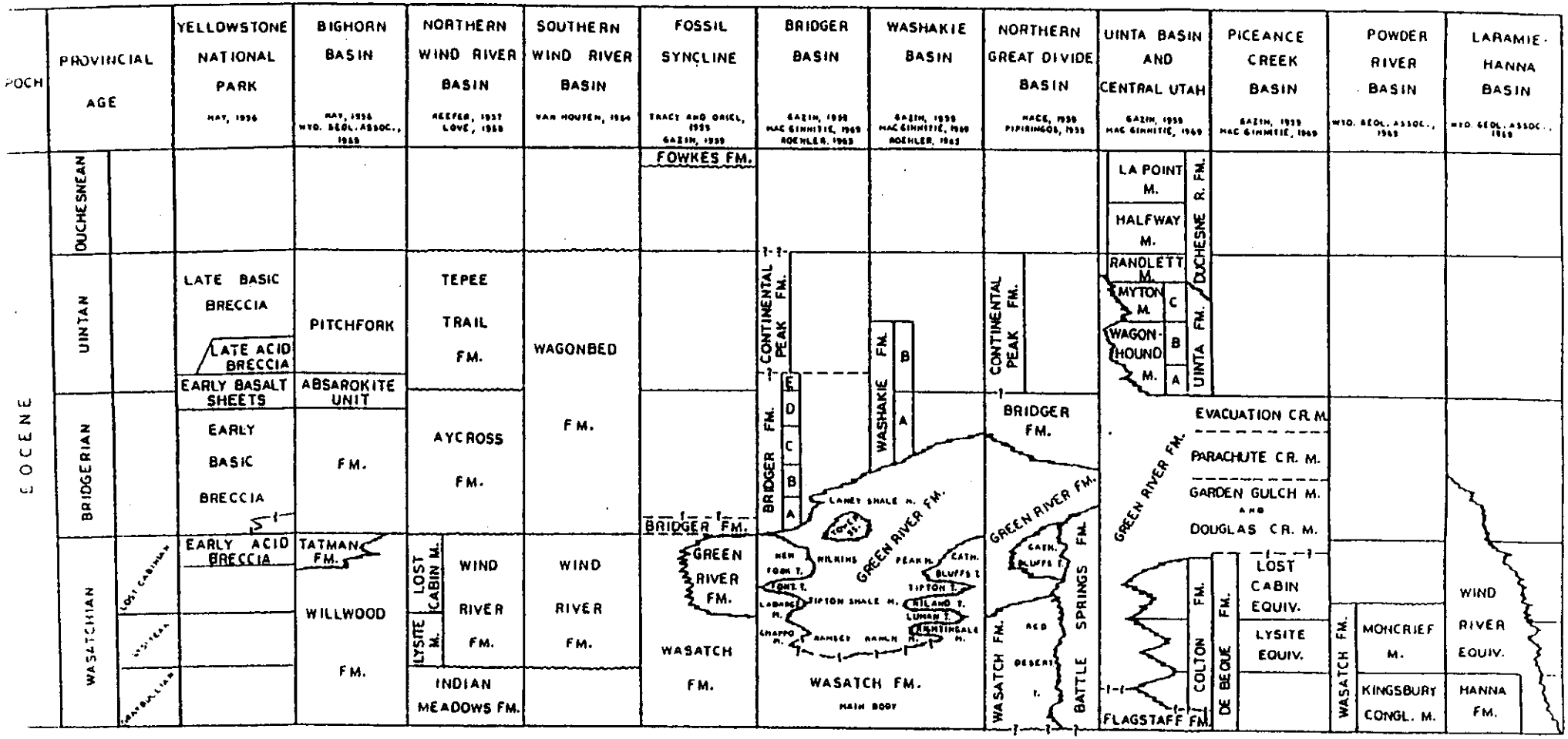
Article by Don L. Deardorff and L. E. Mannion, Contributions to Geology, 1971 Field Conference of Wyoming trona deposits.

Figure 3



Structure Map
Second Frontier Marker
C. I. = 100 feet

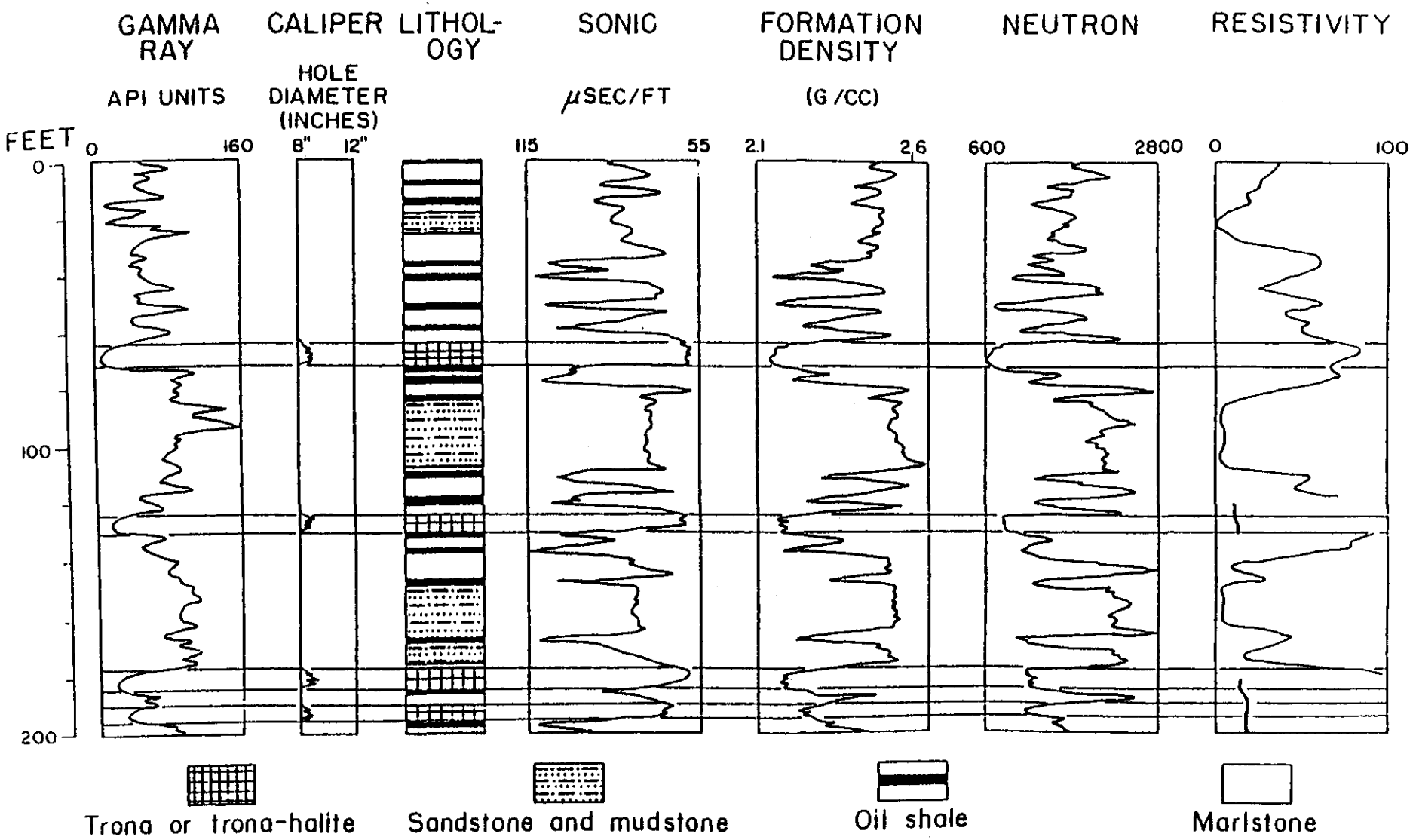
Figure 1



Correlation of Eocene formations in Wyoming, Utah, and Colorado.

Article by Claudia A. Wolfbauer, Contributions to Geology, 1971 Field Conference of Wyoming trona deposits.

Figure 5



Typical log curves of Wilkins Peak Member, southeast part of the Green River Basin, Wyoming.

Article by William C. Culbertson, Contributions to Geology, 1971 Field Conference of Wyoming trona deposits.

Schlumberger

BOREHOLE COMPENSATED SONIC LOG

COMPANY CHRISTMANN & ASSOCIATES

WELL MONTANA POWER 1-16 STATE

FIELD WILDCAT

COUNTY SWEETWATER STATE WYOMING

LOCATION Sw/Nw

SEC 16 TWP 18N RANGE 111W

Other Services: OIL/GR FDC/CNL/GR

Permanent Datum GL Elev. 6373

Log Measured From KB 13 Ft. Above Perm. Datum

Drilling Measured From KB

Elev.: K.B. 6386 D.F. G.L. 6373

Date	11/14/80			
Run No.	ONE			
Depth—Driller	13260			
Depth—Logger (Schl.)	13260			
Btm. Log Interval	13224			
Top Log Interval	1440			
Casing—Driller	9 5/8@ 1503	@	@	@
Casing—Logger	1507			
Bit Size	7 7/8			
Type Fluid in Hole	FGM			
Dens. / Visc.	11.6 / 66			
pH / Fluid Loss	10.5 / 6.0 ml		ml	ml
Source of Sample	MUD TANK			
Rm @ Meas. Temp.	4.68 @ 57°F	@ °F	@ °F	@ °F
Rmf @ Meas. Temp.	1.06 @ 55°F	@ °F	@ °F	@ °F
Rmc @ Meas. Temp.	5.90 @ 55°F	@ °F	@ °F	@ °F
Source: Rmf / Rmc	M / M			
Rm @ BHT	1.36 @ 212°F	@ °F	@ °F	@ °F
TIME Circulation Stopped	11/13 2300			
TIME Logger on Bottom	11/18 1000			
Max. Rec. Temp.	212°F	°F	°F	°F
Equip. / Location	8158 / EVSTN			
Recorded By	DOOGE/BROUHART			
Witnessed By	MCKINLEY			

RECEIVED DEC - 4 1980 WYOMING OIL & GAS CONSERVATION COMMISSION

Reproduced By

Petroleum Information

Houston, Texas 77001

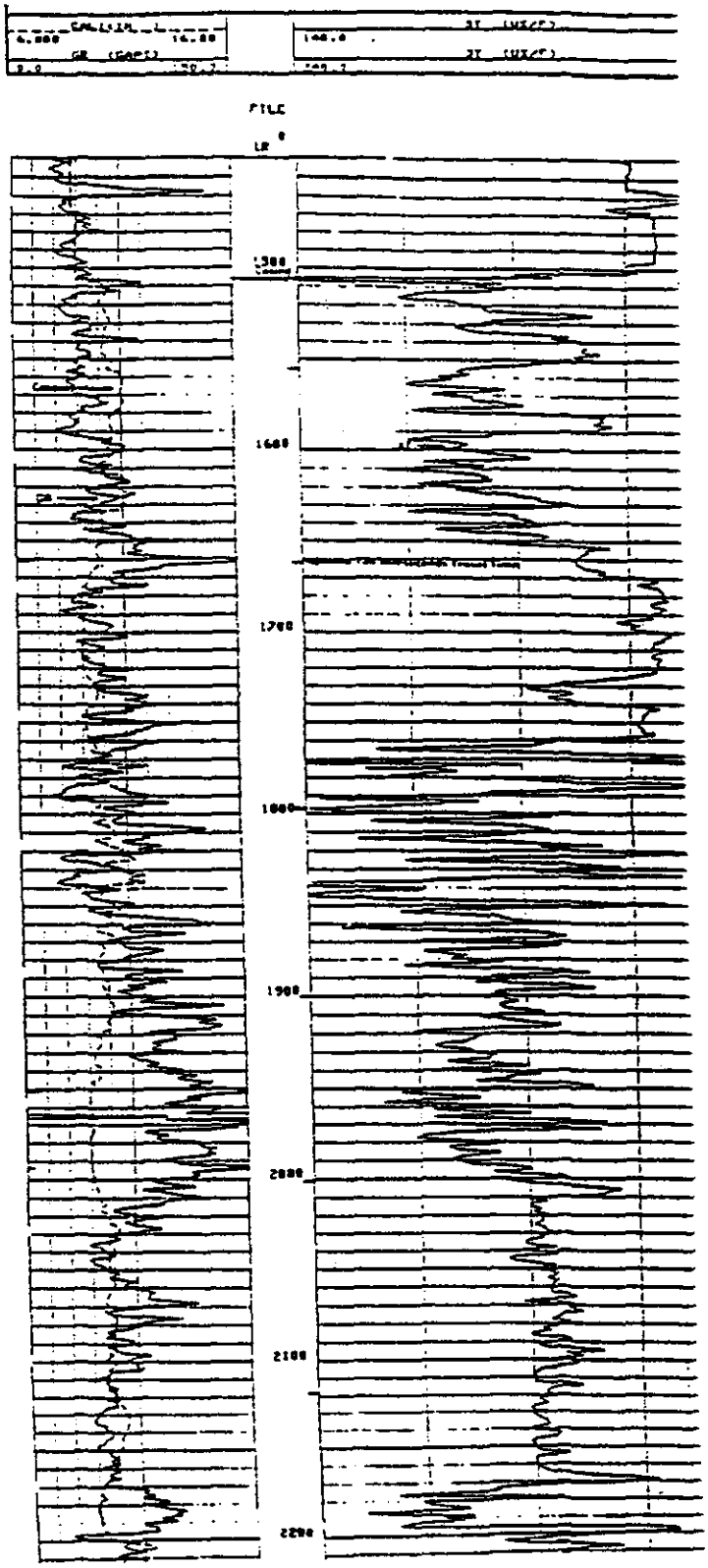


Figure 7

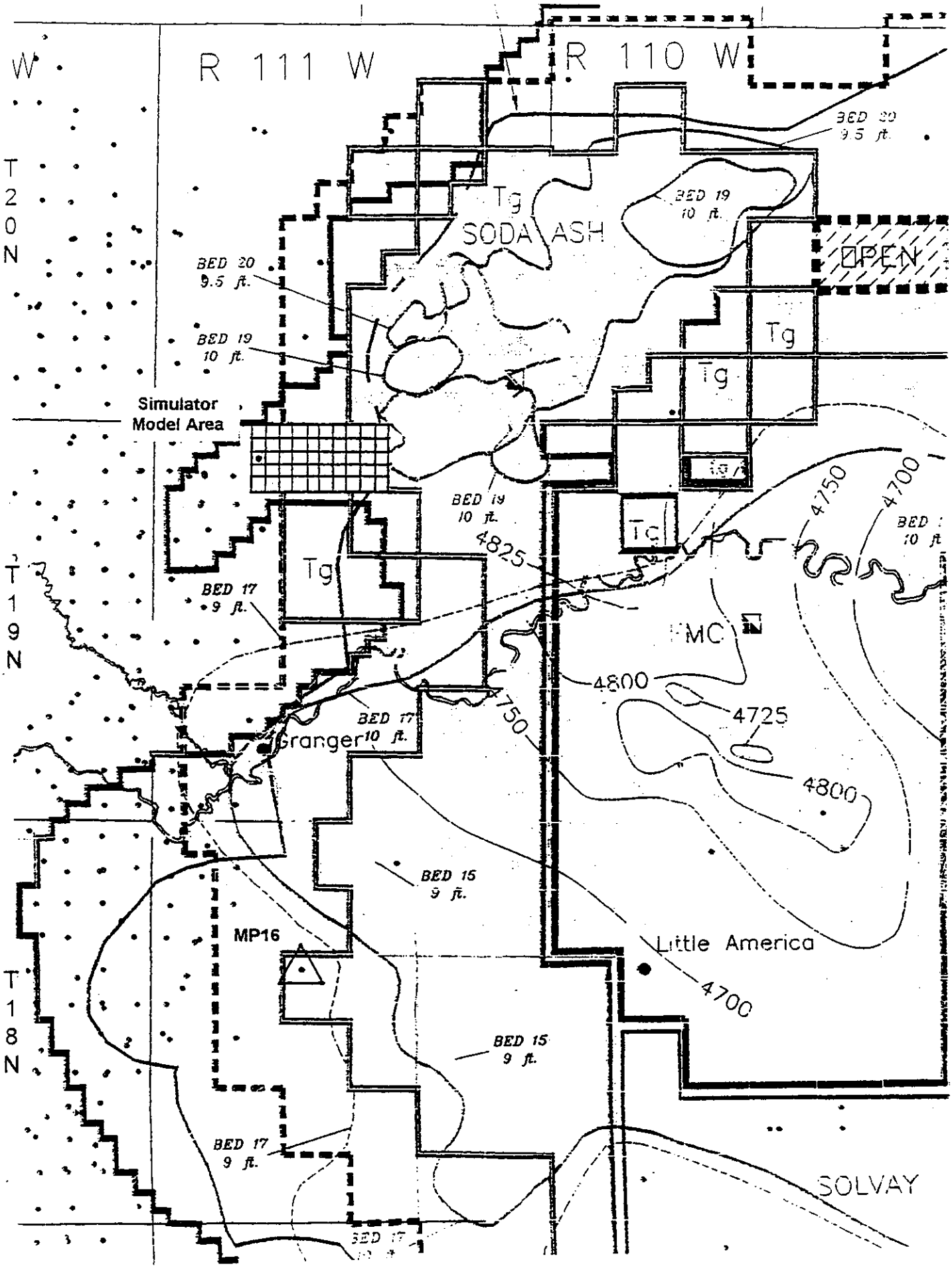
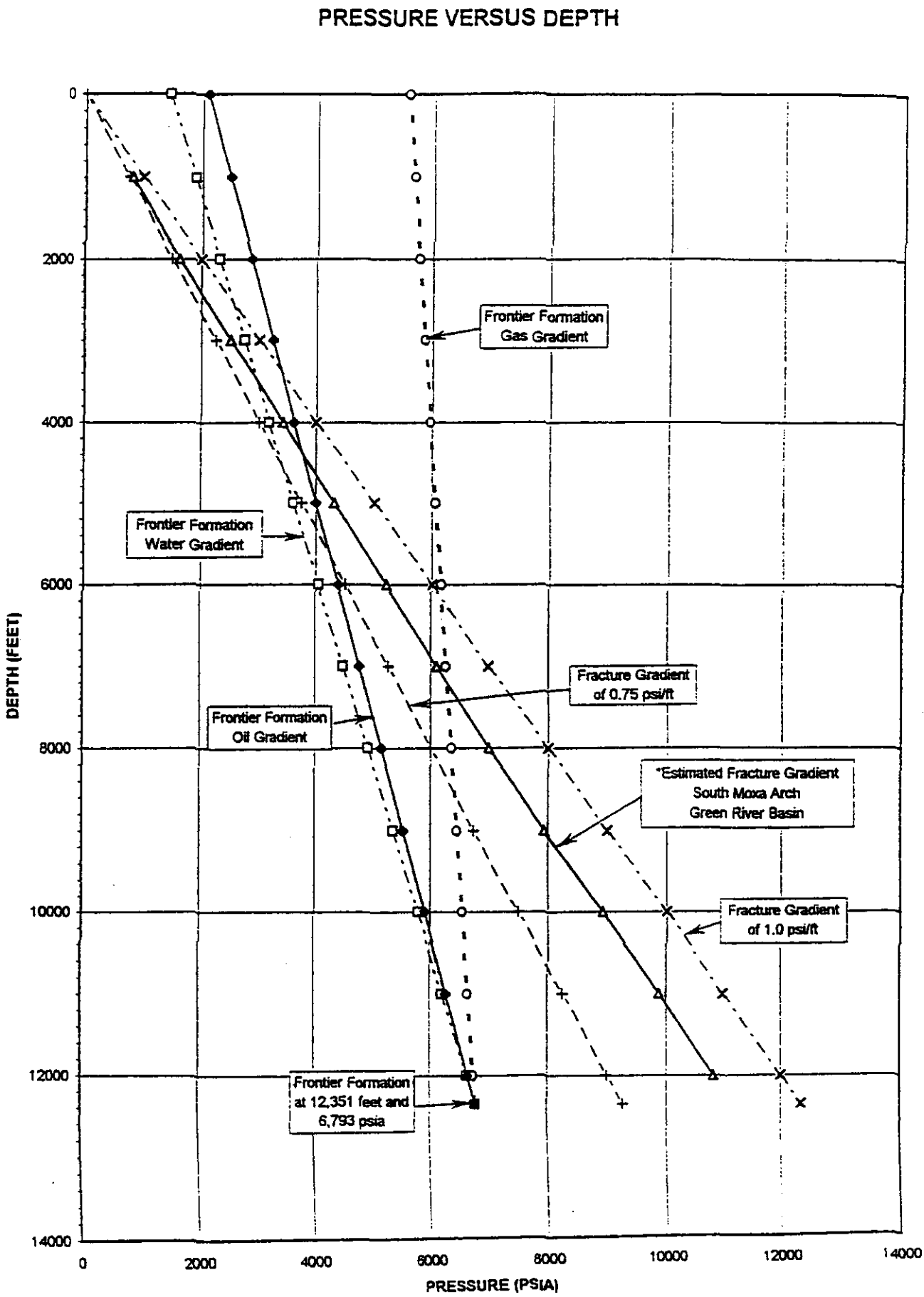

R 111 W
R 110 W
T 20 N
T 19 N
T 18 N
Tg
SODA ASH
OPEN
BED 20
9.5 ft.
BED 19
10 ft.
BED 17
9 ft.
BED 15
9 ft.
Simulator
Model Area
MP16
Granger
FMC
Little America
SOLVAY
4825
4800
4750
4725
4700

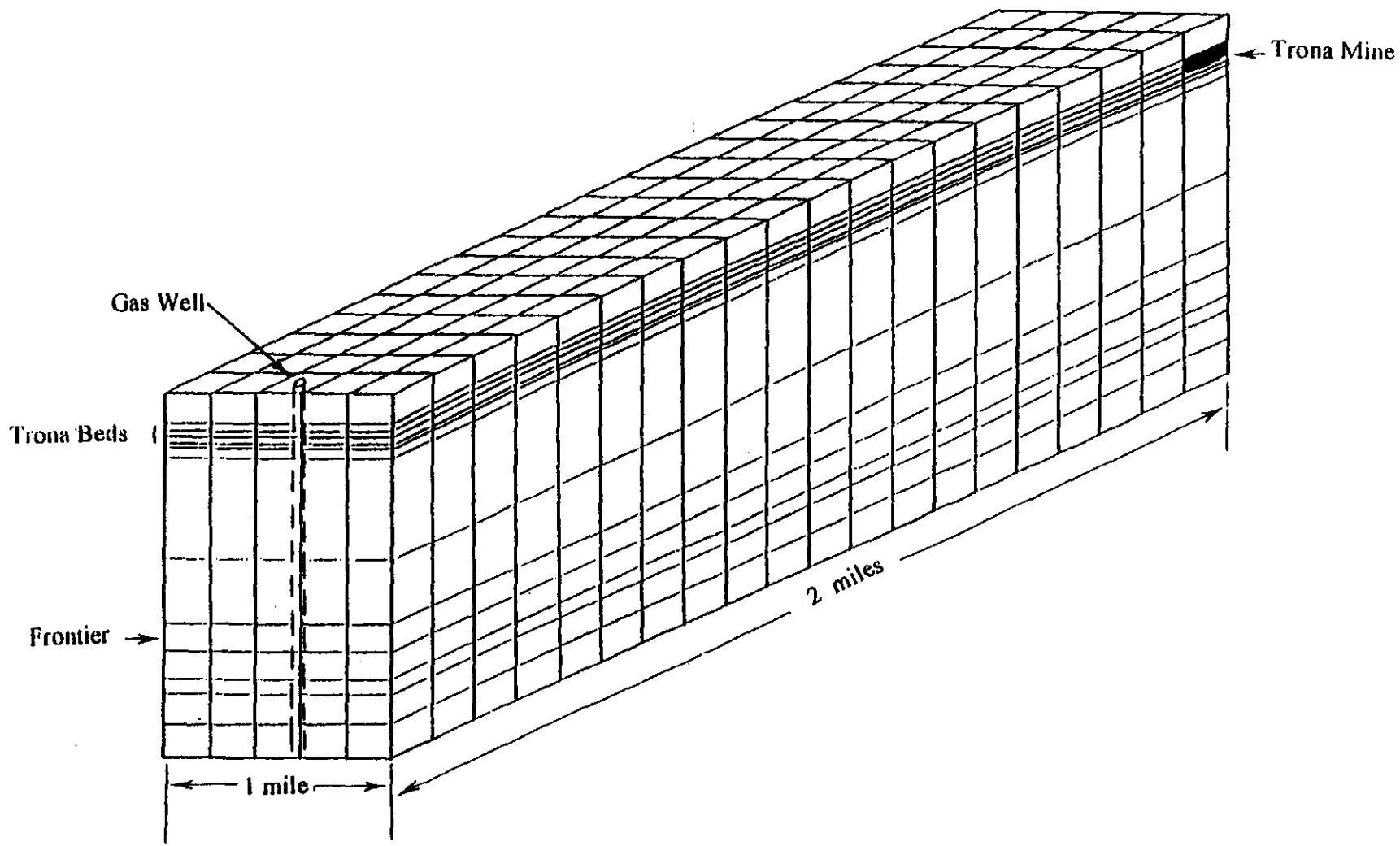
Figure 8



*Successful Drilling Practices Study, Greater Green River Basin; Gas Research Institute, March, 1995

Figure 9

The Simulation Model



TYPICAL WELL COMPLETION

Production or Injection Well

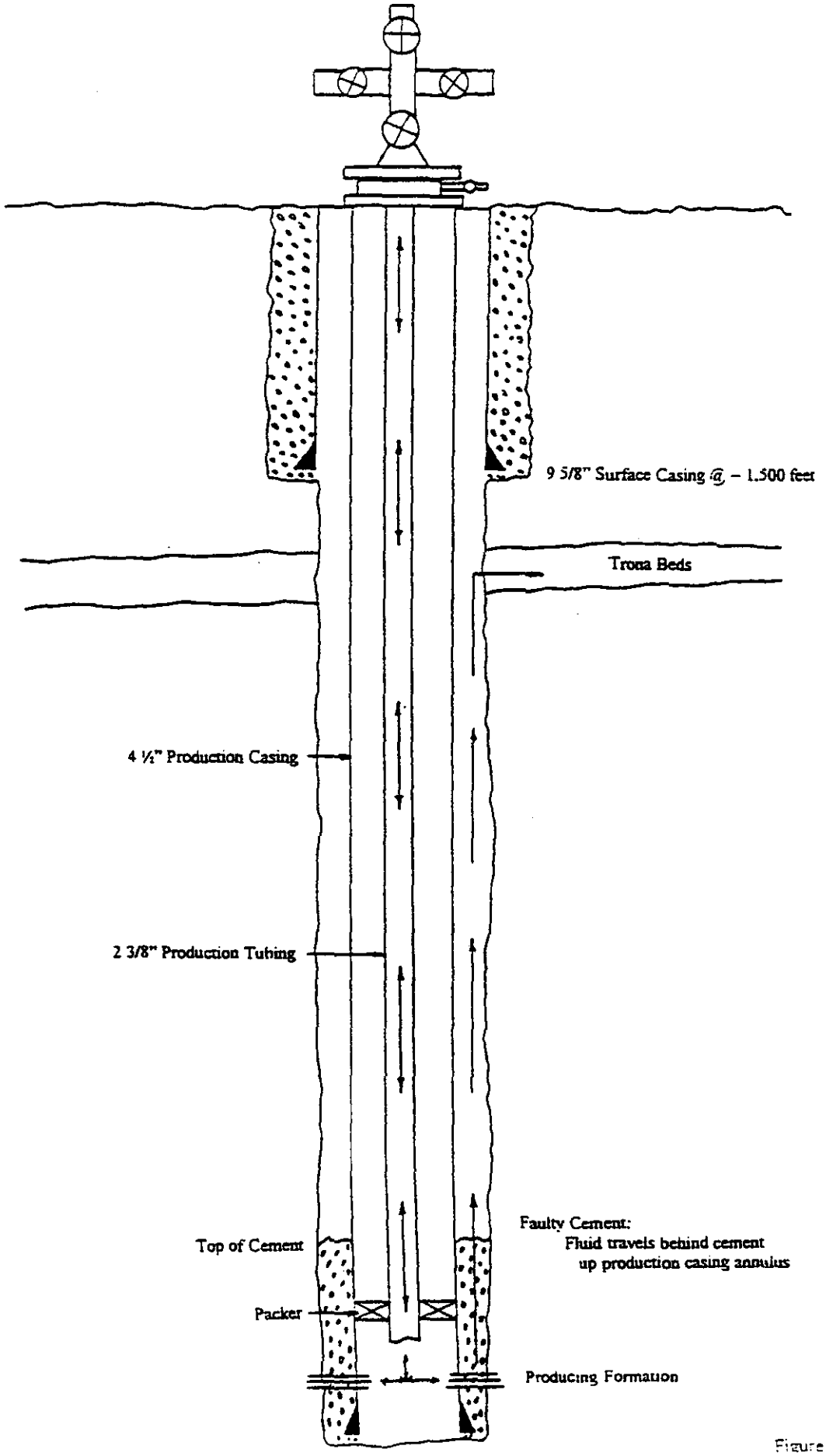


Figure 12

TYPICAL WELL COMPLETION

Producing Gas Well

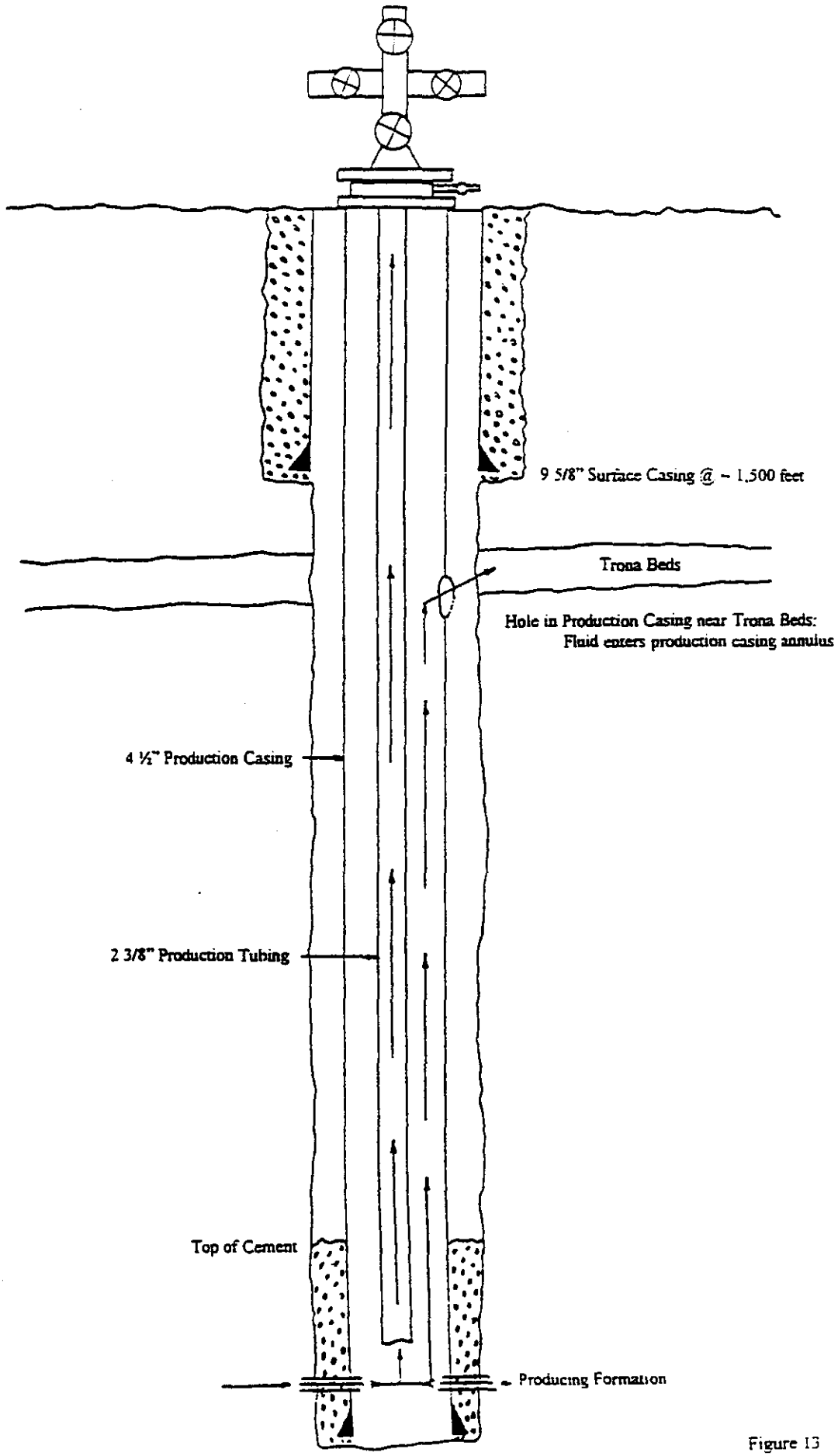


Figure 13

TYPICAL WELL COMPLETION

Producing Gas Well

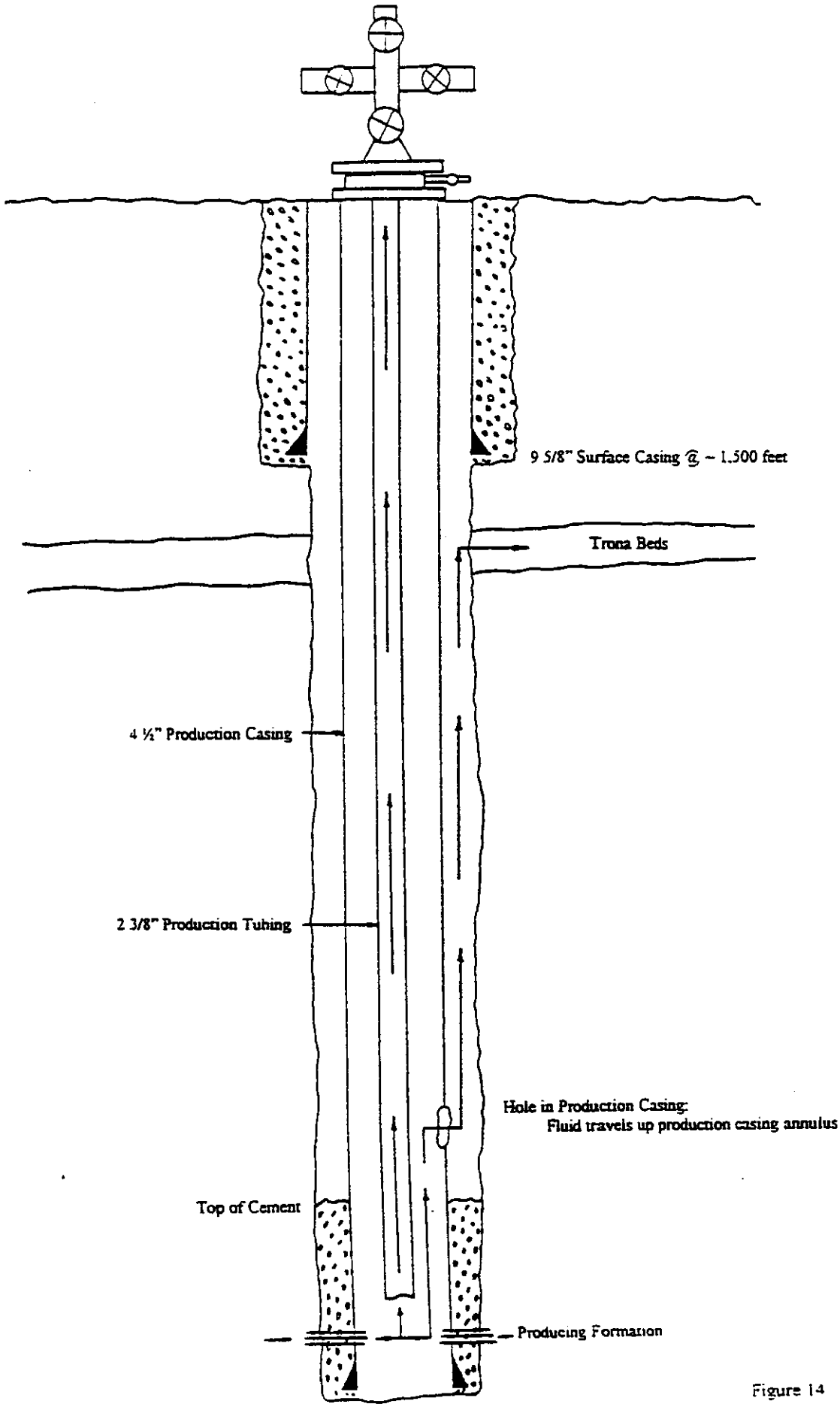


Figure 14

TYPICAL WELL COMPLETION

Production or Injection Well

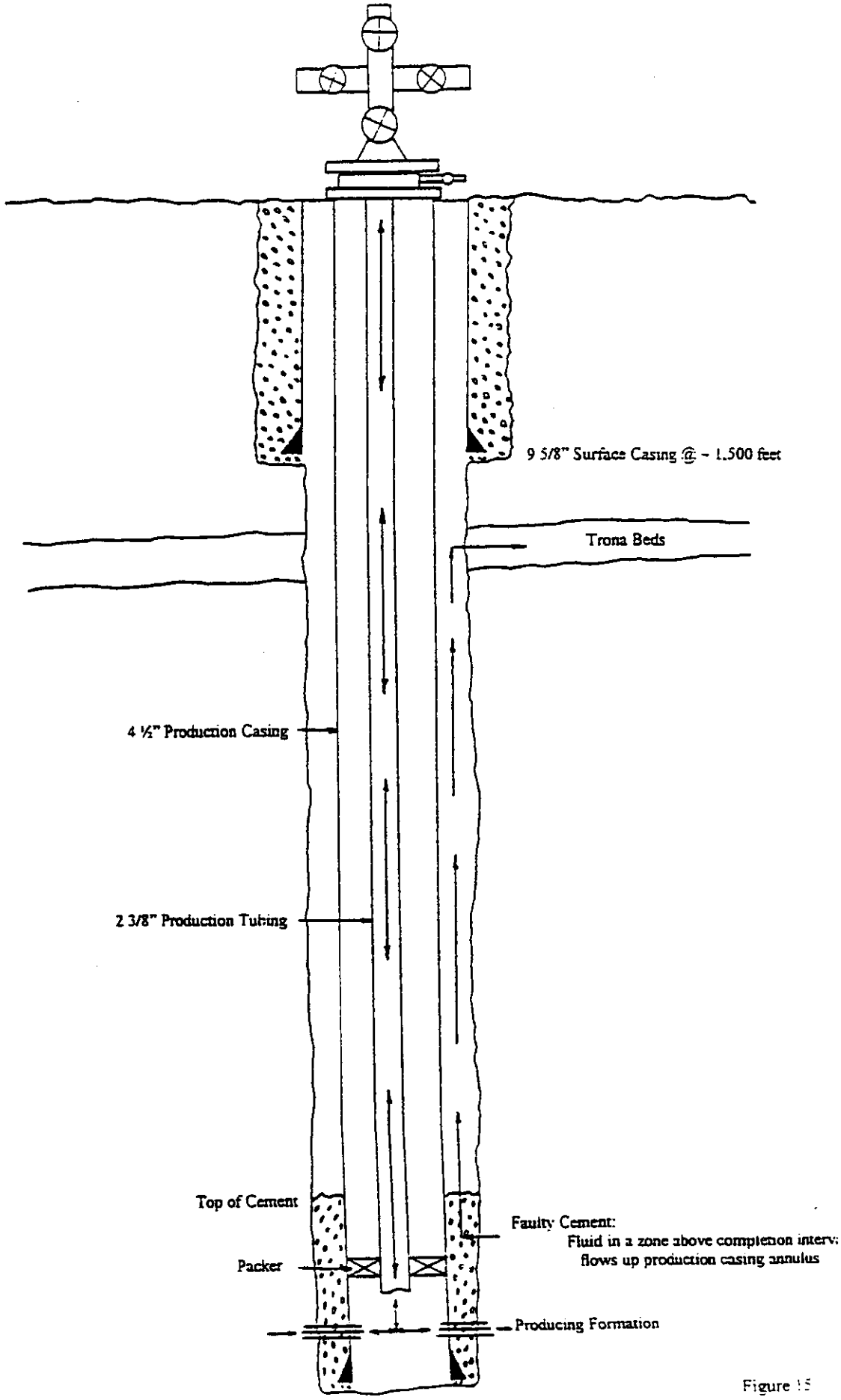
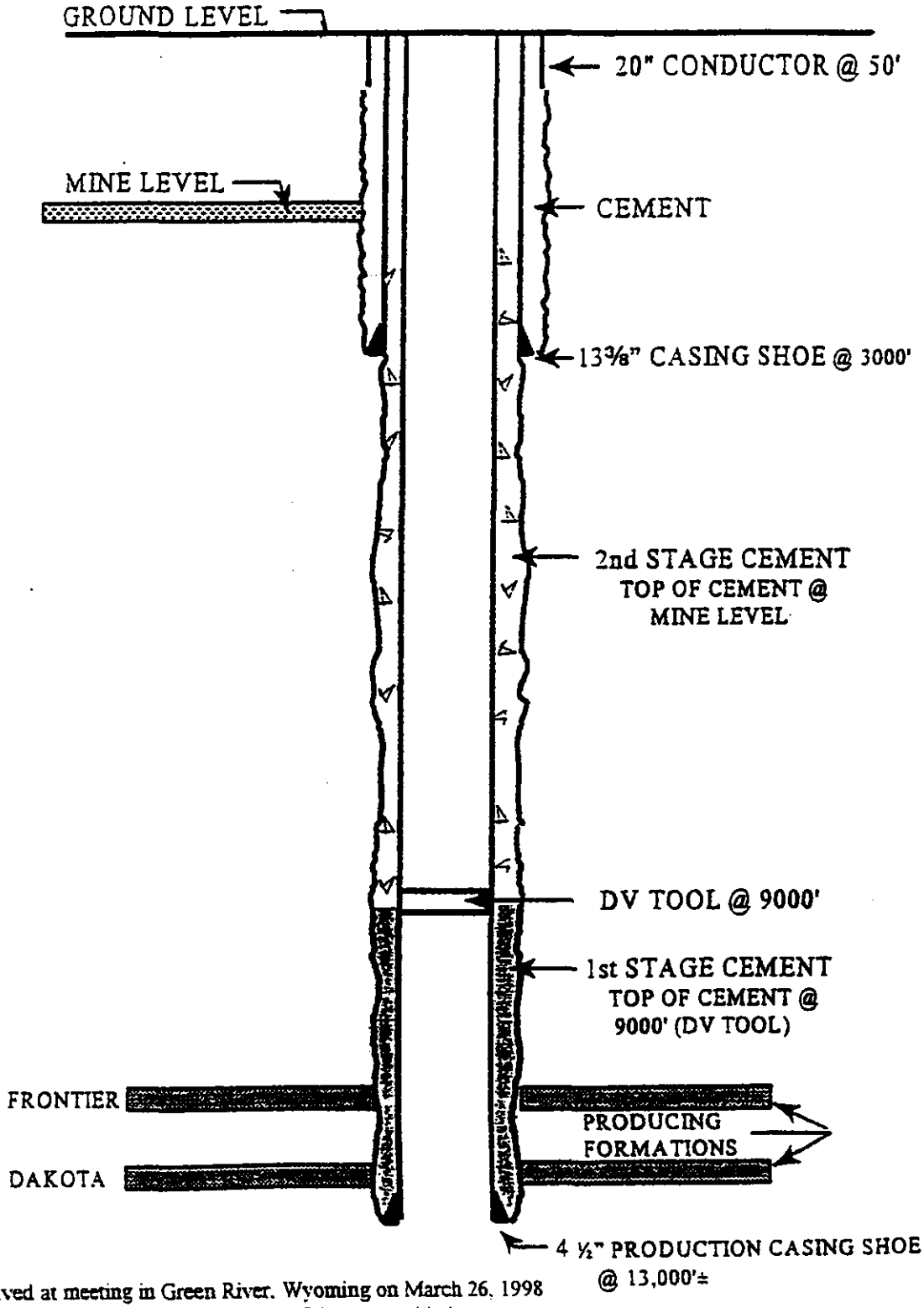


Figure 15

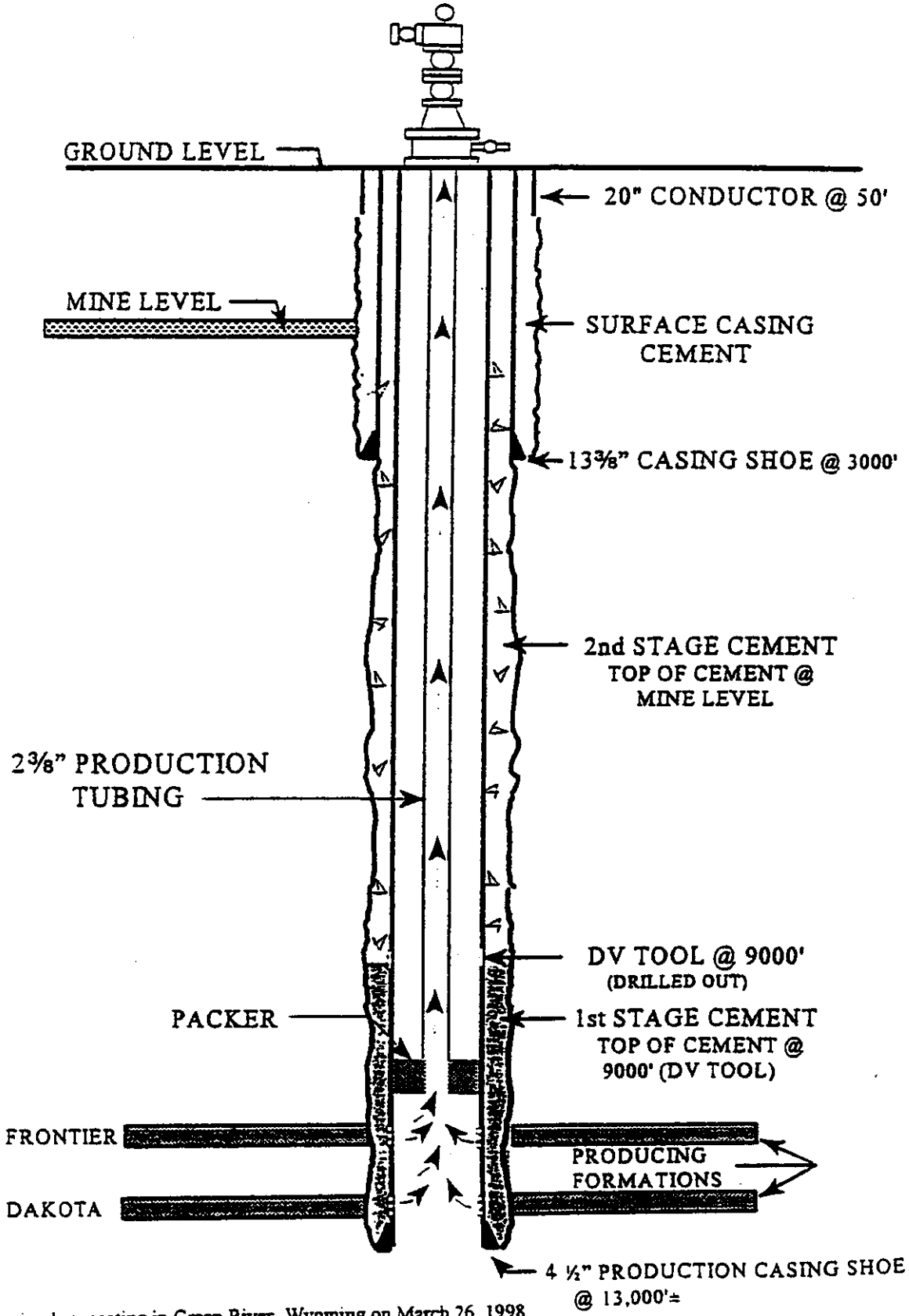
PROPOSED KSLA WELL BORE DIAGRAM



Received at meeting in Green River. Wyoming on March 26, 1998
from Union Pacific Resources as part of document titled
"Draft Proposed KSLA Drilling Prodedures".

Figure 16

PROPOSED KSLA COMPLETED WELL BORE DIAGRAM WITH TUBING & PACKER



Received at meeting in Green River. Wyoming on March 26. 1998 from Union Pacific Resources as part of document titled "Draft Proposed KSLA Drilling Prodedures".

Figure 17

TABLE I

SIMULATOR GEOLOGIC PARAMETERS

Layer Number	Formation Name	Depth Top Formation (feet)	Gross Thickness (feet)	Net Porous Thickness (feet)	Porosity (%)	Permeability (md)
1	Tertiary	0	1,400	NA	NA	NA
2	Trona	1,400	260	NA	NA	NA
3	Sandstone	1,660	60	60	15	100
4	Trona	1,720	130	NA	NA	NA
5	Fracture	1,850	1	1	1	500
6	Tertiary	1,851	150	NA	NA	NA
7	Mesaverde	2,001	6,200	NA	NA	NA
8	Baxter Shale	8,201	4,150	NA	NA	NA
9	Frontier	12,351	450	20	15	*1, 5, 10
10	Mowry	12,801	500	NA	NA	NA
11	Muddy	13,301	150	NA	NA	NA
12	Dakota	13,451	300	NA	NA	NA
13	Morrison	13,751	300	NA	NA	NA

*Sensitivity cases were run in the simulator to test a range of Frontier permeabilities.

TABLE III

SIMULATION RESULTS

Initial Pressure Conditions:

Sandstone Layer; 733 psia at a depth of 1,660 feet

Fracture Layer; 801 psia at a depth of 1,850 feet

Frontier Formation; 6,793 psia at a depth of 12,351 feet

Case	Conditions	Time to Reach Trona Mine	Average Flow Rate (B/D or Mcfd)	Effects
1	Inject gas into the fracture layer. BHP specified at 1,800 psia.	3 days	400 Mcfd	Almost immediate catastrophic gas blowout in mine.
2	Inject gas into the fracture layer. BHP specified at 1,200 psia.	1 week	100 Mcfd	Almost immediate catastrophic gas blowout in mine.
3	Inject gas into the sandstone layer. BHP specified at 1,800 psia.	1.75 years	1,954 Mcfd	Delayed potential catastrophic gas blowout in mine.
4	Inject gas into the sandstone layer. BHP specified at 1,200 psia.	4.1 years	488 Mcfd	Delayed potential catastrophic gas blowout in mine.
5	Gas Crossflow from the Frontier formation (1 md. permeability) to fracture layer.	1.5 days	1,400 Mcfd	Almost immediate catastrophic gas blowout in mine.
6	Gas Crossflow from the Frontier formation (1 md. permeability) to sandstone layer.	9 years	806 Mcfd	Delayed potential catastrophic gas blowout in mine.
7	Gas Crossflow from the Frontier formation (5 md. permeability) to sandstone layer.	1.3 years	4,508 Mcfd	Delayed potential catastrophic gas blowout in mine.
8	Gas Crossflow from the Frontier formation (10 md. Permeability) to sandstone layer.	6 months	8,791 Mcfd	Delayed potential catastrophic gas blowout in mine.
9	Water injection into fracture layer. BHP specified at 1,200 psia.	4 hours	280 B/D	Not life threateing but potentially large economic impact.
10	Water injection into sandstone layer. BHP specified at 1,200 psia.	8 hours	50 % more than actual rates	Not life threateing but potentially large economic impact.

Van Kirk and Associates
10463 E. Chinook Trail
Parker, CO, 80138
Phone (303) 841-1049 Fax (303) 841-4107

July 31, 1998

Mr. Paul W. Hynes
Staff Engineer
Tg Soda Ash, Inc.
P.O. Box 100
Granger, WY 82934

Re: Review of UPR's "Draft Proposed KSLA Drilling Procedures"

Dear Mr. Hynes:

This is our report in response to your request for a critical review of the "Draft Proposed KSLA Drilling Procedures", the document which Union Pacific Resources presented at a meeting in Green River, Wyoming on March 26, 1998. Some of the new proposed procedures offer improvements over older procedures, however, even with the new procedures there remains a significant number of areas of concern which deserve more attention.

The following provides our detailed response to each of the points presented in UPR's "Draft" and corresponds to the same number as in the proposal:

1. This procedure is currently required by all state and Federal agencies regardless of the area where a well will be drilled.
2. Thirty days may not be a sufficient amount of time, depending upon the mining activities near the proposed location. It would be beneficial to have a "protest" procedure in place where the APD (Application and Permit to Drill) could be discussed as to pro's and con's when considering the mining operations. The maximum protest time could be somewhere around 30 days, and then a scheduled hearing within 15 to 30 days. The procedure would take 60 days or less.
3. Operations would not commence until any protest had been heard and ruled upon.
4. Operations that deviate from the proposed procedure have always needed agency approval. The approval process usually involved a telephone call stating the problem and the new procedures that were to be implemented. It is not uncommon that intended procedures have

to be changed. In this case there should be written minimum standards that if not met may necessitate the abandoning of a borehole. A couple of examples;

a. Procedure to set surface pipe at 3,000 feet. If problems occur and the proposed surface pipe depth of 3,000 feet cannot be reached, what would be a minimum requirement 2,500?, 2,000? Who has the authority to change the procedure?

b. Cementing of Production String. If second stage cement does not reach 1,000 feet above the bottom of the surface casing, what are the requirements? Is it recommended to squeeze cement? Who has the authority to change the original procedure?

5. Documenting information is extremely important, especially while drilling through the trona beds to the 3,000-foot level for the surface casing. Normally this is not a depth where much information is recorded, but for this area it might prove to be very beneficial. Also, it would be helpful if the drilling contractor superintendent/engineer or company superintendent/engineer verify the occurrences recorded on the tour sheet. The driller can record his observations and then discuss with the superintendent/engineer any problems or situations that may have occurred that were not considered normal or which caused intended procedures to be modified.

   Types of properties to record:

   Lost circulation zones (very important)

   Volumes lost to "lost circulation zones"

   Mud properties

   RPM's

   Torque

   Penetration Rate

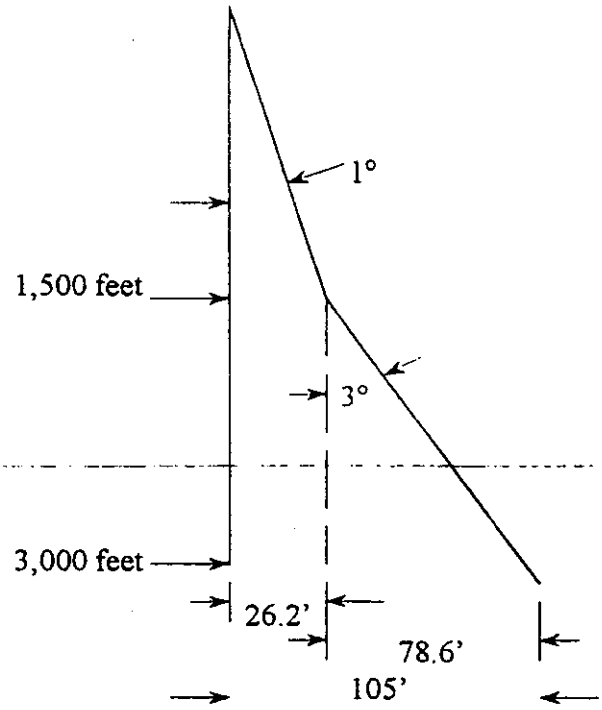
   Bit Type, depths in and out

   Drill pipe (size), drill collars (number and size)

   Deviation (This becomes very important if wells are drilled from a pad and the bottom-hole location is a significant distance from the surface location)

6. What is the procedure if the deviation is greater than 1 degree? What is the allowed tolerance and who gets to authorize a greater than 1 degree deviation? Having a straight hole through the Trona beds is important. The final bottom-hole location should be noted on all documents

filed to the Federal or State agencies. An actual plat of the final bottom-hole location would also be beneficial.



7. The yield pressure for this pipe is 3,090 psi (no safety factor). If gas from the Frontier formation reached the surface the pressure could well exceed the 3,090 psi. A stronger pipe would add a measure of safety. Who is the person responsible for picking the depths for the casing collars? Trona company personnel would be beneficial in identifying the slip planes and also provide a comfort factor.
8. It is imperative to have cement back to the surface. It is not clear what is meant by "stage cement" if cement falls back. If a squeeze is part of a contingency, we recommend against that procedure unless it is the last resort.
9. A 5,000 psi casing head is a minimum. The Frontier formation with a 0.55 psi/ft gradient at 10,000 feet would have a shut-in well head pressure very near 5,000 psi.
10. As a precautionary measure we would recommend a BOP that is rated higher than 5,000 psi.
11. Do the trona companies want a representative to witness the BOP test?
12. This is a very critical step. Who is the person that decides whether the cement bond is adequate? A micro annulus could be a major problem. This cement bond evaluation is critical in trying to maximize safety for the miners. We would recommend a 1,000-foot

bonding requirement above, below , and through the trona beds. Would also like to know the procedure that would be employed in case there is evidence of insufficient bonding or a micro annulus.

13. Do the operators have guidelines to give to the trona people of what procedures should be taken during drilling operations if the following occurs:
    a. pit volume increase
    b. lost circulation

    An underground blowout can cause severe damage. It is very difficult to ascertain the extent of the damage. An underground blowout would be the greatest danger to the miners if gas did reach the trona beds.

14. A copy of all requests or notifications sent to BLM or state of Wyoming should be sent to the trona companies.
15. A minimum time after circulating bottoms up should be established. It is very important to insure the Frontier or Dakota formations are not putting fluids into the borehole.
16. OK, unless the trona companies want some type of log run through the section. In fact, it may be a good opportunity for the trona companies to gather some information. The large borehole is a deterrent, but still some information may be gained.
17. What is the procedure when the LTD (logging total depth) and the DTD (drillers total depth) vary by more than 10 feet? Conditioning hole prior to running casing is standard procedure.
18. Trona personnel should be notified and have the option of being on location any time a surface, intermediate, or production casing string is run.

19-22. Good cement bonds through the Frontier and Dakota intervals are critical. What party is responsible for making the decision as to the adequacy of the cement? What procedures are in place to compensate for a DV tool that does not operate properly? Also, cement bonding can be damaged after performing a frac treatment, a micro annulus can form after such an operation, creating a safety hazard. This is a big deal!!

Additional Well Costs;

It would be beneficial to see an AFE for this type well and an AFE for a "normal" well for this area. This is the only way to do a direct comparison.

Additional thoughts;

1. Daily monitoring of a completed well is very important. Tubing, casing and surface casing pressures should be recorded daily. Also, the pressure information should be required data by the Federal or State agencies. Any time something is changed at the wellhead it should be recorded and reported.
2. At least a 48-hour notification should be given to the mining companies any time a workover rig is moved onto a well, more time if the work to be performed is a frac treatment.
3. A production test and bottom-hole pressure survey should be conducted within 4 weeks of first perforations and once a year thereafter. This information should be filed with the appropriate agency and also sent to the trona companies.
4. Monitoring procedures go beyond the taking of BHP's and recording of WHP's. There are many production logging operations which can enhance monitoring for safety. These procedures include temperature surveys, noise logs, tracer, and spinner surveys. If this type of operation is to be performed, trona personnel should be notified and have the option of attending the operation. Once the data is gathered there should be an opportunity for the trona people to voice their opinion and concerns with regard to the interpreted results of such operations.
5. Trona companies should have the right to visit drilling, workover, or producing locations at any time. Trona companies should have reliable names, addresses, and telephone numbers of oil company personnel in case they observe a dangerous situation or have any questions concerning field operations.
6. Braden head hookups should be on all well heads. The hookups should be standardized for pressure gauge installation (thread type and size).

We hope this critique has given you some useful information which can be incorporated in future meetings with the governing agencies and the oil companies. If you have any questions or comments, please let us know.

Yours truly,

Craig W. Van Kirk

Craig W. Van Kirk