### 2.3.1.3 Northern Region

WIPP-27 is in the northern part of Nash Draw, very close to one of the potash mines. The potash mines discharge various amounts of effluent into Nash Draw depending on their production. When there is not much production, there is not much discharge into Nash Draw. When there is more mining and more refining, they discharge more. WIPP-27 has a lot of distinct features. The plot of water level rise does not exhibit the noise seen in the plot for WIPP-26. Instead, WIPP-27 is responding to

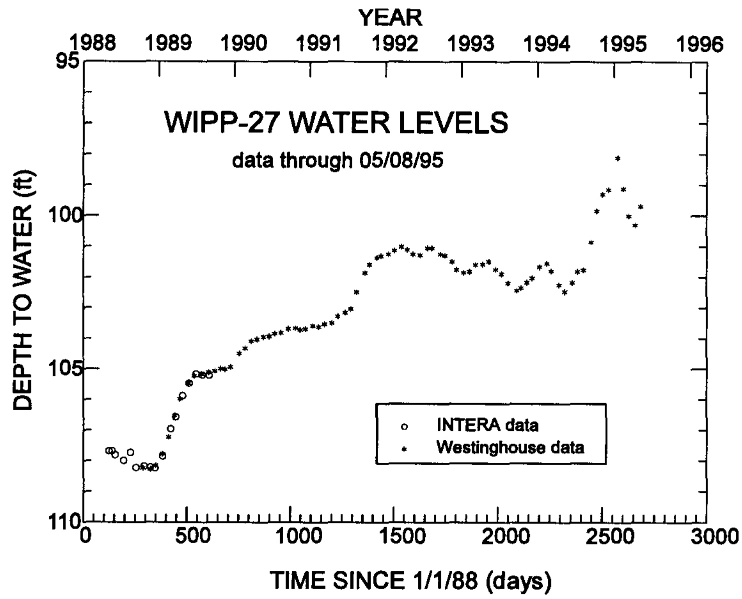


**Figure 2.3-28**. WIPP-27 water levels.

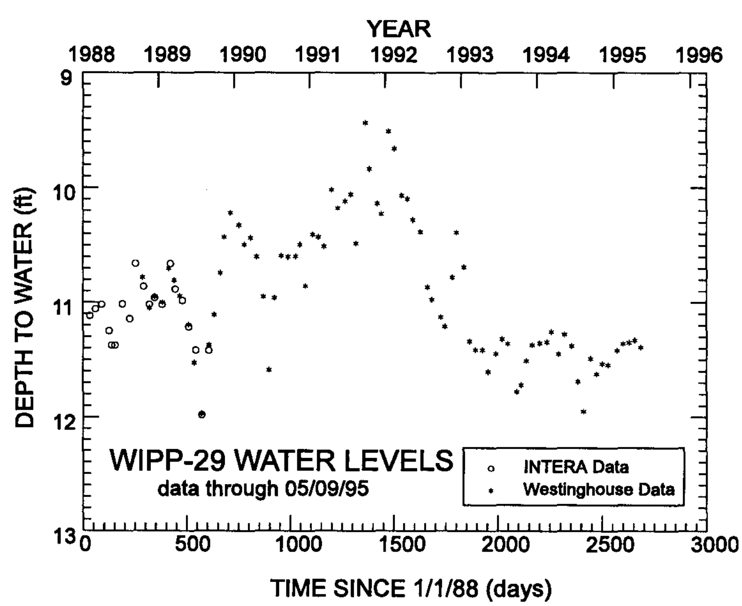


**Figure 2.3-29**. WIPP-29 water levels.

something fairly distinct. WIPP-27 appears to be providing a good indication of the discharge into Nash Draw. Some of these changes probably propagate through Nash Draw towards the northern part of the WIPP Site. But the changes get more diffuse as they get there.

WIPP-29 is so shallow, 11 feet to water, that it could be responding to almost anything.

WIPP-30 showed a rise, a stabilization for a few years, and now appears to be on another rise.

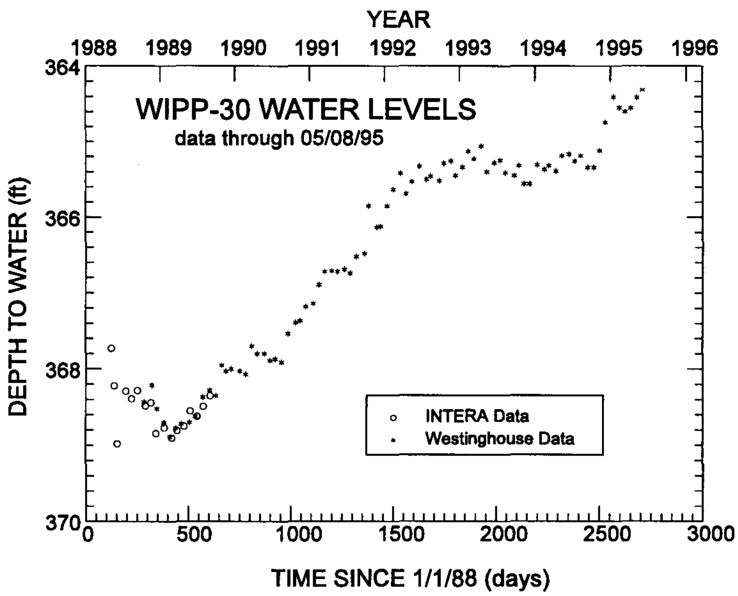


**Figure 2.3-30**. WIPP-30 water levels.

Well P-18 continues to rise. It is not clear where P-18 is headed. In contrast to all of the other plots, which begin in 1988, this plot begins in 1977. This is the complete water level history on P-18. Until

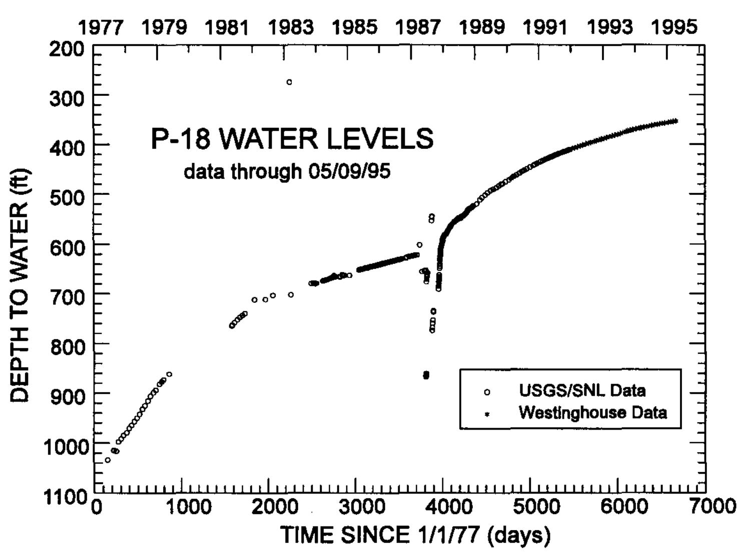


**Figure 2.3-31**. Well P-18 water levels.

about 1987, the water level was rising in a 4-inch well casing. It never actually stabilized. Then in 1987 we put a pip in the well. So, now the water level is rising in 2-3/8 inch tubing instead of 4 inch casing so it goes up faster because of the smaller diameter. The water level still hasn't stabilized there. A lot of people over the years, including myself, have hypothesized that we may not have the best connection to the Culebra in this well. There may be a problem with the cement bond. This is a cased, cemented, and perforated well. There may be a problem with the bridge plug at the bottom. There may be problem with the cement job. We don't have a lot of confidence that what we are seeing here is the Culebra.

#### 2.3.1.4 Summary

To summarize, I see three different things going on with the water levels at the WIPP Site. To the south, centered around H-9, you see one very distinct water level rise that began abruptly in 1988, reached its peak at H-9 and seemed to propagate to the north, which I think is probably related to some kind of injection from some other well in that region. As you get to the center of the WIPP Site and more or less propagating out from the center of the WIPP Site you see recoveries and drawdowns related to events at the WIPP shafts. Those shafts are pretty well sealed right now, so the overall response you see today is rises in water level. As you move to the North and get into Nash Draw, I think you can probably see responses to the discharge of potash mill effluent into Nash Draw. I'm not sure about the availability of discharge records there. It might be possible to try to reconstruct a discharge history and try to relate that to the water levels we have seen. Again, I'm not sure that it's really relevant to WIPP compliance. The water levels and the flow directions are not from the WIPP Site towards Nash Draw. Any minor changes in gradient, in any event, are not going to effect the results of our performance assessment. We are not on such a hair trigger that a difference of 10% or even 100% is really going to make any difference.

### 2.3.1.5 Questions:

**Dennis Powers:** For wells H-7, WIPP-26, and WIPP-27. Are the data precise enough for annual changes?

**Rick Beauheim:** I have doubts about H-7. H-7 at one time pumped at 80 gpm and the responses we saw at the observation wells on the order of 100 feet away were dominated by earth tides. And the earth tidal responses were almost as great as the pumping test response. It may be of interest to no one but me, but earth tides are changes in water level affected by moon tidal affects and the changes in the configuration in the earth in response to tide. Actually, some of the first work on earth tides was done in Nash Draw, in the Culebra, back in the late 1920s, early 1930s. So H-7 is very close to the location where the very first earth tide research was done. The other ones, Dennis, -- yes I think it is possible that you could try to do that -- I'm not sure what you would turn up, but it might be worth a shot.

**Tim Gum**: Rick, on your model study where you indicated the 12 gallon per minute increases in fluid level, what was the total volume which had to be injected in order to get the total rise all the way?

**Rick Beauheim**: The way the modeling was done, the 12 gpm was turned on. I guess I'm not sure exactly when in 1988. In early 1988 this 12 gpm was turned on and was simply allowed to run for the duration of the modeling simulation. At the time that was done, the water levels were all continuing to rise. So the modeling was simply turned on and we watched the hydrograph to see if the simulator hydrograph matched what we observed.

**Tim Gum**: From 1988 on?

**Rick Beauheim**: From 1988 on to however long it ran. I honestly don't recall if we just ran a simulation through 1991 at the time or projected further. But we didn't turn it off and then on.

**Tom Peake**: Yes, do you think this affected your response times, due to rises from the South to the North, up to the Cabin Baby and H-4? Do you think that has any implications for suggesting that there are higher transmissivities in the South Central part of the WIPP site than are currently being modeled?

**Rick Beauheim**: I think you can look at the pattern of water level responses and learn something about the transmissivities. P-17 and H-17, for instance, lie on an east-west line. Yet their responses were different. I look at those two responses, H-17 and P-17, and what they say to me is there is a high transmissivity feature passing between those two wells. A few responses we observed tell me that the high transmissivity feature is more likely closer to P-17 than it is to H-17. Because the P-17 response seems clearer. It seems to catch the subtleties of the response better than the H-17 response. The propagation on toward Cabin Baby, H-4, P-15, I guess I really could not say whether it holds any surprises. I think it would provide an opportunity to take a closer look with our existing Culebra model to see if our current transmissivity distribution would match the responses that you see that much further away in detail.

**Robert Neill**: It is an extremely important area. In fact we have a half hour scheduled this afternoon to address this in greater detail. Rick, a quick question. Do you see any merit, at this point, in trying to obtain some water samples from these wells to examine, from a standpoint of chemistry, any change as both a function of location and a function of time?

**Rick Beauheim**: I really don't think so. We are looking at pressure transient propagation here which can be relatively rapid whereas actual transport of ground water is an extremely slow process. I don't think there is any chance at all of us seeing changes in water chemistry as a result of this.

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## 2.4. Observations of the Effects of Water Flooding on the Salado Formation

Dennis W. Powers, Consulting Geologist, Anthony, Texas

### 2.4.1 Synopsis

The Hartman vs. Texaco lawsuit and subsequent discussions with different people focused my attention on a physical condition common to several concerns. The basic physics or hydrology of liquid and gas movement laterally or vertically through the evaporites, especially the Salado, is common to decisions about oil and gas exploration vs. potash mining, deviated or vertical drilling through evaporites outside WIPP boundaries, and the fate of any gas generated by decomposition of waste at WIPP.

Exclusion zones for drilling and potash mining are presumed to be based on two principal concerns: safety and the desired development of resources. Exclusion zones presumably increase as real (or perceived) safety concerns increase; fewer resources are developed in consequence. Among the safety concerns is the possibility of lateral movement of hydrocarbons along evaporite beds from a leaking well into a mine. The same general setting can exist for WIPP from the nearest well to the underground workings. Gas generation at WIPP raised the possibility of movement away from the disposal mine to a boundary or well. And the Hartman Bates well raised the possibility of injected fluids reaching a well at a distance of about 2 miles from the injection field boundary and in a formation overlying the injection horizon.

Perhaps each situation has to be resolved separately (monetary settlement for Hartman, scenario analysis for WIPP, some other means for potash vs. oil and gas exploration). Nonetheless, as similar occasions arise, there will be a continuing need to understand the hydrology of liquid and gas transport parallel to bedding within the Salado or other rock units. There are probably no better investigations yet of these phenomena than for WIPP, and there will be increasing pressure to understand and apply the results to different versions of the same fundamental problem.

### 2.4.2 Presentation by Dennis Powers

Today I want to cover a few different topics. The title that is listed for you is a little bit misleading. First, I want to give you a little bit of my impression of some things out of the Hartman vs. Texaco lawsuit that struck me. I also want to talk about some common problems, some underlying principles of physics that are important to several different projects and several different ways of thinking about the Salado.

Today, I am speaking on my own behalf and I am not here representing any organization at WIPP even though, I think most you are aware, I am under contract to one or more organizations to do work at WIPP. I am not a lawyer; this is not a legal analysis of the Hartman vs. Texaco case. I think that the comments that Bob Neill made at the beginning were important. This is not a rehash of that case. But there are some items of technical interest.

#### 2.4.2.1 Background

Let's take a look at the setting for that well and the relationship to the Rhodes/Yates waterflooding unit principally operated by Texaco. In January 1991, Hartman and his company began to drill the Bates #2 well on an acquired lease that had previously been drilled by El Paso Natural Gas and had been producing for about 35 years before plugging and abandoning the Bates #1 well. The Bates lease is located in the southeast corner of New Mexico. It is located in the back reef and not in the Delaware Basin. It was drilled to try to produce Yates gas in the lease that Hartman had obtained. At about 2,240 feet the well begin to produce high volumes of high pressure brine. Drilling operations were stopped at 2,280 feet. The New Mexico Oil Conservation Division was notified. Out of concern that an underground blowout might occur, the driller was not allowed to shut the well in for any extended period of time. Casing had been cemented back to the surface from about 456 feet in an approved drilling plan.

The flow, at times, was on the order of 1,200 barrels per hour. Nearly 300 truck loads of brine were hauled away and a pipe line was put in to take brine away to the South Leonard Waterflood Unit. It took five days to work out a final solution in consultation with the New Mexico Oil Conservation Division. That solution was to cement the annulus first, to go back in and check the cement job, and then to cement back to the surface, leaving the drill pipe in place. Thus ended Bates #2.

At that point Hartman and his company began to wonder where this had come from. The question that came up - was this a natural flow or was it not natural, that is, brought by some other means such as the water flood unit operated at Rhodes-Yates field? I am giving you some of my impressions and can't speak to the actual thought processes of anyone involved, but late last fall I was contacted. It appeared that there would be a defense during the legal proceedings that this was a natural event, that it was similar to the high pressure brines in the Castile Formation and several wells in the vicinity of WIPP. It bears certain resemblances to the data that had been obtained from underground testing at the WIPP — data that had been obtained by drilling small diameter holes and testing them with rather sophisticated means over a period of time to determine what the pressure buildup was. Hartman called me to see if I would be available to help counter these arguments. I spent some time reviewing the data and decided that the approach that they wanted to take was consistent with what I believed was going on so I joined their team, for a while, to provide consulting services. I was named as a potential rebuttal witness. I did not testify at trial. That gives you a little bit of a background. I thought that was important so you would know where I was coming from and you can judge accordingly whatever is said.

Some notes - the Bates #1 was drilled in 1953 by El Paso Natural Gas. It produced, again, for about 35 years and then was plugged and abandoned. The Bates #2 well is approximately 100 feet away from Bates #1 well on the surface. To my knowledge, there are no directional surveys. I cannot tell you how far apart they might be at the bottom of the hole which is about 2,280 feet.

At the point where the flow began, there is an anhydrite unit. It's on the order of 10-15 feet thick, based on geophysical logs from that well and nearby wells that can be correlated. We are in the Salado Formation. I have not tried to correlate the individual marker beds with those in the Delaware Basin. It's my guess we are somewhere in the range of marker beds 140 to 142, which would put it below the WIPP repository horizon, which is just above marker bed 139. There is, on the natural gamma log signatures for that drill hole and others, a slight gamma kick at the base of that anhydrite, which is consistent with what we see in shafts and drill cores and other logs of boreholes. But there is probably some clay or argillaceous zones besides anhydrite.

The distance from the Bates #2 well to the administrative boundaries of the Rhodes-Yates water flooding operations is approximately two miles. Structurally, the Bates well is generally updip.

### 2.4.2.2 Observations

The salt water blowout and the subsequent case raised interesting technical issues. One was the unresolved differences in the estimates of the true pressure in the Bates #2 well. The New Mexico Oil Conservation Division was concerned that if the well were shut-in, the high pressure brine would be injected into other formations (an underground blowout). Hence, the well could not be shut-in for an extended period of time to obtain a good bottom hole shut-in pressure. The consultants for Hartman believed that the best shut-in pressure came after the annulus had been cemented and there had been circulation and flow equal to the cementing job which should have relieved any pressure problem, or most of the pressure brought on by a cementing job. That pressure was on the order of 1,000 psi at the surface. The consultants for Texaco had believed there was a more appropriate pressure that was several hundred psi lower. That would have brought the pressure gradient and the formation pressures down considerably from what the Hartman consultants had estimated. Nonetheless, the pressure measurements were less than desirable 1) because of the condition of the hole and 2) because of the inability to shut the well in and obtain a good shut-in pressure.

It was suggested that the pressure gradients can be used as indicators as to whether the water flows were induced by nature or induced by some other source. For the Rhodes-Yates water flood, the injection pressures at the surface ran 1,200 psi and above. Some injection pressures approached 2,000 psi at the surface. If those are correct, those surface injection pressures begin to produce pressure gradients greater than 1 psi per foot vertical. Typically, the measured pressure gradients from brine reservoirs in either the Castile or the very low flows in the Salado are considerably less than 1 psi per foot, ranging down to 0.8 psi per foot or less. The difference in pressures can be used to distinguish between natural or human induced occurrences.

There was testimony on both sides as to whether or not there were unaccounted injection fluids. The consultant for Hartman estimated that there might be as much as 20 million barrels of fluid that had been injected that was unaccounted for in terms of total production and storage capacity of the formation within the water flood unit. Consultants for Texaco testified that they did not believe, by their analysis, that there were any unaccounted for fluids.

There are differences between the geology at the Bates lease and the geology at the WIPP. The Bates well blowout was a large volume, high pressure flow. The bottom of the borehole was in the Salado Formation. The Castile does not exist in the area of the Bates well.

In the WIPP area there are high pressure, high volume reservoirs within the Castile. One brine reservoir was tapped at WIPP-12, approximately 1 mile north of the site center. Those kinds of brine reservoirs are in the Castile and are generally associated with a zone of relatively high deformation of the Castile, within a few miles of the margin of the Capitan Reef.

At the Bates #2 well, the Salado shows little deformation. It shows a general dip, but nothing of any magnitude comparable to the kinds of deformation observed in the Castile in the area of the Capitan Reef. The WIPP pressures from the Salado testing underground, suggests that the projected pressures will show a gradient on the surface much less than the Castile.

The Hartman-Bates well blowout raised interesting questions about expectations for institutional responses and institutional controls and how they change with time. Presumably they get better, but it is one thing that needs to be looked at.

There is a technical basis for scenario development. In the Hartman case, one has to either accept a natural cause or, if it is not natural, one must believe that fluid was transmitted along a bedding plane to the Bates lease perhaps for a distance of 2 miles. Transport along the bedding plane is the best explanation. For years the (WIPP) project has been concerned about gas, generated by waste degradation, either diffusing, fracing (fracturing), or otherwise moving along bedding planes. It is the same problem but moving in a different direction. With any kind of drilling, including water flood operation, around the boundaries at the site, the same issue comes back again. How are we going to address whether fluids can move along bedding planes or within the formation, a certain distance under different conditions? How will we address that?

BLM is having to try to address the issue, I believe, through litigation of the contrasting desires of oil and gas exploration vs. potash mining. How far away from mining is it safe to drill a hole or mine up to a hole? There are cases where mining has hit petroleum casing underground. That makes people nervous — that there is an oil or gas well and that you get that gas leaking into a mine. Several things are going to happen. None of them are good. The most benign is that their expenses go up to try to deal with a gassy mine and they go out of business. It is not very benign. People are working with stock holders. That might be one of the more benign consequences, if such a leak did occur. But of course, every time you change that boundary, you say, well, we need to protect the potash and keep the oil and gas away. That just simply magnifies the amount of resources unavailable for both sides. Obviously, if you were going to maximize the resources, what you'd like to be able to say is "It's safe". You can co-exist. Everybody gets their way that way. So those are some issues that have some common problems.

What I see is that everybody will probably attempt to solve it uniquely because nobody likes to try to produce a general solution for all of the world. It is expensive and difficult. If you can produce a simple solution for your problem or concern or issue, whatever it might be, if you can produce that solution for yourself very simply, you'll do it. But it might be good for the different organizations to be thinking about this with a little bit longer term (framework) and to recognize that there may be consequences, even unintended consequences, from one solution to another one's problems. Even if it's a modeling approach that makes certain assumptions that the modeler says don't cause a problem, somebody else might have some difficulty with those assumptions. We need to make sure that those are specific, unique, and identified as being adequate for that problem but not necessarily general assumptions. Those are a couple of the things I wanted to talk about this morning. I believe that the pressure on the WIPP underground data and related data from the WIPP will increase. By pressure I mean there will be a lot more demands for it and a lot more desire to interpret it, to make sense out of the particular application that you have, from BLM trying to resolve oil and gas versus potash mining, to other people. They need to be aware of that and to think about how best to integrate interactive folks. Thank you, any questions?

### 2.4.2.3 Questions:

**Wendell Weart**: Do you know, Dennis, if there is presently a standoff distance, either legal or practical that the industries have used to keep certain separation between potash excavations and petroleum holes?

**Dennis Powers**: The number I heard was 500 feet but I also know that some of the potash mines have generally, inadvertently drilled into a few, or mined into a few holes, too. Five hundred feet is the number I heard but I haven't seen it written down in some regulatory fashion - it may be there. And there may be somebody that knows that number better than I do.

**Dan Stoelzel**: You said there has been inadvertent mining into petroleum wells. To your knowledge, is there any record of gas leaking into these mines?

**Dennis Powers**: I haven't seen any, no. What they did, the records that I saw, indicated that the casings got marked up. Tungsten carbide bits will do that. And then there were various measures to go ahead and protect the drill casing. In one case, I'm trying to remember which mine it was, there was a caisson built and a big cement block support around it.

**Dan Stoelzel**: What about naturally occurring gas in the potash mines?

**Dennis Powers**: Well they are not classified as gassy mines with methane residence, but there are occasionally these blowouts of gas which have been trapped, most of which is nitrogen. Lokesh [Chaturvedi] has written, edited, and put together a volume that discusses gases occurring in the Salado Formation. That's one good source and there are other sources within some of the Sandia publications that describe some of the gases. But basically it is nitrogen-dominated and few other minor gases. But potash mining people desperately wish to avoid the gassy classification because if they ever wind up in a gassy classification, at least at this point, they'll be out of business. And right now I don't see any — there is no particular reason to fear that, as far as I know.

**Chuck Byrum**: Dennis, do you know why they inadvertently hit some well bores while they were mining?

**Dennis Powers**: No. It may be known, I just don't know.

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## 2.5 Geologic Considerations and the Implications for Waterflooding near WIPP

Lori J. Dotson, Sandia National Laboratories

## Current Petroleum Practices and their Application to WIPP area Development

Daniel M. Stoelzel, Sandia National Laboratories

### 2.5.1 Combined Synopsis

A Rhodes Yates/Vacuum Field scenario (where injected water migrated to the overlying salt) is highly unlikely at WIPP because of: differences in geology, changes in oil-well completion practices from the 1940's, and improved reservoir management. In addition, new state regulations are in place to reduce the possibility of a petroleum well leaking into the Salado.

The differences in geology between WIPP and the Vacuum and Rhodes Yates Fields is significant. WIPP is located in a fore reef environment where a thick zone of anhydrite and halite (the Castile Formation) exists. Oil production is from the Brushy Canyon Formation at depths greater than 7,000 feet (5,000 feet below the WIPP repository). By contrast, the Castile Formation is missing at both the Vacuum and Rhodes Yates Fields which are located in reef and fore reef environments, respectively. Oil production at the Vacuum Field is from the San Andres and Grayburg Formations at depths of approximately 4,500 feet and oil production at the Rhodes Yates Field is from the Yates and Seven Rivers Formations at depths of approximately 3,000 feet. At the Rhodes Yates Field, for example, there is only a couple hundred feet of vertical separation between the Salado Formation and the waterflood injection zone. In addition, the oil pools near WIPP are characterized by channel sands with thin net pay zones, low permeabilities, high irreducible water saturations and high residual oil saturations. Therefore, large-scale waterflooding near WIPP is unlikely. The estimated life of the pools near WIPP is less than 10 years for primary production and less than 10 years for secondary production.

The petroleum industry has made many advances since the time when the Vacuum and Rhodes Yates fields were first developed. Improvements in drilling, casing, and cementing technology have greatly reduced the occurrences of leaks in oil wells. An industry-wide effort to reduce formation damage and increase production has led to improvements in completion design and advances in stimulation. Open-hole (non-cased) production/injection wells and nitroglycerin treatments are no longer used. Acid stimulation and hydraulic fracturing techniques have improved considerably in the last ten years. Service industry support has made this technology available to both the large and small operator. The availability of inexpensive software has lead to improved reservoir management, including waterflood design.

State regulations require a salt isolation casing string for all wells drilled in the WIPP area. Injection pressures are not allowed to exceed fracture pressures for all injection/disposal wells. Operators obey these regulations because the State has power to levy fines and/or shut wells in, should they become aware of a violation.

In conclusion, geological differences, modern petroleum development practices, and regulatory oversight will greatly reduce the risk of oil wells leaking to the Salado in the WIPP area.

### 2.5.2 Geologic Considerations and the Implications for Waterflooding near the Waste Isolation Pilot Plant - Presentation by Lori J. Dotson

There are three main points I'd like to make here.

1) The oil pools near WIPP are relatively small scale when compared to the Vacuum Field and the Rhodes Yates Field.

2) Large scale waterfloods are unlikely. It is not a foregone conclusion that all of the fields will be waterflooded or that any of the fields will be waterflooded.

3) Most importantly, there are a lot of geologic differences between the Rhodes-Yates Field, where the Hartman-Bates well was and WIPP. For one thing there is five thousand feet of vertical separation between the producing interval, at WIPP being the Brushy Canyon Formation of the Delaware Mountain Group and the WIPP repository. It is true that there is salt water disposal in the Bell Canyon Formation, but that is still a vertical separation of about 2,500 feet. In contrast, at the Rhodes-Yates field, you are only looking at a vertical separation of a few hundred feet between where Texaco was water injecting and Hartman encountered the blowout. The Vacuum Field is being produced from the San Andres and Grayburg Formations at approximately 4,500 feet. The Rhodes-Yates is being produced from the Yates and Seven Rivers Formation which is located about 3,000 feet below the ground surface. The producing interval of the Brushy Canyon is located about 3,000 feet below the Bell Canyon. The Castile Formation is present at the WIPP Site but is absent in the backreef at the Rhodes Yates Field.

As to the second point, about generally small pools and thin pay zones, at Livingston Ridge and Lost Tank, you heard Ron Broadhead talk about forty foot of net pay. That's where it is economic to produce oil. There are a lot of wells in the Livingston Ridge area where there is only ten to twenty feet perforated casing. So there are some pretty small pay zones. In contrast, at the Vacuum Field, one block that I looked at had three hundred feet of gross pay. So we're talking not an order of magnitude difference, but close to it. In the Los Medanos and Sand Dunes there are pay zones that range from less than twenty feet up to one hundred forty feet.

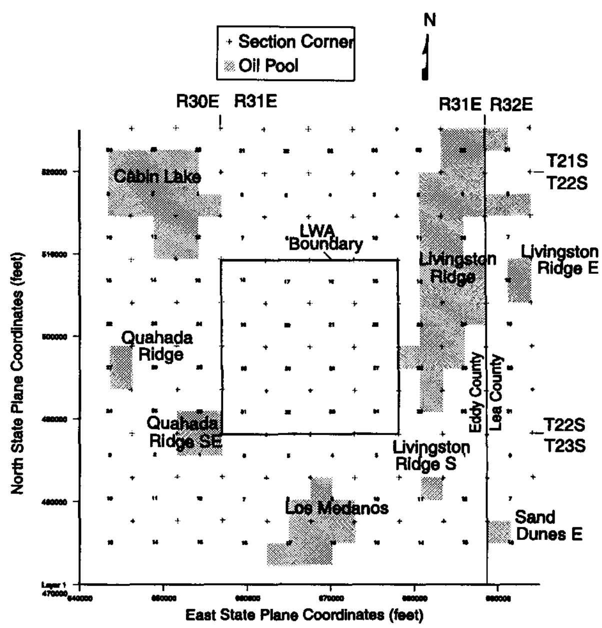


**Figure 2.5.2-1**. Producing oil field leases surrounding the WIPP.

Another point that Ron made that was really good, the primary production from area around WIPP from the Brushy Canyon is going to be less than ten years and for secondary production, less than ten years of secondary recovery. Production from these fields is going to play out in less than twenty years. Water injection, if water flooding took place, would be less than ten years. Just to give you a reference, the Vacuum Field for instance, over 300 million barrels of oil and 200 BCF of gas have been produced. I will have to get the exact figures from Ron, but we will have to leave that for the discussion. But we are looking at order of magnitudes difference between what is going on at the WIPP area and what we have at some of the larger fields.

This last point, the reservoir characteristics, the 7 to 24 millidarcies is actually a number for the Bell Canyon. The information for Brushy Canyon is actually pretty scarce and the characteristics of the Brushy are such that the permeability would actually be less. The Brushy Canyon is siltstone and sandstones, but also there is authigenic clays which tend to clog the pores and reduce the permeability somewhat. What this means is that water flooding could occur, but they may have to space the injection wells closer. But then you get into an economic question. There is a technical question and an economics question. It just may not be economical to drill additional wells. The reservoir is also characterized by highly irreducible water saturation and high residual oil saturation. That emphasizes my previous statement. Yes, you can waterflood these fields, you can waterflood those that have better characteristics, but it is an economics issue. If you have to drill additional wells, it may be too costly to get that oil out.

Cross-Section Depicting the Relative Locations of the Rhodes Yates Field and the WIPP Repository

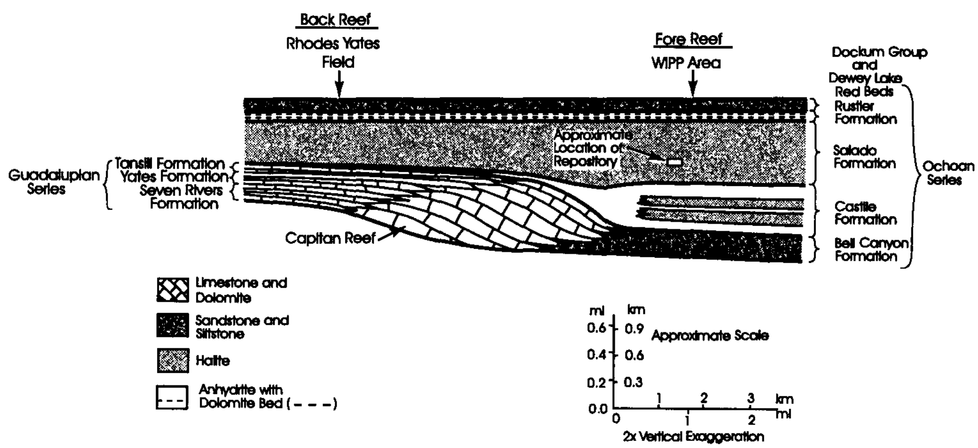


**Figure 2.5.2-2.** Cross-Section of Rhodes Yates Field and WIPP.

I really wanted to focus on the difference in the vertical separation at WIPP versus Rhodes-Yates which this figure illustrates quite nicely.

At the Vacuum Field, the permeabilities are up to 400 millidarcies. There is an order of magnitude difference. At Vacuum, like I already said, the pay zones are much thicker.

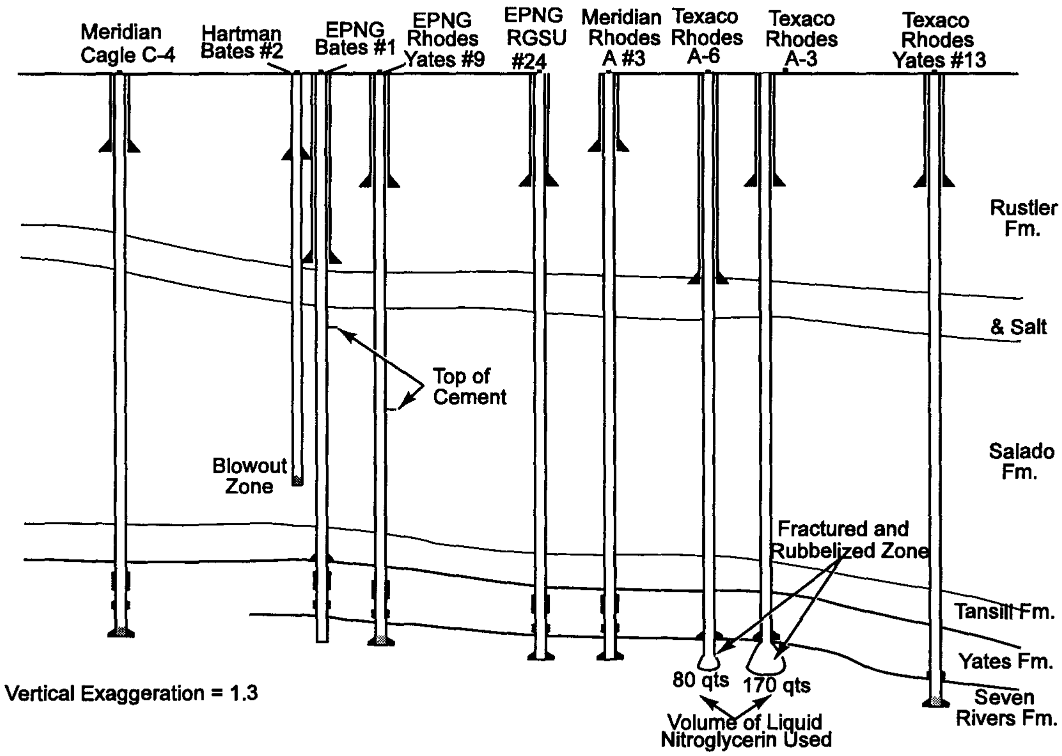


**Figure 2.5.2-3**. Schematic showing location of Hartman Blowout and Texaco Injection Zones.

This is a schematic showing where the Hartman well blew out and where you have water injection from the Texaco wells. Back in the "old days" a well was made more producible by pouring liquid nitroglycerin down the wells and basically just blow up the formation. So there are rubble and fractured zones. You don't know where your fluid is going at all. Like Dennis Powers stated, I also do not wish to comment on the legal issues of the Hartman-Texaco case. There were clearly practices that occurred back then that are not practiced now. Some of the casing, cementing, and developmental practices will be covered by Dan Stoelzel in his presentation. Between the Hartman blowout zone and the Texaco injection zone, there is hundreds of feet of vertical separation and also the suspect casing and cementing jobs. The figure shows where the surface casings are set. It is unclear from this figure what they are actually casing off. Some of these don't look like they extend down to the Culebra. There are really strange well constructions there.

Three main points:

1) Potential waterfloods near WIPP would be relatively small scale. I'm not saying that they would or would not waterflood, but it would be small scale if they occurred.

2) The fields will play out in less than twenty years. I think we are all in agreement on that.

3) The interval where they would inject water for a waterflood is 5000 feet beneath the WIPP repository. So you have quite a distance it would have to travel vertically to affect the repository.

**2.5.2.1 Questions:**

**Wendell Weart**: When were the injection wells completed - in what time frame?

**Lori Dotson**: This is something that Dan (Stoelzel) has more information on. In the Vacuum and Rhodes-Yates fields, for example, we are looking at the 30s and 40s and I think some of them in the 50s. But they are older wells, older construction. I hate to keep pushing everything off to Dan, but he has some really nice schematics that show the differences in well construction from the 30s and 40s to the present time. You are looking at wells that are over forty years old.

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### 2.5.3 Current Petroleum Practices and Their Application to WIPP Area Development - Presentation by Dan Stoelzel

With the older well completion techniques, especially in the Rhodes-Yates Field and Vacuum Field, there has been communication behind pipe caused by situations such as bad cement jobs. In these fields the injection wells were in communication with the overlying strata. In the Vacuum Field, for example, there was concern that some oil field injection wells would contaminate the Ogallala fresh water aquifer. The problems with the Rhodes-Yates waterflood were covered in previous presentations.

The possibility of water injection wells endangering the WIPP is highly unlikely. Neither a Rhodes-Yates nor a Vacuum field scenario will happen at WIPP because of the differences in geology, changes in oil well completion practices from the 1940's, and improved reservoir management. Current industry practices and controls that are in place reduce the risk of injection or disposal wells endangering the WIPP site. There have been changes in the petroleum practices from the 1930s and 1940s and 1950s, even up through the 1970s, versus today. New regulations, mainly statutory regulations, have come into effect. The presentation is divided into the major areas of drilling technology, production and completion technology, and reservoir management. The last 10 or 20 years have seen numerous advances in these areas.

#### 2.5.3.1 Drilling Technology

Since the 1940s and 1950s, there have been considerable improvements in the cement that is used to cement the casing - higher bond strengths, better cement properties, and impermeable cements. Drilling mud technology has improved to limit pole washouts and lost circulation problems. This is especially true when drilling in familiar geology. Lost circulation control becomes a fairly exact science. This is important in the casing stage of a well. If there are lost circulation problems and washout problems, this could lead to communication or leaks behind pipe. Prudent operators know that any kind of leak behind a pipe is detrimental because it could lead to a loss of production, loss of reserves, and loss of revenue. Compared to drilling operations of the 1970's and early 1980's, drillers have a better understanding of operations such as block control and controlling kicks.

There have been numerous improvements in the last 10 to 20 years in corrosion control. Casing and tubing strings are inspected on the surface prior to running in the ground to eliminate potential leaks before running the casing. There are corrosion inhibitors that are routinely pumped into the tubing and casing to limit corrosion problems. Casing strings are routinely pressure checked. State regulations also mandate pressure testing of the casing. There is a lot of research and development in all these areas.

One point that hasn't been brought out yet is that most of the players in the Delaware Basin area, especially around WIPP, are small time operators. The smaller companies generally don't have the big research and development to support their oil and gas development. However, much research is transferred to the smaller companies through the service industry.

There have been significant advances in directional drilling and horizonal drilling in the last 30 years, but especially in the last 10 years. The costs for directional drilling have come way down. This is important for potential WIPP development because it is feasible to tap into much of the possible and probable reserves by directionally drilling from a surface location outside the land withdrawal area.

### 2.5.3.2 Completions

Once a well has been drilled and cased, substantial technology is used to develop the pay interval. There have been considerable improvements in perforating technology, tubing packers, gravel packing, well stimulation, fracturing, and acid stimulation. Open hole completions are rarely used in the industry and are definitely no longer used in the WIPP area. Generally, the production interval is cased and perforated. There have been advances in shape charge perforators, stimulation, and in hydraulic fracing technology, especially in the area of predictive modeling over the last ten years.

There have been substantial developments in fracture height control. Generally, oil companies do not want to hydraulically fracture out of their producing zones. To fracture out of zone could translate to loss of reserves. Operators definitely do not want to exceed fracture pressure in an injection well. The whole purpose for a waterflooding injector is to maintain pressure or inject into a producing horizon. If the operators are injecting out of zone, they are losing reserves.

Acid stimulation has come a long way. Acid stimulation is designed to specific rock types and fluid types.

#### 2.5.3.3 Production

There have been numerous advances in wireline, coiled tubing workovers, and through tubing workovers that greatly reduce cost and could extend the economic lives of wells.

The preferred method of lift in the WIPP area is the sucker rod pump. However, there are alternatives such as gas lift, submersible pump, or plunger lift. Each of these have seen a lot of development in the last 10 to 20 years.

Routinely, coated tubulars are run, especially in injection wells because injection wells are recognized as a highly corrosive environment. Multiple completions are possible. By running dual completion strings, two or more zones can be simultaneously produced. Behind pipe reserves are typically recovered by successively plugging back as the operator comes up the hole.

Leaks are not good. If an operator is aware of a leak, he will generally take remedial action to fix that leak. The state is the regulatory agency that requires frequent pressure checking of tubing and casing. If a leak is detected, the operator must repair the leak.

### 2.5.3.4 Reservoir Management

One improvement in reservoir management includes the advent of affordable personal computers (PCs) and the availability of inexpensive software. During the last five years there have been significant advances in relatively inexpensive software to run on PCs. Whereas, the small company of the past didn't have the manpower or the money to afford this type of luxury item, now it's fairly routine. Various research firms and universities provide software support. Availability of the software has especially assisted the small time operators to optimize field development and field production.

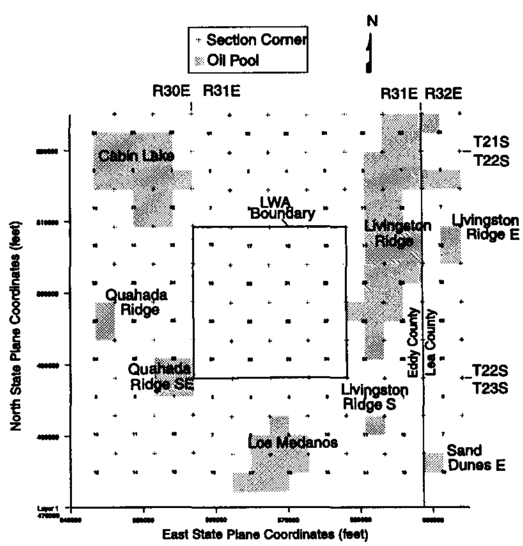


**Figure 2.5.3-1**. Producing petroleum leases adjacent to the WIPP Site.

The five spot water flood pattern is being used at Rhodes-Yates Field and at the Vacuum Field. However in the WIPP area it is highly unlikely that a five spot pattern would be used, especially with small pools. The decision to convert a well to water injection, in most cases will be more determined from the reservoir geology and geometry. For example, the Livingston Ridge Lost Tank Field is a channel sand. An in-line injection flooding pattern would be more likely. In this case, injectors would be located in the southern part of the field and drive oil updip to the producers to the north. For these small pools a five spot water flood pattern would be highly unlikely both economically and geologically.

Source water compatibility between the formation rock and the injected fluids is very important. This is relevant to the WIPP area because there has been some speculation that a future driller may decide to use, for example, Culebra fluid as source water for an injection project. This is highly unlikely. The oil bearing formations contain authigenic or interstitial clays. If less saline water was injected into such a formation, it would cause clay swelling and potential plugging of pore spaces. Injecting Culebra water would essentially ruin the well. At this time, none of the injection wells or disposal wells are using the Culebra for source water. And I expect that will be the same forever. Operators will typically find their source water from the same formation as their oil production.

In addition to source availability, economics is the big question. Can small operators afford the surface facilities and the additional costs to drill injection wells or convert producers into injectors? The small oil companies typically have fairly shallow pockets. A water flood requires substantial capital. The return on the investment will be several years down the road in the producing life of the field. Most small companies wouldn't be able to weather that economic return.

The amount of water being pumped into a pool is a direct function of your recoverable reserves. In the WIPP area, the oil is found in small pools. The operators are not going to be injecting large volumes of water, especially in view of the 10-20 year life that most of these pools will last through secondary recovery. In an injection project, operators will stay below the fracture pressure of a formation. Operators don't want to fracture out of zone and pump water into an unknown formation where it is not beneficial to their productive horizon.

### 2.5.3.5 Wells in the Vicinity of WIPP

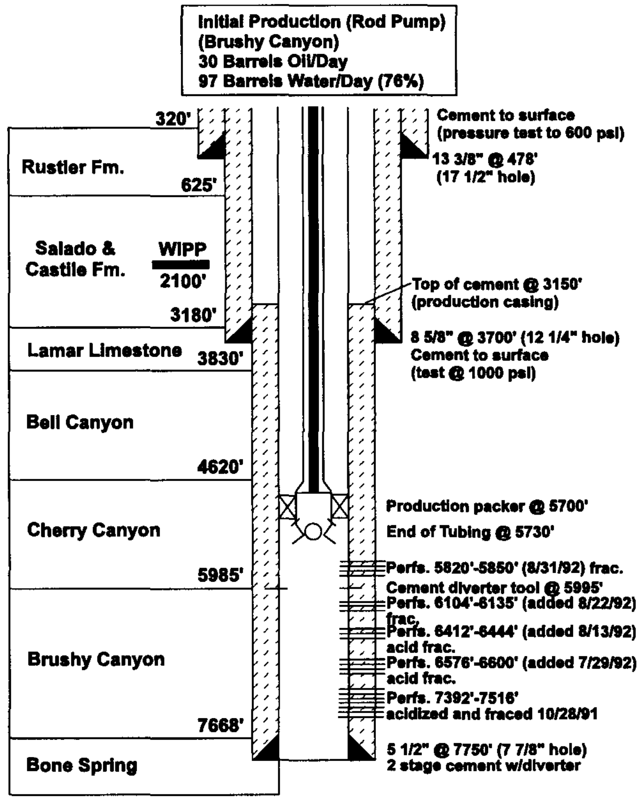


**Figure 2.5.3-2**. Typical Cabin Lake Pool Completion (James E#12).

The James E #12 well is operated by Phillips and produces from the Cabin Lake Pool. In 1988, the State of New Mexico published regulations on completing oil and gas wells in the potash area, which includes the WIPP area. There was concern about natural gas potentially leaking into potash mines. In the Vacuum Field, the State had seen communication potentially into both the Salado and the Ogallala. The state now requires all the oil and gas operators in the potash area to include a salt isolation casing string in their well design. The surface casing typically runs through the upper stratigraphic units such as the Dewey Lake Redbeds and the Culebra. The intermediate casing, which is required by the state, is cased off below the salt formations, the Salado and the Castile. The state also requires that production casing run to the surface.

The James Ranch Unit #19 well is operated by Enron and produces from the Quahada Ridge Delaware pool. The top of the cement surrounding the 5 1/2 inch production casing is at 2,680 feet. The bottom of the 8 5/8" salt isolation casing is at 3,850 feet. There is about 1,200 feet of cement as well as two sets of casing strings to help isolate the salt. The James Ranch Unit #19 is one of the better producing wells. The initial oil production rate was 213 barrels per day. The initial water production rate was 240 barrels of water per day. Initial production was over 50% water. We also see high water production from the Livingston Ridge. Seventy-six percent of the fluid production was water. These fields have a high water content and produce large volumes of the moveable water.

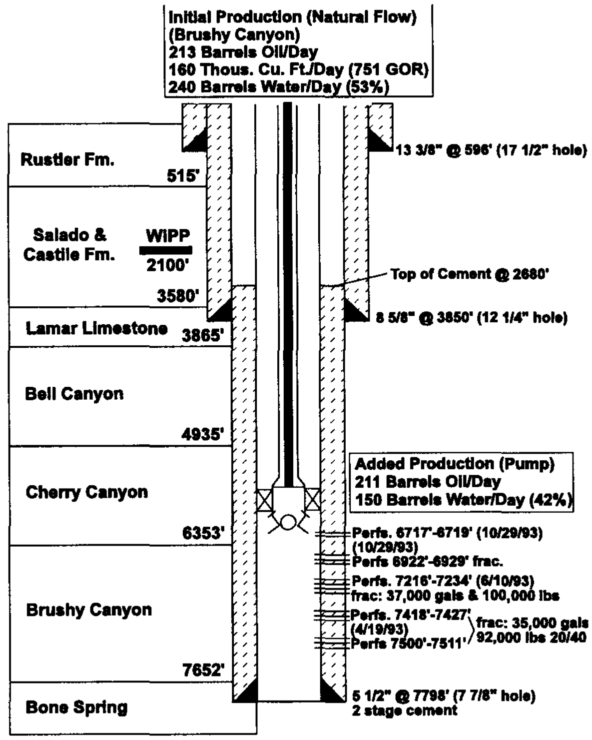


**Figure 2.5.3-3**. Typical Quahada Ridge Delaware Pool. James Ranch Unit #19.

A typical Livingston Ridge completion and a Morrow gas producer completion are shown. Each schematic shows a salt isolation string. For illustration purposes the WIPP horizon is also shown. The vertical separation between their production perforations and the WIPP horizon is on the order of 5,000 feet or more, which is much greater than that of the Vacuum Field and the Rhodes-Yates Field.

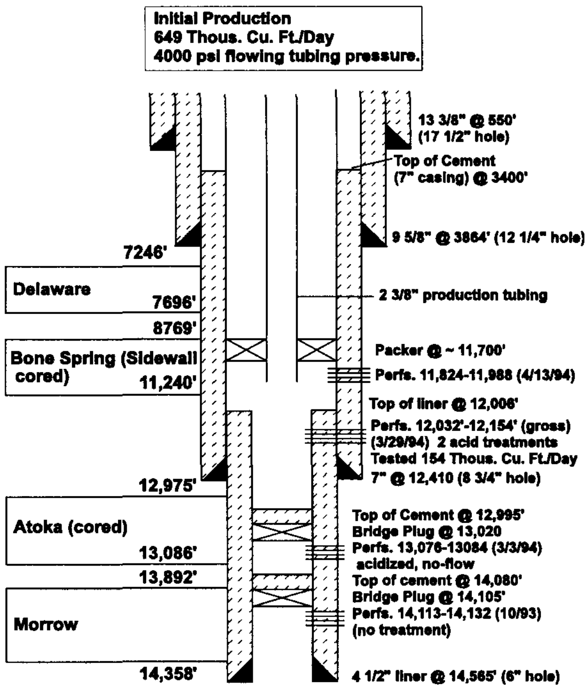


**Figure 2.5.3-4**. Typical Los Medaños Morrow Pool Apache 25 Federal #2.

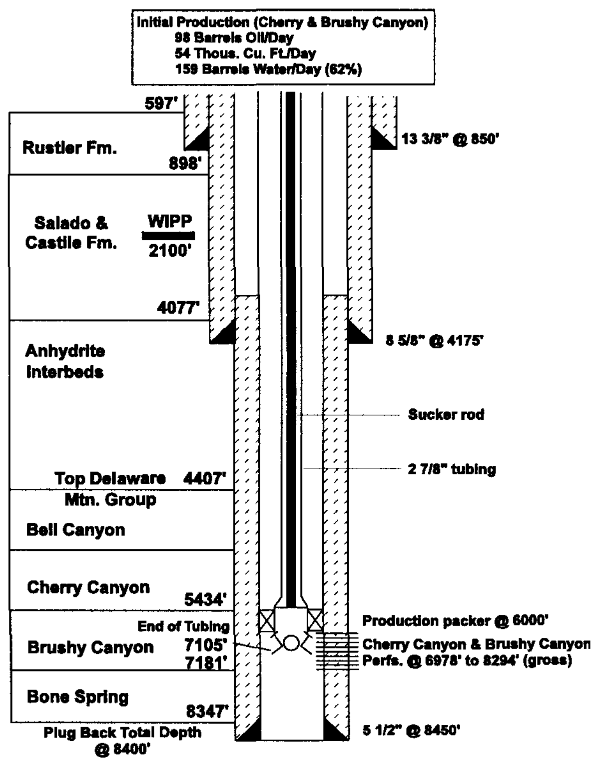


**Figure 2.5.3-5**. Typical Livingston Ridge/Lost Tank Completion.

The Morrow schematic illustrates the success of the plugback technique used by most operators. Probably the only reason this well is economical is because it has multiple pays. This well was originally perforated in the Morrow gas. It came in at a very high rate for this area, over 600,000 cubic feet a day. It was originally completed in the Morrow Formation in October 1993. By March 1994 this interval had been plugged back and the well completed in the Atoka Formation. In less than a year, this Morrow pay had depleted. The lower Atoka was tested but didn't have sufficient flow rate. The lower Atoka was plugged back and the well was completed in the upper Atoka. The well is apparently producing from the upper Atoka, although this formation may also be plugged back. The information comes from the New Mexico Oil Conservation Division in Santa Fe. There is a six month to one year time delay on the Sundry Reports, so the information on these wells may be outdated.

### 2.5.3.6 Early Well Completion Practices

For comparative purposes, the schematics of the Vacuum Field and Rhodes-Yates Field completion are shown here. I didn't have direct well data for these wells. In the case of the Vacuum Field, the discovery well was drilled in 1929 with a cable tool rig. It wasn't developed until the late 1930s and early 1940s. Common practice, during that time, especially in carbonate formations where there is low flow due to tightness, the operator would nitro-frac the completed well. This is a general schematic of their discovery well. It was nitro-frac with 580 quarts of nitroglycerin. I'm not an explosive expert, but I would think that 580 quarts could do considerable damage not only to the formation but to everything else down there.

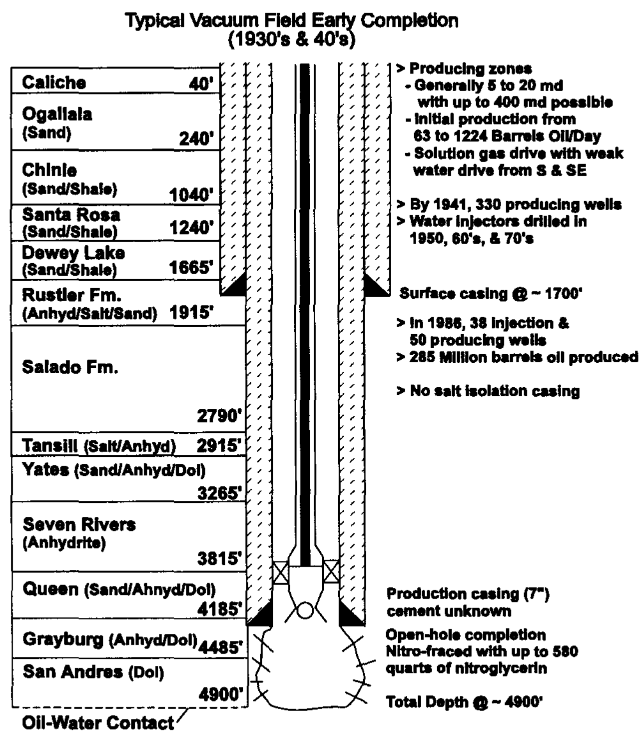


**Figure 2.5.3-6**. Typical Vacuum Field Completion for 1930s and 1940s.

In the 1930s and 1940s the oil and gas industry was in its infancy. Safety issues, reservoir management issues, and formation damage issues were pretty much nonexistent. Since then, there have been substantial improvements. Similar to the Vacuum Field, the Rhodes-Yates fields were also nitro-fraced. An important thing to note about the typical Rhodes-Yates early completion is the small amount of separation from their open hole productive horizon from here to the Salado, approximately 100 to 200 feet. Furthermore, the wells were nitro-fraced.

Originally these early wells were drilled as producers in the 1940s, 1950s, and 1960s. As many of these production wells watered-out, they were reconverted to injection wells. They just pulled sucker rod pumps out and maybe changed out the tubing string. They didn't take any remedial action as far as casing this open hole interval or cement squeezing behind the body to isolate. They just turned it right around and started injecting into this thing. So it is no wonder that there is considerable potential for injection fluid to go anywhere other than where they want it to go. It is going to the path of least resistance.

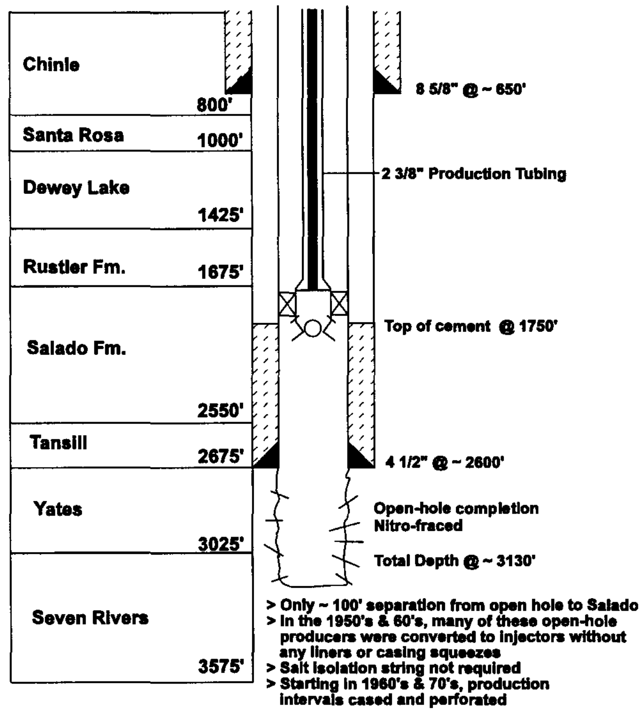


**Figure 2.5.3-7**. Typical Rhodes Yates-Seven Rivers early completion, 1940s-1950s.

The state rule on the salt isolation casing didn't come into effect until the late 1980s. Both these fields, the Vacuum Field and the Rhodes Yates Field, did not have salt isolation casing. As shown, the Salado is just behind one casing string. Early cementing and completion practices were such that, who knows where the cement went when they pumped it. A lot has improved since the days of these wells.

An older well, Todd 26 Federal #3, is shown. Todd 26 Federal #3 is the suspect well, about one and a half to two miles offset from the H9 WIPP test pad. It was here that Rick Beauheim observed the water table fluctuations. The rises in the Culebra due to potential leaking was attributed to this well. After looking at this schematic, I tend to agree with that. This well was completed in 1971. Originally it was drilled as a Cherry Canyon test well that was probably nonproductive. The well was converted to a disposal well. There was no salt isolation casing and it was an open hole completion somewhat similar to the Rhodes/Yates Field or Vacuum Field situation. This well was a disposal well for about 20 years. It is now plugged and abandoned. I am not sure when that was. I am trying to find out from the New Mexico Oil Conservation Division (NMOCD). There are very few records on this well. However, it is no longer disposing salt water.

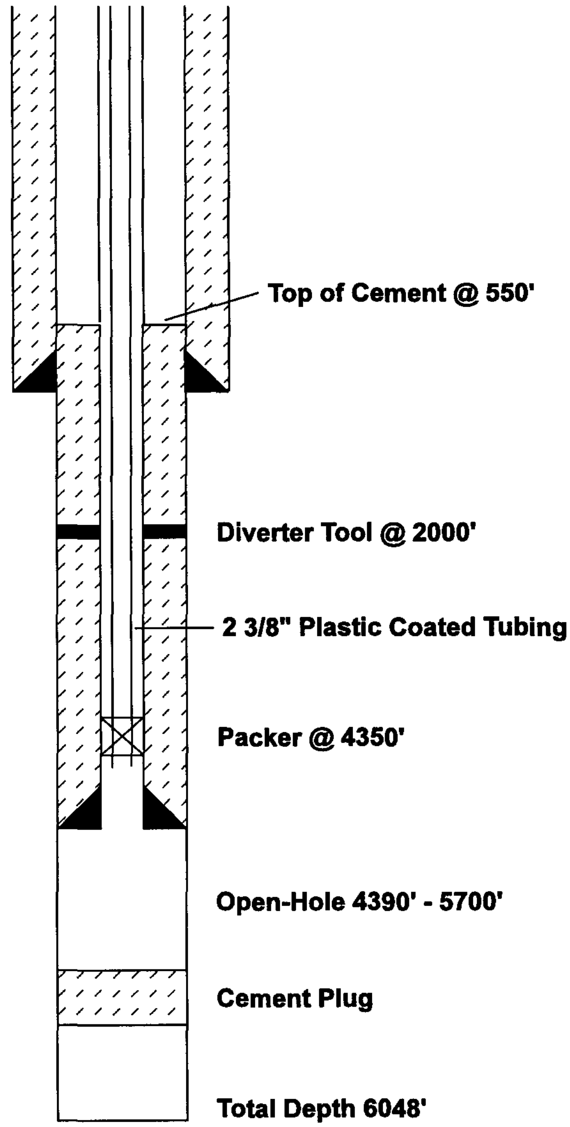

**Figure 2.5.3-8.** Texas American Oil Corporation Todd 26 Federal No. 3 Water Disposal Well.

A current salt water disposal design planned for the Livingston Ridge Field is shown. The plan shows the salt isolation casing. The production casing is run through the interval and perforated. The well was originally a strong producer. It is not uncommon to convert watered-out or nonproductive production wells to disposal or injection wells, which is the case for this well. The Sundry intent was filed on September 24, 1992. Surface injection pressure for this well is limited to 750 psi which is below fracture pressure. New state regulations require that operators stay below fracture pressures, either below 0.2 psi per foot above the hydrostatic gradient or below the fracture pressure as determined from injectivity tests.

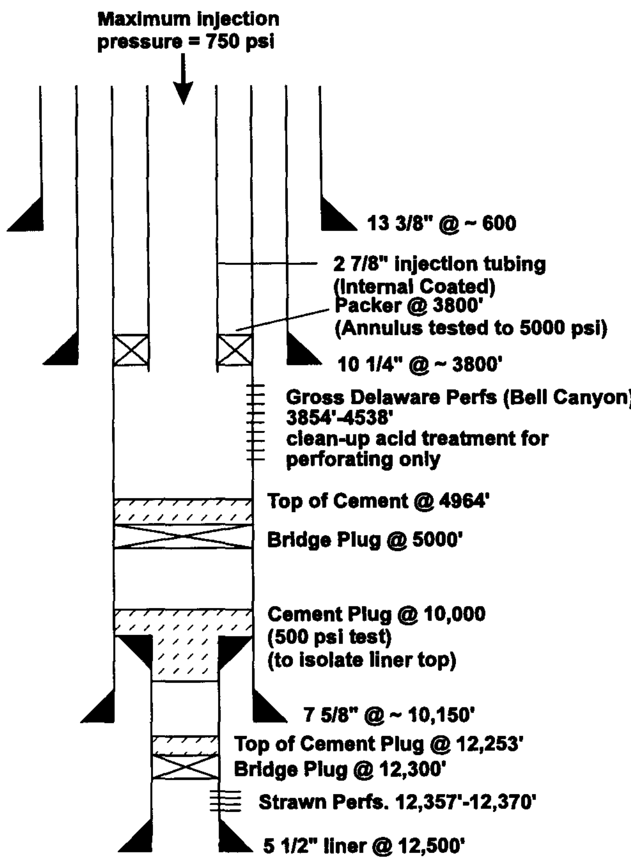

**Figure 2.5.3-9**. Current Salt Water Disposal Well Livingston Ridge Federal #9. Intent filed September 24, 1992.

### 2.5.3.7 <u>Questions</u>:

**Robert Neill**: Dan, you give a very compelling case for some of the current drilling practices and plugging practices. It is a great improvement over what has been done in the past. On the EPA standards, one is talking about what will be the behavior for human intrusion over long time periods. How comfortable do you feel with commitments requiring operators to keep injection pressures less than fracturing pressures and then going to EPA and arguing that this will continue to be true in the long term future.

**Dan Stoelzel**: I think it highly likely. Like anything the oil business does, it is driven by economics. Nobody can predict the price of oil in the future which is the governing driver for anything an oil operator does. These regulations are put into effect because of the experiences of the oil companies — the isolation string and the requirement not to exceed fracture pressure. That is not only a regulation but like I said, a common practice with the operators because it is not a good thing to exceed fracture pressure in injection wells. I think it is highly likely that if anything, more constraints and regulations will come into effect or if nothing else, it will remain the same. The industries evolved to this point and because of this we are getting a lot more reserves out of the ground than we did back in the 40s and 50s. You know it is a learning process and I think the oil industry is reaching the top of that curve. They have come a long way.

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