PROPOSAL TO UNITIZE FOR SECONDARY RECOVERY OPERATIONS

DAGGER DRAW FIELD, EDDY COUNTY, NEW MEXICO

Prepared for:

YATES PETROLEUM CORPORATION

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INTRODUCTION

The Dagger Draw Field is located in Eddy County in southeast New Mexico and is one of the key oil and gas producing fields in the state (Figure 1). Yates Petroleum Corporation (Yates) is the principal operator in the field. The primary oil-producing horizon is the Pennsylvanian age Canyon dolomite at an average depth of 7,750 feet. As of September 2002, over 300 wells had been drilled with cumulative production in excess of 50 MMBO, 150 BCF, and 200 MMBW. The field is under primary production although a waterflood pilot was implemented in the southern part of the field with less than successful results.

The Dagger Draw field reservoir occurs within a patch reef complex that formed on the northwest shore of the Delaware Basin. The complex (including Dagger Draw and Indian Basin fields) is approximately 24 miles in length from south-southwest to north-northeast (Figure 1) and varies in width from 2.5 to 8.5 miles. The reefs formed in a sub- to intra-tidal near-shore regime. Deepwater shale and limestone occur to the southeast and higher energy shoreward facies occur to the northwest. The reservoir sequence includes porous dolomite and non-porous limestone. Shale beds occur low in the section over much of the field and interbedded throughout the section along the southeastern edge.

The porosity in the dolomite is reported as being the result of the primary fabric of the algal reef detritus. Dolomitization is the result of fluid movement through the porous facies. Because of the vuggy nature of the reservoir, it is believed that conventional log analysis may not adequately characterize the reservoir, and therefore it is difficult to estimate reliably the original oil in place. Other production abnormalities have also been observed in this field. Most notable are contrasting performance behavior of wells in close proximity, apparent loss of production potential of wells following a rate cutback, and the poor performance of the waterflood pilot study in the southern part of the field.

Yates has requested preparation of a proposal to inject produced water in a nine-section area of the Upper Pennsylvanian Canyon formation of the Dagger Draw Field in an effort to increase the recovery of oil above the currently projected 16.9 percent of original oil in place. As per Yates direction, the focus of the proposed project has been on a nine-section area including Sections 16, 17, 18, 19, 20, 21, 28, 29 and 30 of Township 19 South, Range 25 East in Eddy County, New Mexico. The study and its recommendations include work previously presented in several reports by The Scotia Group, Inc. (Scotia). These reports and their findings are included in this report by reference and not restated herein. The previous Scotia work generally focused on an area in size which is less than the nine sections discussed in this study and addressed petrophysical and flow unit characterization of the Upper Pennsylvanian Canyon formation along with material balance and numerical simulation studies of the reservoir.

This proposal contemplates conversion of 21 wells for water injection in an irregular pattern designed to mobilize oil in areas of the nine sections that have not experienced significant water production and are assumed to be part of the reservoir matrix not extensively connected with the more permeable (i.e., fracture or vugular) regions of the reservoir in the dual porosity system. The proposed implementation of the water injection project is set forth as two phases in an effort to minimize the impact on field production and operations. Phase 1 includes 13 injection wells and associated injection facilities and water distribution lines in Sections 18, 19, 20 and 30. Phase 2 includes eight injection wells and associated injection facilities and water distribution lines in Sections 16, 17, 21, 28 and 29.

CONCLUSIONS

- Ultimate recovery for the proposed nine-section waterflood area under primary conditions is estimated to be 16.9 percent of original oil in place.
- Performance to date suggests that injection into fracture or vugular porosity dominated areas (high cumulative production, significant water production) will only result in "cycling" of water between injection wells and producer wells with no meaningful incremental secondary oil recovery.
- It is proposed that water injection should focus on matrix porosity dominated areas (low cumulative production, low water production) in an effort to mobilize bypassed oil towards fracture and vugular porosity ("pipeline") areas in an effort to recover additional oil.
- An irregular pattern is recommended in order to properly locate injection wells in matrix porosity dominated areas relative to producing wells and optimize secondary recovery from the reservoir.
- Incremental recovery for Phase 1 and 2 <u>with no new drilling</u> is estimated to be 2.2 MMBO and 0.4 BCF net to unit ownership. These net incremental reserves have an undiscounted cash flow and present worth discounted at 10 percent of $22.9 MM and $15.6 MM, respectively. (See Table 9 and Figure 63)
- Incremental recovery for Phase 1 and 2 <u>with the drilling of seven new wells</u> is 2.9 MMBO and 1.1 BCF net to unit ownership. These net incremental reserves have an undiscounted cash flow and present

worth discounted at 10 percent of \$28.1 MM and \$18.0 MM, respectively. (See Table 12 and Figure 66)

- The "seven well drilling" case when compared to the "non-drilling" case is projected to recover 0.67 and 0.62 BCF additional reserves as a result of improved areal recovery and new well response based on the incremental forecasts and economics. Actual waterflood response and economics that exceed the current forecasts, however, may support future drilling.
- Additional upside may be demonstrated with expansion of the waterflood project beyond the nine section project area and with infill drilling to less than 40 acre well spacing.

RECOMMENDATIONS

The following recommendations are proposed for implementation of water injection for increased oil recovery in the Dagger Draw Field:

- Conversion of 21 wells for water injection (see attached Figure 2).
- Restoration of nine wells for production.
- Remedial well work to add/squeeze perforated intervals in 57 wells.
- Deferment of any new drilling pending evaluation of actual waterflood response.
- Additional core recovery operations for any future new wells in an effort to better describe and characterize the Upper Pennsylvanian Canyon Dolomite reservoir and understand the complex porosity-permeability inter-relationship of the reservoir and its impact on fluid production.
- Future construction of a detailed reservoir simulation model that captures the complexities of the Upper Pennsylvanian Canyon Dolomite reservoir in the nine-section waterflood area, incorporating data from all recently drilled horizontal wells, data from any future drilling operations, and actual reservoir performance.

1.0 FIELD STATUS REVIEW

Production within the reservoir sections of interest commenced in March 1971 from the Dagger Draw 30N No. 1 well, however, active field development was not initiated until 15 years later. In the nine sections of this study area, production peaked at over 13,000 barrels of oil per day (BOPD) in December 1995 and has declined rapidly to below 1,000 BOPD in January 2001. Initial reservoir pressure has also declined from approximately 3,000 psi to a current level of 500 to 700 psi. A total of 115 wells have been drilled in the nine-section study area.

The combined producing rate for the Dagger Draw Field for the nine sections of interest as of September 2002 was 623 BOPD, 3,997 MCFD and 6,353 BWPD. Currently there are 94 active wells producing from the Upper Pennsylvanian Canyon Dolomite in the nine-section area. The combined field producing rate in the nine sections of interest after conversion of 21 wells for water injection is anticipated to only decrease by approximately 100 BOPD. This producing rate does not include anticipated production increases from wells restored to production or drilled for production along with response to the water injection operations.

2.0 RESERVOIR CHARACTERIZATION

2.1 Geology

2.1.1 Discussion

The structure of the region dips southeastward into the depositional basin. Although true structural closures do not emanate on the top of the Canyon carbonate interval (Figure 3), local structurally high closure can occur due to the occurrence of porous dolomite high in the section surrounded by non-porous rock. Three structure maps across the nine-block area are included for reference (Figures 3, 4, and 5). Figure 3 is a map on the top of the Canyon Limestone and shows nearly monoclinal southeast dip at about 1 to 1.5 degrees. Figure 4 shows the top of the dolomitized layer. Although the general southeast dip is evident, the surface is much more irregular than the limestone top. The dolomite unit ranges in thickness from 150 feet in the northwest portion of the unit area to almost 400 feet in a strike-trending band in the southeast portion (Figure 7). This layer is overlain by an impermeable limestone (Canyon Limestone) ranging in thickness from a few feet to over 150 feet (Figure 6).

These rocks have been deposited in a series of shallowing upward cycles capped by marine flooding surfaces (parasequences). In various cored wells across the field area, between 27 and 39 parasequences were interpreted in intervals ranging from 203 to 262 feet. On average, the parasequences are seven feet thick for wells situated in an updip position. These parasequences thicken off-structure as evidenced by the core taken in the Dagger Draw 31 Federal No. 7 well. In this well, eight parasequences were interpreted in 117 feet of analyzed core resulting in a 15-foot average thickness. Figure 8 shows a similar set of sequences in outcrop for a scale perspective. Four primary lithofacies are observed within these parasequences reflecting water depth and overall energy of depositional environment. These lithofacies, illustrated in a general sense in Figure 9 and 10, are described below.

2.1.2 Lithofacies

The base of the parasequence is often marked by a thin, dark, fissile shale. These shales range in thickness from 1 inch to 3 feet and reflect a deepwater basinal environment. Stagnant (low energy), anoxic conditions and a low sedimentation rate lead to thin beds with a scarcity of fossils. Little or no reservoir potential exists in these beds.

Overlying the basinal shales are fossiliferous mudstones and wackestones. These rocks range from 6 inches to 35 feet in thickness and are roughly 75 percent dolomitized in the cored intervals across the area. The wide diversity seen within the fossil assemblage and abundance of burrowing structures reflect well-oxygenated, normal marine conditions updip of the basinal facies. This lithofacies is often the deepest water environment within a given parasequence, as the basinal shales are not always observed. Little visible intergranular pore space was reported in core observations, however, occasional moldic pores and irregular vugs are noted. These rocks are generally considered to be of marginal reservoir quality with porosity averaging 2.1 percent and permeability of 1.8 millidarcies.

Above the wackestone facies are algal boundstones ranging from 6 to 32 inches thick. These stromatolitic buildups are 100 percent dolomitized. They are usually laminated and display fenestral porosity oriented parallel with the bedding surface. Columnar growth, however, is not uncommon. Solution enhancement of the fenestral voids creates sizable vugs. Vertical solution fractures noted in these rocks help interconnect isolated framework pores. These deposits have been interpreted as algal bank bioherms that developed in a tropical to subtropical, shallow water, subtidal environment. This lithofacies is considered to have the highest reservoir quality within the sequence. Porosities from core measurements average four percent and permeability averages 9.3 millidarcies.

Generally overlying the algal boundstones are grainstones composed of locally derived shell fragments and in-situ ooids. These rocks display primary intergranular porosity as well as moldic, vugular and dissolution fracture secondary porosity. They are indicative of a shallower water, higher energy environment updip of the algal reefs. The increased wave and tidal action of this intertidal position winnowed out clay particles and enhanced formation of ooid grains. Reservoir quality is almost as high as the underlying algal boundstones. Porosity and permeability averages 4.5 percent and 5.9 millidarcies, respectively. Where it is observed, this lithofacies represents the top of the parasequence and will be overlain by a basinal shale or open shelf wackestone or mudstone.

2.1.3 Depositional Model

The dolomite reservoir that comprises Dagger Draw Field was deposited on a low relief slope off the southeastern edge of the northwest shelf as it ramped into the northwestern margin of the developing Delaware Basin. This shallow water, tropical shelf environment allowed late Pennsylvanian and Permian age reefs and algal banks to prograde into the basin and help form the current basin edge. The algal bank boundstone and intertidal shoal grainstone trends in this field are an example of reef progradation that occurred in late Pennsylvanian time.

In the deepest water portion of the sequence, thin laminated shales were deposited as clay particles settled from suspension in stagnant, reducing conditions.

Updip of the basinal facies, quiet water normal marine conditions prevailed. Well-oxygenated water allowed for a wide diversity of observed fossil fragments and burrow structures. The mud supported wackestones and mudstones were deposited in this open shelf environment.

Further updip along the open shelf, stromatolitic and phylloid algae formed broad algal banks in elongate bodies that paralleled the shoreline. The algal boundstone reservoir trend documents this environment. These boundstones are found in every parasequence indicating these reef buildups were continuous in nature. Their pronounced thickness in certain parasequences is indicative of a gradual rise in sea level that allowed the vertical aggradation of the reef to keep pace.

Updip of the reef trend, algal bank growth is hindered in the higher energy intertidal zone due to increased wave action, higher sedimentation rates and intermittent subaerial exposure. This environment produced the grainstone lithology generally observed above the reef deposits. As in the algal reef trend, the grainstone facies was deposited in linear strike-oriented belts. The algal boundstones and intertidal grainstones are often found thinly interbedded with each other, indicating these two environments were likely closely associated and may only be separated by a few feet in water depth. The relatively thin nature of these deposits indicates this high energy, low sea level environment was probably short-lived.

2.1.4 Observations

The depositional model described above clearly results in a changing facies, and hence, changing lithology along a common time horizon. Time horizons dip from northwest to southeast into the depositional basin. Along this horizon, observed lithology will change from grainstones to boundstones, then to wackstones, mudstones and, finally, to thin basinal shales. As the cycles repeat following marine flooding events, the shallow water grainstones and boundstones prograde basinward as they build on older reefal deposits (Figure 11). Consequently, wells drilled in an updip position will encounter the favorable shallow water facies in older deposits than wells drilled further into the basin. Also, correlation of like facies in a dip direction will result in a surface that climbs relative to the actual time surface. As such, the top of the Cisco-Canyon Limestone surface is itself likely a time transgressive surface.

Having stated this, however, it must be noted that field-wide boundaries are not apparent from the log data. Rather, non-porous rocks indicative of high-stands, while appearing to occur at a relatively consistent depth, do not form continuous widespread boundaries to vertical flow. Facies indicative of low-stand could not be delineated from logs. The general impression gained from correlations in the area is that the reservoir architecture is controlled primarily by the patch-reef morphology and not regional sequence tracts.

As stated earlier, facies belts in this setting are related to water depth at the time of deposition and are generally deposited along strike. Production patterns in Dagger Draw Field tend to mimic the trend of reefal facies. Maps of cumulative oil production (Figure 15), cumulative gas production (Figure 16), cumulative water production (Figure 17), cumulative total fluid production (Figure 18), and Ø·h (i.e., porosity x thickness) (Figure 12) reveal three distinct belts of high production associated with increased section of porous rock trending northeast to southwest parallel to the edge of the Delaware Basin. These distinct belts of high production would likely correspond to areas dominated by shallow water facies (grainstone/boundstone) of differing age. Narrower avenues dominated by open shelf wackestones and mudstones separate these belts.

It is commonly accepted and demonstrated that the shallow water facies provides the superior reservoir rock in both primary and secondary porosity and permeability. These areas dominated by reefal and intertidal deposition would clearly be the preferred focus areas of exploratory activity.

Oil production within these zones has been substantially higher than that seen in the areas dominated by open shelf deposition. However, copious amounts of water production accompany this higher oil production. From this, it would seem that the pore space in this portion of the reservoir has been pervasively swept at this mature stage. It does not seem likely that injecting additional water into this higher porosity portion of the formation would result in any appreciable additional oil production. The large amount of water production indicates a substantial aquifer is connected with the pore space network in the higher productivity zones. Injection of water into these zones would result in sweeping of areas already exposed to substantial water flow while pumping water back into the source aquifer only to be produced again later. Any potential to mobilize additional oil would occur within the lower permeability areas dominated by wackestones and mudstones. Scotia's waterflood strategy is to focus water injection in these lower porosity and permeability areas in an attempt to move oil into the porosity network utilized by the higher productive wells. The injection pattern that results is geometrically irregular and is driven by relative well performance across this mature oil field.

2.2 Engineering

Material balance calculations for the entire field indicate substantial original oil in place of approximately 250 million barrels of oil. When reviewing the pressure data associated with the material balance study, pressure measurements of approximately 85 to 90 percent of estimated original reservoir pressure were observed after more than 50 million barrels of oil were produced. Later pressure observations in these same wells, one to two years later, showed pressure measurements of less than 30 percent of estimated original reservoir pressure. From this rapid decline in measured reservoir pressure, it can be inferred that more than one system of porosity and permeability may control the flow of oil, gas and water in the reservoir. This is consistent with the dual porosity reservoir system as described in core reports which was a necessary assumption for history matching in the previous Scotia reservoir simulation work.

While over 50 MMBO have been produced from approximately 300 wells from the entire Dagger Draw Field, overall recovery as a percent of original oil is only about 21 percent. The original reservoir pressure was approximately 3,037 psia and it is believed that free gas existed when the field was first developed. Later work done to recommend a North Waterflood Pilot Study by Scotia estimated the initial gas saturation to be four percent. A special core study provided the relative permeability relationship of oil and water and the estimate of initial water saturation is observed at 30 percent. The original reservoir properties used in this report are summarized in the following table:

Average Reservoir Properties For Dagger Draw Field		
Oil Saturation		66 %
Water Saturation		30 %
Original Gas Saturation		4 %
Reservoir Temperature		130 °F
Reservoir Pressure		3,037 psia
Porosity		7.6 % mean (5.7-27.4)
Permeability		<.06 - > 1,000 md.
Oil-Water contact		-4,380 ft
Formation Volume Factor		1.4965 Res bbl/STB

The remaining discussion of reservoir performance is focused on the nine-section waterflood area identified by Yates for improved recovery operations.

2.3 Geocellular Modeling

In an effort to aid in identifying injection locations, a grid of 24 cross-sections across the nine sections of interest (Figure 30) was generated from Scotia's previously developed Geocellular Model. The Geocellular Model was based on petrophysical analysis and correlation of porosity trends computed from neutron-density cross-plots within the Canyon Dolomite. Further detail on construction of this model is contained in previous reports by Scotia regarding Dagger Draw Field (References 3 and 5).

Twelve cross-sections oriented north-south and twelve cross-sections oriented east-west were used in the analysis. Performance trend maps (see Figures 15 through 29) were then developed relating to cumulative production (oil, water and gas), current rate (oil, water and gas) and gas-oil ratio. These performance trend maps were then reviewed in conjunction with the Geocellular Model cross-sections along with perforation and pressure data in an effort to arrive at what Scotia considers to be optimum injection locations within matrix porosity dominated areas.

Several of these cross-sections are discussed below for reference and illustration. Cross-section DDNS2 (Figure 32) is extracted from the western portion of the proposed unit area. This section shows three proposed injectors and two proposed drill sites. Note that one drill site is flanked by two proposed injectors. The next drill location to the north shows good apparent porosity connectivity with the proposed injector one location south.

Figure 34 shows cross-section DDNS4 extracted along well locations on the eastern edge of Sections 18, 19, and 30. Six Phase 1 proposed injector locations occur on the cross-section which is situated within a generally lower porosity, lower oil productivity corridor (Figures 12 and 15).

Figure 38 shows cross-section DDNS8 along well locations on the eastern edge of Sections 17, 20, and 29. Two proposed drill sites and three proposed injectors are shown on the cross-section. The open location in the northeast quarter of the southeast quarter of Section 17 (Location 17I) is flanked by three proposed injectors (all Phase 2) and would be necessary for improved sweep efficiency. The Phase 1 proposed injector in the northeast quarter of the southeast quarter of Section 20 (Location 20I) is shown to occur in a generally low porosity area flanked by higher porosity wells. The proposed drill sites in the southeast quarter of the southeast quarter of Section 29 (Location 29P) is situated at the edge of the proposed unit and would be drilled to prevent oil from being swept out of the unit area.

Figure 48 shows cross-section DDEW6 through the center of the unit area in Sections 19, 20, and 21. One proposed drill site and three proposed injectors are situated on this line. The drill location in the northeast quarter of the southwest quarter of Section 19 (Location 19K) is in an area of apparent good porosity and should be in an optimum location to recover oil from the injector located one location south. Porosity degradation at the locations of the three proposed injectors is also apparent.

Figure 51 shows cross-section DDEW9 along the southern edge of Sections 16, 17, and 18. One drill location and three injectors (all Phase 2) are situated on the cross-section. The drill location in the southwest quarter of the southeast quarter of Section 17 (Location 17O) is adjacent to two proposed injectors and is shown as having good apparent connectivity with those locations. Once again, generally lower porosity is noted at the injector locations.

The cross-section north of cross-section DDEW9, DDEW10, shows three Phase 2 drill sites, one Phase 1 injector, and one Phase 2 injector. The drill locations in the northwest quarter of the southeast quarter of Section 16 (Location 16J) and the northwest quarter of the southwest quarter of Section 16 (Location 16L) are each adjacent to two proposed injectors not shown on this section. The proposed drill site in the northeast quarter of the southeast quarter of Section 17 (Location 17I) is adjacent to three injectors.

3.0 RESERVOIR PERFORMANCE

3.1 Primary Recovery

Table 1 presents for each well in the nine-section area various historical production data. The cumulative production and current producing rate information in Table 1 is as of April 2002 and does not reflect any subsequent work undertaken by Yates since that time.

As described in previous work by Scotia, reservoir description through the use of conventional log analysis is difficult. Core data is limited and therefore does not provide any better reservoir parameters for determining the original oil in place by volumetric methods. For the waterflood area in this study, porosity-thickness (Ø·h) values were computed for each well for which log data was available. A cut off of four percent porosity was used to determine the net Ø·h for each well. The resulting pore volume above the oil-water contact at 4,380 feet subsea true vertical depth was then estimated at 42,407.17 acre·Ø·h. Using the fluid properties at initial conditions, the original oil in place was then estimated to be 145.1 million stock tank barrels. Cumulative production at the end of September 2002 for the waterflood area was 24.3 MMBO or 16.7 percent of the original oil in place. Based on current trends and operations, the remaining primary production gross reserves are estimated to be 0.28 MMBO and 1.8 BCF (Table 6 and Figure 60). Therefore only 16.9 percent of the original oil in place in the waterflood area is projected to be recovered under primary production leaving more than 100 MMBO in place which can be targeted for improved recovery operations.

As noted previously when reviewing the pressure data associated with the material balance study of the full field, pressure measurements were observed in numerous wells that were 85 to 90 percent of the original reservoir pressure after almost 50 MMBO were produced. Later pressure observations in these same wells, one to two years later, showed recorded pressures of less than 30 percent of the estimated original pressure. This rapid decline in reservoir pressure would tend to support a dual porosity-permeability reservoir system that is described in the core reports and was a necessary assumption in obtaining an acceptable history match in the reservoir simulation study work performed by Scotia (Reference 5) covering a portion of the proposed nine section waterflood area presented in this report.

Therefore, when contemplating enhanced or improved recovery operations in the Dagger Draw Field, this dual porosity-permeability system must be considered in the design and implementation of the program. It should also be noted that many wells have produced significant volumes of water based on a review of historical production for each well. To better understand the historical field performance, maps of cumulative oil, cumulative water, cumulative total fluid (oil and water) and gas-oil ratio were prepared (Figures 15 through 29). These maps show areas of varied historical performance, which is not inconsistent with the expectations as described by the geologic model and detailed core studies. An important observation is that areas of the waterflood area that produced lower cumulative volumes of oil also tended to produce less associated water. These areas are interpreted to be in the lower porosity-permeability system in contrast to the areas of higher cumulative oil and water production which are interpreted to be in the fracture or vugular porosity dominated areas of the reservoir.

The drive mechanism for the Upper Pennsylvanian Canyon Dolomite reservoir is considered to be a partial water drive, especially since the reservoir pressure has declined substantially. The current average reservoir pressure has been estimated to be 800 psia as determined in the previous Scotia material balance study (Reference 2). However, a seemingly unlimited source of water appears to be connected to the reservoir based on the 80.6 MMBW that has been produced with the cumulative oil production of 24.3 MMBO. Additionally, water production associated with the current field operations does not appear to be declining. This would re-enforce the seemingly limitless water source connected to the reservoir. Again, as noted on the historical performance maps, not all portions of the waterflood area have performed in the same manner. These observations substantiate a lower porosity-permeability system associated with lower fluid recovery in contrast to the areas of higher cumulative oil and water production which are interpreted to be in the fracture or vugular porosity dominated areas of the reservoir.

3.2 Performance of South Dagger Draw Pilot

A production history review was made of public domain production data obtained for the pilot line drive waterflood program in the southern part of Dagger Draw in Sections 14 and 23 of T20S-R24E. Injection volumes for the four converted north to south line injectors together with two well spacings of producers were examined. A dramatic response was observed in all offset wells to the four injectors. Essentially, the offset producers demonstrated significant water production increase within 12 months of commencement of injection. With one exception, the Hillview AHE Federal No. 13 well, the increase in water production in each well was accompanied by a decrease in oil production. The important point to note here is that this phenomenon (i.e., increase in water production) occurred in every well surrounding the four north to south line injectors.

A review of wells other than direct offset wells to the four injectors also indicated an increase of water production in significant quantities as well. In response to the increasing water production in these offset wells beyond the first offset to the injection wells, the injection volumes were decreased by the operator based on the expectation of continued increased water production without a corresponding increase in oil production.

From the observed performance histories of the wells in the South Dagger Draw waterflood area, there appears to be an effective conduit for water between wells with no clear distinct bias in direction. Additionally, while there may have been mechanical reasons associated with the decrease in oil production once significant water production was experienced in the wells offset to the injectors, it could suggest that increased reservoir pressure as a result of the injected water is inhibiting the mobilization of oil in the matrix.

4.0 SECONDARY RECOVERY FORECAST

4.1 Discussion

Based on the geologic model and reservoir performance to date, a program to improve oil recovery is proposed focusing on portions of the reservoir that have produced lesser volumes of oil and water and are interpreted to be in the matrix porosity dominated areas of the reservoir system. The proposed water injection program has been divided into Phases 1 and 2. Phase 1 covers 13 injection wells and associated injection facilities and water distribution lines for Sections 18, 19, 20 and 30. Phase 2 covers eight injection wells and associated injection facilities and water distribution lines for Sections 16, 17, 21, 28 and 29. The Phase 1 and 2 plans reflect an orderly implementation of remedial well activity and installation of injection facilities for the more than 115 wells that have been drilled in the waterflood area to date.

As discussed previously, Table 1 presents for each well in the nine-section area various historical production data and a brief comment of recommended action for implementation of the proposed waterflood. It is anticipated that initial average water injection rates would range from 2,000 to 5,000 barrels of water per well per day based on the previous reservoir simulation work performed by Scotia. The actual volumes of water injected will be dependent on bottomhole pressure constraints such that the fracture gradient is not exceeded. It should be noted that a detailed study of each well's historical records and mechanical condition has been performed by Yates. For implementation of secondary recovery operations, Yates has provided various cost estimates for remedial work of existing wells including conversion of 21 wells for injection, water injection facilities and water distribution lines. These costs are discussed in the economics section of this report (Section 6.0).

Various methods were considered to project incremental oil recovery resulting from water injection operations. However, as discussed previously, reservoir characterization is difficult and detailed data is limited. It is felt that a full reservoir simulation study at this time would not necessarily provide a better result than a conventional Dykstra-Parsons approach given the available data. Therefore, a ten-layer Dykstra-Parsons model has been used based on the core data from six wells in the Dagger Draw Field. The formulation and relevant assumptions of the model are discussed in the next section. The projected volumes of oil from the Dykstra-Parsons model are felt to represent the most likely incremental oil recovery from water injection operations and are consistent with the incremental recovery projections from previous reservoir simulation work performed by Scotia (Reference 5) in other areas of the Upper Pennsylvanian Canyon formation.

4.2 Secondary Recovery Model

A Dykstra-Parsons model has been constructed for both the estimation of incremental oil and the projection of that oil over time. The model assumes piston displacement (i.e., each barrel of water injected displaces a constant equivalent fraction volume of oil) of the oil by water in a linear displacing process. The total reservoir thickness for an injection pattern is based on the thickness computed for the injection well and is assumed constant over the injection pattern pore volume. The pore volume for each injection pattern was computed based on the pore volume map. An areal sweep factor has been computed for each injection pattern based on producing well locations. The sweep factor is defined as the ratio of the volume of the reservoir swept by injected water at any time to the total volume of the reservoir subject to injection. Figure 58 shows the computed areal sweep factors for each pattern for the existing wells. Figure 59 shows the computed areal sweep factors for each pattern for the infill wells. Ten layers of equal thickness are assumed and the permeability for each layer was varied based on core data from the six wells as shown in the table below:

	Permeability, md					
Layer	**Dagger Draw #12**	**Saguaro #8**	**Barbara #12**	**Cooper AHH #1**	**Barbara #2**	**Ocotillo #1**
1	79.80	184.0	318.0	25.00	49.0	20.0
2	9.98	8.1	13.2	4.10	11.0	3.1
3	1.81	4.6	3.2	1.00	7.6	1.4
4	0.89	2.8	1.2	0.46	1.3	0.7
5	0.52	1.4	0.6	0.29	0.8	0.3
6	0.36	0.8	0.5	0.17	0.4	0.2
7	0.19	0.4	0.2	0.07	0.3	0.1
8	0.12	0.3	0.2	0.03	0.2	0.1
9	0.09	0.1	0.1	0.02	0.1	0.0
10	0.06	0.0	0.1	0.01	0.1	0.0

A delay time was computed simplistically as the time equal to inject a volume of water equivalent to the volume of gas in the injection pattern assuming a current gas saturation of 12 percent. The estimation of a 12 percent gas saturation was determined in the Scotia report entitled "North Pilot Water Injection Recommendation" (Reference 4). The current water saturation was estimated to be 44 percent in this same report (Reference 4). Incremental oil recovery and the rate projections are based on 2,500 barrels of injected water per day in each injection pattern.

Because of the wide variability of the permeability data exhibited from core analysis coupled with the fact that all wells have produced water, the projected oil recovery from the highest permeability layer (layer 1) in the Dykstra-Parsons calculations was not included in the projected incremental recovery. It is assumed that the produced water to date would have preferentially swept this high permeability zone. The projected incremental oil from the ten-layer waterflood model is the average of the six cases and therefore excludes any response associated with the highest permeability layer defined by the Dykstra-Parsons variance. Table 2 summarizes the incremental oil recovery for each of the water injection patterns for the existing field development case (i.e., no new wells). Table 3 summarizes the incremental oil recovery for each of the water injection patterns for the expanded field development case (i.e., seven new wells). The tables also describe the variability of pattern area, porous acre-feet, injection well thickness, average porosity greater than four percent, allocated cumulative production, recoverable original oil in place for an injection pattern, area sweep factor and estimated current remaining original oil in place.

5.0 WATERFLOOD DESIGN AND IMPLEMENTATION

5.1 Phase 1

Phase 1 is the first phase of implementation and includes 13 injection wells in Sections 18, 19, 20 and 30 as shown in Figures 58 and 59. Phase 1 implementation also includes the drilling of two wells, which are targeted for patterns located in the northeast quarter of the southwest quarter of Section 19 (Location 19K) and in the northeast quarter of the northwest quarter of Section 30 (Location 30C). For each injection pattern, the acreage and the areal sweep factor are shown in Table 2, based on current wells, and in Table 3, which includes the benefit from the drilling of new wells. The projected response of future rates of oil production over a ten-year period for Phase 1 is shown in Table 4. Gross incremental recoverable oil for Phase 1 over a ten-year period is estimated to be 2.2 MMBO without drilling and 2.4 MMBO with the drilling of two infill wells. These volumes of incremental oil are before consideration of the impact of net revenue ownership and operating cost burden.

5.2 Phase 2

Phase 2 is the second phase of implementation and includes eight injection wells in Sections 16, 17, 21, 28 and 29 as shown in Figures 58 and 59. Phase 2 implementation also includes the drilling of five wells which are targeted for patterns in the northwest quarter of the southeast quarter of Section 16 (Location 16J), the northwest quarter of the southwest quarter of

Section 16 (Location 16L), the northeast quarter of the southeast quarter of Section 17 (Location 17I), the southwest quarter of the southeast quarter of Section 17 (Location 17O) and the southeast quarter of the southeast quarter of Section 29 (Location 29P). For each injection pattern, acreage and the areal sweep factor is shown in Table 2, based on current wells, and in Table 3, which includes the benefit from the drilling of new wells. The projected response of future rates of oil production over a ten-year period for Phase 2 is shown in Table 5. Gross incremental recoverable oil for Phase 2 over a ten-year period is estimated to be 1.1 MMBO without drilling and 1.4 MMBO with the drilling of five infill wells. These volumes of incremental oil are before consideration of the impact of net revenue ownership and operating cost burden.

6.0 ECONOMICS

The waterflood plan has been divided into two parts, with Phase 1 consisting of injection in Sections 18, 19, 20 and 30 in T19S R25E, followed by Phase 2 which consists of injection in Sections 16, 17, 21, 28 and 29. The following table summarizes the cost estimates prepared by Yates for Phase 1 and Phase 2:

Costs Estimated for North Dagger Draw Waterflood

	Phase 1 $MM	Phase 2 $MM	Total $MM
Prepare existing wells for waterflood	3.26	2.82	6.08
Drill new producing wells	1.73	4.33	6.06
Install water injection lines	0.32	0.20	0.52
Install water injection facilities	0.45	0.37	0.82
Total	5.76	7.72	13.48

Additional information used in the economic analysis of the waterflood project and unit operations is summarized in the following table:

Working Interest		100 %
Net Revenue Interest		83.0 %
Oil Price		$25 /barrel
Gas Price		$2.50 MCF
Operating Cost		$2,600 /well/month
Water injection cost		$0.06 /bbl
Produced water handling cost		$0.02 /bbl
Water supply cost		$0.05 /bbl

For purposes of the economic projection, all costs and prices have been scheduled without escalation in future years. The effective date for the economic forecasts is January 1, 2003. Phase 1 and Phase 2 water injection have been scheduled to commence on July 1, 2003 and July 1, 2005, respectively.

Summarized in the table below are the results of the reserves evaluation and economic analysis for the primary production case as compared with the projections for Phase 1 and 2. Separate cases are shown for no new drilling versus the drilling of additional wells as previously discussed. Reserves and economics for Phase 1 are incremental to the primary production case. Likewise, Phase 2 reserves and economics are incremental to the combined Phase 1 and primary production cases. The production forecasts and economic schedules corresponding to the results summarized below are shown in the Tables and Figures indicated.

Without Drilling

Case	Net Reserves	Undiscounted Cash Flow	Present Worth Disc. @ 10%	Reference
Primary	0.23 MMBO 1.54 BCF	$ 5.47 MM	$ 4.57 MM	Table 6, Figure 60
Phase 1	1.52 MMBO 0.30 BCF	$17.98 MM	$ 13.11 MM	Table 7, Figure 61
Phase 2	0.72 MMBO 0.14 BCF	$ 4.90 MM	$ 2.53 MM	Table 8, Figure 62
Total	**2.47 MMBO 1.98 BCF**	**$28.35 MM**	**$20.21 MM**	--

With Drilling

Case	Net Reserves	Undiscounted Cash Flow	Present Worth Disc. @ 10%	Reference
Primary	0.23 MMBO 1.54 BCF	$ 5.47 MM	$ 4.57 MM	Table 6, Figure 60
Phase 1	1.80 MMBO 0.54 BCF	$20.19 MM	$14.16 MM	Table 10, Figure 64
Phase 2	1.11 MMBO 0.52 BCF	$ 7.94 MM	$ 3.87 MM	Table 11, Figure 65
Total	**3.14 MMBO 2.60 BCF**	**$33.60 MM**	**$22.60 MM**	--

The "seven well drilling" case when compared to the "non-drilling" case is projected to recover 0.67 MMBO and 0.62 BCF additional reserves as a result of improved areal recovery and new well response based on the incremental forecasts and economics. Actual waterflood response and economics that exceed the current forecasts, however, may support future additional drilling. As shown in the costs provided by Yates, the cost of drilling seven new wells is 45 percent of the estimated total cost of the entire project. The need for these new wells plus additional wells should be carefully evaluated for cost effectiveness coupled with evaluation of waterflood response. Additional measures to reduce or delay costs and possibly improve incremental recovery by lowering the economic limit could include the following:

- Delay conversion of some of the injection wells in Phase 2.
- Delay drilling of new wells.
- Use existing low-pressure transfer pumps at the beginning of the waterflood until injection wells pressure up.
- Reuse high-pressure pumps from the Sawbuck pilot when necessary.

7.0 QUALIFICATIONS AND LIMITATIONS

7.1 Independence and conflict of Interest

This report has been prepared by The Scotia Group. Scotia is an independent oil and gas advisory firm headquartered in Dallas, Texas. All evaluations performed by Scotia are strictly fee-based and Scotia has not and will not receive any benefit, which may be regarded as affecting its ability to render an unbiased opinion on the petroleum interests held by Yates.

7.2 Use of this Report

This report has been prepared exclusively for Yates and should not be duplicated or distributed to any third parties without the express written consent of Yates and the Scotia Group, except as required by law.

7.3 Available Data

This study was based on data supplied by Yates, on public domain information and on nonproprietary data from in-house files. The supplied data was reviewed for reasonableness from a technical perspective. As is common in oil field situations, basic physical measurements taken over time cannot be verified independently in retrospect. As such, beyond the application of normal professional judgment, such data must be accepted as representative. While we are not aware of any falsification of records or data pertinent to the results of this study, Scotia does not warrant the accuracy of the data and accepts no liability for any losses from actions based upon reliance on data, which is subsequently shown to be falsified or erroneous.

7.4 Professional Qualifications

Scotia personnel who prepared this report are degreed professionals with the appropriate qualifications and experience to complete the project brief. Scotia and its staff do not claim expertise in accounting, legal and environmental matters, and opinions on such matters do not form part of this report.

7.5 Reserves Estimates

Reserves estimates were made using extrapolation of performance trends and other accepted engineering methods as described within. The estimates were made in accordance with the 1997 oil and gas reserves definitions as endorsed by the SPE. The reserves definitions allow for changes in category as information is gathered and as producing history is accumulated. As such, the volume and class of reserves is expected to change and be revised with time.

Net oil and gas reserves are those estimated quantities of crude oil, natural gas and natural gas liquids attributed to the evaluated interests (after deduction of applicable royalties and overriding royalties) that are considered to be economically recoverable under the economic conditions modeled. It is implicit that good oil field practices are maintained in order to effect recovery of the estimated reserves.

7.6 Future Net Revenue Estimates

Future net revenue estimates are based upon the estimated future production profile and future prices for oil and gas adjusted for capital expenditure, operating costs, interest reversions and severance and ad valorem taxes, but without consideration of any federal income tax liability or any other types of encumbrance that might exist against the evaluated interests. The estimates do not include the salvage value for the leases or the cost of abandonment and site restoration. The present worth of future net revenues reflects the application of certain discount factors and does not represent an estimate of fair market value for the properties.

Future net revenue and present worth of future net revenue estimates are representative of the pricing scenarios that have been modeled. Such estimates should not be construed as exact quantities. Future production rates, product prices, operating costs and revenues from the sale of petroleum products could differ from the estimates presented.

7.7 Conclusions

Scotia cannot attest to the validity or correctness of the ownership information provided by Yates and such an opinion does not form a part of this report. Cost parameters and operating cost data were supplied by Yates. This report is restricted to an independent engineering estimate of reserves and the future estimated cash flows. It is not the intention or purpose of this report to comment on title, ownership or legal encumbrances, and commercial or business relationships or sunk costs involved in acquiring the properties.

7.8 Field Visit and Inspection

No field visit to the properties, which are the subject of this report, has been made. As is customary in this type of evaluation, a field visit was not considered necessary. As such, Scotia is not in a position to comment on the state of operations or that such operations are in compliance with any state or federal regulations that may apply to them.

7.9 Liability Waiver

This report has been prepared on a best efforts basis to address the requirement of the brief specified by Yates. The results and conclusions represent informed professional judgments based on the data available and time frame allowed to perform this work. No warranty is implied or expressed that actual results will conform with these estimates. Scotia accepts no liability for actions or losses derived from reliance on this report or the data on which it was based.

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Summary Table
Well Recommendations
Dagger Draw Field

Location	Well Name	Cum. Production Oil (MBO)	Cum. Production Gas (MMcf)	Cum. Production Water (MBW)	Current Rate Oil (BPM)	Current Rate Gas (Mcf/M)	Current Rate Water (BPM)	Recommendation	Notes
16A	Boyd X Com #1	106	191	503	34	553	2,652	Produce	North edge of unit; Good unperf'd lower porosity
16B	Aparejo 'APA' State #3	266	419	1,092	0	336	0	Produce	North edge of unit; Good unperf'd lower porosity; High cum. oil & water
16C	Aparejo 'APA' State #5	167	757	1,290	648	3,714	5,934	Produce	North edge of unit; High cum. water; High current rate
16D	Aparejo 'APA' State #1	313	638	908	295	1,894	4,525	Produce	North edge of unit; High current rate
16E	Not Drilled								
16F	Aparejo 'APA' State #2	75	222	1,701	26	442	4,296	Possible Injector	High water - Yates recommended injector
16G	Not Drilled								
16H	Boyd X State Com #12	66	121	571	23	507	8,772	Produce	East edge of unit; Perf'd in middle section only; Unper'd porosity in upper & lower section
16I	Amole 'AMM' State #4	55	122	129	376	1,645	872	Produce	High Current Rate; East edge of unit
16J	Not Drilled								
16K	Amole 'AMM' State #2	138	298	2,510	355	962	18,579	Produce	High Current Rate: Very high cum. water
16L	Not Drilled								
16M	Amole 'AMM' State #1	89	183	855	266	702	1,574	Produce	Marginally high current rate; Perf'd in upper section only; Good unperf'd porosity in middle & lower section
16N	Amole 'AMM' State #3	31	44	290	0	3	0	Injector	Low Cum. - Overall low calculated porosity, but decent unperf'd porosity in middle section.
16O	Boyd X State Com #10	92	287	124	191	1,655	274	Injector	Low cum. - Perf'd intervals show relatively high calculated porosity.
16P	Boyd X State Com #11	77	219	146	312	990	584	Produce	East edge of unit; Basal porosity not perf'd.
17A	Julie #3							Recomplete as producer	North Edge of unit - Not perf'd in Canyon. Need to add Canyon perfs to receive sweep. Proposed injector one location south.
17B	Julie #2	181	369	104	186	981	428	Produce	North edge of unit
17C	Jenny Com #2	61	278	133	249	287	268	Produce	North edge - Relatively high rate
17D	Not Drilled							Drill as producer	North edge of unit; Need location to receive sweep
17E	Jenny Com #1	32	292	1,184				Possible injector	Relatively high water producer; Extensively perf'd with high overall calculated porosity.
17F	Barbara Federal #3	229	347	1,006				Reactivate as producer	Temp. Abn. - High cum. oil & water; Very small perf'd interval; Need to reactivate & add perfs to receive sweep.
17G	Dagger Draw A #1	206	361	302				Produce	Last prod 2/02. High overall calculated porosity. Yates recommended injector.
17H	Julie Com #1	65	159	362				Injector	Temp. Abn. - Good calculated porosity in middle & lower section, but lower section is not perf'd.
17I	Not Drilled							Potential producer	This location is surrounded by 3 recommended injectors. Once the ability to mobilize oil is established, this location should be drilled to receive the sweep.
17J	Barbara Federal #7	31	210	303				Injector	Temp. Abn. - Perf'd in middle section only; Need explore adding perfs in a substantial section of high calculated porosity in basal portion.
17K	Barbara 17 SW Co #17	150	364	167	428	2,140	522	Produce	High current rate.
17L	Barbara Federal #4	215	319	422				Reactivate as producer	Good calculated porosity in perf'd intervals.
17M	Barbara 17 SW Co #10	160	241	252	275	639	410	Produce	High current rate. Could add perfs in lower section. Yates recommended injector.
17N	Not Drilled								
17O	Not Drilled							Potential producer	This location is adjacent to 2 recommended injectors. Once the ability to mobilize oil is established, this location should be drilled to receive the sweep.
17P	Barbara 17 SE Co #18	30	93	56	64	288	124	Injector	Low cum. - Extensivley perf'd in upper section, but could add perfs in lower.

Summary Table
Well Recommendations
Dagger Draw Field

Location	Well Name	Cum. Production Oil (MBO)	Cum. Production Gas (MMcf)	Cum. Production Water (MBW)	Current Rate Oil (BPM)	Current Rate Gas (Mcf/M)	Current Rate Water (BPM)	Recommendation	Notes
18A	Conoco Com #1	259	425	414	1,009	4,225	1,377	Produce	North Edge - High current rate
18B	Not Drilled								
18C	Not Drilled								
18D	Not Drilled								
18E	Not Drilled								
18F	Barbara 18 NW Federal #16	0	0	7				Reactivate as producer	Low cum. - TA - No wells between this well and edge of unit.
18G	Conoco Com #9	134	364	605				Reactivate as producer	TA - No wells between this well and edge of unit; Could add perfs in uppermost section.
18H	Barbara Federal #1	272	734	2,575				Produce	High cum. oil & water. Yates recommended injector.
18I	Not Drilled								
18J	Barbara Federal #6	292	962	1,407				Reactivate as producer	High cum. oil & water. TA. Could add perfs in lower high porosity section.
18K	Barbara Federal #2	158	540	673				Injector	TA. Long section of high calculated porosity in middle & lower portion. Yates recommended injector.
18L	Lehman Com #11	289	979	321	261	1,984	1,579	Produce	West Edge - High current rate
18M	Lehman Com #1	281	734	216	32	2,064	117	Produce	West Edge; High gas rate
18N	Not Drilled								
18O	Barbara 18 SE Federal #12	177	430	335	464	2,191	1,111	Produce	High current rate; Lower porosity not all perf'd.
18P	Barbara 18 SE Federal #8	260	527	856	608	2,677	857		High current rate; High cum. oil; Extensively perf'd.
19A	Ross EG Federal #5	78	166	552	2	506	3,684	Injector	Locally high GOR; Good lower porosity not perf'd
19B	Ross EG Federal #2	331	685	2,017	52	719	2,368	Produce	High cum. oil & very high cum. water; Extensively perf'd.
19C	Lodewick A #1	646	1,454	2,415	50	724	1,958	Produce	High cum. oil & very high cum. water; Highest porosity in lower section, but could add perfs in middle section as well.
19D	Lodewick A #3	112	717	196	0	1,163	0	Produce	West edge of unit; Currently all gas production; Extensively perf'd.
19E	Lodewick A Com #2	156	569	241	0	698	0	Produce	West edge of unit; Gas well; Low current liquid production; high basal porosity not perf'd.
19F	Not Drilled							Drill as producer	Undrilled location near edge of unit in high volume area.
19G	Parish IV Com #4	267	567	336	55	646	872	Produce	High cum. oil - Yates recommended injector.
19H	Ross EG Federal #12	32	109	191	114	464	1,078	Injector	Low volumes; Add perfs in lowest portion of section.
19I	Ross EG Federal #9	28	109	572	1	518	3,802	Injector	Locally high GOR; phi-h=79.8; Good lower porosity; Add perfs in lowest portion of section.
19J	Parish IV Deep C #1	287	413	2,066	27	227	1,181	Produce	High cum. oil & water; Extensively perf'd.
19K	Not Drilled							Drill as Producer	Adjacent to high cum. oil area and has several recommended injectors to the east.
19L	Dagger Draw 19 S #4	791	1,988	2,843				Produce	West edge of unit;high cum. oil, water & gas
19M	Dagger Draw 19 S #10	295	981	253	89	2,453	911	Produce	West edge of unit; High cum. oil
19N	Dagger Draw 19 S #14	95	304	128	40	1,065	642	Injector	Good porosity in lower section; extensively perf'd.
19O	Chamiza AJC Com #1	185	556	463	81	1,176	737	Produce; 2nd Stage Injector	Similar to 19N with slightly better porosity in upper section. Yates recommended injector. Produce until breakthrough observed, then convert to injection.
19P	Parish IV Com #5	183	575	689	92	1,248	1,511	Produce; 2nd Stage Injector	Similar to 19O & 19N Few perfs in upper section; Produce until breakthrough observed, then convert to injection.

Summary Table
Well Recommendations
Dagger Draw Field

Location	Well Name	Cum. Production Oil (MBO)	Cum. Production Gas (MMcf)	Cum. Production Water (MBW)	Current Rate Oil (BPM)	Current Rate Gas (Mcf/M)	Current Rate Water (BPM)	Recommendation	Notes
20A	Hooper Amp Com #4	199	531	227	218	1,944	1,085	Produce	High current rate; Good porosity in upper & lower section with middle of lesser quality; Only upper is perf'd.
20B	Not Drilled								
20C	Ross EG Federal #6	142	254	584	232	974	1,749	Produce	High current rate; Little porosity in upper section & no perfs; Avg porosity in middle section is perf'd; Could add perfs in next lobe deeper.
20D	Ross EG Federal #3	159	235	896	73	578	3,396	Produce	High current rate
20E	Ross EG Federal #4	233	380	1,151	121	632	4,018	Produce	Marginally hi cum. oil; high cum. water; Basal poorosity not perf'd; Yates recommended injector.
20F	Ross EG Federal #7	27	83	443				Produce	Low volumes; High water relative to oil; Porosity in lower section only, & this section not perf'd
20G	Ross EG Federal #10	38	213	575	59	239	329	Injector	Low volumes & high water; Undrilled locations north & south. Yates recommended injector.
20H	Hooper Amp Com #3	184	620	303	236	1,746	954	Produce	High current rate; Thick section of high porosity is perf'd. Middle & lower section shows average to good porosity, but not perf'd.
20I	Ross EG Federal #13	17	105	75				Injector	Low rate; Low volumes; Mapped as high GOR, but good candidate since rate is quite low; Undrilled locations east & west; Yates recommended injector.
20J	Not Drilled								
20K	Ross EG Federal #1	134	418	1,443	116	1,210	1,454	Produce	High cum. water & high GOR; Low overall calculated porosity.
20L	Ross EG Federal #8	60	116	581	114	393	2,425	Injector	Low oil with relatively high water; Lowest high porosity lobe is unperf'd.
20M	Patriot AIZ Com #1	96	188	1,158	15	0	30	Injector	High cum. water; Yates recommended injector.
20N	Patriot AIZ Com #4	96	490	279	211	1,463	928	Produce	Perf'd in upper section with good porosity, Basal porosity not perf'd.
20O	Patriot AIZ Com #2	247	1,124	450	48	901	260	Produce	High cum. oil & GOR. Yates recommended injector.
20P	Patriot AIZ Com #3	294	664	1,394	250	819	4,158	Produce	Hi cum. oil & water; Middle section porosity not perf'd.
21A	Rodke ADY Com #1-H	25	60	53	3,397	7,193	6,349	Produce	East edge of unit; High current rate.- Horizontal
21B	Ross EG Federal #14	563	696	441	562	2,451	1,210	Produce	High current rate; High cum. oil.
21C	Not Drilled							Produce	High current rate; Recent well - Horizontal
21D	Vann APD #1	453	537	612	180	1,070	2,121	Produce	High current rate; High cum. oil.; Thick section of basal porosity not perf'd.
21E	Hooper Amp #2	438	705	722	635	3,397	2,052	Produce	High current rate; High cum. oil.; All porosity is in lower section.
21F	Patriot AIZ #11-H	133	458	107	1,773	7,062	4,634		
21G	Osage #1	15	55	552				Injector	TA; Low volumes with high water; Could sweep to 21B updip to north *or 21O updip to south. Yates recommended injector.*
21H	Not Drilled								
21I	Patriot AIZ #6-H	4	16	9	272	1,949	832	Produce	High current rate; Recent well; East edge of unit.
21J	Not Drilled								
21K	Not Drilled								
21L	Not Drilled								
21M	Hooper Amp #1	245	517	1,117	49	378	2,587	Produce	High cum. oil & water; Uppermost high porosity not perf'd; Yates recommended injector.
21N	Patriot AIZ #10-H	600	1,031	441	448	4,481	1,289	Produce	High current rate; High cum. oil; recent well; Good middle section porosity not perf'd.
21O	Patriot AIZ #5	112	163	693	251	527	5,252	Produce	*Moderate current rate; Extensive high porosity section in middle &* lower section not perf'd.
21P	Cutter APC #1	580	847	1,492	68	474	3,728	Produce	East edge of unit; High cum. oil; Good porosity in lower section not perf'd.

Summary Table
Well Recommendations
Dagger Draw Field

Location	Well Name	Cum. Production Oil (MBO)	Cum. Production Gas (MMcf)	Cum. Production Water (MBW)	Current Rate Oil (BPM)	Current Rate Gas (Mcf/M)	Current Rate Water (BPM)	Recommendation	Notes
28A	Not Drilled								
28B	Hinkle ALD #2	516	1,008	1,389	165	1,141	4,536	Produce	High cum. oil & water; Moderate basal porosity not perf'd. Phi-h = 57.0
28C	Ross IZ #3	11	97	58	63	1,607	1,216	Injector	Low volumes
28D	Lorene Ann #1	260	514	111	14	162	89	Produce	High cum. oil; Phi-h = 77.8; Several lower lobes of high porosity not perf'd.
28E	Ross IZ #2	84	458	228	170	2,082	2,802	Produce	High current rate & GOR; Phi-h = 72.8; Several lower lobes of high porosity not perf'd.
28F	Ross IZ Com #1	533	909	362	51	1,239	735	Produce	High cum. oil & current GOR; Abundant lower porosity not perf'd.
28G	Hinkle ALD #1	283	306	262	39	222	292	Produce	High cum. oil; Abundant lower porosity not perf'd.
28H	Hinkle ALD #3-H	159	863	380	234	3,717	5,264	Produce	East edge of unit; Horizontal; Newer well showing high cum. oil & GOR relative to age.
28I	Tackitt AOT #1	335	1,093	1,085	416	1,993	893	Produce	East edge of unit; High cum. oil & water; abundant unperf'd basal porosity.
28J	Tackitt AOT #2	265	1,277	1,475	301	2,485	6,364	Produce	High cum. oil; High current rate; Abundant unperf'd basal porosity.
28K	State K #3-H	785	1,895	835	144	1,599	1,267	Produce	Horizontal; High cum. oil & gas; Abundant unperf'd middle & lower porosity.
28L	Not Drilled							Produce	New well; Minimal calculated porosity
28M	Not Drilled							Drill as producer	South edge of unit; Drill location to prevent seeping oil off unit.
28N	State K #1	100	222	117	1,023	1,001	2,496	Produce	South edge of unit; High current rate; Ample unperf'd porosity in middle section.
28O	Tackitt AOT #3	447	1,129	656	338	3,559	2,293	Produce	South edge of unit; High current rate; Abundant unperf'd high porosity in middle & lower section.
28P	Not Drilled							Drill as producer	South edge of unit; Drill location to prevent seeping oil off unit.
29A	Binger AKU #4-H	7	60	102	407	1,483	4,277	Produce	Horizontal; High current rate; No log data loaded
29B	Binger AKU #1	770	1,087	731	168	2,205	1,738	Produce	High cum. oil; Ample section of unperf'd porosity in middle & lower section.
29C	Voight AJD Com #3	347	979	1,098	173	1,673	5,526	Produce	High cum. oil; High current rate; No log data loaded
29D	Voight AJD Com #1	275	583	638	64	606	919	Produce	High cum. oil; Only uppermost zone perf'd; Several porous lobes beneath appear untouched
29E	Voight AJD Com #2	285	852	1,043	148	1,322	3,139	Produce	High cum. oil; Abundant unperf'd basal porosity; Yates recommended injector.
29F	Aspden AOH Federal #3	204	553	313	229	1,061	1,678	Produce	High current rate; Abundant unperf'd porosity in middle & lower section.
29G	Binger AKU #2	285	665	269	121	1,023	1,904	Produce	High cum. oil; Only a small interval of perfs in middle section; Large section of unperf'd porosity in upper & lower section.
29H	Not Drilled								BHL for 29A horizontal.
29I	Boyd X State Com #5	195	428	143	94	1,075	1,103	Produce	Lower volumes than surrounding wells; Abundant unperf'd basal porosity; Adjacent to recommended injector; monitor for breakthrough
29J	Boyd X State #3	190	269	521	0	171	0	Injector	Low volume well between 2 high cum. areas; Ample unperf'd lower porosity.
29K	Boyd X State Com #4	157	307	577	120	615	2,345	Produce	Lower volumes than surrounding wells; Abundant unperf'd porosity in middle section; Adjacent to recommended injector; monitor for breakthrough
29L	Boyd X State Com #2	345	690	2,957				Produce	High cum. oil with very little calculated porosity.
29M	Aspden AOH Federal #1	104	168	80	37	342	575	Produce	South edge of unit; Perf'd only in uppermost section
29N	Aspden AOH Federal #2	275	526	229				Produce	South edge of unit; Perf'd only in uppermost section; Very little calculated porosity in middle & lower section; High current rate & high cum. oil.
29O	Boyd X State #6	405	756	334	105	710	564	Produce	South edge of unit; High cum. oil; Very small perf'd interval in uppermost section only; Very ample section of high porosity in middle section.
29P	Not Drilled							Drill as producer	South edge of unit; Drill location to captrue swept oil on unit.

Summary Table
Well Recommendations
Dagger Draw Field

Location	Well Name	Cum. Production Oil (MBO)	Gas (MMcf)	Water (MBW)	Current Rate Oil (BPM)	Gas (Mcf/M)	Water (BPM)	Recommendation	Notes
30A	Dagger Draw 30 N #15	57	243	124	77	1,092	635	Injector	Moderately high cum. oil
30B	Dagger Draw 30 N #5	121	826	2,063				Reactivate as producer	High cum. water; Ample unperf'd lower porosity
30C	Not Drilled							Drill as Producer	Undrilled location; Could drill location to produce & observe until breakthrough achieved, then convert to injection.
30D	Dagger Draw 30 N #1	469	1,435	3,236				Produce	West edge of unit; High cum. oil; No log data loaded.
30E	Dagger Draw 30 N #9	220	576	338	58	1,198	1,382	Produce	West edge of unit; extensively perf'd
30F	Dagger Draw 30 N #13	89	494	287	84	1,780	1,244	Injector	Extensivley perf'd in good porosity in middle section, but could add perfs in uppermost & lowermost section.
30G	Dagger Draw 30 N #12	200	684	248	108	1,424	984	Produce	High current total liquid rate; Perf'd In upper section only; Abundant lower porosity unperf'd. Yates recommended injector.
30H	Dagger Draw 30 N #17	85	292	201	6	681	923	Injector	Lower cums.; Limited current fluid rate; Abundant lower porosity unperf'd; phi-h = 51.2
30I	Dagger Draw #2	53	203	527				Injector	Lower cums.; Extensively perf'd. phi-h = 53.0
30J	Dagger Draw 30 S #8	329	1,327	1,937	98	2,790	3,603	Produce	High cum. oil; Ample unperf'd porosity in uppermost & lowermost section; phi-h = 75.8;
30K	Dagger ZW #1	250	1,560	1,484	145	1,633	2,605	Produce	High cum. oil & water; Could add perfs in lower section; Continue to produce until breakthrough is observed, then convert to injection; Yates recommended injector.
30L	Dagger ZW #3	108	403	413	79	1,747	4,335	Produce	West edge of unit; Low cums.; Extensively prf'd.
30M	Pincushion AHN #1	214	584	551	89	979	2,454	Produce	SW edge of unit; Little calculated porosity; Moderate cums.
30N	Pincushion AHN #3	112	438	676	13	358	1,111	Produce	South edge of unit; lower cums.; Could add perfs in lower section.
30O	Dagger Draw 30 S #11	565	956	411	18	1,087	2,025	Produce	South edge of unit; High cum. oil; Abundant unperf'd lower porosity
30P	Dagger Draw 30 S #16	141	449	241	0	3	0	Produce	South edge of unit; Lower cums.; Ample unperf'd lower porosity.
	Total	24,176	60,092	79,310	21,432	130,232	197,755		
	Total for Proposed Producers				18,195	109,589	171,562		

Waterflood Summary
by Injection Pattern without Drilling
Inj = 2,500 BWPD with Volumetrics based on 4% cut-off

Pattern	acres	porosity-acre-ft	average porosity	thickness, ft	area sweep	time to breakthrough, years	Np 10 years, MBO	Secondary Recovery, %	Original Oil-in-Place, MBO	Cumulative Production, MBO	Cumulative Recovery to date, %
18k	154.32	1128.57	6.12%	119.5	62.00%	1.15	177.3	4.6	3,861.4	596.3	15.4
19a	126.81	835.44	9.28%	71	100.00%	0.85	202.4	7.1	2,858.5	537.2	18.8
19h	79.55	438.06	8.34%	66	100.00%	0.45	125.7	8.4	1,498.8	282.2	18.8
19i	85.09	339.91	8.32%	48	100.00%	0.35	103.6	8.9	1,163.0	309.3	26.6
19n	171.32	1878.05	8.88%	123.5	56.64%	1.92	229.2	3.6	6,425.8	752.2	11.7
20g	124.12	614.35	6.60%	75	39.94%	0.63	78.8	3.7	2,102.0	202.2	9.6
20i	137.44	540.51	9.48%	41.5	46.50%	0.55	80.5	4.4	1,849.4	465.5	25.2
20k	115.34	475.19	25.75%	16	66.16%	0.48	97.0	6.0	1,625.9	323.0	19.9
20m	102.46	625.59	20.70%	29.5	100.00%	0.64	164.5	7.7	2,140.5	383.1	17.9
30a	114.46	579.99	9.74%	52	100.00%	0.59	155.4	7.8	1,984.4	335.7	16.9
30f	166.19	2400.99	8.63%	167.5	74.70%	2.45	313.8	3.8	8,215.0	680.7	8.3
30h	71.73	502.03	7.25%	96.5	100.00%	0.51	139.4	8.1	1,717.7	327.4	19.1
30i	124.04	1421.82	10.37%	110.5	100.00%	1.45	282.7	5.8	4,864.8	627.5	12.9
Phase 1	**1,573**						**2,150.4**	**5.3**	**40,307.0**	**5,822.4**	**14.4**
16n	112.37	320.84	11.90%	24	57.32%	0.33	59.6	5.4	1,097.8	257.8	23.5
16o	112.6	555.33	6.95%	71	54.13%	0.57	88.5	4.7	1,900.1	431.7	22.7
17h	140.51	743.39	6.30%	84	37.46%	0.76	82.9	3.3	2,543.5	266.2	10.5
17j	136.7	627.85	6.51%	70.5	23.69%	0.64	49.3	2.3	2,148.2	240.7	11.2
17p	133.65	590.72	6.80%	65	32.10%	0.60	61.0	3.0	2,021.2	237.7	11.8
21g	159.53	974.27	7.93%	77	100.00%	0.99	205.3	6.2	3,333.5	370.3	11.1
28c	174.65	1579	9.52%	95	100.00%	1.61	270.0	5.0	5,402.6	1,147.0	21.2
29j	172.12	1148.38	10.94%	61	77.55%	1.17	191.7	4.9	3,929.2	831.1	21.2
Phase 2	**1,142**						**1,008.3**	**4.5**	**22,375.9**	**3,782.6**	**16.9**

Table 2

Waterflood Summary
by Injection Pattern with Drilling
Inj = 2,500 BWPD with Volumetrics based on 4% cut-off

Pattern	acres	porosity-acre-ft	average porosity	thickness, ft	area sweep	time to breakthrough, years	Np 10 years, MBO	Secondary Recovery, %	Original Oil-in-Place, MBO	Cumulative Production, MBO	Cumulative Recovery to date, %
18k	154.32	1128.57	6.12%	119.5	62.00%	1.15	184.6	4.8	3,861.4	596.3	15.4
19a	126.81	835.44	9.28%	71	100.00%	0.85	212.0	7.4	2,858.5	537.2	18.8
19h	79.55	438.06	8.34%	66	100.00%	0.45	130.0	8.7	1,498.8	282.2	18.8
19i	85.09	339.91	8.32%	48	100.00%	0.35	106.1	9.1	1,163.0	309.3	26.6
19n	171.32	1878.05	8.88%	123.5	100.00%	1.92	354.9	5.5	6,425.8	752.2	11.7
20g	124.12	614.35	6.60%	75	39.94%	0.63	80.5	3.8	2,102.0	202.2	9.6
20i	137.44	540.51	9.48%	41.5	46.50%	0.55	82.3	4.4	1,849.4	465.5	25.2
20k	115.34	475.19	25.75%	16	66.16%	0.48	99.2	6.1	1,625.9	323.0	19.9
20m	102.46	625.59	20.70%	29.5	100.00%	0.64	170.9	8.0	2,140.5	383.1	17.9
30a	114.46	579.99	9.74%	52	100.00%	0.59	161.3	8.1	1,984.4	335.7	16.9
30f	166.19	2400.99	8.63%	167.5	100.00%	2.45	398.5	4.9	8,215.0	680.7	8.3
30h	71.73	502.03	7.25%	96.5	100.00%	0.51	144.5	8.4	1,717.7	327.4	19.1
30i	124.04	1421.82	10.37%	110.5	100.00%	1.45	300.6	6.2	4,864.8	627.5	12.9
Phase 1	**1,573**						**2,425.4**	**6.0**	**40,307.0**	**5,822.4**	**14.4**
16n	112.37	320.84	11.90%	24	100.00%	0.33	96.8	8.8	1,097.8	257.8	23.5
16o	112.6	555.33	6.95%	71	100.00%	0.57	147.9	7.8	1,900.1	431.7	22.7
17h	140.51	743.39	6.30%	84	59.98%	0.76	123.6	4.9	2,543.5	266.2	10.5
17j	136.7	627.85	6.51%	70.5	67.55%	0.64	119.3	5.6	2,148.2	240.7	11.2
17p	133.65	590.72	6.80%	65	82.39%	0.60	133.0	6.6	2,021.2	237.7	11.8
21g	159.53	974.27	7.93%	77	100.00%	0.99	217.6	6.5	3,333.5	370.3	11.1
28c	174.65	1579	9.52%	95	100.00%	1.61	289.2	5.4	5,402.6	1,147.0	21.2
29j	172.12	1148.38	10.94%	61	100.00%	1.17	240.7	6.1	3,929.2	831.1	21.2
Phase 2	**1,142**						**1,368.1**	**6.1**	**22,375.9**	**3,782.6**	**16.9**

Table 3

Annual Projected Volumes
Secondary Recovery
without Drilling Case

	Phase 1					Phase 2			
	Q oil,Total bbl/day	Q oil,Total bbl/yr	Q gasl,Total Mcf/yr	Q wtr,Total bbl/yr		Q oil,Total bbl/day	Q oil,Total bbl/yr	Q gasl,Total Mcf/yr	Q wtr,Total bbl/yr
1	116	21,031	4,119	62,418	1	0	0	0	0
2	1,569	572,786	112,191	4,443,040	2	0	0	0	0
3	1,216	443,664	86,900	6,510,920	3	47	17,033	3,336	78,685
4	1,053	384,212	75,255	7,472,753	4	792	289,183	56,642	2,769,533
5	664	242,268	47,453	7,684,561	5	780	284,685	55,761	4,437,229
6	463	169,169	33,135	7,757,660	6	451	164,437	32,208	4,713,612
7	380	138,612	27,150	7,788,218	7	297	108,503	21,252	4,769,546
8	298	108,886	21,328	7,817,943	8	224	81,843	16,031	4,796,205
9	249	90,810	17,787	7,836,019	9	166	60,766	11,902	4,817,282
10	215	78,580	15,391	7,848,249	10	146	53,253	10,431	4,824,796

Annual Projected Volumes
Secondary Recovery
with Drilling Case

	Phase 1					Phase 2			
	Q oil,Total bbl/day	Q oil,Total bbl/yr	Q gasl,Total Mcf/yr	Q wtr,Total bbl/yr		Q oil,Total bbl/day	Q oil,Total bbl/yr	Q gasl,Total Mcf/yr	Q wtr,Total bbl/yr
1	116	21,031	4,119	62,418	1	0	0	0	0
2	1,569	572,786	112,191	4,443,040	2	0	0	0	0
3	1,213	442,706	86,713	6,465,817	3	56	20,326	3,981	67,646
4	1,175	428,862	84,001	7,393,737	4	1,060	386,812	75,765	2,601,059
5	742	270,730	53,028	7,656,100	5	992	361,962	70,897	4,359,952
6	548	200,058	39,185	7,726,771	6	563	205,576	40,266	4,672,473
7	435	158,887	31,121	7,767,942	7	383	139,965	27,415	4,738,084
8	359	131,097	25,678	7,795,732	8	292	106,489	20,858	4,771,559
9	295	107,784	21,112	7,819,045	9	221	80,704	15,807	4,797,345
10	250	91,415	17,905	7,835,414	10	182	66,256	12,978	4,811,793

Final
ZMAINbas
Run Start- 2003
Proved Producing

COMBINED YEARLY ECONOMICS

UNESCALATED NET RUN

Table 6
Client : Yates Petroleum Corp
Effective Date : 1 2003
BBLS,MCF,$

		ESTIMATED 8/8 THS PRODUCTION			COMPANY NET PRODUCTION			PRODUCT PRICES	
Date	Well Count	Oil-BBL	Condensate-BBL	Gas-MCF	Oil-BBL	Condensate-BBL	Gas-MCF	Oil/Cond-$/BBL	Gas $/MCF
12-2003	1	114,646	0	701,969	95,156	0	582,634	25.00	2.50
12-2004	1	63,395	0	409,670	52,618	0	340,026	25.00	2.50
12-2005	1	33,917	0	251,738	28,151	0	208,943	25.00	2.50
12-2006	1	20,971	0	152,296	17,406	0	126,406	25.00	2.50
12-2007	1	14,174	0	94,548	11,764	0	78,475	25.00	2.50
12-2008	1	10,714	0	77,755	8,893	0	64,537	25.00	2.50
12-2009	1	7,476	0	56,140	6,205	0	46,596	25.00	2.50
12-2010	1	4,767	0	42,305	3,957	0	35,113	25.00	2.50
12-2011	1	3,911	0	35,819	3,246	0	29,730	25.00	2.50
12-2012	1	3,061	0	16,497	2,541	0	13,693	25.00	2.50
12-2013	1	1,757	0	6,010	1,458	0	4,988	25.00	2.50
12-2014	1	1,458	0	4,988	1,210	0	4,140	25.00	2.50
Sub T		280,247	0	1,849,735	232,605	0	1,535,280	25.00	2.50
Remn		0	0	0	0	0	0	0.00	0.00
Total		280,247	0	1,849,735	232,605	0	1,535,280	25.00	2.50

	COMPANY FUTURE GROSS REVENUES				PRODUCTION TAXES			NET REVENUE
Date	Oil-$	Condensate-$	Gas-$	Total-$	Oil/Cond-$	Gas-$	Total-$	$
12-2003	2,378,904	0	1,456,586	3,835,490	160,398	96,353	256,751	3,578,739
12-2004	1,315,446	0	850,065	2,165,512	76,362	47,204	123,566	2,041,946
12-2005	703,778	0	522,356	1,226,134	40,854	29,006	69,861	1,156,274
12-2006	435,148	0	316,014	751,163	25,260	17,548	42,809	708,354
12-2007	294,111	0	196,187	490,298	17,073	10,894	27,967	462,330
12-2008	222,316	0	161,342	383,657	12,905	8,959	21,865	361,792
12-2009	155,127	0	116,491	271,618	9,005	6,469	15,474	256,144
12-2010	98,915	0	87,783	186,698	5,742	4,875	10,617	176,082
12-2011	81,153	0	74,324	155,478	4,711	4,127	8,838	146,640
12-2012	63,516	0	34,231	97,747	3,687	1,901	5,588	92,159
12-2013	36,458	0	12,471	48,929	2,116	693	2,809	46,120
12-2014	30,253	0	10,350	40,604	1,756	575	2,331	38,273
Sub T	5,815,125	0	3,838,200	9,653,325	359,870	228,604	588,474	9,064,851
Remn	0	0	0	0	0	0	0	0
Total	5,815,125	0	3,838,200	9,653,325	359,870	228,604	588,474	9,064,851

	COSTS			FUTURE CASH FLOW BEFORE INCOME TAX		
Date	Operating-$	Capital-$	Total-$	Undisc-$	Cumulative-$	10.0% DCF -$
12-2003	1,327,110	0	1,327,110	2,251,630	2,251,630	2,146,845
12-2004	820,180	0	820,180	1,221,766	3,473,395	1,059,007
12-2005	440,138	0	440,138	716,136	4,189,530	564,304
12-2006	251,306	0	251,306	457,048	4,646,578	327,407
12-2007	157,170	0	157,170	305,160	4,951,739	198,729
12-2008	156,931	0	156,931	204,861	5,156,600	121,283
12-2009	125,469	0	125,469	130,675	5,287,275	70,330
12-2010	93,967	0	93,967	82,115	5,369,389	40,177
12-2011	93,894	0	93,894	52,746	5,422,135	23,461
12-2012	62,491	0	62,491	29,668	5,451,803	11,997
12-2013	31,214	0	31,214	14,906	5,466,709	5,479
12-2014	31,210	0	31,210	7,063	5,473,771	2,360
Sub T	3,591,080	0	3,591,080	5,473,771	5,473,771	4,571,378
Remn	0	0	0	0	0	0
Total	3,591,080	0	3,591,080	5,473,771	5,473,771	4,571,378

INDICATORS		
Gross Well Count		1.
No Entities Combined		1.
Acreage Allocation		
Overall Life	Yrs	12.
Economic Half Life	tr2	2004
Peak Revenue Year		3.
Revenue/Equiv Bbl	$	19.76
Invest/Equiv Bbl	$	
Aver Opcst/Eq Bbl	$	7.35
Net CF/Equiv Bbl	$	11.21
Payout		
Discounted ROR	%	Over 100
Return on Inv(ROI)		0.00
5.0% DCF	$	4,972,339
7.0% DCF	$	4,801,685
10.0% DCF	$	4,571,378
12.5% DCF	$	4,399,611
15.0% DCF	$	4,243,478
20.0% DCF	$	3,970,191
25.0% DCF	$	3,738,719
30.0% DCF	$	3,539,937
35.0% DCF	$	3,367,185
40.0% DCF	$	3,215,497

These results are subject to the qualifications and limitations contained in a document titled "Proposal to Unitize for Secondary Recovery Operations, Dagger Draw Field, Eddy County, New Mexico".

Final | **COMBINED YEARLY ECONOMICS** | **Table 7**

ZMAINP11 — UNESCALATED NET RUN — Client : Yates Petroleum Corp

Run Start- 2003 — Effective Date : 1 2003

Probable Phase 1 without Drilling — BBLS,MCF,$

Date	Well Count	ESTIMATED 8/8 THS PRODUCTION Oil-BBL	Condensate-BBL	Gas-MCF	COMPANY NET PRODUCTION Oil-BBL	Condensate-BBL	Gas-MCF	PRODUCT PRICES Oil/Cond-$/BBL	Gas $/MCF
12-2003	54	21,031	0	4,119	17,456	0	3,419	25.00	2.50
12-2004	54	572,786	0	112,191	475,412	0	93,119	25.00	2.50
12-2005	54	443,664	0	86,900	368,241	0	72,127	25.00	2.50
12-2006	54	384,212	0	75,255	318,896	0	62,462	25.00	2.50
12-2007	54	242,268	0	47,453	201,083	0	39,386	25.00	2.50
12-2008	54	169,169	0	33,135	140,410	0	27,502	25.00	2.50
Sub T		1,833,131	0	359,053	1,521,498	0	298,014	25.00	2.50
Remn		0	0	0	0	0	0	0.00	0.00
Total		1,833,131	0	359,053	1,521,498	0	298,014	25.00	2.50

Date	COMPANY FUTURE GROSS REVENUES Oil-$	Condensate-$	Gas-$	Total-$	PRODUCTION TAXES Oil/Cond-$	Gas-$	Total-$	NET REVENUE $
12-2003	436,398	0	8,548	444,946	25,333	475	25,808	419,138
12-2004	11,885,306	0	232,796	12,118,102	689,942	12,932	702,874	11,415,228
12-2005	9,206,025	0	180,317	9,386,343	534,410	10,017	544,426	8,841,916
12-2006	7,972,405	0	156,155	8,128,559	462,798	8,674	471,472	7,657,087
12-2007	5,027,069	0	98,465	5,125,533	291,821	5,470	297,291	4,828,242
12-2008	3,510,260	0	68,755	3,579,015	203,771	3,819	207,590	3,371,425
Sub T	38,037,462	0	745,036	38,782,497	2,208,075	41,387	2,249,461	36,533,036
Remn	0	0	0	0	0	0	0	0
Total	38,037,462	0	745,036	38,782,497	2,208,075	41,387	2,249,461	36,533,036

Date	COSTS Operating-$	Capital-$	Total-$	FUTURE CASH FLOW BEFORE INCOME TAX Undisc-$	Cumulative-$	10.0% DCF -$
12-2003	1,239,345	4,030,000	5,269,345	-4,850,206	-4,850,206	-4,812,036
12-2004	2,528,928	0	2,528,928	8,886,300	4,036,094	7,702,504
12-2005	2,624,655	0	2,624,655	6,217,261	10,253,354	4,899,112
12-2006	2,691,256	0	2,691,256	4,965,831	15,219,186	3,557,275
12-2007	2,718,038	0	2,718,038	2,110,204	17,329,390	1,374,223
12-2008	2,717,789	0	2,717,789	653,636	17,983,026	386,969
Sub T	14,520,011	4,030,000	18,550,011	17,983,025	17,983,025	13,108,046
Remn	0	0	0	0	0	0
Total	14,520,011	4,030,000	18,550,011	17,983,025	17,983,025	13,108,046

INDICATORS

Gross Well Count		3.
No Entities Combined		54.
Acreage Allocation		
Overall Life	Yrs	6.
Economic Half Life	tr4	2005
Peak Revenue Year		4.
Revenue/Equiv Bbl	$	24.68
Invest/Equiv Bbl	$	2.56
Aver Opcst/Eq Bbl	$	9.24
Net CF/Equiv Bbl	$	11.45
Payout		Qtr3 2004
Discounted ROR	%	Over 100
Return on Inv(ROI)		5.46
5.0% DCF	$	15,312,397
7.0% DCF	$	14,381,145
10.0% DCF	$	13,108,046
12.5% DCF	$	12,147,569
15.0% DCF	$	11,267,514
20.0% DCF	$	9,714,789
25.0% DCF	$	8,392,618
30.0% DCF	$	7,257,232
35.0% DCF	$	6,274,749
40.0% DCF	$	5,418,626

These results are subject to the qualifications and limitations contained in a document titled "Proposal to Unitize for Secondary Recovery Operations, Dagger Draw Field, Eddy County, New Mexico".

Final

ZMAINP22

Run Start- 2005

Probable Phase 2 without Drilling

COMBINED YEARLY ECONOMICS

UNESCALATED NET RUN

Table 8

Client : Yates Petroleum Corp

Effective Date : 1 2003

BBLS,MCF,$

		ESTIMATED 8/8 THS PRODUCTION			COMPANY NET PRODUCTION			PRODUCT PRICES	
Date	Well Count	Oil-BBL	Condensate-BBL	Gas-MCF	Oil-BBL	Condensate-BBL	Gas-MCF	Oil/Cond-$/BBL	Gas $/MCF
12-2005	39	17,033	0	3,336	14,137	0	2,769	25.00	2.50
12-2006	39	289,183	0	56,642	240,022	0	47,013	25.00	2.50
12-2007	39	284,685	0	55,761	236,289	0	46,282	25.00	2.50
12-2008	39	164,437	0	32,208	136,483	0	26,733	25.00	2.50
12-2009	39	108,503	0	21,252	90,058	0	17,640	25.00	2.50
Sub T		863,840	0	169,200	716,988	0	140,436	25.00	2.50
Remn		0	0	0	0	0	0	0.00	0.00
Total		863,840	0	169,200	716,988	0	140,436	25.00	2.50

	COMPANY FUTURE GROSS REVENUES				PRODUCTION TAXES			NET REVENUE
Date	Oil-$	Condensate-$	Gas-$	Total-$	Oil/Cond-$	Gas-$	Total-$	$
12-2005	353,425	0	6,923	360,348	20,516	385	20,901	339,447
12-2006	6,000,544	0	117,532	6,118,076	348,332	6,529	354,860	5,763,216
12-2007	5,907,213	0	115,704	6,022,917	342,914	6,427	349,341	5,673,576
12-2008	3,412,065	0	66,832	3,478,897	198,070	3,713	201,783	3,277,114
12-2009	2,251,442	0	44,099	2,295,541	130,696	2,450	133,146	2,162,395
Sub T	17,924,689	0	351,089	18,275,778	1,040,528	19,503	1,060,031	17,215,747
Remn	0	0	0	0	0	0	0	0
Total	17,924,689	0	351,089	18,275,778	1,040,528	19,503	1,060,031	17,215,747

	COSTS			FUTURE CASH FLOW BEFORE INCOME TAX		
Date	Operating-$	Capital-$	Total-$	Undisc-$	Cumulative-$	10.0% DCF -$
12-2005	1,785,146	3,390,000	5,175,147	-4,835,700	-4,835,700	-3,940,843
12-2006	1,768,765	0	1,768,765	3,994,451	-841,249	2,861,427
12-2007	1,786,566	0	1,786,566	3,887,010	3,045,761	2,531,329
12-2008	1,779,294	0	1,779,294	1,497,820	4,543,581	886,747
12-2009	1,809,520	0	1,809,520	352,875	4,896,456	189,919
Sub T	8,929,291	3,390,000	12,319,291	4,896,456	4,896,456	2,528,579
Remn	0	0	0	0	0	0
Total	8,929,291	3,390,000	12,319,291	4,896,456	4,896,456	2,528,579

INDICATORS		
Gross Well Count		3.
No Entities Combined		39.
Acreage Allocation		
Overall Life	Yrs	5.
Economic Half Life	tr4	2007
Peak Revenue Year		6.
Revenue/Equiv Bbl	$	24.68
Invest/Equiv Bbl	$	4.58
Aver Opcst/Eq Bbl	$	12.06
Net CF/Equiv Bbl	$	6.61
Payout	Qtr1	2007
Discounted ROR	%	40.22
Return on Inv(ROI)		2.44
5.0% DCF	$	3,535,937
7.0% DCF	$	3,096,974
10.0% DCF	$	2,528,579
12.5% DCF	$	2,125,128
15.0% DCF	$	1,775,533
20.0% DCF	$	1,208,116
25.0% DCF	$	777,842
30.0% DCF	$	449,985
35.0% DCF	$	199,350
40.0% DCF	$	7,440

These results are subject to the qualifications and limitations contained in a document titled "Proposal to Unitize for Secondary Recovery Operations, Dagger Draw Field, Eddy County, New Mexico".

Final | **COMBINED YEARLY ECONOMICS** | **Table 9**

ZMAINndr | UNESCALATED NET RUN | **Client : Yates Petroleum Corp**

Run Start- 2003 | **Effective Date : 1 2003**

Probable Phase 1 and 2 without Drilling | **BBLS,MCF,$**

		ESTIMATED 8/8 THS PRODUCTION			COMPANY NET PRODUCTION			PRODUCT PRICES	
Date	Well Count	Oil-BBL	Condensate-BBL	Gas-MCF	Oil-BBL	Condensate-BBL	Gas-MCF	Oil/Cond-$/BBL	Gas $/MCF
12-2003	54	21,031	0	4,119	17,456	0	3,419	25.00	2.50
12-2004	54	572,786	0	112,191	475,412	0	93,119	25.00	2.50
12-2005	93	460,696	0	90,236	382,378	0	74,896	25.00	2.50
12-2006	93	673,395	0	131,897	558,918	0	109,475	25.00	2.50
12-2007	93	526,953	0	103,214	437,371	0	85,667	25.00	2.50
12-2008	93	333,606	0	65,343	276,893	0	54,235	25.00	2.50
12-2009	39	108,503	0	21,252	90,058	0	17,640	25.00	2.50
Sub T		2,696,971	0	528,253	2,238,486	0	438,450	25.00	2.50
Remn		0	0	0	0	0	0	0.00	0.00
Total		2,696,971	0	528,253	2,238,486	0	438,450	25.00	2.50

	COMPANY FUTURE GROSS REVENUES				PRODUCTION TAXES			NET REVENUE
Date	Oil-$	Condensate-$	Gas-$	Total-$	Oil/Cond-$	Gas-$	Total-$	$
12-2003	436,398	0	8,548	444,946	25,333	475	25,808	419,138
12-2004	11,885,306	0	232,796	12,118,102	689,942	12,932	702,874	11,415,228
12-2005	9,559,450	0	187,240	9,746,690	554,926	10,401	565,327	9,181,363
12-2006	13,972,948	0	273,687	14,246,635	811,130	15,203	826,333	13,420,302
12-2007	10,934,281	0	214,169	11,148,449	634,735	11,897	646,632	10,501,817
12-2008	6,922,325	0	135,587	7,057,912	401,841	7,532	409,373	6,648,539
12-2009	2,251,442	0	44,099	2,295,541	130,696	2,450	133,146	2,162,395
Sub T	55,962,150	0	1,096,125	57,058,274	3,248,603	60,890	3,309,493	53,748,782
Remn	0	0	0	0	0	0	0	0
Total	55,962,150	0	1,096,125	57,058,274	3,248,603	60,890	3,309,493	53,748,782

	COSTS			FUTURE CASH FLOW BEFORE INCOME TAX		
Date	Operating-$	Capital-$	Total-$	Undisc-$	Cumulative-$	10.0% DCF -$
12-2003	1,239,345	4,030,000	5,269,345	-4,850,206	-4,850,206	-4,812,036
12-2004	2,528,928	0	2,528,928	8,886,300	4,036,094	7,702,504
12-2005	4,409,802	3,390,000	7,799,802	1,381,561	5,417,656	958,269
12-2006	4,460,021	0	4,460,021	8,960,281	14,377,937	6,418,702
12-2007	4,504,604	0	4,504,604	5,997,214	20,375,150	3,905,553
12-2008	4,497,083	0	4,497,083	2,151,456	22,526,606	1,273,716
12-2009	1,809,520	0	1,809,520	352,875	22,879,480	189,919
Sub T	23,449,302	7,420,000	30,869,302	22,879,481	22,879,481	15,636,626
Remn	0	0	0	0	0	0
Total	23,449,302	7,420,000	30,869,302	22,879,481	22,879,481	15,636,626

INDICATORS		
Gross Well Count		6.
No Entities Combined		93.
Acreage Allocation		
Overall Life	Yrs	7.
Economic Half Life	tr3	2006
Peak Revenue Year		6.
Revenue/Equiv Bbl	$	24.68
Invest/Equiv Bbl	$	3.21
Aver Opcst/Eq Bbl	$	10.14
Net CF/Equiv Bbl	$	9.90
Payout	Qtr3	2004
Discounted ROR	%	92.56
Return on Inv(ROI)		4.08
5.0% DCF	$	18,848,334
7.0% DCF	$	17,478,117
10.0% DCF	$	15,636,626
12.5% DCF	$	14,272,698
15.0% DCF	$	13,043,048
20.0% DCF	$	10,922,905
25.0% DCF	$	9,170,460
30.0% DCF	$	7,707,218
35.0% DCF	$	6,474,100
40.0% DCF	$	5,426,066

These results are subject to the qualifications and limitations contained in a document titled "Proposal to Unitize for Secondary Recovery Operations, Dagger Draw Field, Eddy County, New Mexico".

Final
ZMAINP1d
Run Start- 2003
Probable Phase 1 with Drilling

COMBINED YEARLY ECONOMICS

UNESCALATED NET RUN

Table 10
Client : Yates Petroleum Corp
Effective Date : 1 2003
BBLS,MCF,$

		ESTIMATED 8/8 THS PRODUCTION			COMPANY NET PRODUCTION			PRODUCT PRICES	
Date	Well Count	Oil-BBL	Condensate-BBL	Gas-MCF	Oil-BBL	Condensate-BBL	Gas-MCF	Oil/Cond-$/BBL	Gas $/MCF
12-2003	56	36,275	0	54,423	30,108	0	45,171	25.00	2.50
12-2004	56	592,845	0	178,386	492,061	0	148,060	25.00	2.50
12-2005	56	455,316	0	128,324	377,912	0	106,509	25.00	2.50
12-2006	56	437,522	0	112,579	363,143	0	93,441	25.00	2.50
12-2007	56	277,045	0	73,867	229,947	0	61,309	25.00	2.50
12-2008	56	204,867	0	55,054	170,039	0	45,695	25.00	2.50
12-2009	56	162,671	0	43,608	135,017	0	36,195	25.00	2.50
Sub T		2,166,540	0	646,241	1,798,228	0	536,380	25.00	2.50
Remn		0	0	0	0	0	0	0.00	0.00
Total		2,166,540	0	646,241	1,798,228	0	536,380	25.00	2.50

	COMPANY FUTURE GROSS REVENUES				PRODUCTION TAXES			NET REVENUE
Date	Oil-$	Condensate-$	Gas-$	Total-$	Oil/Cond-$	Gas-$	Total-$	$
12-2003	752,701	0	112,928	865,629	43,694	6,273	49,967	815,661
12-2004	12,301,531	0	370,151	12,671,682	714,104	20,562	734,666	11,937,016
12-2005	9,447,806	0	266,273	9,714,078	548,445	14,791	563,237	9,150,842
12-2006	9,078,585	0	233,602	9,312,187	527,012	12,977	539,988	8,772,198
12-2007	5,748,674	0	153,273	5,901,948	333,710	8,514	342,225	5,559,723
12-2008	4,250,983	0	114,237	4,365,220	246,770	6,346	253,115	4,112,104
12-2009	3,375,423	0	90,487	3,465,910	195,943	5,027	200,970	3,264,940
Sub T	44,955,702	0	1,340,951	46,296,652	2,609,678	74,490	2,684,168	43,612,484
Remn	0	0	0	0	0	0	0	0
Total	44,955,702	0	1,340,951	46,296,652	2,609,678	74,490	2,684,168	43,612,484

	COSTS			FUTURE CASH FLOW BEFORE INCOME TAX		
Date	Operating-$	Capital-$	Total-$	Undisc-$	Cumulative-$	10.0% DCF -$
12-2003	1,271,560	5,762,600	7,034,161	-6,218,500	-6,218,500	-6,197,283
12-2004	2,593,048	0	2,593,048	9,343,969	3,125,469	8,099,203
12-2005	2,689,785	0	2,689,785	6,461,057	9,586,525	5,091,219
12-2006	2,757,128	0	2,757,128	6,015,071	15,601,596	4,308,900
12-2007	2,782,173	0	2,782,173	2,777,549	18,379,144	1,808,817
12-2008	2,781,821	0	2,781,821	1,330,284	19,709,428	787,562
12-2009	2,781,663	0	2,781,663	483,278	20,192,706	260,102
Sub T	17,657,177	5,762,600	23,419,777	20,192,708	20,192,708	14,158,520
Remn	0	0	0	0	0	0
Total	17,657,177	5,762,600	23,419,777	20,192,708	20,192,708	14,158,520

INDICATORS		
Gross Well Count		4.
No Entities Combined		56.
Acreage Allocation		
Overall Life	Yrs	7.
Economic Half Life	tr1	2006
Peak Revenue Year		4.
Revenue/Equiv Bbl	$	24.53
Invest/Equiv Bbl	$	3.05
Aver Opcst/Eq Bbl	$	9.35
Net CF/Equiv Bbl	$	10.70
Payout	Qtr3	2004
Discounted ROR	%	83.97
Return on Inv(ROI)		4.50
5.0% DCF	$	16,866,154
7.0% DCF	$	15,717,981
10.0% DCF	$	14,158,520
12.5% DCF	$	12,989,937
15.0% DCF	$	11,925,318
20.0% DCF	$	10,061,534
25.0% DCF	$	8,489,514
30.0% DCF	$	7,150,888
35.0% DCF	$	6,001,144
40.0% DCF	$	5,005,891

These results are subject to the qualifications and limitations contained in a document titled "Proposal to Unitize for Secondary Recovery Operations, Dagger Draw Field, Eddy County, New Mexico".

Final
ZMAINP2d
Run Start- 2005
Probable Phase 2 with Drilling

COMBINED YEARLY ECONOMICS

UNESCALATED NET RUN

Table 11
Client : Yates Petroleum Corp
Effective Date : 1 2003
BBLS,MCF,$

		ESTIMATED 8/8 THS PRODUCTION			COMPANY NET PRODUCTION			PRODUCT PRICES	
Date	Well Count	Oil-BBL	Condensate-BBL	Gas-MCF	Oil-BBL	Condensate-BBL	Gas-MCF	Oil/Cond-$/BBL	Gas $/MCF
12-2005	44	65,051	0	151,573	53,992	0	125,805	25.00	2.50
12-2006	44	413,227	0	162,934	342,979	0	135,235	25.00	2.50
12-2007	44	379,401	0	128,445	314,903	0	106,609	25.00	2.50
12-2008	44	217,949	0	81,098	180,898	0	67,311	25.00	2.50
12-2009	44	149,200	0	57,890	123,836	0	48,049	25.00	2.50
12-2010	44	113,646	0	44,474	94,326	0	36,913	25.00	2.50
Sub T		1,338,474	0	626,413	1,110,933	0	519,923	25.00	2.50
Remn		0	0	0	0	0	0	0.00	0.00
Total		1,338,474	0	626,413	1,110,933	0	519,923	25.00	2.50

	COMPANY FUTURE GROSS REVENUES				PRODUCTION TAXES			NET REVENUE
Date	Oil-$	Condensate-$	Gas-$	Total-$	Oil/Cond-$	Gas-$	Total-$	$
12-2005	1,349,810	0	314,513	1,664,323	78,356	17,471	95,828	1,568,496
12-2006	8,574,465	0	338,089	8,912,554	497,748	18,781	516,529	8,396,025
12-2007	7,872,571	0	266,522	8,139,094	457,003	14,805	471,808	7,667,286
12-2008	4,522,449	0	168,277	4,690,726	262,528	9,348	271,876	4,418,850
12-2009	3,095,894	0	120,122	3,216,016	179,717	6,673	186,389	3,029,627
12-2010	2,358,147	0	92,283	2,450,430	136,890	5,126	142,017	2,308,413
Sub T	27,773,335	0	1,299,806	29,073,142	1,612,242	72,204	1,684,446	27,388,695
Remn	0	0	0	0	0	0	0	0
Total	27,773,335	0	1,299,806	29,073,142	1,612,242	72,204	1,684,446	27,388,695

	COSTS			FUTURE CASH FLOW BEFORE INCOME TAX		
Date	Operating-$	Capital-$	Total-$	Undisc-$	Cumulative-$	10.0% DCF -$
12-2005	1,944,716	7,720,000	9,664,716	-8,096,220	-8,096,220	-6,676,621
12-2006	1,932,410	0	1,932,410	6,463,615	-1,632,605	4,630,215
12-2007	1,946,957	0	1,946,957	5,720,328	4,087,724	3,725,237
12-2008	1,938,186	0	1,938,186	2,480,663	6,568,387	1,468,615
12-2009	1,967,826	0	1,967,826	1,061,800	7,630,187	571,466
12-2010	1,998,157	0	1,998,157	310,256	7,940,443	151,801
Sub T	11,728,253	7,720,000	19,448,253	7,940,443	7,940,443	3,870,712
Remn	0	0	0	0	0	0
Total	11,728,253	7,720,000	19,448,253	7,940,443	7,940,443	3,870,712

INDICATORS		
Gross Well Count		4.
No Entities Combined		44.
Acreage Allocation		
Overall Life	Yrs	6.
Economic Half Life	tr4	2007
Peak Revenue Year		6.
Revenue/Equiv Bbl	$	24.28
Invest/Equiv Bbl	$	6.45
Aver Opcst/Eq Bbl	$	9.79
Net CF/Equiv Bbl	$	6.63
Payout	Qtr2	2007
Discounted ROR	%	34.85
Return on Inv(ROI)		2.03
5.0% DCF	$	5,591,617
7.0% DCF	$	4,839,574
10.0% DCF	$	3,870,712
12.5% DCF	$	3,186,820
15.0% DCF	$	2,597,155
20.0% DCF	$	1,647,003
25.0% DCF	$	933,718
30.0% DCF	$	395,916
35.0% DCF	$	-10,554
40.0% DCF	$	-317,851

These results are subject to the qualifications and limitations contained in a document titled "Proposal to Unitize for Secondary Recovery Operations, Dagger Draw Field, Eddy County, New Mexico".

Final | **COMBINED YEARLY ECONOMICS** | **Table 12**

ZMAINdrl | UNESCALATED NET RUN | **Client : Yates Petroleum Corp**

Run Start- 2003 | **Effective Date : 1 2003**

Probable Phase 1 and 2 with Drilling | **BBLS,MCF,$**

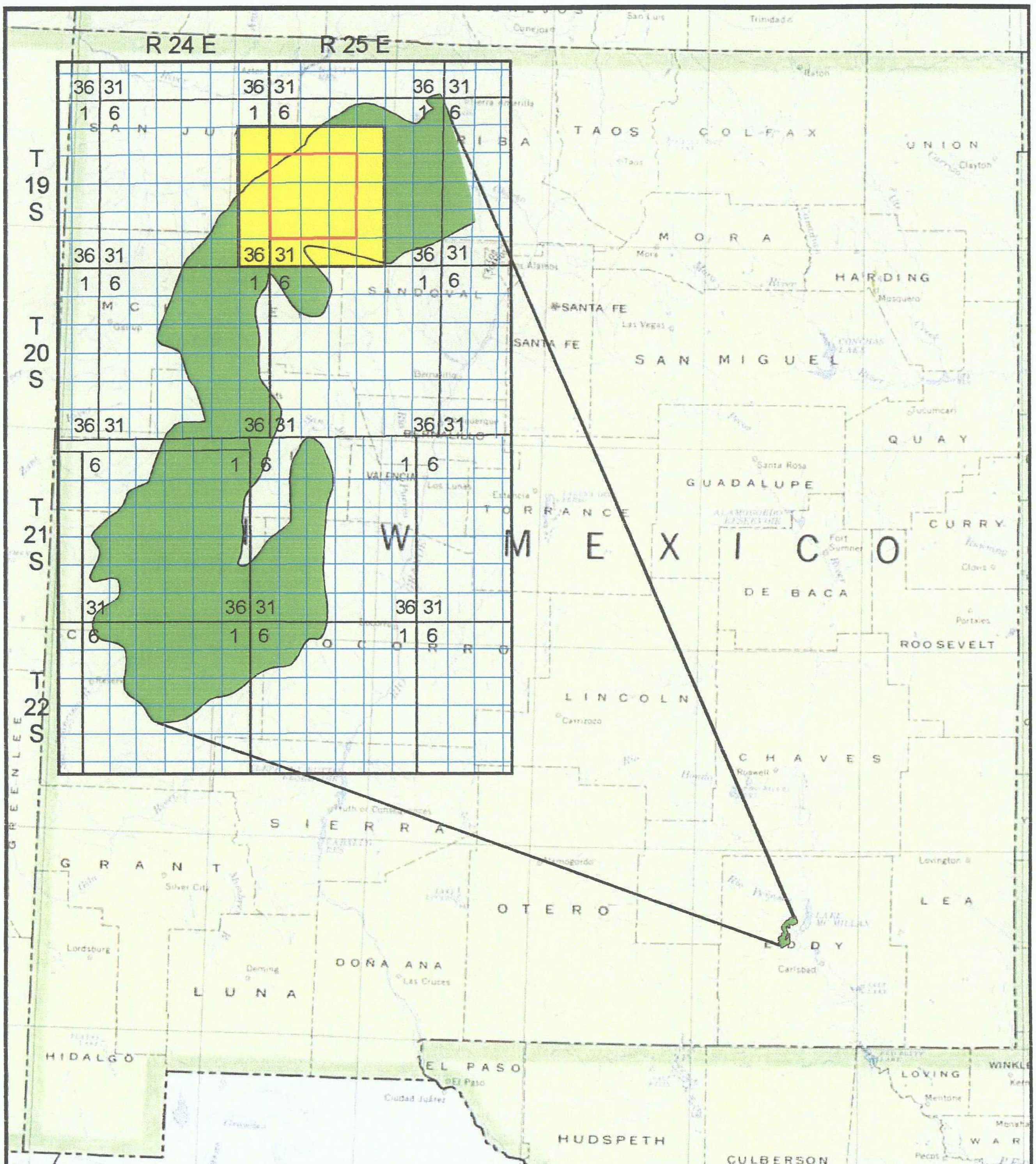
		ESTIMATED 8/8 THS PRODUCTION			COMPANY NET PRODUCTION			PRODUCT PRICES	
Date	Well Count	Oil-BBL	Condensate-BBL	Gas-MCF	Oil-BBL	Condensate-BBL	Gas-MCF	Oil/Cond-$/BBL	Gas $/MCF
12-2003	56	36,275	0	54,423	30,108	0	45,171	25.00	2.50
12-2004	56	592,845	0	178,386	492,061	0	148,060	25.00	2.50
12-2005	100	520,367	0	279,897	431,905	0	232,314	25.00	2.50
12-2006	100	850,749	0	275,513	706,122	0	228,676	25.00	2.50
12-2007	100	656,446	0	202,311	544,850	0	167,918	25.00	2.50
12-2008	100	422,816	0	136,152	350,937	0	113,006	25.00	2.50
12-2009	100	311,871	0	101,498	258,853	0	84,244	25.00	2.50
12-2010	44	113,646	0	44,474	94,326	0	36,913	25.00	2.50
Sub T		3,505,014	0	1,272,654	2,909,162	0	1,056,303	25.00	2.50
Remn		0	0	0	0	0	0	0.00	0.00
Total		3,505,014	0	1,272,654	2,909,162	0	1,056,303	25.00	2.50

	COMPANY FUTURE GROSS REVENUES				PRODUCTION TAXES			NET REVENUE
Date	Oil-$	Condensate-$	Gas-$	Total-$	Oil/Cond-$	Gas-$	Total-$	$
12-2003	752,701	0	112,928	865,629	43,694	6,273	49,967	815,661
12-2004	12,301,531	0	370,151	12,671,682	714,104	20,562	734,666	11,937,016
12-2005	10,797,616	0	580,786	11,378,401	626,802	32,263	659,064	10,719,337
12-2006	17,653,050	0	571,690	18,224,740	1,024,760	31,757	1,056,517	17,168,224
12-2007	13,621,244	0	419,796	14,041,041	790,713	23,320	814,033	13,227,008
12-2008	8,773,432	0	282,514	9,055,946	509,298	15,694	524,991	8,530,955
12-2009	6,471,317	0	210,609	6,681,926	375,660	11,699	387,359	6,294,567
12-2010	2,358,147	0	92,283	2,450,430	136,890	5,126	142,017	2,308,413
Sub T	72,729,039	0	2,640,757	75,369,795	4,221,921	146,694	4,368,615	71,001,180
Remn	0	0	0	0	0	0	0	0
Total	72,729,039	0	2,640,757	75,369,795	4,221,921	146,694	4,368,615	71,001,180

	COSTS			FUTURE CASH FLOW BEFORE INCOME TAX		
Date	Operating-$	Capital-$	Total-$	Undisc-$	Cumulative-$	10.0% DCF -$
12-2003	1,271,560	5,762,600	7,034,161	-6,218,500	-6,218,500	-6,197,283
12-2004	2,593,048	0	2,593,048	9,343,969	3,125,469	8,099,203
12-2005	4,634,502	7,720,000	12,354,501	-1,635,164	1,490,305	-1,585,402
12-2006	4,689,538	0	4,689,538	12,476,686	13,968,991	8,939,114
12-2007	4,729,130	0	4,729,130	8,497,878	22,466,870	5,534,054
12-2008	4,720,008	0	4,720,008	3,810,947	26,277,816	2,256,177
12-2009	4,749,489	0	4,749,489	1,545,078	27,822,894	831,568
12-2010	1,998,157	0	1,998,157	310,256	28,133,150	151,801
Sub T	29,385,430	13,482,600	42,868,030	28,133,150	28,133,150	18,029,232
Remn	0	0	0	0	0	0
Total	29,385,430	13,482,600	42,868,030	28,133,150	28,133,150	18,029,232

INDICATORS		
Gross Well Count		8.
No Entities Combined		100.
Acreage Allocation		
Overall Life	Yrs	8.
Economic Half Life	tr1	2007
Peak Revenue Year		6.
Revenue/Equiv Bbl	$	24.43
Invest/Equiv Bbl	$	4.37
Aver Opcst/Eq Bbl	$	9.52
Net CF/Equiv Bbl	$	9.12
Payout	Qtr3	2004
Discounted ROR	%	70.37
Return on Inv(ROI)		3.09
5.0% DCF	$	22,457,770
7.0% DCF	$	20,557,554
10.0% DCF	$	18,029,232
12.5% DCF	$	16,176,757
15.0% DCF	$	14,522,472
20.0% DCF	$	11,708,537
25.0% DCF	$	9,423,232
30.0% DCF	$	7,546,804
35.0% DCF	$	5,990,590
40.0% DCF	$	4,688,040

These results are subject to the qualifications and limitations contained in a document titled "Proposal to Unitize for Secondary Recovery Operations, Dagger Draw Field, Eddy County, New Mexico".



Study Area

Dagger Draw/
Indian Basin Fields

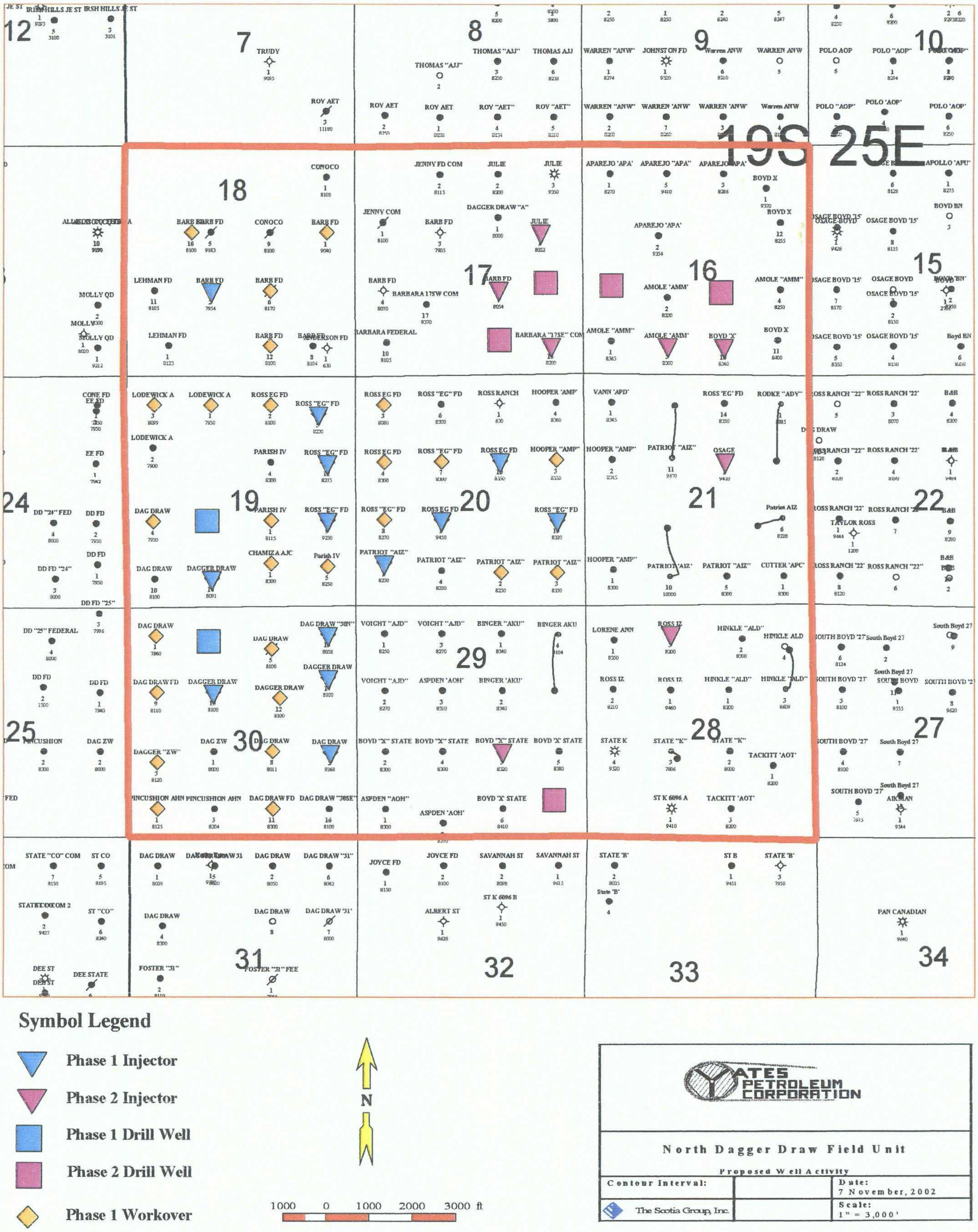
N

Yates Petroleum Corporation

Dagger Draw Field
Study Area Location

Prepared by The Scotia Group

Date: 11/13/2002	Figure 1



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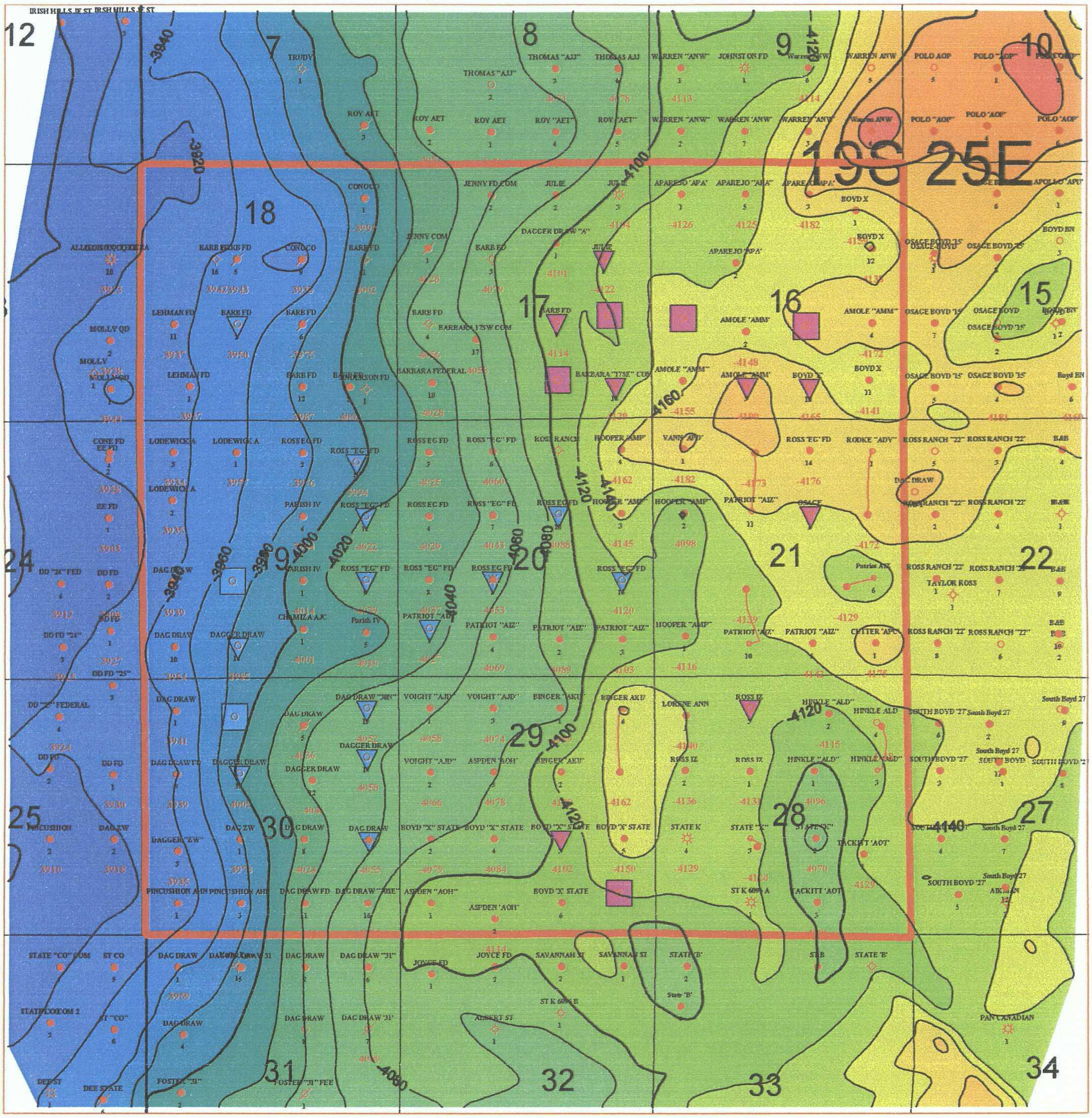
34
Symbol Legend
Phase 1 Injector
Phase 2 Injector
Phase 1 Drill Well
Phase 2 Drill Well
Phase 1 Workover
N
1000 0 1000 2000 3000 ft
YATES PETROLEUM CORPORATION
North Dagger Draw Field Unit
Proposed Well Activity
Contour Interval:
Date: 7 November, 2002
Scale: 1" = 3,000'
The Scotia Group, Inc.



Symbol Legend

- Phase 1 Injector
- Phase 2 Injector
- Phase 1 Drill Well
- Phase 2 Drill Well

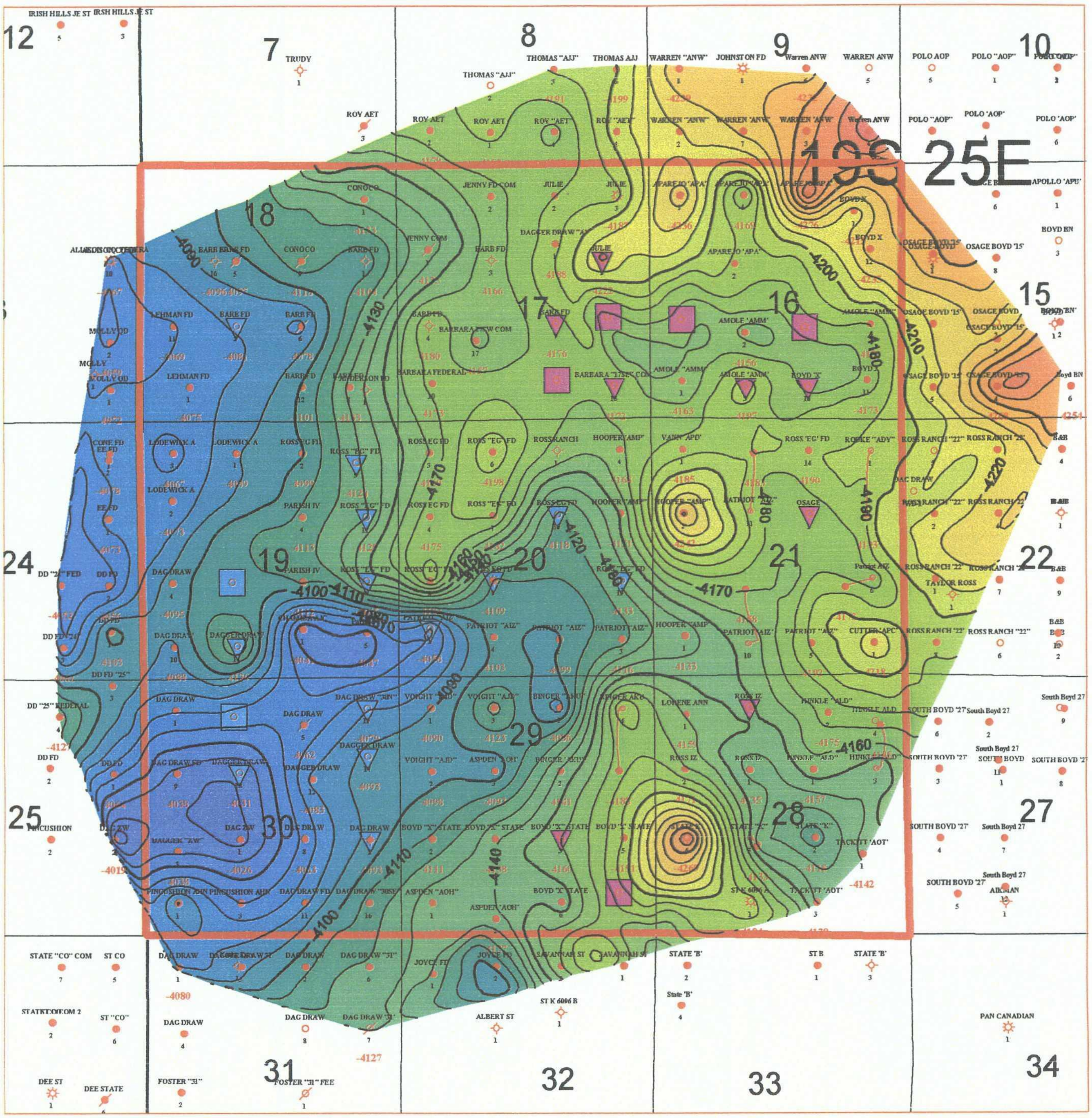
N

1000 0 1000 2000 3000 ft

YATES PETROLEUM CORPORATION

North Dagger Draw Field Unit
Upper Canyon Limestone
Subsea Top of Formation Structure

Contour Interval: 20'	Date: 7 November, 2002
The Scotia Group, Inc.	Scale: 1" = 3,000'



Symbol Legend

- Phase 1 Injector
- Phase 2 Injector
- Phase 1 Drill Well
- Phase 2 Drill Well

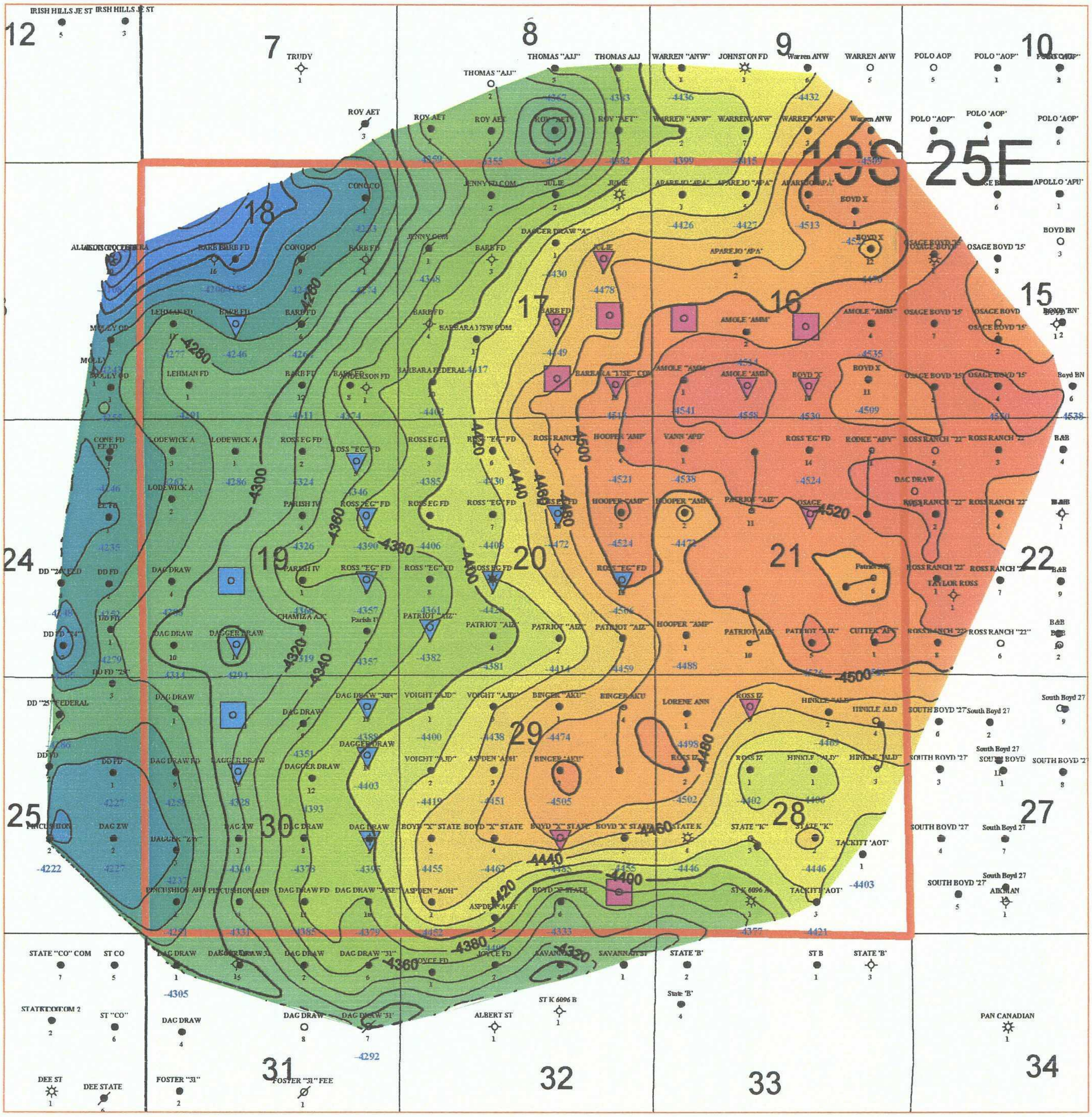
N

1000 0 1000 2000 3000 ft

YATES PETROLEUM CORPORATION

North Dagger Draw Field Unit
Canyon Dolomite
Subsea Top of Formation Structure

Contour Interval: 10'		Date: 7 November, 2002
The Scotia Group, Inc.		Scale: 1" = 3,000'



Symbol Legend

- Phase 1 Injector
- Phase 2 Injector
- Phase 1 Drill Well
- Phase 2 Drill Well

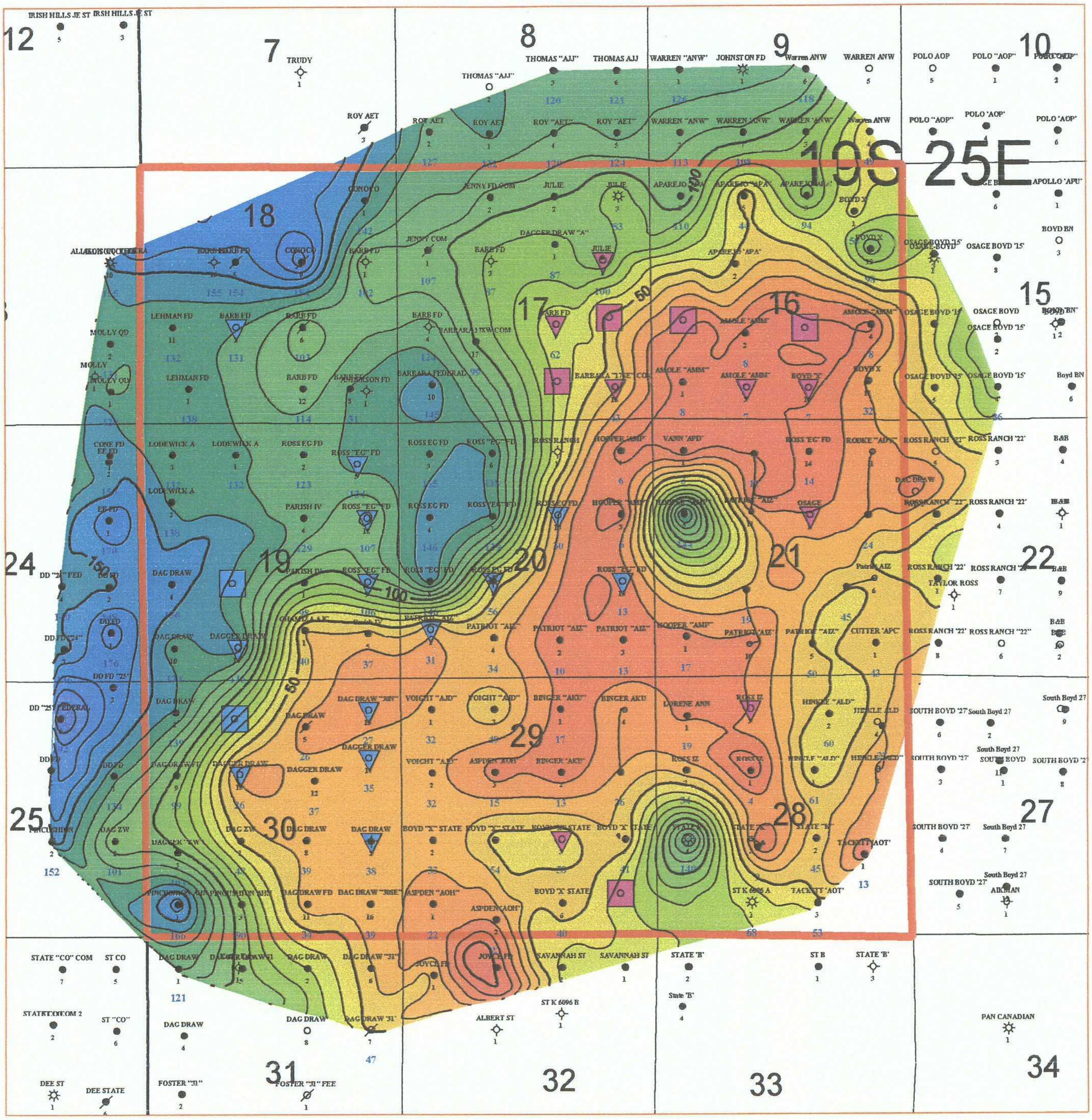
N

1000 0 1000 2000 3000 ft

YATES PETROLEUM CORPORATION

North Dagger Draw Field Unit
Canyon Dolomite
Subsea Base of Formation Structure

Contour Interval: 20'		Date: 7 November, 2002
The Scotia Group, Inc.		Scale: 1" = 3,000'



Symbol Legend

- Phase 1 Injector
- Phase 2 Injector
- Phase 1 Drill Well
- Phase 2 Drill Well

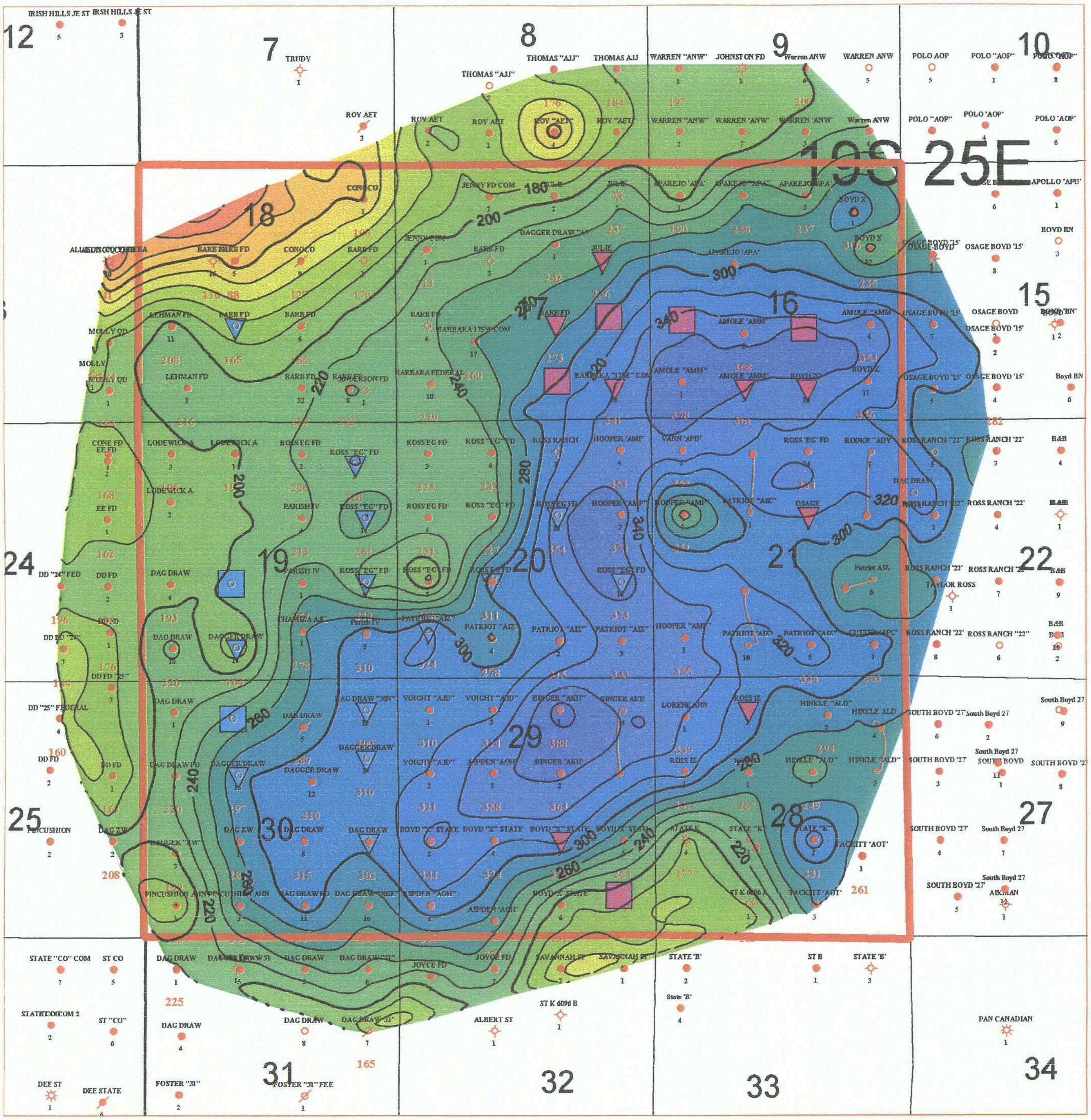
N

1000 0 1000 2000 3000 ft

YATES PETROLEUM CORPORATION

North Dagger Draw Field Unit
Upper Canyon Limestone
Cross Thickness Isochore

Contour Interval:		Date:
10'		12 November, 2002
The Scotia Group, Inc.		Scale: 1" = 3,000'



Symbol Legend

- Phase 1 Injector
- Phase 2 Injector
- Phase 1 Drill Well
- Phase 2 Drill Well

N

1000 0 1000 2000 3000 ft

YATES PETROLEUM CORPORATION

North Dagger Draw Field Unit
Canyon Dolomite
Cross Thickness Isochore

Contour Interval:		Date:
20'		7 November, 2002
The Scotia Group, Inc.		Scale: 1" = 3,000'

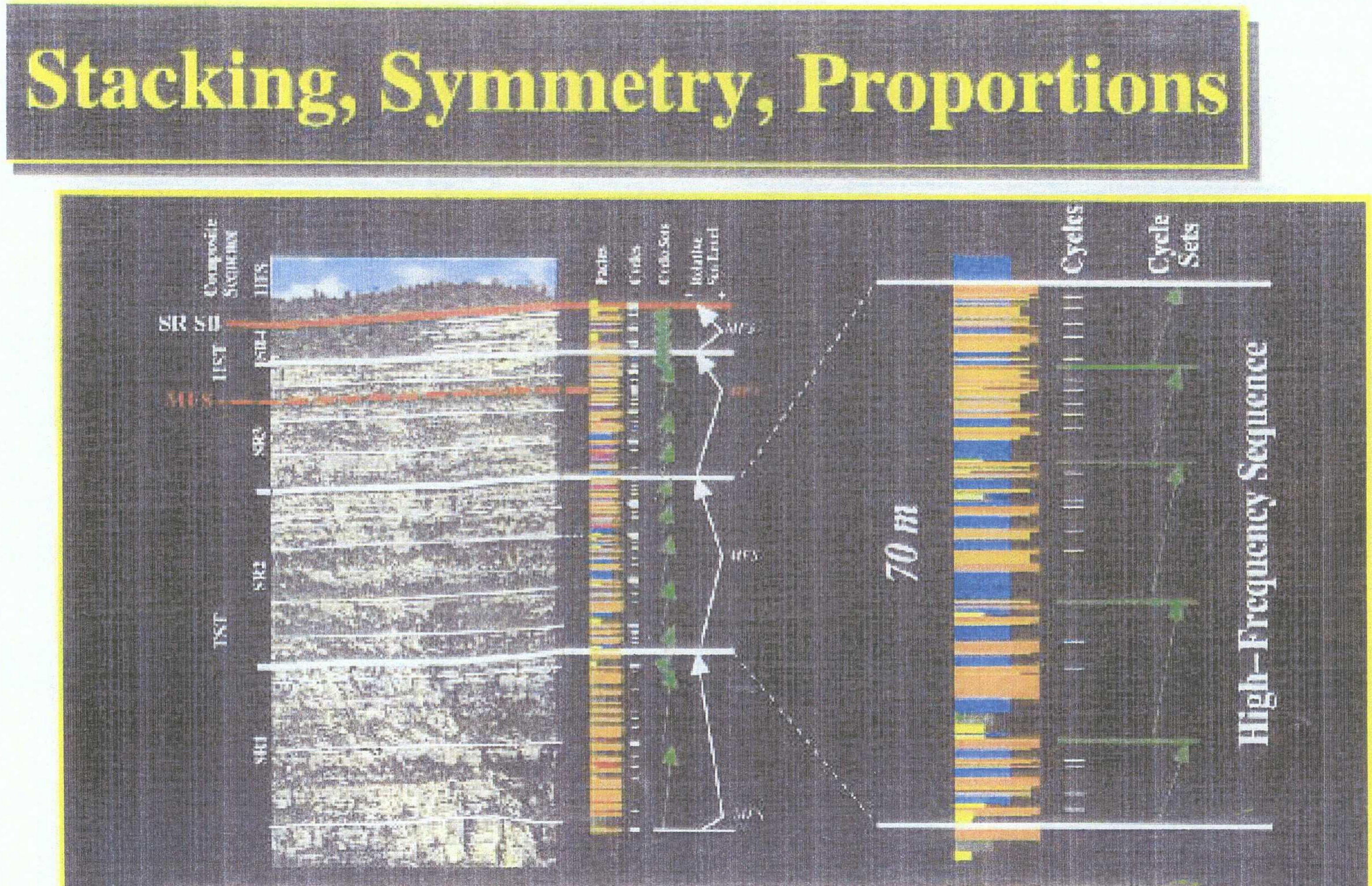


Figure 8 (Tinker et al) – Sedimentary cycles shown in outcrop for a proportional perspective.

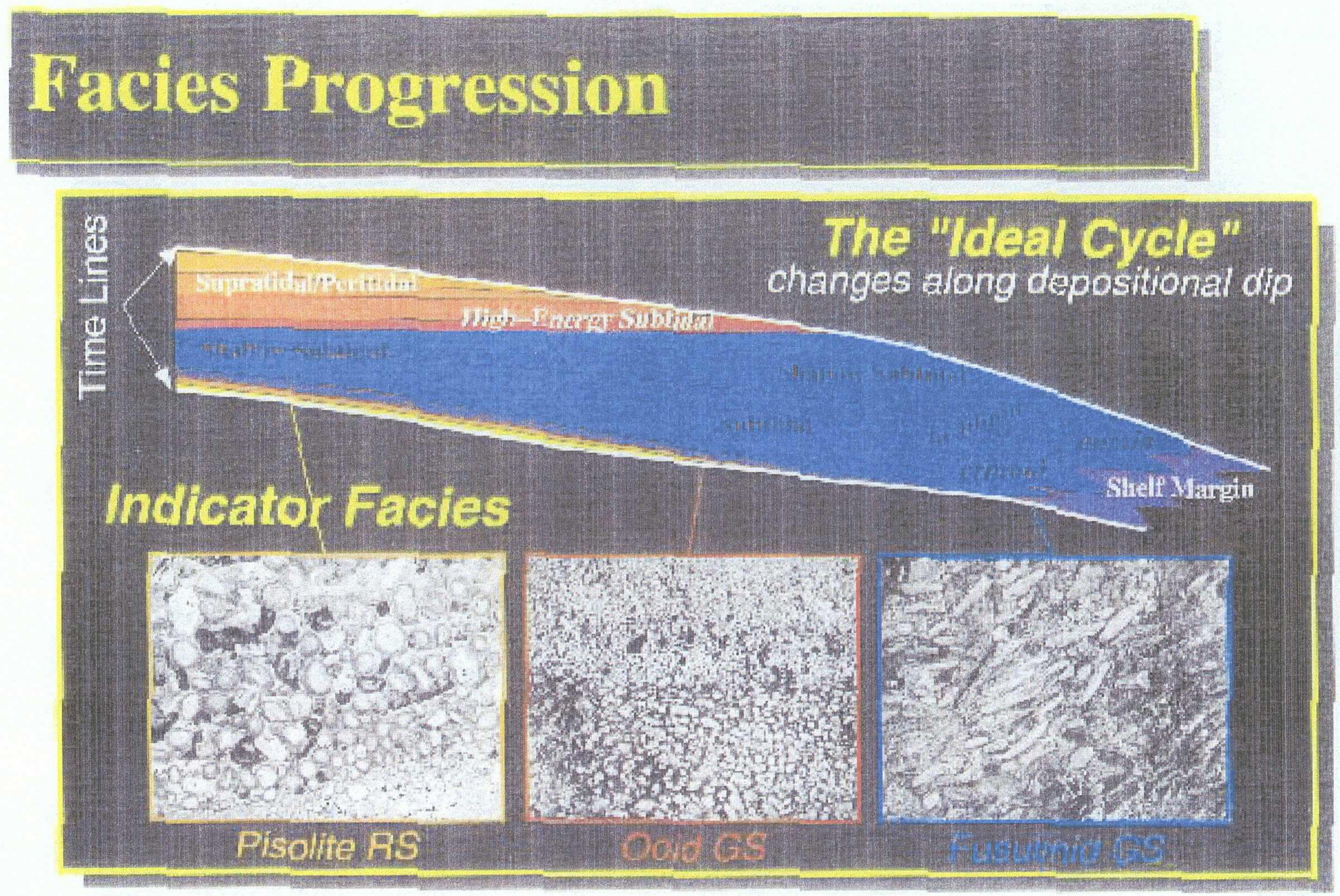


Figure 9 (Tinker et al) – Generalized sedimentary environment and facies progression across Dagger Draw Field in a dip direction.

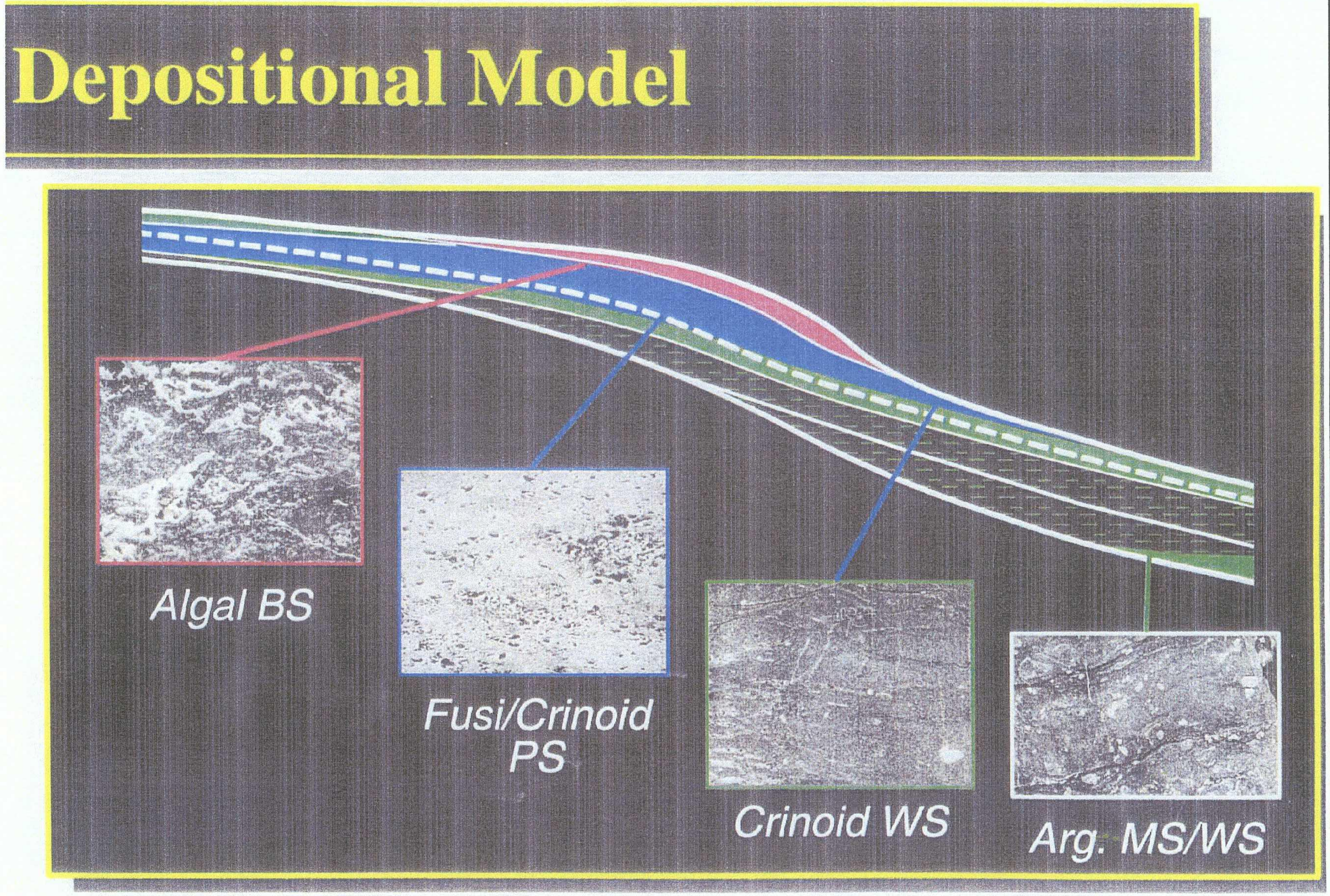


Figure 10 (Tinker et al) – Idealized drawing showing the Depositional Model for Dagger Draw along with facies and lithologic stacking.

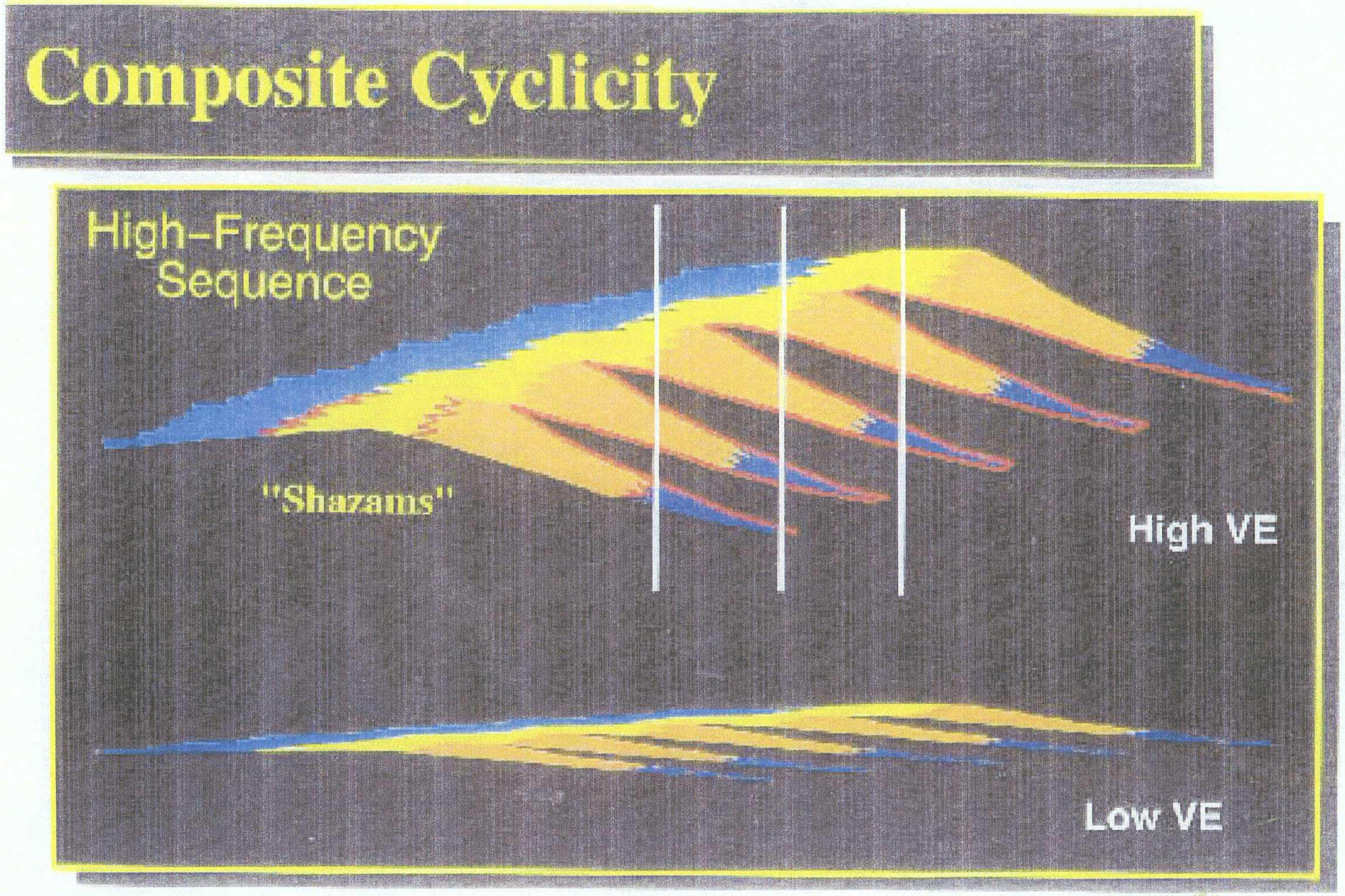
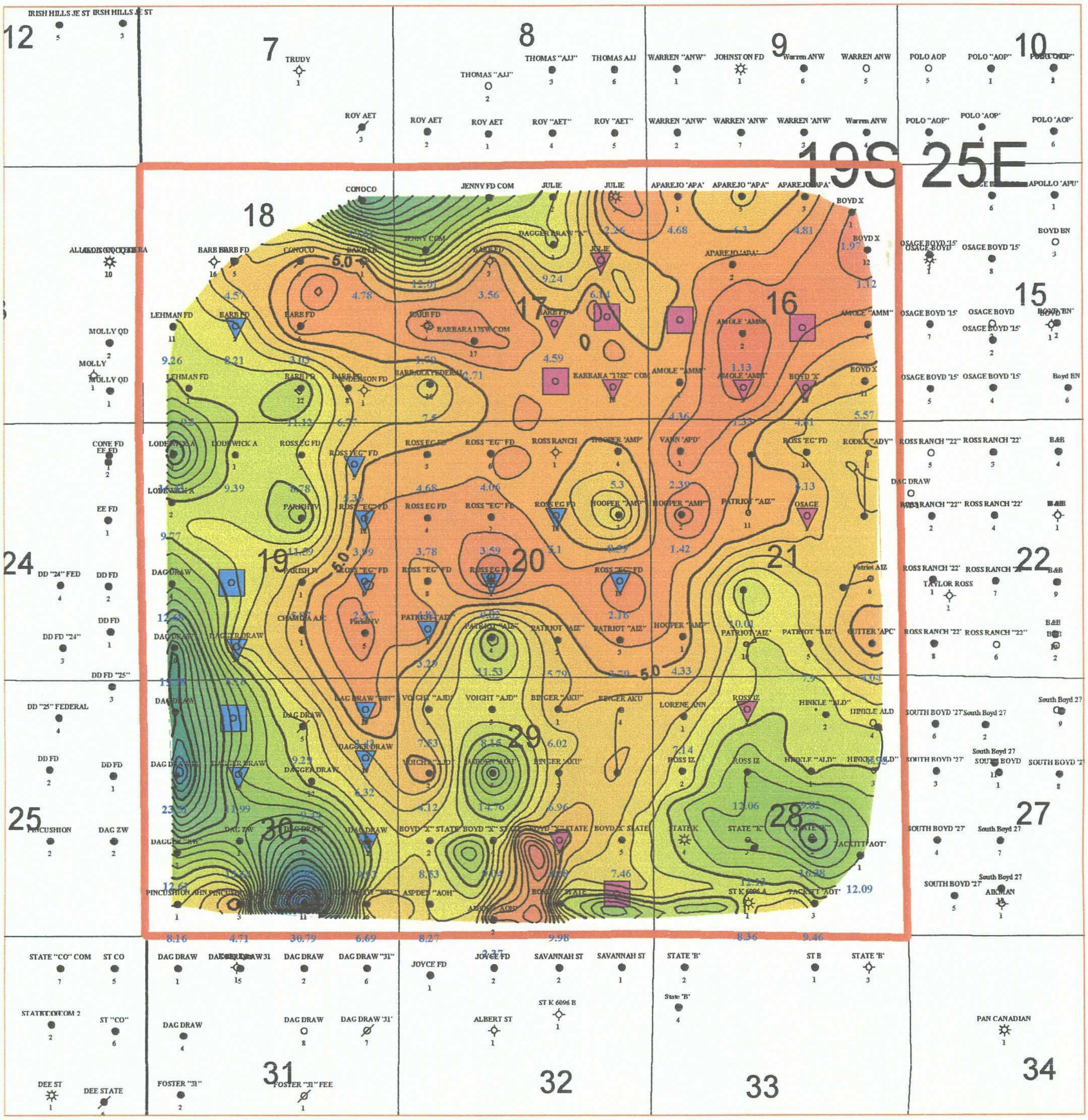


Figure 11 (Tinker et al) – Idealized drawing of the sedimentary geometry and cyclicity in the Dagger Draw area. Light blue shows intertidal facies; Yellow shows the algal boundstone facies; Orange shows the open shelf deposits; Dark blue are basinal shales.



Symbol Legend

- Phase I Injector
- Phase II Injector
- Phase I Drill Well
- Phase II Drill Well

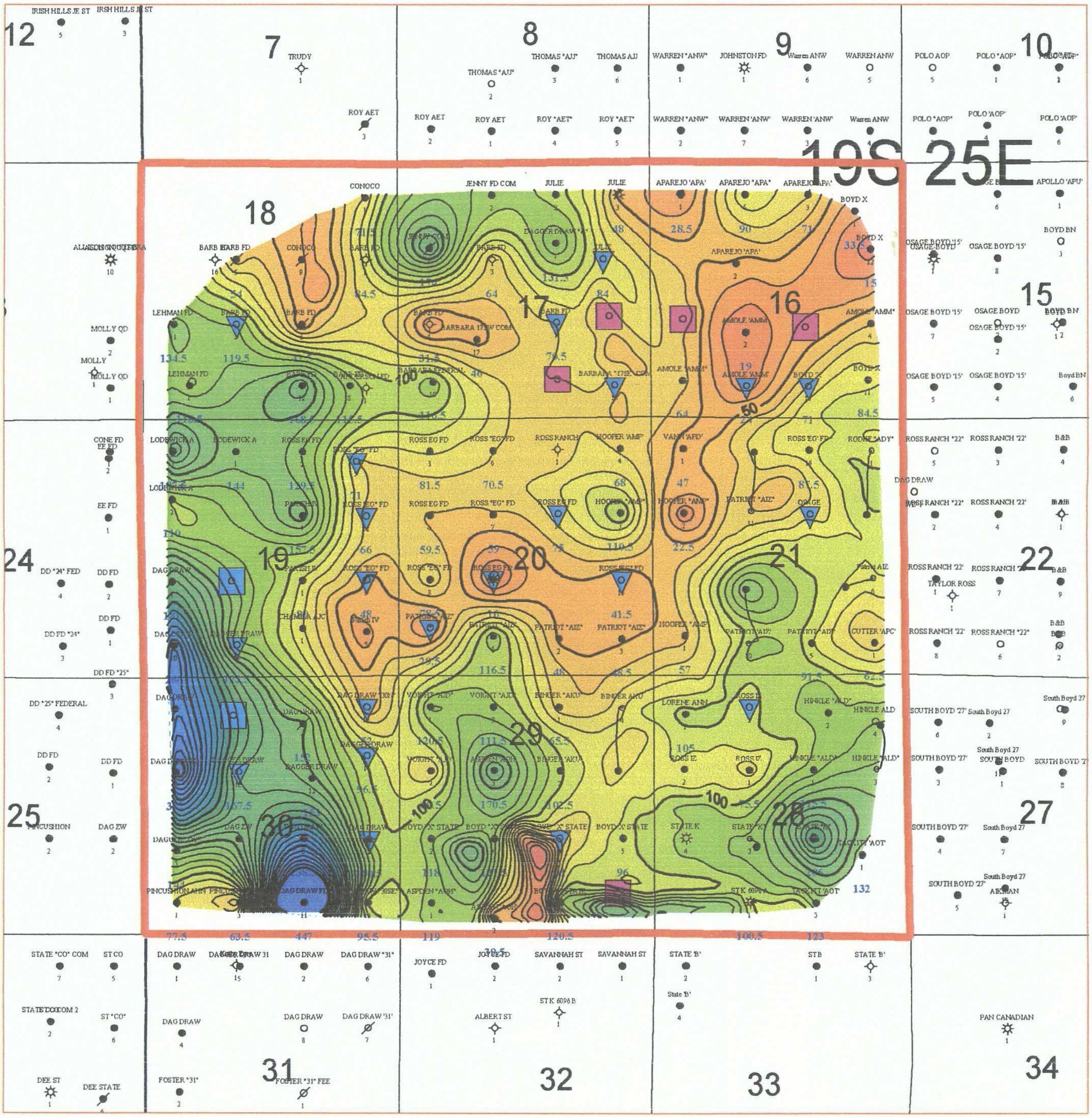
N

1000 0 1000 2000 3000 ft

YATES PETROLEUM CORPORATION

North Dagger Draw Field Unit
Canyon Dolomite
Porosity Feet Above 4,380' (4% Porosity Cutoff)

Contour Interval: 1'	Date: 19 November, 2002
The Scotia Group, Inc.	Scale: 1" = 3,000'



Symbol Legend

- Phase I Injector
- Phase II Injector
- Phase I Drill Well
- Phase II Drill Well

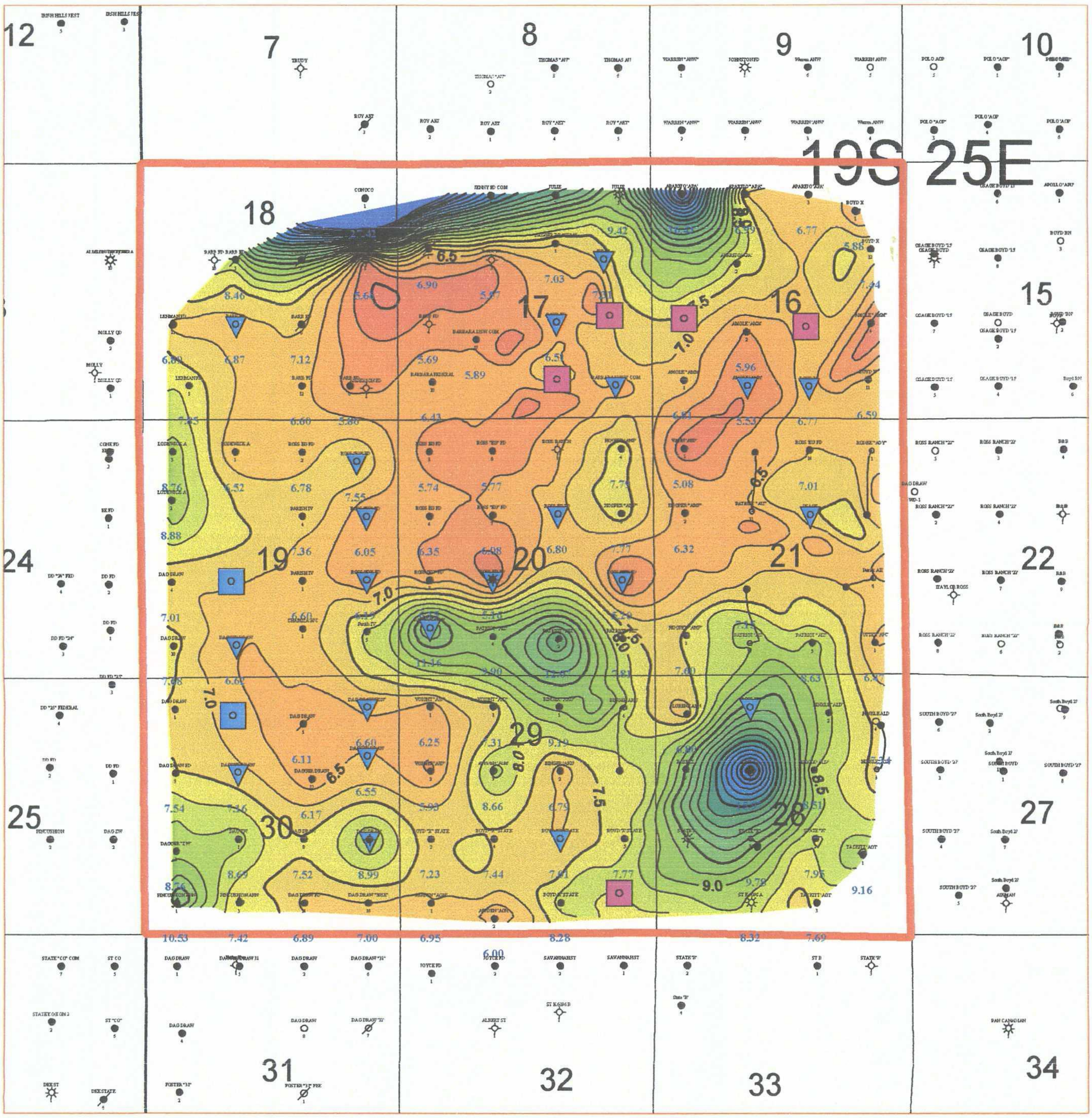
N

1000 0 1000 2000 3000 ft

YATES PETROLEUM CORPORATION

North Dagger Draw Field Unit
Canyon Dolomite
Net Feet of Porosity Above -4,380' (4% Phi Cutoff)

Contour Interval: 10'	Date: 19 November, 2002
The Scotia Group, Inc.	Scale: 1" = 3,000'



Symbol Legend

- Phase I Injector
- Phase II Injector
- Phase I Drill Well
- Phase II Drill Well

N

1000 0 1000 2000 3000 ft

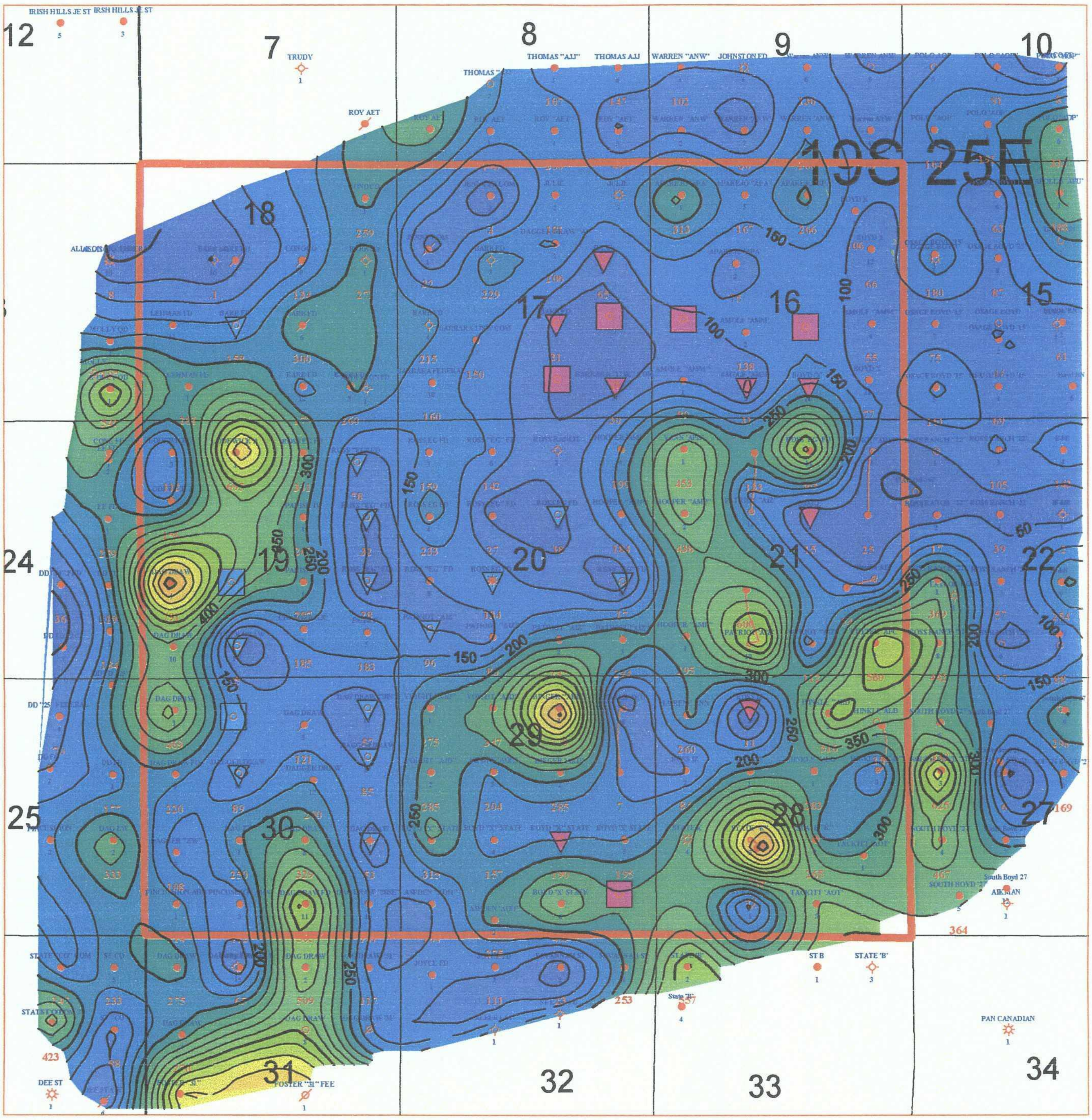
YATES PETROLEUM CORPORATION

North Dagger Draw Field Unit

Canyon Dolomite

Average Porosity Above -4,380' (4% Phi Cutoff)

Contour Interval: 0.5%	Date: 19 November, 2002
The Scotia Group, Inc.	Scale: 1" = 3,000'



Symbol Legend

- Phase I Injector
- Phase II Injector
- Phase I Drill Well
- Phase II Drill Well

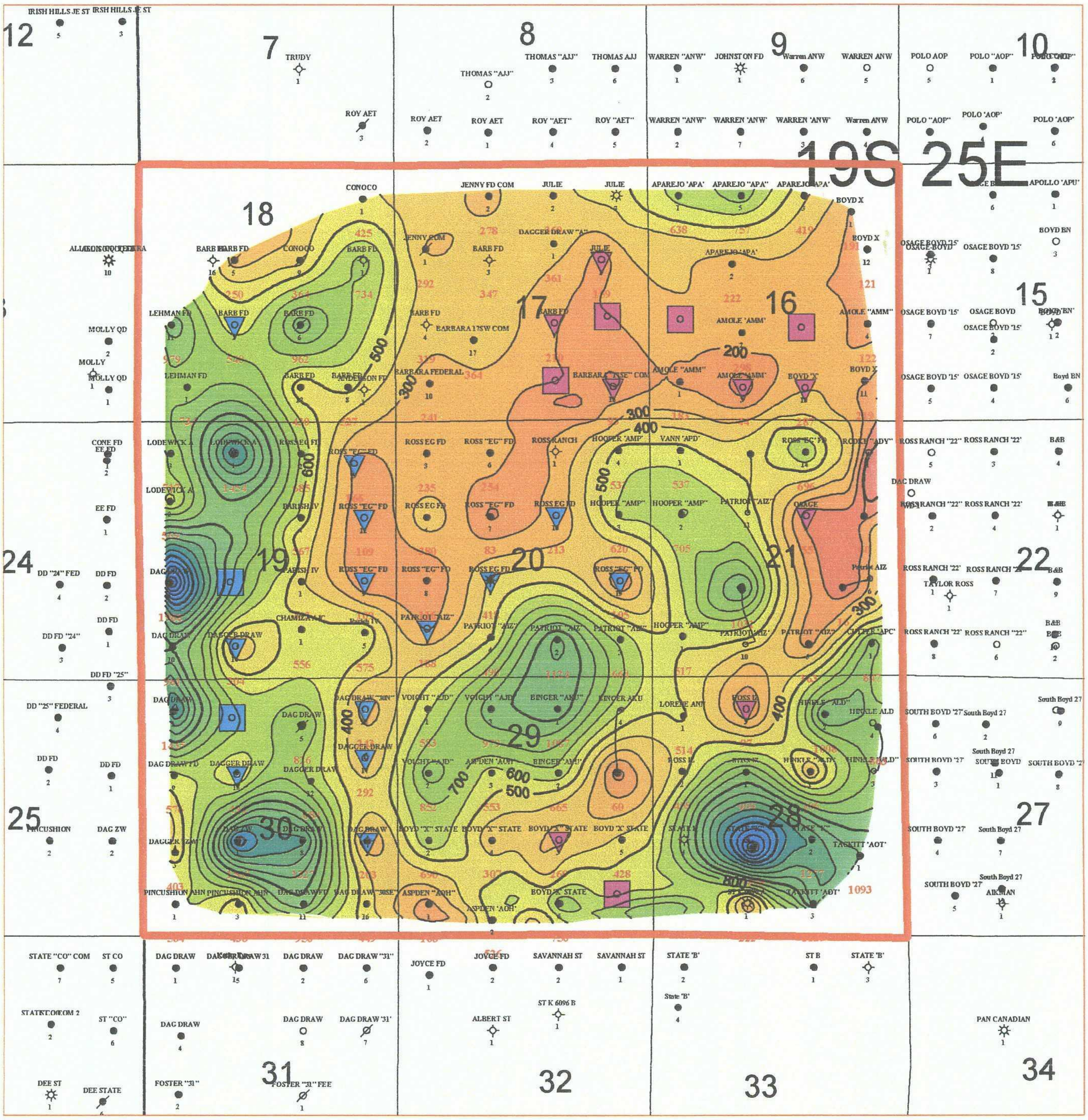
N

1000 0 1000 2000 3000 ft

YATES PETROLEUM CORPORATION

North Dagger Draw Field Unit
Canyon Dolomite
Cumulative Oil Production Through April, 2002

Contour Interval: 50 MBO	Date: 19 November, 2002
The Scotia Group, Inc.	Scale: 1" = 3,000'



Symbol Legend

- Phase 1 Injector
- Phase 2 Injector
- Phase 1 Drill Well
- Phase 2 Drill Well

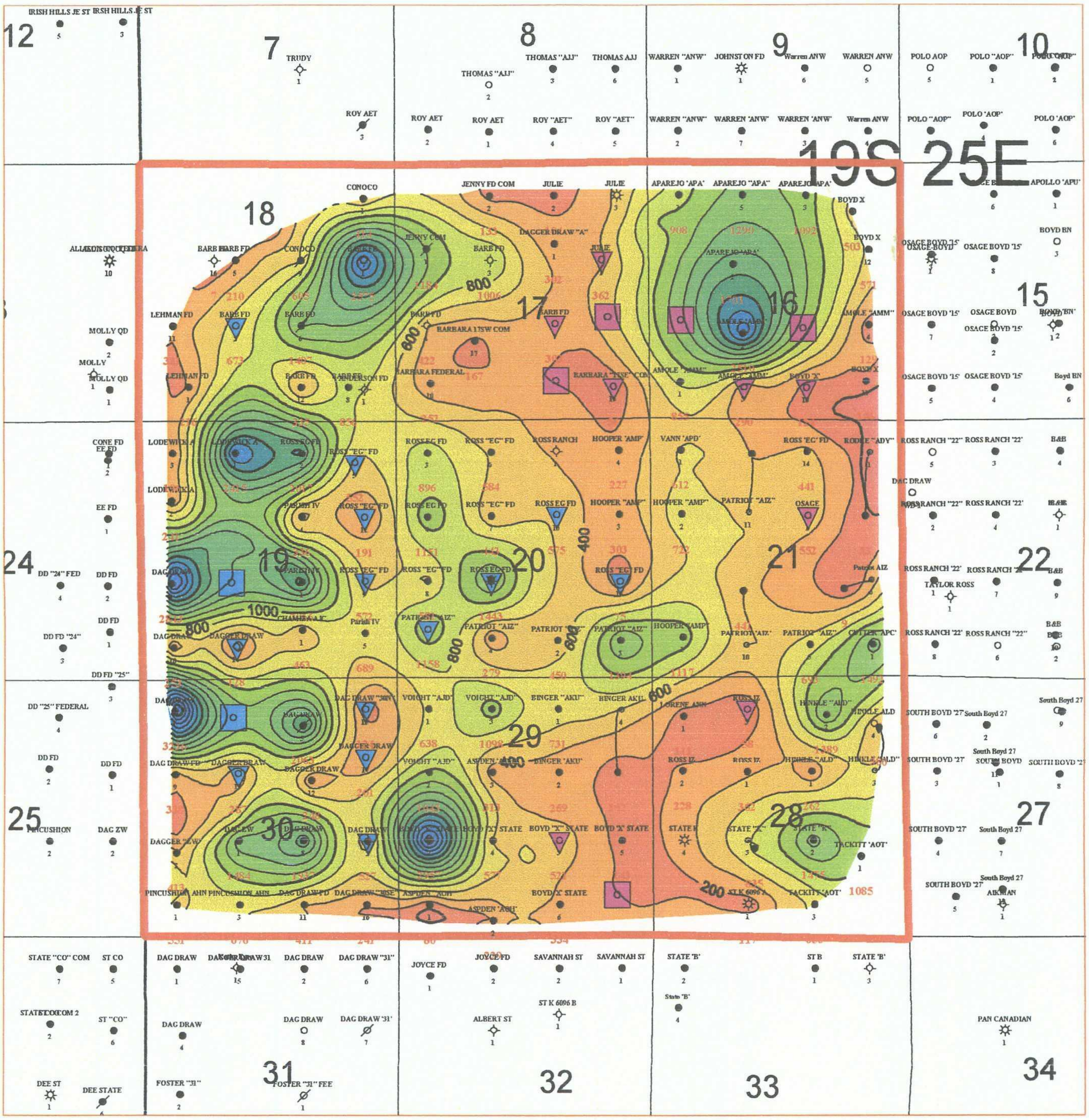
N

1000 0 1000 2000 3000 ft

YATES PETROLEUM CORPORATION

North Dagger Draw Field Unit
Canyon Dolomite
Cumulative Gas Production Through April, 2002

Contour Interval: 100 MMcf		Date: 11 November, 2002
The Scotia Group, Inc.		Scale: 1" = 3,000'



Symbol Legend

- Phase 1 Injector
- Phase 2 Injector
- Phase 1 Drill Well
- Phase 2 Drill Well

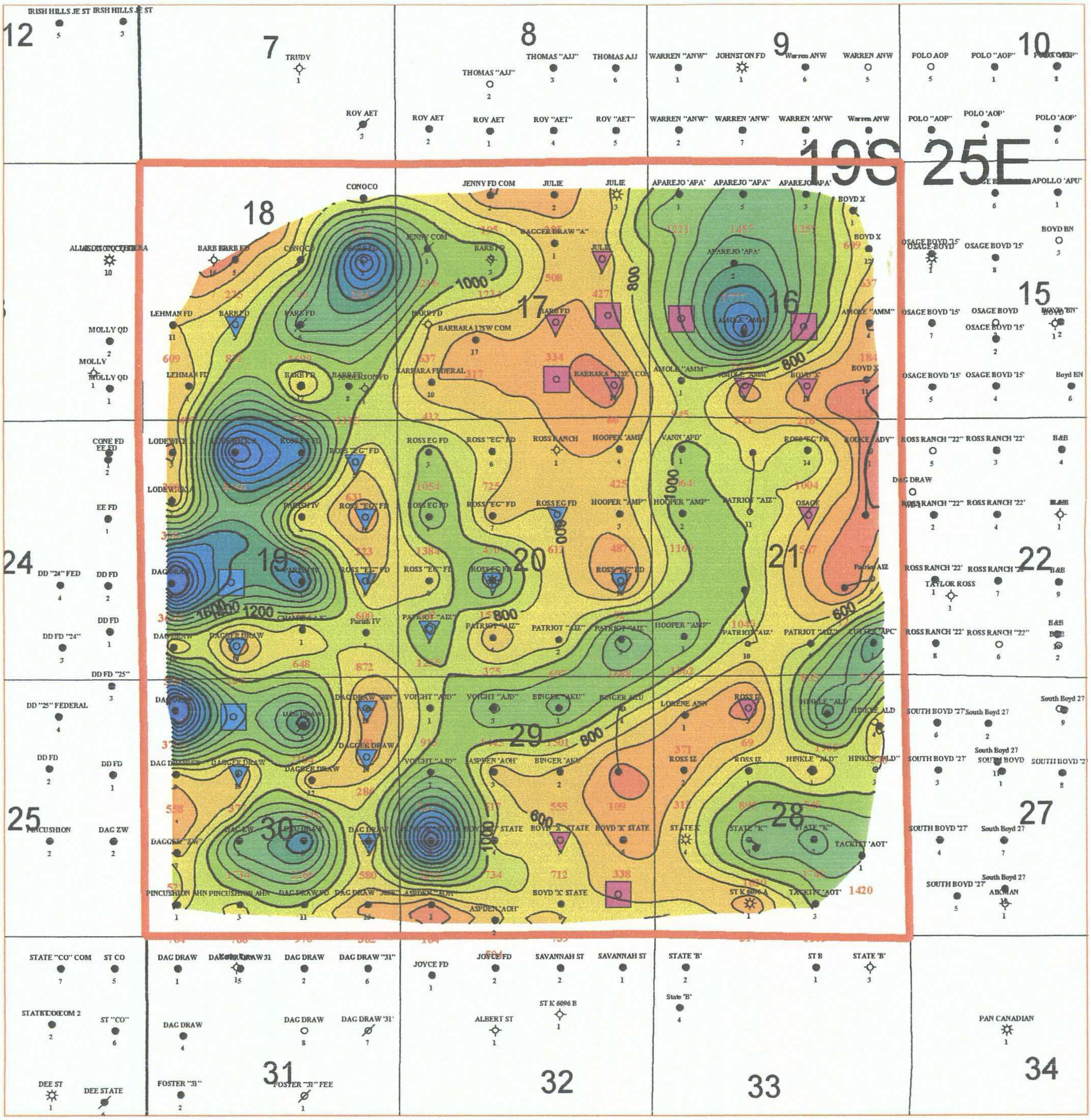
N

1000 0 1000 2000 3000 ft

YATES PETROLEUM CORPORATION

North Dagger Draw Field Unit
Canyon Dolomite
Cumulative Water Production Through April, 2002

Contour Interval: 200 MBW	Date: 11 November, 2002
The Scotia Group, Inc.	Scale: 1" = 3,000'



Symbol Legend

- Phase I Injector
- Phase II Injector
- Phase I Drill Well
- Phase II Drill Well

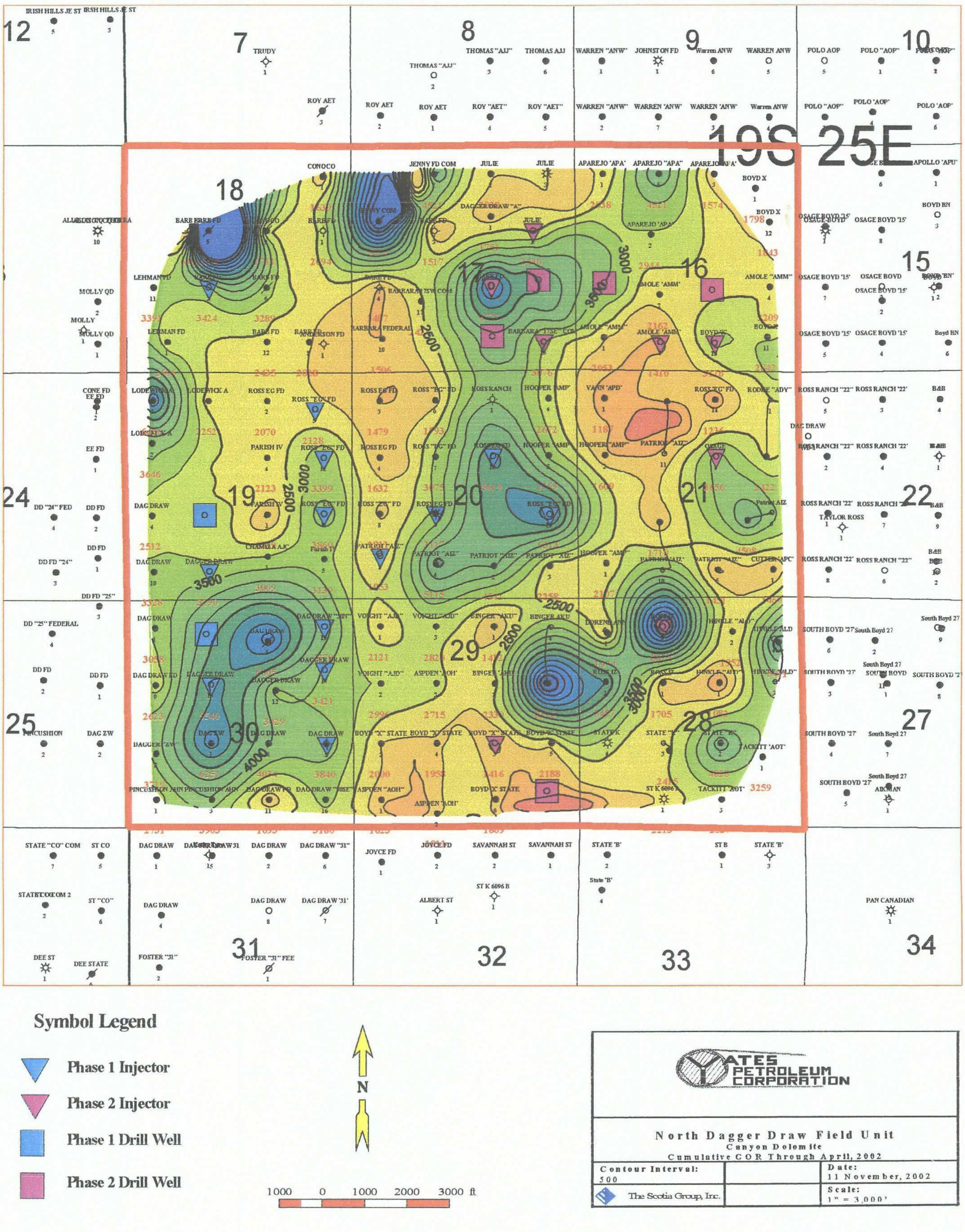
N

1000 0 1000 2000 3000 ft

YATES PETROLEUM CORPORATION

North Dagger Draw Field Unit
Canyon Dolomite
Cum. Total Fluid (Oil + Water) Production
Through April, 2002

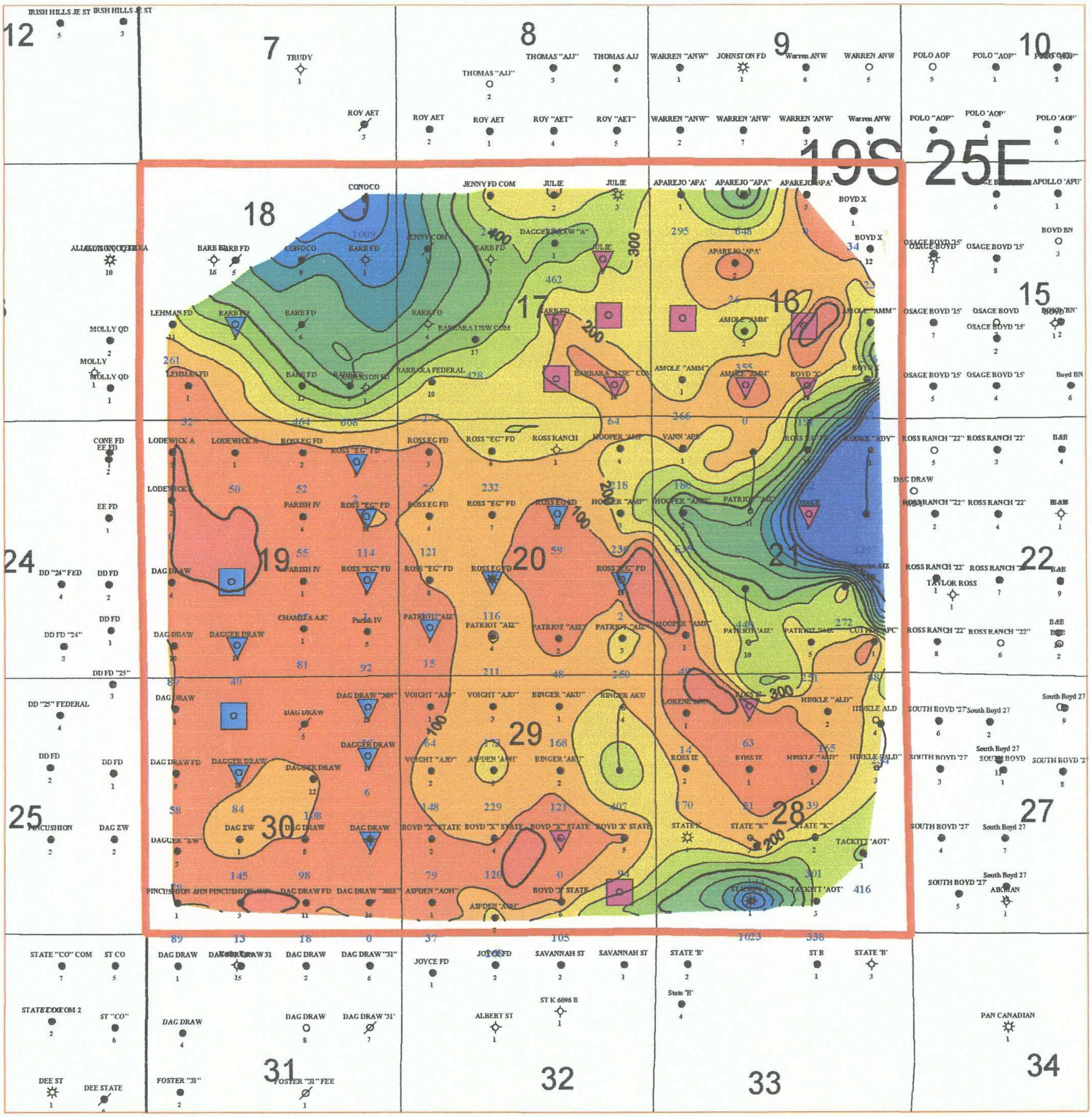
Contour Interval: 200 MBF		Date: 19 February, 2003
The Scotia Group, Inc.		Scale: 1" = 3,000'



YATES PETROLEUM CORPORATION

North Dagger Draw Field Unit
Canyon Dolomite
Cumulative GOR Through April, 2002

Contour Interval: 500	Date: 11 November, 2002
The Scotia Group, Inc.	Scale: 1" = 3,000'



Symbol Legend

- Phase I Injector
- Phase II Injector
- Phase I Drill Well
- Phase II Drill Well

N

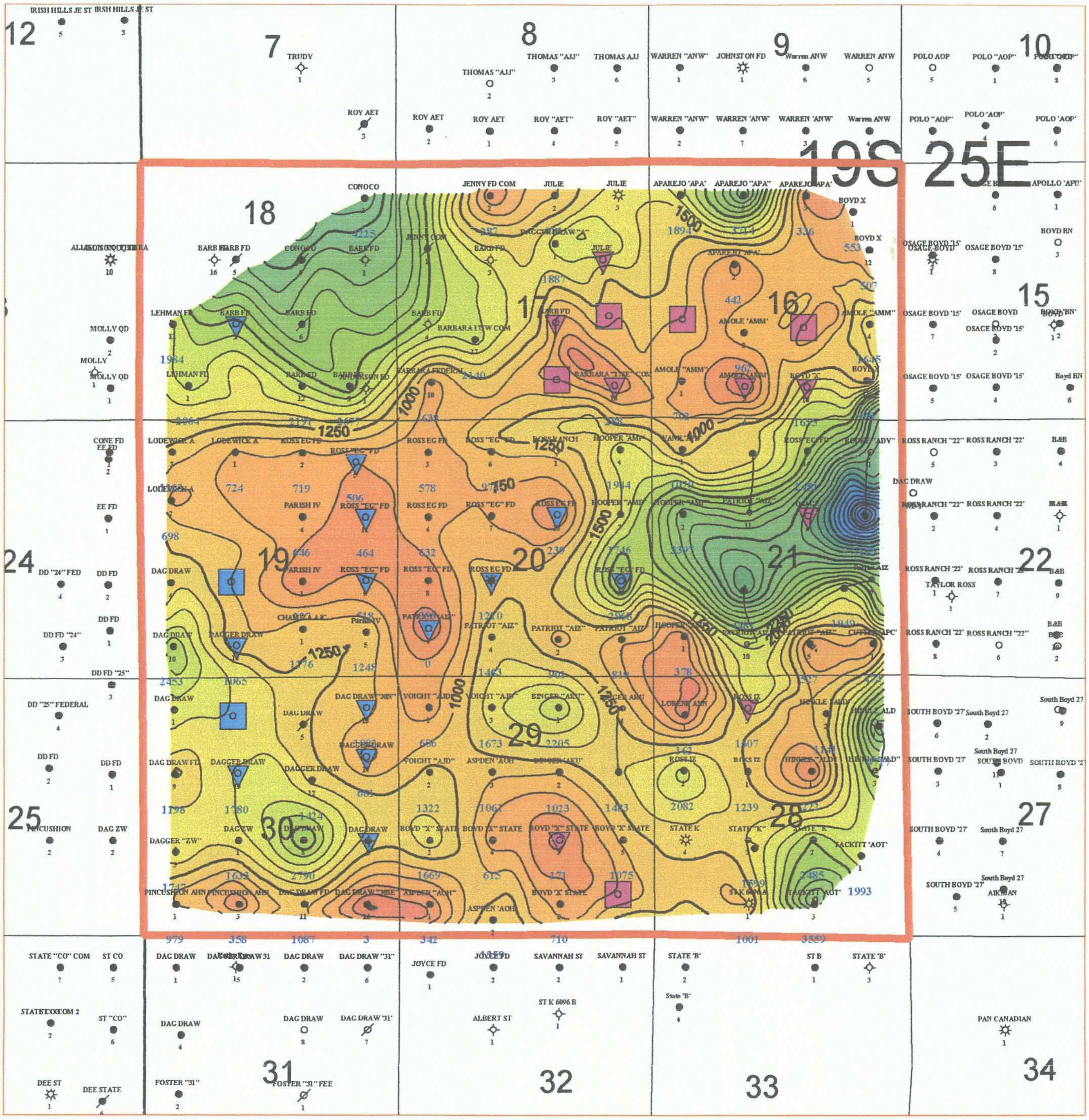
1000 0 1000 2000 3000 ft

YATES PETROLEUM CORPORATION

North Dagger Draw Field Unit

Current Oil Rate (April, 2002)

Contour Interval: 100 Bbls/Mo.	Date: 22 November, 2002
The Scotia Group, Inc.	Scale: 1" = 3,000'



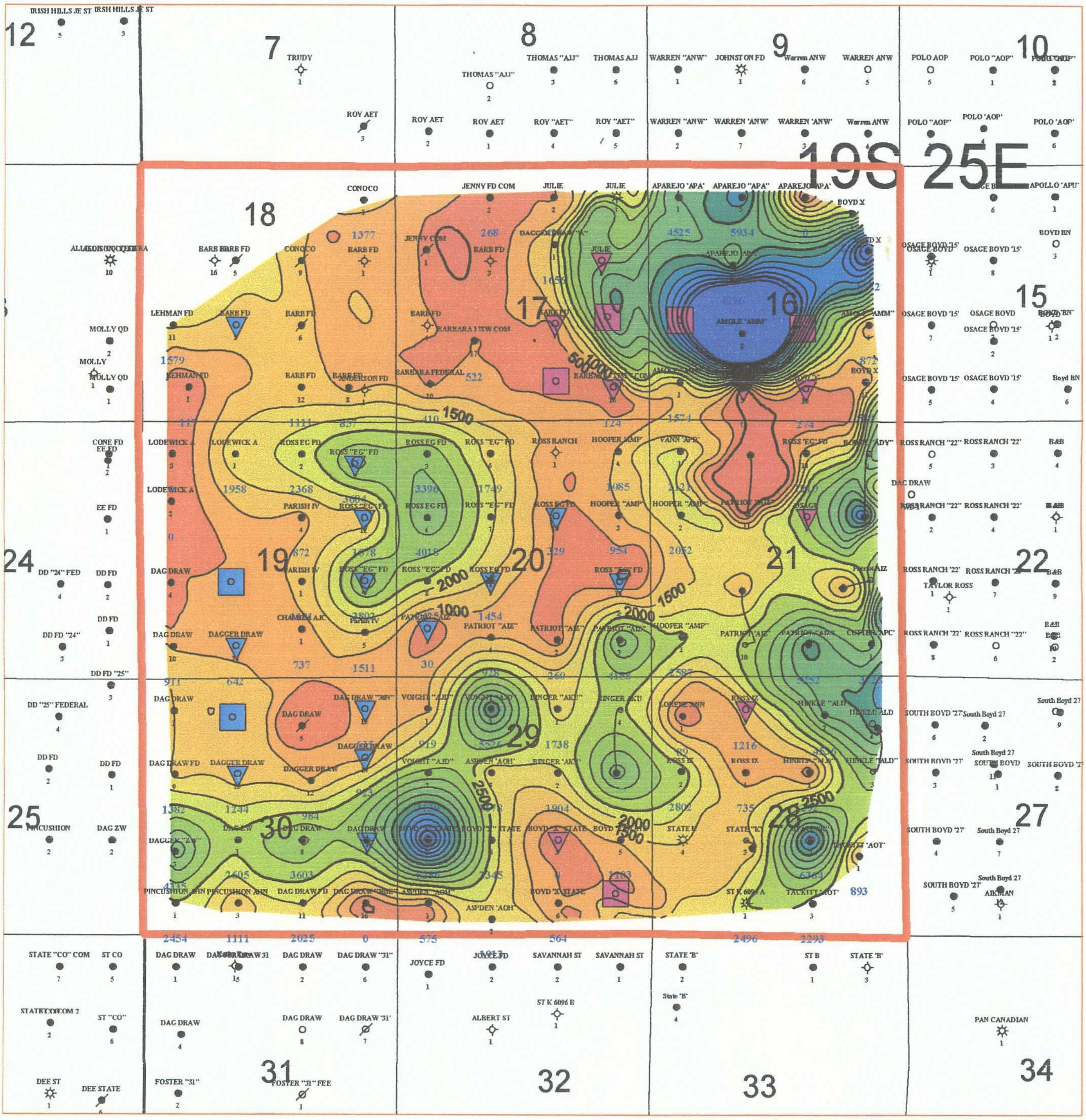
Symbol Legend

- Phase I Injector
- Phase II Injector
- Phase I Drill Well
- Phase II Drill Well

YATES PETROLEUM CORPORATION

North Dagger Draw Field Unit
Canyon Dolomite
Current Gas Rate (April, 2002)

Contour Interval: 250 Mcf/Mo.	Date: 11 November, 2002
The Scotia Group, Inc.	Scale: 1" = 3,000'



Symbol Legend

- Phase 1 Injector
- Phase 2 Injector
- Phase 1 Drill Well
- Phase 2 Drill Well

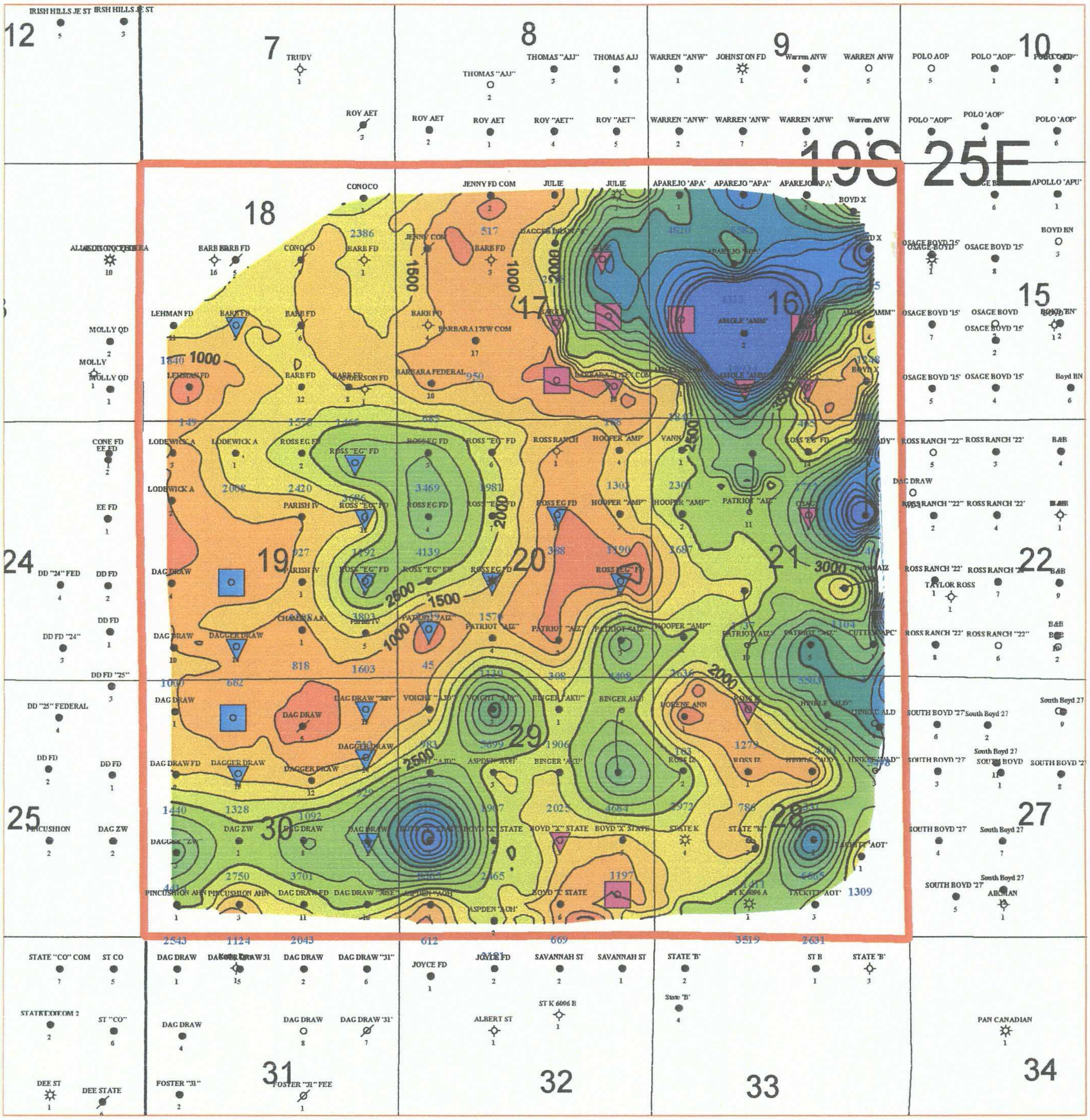
N

1000 0 1000 2000 3000 ft.

YATES PETROLEUM CORPORATION

North Dagger Draw Field Unit
Canyon Dolomite
Current Water Rate (April, 2002)

Contour Interval: 500 Bbls/Mo.	Date: 11 November, 2002
The Scotia Group, Inc.	Scale: 1" = 3,000'



Symbol Legend

- Phase I Injector
- Phase II Injector
- Phase I Drill Well
- Phase II Drill Well

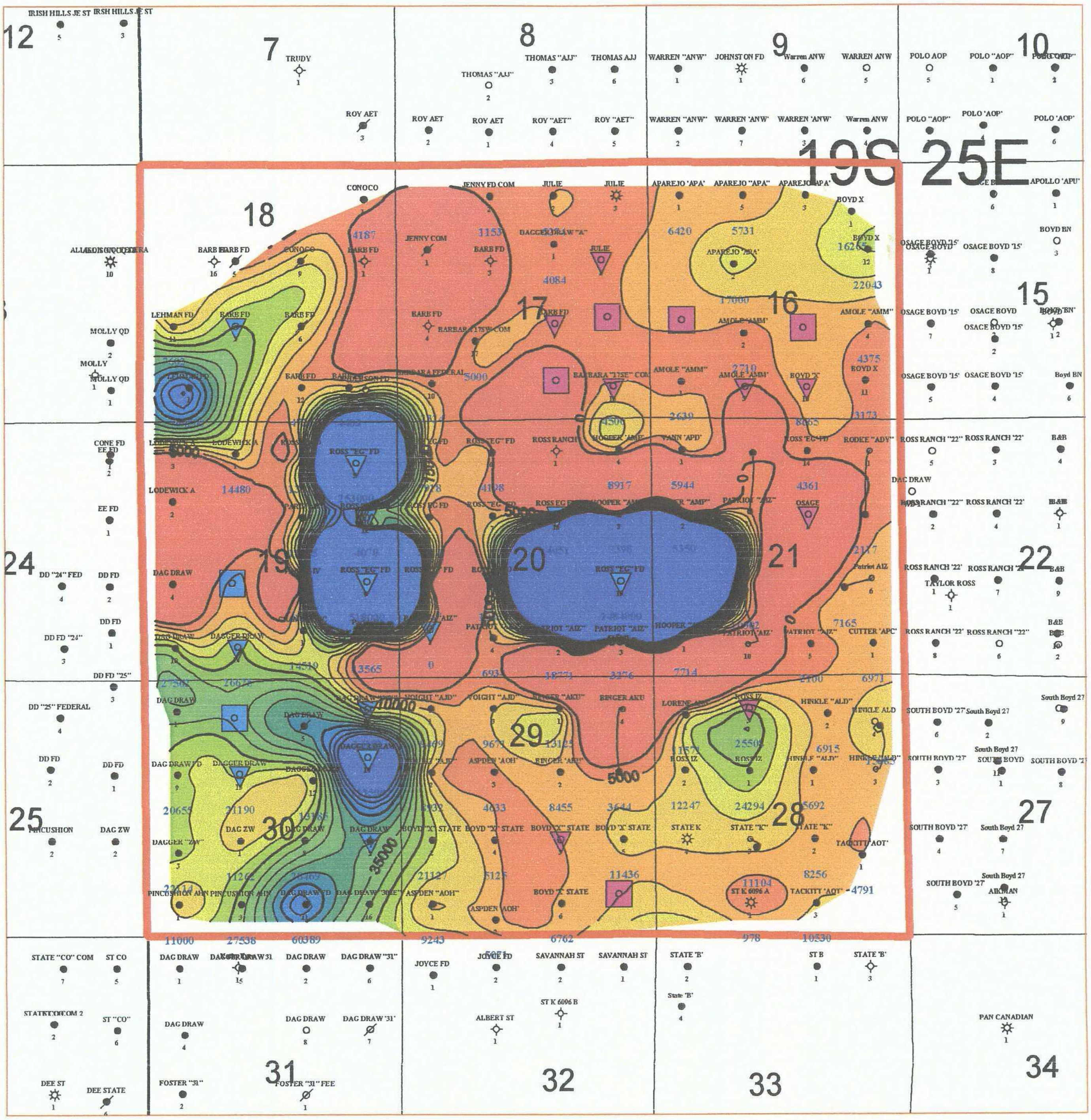
N

1000 0 1000 2000 3000 ft

YATES PETROLEUM CORPORATION

North Dagger Draw Field Unit
Canyon Dolomite
Current Total Fluid (Oil + Water) Rate
(April, 2002)

Contour Interval: 500 Bbls/Mo.	Date: 26 February, 2003
The Scotia Group, Inc.	Scale: 1" = 3,000'



Symbol Legend

- Phase I Injector
- Phase II Injector
- Phase I Drill Well
- Phase II Drill Well

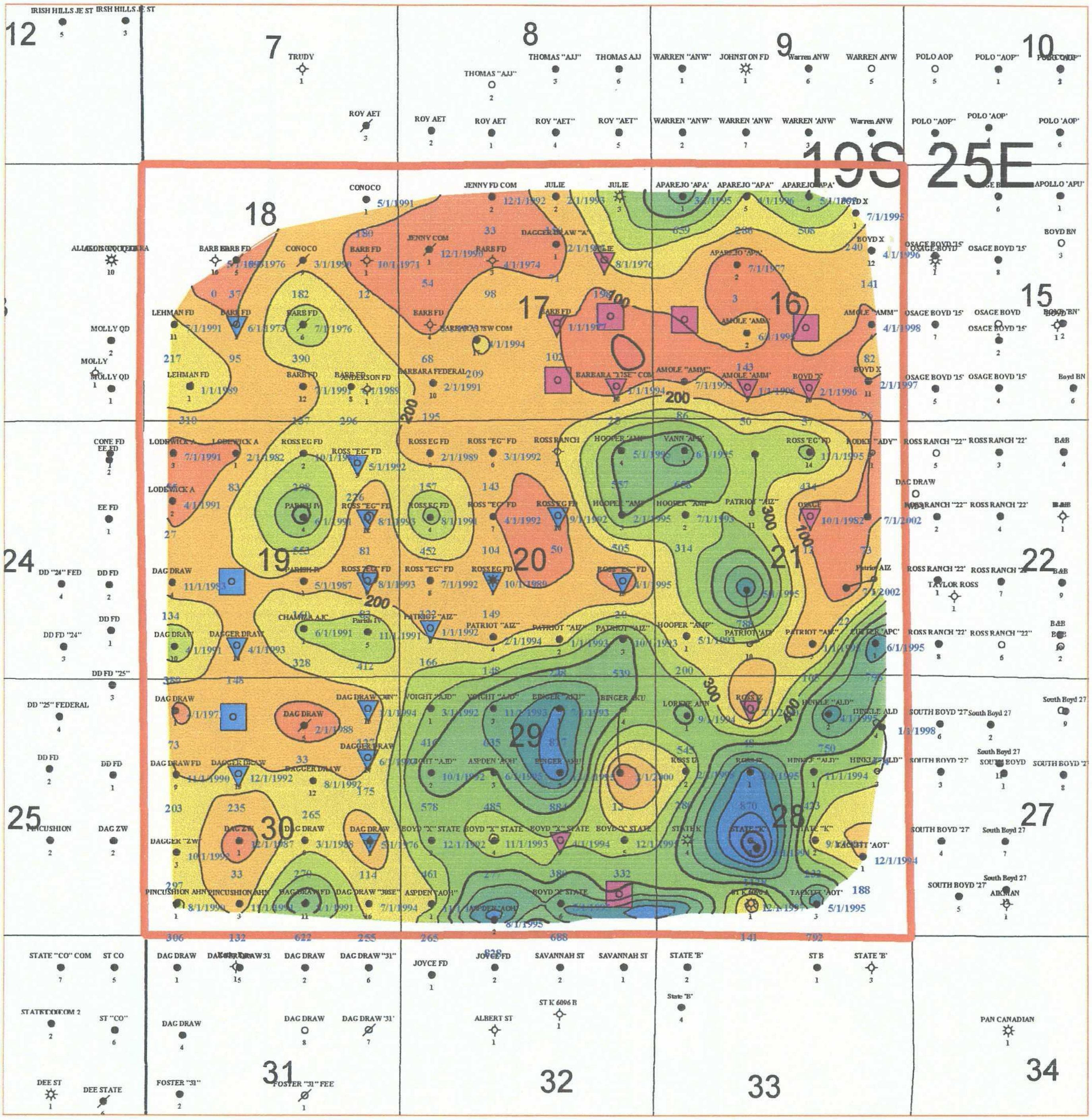
N

1000 0 1000 2000 3000 ft

YATES PETROLEUM CORPORATION

North Dagger Draw Field Unit
Canyon Dolomite
Current GOR (April, 2002)

Contour Interval: 5,000	Date: 19 November, 2002
The Scotia Group, Inc.	Scale: 1" = 3,000'



Symbol Legend

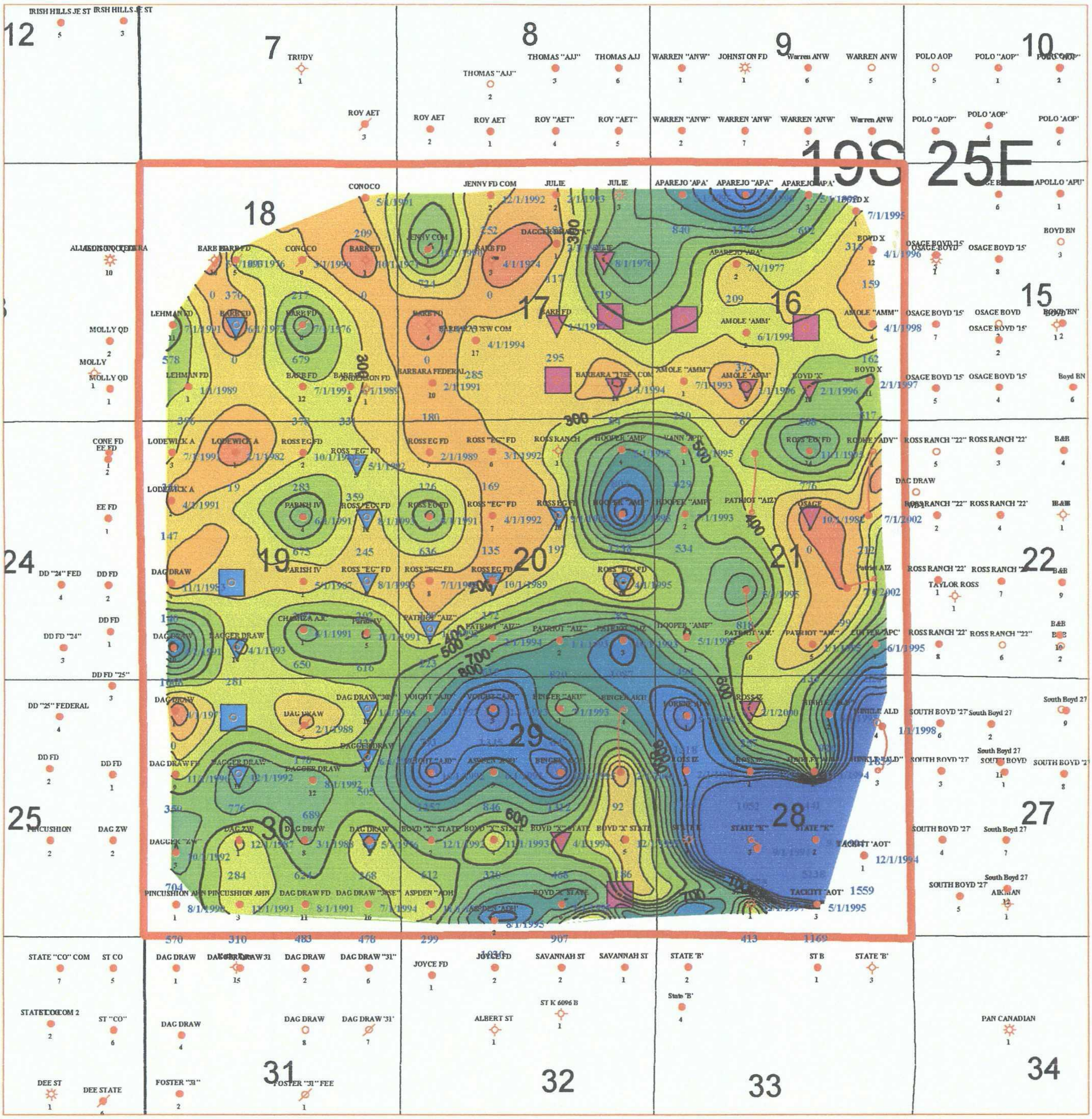
- Phase 1 Injector
- Phase 2 Injector
- Phase 1 Drill Well
- Phase 2 Drill Well

1000 0 1000 2000 3000 ft

YATES PETROLEUM CORPORATION

North Dagger Draw Field Unit
Canyon Dolomite
Initial Oil Rate

Contour Interval:		Date:
100 Bbls/Day		12 November, 2002
The Scotia Group, Inc.		Scale: 1" = 3,000'



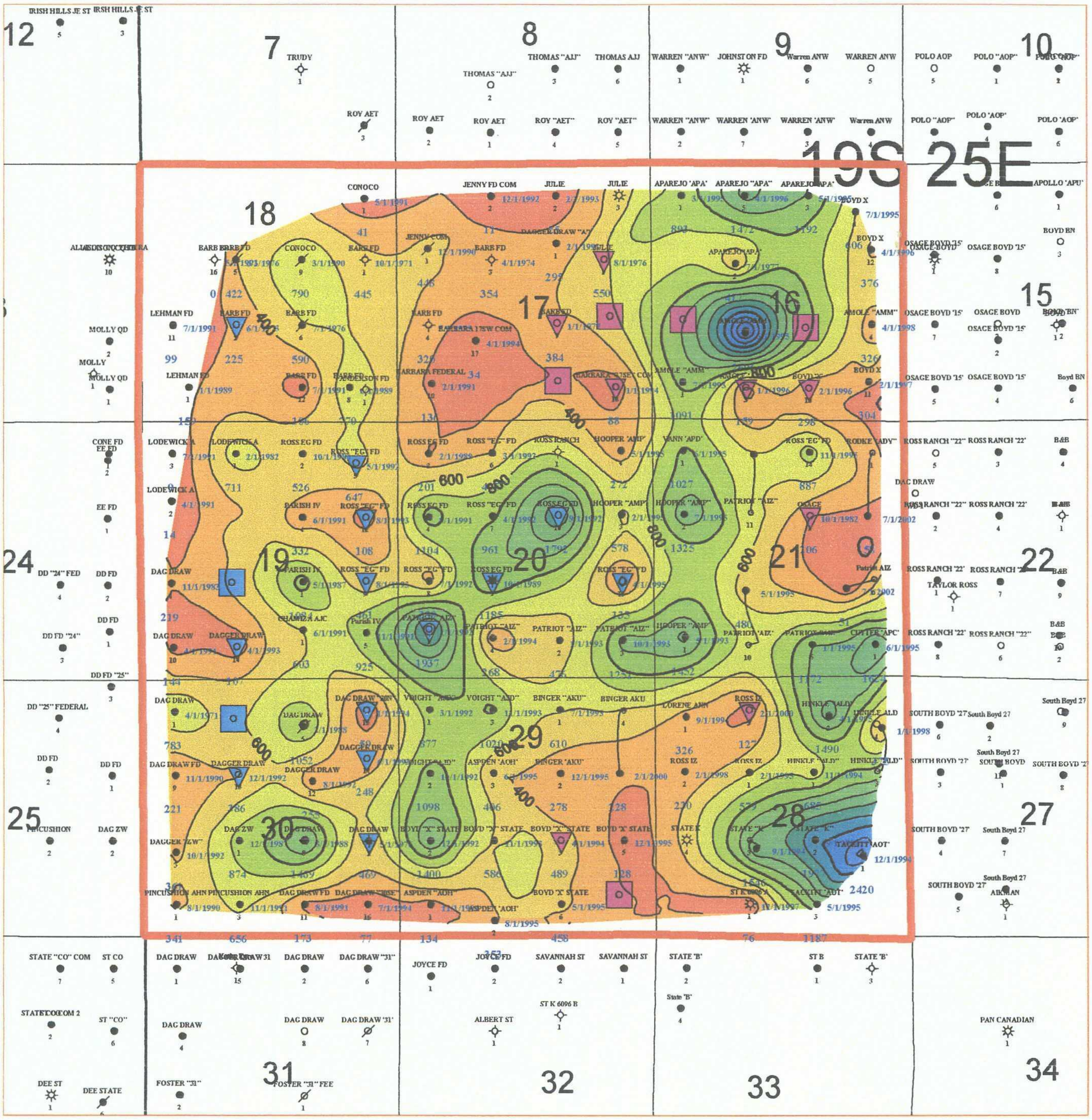
Symbol Legend

- Phase 1 Injector
- Phase 2 Injector
- Phase 1 Drill Well
- Phase 2 Drill Well

YATES PETROLEUM CORPORATION

North Dagger Draw Field Unit
Canyon Dolomite
Initial Gas Rate

Contour Interval: 100 M cf/D		Date: 12 November, 2002
The Scotia Group, Inc.		Scale: 1" = 3,000'



Symbol Legend

- Phase 1 Injector
- Phase 2 Injector
- Phase 1 Drill Well
- Phase 2 Drill Well

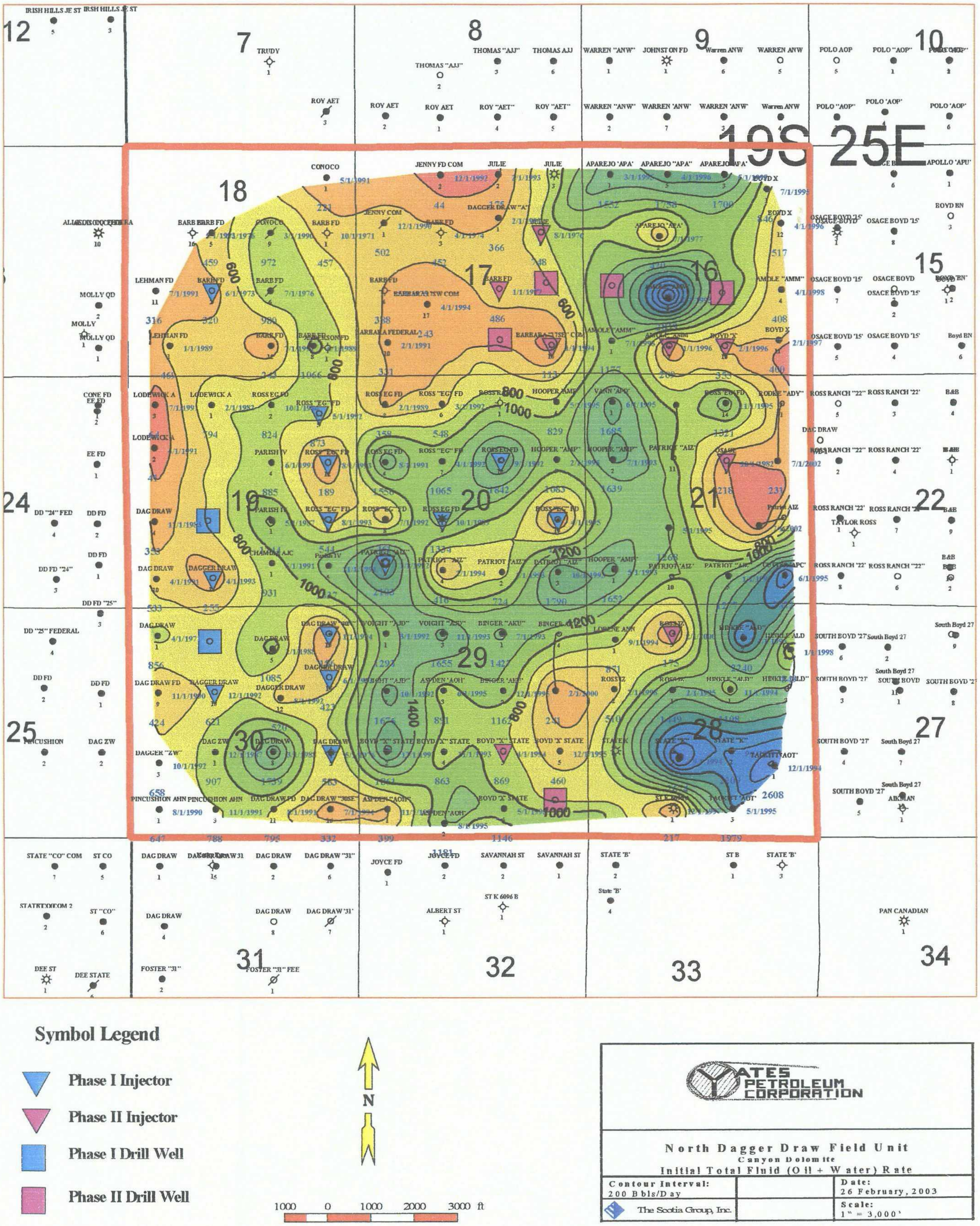
N

1000 0 1000 2000 3000 ft

YATES PETROLEUM CORPORATION

North Dagger Draw Field Unit
Canyon Dolomite
Initial Water Rate

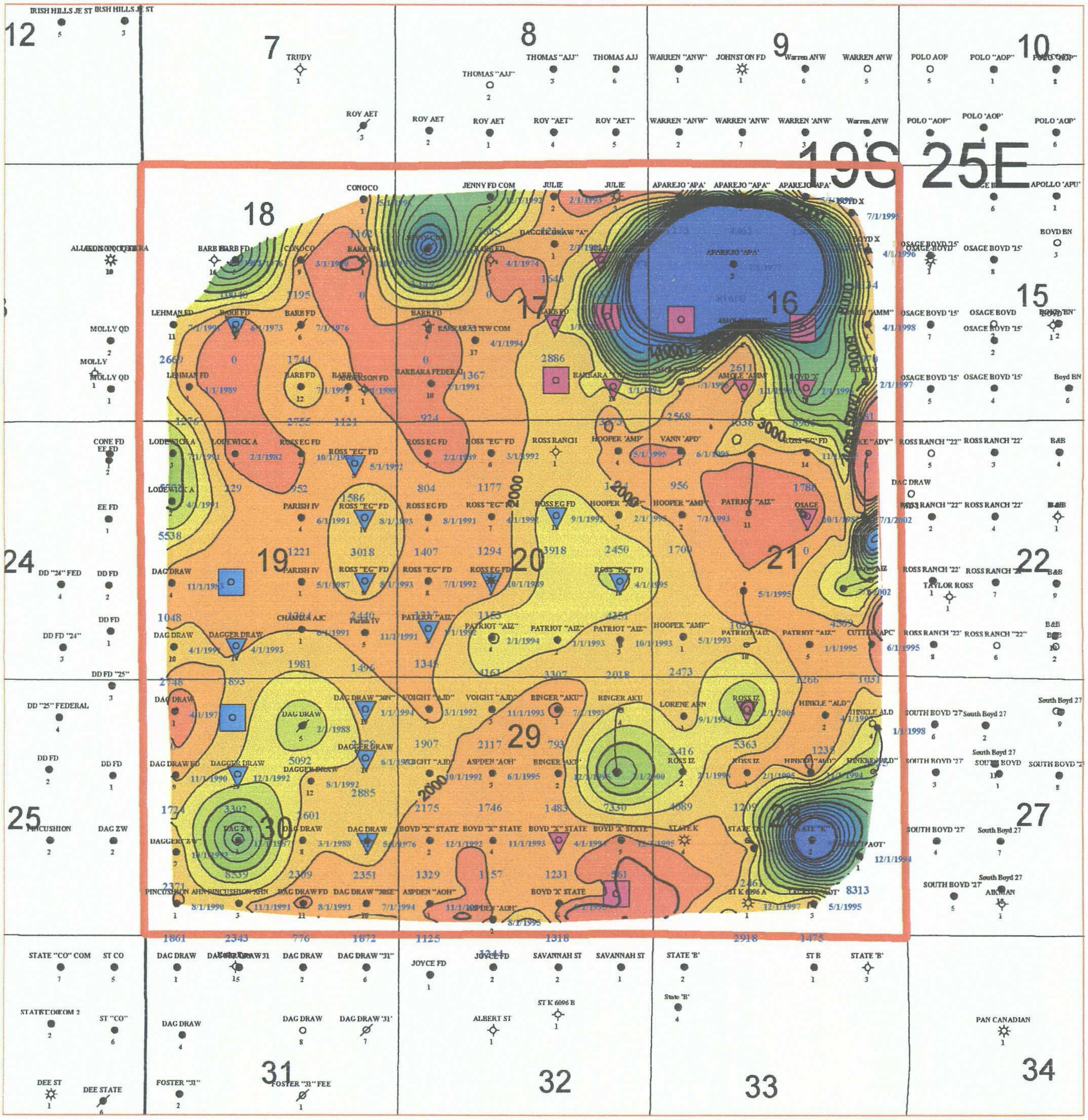
Contour Interval: 200 Bbls/Day	Date: 12 November, 2002
The Scotia Group, Inc.	Scale: 1" = 3,000'



YATES PETROLEUM CORPORATION

North Dagger Draw Field Unit
Canyon Dolomite
Initial Total Fluid (Oil + Water) Rate

Contour Interval: 200 Bbls/Day	Date: 26 February, 2003
The Scotia Group, Inc.	Scale: 1" = 3,000'



Symbol Legend

- Phase 1 Injector
- Phase 2 Injector
- Phase 1 Drill Well
- Phase 2 Drill Well

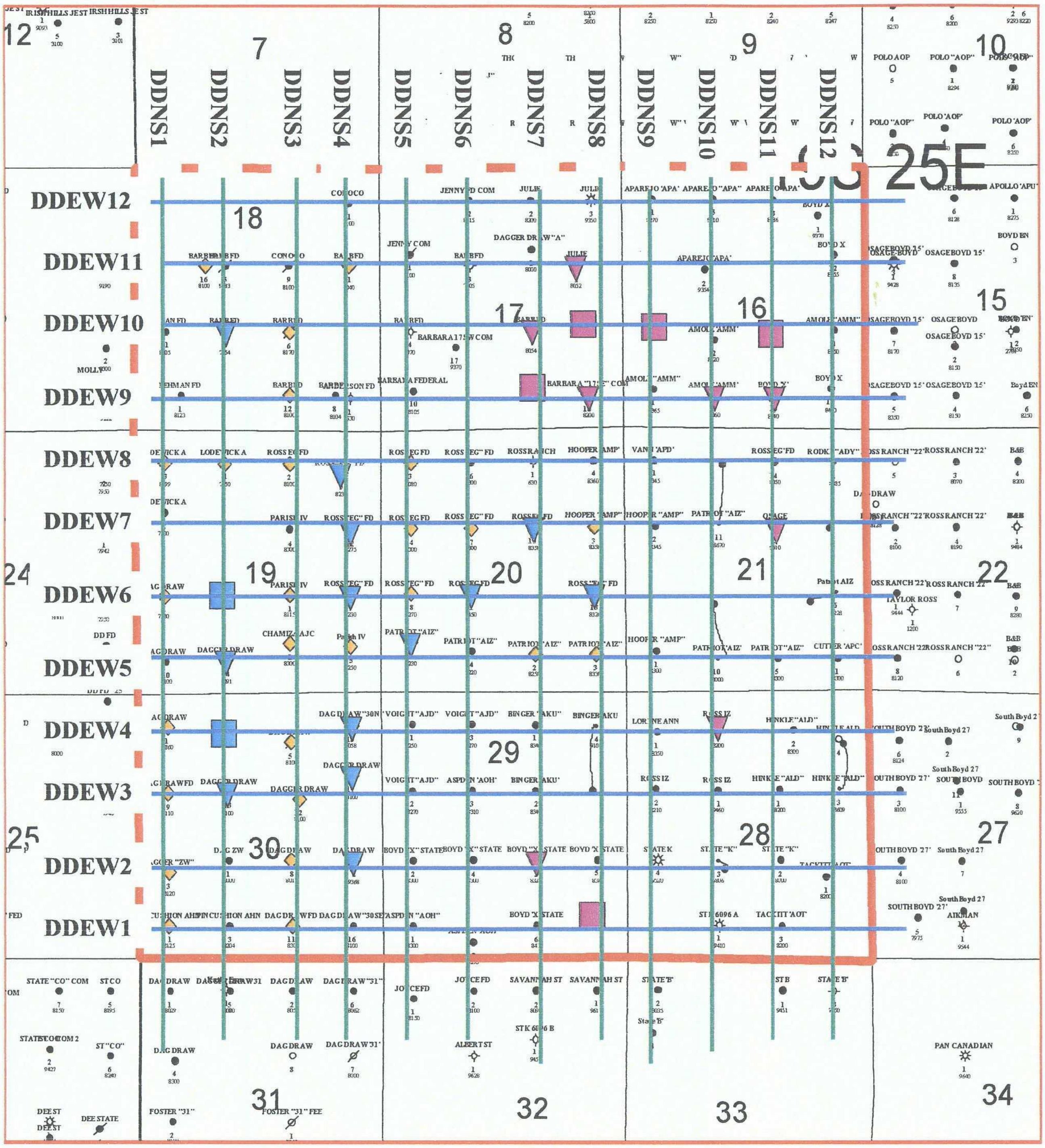
N

1000 0 1000 2000 3000 ft

YATES PETROLEUM CORPORATION

North Dagger Draw Field Unit
Canyon Dolomite
Initial GOR

Contour Interval:		Date:
1,000		12 November, 2002
The Scotia Group, Inc.		Scale: 1" = 3,000'



Symbol Legend

- Phase 1 Injector
- Phase 2 Injector
- Phase 1 Drill Well
- Phase 2 Drill Well
- Phase 1 Workover

N

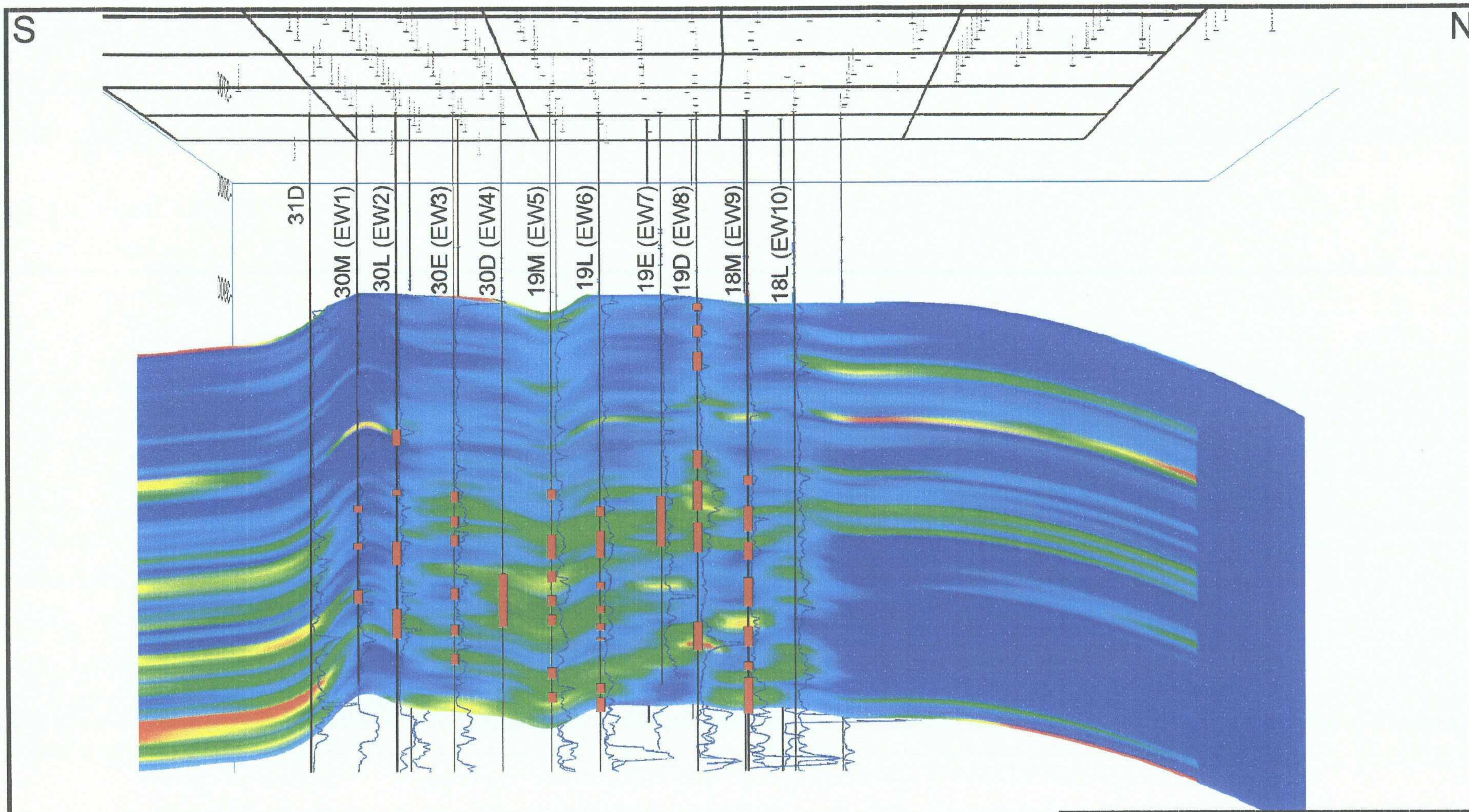
1000 0 1000 2000 3000 ft

YATES PETROLEUM CORPORATION

North Dagger Draw Field Unit

Geocell Cross-Section Index

Contour Interval:	**Date:** 12 November, 2002
The Scotia Group, Inc.	**Scale:** 1" = 3,000'



Yates Petroleum Corporation

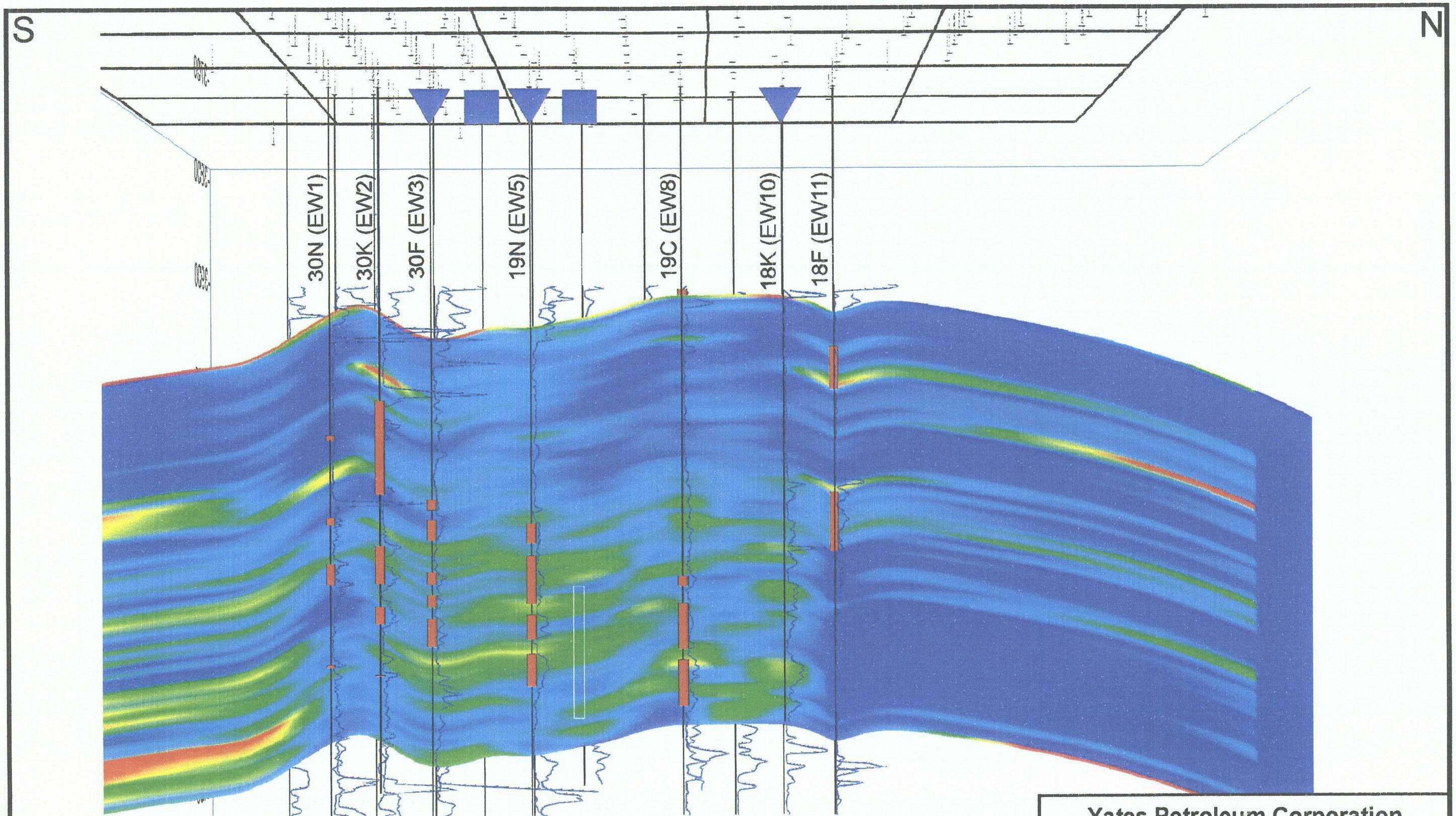
DDNS1

*Porosity curves increase to the right.

Prepared by The Scotia Group

Date: 11/13/2002

Figure 31



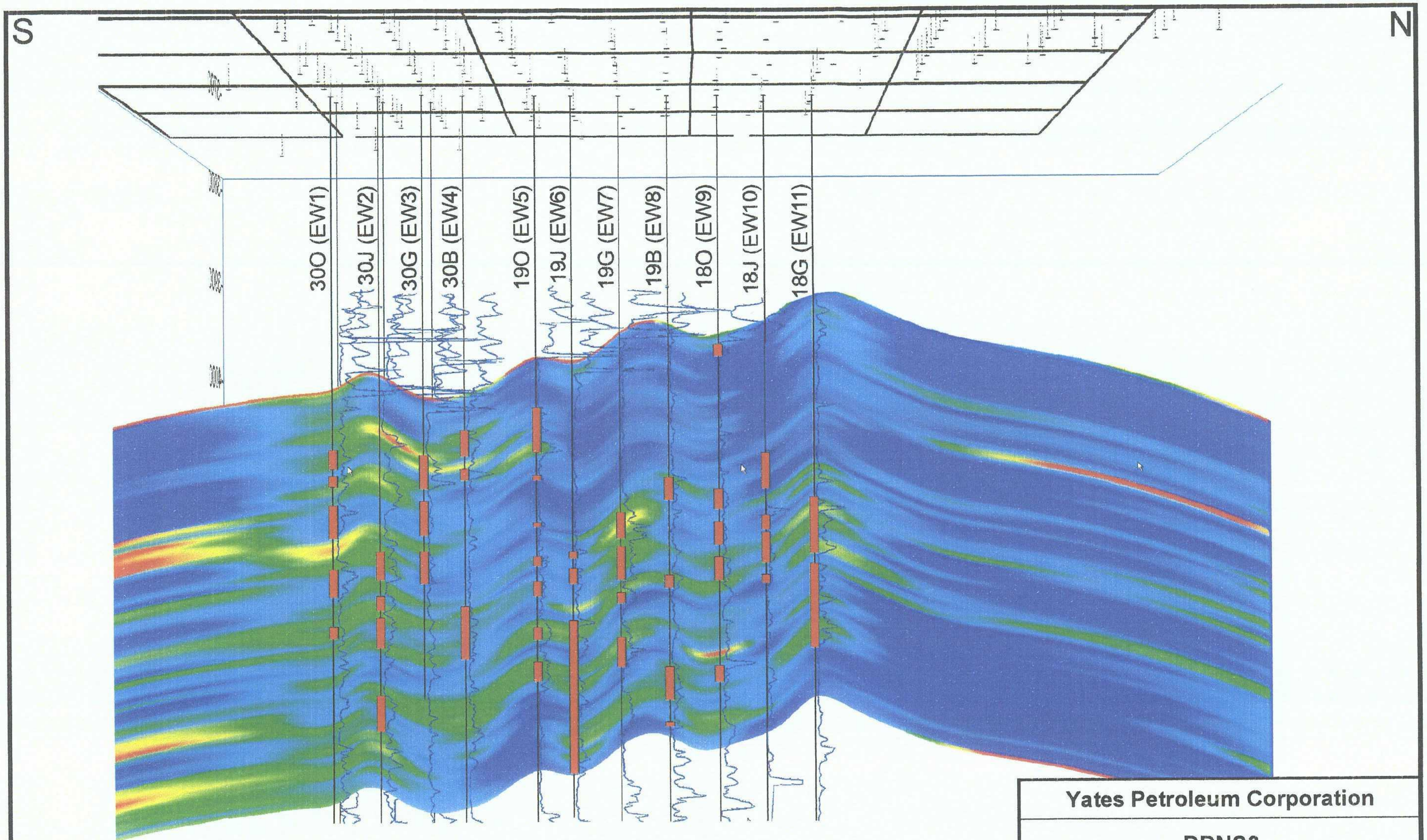
Yates Petroleum Corporation

DDNS2

■ Proposed Phase 1 Well Location
▼ Proposed Phase 1 Injector
*Porosity curves increase to the right.

Prepared by The Scotia Group

Date: 11/13/2002 | Figure 32



Yates Petroleum Corporation

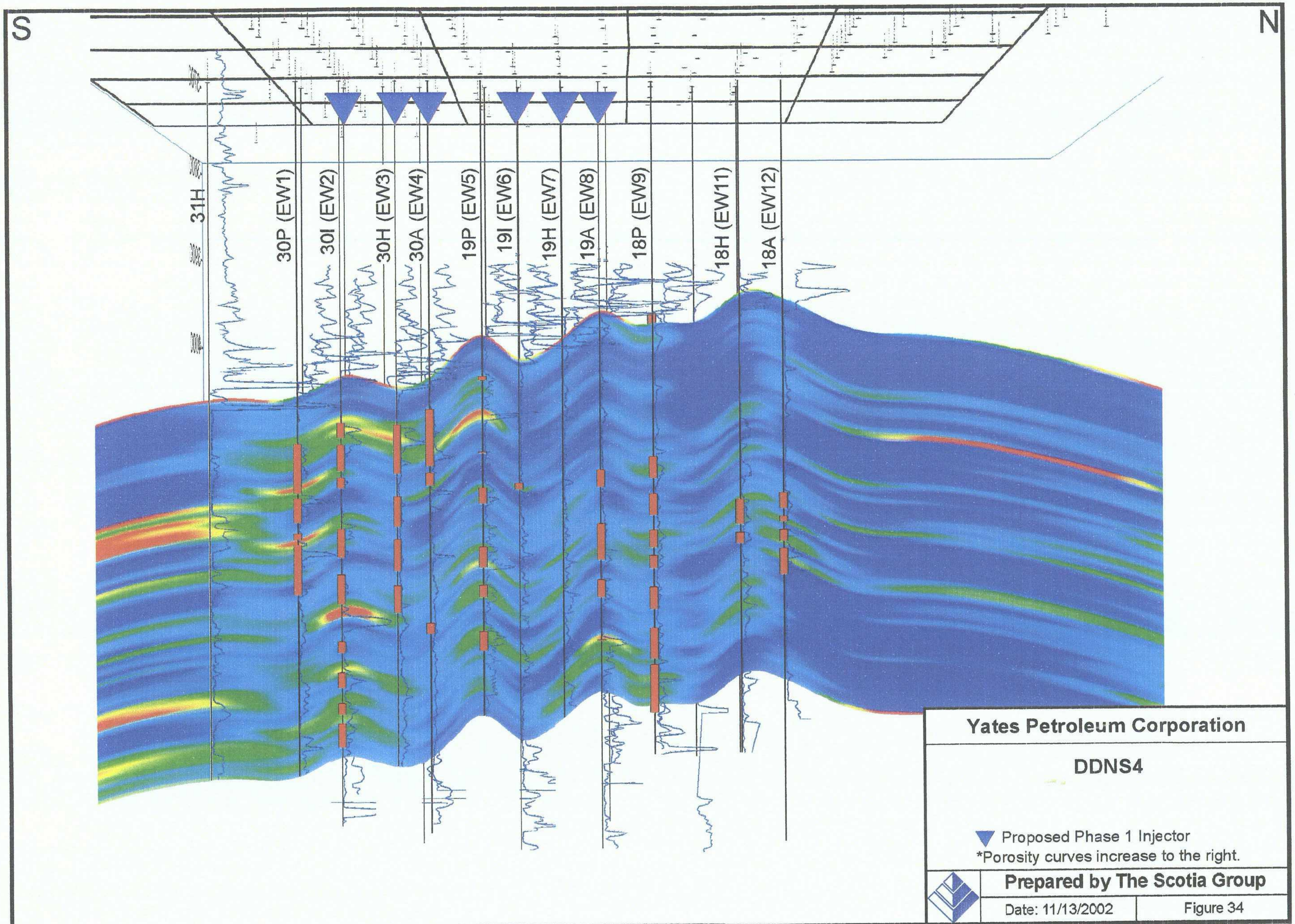
DDNS3

*Porosity curves increase to the right.

Prepared by The Scotia Group

Date: 11/13/2002

Figure 33



Yates Petroleum Corporation

DDNS4

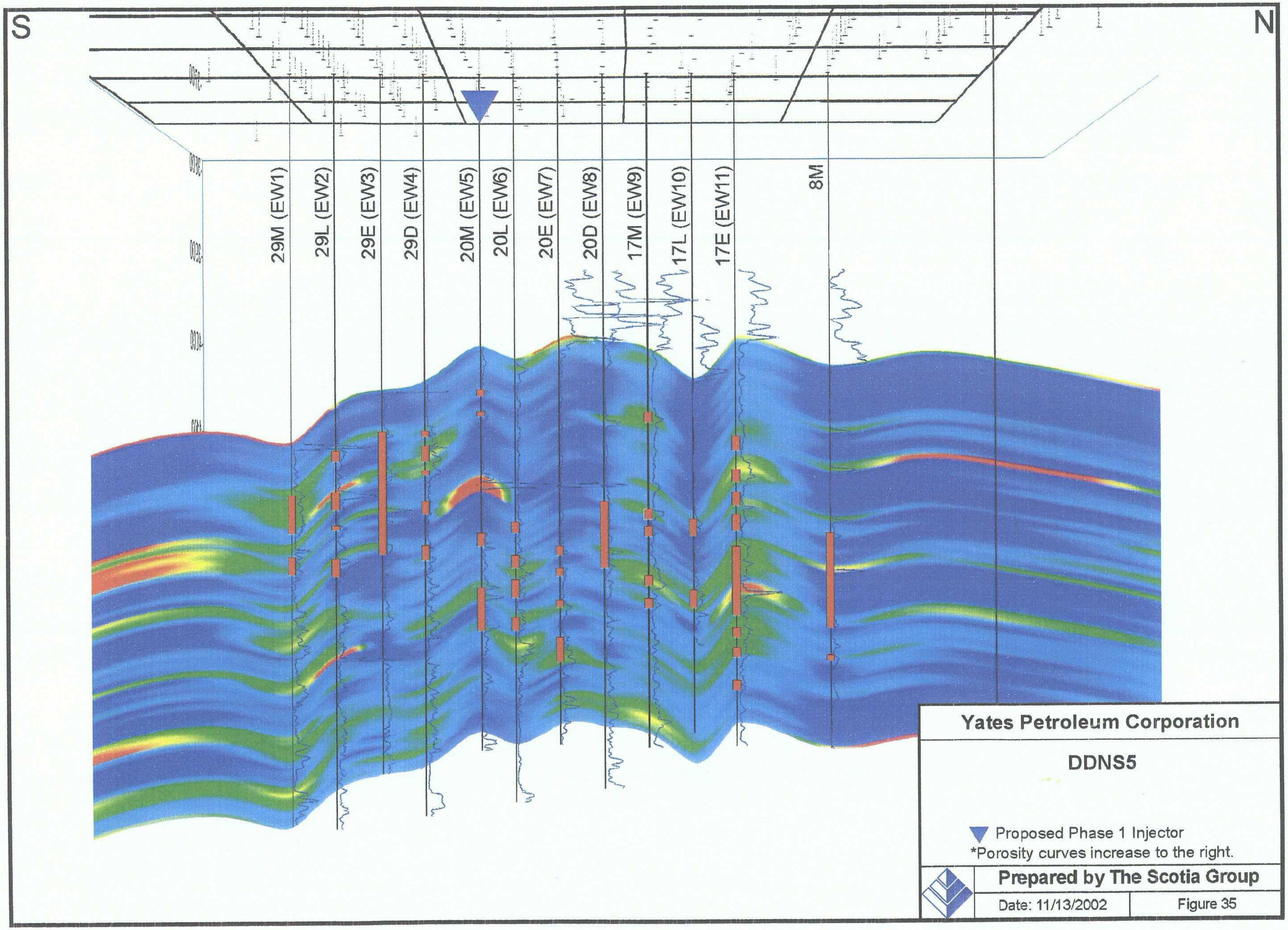
▼ Proposed Phase 1 Injector

*Porosity curves increase to the right.

Prepared by The Scotia Group

Date: 11/13/2002

Figure 34



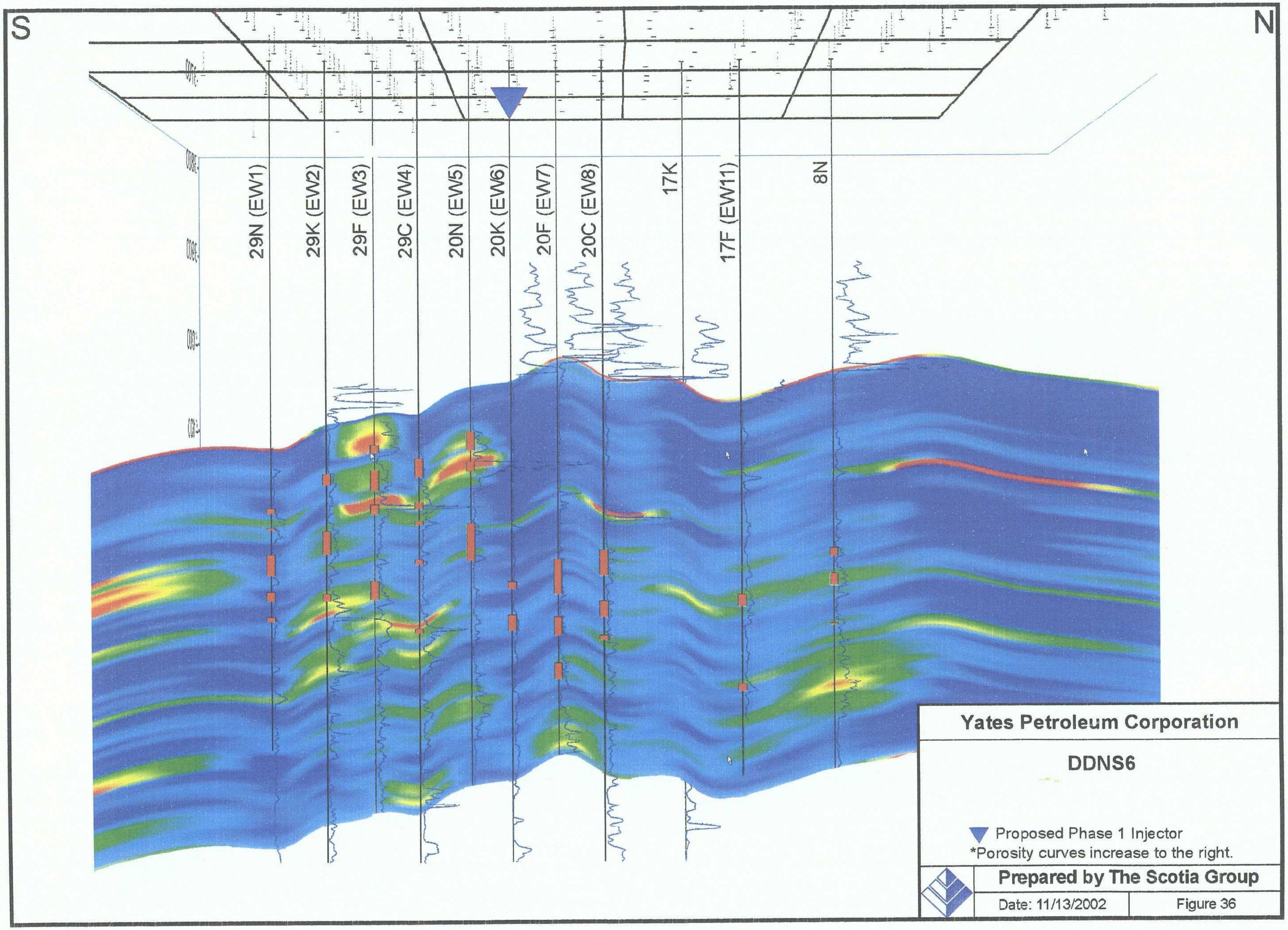
Yates Petroleum Corporation

DDNS5

▼ Proposed Phase 1 Injector
*Porosity curves increase to the right.

Prepared by The Scotia Group

Date: 11/13/2002 | Figure 35



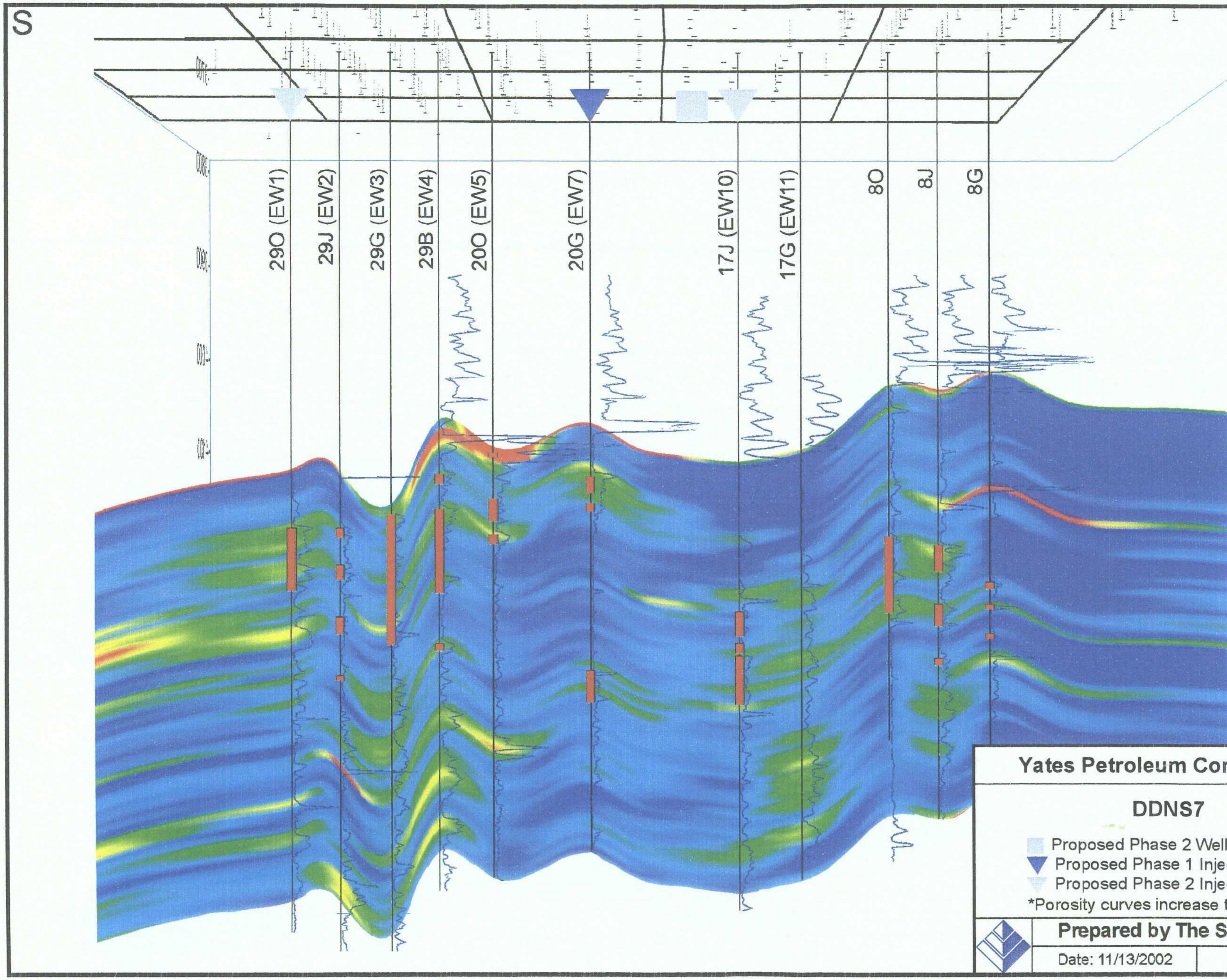
Yates Petroleum Corporation

DDNS6

▼ Proposed Phase 1 Injector
*Porosity curves increase to the right.

Prepared by The Scotia Group

Date: 11/13/2002 | Figure 36



Yates Petroleum Corporation

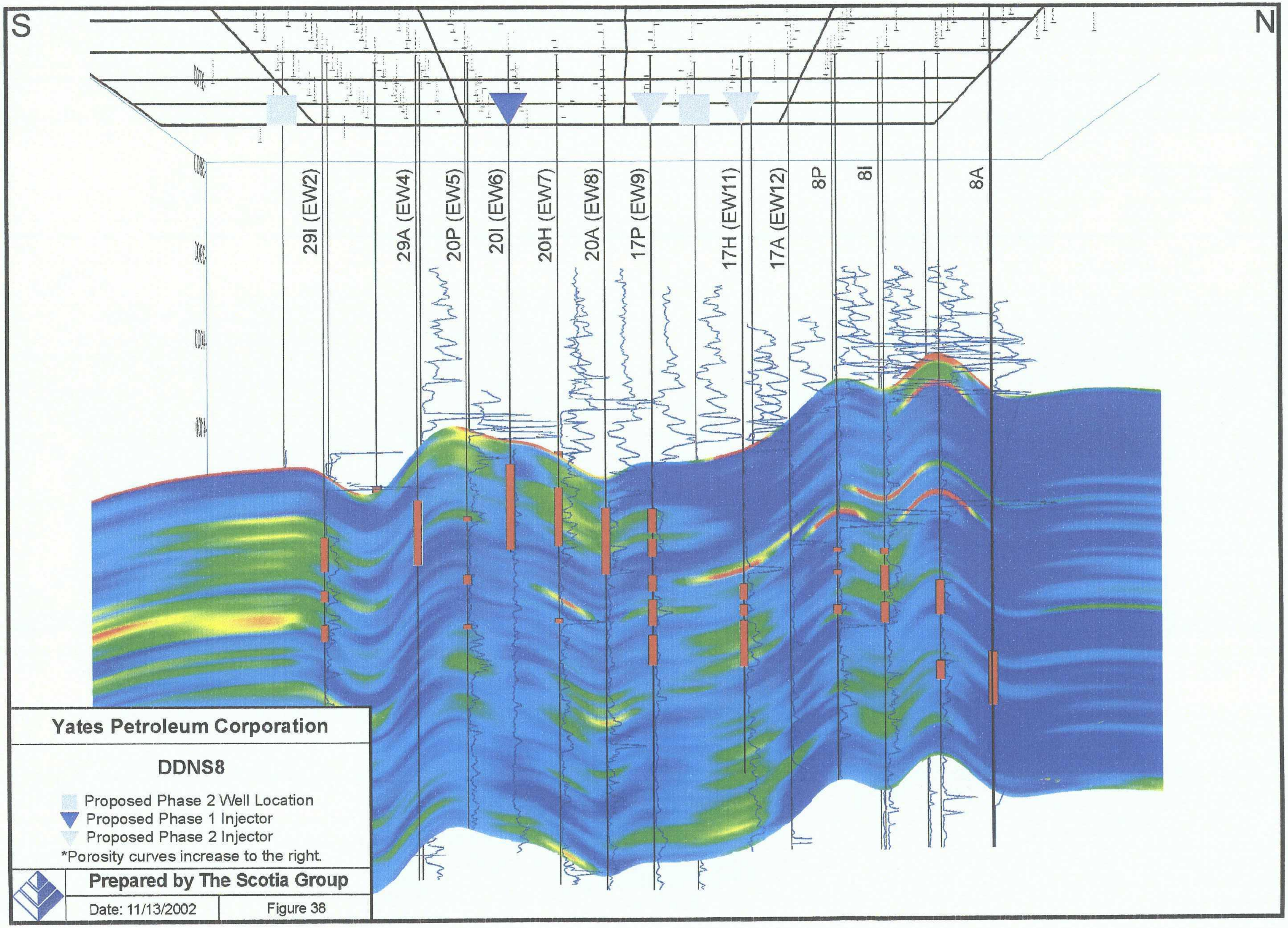
DDNS7

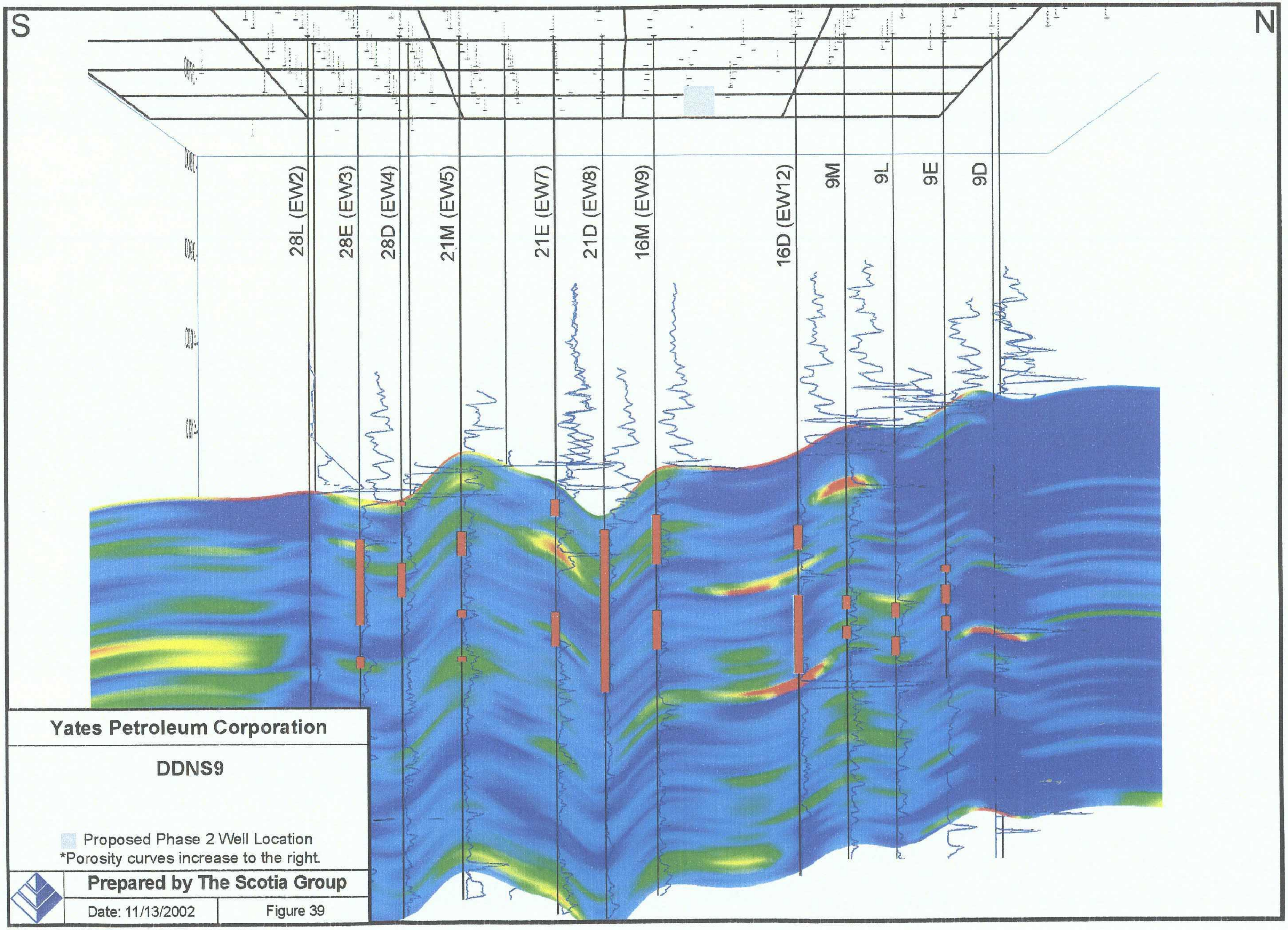
- Proposed Phase 2 Well Location
- Proposed Phase 1 Injector
- Proposed Phase 2 Injector

*Porosity curves increase to the right.

Prepared by The Scotia Group

Date: 11/13/2002 | Figure 37


S
N
29I (EW2)
29A (EW4)
20P (EW5)
20I (EW6)
20H (EW7)
20A (EW8)
17P (EW9)
17H (EW11)
17A (EW12)
8P
8I
8A
Yates Petroleum Corporation
DDNS8
Proposed Phase 2 Well Location
Proposed Phase 1 Injector
Proposed Phase 2 Injector
*Porosity curves increase to the right.
Prepared by The Scotia Group
Date: 11/13/2002
Figure 38



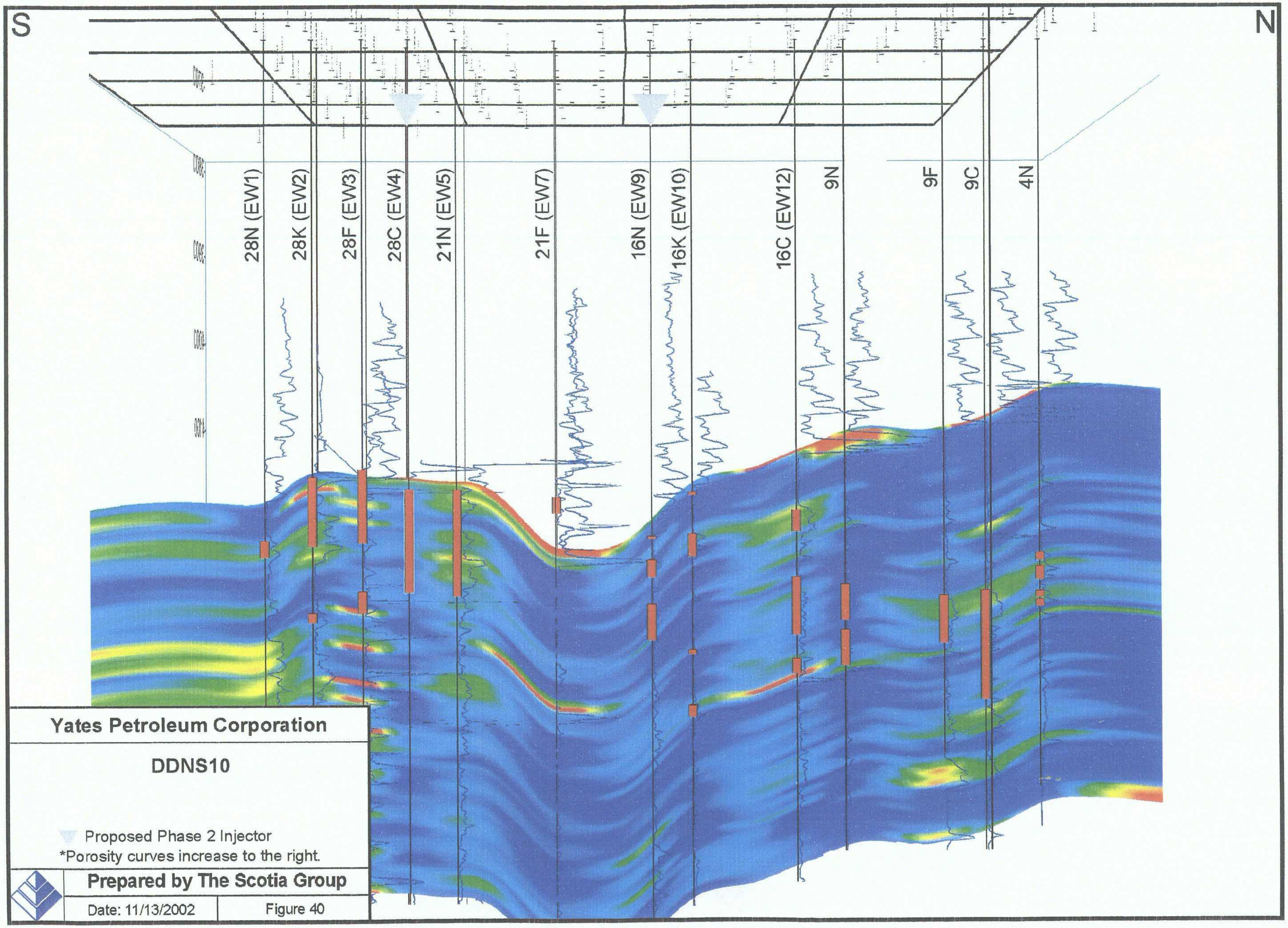
Yates Petroleum Corporation

DDNS9

Proposed Phase 2 Well Location
*Porosity curves increase to the right.

Prepared by The Scotia Group

Date: 11/13/2002 | Figure 39



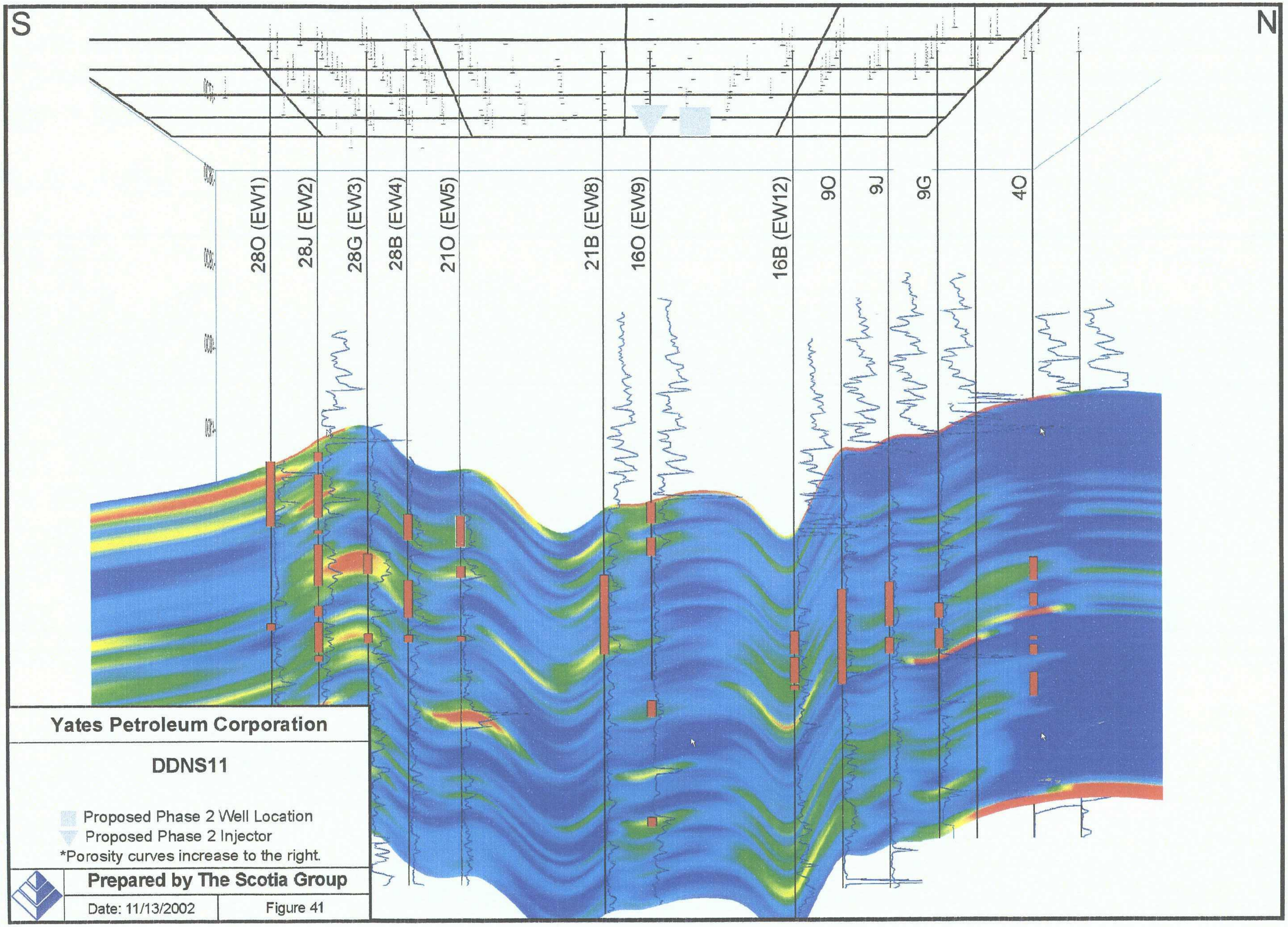
Yates Petroleum Corporation

DDNS10

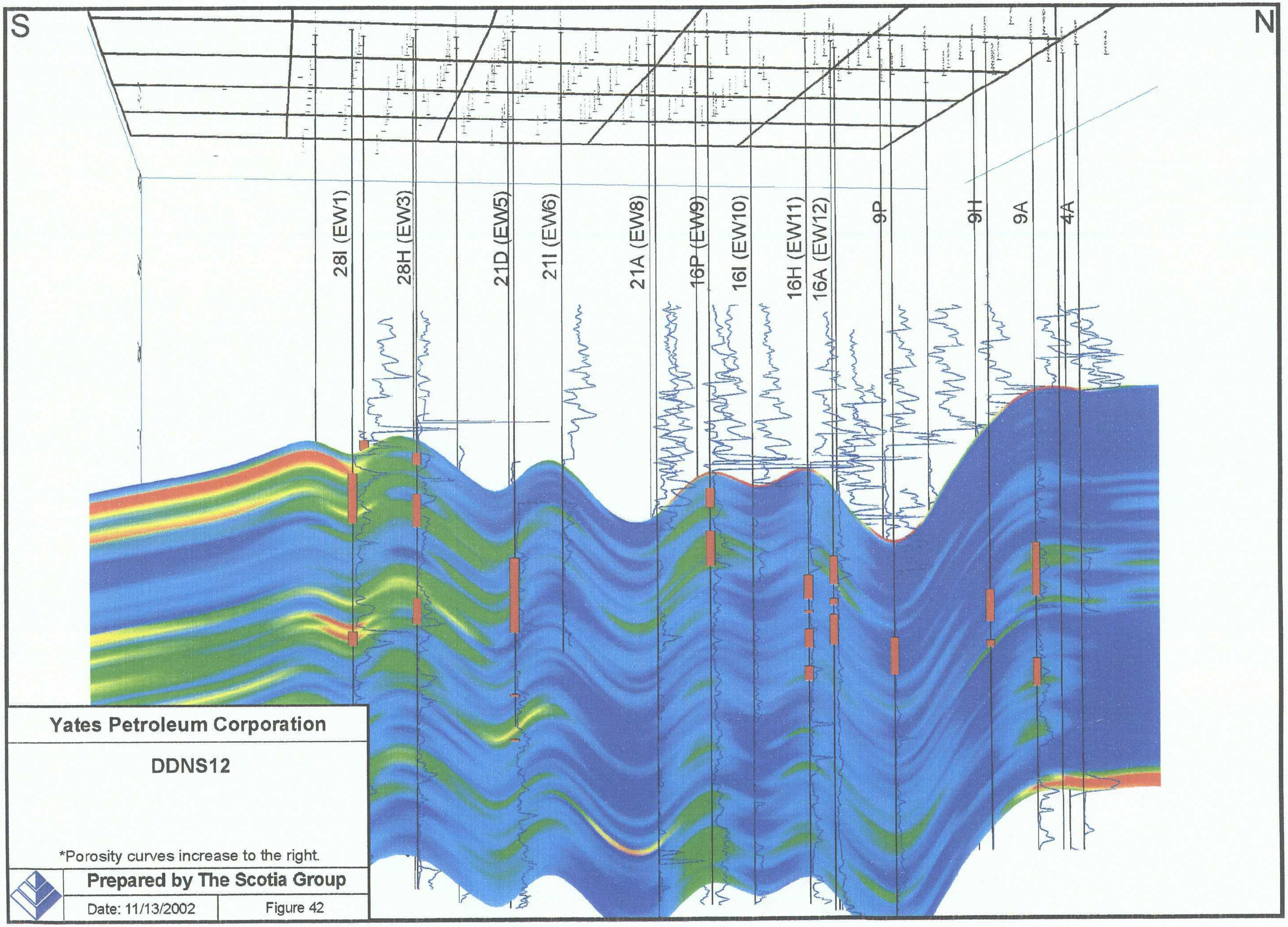
Proposed Phase 2 Injector
*Porosity curves increase to the right.

Prepared by The Scotia Group

Date: 11/13/2002 | Figure 40



Yates Petroleum Corporation	
DDNS11	
Proposed Phase 2 Well Location Proposed Phase 2 Injector *Porosity curves increase to the right.	
Prepared by The Scotia Group	
Date: 11/13/2002	Figure 41



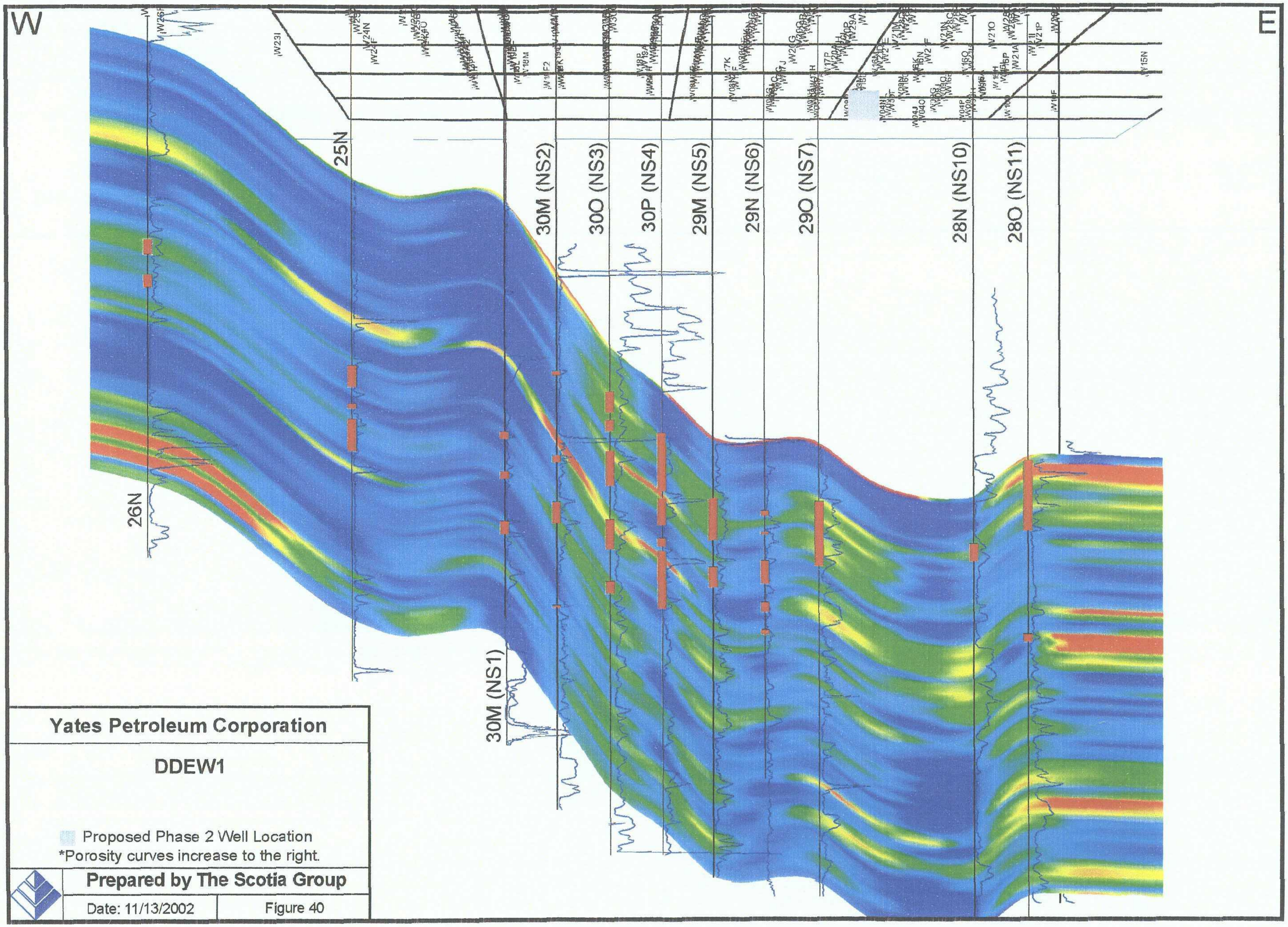
Yates Petroleum Corporation

DDNS12

*Porosity curves increase to the right.

Prepared by The Scotia Group

Date: 11/13/2002 | Figure 42



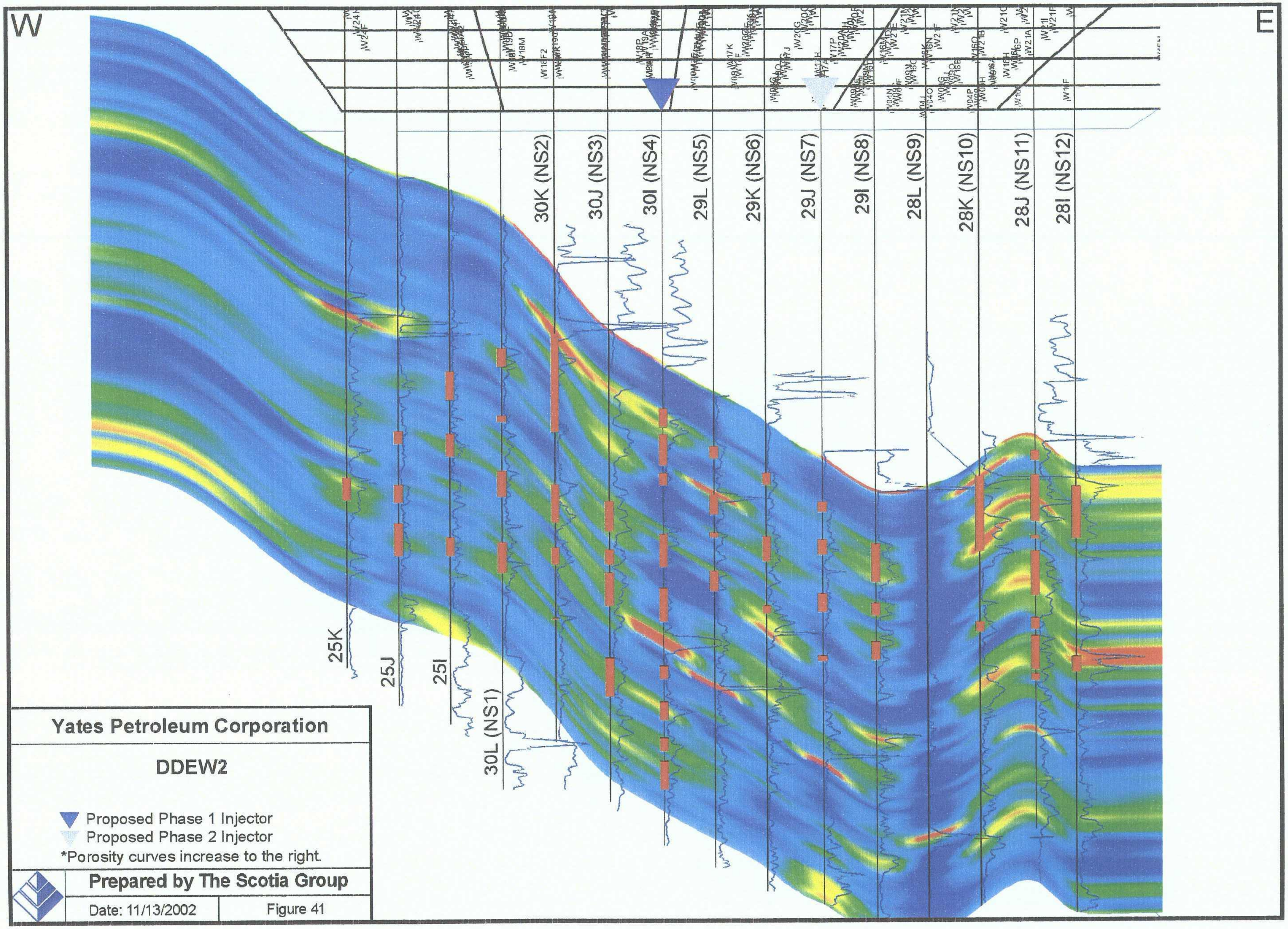
Yates Petroleum Corporation

DDEW1

Proposed Phase 2 Well Location
*Porosity curves increase to the right.

Prepared by The Scotia Group

Date: 11/13/2002 | Figure 40



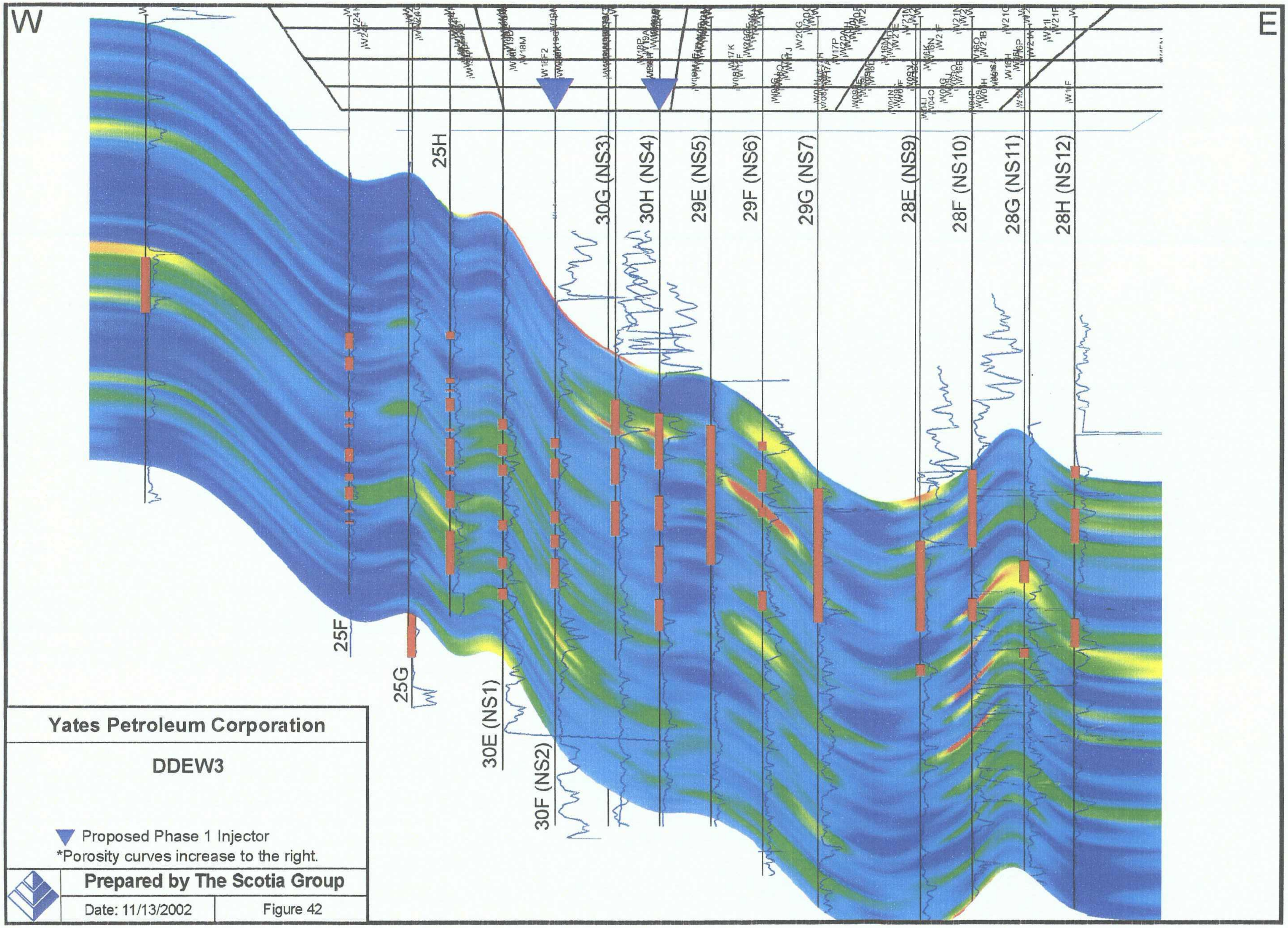
Yates Petroleum Corporation

DDEW2

▼ Proposed Phase 1 Injector
▼ Proposed Phase 2 Injector
*Porosity curves increase to the right.

Prepared by The Scotia Group

Date: 11/13/2002 | Figure 41



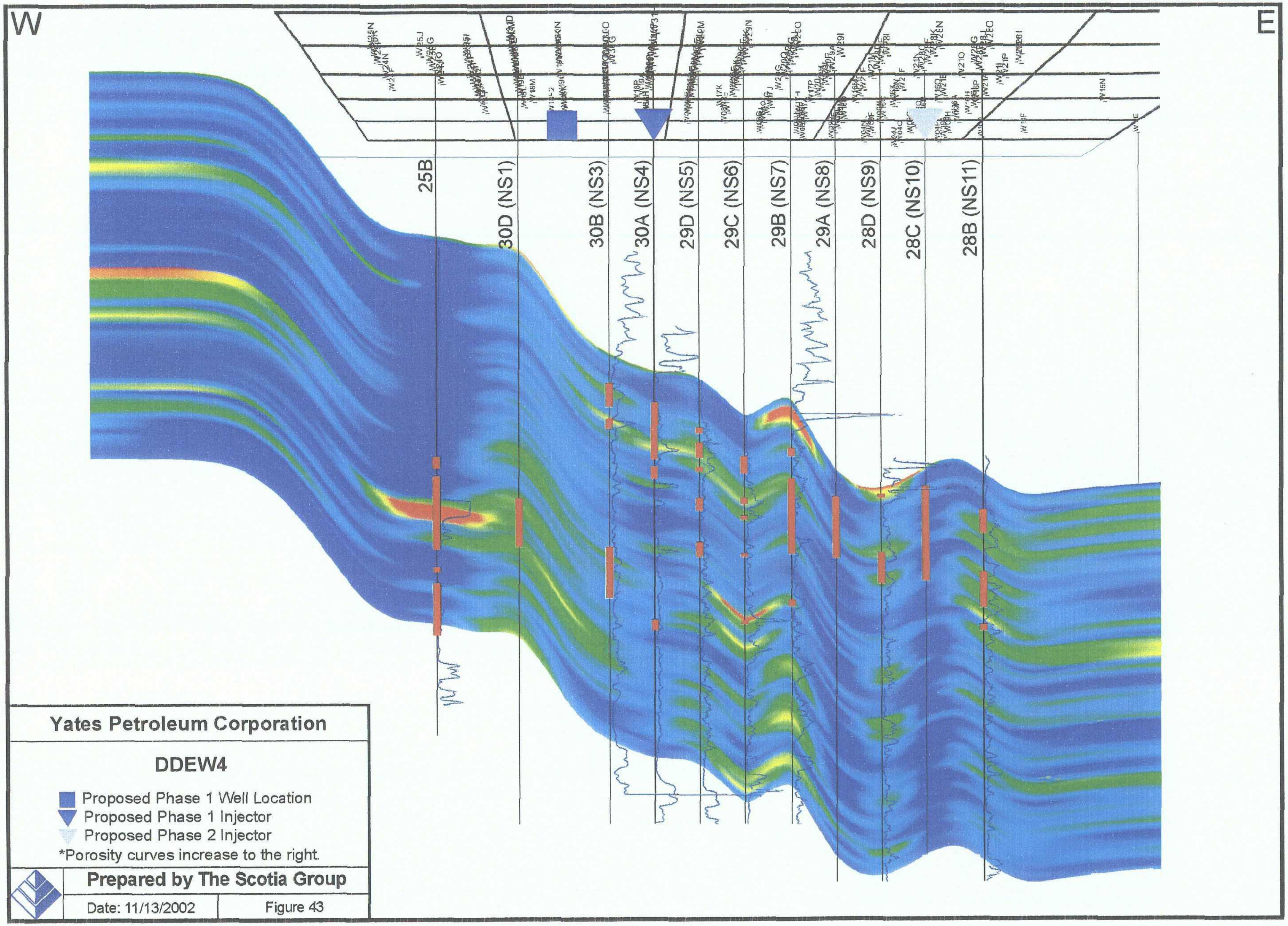
Yates Petroleum Corporation

DDEW3

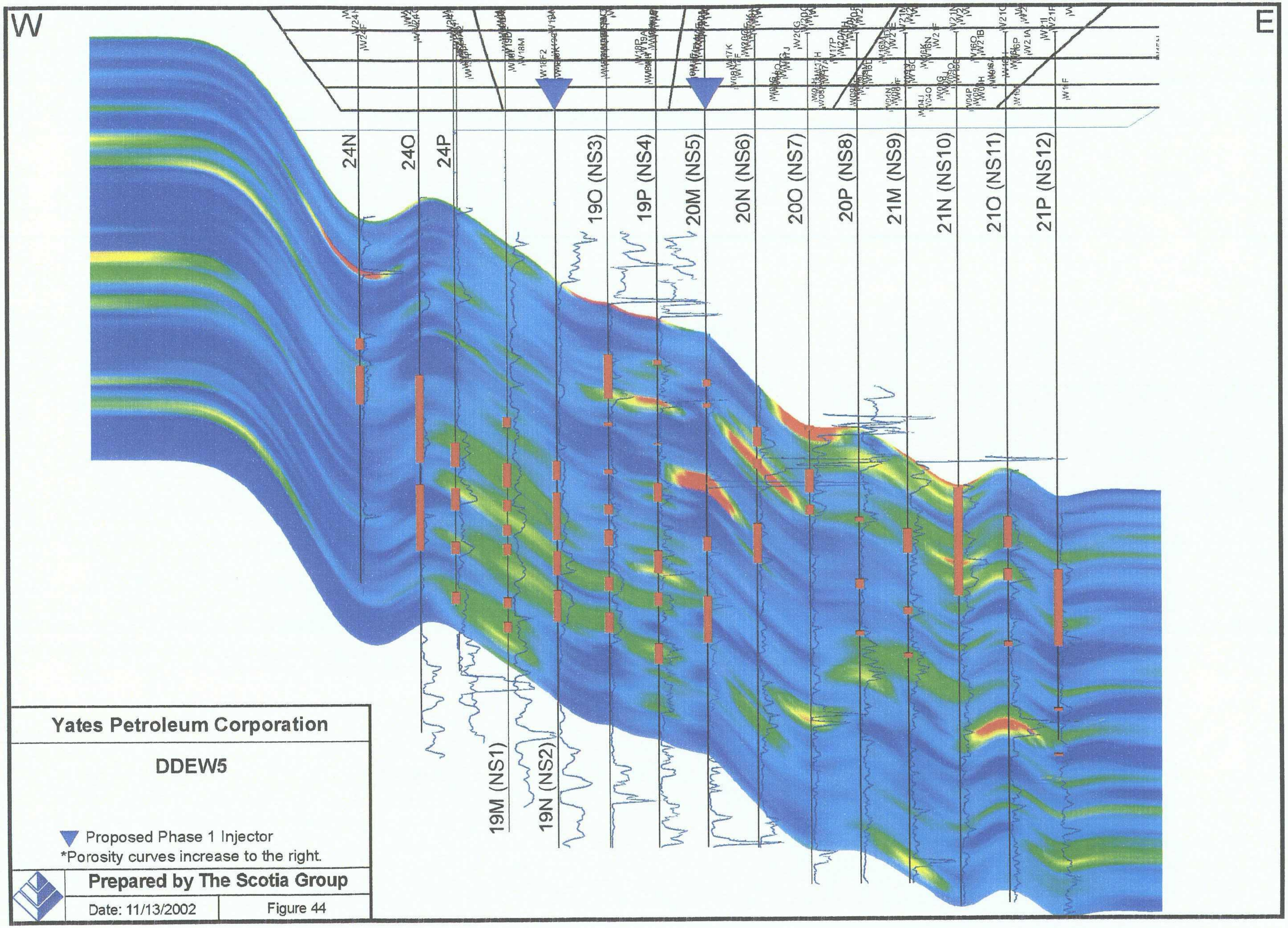
▼ Proposed Phase 1 Injector
*Porosity curves increase to the right.

Prepared by The Scotia Group

Date: 11/13/2002 | Figure 42



W
E
25B
30D (NS1)
30B (NS3)
30A (NS4)
29D (NS5)
29C (NS6)
29B (NS7)
29A (NS8)
28D (NS9)
28C (NS10)
28B (NS11)
Yates Petroleum Corporation
DDEW4
Proposed Phase 1 Well Location
Proposed Phase 1 Injector
Proposed Phase 2 Injector
*Porosity curves increase to the right.
Prepared by The Scotia Group
Date: 11/13/2002
Figure 43



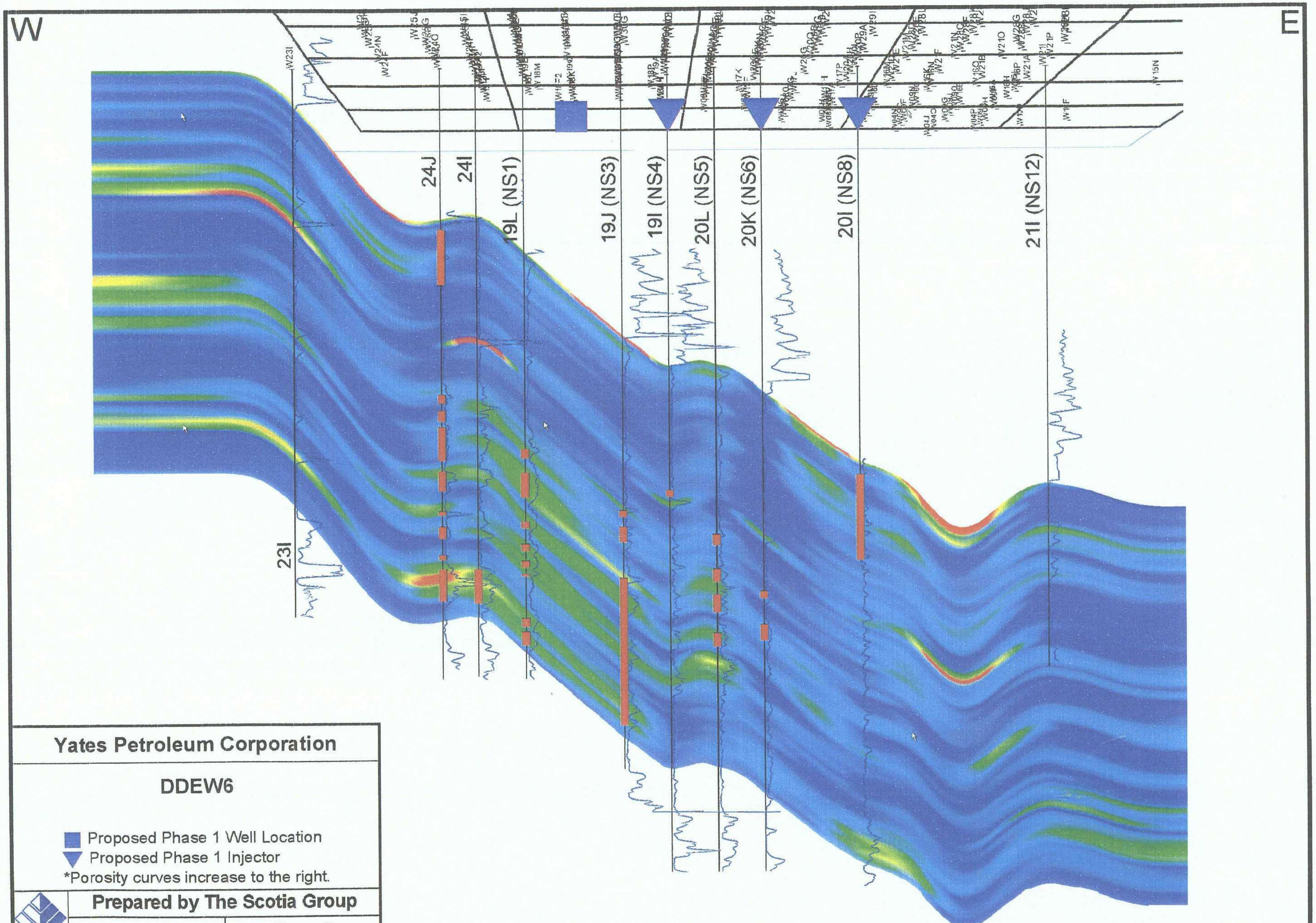
Yates Petroleum Corporation

DDEW5

▼ Proposed Phase 1 Injector
*Porosity curves increase to the right.

Prepared by The Scotia Group

Date: 11/13/2002 | Figure 44



Yates Petroleum Corporation

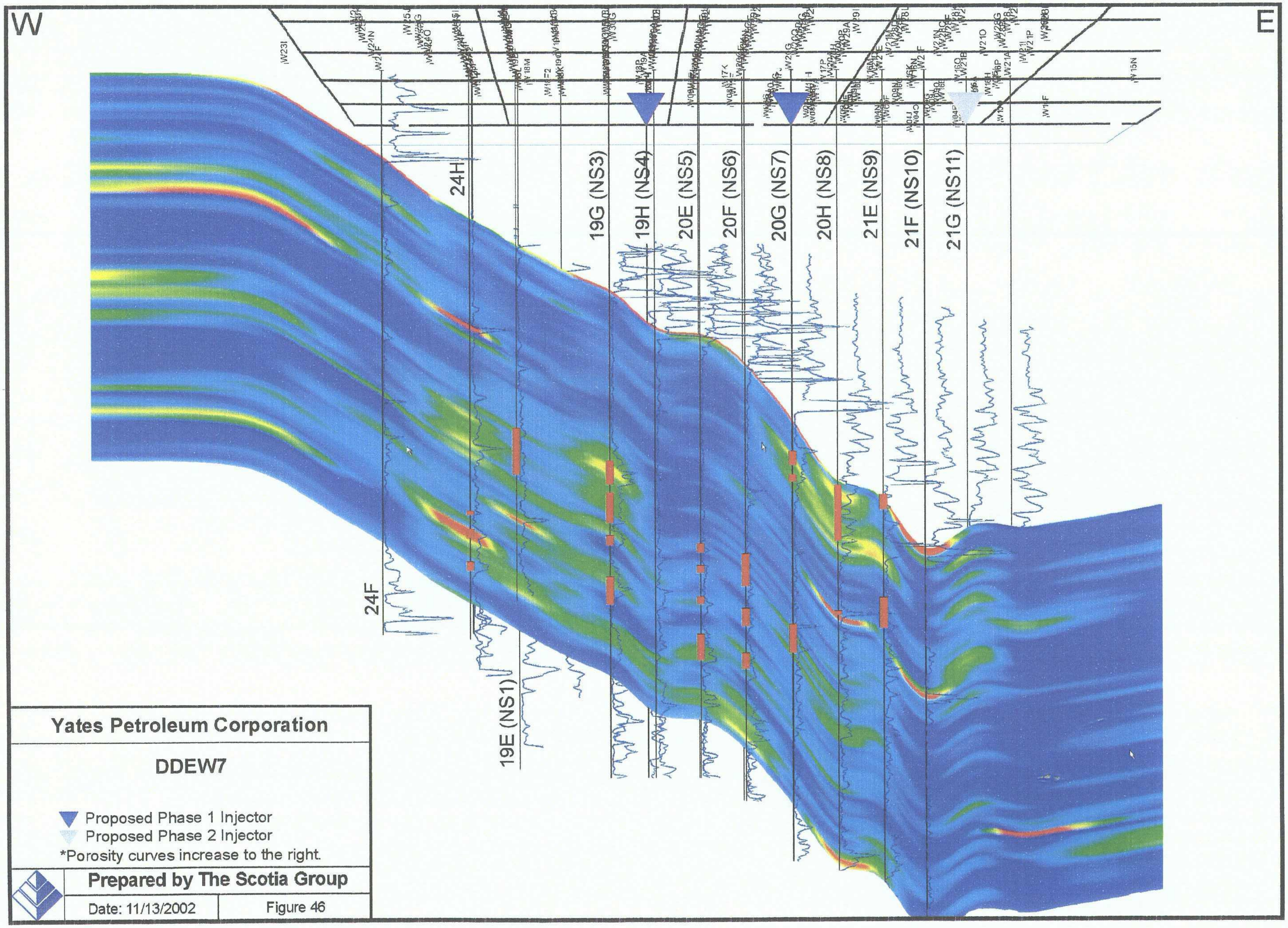
DDEW6

- Proposed Phase 1 Well Location
- Proposed Phase 1 Injector

*Porosity curves increase to the right.

Prepared by The Scotia Group

Date: 11/13/2002	Figure 45



Yates Petroleum Corporation

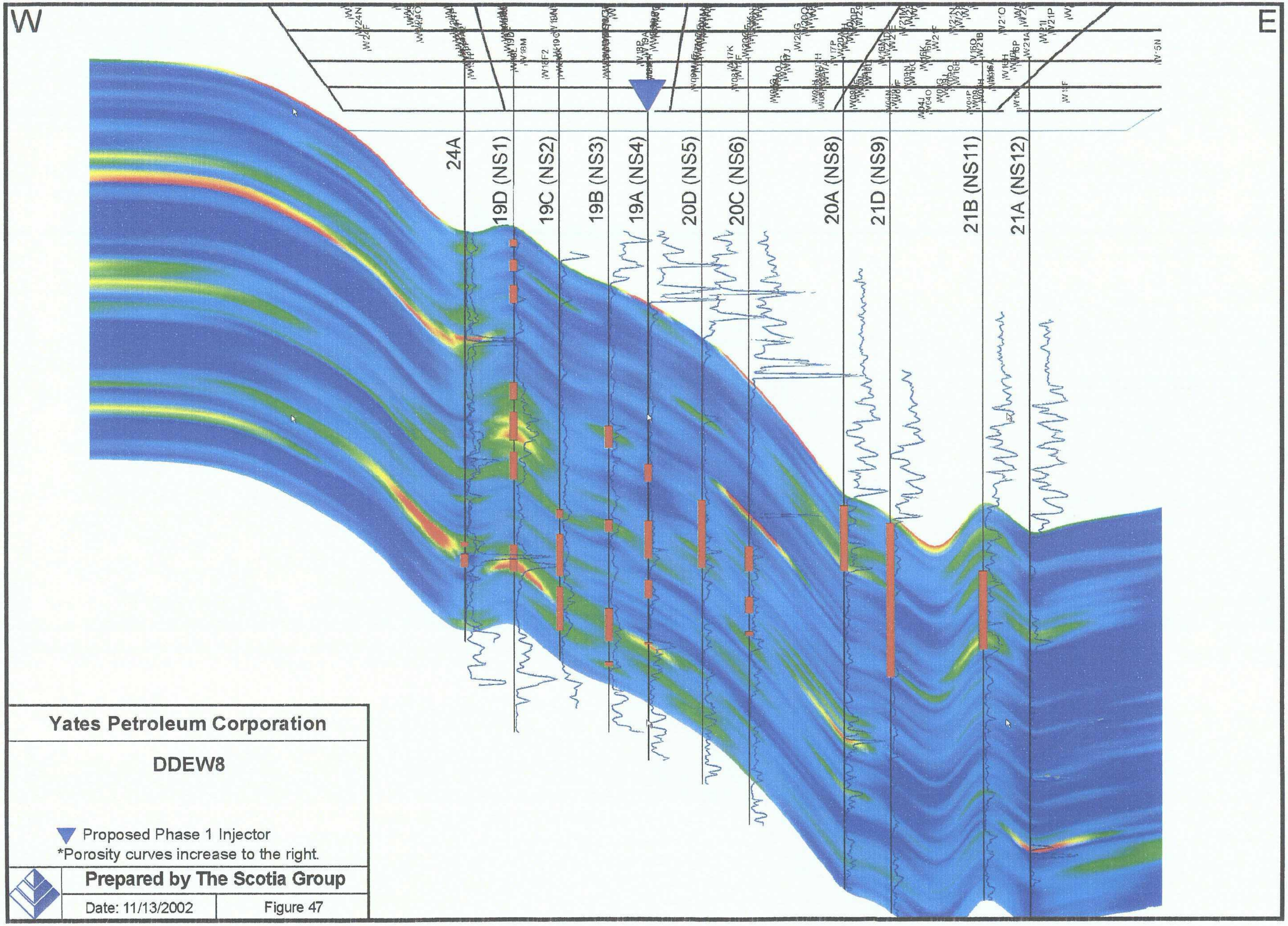
DDEW7

- Proposed Phase 1 Injector
- Proposed Phase 2 Injector

*Porosity curves increase to the right.

Prepared by The Scotia Group

Date: 11/13/2002 | Figure 46



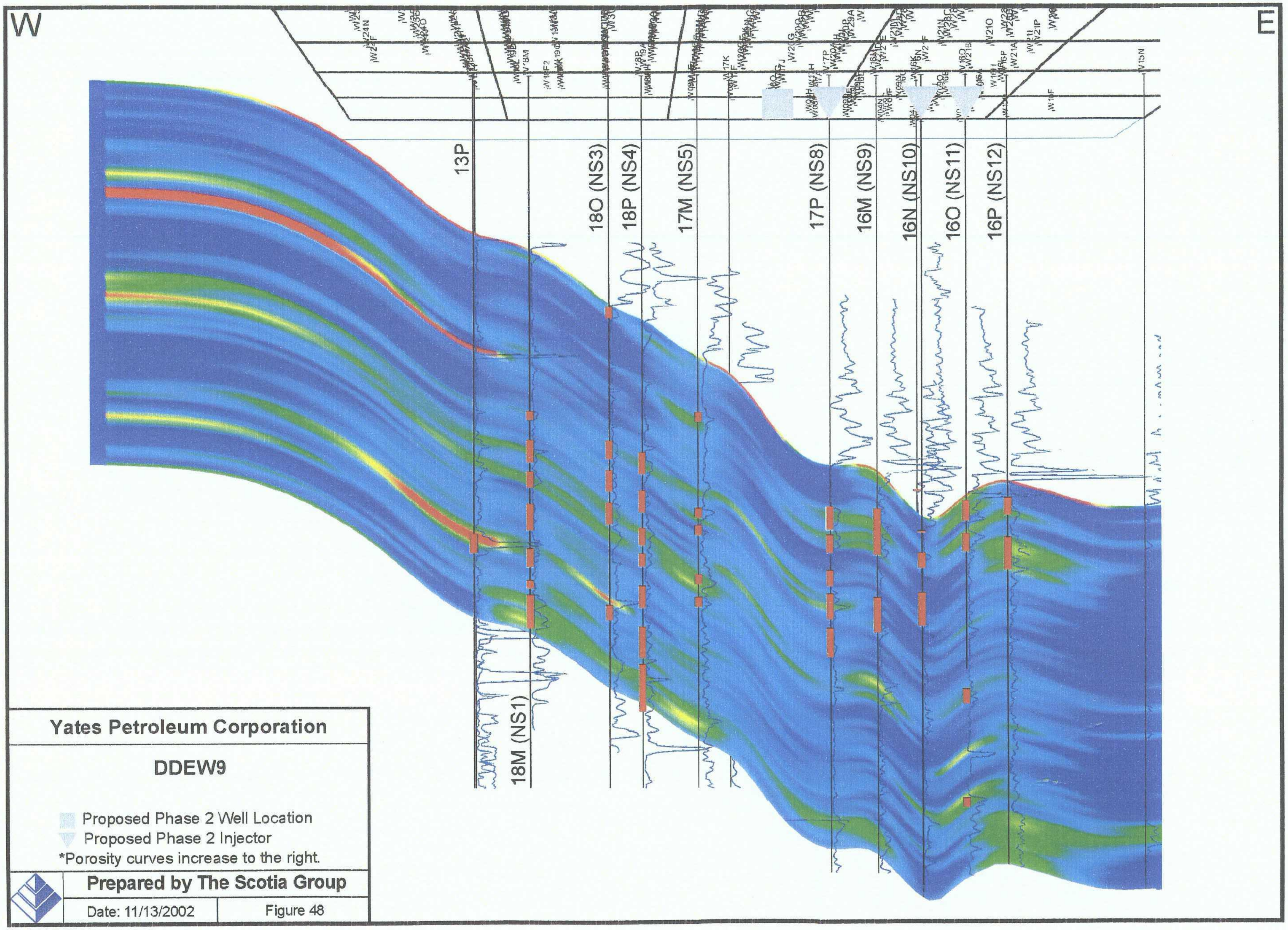
Yates Petroleum Corporation

DDEW8

▼ Proposed Phase 1 Injector
*Porosity curves increase to the right.

Prepared by The Scotia Group

Date: 11/13/2002 | Figure 47



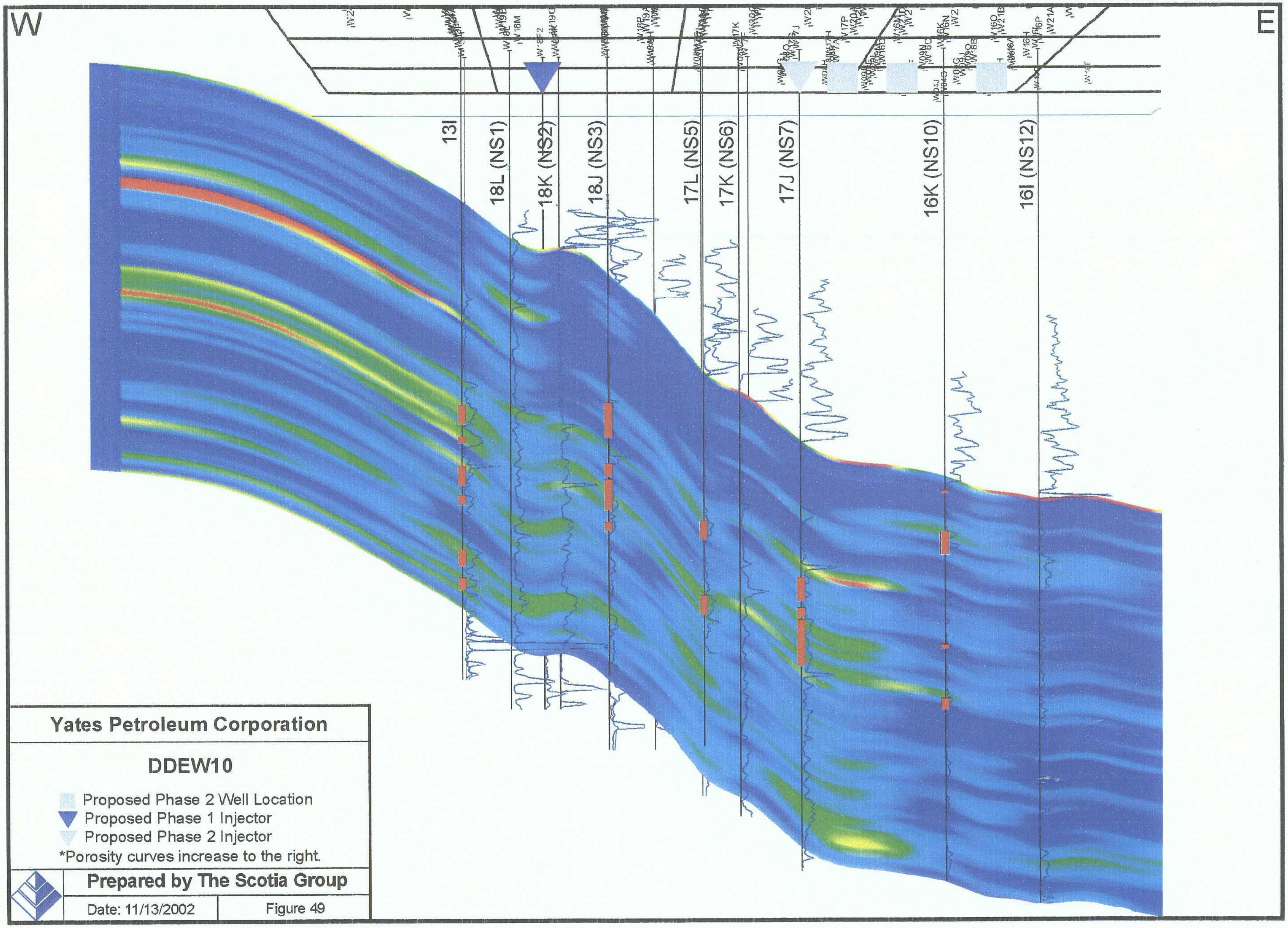
Yates Petroleum Corporation

DDEW9

Proposed Phase 2 Well Location
Proposed Phase 2 Injector
*Porosity curves increase to the right.

Prepared by The Scotia Group

Date: 11/13/2002 | Figure 48



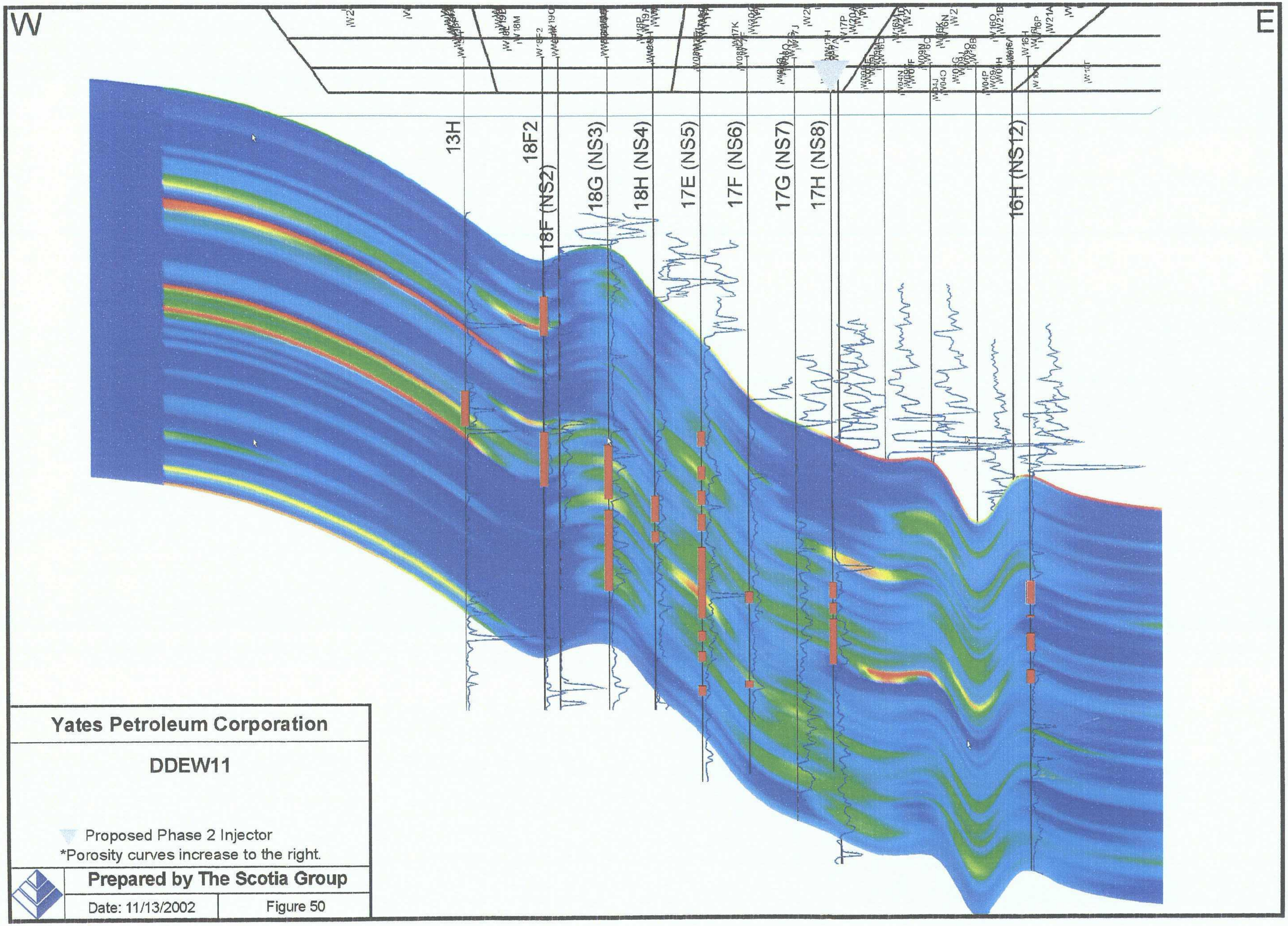
Yates Petroleum Corporation

DDEW10

Proposed Phase 2 Well Location
Proposed Phase 1 Injector
Proposed Phase 2 Injector
*Porosity curves increase to the right.

Prepared by The Scotia Group

Date: 11/13/2002 | Figure 49



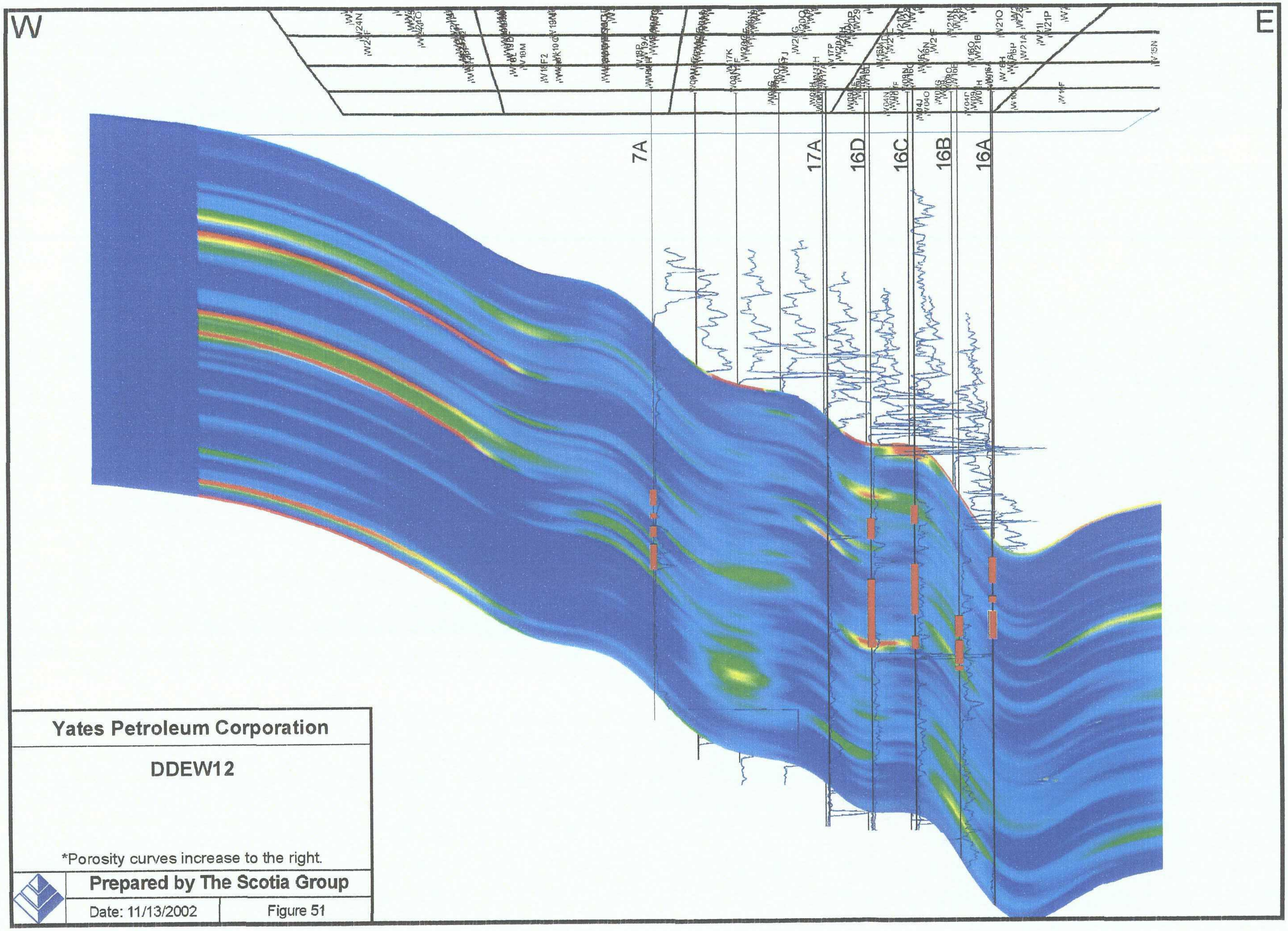
Yates Petroleum Corporation

DDEW11

Proposed Phase 2 Injector
*Porosity curves increase to the right.

Prepared by The Scotia Group

Date: 11/13/2002 | Figure 50



Yates Petroleum Corporation	
DDEW12	
*Porosity curves increase to the right.	
Prepared by The Scotia Group	
Date: 11/13/2002	Figure 51

Dagger Draw #12
Permeability Variance

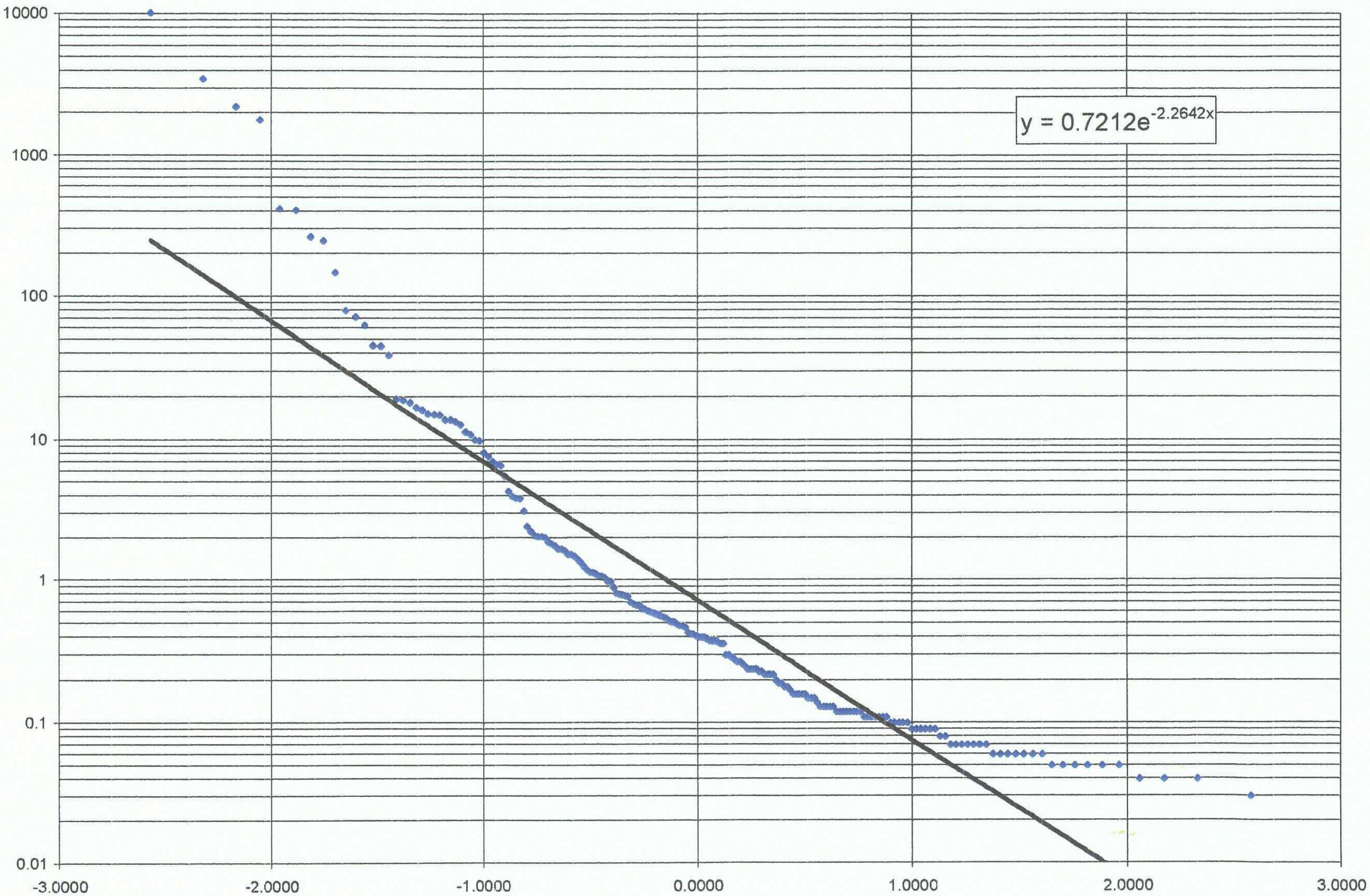


Figure 55a

Saguaro #8
Permeability Variance

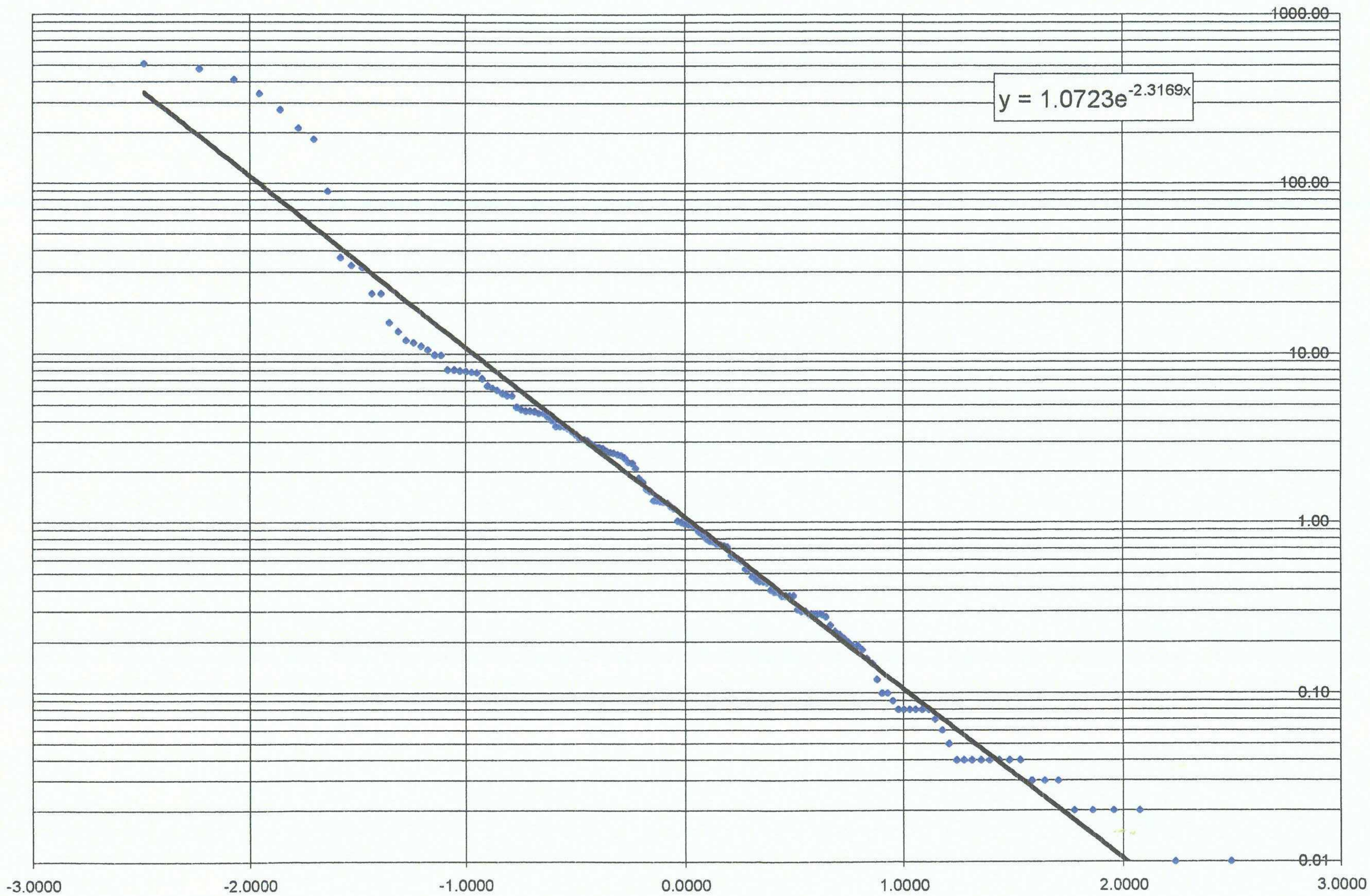


Figure 55b

Barbara #12
Permeability Variance

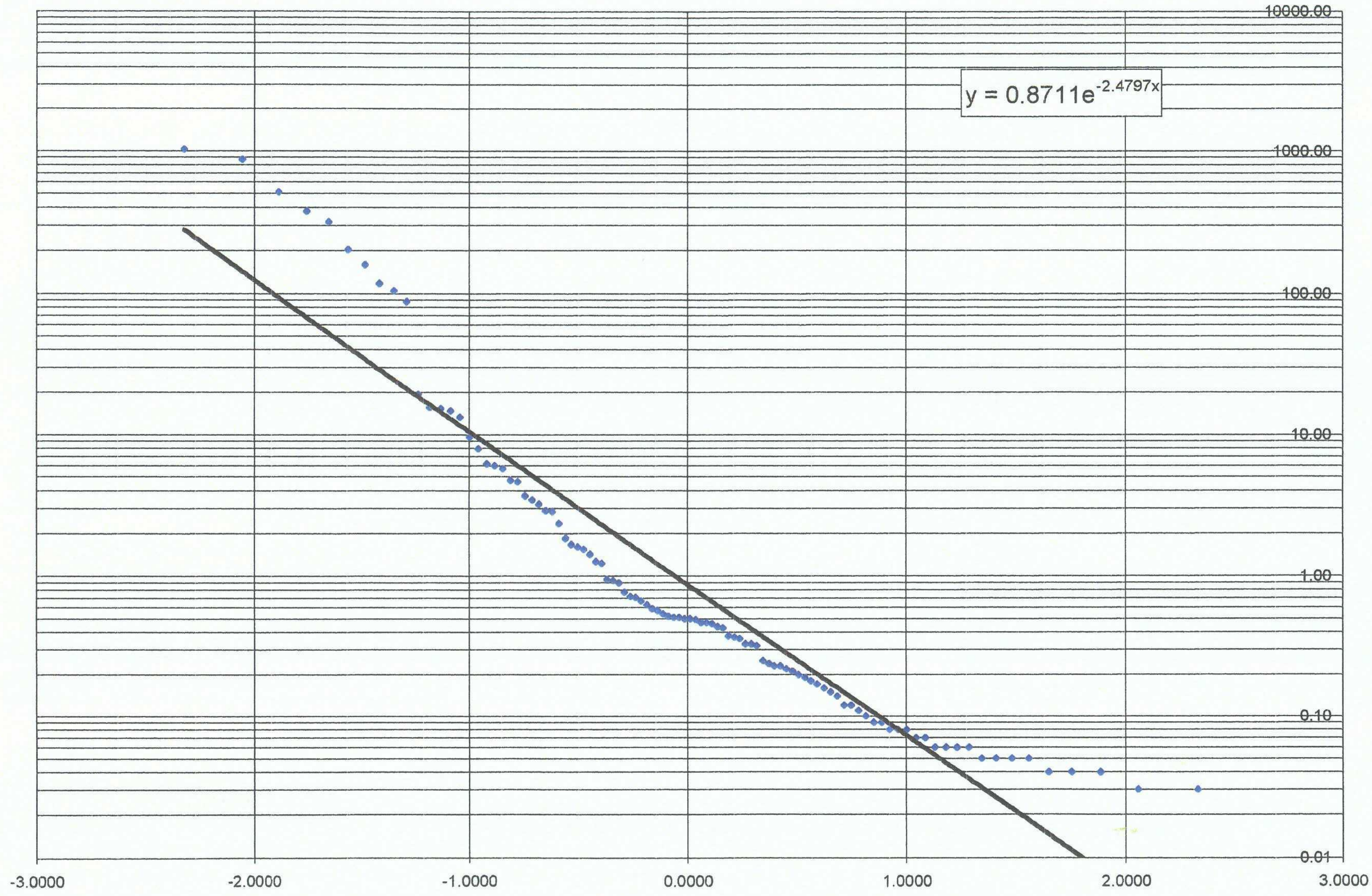


Figure 55c

Barbara #2
Permeability Variance

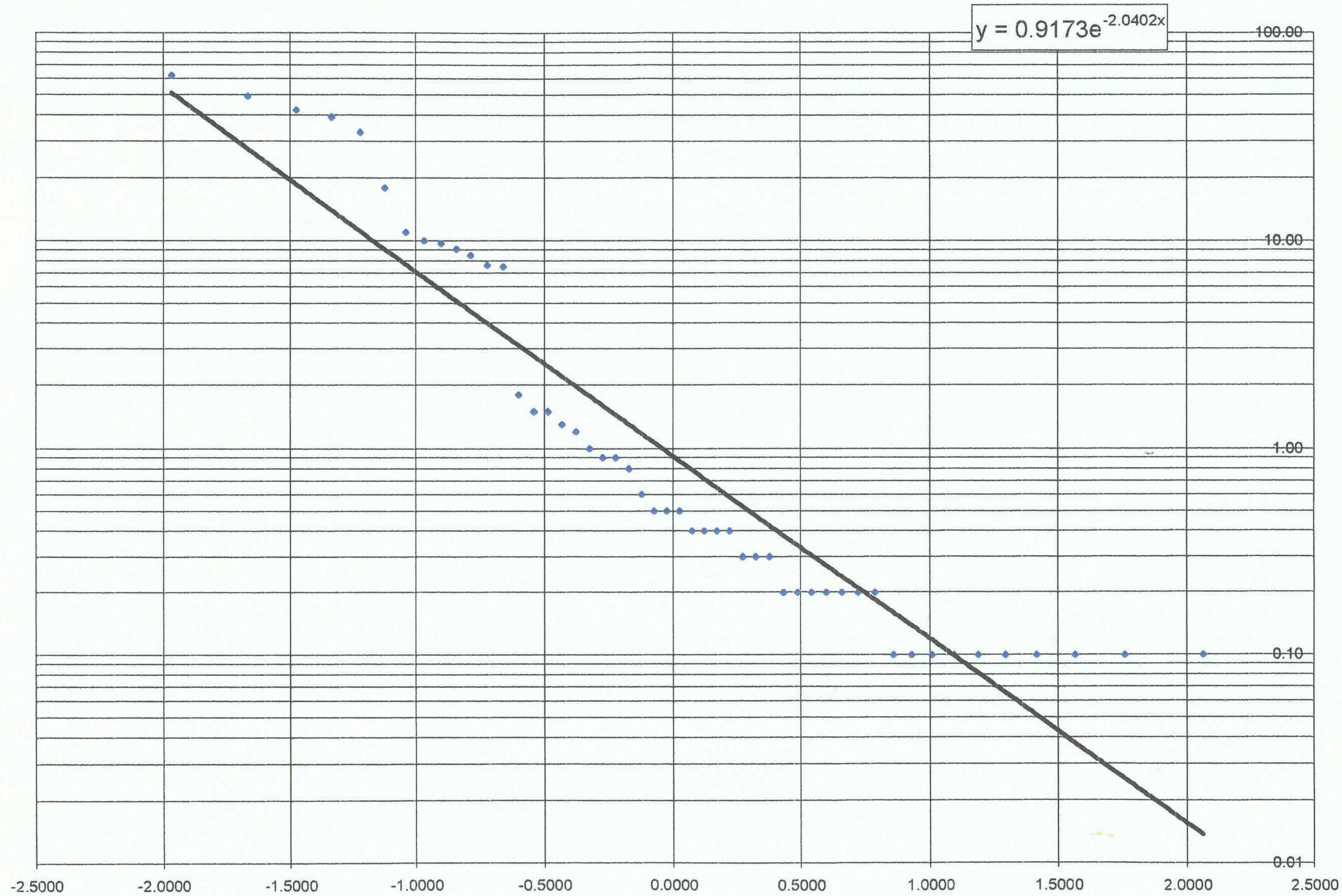


Figure 55e

Barbara #2
Permeability Variance

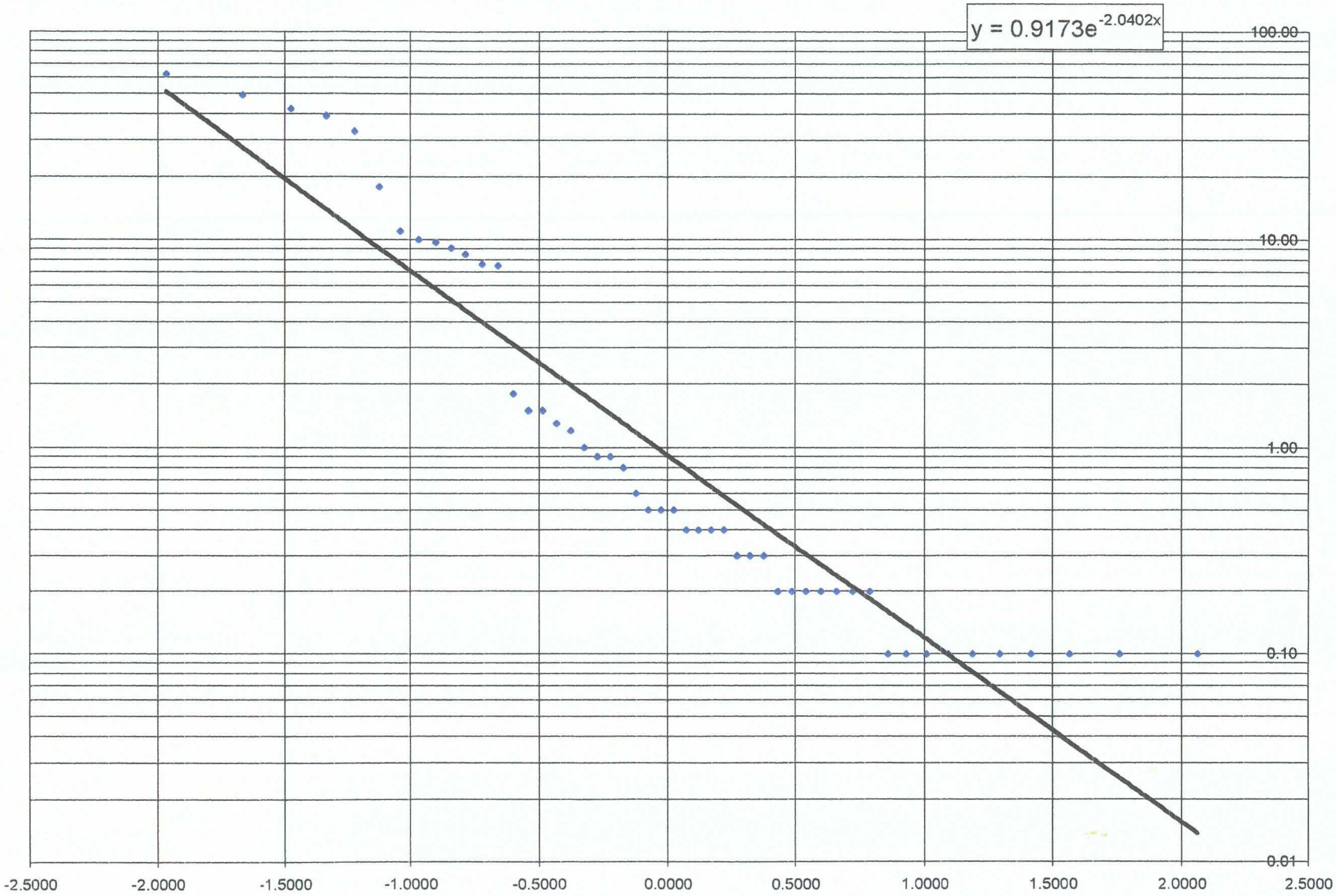


Figure 55e

Ocotillo #1
Permeability Variance

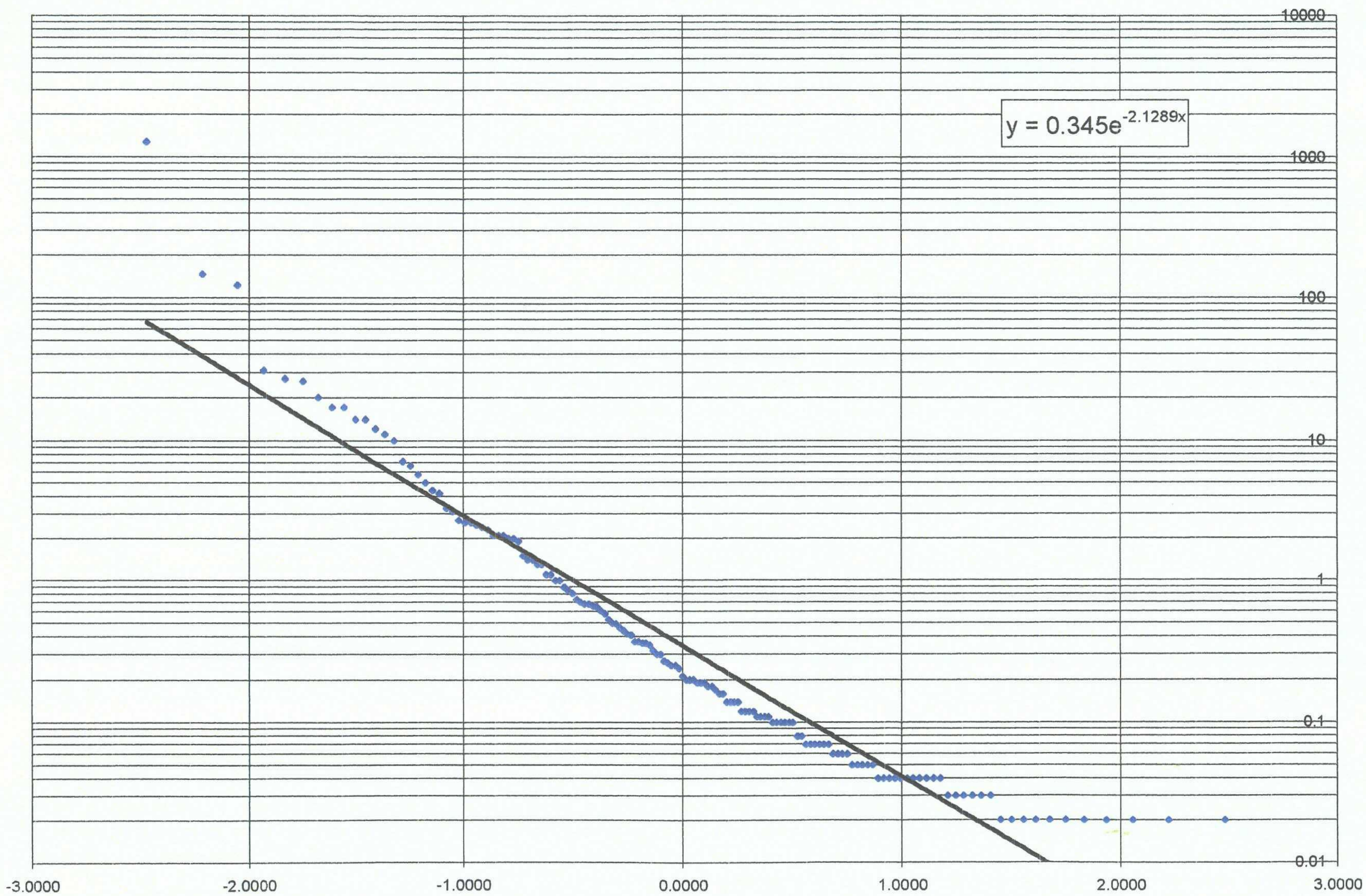
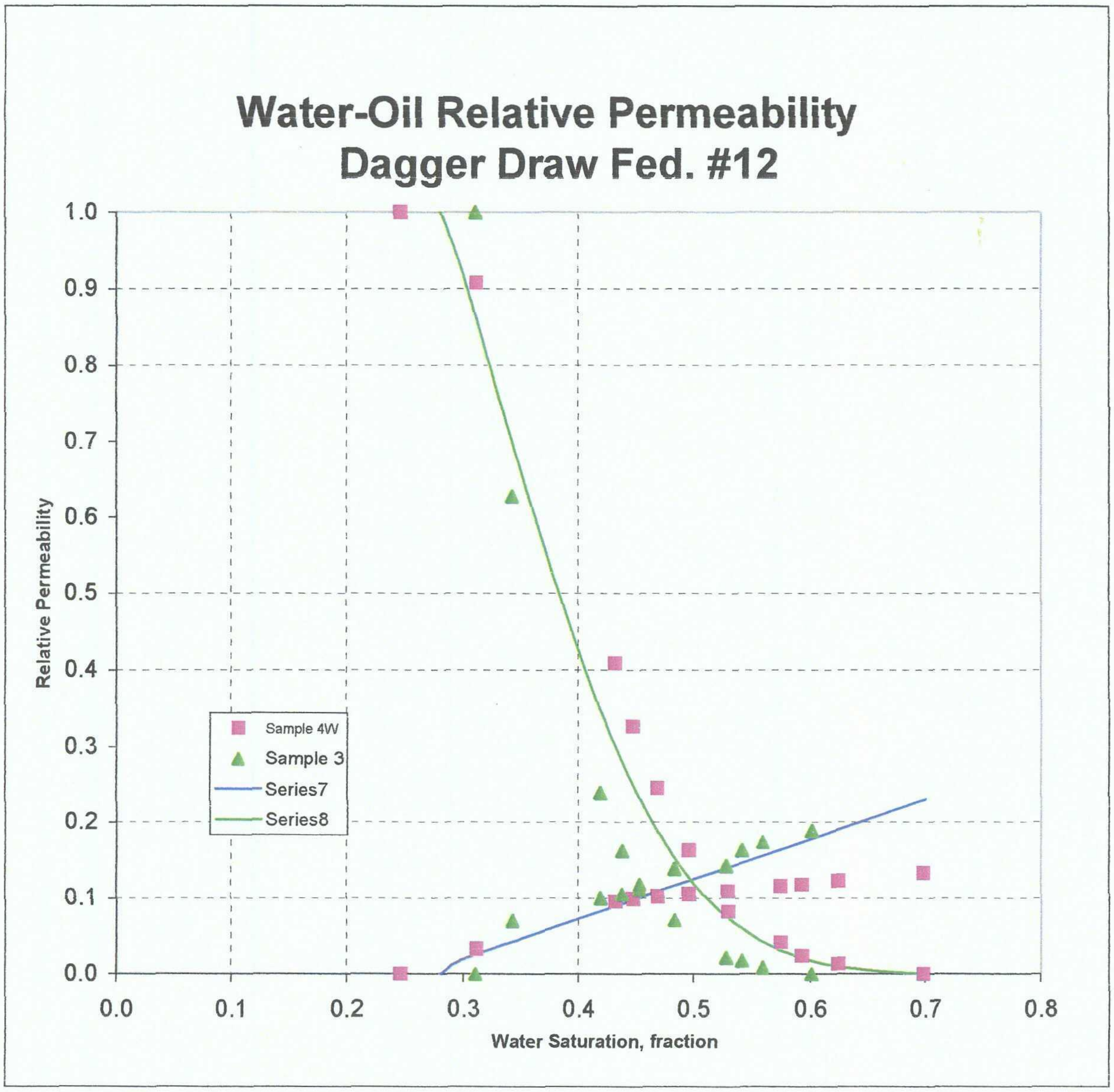
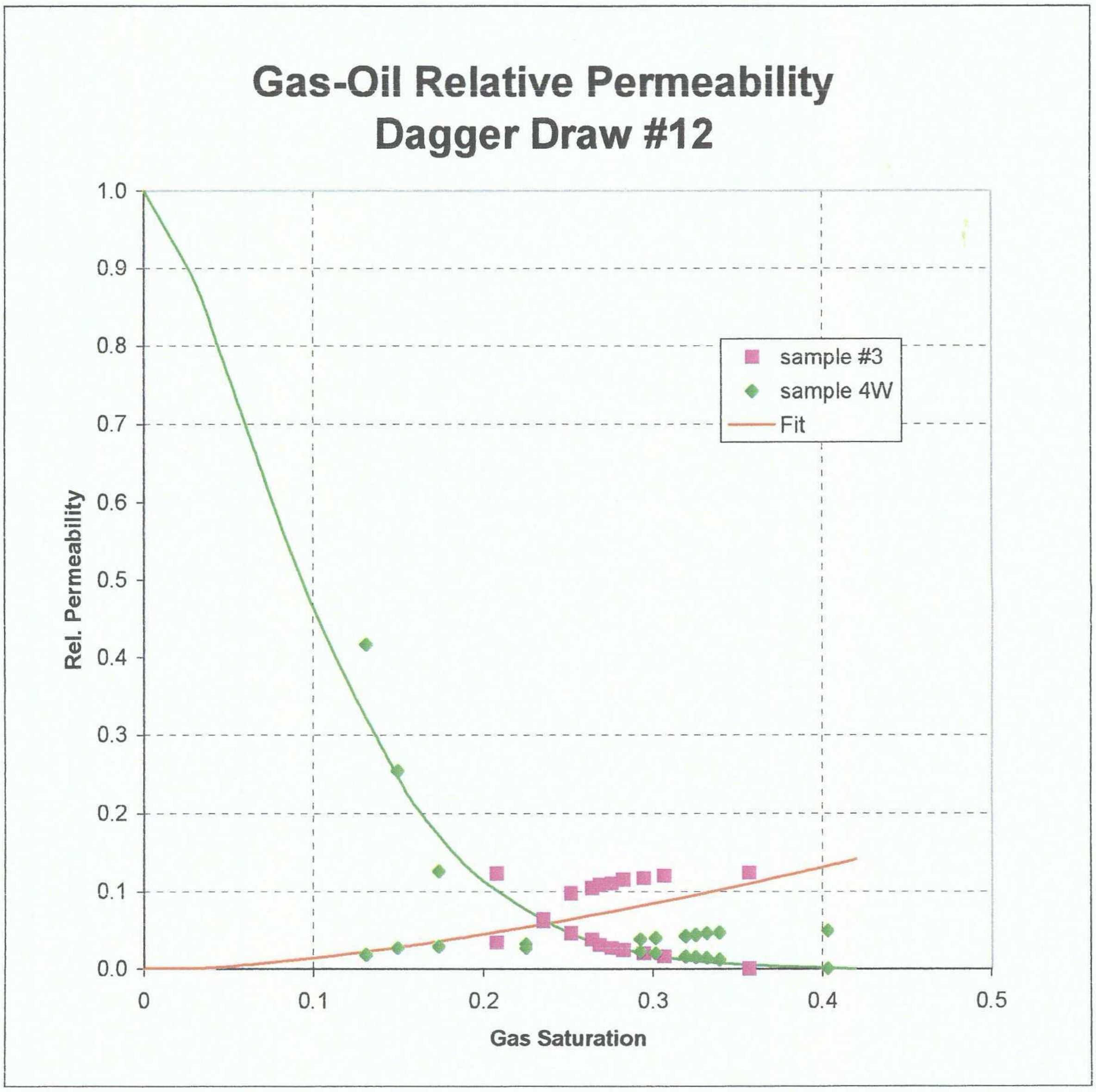


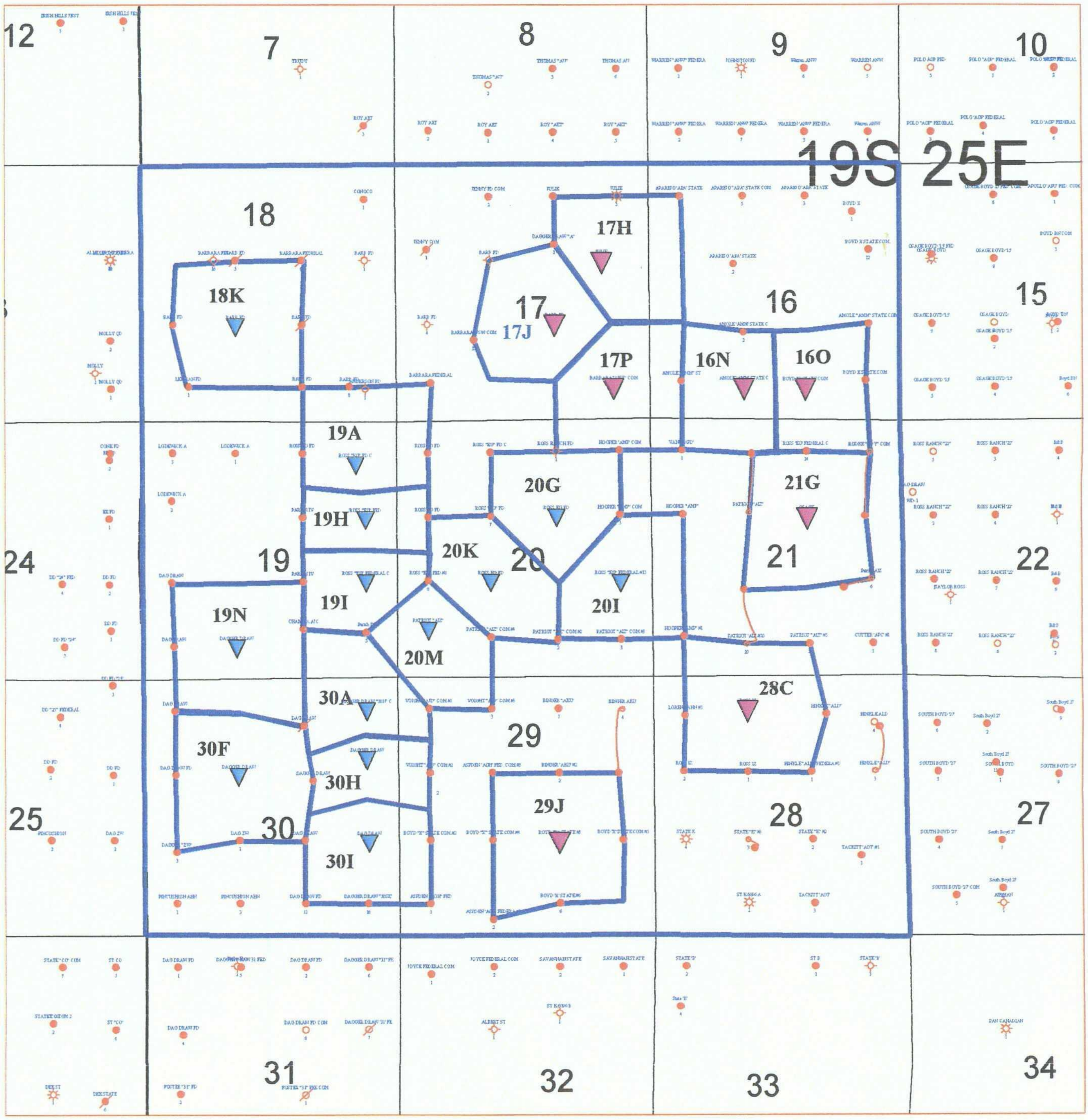
Figure 55f



Water-Oil Relative Permeability
Dagger Draw Fed. #12
Relative Permeability
Water Saturation, fraction
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
Sample 4W
Sample 3
Series7
Series8



Gas-Oil Relative Permeability
Dagger Draw #12
Rel. Permeability
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
0
0.1
0.2
0.3
0.4
0.5
Gas Saturation
sample #3
sample 4W
Fit



Symbol Legend

Phase I Injector

Phase II Injector

Pattern No. is shown for each injector. See Table 2 for areas, parameters, & sweep factors.

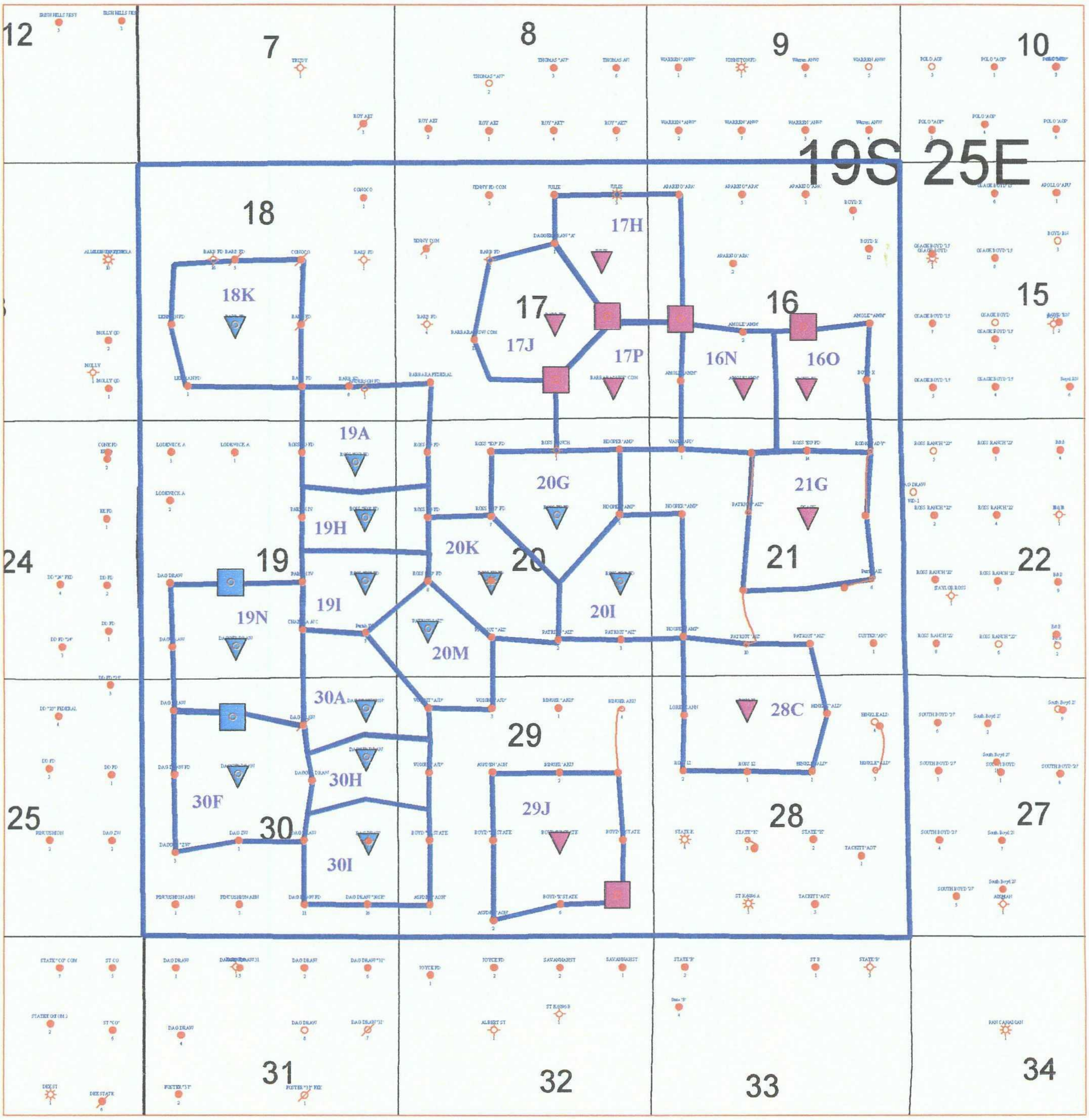
N

1000 0 1000 2000 3000 ft

YATES PETROLEUM CORPORATION

North Dagger Draw Field Unit
Current Injector Areas (No Infill Drilling)

Contour Interval:		Date: 22 November, 2002
		Scale: 1" = 3,000'



Symbol Legend

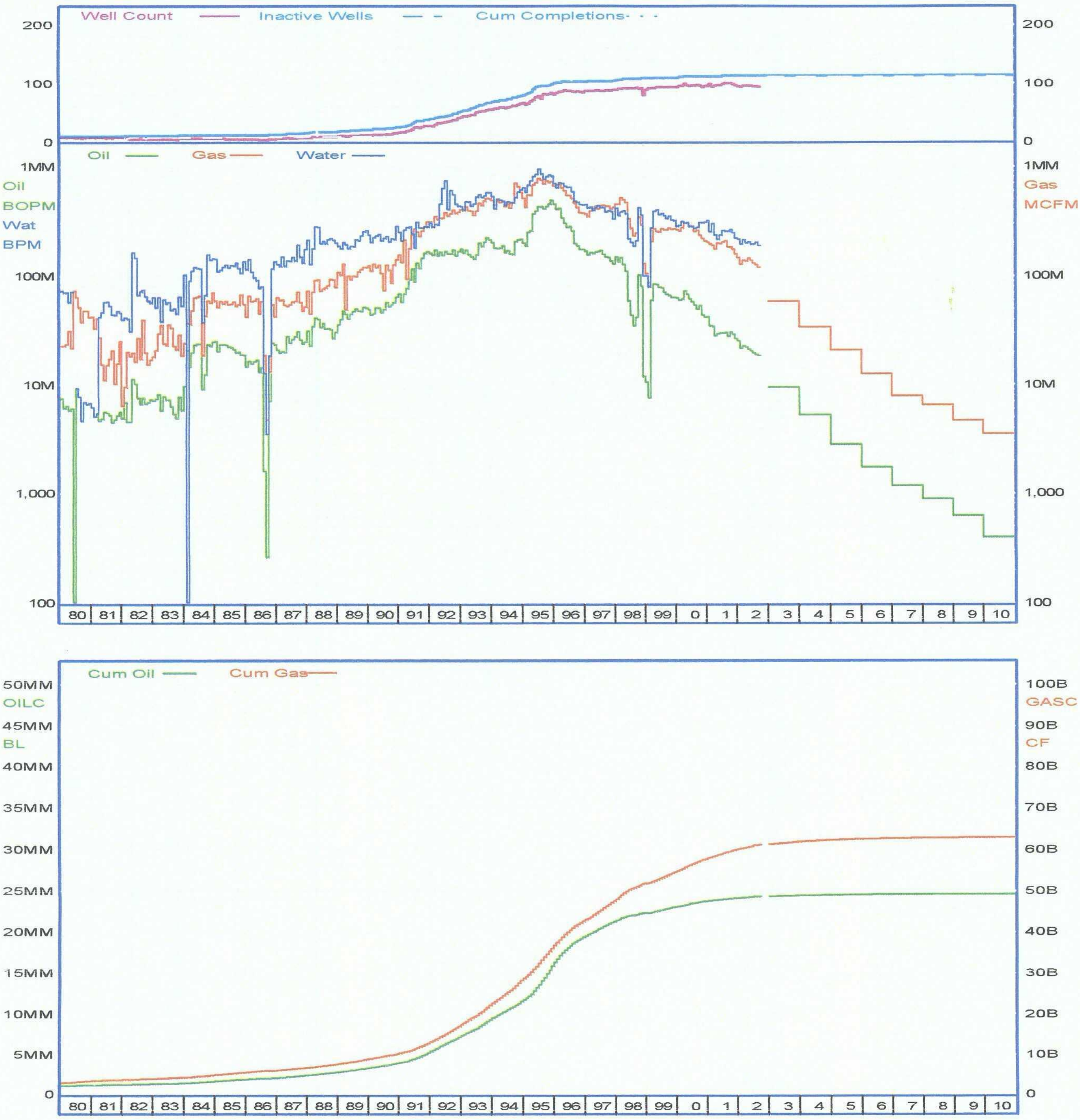
- Phase I Injector
- Phase II Injector
- Phase I Drill Well
- Phase II Drill Well

Pattern No. is shown for each injector. See Table 3 for areas, parameters, & sweep factors.

YATES PETROLEUM CORPORATION

North Dagger Draw Field Unit Proposed Injector Outlines Including Infill Drilling		
Contour Interval:		Date: 19 February, 2003
		Scale: 1" = 3,000'

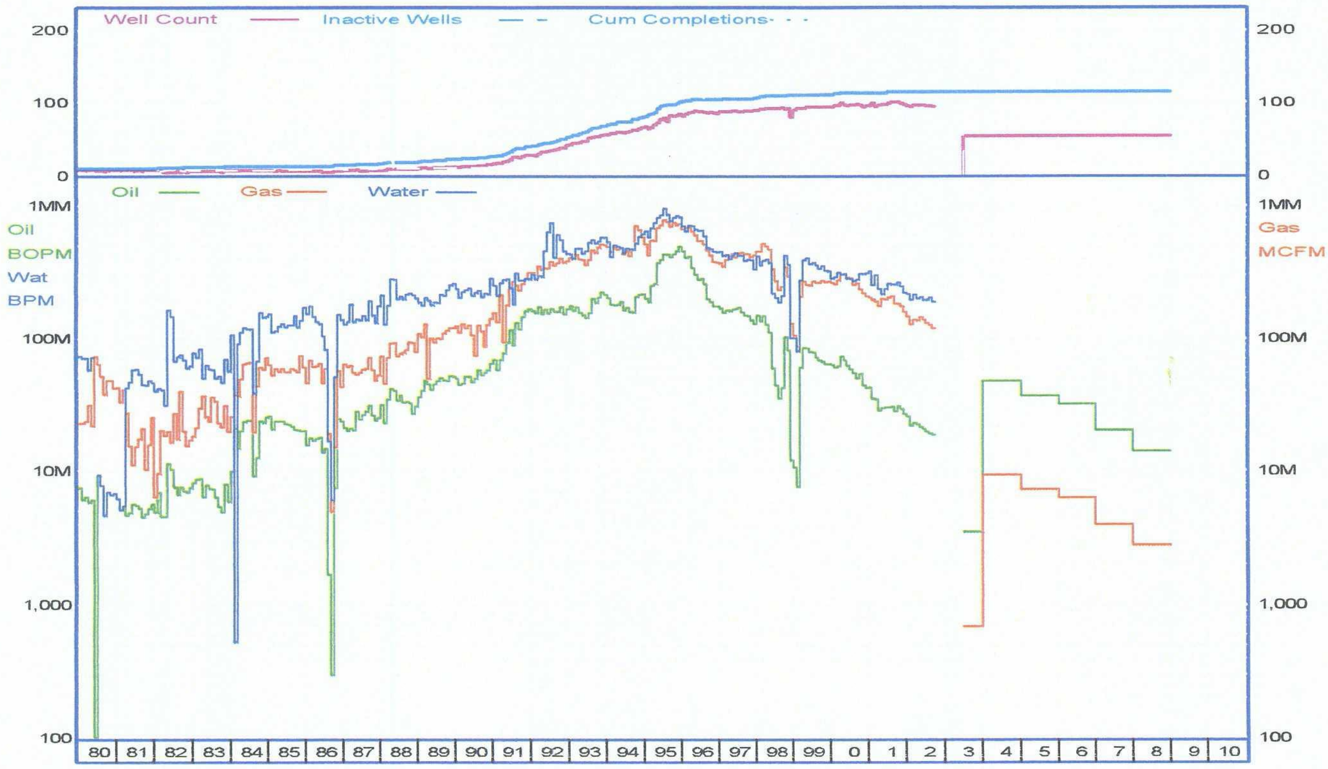
Fig 60

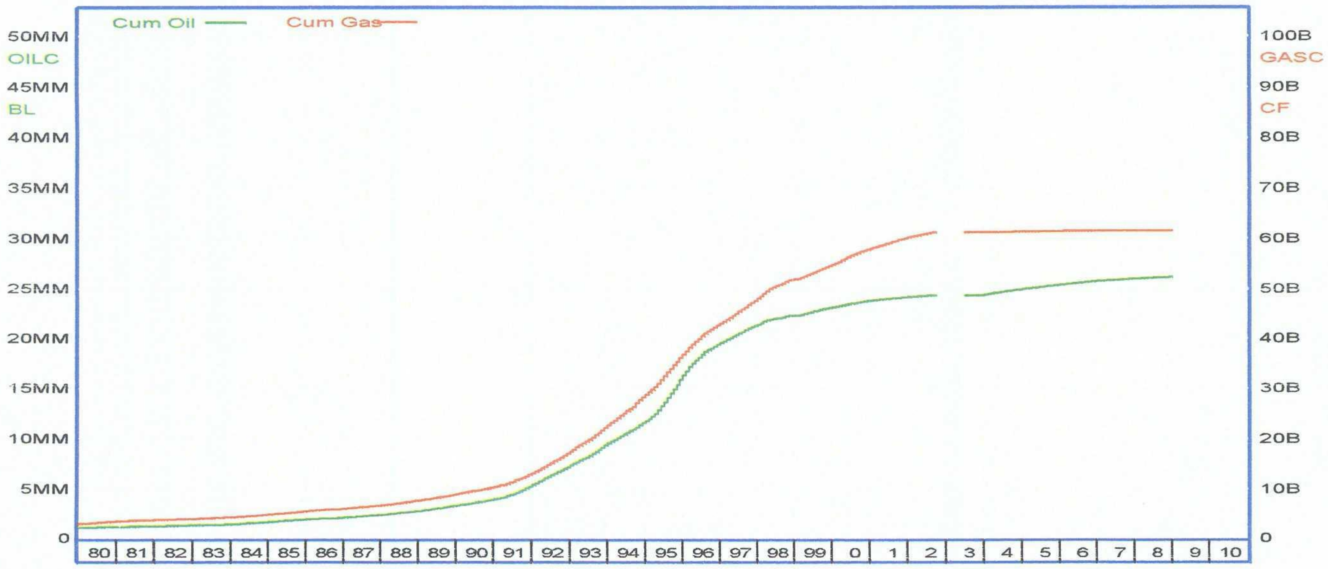


Proved Producing
Projections are averages for each year commencing at the effective date of the evaluation.
Results are subject to the qualifications and limitations stated in the attached document.

These results are subject to the qualifications and limitations contained in a document titled "Proposal to Unitize for Secondary Recovery Operations, Dagger Draw Field, Eddy County, New Mexico".

Fig 61

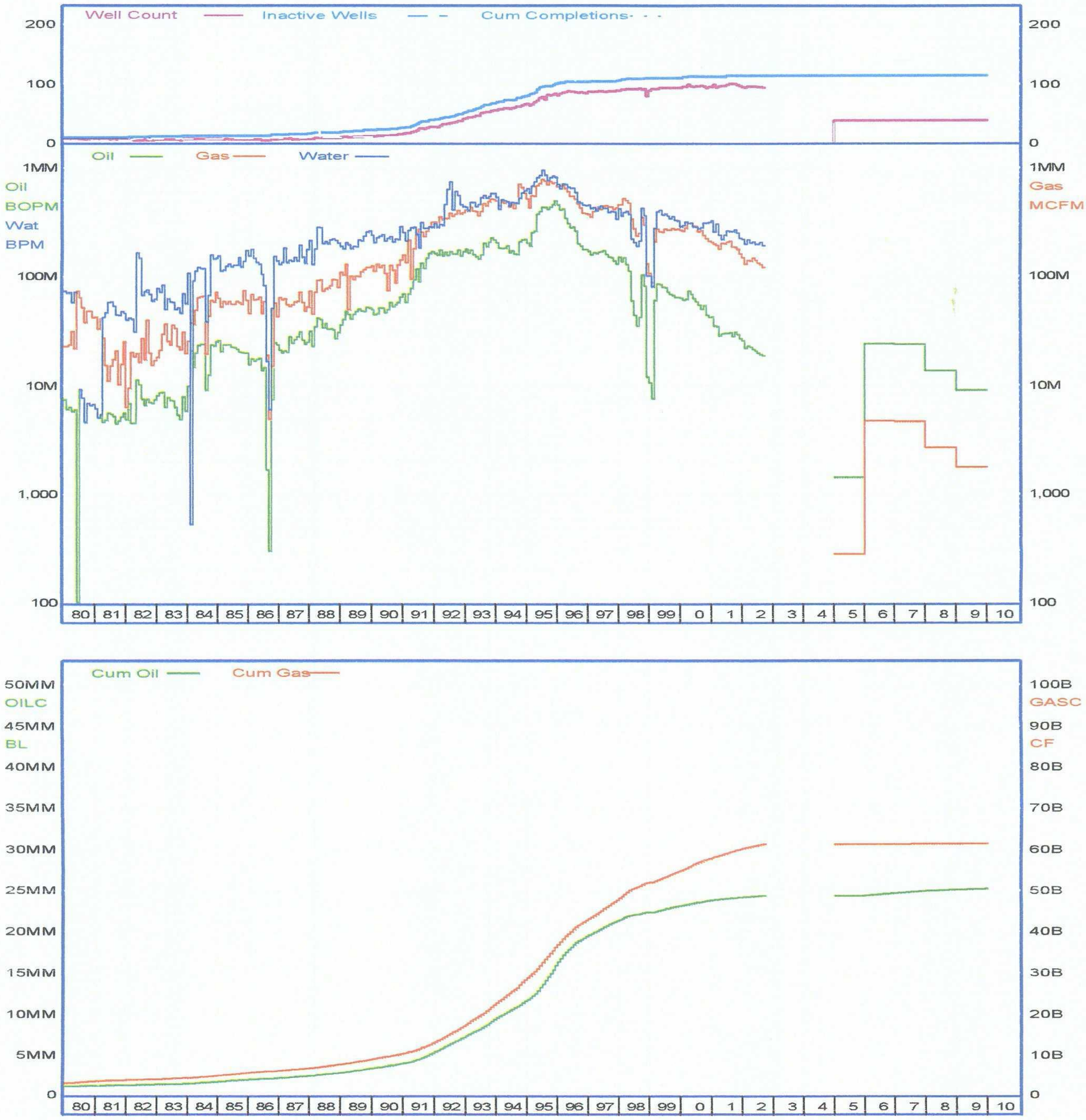




Probable Phase 1 without Drilling
Projections are averages for each year commencing at the effective date of the evaluation. Results are subject to the qualifications and limitations stated in the attached document.

These results are subject to the qualifications and limitations contained in a document titled
"Proposal to Unitize for Secondary Recovery Operations, Dagger Draw Field, Eddy County, New Mexico".

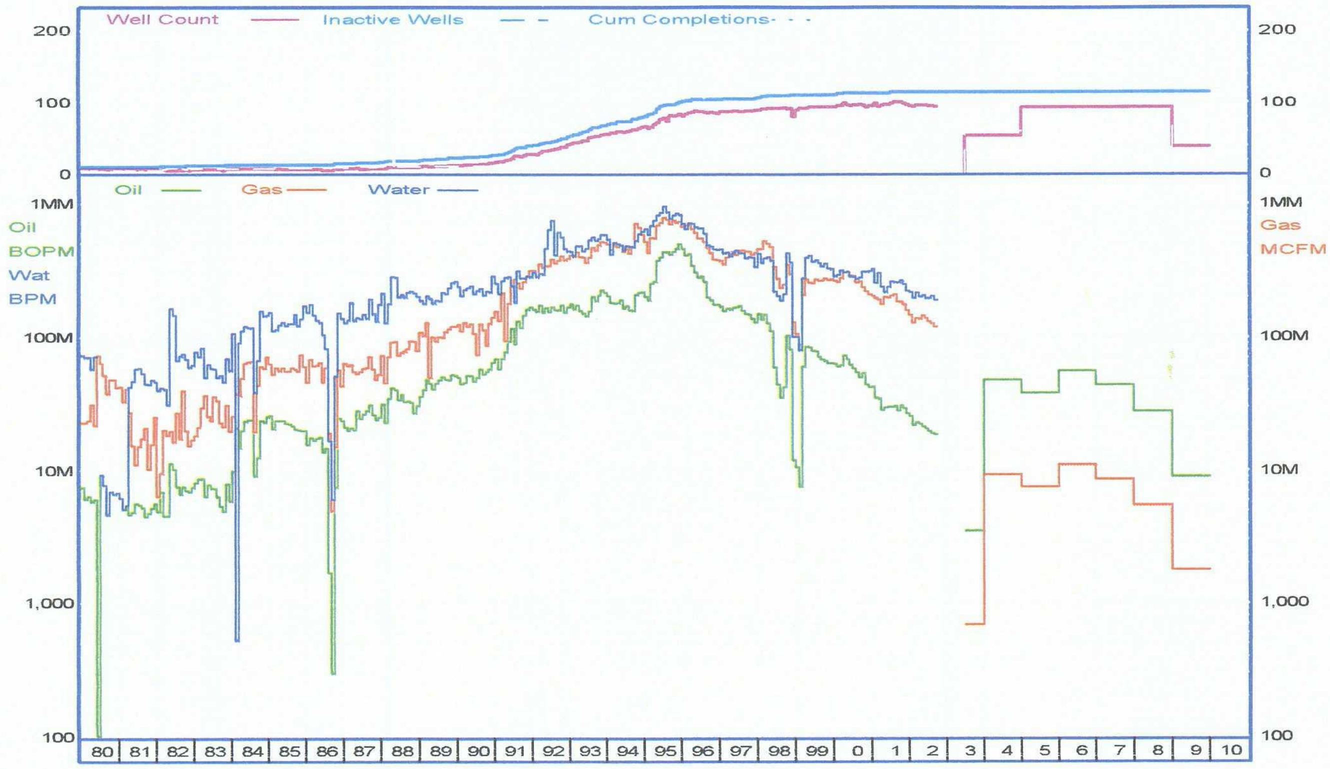
Fig 62

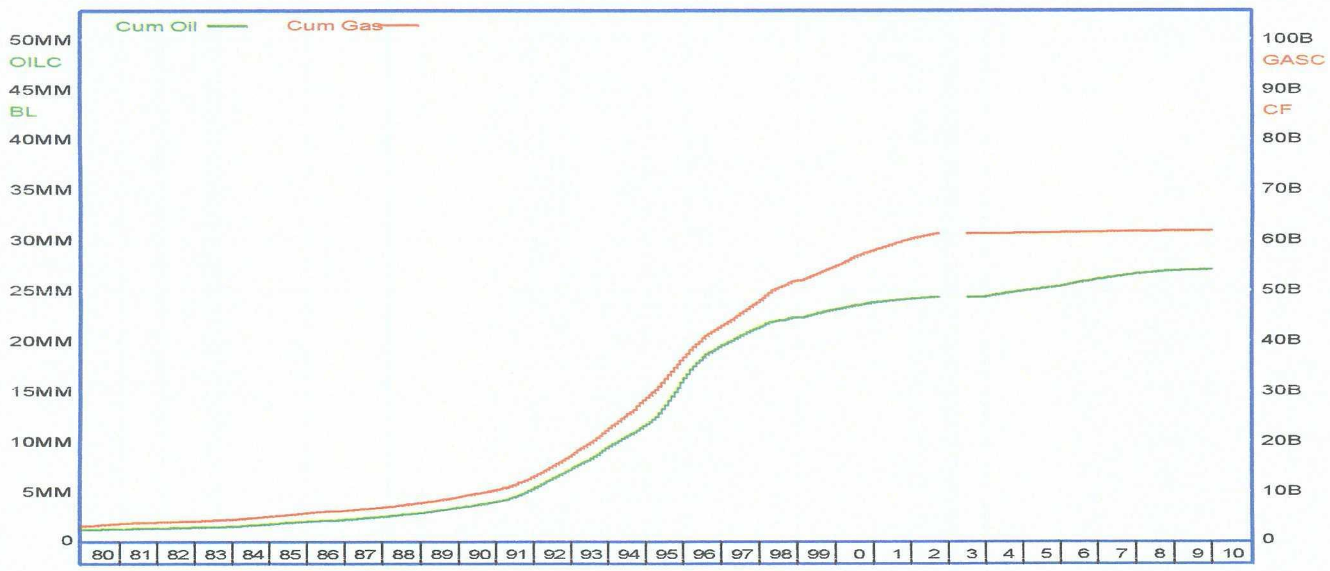


Probable Phase 2 without Drilling
Projections are averages for each year commencing at the effective date of the evaluation.
Results are subject to the qualifications and limitations stated in the attached document.

These results are subject to the qualifications and limitations contained in a document titled "Proposal to Unitize for Secondary Recovery Operations, Dagger Draw Field, Eddy County, New Mexico".

Fig 63

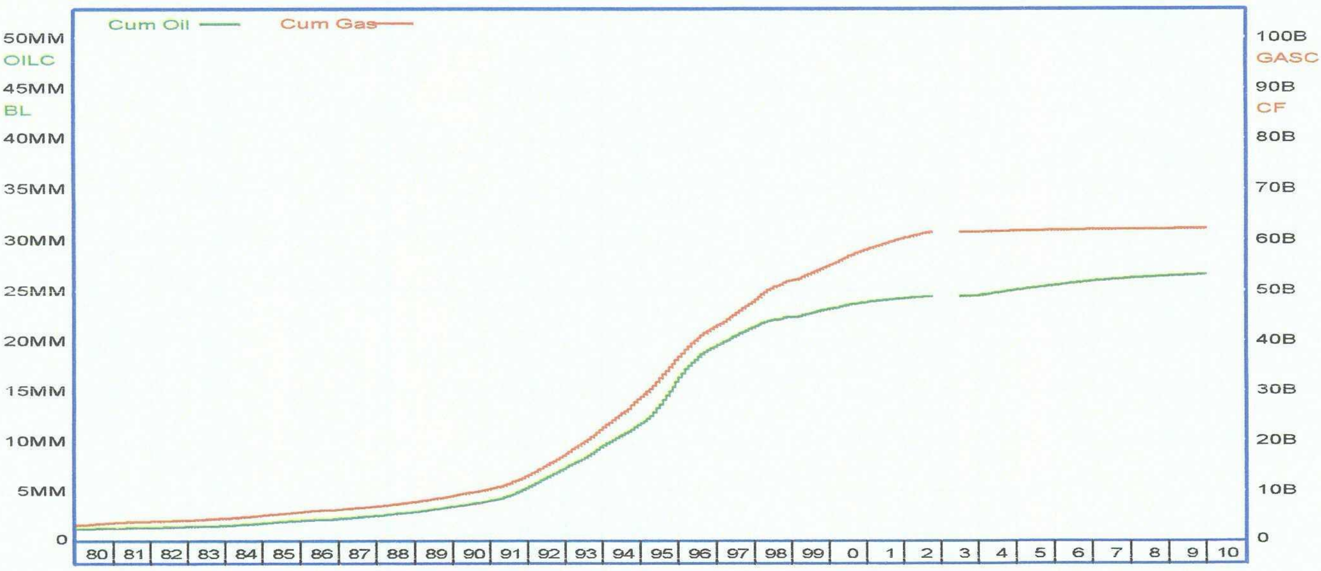




Probable Phase 1 and 2 without Drilling
Projections are averages for each year commencing at the effective date of the evaluation. Results are subject to the qualifications and limitations stated in the attached document.

These results are subject to the qualifications and limitations contained in a document titled "Proposal to Unitize for Secondary Recovery Operations, Dagger Draw Field, Eddy County, New Mexico".

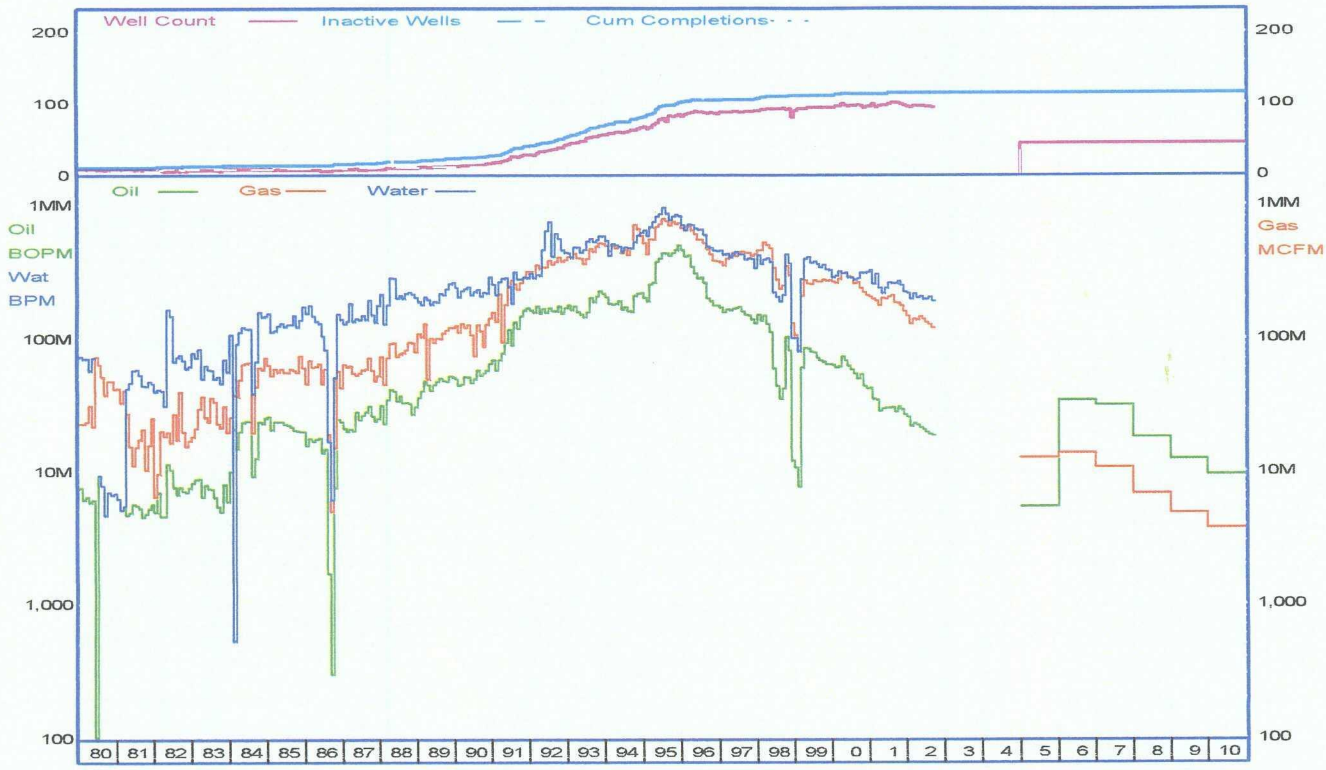
Fig 64

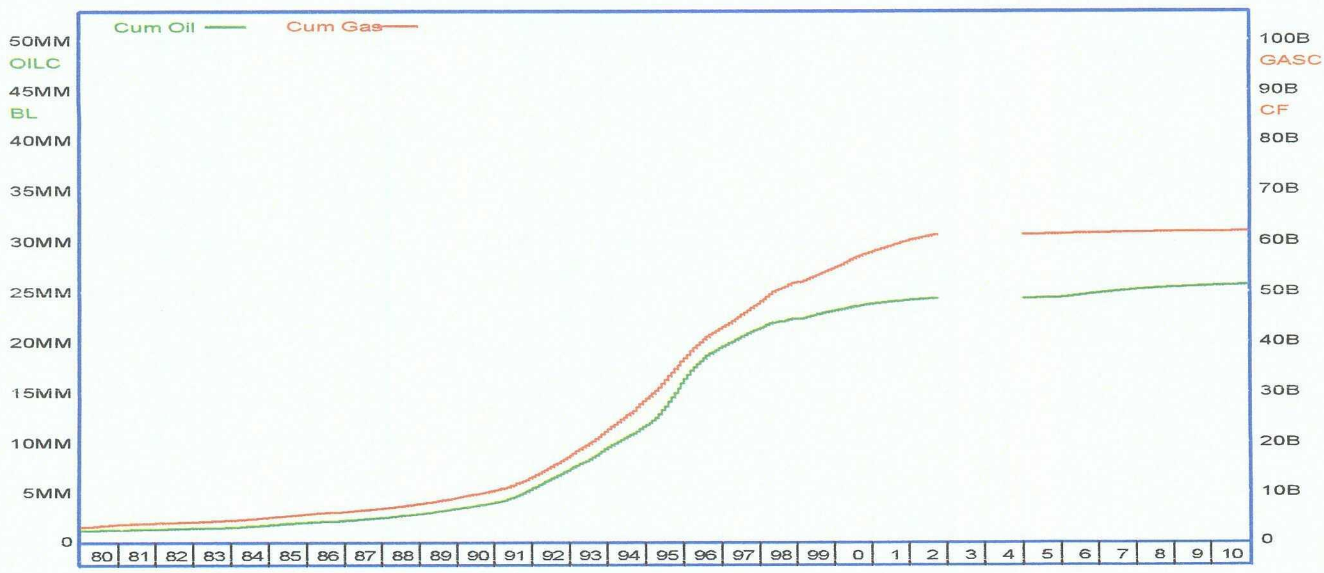


Probale Phase 1 with Drilling
Projections are averages for each year commencing at the effective date of the evaluation.
Results are subject to the qualifications and limitations stated in the attached document.

These results are subject to the qualifications and limitations contained in a document titled "Proposal to Unitize for Secondary Recovery Operations, Dagger Draw Field, Eddy County, New Mexico".

Fig 65





Probable Phase 2 with Drilling
Projections are averages for each year commencing at the effective date of the evaluation. Results are subject to the qualifications and limitations stated in the attached document.

These results are subject to the qualifications and limitations contained in a document titled "Proposal to Unitize for Secondary Recovery Operations, Dagger Draw Field, Eddy County, New Mexico".

Fig 66

Probable Phase 1 and 2 with Drilling
Projections are averages for each year commencing at the effective date of the evaluation.
Results are subject to the qualifications and limitations stated in the attached document.

These results are subject to the qualifications and limitations contained in a document titled "Proposal to Unitize for Secondary Recovery Operations, Dagger Draw Field, Eddy County, New Mexico".