Title: **"Improved Miscible Nitrogen Flood Performance Utilizing Advanced Reservoir Characterization and Horizontal Laterals in a Class I Reservoir – East Binger (Marchand) Unit"**

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Abstract

The East Binger Unit ("EBU") in Caddo County, Oklahoma produces light oil from tight Upper Marchand sandstones at a depth of about 10,000'. Since unitization in 1977, the EBU has had ongoing miscible flue gas and miscible nitrogen flood operations. Greater-than-expected production of the non-flammable injectant gases has occurred throughout the life of the flood, causing a number of reactive actions in the late 1970s and early 1980s and leading to the construction of a new gas plant in 1986 to process high nitrogen content gas.

By the late 1990s, with less than 20% of the original oil in place recovered and the fraction of nitrogen in produced gas approaching the design limit of the plant, the EBU owners initiated a comprehensive reservoir study to determine how oil was being bypassed, whether there were specific attributes of the flood that were promoting the cycling of injected nitrogen, and whether options existed to reduce that cycling and improve the performance of the flood.

The Upper Marchand sandstones are tight sandstones with no water drive. Within the EBU, the sands are vertically segregated by interbedding shales into three primary units: from top to bottom, the A Sands, the B Sand, and the C Sand. The C Sand is by far the dominant sand within the EBU, containing about 95% of the original oil in place.

Compositional reservoir simulation activities conducted as part of the reservoir study suggested that the leading causes of nitrogen cycling were a high permeability channel along the top of the Marchand C sand along with gravity override of the injected gases over the reservoir oil. Among a variety of options investigated, it appeared that drilling horizontal producing laterals along the base of the reservoir and horizontal injection laterals along the top of the reservoir would significantly improve flood performance and ultimate recovery.

It was on this basis that this project was proposed to the U.S. Department of Energy's National Petroleum Technical Office, under the Class Revisit program. A six-year project to gather data and investigate horizontal development options, implement a selected program, and monitor results was initiated in April 2000.

Through project development and additional research, the operator's understanding of fluid flow mechanisms in the reservoir was enhanced and drastically altered. Poor areal sweep efficiency – not poor vertical sweep as believed at project initiation – is the primary factor causing nitrogen cycling and limiting oil recovery in the EBU. Most infill wells were drilled in areas with little sweep and came online producing gas with much lower nitrogen contents than other wells in the field and in the project area that existed prior to the project.

Within the project, the operators drilled and complete the first three horizontal wells ever drilled in the Marchand reservoir. The performances of these wells, however, were

necessarily limited by wellbore orientation and completion techniques, and proved to be economically inferior to vertical wells in this reservoir/recovery setting.

Despite the relative lack of economic success with the horizontal wells, the project proved to be very successful in improving ultimate recovery from the field and reducing nitrogen cycling in the project area. Over the course of the project, three horizontal wells and seven vertical wells were drilled in the project area, and four producing wells were converted to injection service.

Together, these projects more than doubled the oil rate in the project area, from 242 to 502 bopd, adding 298,000 barrels of produced oil by the end of the project. The production increase from the project – 259 bopd – currently accounts for 33% of daily oil production from the Unit. Project area NGL and plant residue (hydrocarbon) gas production rates have also increased, from 156 to 256 bpd and 550 to 940 MCFD, respectively. These increases (100 bpd NGL and 390 MCFD gas) represent about 19% of the current total Unit production of these products. Incremental production of 136,000 barrels of NGLs and 547,000 MCF of residue gas has occurred.

Based on the pre-project decline and the rate at the end of the reporting period, the project will added ultimate reserves of 1,900,000 barrels of oil, 800,000 barrels of NGL, and 3,100,000 MCF of residue gas.

In a reservoir where both vertical and horizontal wells must be fracture stimulated to obtain commercially productive rates, where directional permeability exists, and where secondary or tertiary flood operations are being employed, it will be very difficult to economically justify drilling horizontal wells. Binger Operations, LLC (“BOL”) believes this is the case in the EBU.

Recycling of injected nitrogen has also decreased as a result of the project. Injection into the pilot area increased 60% over levels prior to the project, while gas production and nitrogen content of produced gas have both decreased, resulting in a net “recycle rate” reduction from 72% prior to initiation of the project to about 40% today. With an improved understanding of fluid flow in the EBU, BOL plans to continue developing additional oil and gas reserves with vertical infill wells in a line drive flood.

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Introduction

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The fraction of nitrogen in produced gas continued to increase – an inevitable outcome of nitrogen injection – and by the late 1990s was approaching the design limit of the plant. With less than 20% of the original oil in place recovered, the EBU owners initiated a comprehensive reservoir study in an effort to determine how oil was being bypassed, whether there were specific attributes of the flood that were promoting the cycling of injected nitrogen, and whether options existed to reduce that cycling and improve the performance of the flood.

The Upper Marchand sandstones are tight sandstones with no water drive. Within the EBU, the sands are vertically segregated by interbedding shales into three primary units: from top to bottom, the A Sands, the B Sand, and the C Sand. The C Sand is by far the dominant sand within the EBU, containing about 95% of the original oil in place.

Compositional reservoir simulation activities conducted as part of the reservoir study suggested that the leading causes of nitrogen cycling were a high permeability channel along the top of the Marchand C sand along with gravity override of the injected gases over the reservoir oil. Among a variety of options investigated, it appeared that drilling horizontal producing laterals along the base of the reservoir and horizontal injection laterals along the top of the reservoir would significantly improve the flood performance and ultimate recovery. Significant unknown aspects of this, however, were the productivity and injectivity of horizontal laterals in the tight Marchand C Sand.

It was on this basis that this project was proposed to the U.S. Department of Energy's National Petroleum Technical Office, under the Class Revisit program. A five-year project to gather data and investigate horizontal development options, implement a selected program, and monitor results was initiated in April 2000.

The project would ultimately take six years and undergo significant evolution. Through project development and additional research, the operator's understanding of fluid flow mechanisms in the reservoir would be enhanced and completely altered. Within the project, the operators would drill and complete the first three horizontal wells ever drilled in the Marchand reservoir. The performances of these wells, however, were necessarily limited by wellbore orientation and completion techniques, with the conclusion that they are not economically justified in this reservoir/recovery setting.

Despite the relative lack of economic success with the horizontal wells, the project proved to be very successful in improving ultimate recovery from the field and reducing nitrogen cycling in the project area. Most of all, this resulted from the improved understanding of fluid flow.

This report covers the entire six years of the project. The first two years consisted of gathering reservoir data, including horizontal well productivity data, assembling wellbore information, and planning project development. The project was implemented in years three and four, with monitoring of performance and results continuing through years five and six.

Executive Summary

The East Binger Unit ("EBU") in Caddo County, Oklahoma produces light oil from tight Upper Marchand sandstones at a depth of about 10,000'. Since unitization in 1977, the EBU has had ongoing miscible flue gas and miscible nitrogen flood operations. Greater-than-expected production of the non-flammable injectant gases has occurred throughout the life of the flood, causing a number of reactive actions in the late 1970s and early 1980s and leading to the construction of a new gas plant in 1986 to process high nitrogen content gas.

By the late 1990s, with less than 20% of the original oil in place recovered and the fraction of nitrogen in produced gas approaching the design limit of the plant, the EBU owners initiated a comprehensive reservoir study to determine how oil was being bypassed, whether there were specific attributes of the flood that were promoting the cycling of injected nitrogen, and whether options existed to reduce that cycling and improve the performance of the flood.

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Through project development and additional research, the operator's understanding of fluid flow mechanisms in the reservoir was enhanced and completely changed. Poor areal sweep efficiency – not poor vertical sweep as believed at project initiation – is the primary factor causing nitrogen cycling and limiting oil recovery in the EBU. Most infill wells were drilled in areas with little

sweep and came online producing gas with much lower nitrogen contents than other wells in the field and in the project area that existed prior to the project.

Over the course of the project, three horizontal wells and seven vertical wells were drilled in the project area, and four producing wells were converted to injection service. These were the first three horizontal wells ever drilled in the Marchand reservoir. The performances of these wells, however, were necessarily limited by wellbore orientation and completion techniques, and proved to be economically inferior to vertical wells in this reservoir/recovery setting. Despite the relative lack of economic success with the horizontal wells, however, the project proved to be very successful in improving ultimate recovery from the field and reducing nitrogen cycling in the project area.

Together, the project more than doubled the oil rate in the project area, from 242 to 502 bopd, adding 298,000 barrels of produced oil by the end of the project. The production increase from the project – 259 bopd – currently accounts for 33% of daily oil production from the Unit. Project area NGL and plant residue (hydrocarbon) gas production rates have also increased, from 156 to 256 bpd and 550 to 940 MCFD, respectively. These increases (100 bpd NGL and 390 MCFD gas) represent about 19% of the current total Unit production of these products. Incremental production of 136,000 barrels of NGLs and 547,000 MCF of residue gas has occurred.

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In a reservoir where both vertical and horizontal wells must be fracture stimulated to obtain commercially productive rates, where directional permeability exists, and where secondary or tertiary flood operations are being employed, it will be very difficult to economically justify drilling horizontal wells. Binger Operations, LLC (“BOL”) believes this is the case in the EBU.

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Basis for Project

Field History and Injectant Cycling

The East Binger Unit (“EBU”) is located approximately 60 miles southwest of Oklahoma City, on the east flank of east end of the Anadarko Basin (**Figure 1**). Although the field was discovered in 1935, only a handful of wells were drilled before 1975. Sixty-eight wells were drilled in 1975-76, and unitization followed fairly quickly after in August of 1977. Since

Figure 1. Locator map – the East Binger Unit lies approximately 60 miles west-southwest of Oklahoma City, Oklahoma.

unitization, the EBU has had ongoing enhanced recovery operations in the form of a miscible gas flood. From August 1977 through November 1986, the injectant was gas plant flue gas. Since December 1986, the injectant has been nitrogen.

Early breakthrough and cycling of the injected gas have been apparent since early in the life of the EOR project, and were partially responsible for a change in the injectant from flue gas to nitrogen. Within one year of the initiation of gas injection, gas breakthrough was noted in various producing wells. As the channeling and breakthrough problems continued, they were initially handled by shutting in offending producing wells, or by converting them to injection if properly located. Until 1986, the produced gas was sold directly to one of three pipelines. As the flood progressed and matured, the increasing nitrogen content in produced gas reduced the BTU value of that gas, rendering it unmarketable.

In 1986, the unit owners reached agreement on the construction of a Nitrogen Management Facility (NMF) for the EBU. (The owners would eventually buy the NMF in 1998 and take over operations of it in 2001.) The NMF has three primary functions: 1) cryogenic processing of the EBU's high-nitrogen-content produced gas into natural gas liquids (NGLs), sellable low-nitrogen-content residue gas, and nitrogen for reinjection; 2) cryogenic air separation for the purpose of providing additional "make-up" nitrogen for injection; and 3) compression of nitrogen for injection in the EBU.

The construction and use of the NMF reduced the cost of inert gas production, addressed tubular corrosion and injector plugging problems attributable to products formed by the flue gas, and improved field economics by enabling oil production and recovery of NGLs from wells that had been shut-in due to gas breakthrough.

The plant was originally designed to handle inlet gas with a nitrogen content of up to 70%. At NMF startup in December 1986, total unit produced gas nitrogen content was approximately 40%. By the late 1990s, when this project was proposed, the field's nitrogen content had increased to about 70%, and several producing wells had been shut-in due to excessively high nitrogen content in the produced gas. The field was producing 850-900 bopd, 650 bpd of NGLs, and 2400 Mcfd residue gas. Oil decline was running about 9% per year, NGL decline about 7% per year, and residue gas decline about 5% per year. There were 77 active wells (51 producers, 26 injectors) and 4 idle wells.

Reservoir Geology and Characterization

The Upper Pennsylvanian-Missourian age Upper Marchand Sands in the East Binger field consist of three sand intervals: the A (youngest), B, and C (oldest) sands. With the boundary of the East Binger Unit (EBU), the C Sand is the dominant sand body. All of these sands are tight, cemented sandstones. **Figure 2** shows a type log from the field. As depicted, the A and B Sands are typically much thinner, though the A Sand is the dominant sand in the eastern part of the EBU, where the C Sand is largely absent. **Figure 3** shows a C Sand net pay map, circa 2000, and **Figure 4** shows a cross section across the Unit.

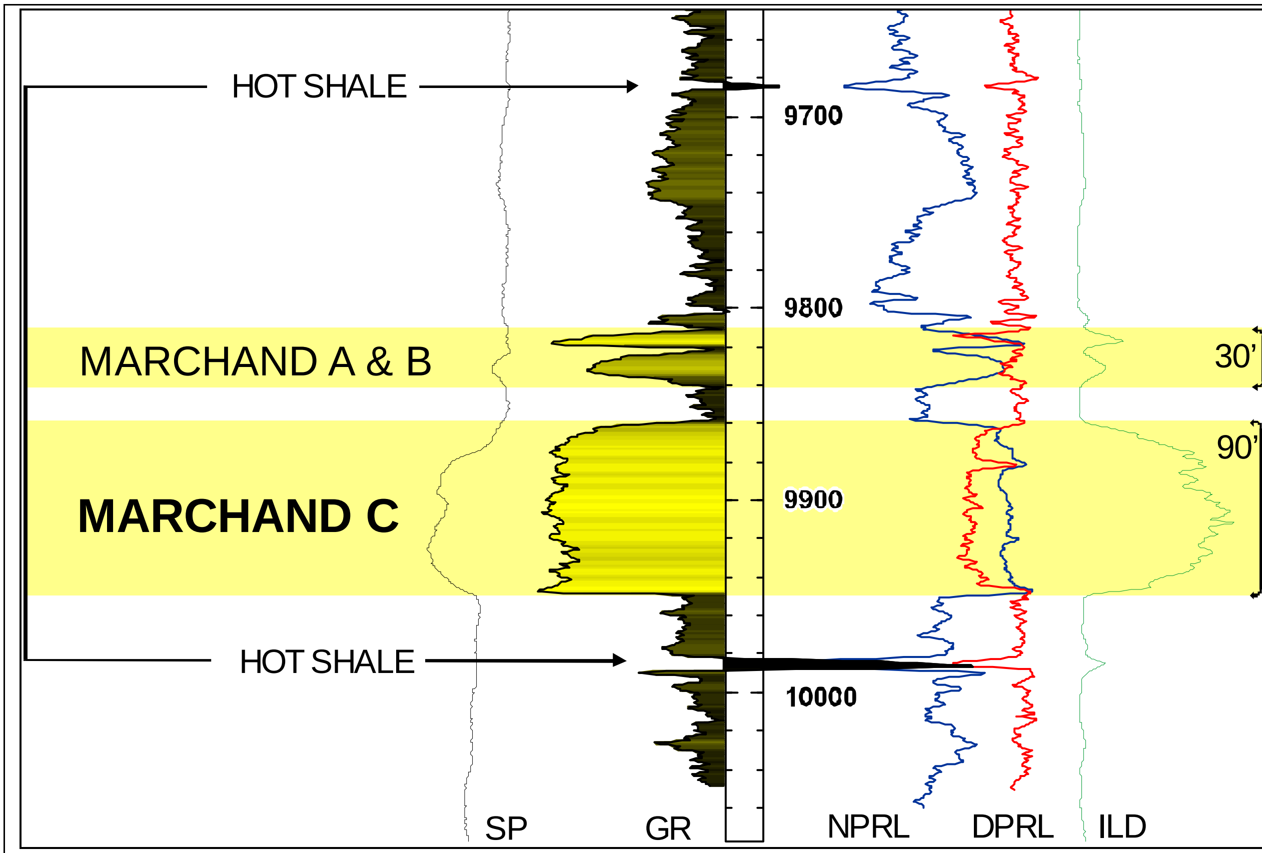

Figure 2. East Binger Unit type log (well 46-3). This well was drilled in 2004; its location is shown on Figure 48.

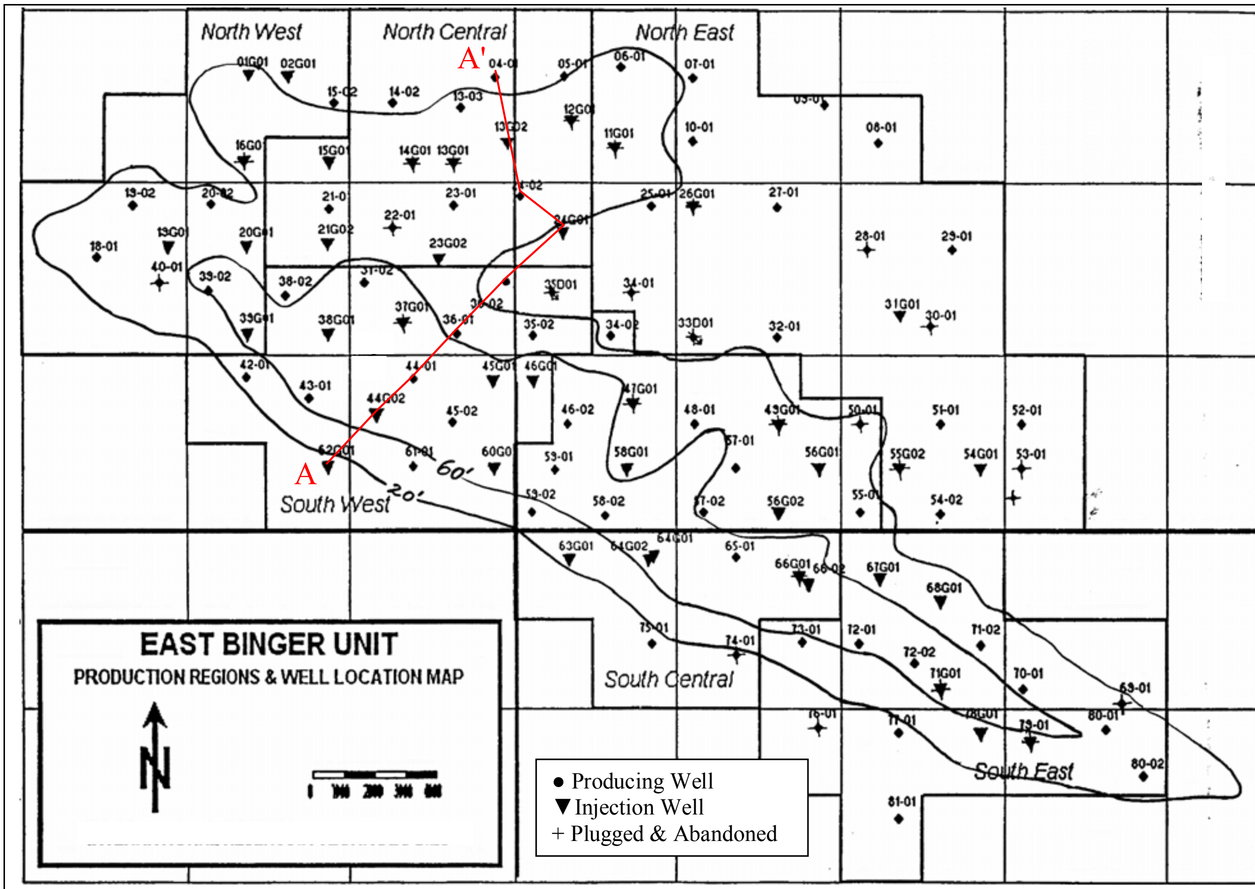

Figure 3. Base map of the East Binger Unit circa 2000, prior to the project, with 20' and 60' net pay contours. Cross section A-A' is shown in Figure 4.

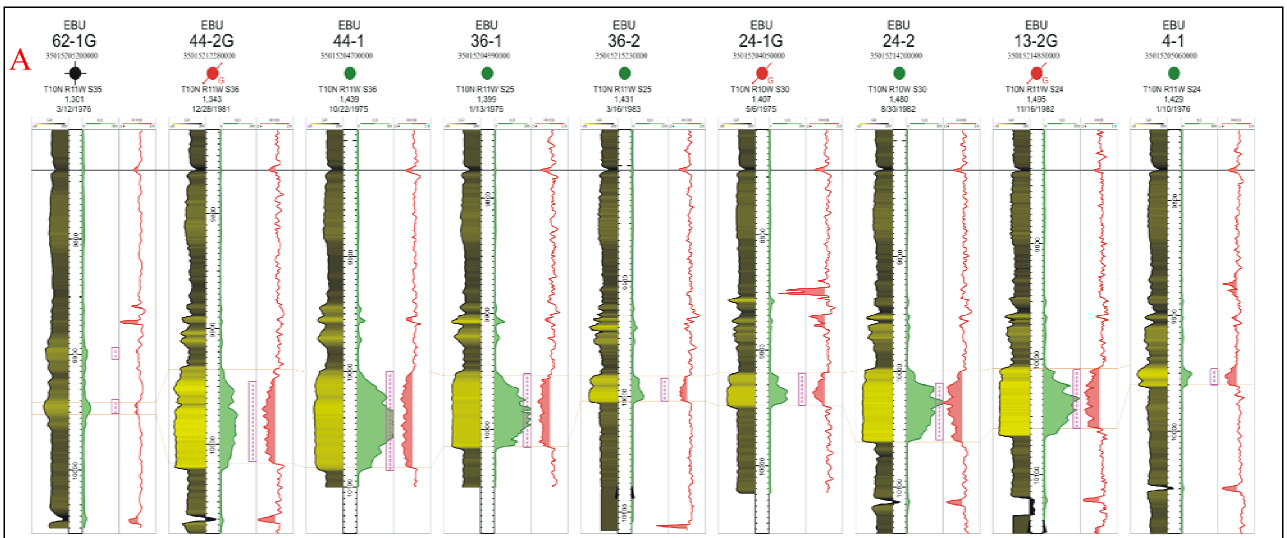

Figure 4. Cross-section of the Marchand Sands of the East Binger Unit, from SW to NE across the main sand body, then from S to N across the north sand accumulation. The location of this section is shown on Figure 3.

The depositional environment of the Upper Marchand Sands has been variously interpreted to be fluvio-deltaic (Graff, 1971, and White et al, 1999), offshore shallow marine (Sawyerr, 1972, and

Shelton and Wilson, 1978), and deep marine (Baker, 1979, Easterly et al, 1981, and Berg, 1986). In the thickest area of sand accumulation, the C Sand is over 90' thick, with net pay estimated at over 80'. Field wide, net pay averages 39'. The A and B Sands together average only about 3' in total net pay across the Unit, but a B Sand lobe in the western part of the Unit has as much as 18' of net pay, and an A Sand lens in the eastern part of the Unit has up to 14'. Water saturation averages about 25% in the C Sand and 35% in the A and B Sands.

The porosity and permeability of these sands are quite low for an oil reservoir, and are generally similar from sand to sand. Porosity averages about 7.5%, and permeability averages about 0.1 md. Locally, one A Sand lens has permeability of 1 to 5 md. This A Sand is similar to the Marchand Sand that is waterflooded in the nearby Northeast Binger (Marchand) Unit. Because of the low permeability of the sands, every well that has been completed has had hydraulic fracture stimulation. Implications of this are discussed later in the report.

Regional structure dips gently (~0.5 to 1.0 degrees) to the southwest, and has little to no impact on reservoir performance. Growth in sand thickness occurs where the underlying shale is thinner; the distances between the two "hot shales" noted in **Figure 2** and between the upper "hot shale" and the top of the C Sand are very consistent across the Unit. Depth of the sands is approximately 10,000'.

The Marchand sands in the East Binger Unit have never produced much water. The oil is 46 degree sweet oil with a solution gas ratio of 964 scf/bbl and an initial formation volume factor of 1.47 RB/STB. The reservoir was slightly overpressured at discovery, with an initial reservoir pressure of 5815 psia. It was also undersaturated; the initial bubble point pressure was 2786 psi.

A reservoir characterization and 3-D full-field compositional simulation study of the EBU was initiated in April, 1998 to evaluate the potential future recovery from existing and alternative enhanced recovery methods, and to identify potential improvements in the miscible flood currently in place. International Reservoir Technologies, Inc. (IRT) of Lakewood, Colorado, was chosen during a competitive bid process to provide the services required for the compositional study. A simulation model was constructed using data that was generated from prior integrated, multidisciplinary engineering and geologic studies.

Problem Diagnosis

Based on reservoir characterization and simulation work conducted in the history match phase of the simulation study, it was interpreted that relatively high permeability channels exist within the reservoir, particularly along the top of the Marchand "C" Sand. It was believed that these high permeability channels were the primary conduit for the channeling and cycling of injected gas through the reservoir. Further, it was also interpreted that gravity segregation of fluids within the sand body are exacerbating the gas-channeling problem. In addition, there appeared to be areas within the reservoir which were not receiving pressure support due to the cycling effects, and had fallen below miscibility pressure. Indications were that all of these situations – high permeability streaks near the top of the reservoir, gravity segregation, and areas of low pressure – were working negatively against the ultimate recovery from this EOR process.

Proposed Solution

In our proposal to the DOE, Binger Operations, LLC ("BOL") offered a multi-faceted approach to address the problems diagnosed in the reservoir characterization and simulation study. This included drilling lateral sections from existing wellbores of both producers and injectors, conversions of producers to injectors to improve pressure maintenance and properly align flood patterns, drilling new wells with horizontal laterals to replace wells lost to corrosion problems, and increasing injection compression capacity at the NMF.

Horizontal Laterals in Existing Wells. In order to utilize directional permeability and maximize wellbore exposure at the base of the Marchand formation where it appeared gravity segregation had left unswept oil, it was proposed to set a whipstock in existing usable wellbores, cut a casing window, and drill at least one 1,000-1,500' lateral per wellbore. In addition, horizontal sidetracking was planned for at least two injection wells. The horizontal lateral would go into the top of the sand to augment artificial gas cap creation and vertical sweep efficiency. It was believed that using existing wellbores would save up to $350,000 per well over the cost of a new well from ground level.

Conversions of Producers to Injection. In order to maximize gas injection, optimize pattern alignment, and build/maintain bottom hole pressure, it was anticipated that two existing vertical producers would be converted to injection.

Redrill Infill Locations. Corrosion problems led to the plugging and abandonment of many EBU wells in the 1980s and 1990s, leaving a number of areas with limited well density. When this project was proposed, it was suggested that at least two new wells, both with horizontal segments in the Marchand, would be drilled in the pilot area.

Expansion of Injection Compression Capacity. Injection capacity at the NMF was 18 MMCFPD when this project was proposed. The above described field work was expected to increase both withdrawals and well injection capacity. The proposal therefore included acquisition and installation of an additional compressor to increase injection capacity to approximately 23 MMCFPD.

The project was proposed to be broken into three phases, which would align with DOE "Budget Periods". Phase I (Budget Period 1) would include additional data gathering to more fully define the project, as well as selection of the optimal area to implement it. Initial simulation forecasting indicated that the productivity and injectivity of horizontal wellbores was a critical aspect of the project, and one for which there was little historical data. In fact, there had not been a horizontal well drilled into the Marchand sandstone prior to this project. Plans for Phase I therefore included the drilling of two horizontal laterals – one each from an injector and a producer – to better defined horizontal well injectivity and productivity, respectively.

Phase II (Budget Period 2) of the project would involve the implementation of the project, as well as the initiation of project monitoring activities. As mentioned above, it was envisioned at the time of the proposal that this would include drilling laterals from existing wells, drilling replacement wells, converting existing producers to injection service, and expanding injection compression capacity.

Finally, Phase III (Budget Period 3) was planned as a two-year period of monitoring the project, primarily through the sampling of produced gas at all wells in and near the project area, to determine whether the project implemented in Phase II was having the desired effect of reducing gas channeling and cycling and increasing the expected ultimate oil recovery from the field.

Project Phase I (Budget Period 1) – Additional Data Gathering, Project Area Selection, and Project Definition

The primary focus of Phase I was to define the project to be implemented in Phase II. This included the selection of an area for the entire project and specific items – new drill wells, conversions, sidetracks, etc. – to include within that project area. Completion of a number of associated tasks was necessary to accomplish this overall goal. These included gathering a variety of types of data, updating the existing full field simulation model, building a new pilot area model, and forecasting a variety of scenarios with that model. Each of these aspects of the project will be discussed here.

Data Gathering

The gathering of data was integral to the updating and fine-tuning of the full-field simulation model and planning of the project to be implemented in Project Phase II. The most significant aspect of the data-gathering program was obtaining horizontal well performance data. Because of its significance, and the many other issues associated with the horizontal well, it is discussed separately the section that follows. Other aspects included gathering pressure and profile data from injection and production wells.

<u>Pressure Data</u>. Pressure transient tests were conducted in four producers – 44-1, 46-2, 48-1, and 57-2 – and four injectors – 38G-1, 44G-2, 45G-1, and 58G-1. Combined with pressure tests of three injection wells run in 1999, they provided an excellent swath of pressure data through the heart of the reservoir.

Results from these tests are provided in **Figure 5** and **Figure 6**. The average reservoir pressures measured in the four producers ranged from 2600 to 3070 psi, with an average of about 2900 psi. The average reservoir pressures measured in the injection wells ranged from 5340 to 6220 psi, with an average of about 5800 psi. Averaging the injection well average pressure with the producing well average pressure suggests an overall average reservoir pressure of about 4300 psi.

Reservoir pressures around all of the producers were lower than had been predicted by the full field model, while pressures around all of the injectors were higher than predicted by the model. Implications of these results were that model permeabilities were too high. While the average pressure in the model was fairly close to the estimated average field pressure of 4300 psi, the pressure gradient between injectors and producers is much steeper in the field than had been predicted by the model – an average of 2900 psi actual versus an average of 1300 psi predicted by the model for the same area. In attempting to match observed gas-oil ratios in the field, model permeabilities were increased throughout the section. Following this realization, when the pilot model was built, efforts were taken toward better matching field pressure gradients while still matching field gas production.

Well	Date	SI Time (hr)	Interpreted Press (psia)	Gauge Depth (ft KB)	Est. WB Fluid Grad (psi/ft)	Est. Res. Fluid Grad (psi/ft)	Mid Perf Pressure (psia)		Model Pressure (psi)	Rel Perm (md)	Skin	Frac Evident?	Lf (ft)	R of Inv (ft)	Comment
38G01	12/2000	335	4450	13	0.143	0.14	5876	>	4800	0.06	-	Y	420	310	
44G02	12/2000	670	4770	11	0.144	0.14	6206	>>	4400	0.04	-	Y	410	360	
45G01	12/2000	335	4800	14	0.144	0.14	6224	>	5700	0.39	-5.9	N	-	-	
58G01	12/2000	335	4050	13	0.141	0.14	5465	=	5300	0.17	-	Y	550	570	
44-01	12/2000	143	2900	9899	0.07	0.26	2910	<	3800	0.04	-0.8	N	-	49	
48-01	12/2000	168	2900	10000	0.07	0.26	2900	<	4000	0.08	1.8	N			
57-02	12/2000	168	2600	9974	0.07	0.26	2600	<	3600	0.04	-	Y	70	87	Non-unique solution
46-02	10/2000	168	3070	9990	0.07	0.26	3070	<	4200	0.06	-1.6	N	-	95	Exhibits dual perm behav.
64G02	06/1999	360	5300	9666	0.14	0.14	5344	>	5000	.02-.04	-	Y	300	200	
66G02	06/1999	360	5440	9632	0.14	0.14	5490	>	4500	0.03	-	Y	360	220	
56G02	06/1999	360	5700	9594	0.26	0.26	5781	>	5200	.06-.30	-	Y	10-400	100-300	Cannot determine Lf

Figure 5. 4Q 2000 Pressure Surveys in the East Binger Unit. Pressures measured in injection wells are shown in red. Pressures measured in producing wells are shown in green.

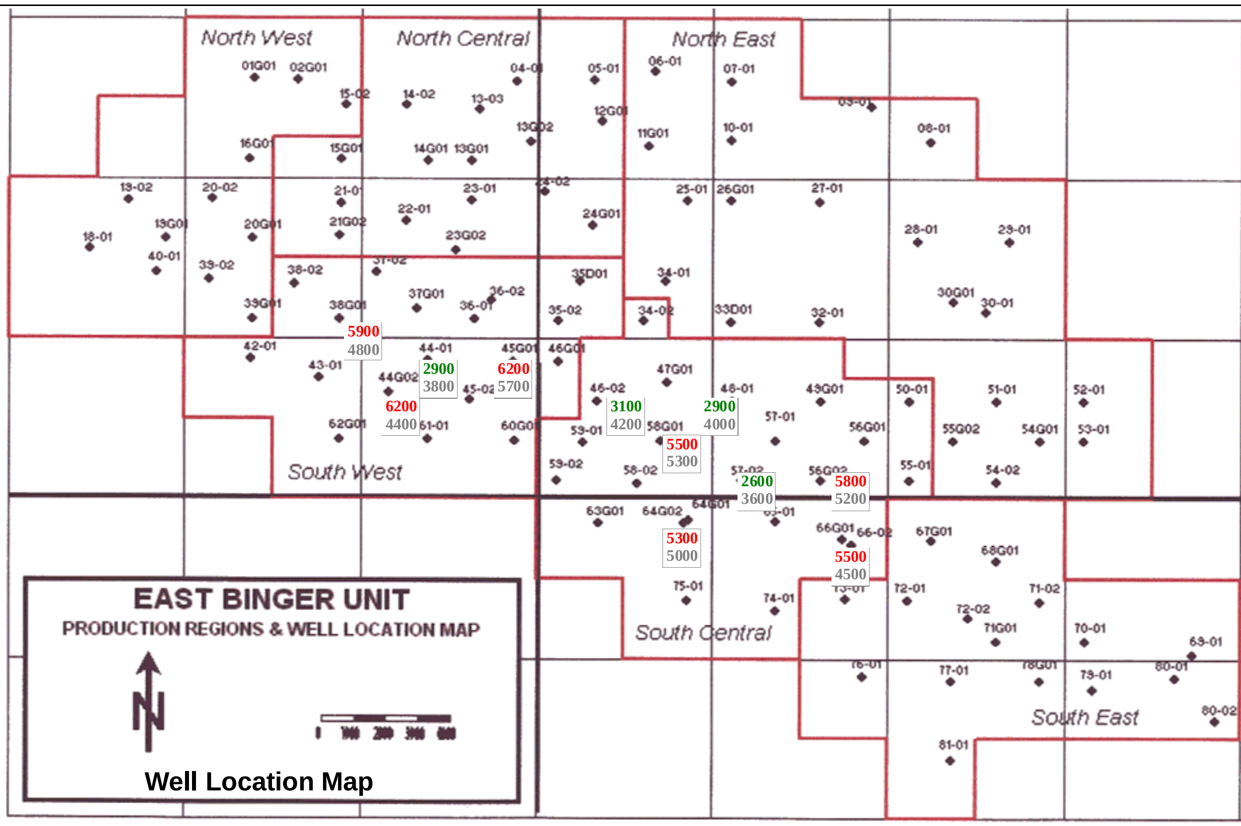

Figure 6. Map showing measured and model-predicted pressures. Actual pressures measured in injectors are shown in red; actual pressures measured in producers are shown in green. Model-predicted pressures are shown in gray.

Another realization from the pressure tests was confirmation of a prior conclusion from the model study – the productivities of the wells appeared to be decreasing with time. In three of the four buildup tests conducted in producing wells, the pressure response suggests there is no longer an effective hydraulic fracture. Most of the injection wells still appeared to be adequately stimulated.

Profile Data. Four injection profiles and two production profiles were run on wells within the main channel. Initially, profiles were run in two injection wells with anomalously high nitrogen injection rates - EBU 68G-1 and EBU 78G-1. Both are located in the Southeast region of the field (see **Figure 3**). The profiles were run in an attempt to determine whether there were mechanical issues such as parted casing or casing leaks in these wellbores which might affect the local area's selection for a pilot area project.

On EBU 68G-1, indication was that all injected gas was staying within the Marchand sand, but 72% of it was entering the Marchand A and B perforations and only 28% was entering the Marchand C Sand. Within the Marchand C Sand, all of the gas appears to be entering only the top 14 feet of sand, with no gas entering the bottom 20 feet. There were no apparent mechanical integrity problems with this wellbore.

Due to a mechanical restriction in the tubing on EBU 78G-1, a radioactive survey was run inside the tubing above the formation to check for injection out of zone. Indications were that injected fluids are staying within the Marchand sand. There are no apparent mechanical integrity problems with this wellbore.

A set of additional injection and production profiles were run later in Phase I. Injection profiles were run in EBU 38G-1 and EBU 45G-1; production profiles were run in EBU 55-1 and EBU 72-1. These were conducted both to determine where the majority of flow is occurring and to compare with the full field model predictions.

EBU 38G-1 is a C-Sand only injection well in the west central area of the field, just northwest of the area eventually selected for the project. It has 74' of perforations. Whereas the model predicted fairly uniform injection through the C Sand, the interpretation of the profile is that 67% of the gas is going into the top 22' of perforations. See **Figure 7**.

EBU 45G-1 is perforated in the A, B, and C Sands. The model does not have the A or B sands in communication with any offset producing wells, and consequently predicts no injection in these sands. It also predicts uniform injection through the C Sand. Interpretation of the injection profile is that over 50% of the gas in going into these sands, with the remainder in the top 30' of the 74' of C Sand. See **Figure 8**.

EBU 55-1 and EBU 72-1 are both producers in the southeast part of the field. Both are perforated in the A and C Sands, and are within about ¾ mile of injection well EBU 68G-1.

In EBU 55-1, the interpretation of the production profile is that 80% of the produced gas, or about 230 MCFD, is coming from the A Sand, versus 33% predicted by the model. There is apparently no oil coming out of the A Sand. Within the C Sand (29'), gas and oil production appear to be fairly uniformly distributed across the zone. See **Figure 9**.

38G01 Jan. 2001 Log

KB= 1392

PPC Database	Perfs (subsea)	Perfs (md)
From (ft)	8,592	9,984
To (ft)	8,666	10,058

Note: Most of the difference in the results for this well is in the top interval of the C Zone (FFM layer 6), with the FFM essentially showing no GI rate. This is due to the well being very near the edge of the reservoir, thus having limited PV to inject into. Again, this is probably related to a geologic reservoir description problem.

MODEL Layers		Model Layers				Model	Model	Profile Log		Log	Log
		Layer Top (subsea)	Layer Bottom (subsea)	Layer Top (md)	Layer Bottom (md)	Calculated Interval Injection, %	Calculated Cumulative Injection, %	Top Interval (md)	Bottom Interval (md)	Calculated Interval Injection, %	Calculated Cumulative Injection, %
Top A	1	8,506	8,517	9,898	9,909						
	2	8,517	8,528	9,909	9,920						
	3	8,528	8,538	9,920	9,930						
	4	8,538	8,580	9,930	9,972						
Top C	5	8,580	8,591	9,972	9,983						
	6	**8,591**	**8,602**	**9,983**	**9,994**	1%	100%	9,984	9,994	54%	100%
	7	**8,602**	**8,613**	**9,994**	**10,005**	20%	99%	9,994	10,004	13%	46%
	8	**8,613**	**8,624**	**10,005**	**10,016**	23%	79%	10,004	10,014	0%	34%
	9	**8,624**	**8,636**	**10,016**	**10,028**	18%	56%	10,014	10,024	8%	34%
	10	**8,636**	**8,647**	**10,028**	**10,039**	14%	38%	10,024	10,034	7%	25%
	11	**8,647**	**8,658**	**10,039**	**10,050**	24%	24%	10,034	10,044	5%	18%
	12	8,658	8,669	10,050	10,061		0%	10,044	10,058	13%	13%

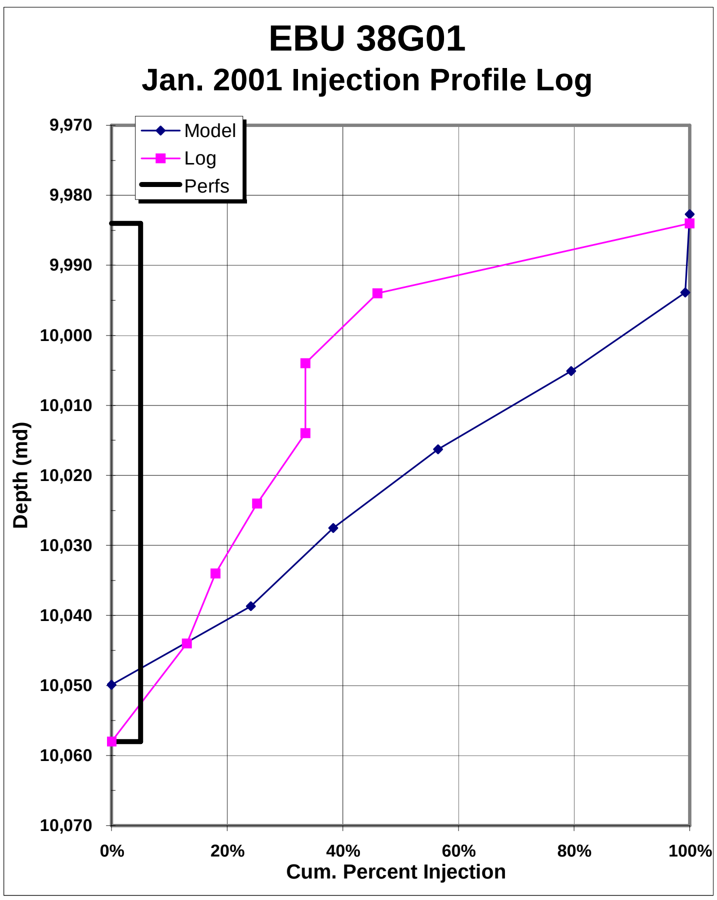

Figure 7. January 2001 injection profile from well 38G-1, with comparison with model-predicted profile.

45G01 Jan. 2001 Log

KB= 1334

PPC Database	**Perfs (subsea)**	**Perfs (md)**
From (ft)	8,503	9,837
To (ft)	8,628	9,962

Note: The GI into the top 2 layers in the FFM (L2 & L3) are limited to zero rate due to high pressure. Layer 2 has a very small PV in the FFM and Layer 3 is near the edge of the reservoir. The uniform GI in the C Zone layers is a function of the similar reservoir properties at the well across the C interval. Layer 4 , which took 33% of the GI on the log, is not present/active in the FFM. Again, these variances appear to be due to a geologic reservoir description problem.

MODEL Layers		**Model Layers**				**Model**	**Model**	**Profile Log**		**Log**	**Log**
		Layer Top (subsea)	**Layer Bottom (subsea)**	**Layer Top (md)**	**Layer Bottom (md)**	**Calculated Interval Injection, %**	**Calculated Cumulative Injection, %**	**Top Interval (md)**	**Bottom Interval (md)**	**Calculated Interval Injection, %**	**Calculated Cumulative Injection, %**
Top A	1	8,486	8,495	9,820	9,829						
	2	**8,495**	**8,503**	**9,829**	**9,837**	0%	100%				
	3	**8,503**	**8,512**	**9,837**	**9,846**	0%	100%	9,837	9,844	21%	100%
	4	8,512	8,552	9,846	9,886			9,850	9,858	33%	79%
Top C	**5**	**8,552**	**8,563**	**9,886**	**9,897**	4%	100%	9,888	9,900	2%	46%
	6	**8,563**	**8,574**	**9,897**	**9,908**	14%	96%	9,900	9,919	41%	44%
	7	**8,574**	**8,586**	**9,908**	**9,920**	14%	82%	9,919	9,925	3%	3%
	8	**8,586**	**8,597**	**9,920**	**9,931**	15%	68%	9,925	9,962	0%	0%
	9	**8,597**	**8,608**	**9,931**	**9,942**	18%	53%				
	10	**8,608**	**8,619**	**9,942**	**9,953**	15%	34%				
	11	**8,619**	**8,630**	**9,953**	**9,964**	19%	19%				
	12	**8,630**	**8,634**	**9,964**	**9,968**	1%	1%	*9,962*			

*Note: **Bold** Layer Depths indicate active layers in FFM*

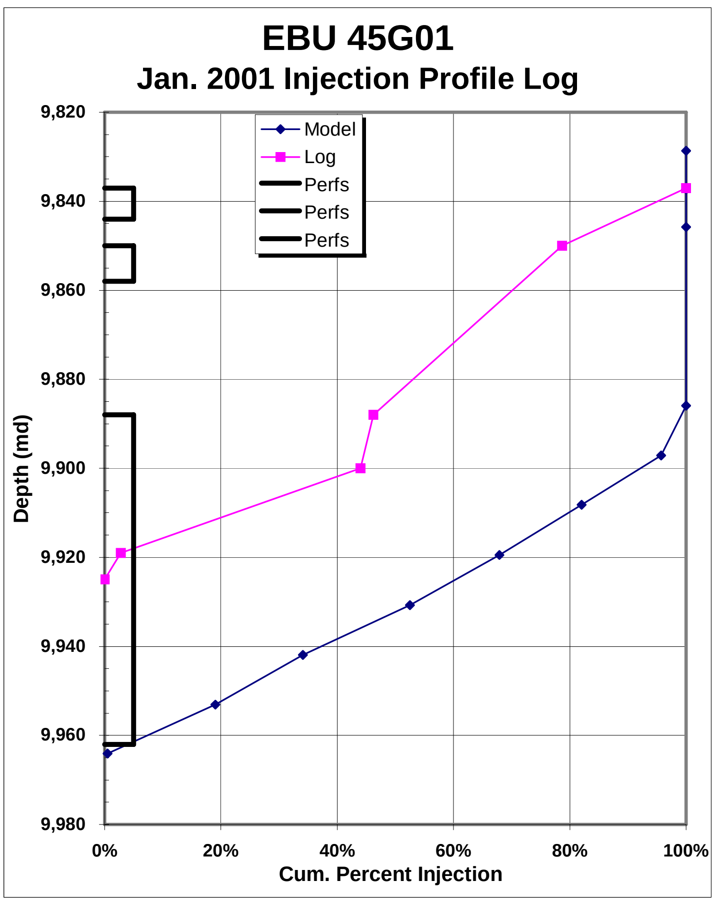

Figure 8. January 2001 injection profile from well 45G-1, with comparison with model-predicted profile.

55-01 Dec. 2000 Log

KB= 1401

PPC Database	Perfs (subsea)	Perfs (md)
From (ft)	8,482	9,883
To (ft)	8,488	9,889
From (ft)	8,500	9,901
To (ft)	8,501	9,902
From (ft)	8,555	9,956
To (ft)	8,584	9,985

Note: Oil profiles are similar in the FFM and from the log. Layers 2 & 3 are not active/present in model; i.e., no pay at 9901'-9902'. Ignoring the effect of this interval, the gas production profile from the FFM is similar to the log result, although the model did produce more gas from the bottom perfs. The absence of the 9,901'-02' interval in the model is a function of the geologic reservoir description.

OIL PRODUCTION

MODEL Layers		Model Layers				Model	Model	Profile Log		Log	Log
		Layer Top (subsea)	Layer Bottom (subsea)	Layer Top (md)	Layer Bottom (md)	Calculated Interval Prod., %	Calculated Cumulative Prod., %	Top Interval (md)	Bottom Interval (md)	Calculated Interval Prod., %	Calculated Cumulative Prod., %
Top A	1	**8,478**	**8,489**	**9,879**	**9,890**	8%	100%	9,883	9,889	0%	100%
								9,901	9,902	0%	100%
Top C	5	**8,545**	**8,556**	**9,946**	**9,957**	1%	92%				
	6	**8,556**	**8,567**	**9,957**	**9,968**	15%	91%	9,956	9,985	100%	100%
	7	**8,567**	**8,579**	**9,968**	**9,980**	51%	77%	*9,985*			0%
	8	**8,579**	**8,588**	**9,980**	**9,989**	25%	25%				

GAS PRODUCTION

		Model Layers				Model	Model	Profile Log		Log	Log
		Layer Top (subsea)	Layer Bottom (subsea)	Layer Top (md)	Layer Bottom (md)	Calculated Interval Prod., %	Calculated Cumulative Prod., %	Top Interval (md)	Bottom Interval (md)	Calculated Interval Prod., %	Calculated Cumulative Prod., %
Top A	1	**8,478**	**8,489**	**9,879**	**9,890**	33%	100%	9,883	9,889	45%	100%
								9,901	9,902	34%	55%
Top C	5	**8,545**	**8,556**	**9,946**	**9,957**	7%	67%				
	6	**8,556**	**8,567**	**9,957**	**9,968**	48%	60%	9,956	9,985	21%	21%
	7	**8,567**	**8,579**	**9,968**	**9,980**	13%	13%	*9,985*			0%
	8	**8,579**	**8,588**	**9,980**	**9,989**	0%	0%				

*Note: **Bold** Layer Depths indicate active layers in FFM*

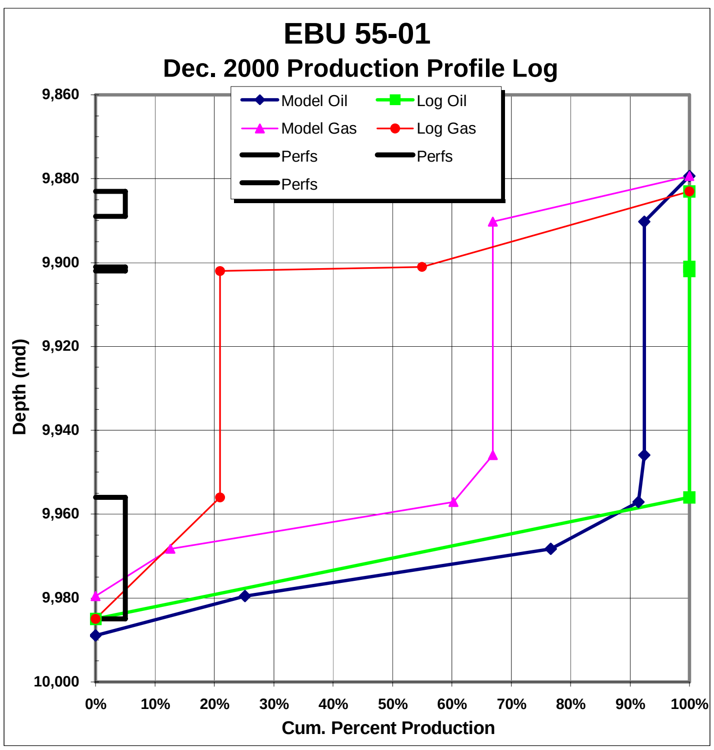

Figure 9. December 2000 production profile from well 55-1, with comparison with model-predicted profile.

In EBU 72-1, the profile interpretation is that all of the gas is from the C Sand (82'), and it is fairly evenly distributed. The model matched this (100% of gas from C Sand), but predicted more gas coming from the upper part of the C Sand. See **Figure 10**.

72-01 Dec. 2000 Log

KB= 1465

PPC Database	Perfs (subsea)	Perfs (md)
From (ft)	8,503	9,968
To (ft)	8,509	9,974
From (ft)	8,569	10,034
To (ft)	8,597	10,062
From (ft)	8,603	10,068
To (ft)	8,657	10,122

Note: The production log indicates more oil rate from the A/B interval than the FFM. And the log suggests a more uniform distribution of the gas production from the C Zone perfs than the FFM, which shows most of the gas coming from the upper C Zone perfs only. The A/B Zone layers in the model have a somewhat limited areal extent and also have relatively poor reservoir quality, leading to the lack of production shown.

OIL PRODUCTION

MODEL Layers		Model Layers: Layer Top (subsea)	Layer Bottom (subsea)	Layer Top (md)	Layer Bottom (md)	Model Calculated Interval Prod., %	Model Calculated Cumulative Prod., %	Profile Log: Top Interval (md)	Bottom Interval (md)	Log Calculated Interval Prod., %	Log Calculated Cumulative Prod., %
Top A	1	8,498	8,508	9,963	9,973	0%	100%	9,968	9,974	27%	100%
	2	8,508	8,518	9,973	9,983	0%	100%				
Top C	5	8,570	8,580	10,035	10,045	0%	100%	10,034	10,062	0%	73%
	6	8,580	8,592	10,045	10,057	9%	100%				
	7	8,592	8,603	10,057	10,068	2%	91%				
	8	8,603	8,615	10,068	10,080	6%	89%	10,068	10,123	73%	73%
	9	8,615	8,626	10,080	10,091	15%	83%	*10,123*			*0%*
	10	8,626	8,637	10,091	10,102	20%	68%				
	11	8,637	8,648	10,102	10,113	31%	48%				
	12	8,648	8,658	10,113	10,123	17%	17%				

GAS PRODUCTION

MODEL Layers		Model Layers: Layer Top (subsea)	Layer Bottom (subsea)	Layer Top (md)	Layer Bottom (md)	Model Calculated Interval Prod., %	Model Calculated Cumulative Prod., %	Profile Log: Top Interval (md)	Bottom Interval (md)	Log Calculated Interval Prod., %	Log Calculated Cumulative Prod., %
Top A	1	8,498	8,508	9,963	9,973	0%	100%	9,968	9,974	1%	100%
	2	8,508	8,518	9,973	9,983	0%	100%				
Top C	5	8,570	8,580	10,035	10,045	3%	100%	10,034	10,062	36%	99%
	6	8,580	8,592	10,045	10,057	57%	97%				
	7	8,592	8,603	10,057	10,068	12%	41%				
	8	8,603	8,615	10,068	10,080	23%	29%	10,068	10,123	63%	63%
	9	8,615	8,626	10,080	10,091	5%	6%	*10,123*			*0%*
	10	8,626	8,637	10,091	10,102	1%	2%				
	11	8,637	8,648	10,102	10,113	1%	1%				
	12	8,648	8,658	10,113	10,123	0%	0%				

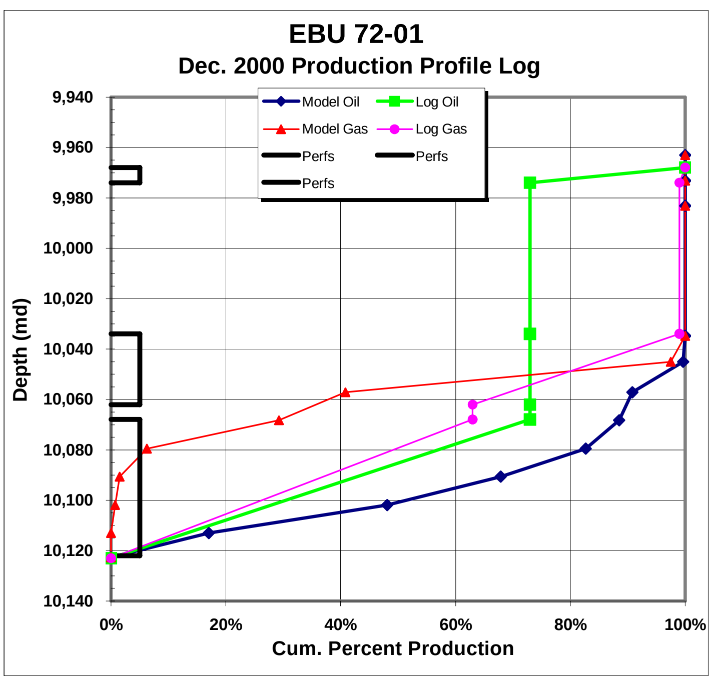

Figure 10. December 2000 production profile from well 72-1, with comparison with model-predicted profile.

The set of injection well profiles provided evidence to suggest that gas within the C Sand was indeed overriding the oil and failing to sweep the deeper parts of the reservoir, as the simulation model predicted. The producing well surveys, however, provided evidence to the contrary, as both surveys indicated fairly uniform production from the C Sand. This was the first evidence to suggest that the interpretation from the simulation results of a vertical sweep problem might not be correct.

Horizontal Well Planning, Drilling, Completion, and Performance

One of the most important aspects of Phase I of the project was the calibration of the simulation model to actual horizontal well performance. The original plan for this phase was to sidetrack one producer and one injector so that both horizontal production and injection could be calibrated. However, after reviewing the wells in the field for suitability and getting new cost estimates for this work, it was decided to replace the injection well sidetrack with a new horizontal injector drilled from surface. Subsequently, due to difficulties and costs incurred with the drilling of that well, its bottom hole location was altered, the producer sidetrack was canceled, and the new horizontal well was completed as a producer. Discussion of various items related to the horizontal well follows.

Prior to the drilling of EBU 37-3H (the "H" denotes horizontal), no horizontal drilling had occurred in the Marchand reservoir. A number of aspects of the drilling program were studied at some length; the most significant ones are discussed here.

<u>Planning: Completion</u>. An open hole completion was planned and implemented. Based on the perception that gravity override of injected gas was a major factor in poor sweep efficiency, Binger Operations believed avoiding hydraulically fracturing horizontal wells, especially producing wells, was of the utmost importance. Hydraulic fractures in horizontal wells would almost certainly migrate to the top of the formation, where more gas-swept and gas saturated was expected. This was less of a concern for horizontal injectors, and it was recognized that fracturing might be the best option if a horizontal well did not have adequate productivity without stimulation.

An open hole completion would be the least expensive and least damaging to the formation, but would also provide less flexibility for stimulating the well or squeezing sections affected by gas breakthrough. Two other completion options were considered – cased, cemented, and perforated, and cased with external casing packers (ECPs) and sliding sleeves, perforated pipe, or slotted pipe.

A cased, cemented, and perforated completion would have been the most expensive option but would also have offered more long-term formation control. This option was ruled out because it was believed that if it had been chosen, hydraulically fracturing would have been required, without certainty that it offered any productivity enhancement over open hole fracturing. The option involving ECPs was rejected due to concern that ECPs had not had enough proven success in this application.

Planning: Build Radius. A "medium" build radius of about 14°/100' was determined to be the best choice for this application. A "short radius" (high build rate) would have reduced the total measured depth to be drilled, but likely would have resulted in lower rate of penetration in the horizontal section, as well as greater difficulty with completion activities. A longer radius and departure was thought to be unnecessary and more costly.

Planning: Mud system. At the outset of drilling operations, it was planned to drill the vertical section and curve with a water-based mud, set casing through the curve, and drill the horizontal section of the well with a foamed mud. Ultimately, due to drilling problems, the lower portion of the vertical hole, the curve, and the horizontal section were drilled with oil-based mud.

Foamed mud was planned for the horizontal section because it would have allowed any horizontal section to be drilled underbalanced to minimize formation damage. It also provides the best cuttings transport and therefore highest rate of penetration, but might not be of sufficient density to control high formation pressures around current or former injection wells. The plan had been to adjust foam quality and therefore mud weight to maintain well control. Although foam systems are typically much more expensive than water-based mud, it was anticipated that the cost increase would not have been significant in this case because of the plentiful supply of nitrogen in the field. The nitrogen plant has the capability of making more nitrogen than could be injected, so nitrogen could have been supplied at very little cost. One drawback to using foamed mud is that it would have required the use of a more expensive gamma ray logging device.

As mentioned above in the discussion on the completion, Binger Operations believed avoiding hydraulically fracturing was very important. For that reason, minimizing formation damage was of the utmost importance. The permeability of the rock is very low (< 1 millidarcy) and the likelihood of having to hydraulically fracture the well increases with increased damage.

A second major priority with the mud system was well control. Additional considerations include hole cleaning ability, cost, and ease of use. Oil-based mud was expected to be the least damaging to the reservoir, but would also the most expensive and the most difficult to handle logistically. Water-based mud was expected to be the least expensive and easiest to work with, but had the most potential to damage the reservoir, especially in the producer. Use of water-based mud would have allowed for the use of a standard gamma ray logging device for monitoring the position of the bit.

Drilling EBU 37-3H. Significant problems were encountered during the drilling operations of EBU 37-3H. Two sidetracks were required as a result of tubulars lost in the hole.

The original drilling plan for the well had been as follows:

A. Drill 12-1/4" surface hole to 1100'.
B. Run 9-5/8" surface casing.
C. Drill 8-3/4" hole with water base mud through the curve to a horizontal target within the Marchand C Sand.
D. Run 7" casing.
E. Drill 6-1/8" horizontal hole with foam mud.

F. Complete open hole.

The first major problem occurred while preparing the hole for the 7" casing. After drilling to the casing point, a reaming/conditioning trip was conducted. The drilling assembly would not go back through the middle of the curve (about 60° inclination) due to what was believed to be a cuttings/cavings buildup. The bottom hole assembly was changed to a bit without nozzles and progress was being made when the drill pipe parted near the bit. After a failed fishing attempt, the hole was plugged back and sidetracked.

The second major problem occurred while preparing the sidetracked hole for 7" casing. After making a bit trip near the casing point, there was again difficulty working back through the middle part of the curve. This was worked through, the well was drilled to the casing point, and two short trips were made. While pulling the drilling assembly for the casing run, it got stuck with about 4600' of drill collars and pipe still in the hole. The upper 3100' of the string was backed off and pulled out and the remaining pipe – about 500' of drill collars and 1000' of drill pipe – was washed over, releasing it to fall down the hole. Only the collars and 1-1/2 joints of drill pipe could be recovered. The drill pipe below the collars was severely corkscrewed. This forced a second plugback and sidetrack and led to a revision to the drilling plan for the curve and horizontal portion of the hole. 7" casing was run as deep as possible (to the top of the remaining fish), a window was milled, and the second sidetrack was drilled.

The revised plan involved cutting a window out of the 7" casing and drilling the entire curve and horizontal section with a 6-1/8" bit and an oil-based mud system, then running a 4-1/2" liner through the curve, leaving the horizontal section open hole. The liner was run with an external casing packer (ECP) on bottom to allow the liner to be cemented in place. This plan was conducted without further problems. Due to the change from foam to an oil-base mud, the horizontal section was drilled overbalanced instead of underbalanced as had been planned.

It is believed that the hole problems resulted from very water-sensitive shales just above the Marchand A Sand and between the Marchand A, B, and C Sands. The change to an oil base mud was made to prevent further problems with these shales. For added insurance, a mud weight of 9.5 ppg or higher was maintained throughout the curve and horizontal section.

One other drilling problem occurred at the end of the horizontal section. After drilling about 1300' of horizontal section, the bottom of the drilling assembly got stuck in the hole. The tool string was backed off above the stuck point and the bottom 185' of the drilling assembly was left at the end of the horizontal open hole. **Figure 11** is a plot of the path of the wellbore within the C Sand; the bit actually reached an additional 60' beyond the last point measured. Toward the end of the drilled section, the wellbore was drifting up in the section, despite efforts to keep it level and then turn it back down.

Completing EBU 37-3H. Significant difficulties were also encountered in obtaining satisfactory production rates from the new horizontal well. After disappointing initial flow results, it was determined that the ECP had failed, allowing cement to escape about 250' past the liner shoe into the open hole. This was drilled out and the horizontal section was washed with gelled diesel, recovering significant amounts of cement, mud, and mud solids. The well subsequently

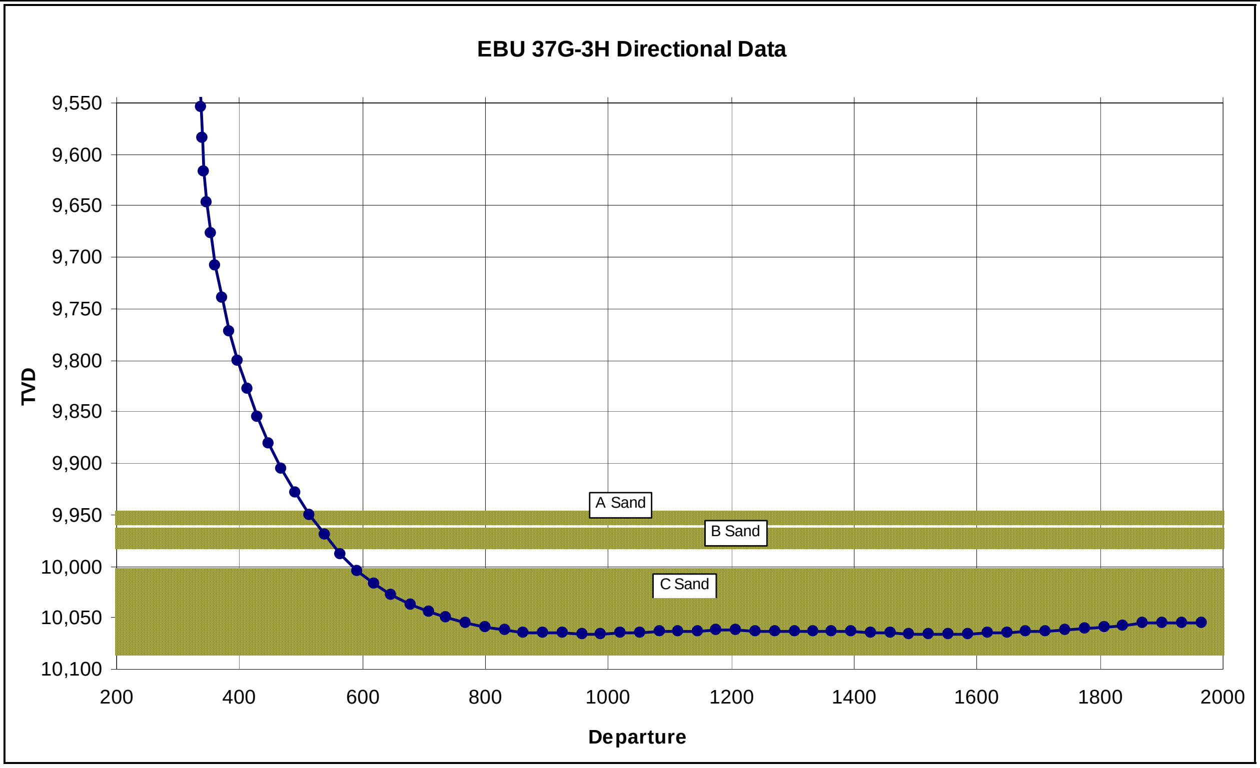

Figure 11. Path of EBU 37G-3H wellbore.

flowed 5-10 bopd and 400 Mcfd. A gas sample was analyzed and found to contain 78% nitrogen.

After various stimulation options were investigated, a series of intervals were perforated in an attempt to get beyond any very near wellbore damage, with the added benefit that they could create weak points for fracture initiation should hydraulic fracturing be necessary. Six sets of perforations were shot, each 16' long, with 2 shots per foot (spf) in 13' of the 16', and 6 spf in 3' in the middle of the interval. The intervals were spaced roughly 100' apart on average, as noted in the wellbore schematic provide as **Figure 12**.

Production improved only slightly following the perforating, to 10-15 bopd and 560 – 630 Mcfd, with little change in nitrogen content in the gas. A production log was run to determine the source of the gas production. It was found that most, if not all, of the gas was coming from beyond 10,300', ruling out the possibility that the gas was coming through a cement channel from overlying A and B sands or the upper part of the C Sand.

Finally, the well was hydraulically fractured. Approximately 78,500 pounds of 20/40 mesh intermediate strength proppant was placed into the formation. The proppant slurry was pumped at an average rate of 30 bbls/min and an average pressure of 4500 psi. The well's production improved to over 200 bopd and 2500 Mcfd initially. Most significantly, the nitrogen content of the produced gas declined from 77% prior to the treatment to 71% in the first few days after it, and then declined further to as low as 63% before gradually rising back up to about 69% prior to its conversion to injection two years later, in October 2003. This was in complete contrast to what was expected, given the perception of injected gas overriding the oil zone, and was another indicator that the assumption that gravity override was a major problem was incorrect.

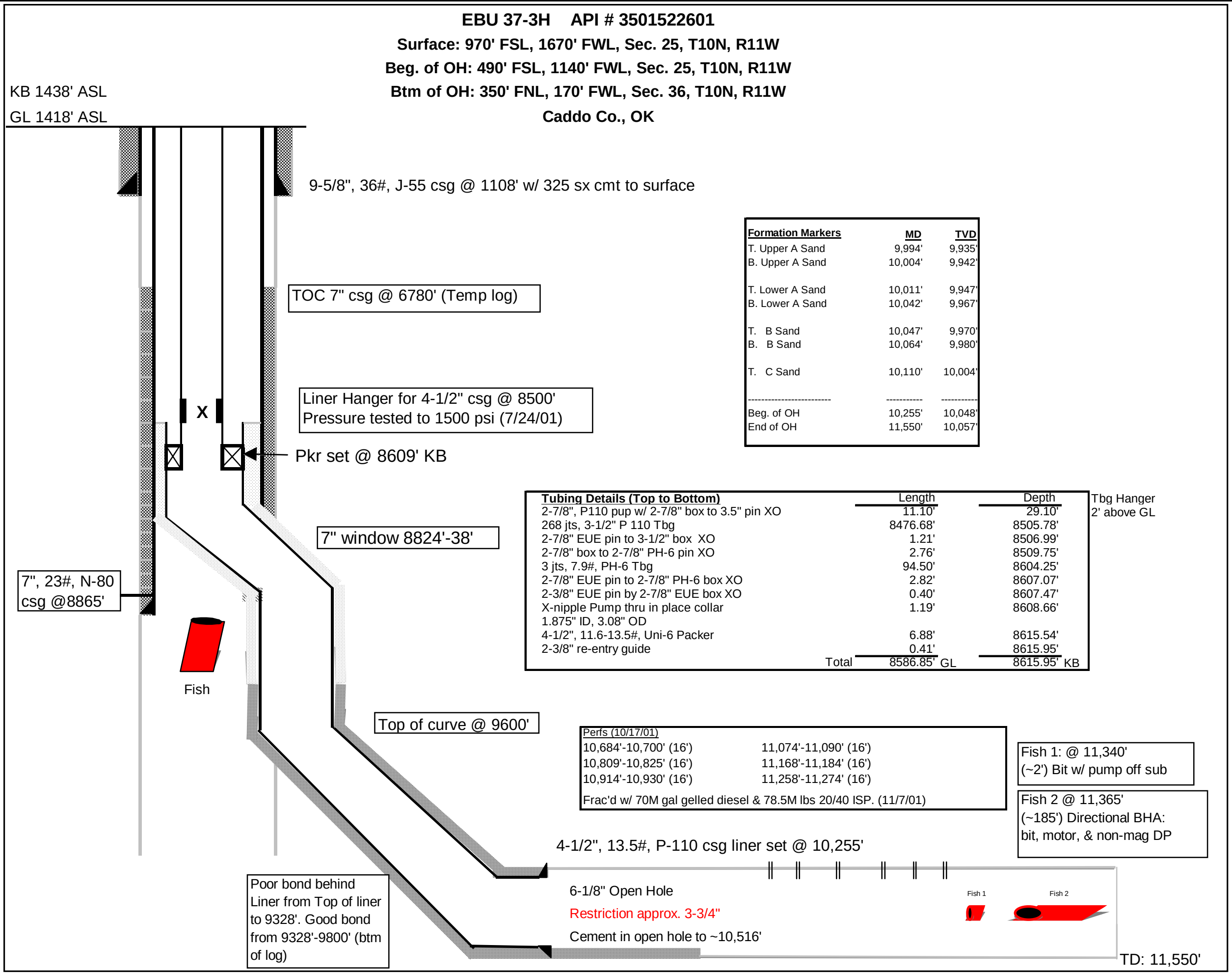

Figure 12. Wellbore schematic for EBU 37-3H.

Performance of EBU 37-3H. Early post-frac performance of this well was encouraging, but over the 24 months the well was on production (prior to conversion to injection), the oil rate declined to about 10 bopd, with the GOR rising to about 100 Mcf/stb. See **Figure 13**. This is a lower oil rate and a higher GOR than typical producing wells in the field, most of which have been on production for 20 years or more. However, EBU 37-3H was originally planned and drilled to replace an abandoned injection well, so this was not unexpected.

Screening and Selection of Pilot Area

Figure 14 shows the area selected for the pilot. Although called the “pilot area”, it might better be called the “project area”, as multiple well activities were conducted in this area, and some were specifically related to each other. Key issues or selection considerations that went into the selection of this area included:

- The area should be located within the main channel of the Marchand C Sand where the greatest oil in place and best sand quality exists, as well as largest area in which to expand the pilot should it prove successful. (The main channel of the C Sand runs northwest-southeast, as shown in **Figure 3**.)

- The area should be of adequate size to contain enough wells so that an individual well would not dominate the model performance, yet small enough that run-times of a new simulation model with finer gridding in the project area would not be excessive.
- Existence of useable wellbores within proposed area – i.e. mechanically sound or limited remedial work required to make them suitable for addition of a lateral section.
- An area with a better relative history match in the existing full field simulation model should have preference over an area with poor history match.
- Area fairly representative of the reservoir rock within the main Marchand C Sand channel.
- A reasonably accurate understanding of fluid movement patterns, directional permeability trends, and pressure profiles across the pilot area.

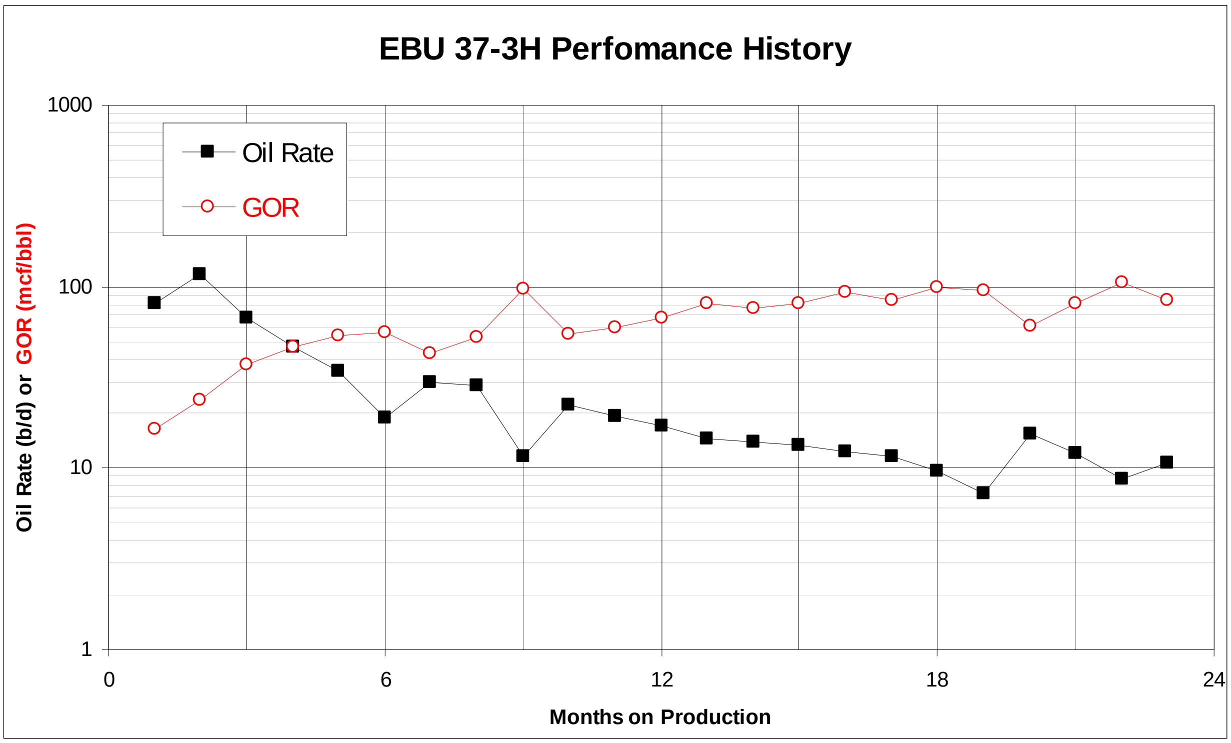

Figure 13. Production history of EBU 37-3H.

In order to determine the potential utility of each wellbore for the project, a review of completions, wellbore integrity, and performance for all wells through the main channel of the reservoir was completed. This information is presented in **Figure 15**.

Estimates of original and remaining oil in place, production, percent recovery, and other performance measures for pilot areas selection were computed on a quarter section basis using date from the full field model, in order to ensure that the selected pilot area was representative of the main sand channel. **Figure 16** (Original Oil In Place), **Figure 17** (Production), **Figure 18** (Remaining Oil In Place), and **Figure 19** (Percent Recovery) are bubble map displays of this data. As these figures show, the data in the area selected for the pilot is representative of the main sand channel.

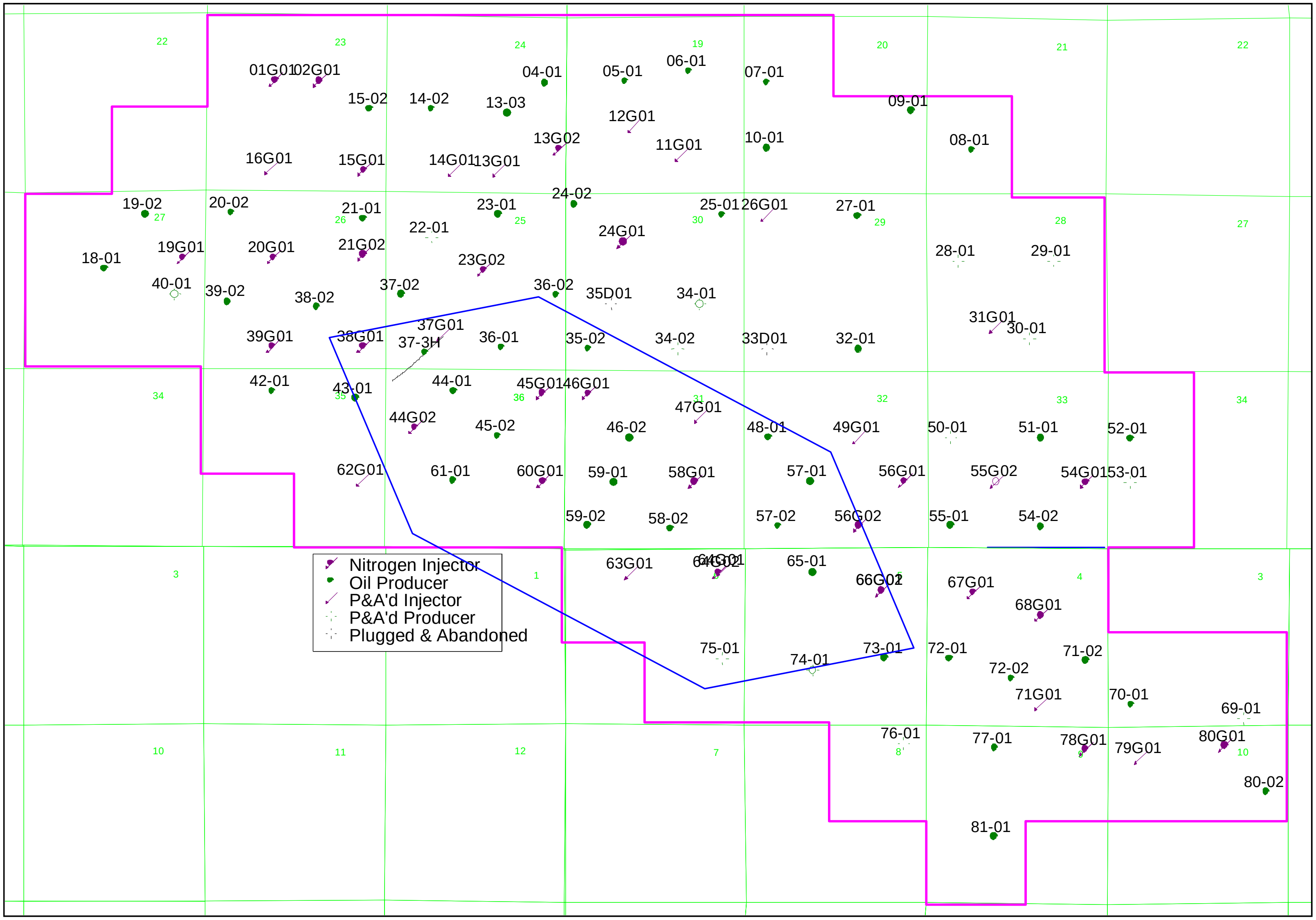

Figure 14. East Binger Unit map showing well locations and the area selected for the DOE Project work.

EBU	CTI	Intermediate Casing			Production Casing			Liner		Liner Depths		Tubing		
Well No	Date	Size	Wt	Depth	Size	Wt	Depth	Size	Wt	Top	Btm	Size	Comments	Suitable for Sidetrack?
35-2					5 1/2	17 & 15.5	10,050					2.875	TOC 8442'	Yes - out of 5-1/2"
36-1					5 1/2	17 & 15.5	10,120					2.875		Yes - out of 5-1/2"
36-2		7-5/8"	26.4#	8590'	4 1/2	11.6#, 13.5#	10,088					2.375	TOC 7525'	Yes - out of 7-5/8" @ 7400'
37-2		7-5/8"	26.4#	8600'	4 1/2	11.6#, 13.5#	10,205					2.375	TOC 9100' (?)	Yes - out of 7-5/8" @ 8500'
38G-1	03/01/79				5 1/2	17#	10,216					2.375	TOC 8534'	Yes - out of 5-1/2"
38-2		7-5/8"	26.4#	8510'	4 1/2	11.6#, 13.5#	10,130					2.375	TOC ~ 6700' - 6950'	Yes - out of 7-5/8" @ 6600'
39G-1	11/01/79				5 1/2	17#	10,076					2.375		Yes - out of 5-1/2"
39-2		7-5/8"	26.4#	8550'	4 1/2	13.5#	10,120					2.375	TOC 7298'	Yes - out of 7-5/8" @ 7100'
42-1					5 1/2	17#	10,095					2.875		Yes - out of 5-1/2"
43-1					5 1/2	17#	10,245					2.875	TOC 7,850'	Yes - out of 5-1/2"
44-1		None			4 1/2	15.1#	10,178					2.375	TOC above 9300' (top of log)	No - no Interm.
44G-2	11/01/83	7-5/8"	26.4#	8480'	4 1/2	11.6#, 13.5#	10,110					2.375	TOC 7000'	Yes - out of 7-5/8" @ 6900'
45G-1	01/01/87				5 1/2	17#	10,410					2.375	TOC 9210'	Yes - out of 5-1/2"
45-2		7-5/8"	26.4#	8445'	4 1/2	11.6#, 13.5#	10,050					2.375	TOC 8175'	Yes - out of 7-5/8" @ 8000'
46G-1	08/20/81				5 1/2	17#, 15.5#	10,051					2.375	TOC 9000'	Yes - out of 5-1/2"
46-2		7"	26#	8537'	4 1/2	13.5#, 11.6#	10,110					2.375	TOC 8160'	Yes - out of 7" @ 8000'
48-1					5 1/2	12#, 17#, 20#	10,094					2.875	TOC 8620'	Yes - out of 5-1/2"
55-1		None			4 1/2	11.6#	10,164					2.375		No - no Interm.
56G-1	03/01/84				5 1/2	17#	10,380					2.375		Yes - out of 5-1/2"
56G-2	05/27/83	7"	26#	8435'	4 1/2	11.6 & 13.5	9,990					2.375	TOC 7962'	Yes - out of 7" @ 7800'
57-1					5 1/2	17#	10,220					2.375	TOC 9195'; tubing replaced in 4/97	Yes - out of 5-1/2"
57-2	03/01/91	7-5/8"	26.4#	8480'	4 1/2	11.6#	10,107					2.375	TOC 7863'	Yes - out of 7-5/8" @ 7700'
58G-1	09/01/81				5 1/2	17#, 15.5#	10,165	4	11	3,950	5,357	2.375	TOC 9935'; liner is a scab to fix casing leal	No - small liner
58-2		7-5/8"	26#	8560'	4 1/2	13.5	10,180					2.375	TOC 7820'	Yes - out of 7-5/8" @ 7700'
59-1					5 1/2	17#, 15.5#	10,406					2.375	TOC 8850'; fish (pkr assembly) at 10,365'.	Yes - out of 5-1/2"
59-2		7-5/8"	26.4#	8520'	4 1/2	11.6#	10,145					2.375	TOC 7800'; Plug stuck in tbg/Perf' tbg - 6 s	Yes - out of 7-5/8" @ 7700'
60G-1	08/20/81				5 1/2	17#	10,194					2.375	TOC 8170'	Yes - out of 5-1/2"
61-1					5 1/2	17#	10,080					2.375		Yes - out of 5-1/2"
62G-1	10/01/96				5 1/2	17#, 15.5#	10,349					2.875		Yes - out of 5-1/2"
63G-1	01/17/86				5 1/2	17#, 15.5#	10,138					2.375		Yes - out of 5-1/2"
64G-2	11/28/84	7"	26#	8500'	4 1/2	11.6 & 13.5	10,083					2.375	TOC 7140'	Yes - out of 7" @ 7000'
65-1					5 1/2	17#	10,020					2.375	TOC 8850'	Yes - out of 5-1/2"
66G-2	03/01/98				5 1/2	17#	10,127					2.375		Yes - out of 5-1/2"
67G-1	07/21/86				5 1/2	17#	10,395	4	11#	5,426	7,390	2.875		No - small liner
68G-1	07/15/86				5 1/2	17#	10,180					2.875		Yes - out of 5-1/2"
70-1					5 1/2	15.5#, 17#	10,126					2.375		Yes - out of 5-1/2"
71-2		7-5/8	26.4#	8,580	4 1/2	11.6#, 13.5#	10,151					2.375	TOC 7280'	Yes - out of 7" @ 7100'
72-1					5 1/2	17#	10,169	4		6,091	8,310	2.875	liner is a scab to fix casing leaks	No - small liner
72-2					5 1/2	17#	10,250					2.875		Yes - out of 5-1/2"
73-1					5 1/2	17#	10,090					2.375		Yes - out of 5-1/2"
75-1					5 1/2	17#	10,045					2.875		Yes - out of 5-1/2"
77-1					5 1/2	17#	10,166					2.875		Yes - out of 5-1/2"
78G-1	04/15/96				5 1/2	17#, 20#	10,238	3.5	9.3#	0	9,880	2-1/16	liner to fix casing leaks	No - small liner

Figure 15. Review of Wellbores in Main Channel of the East Binger Unit.

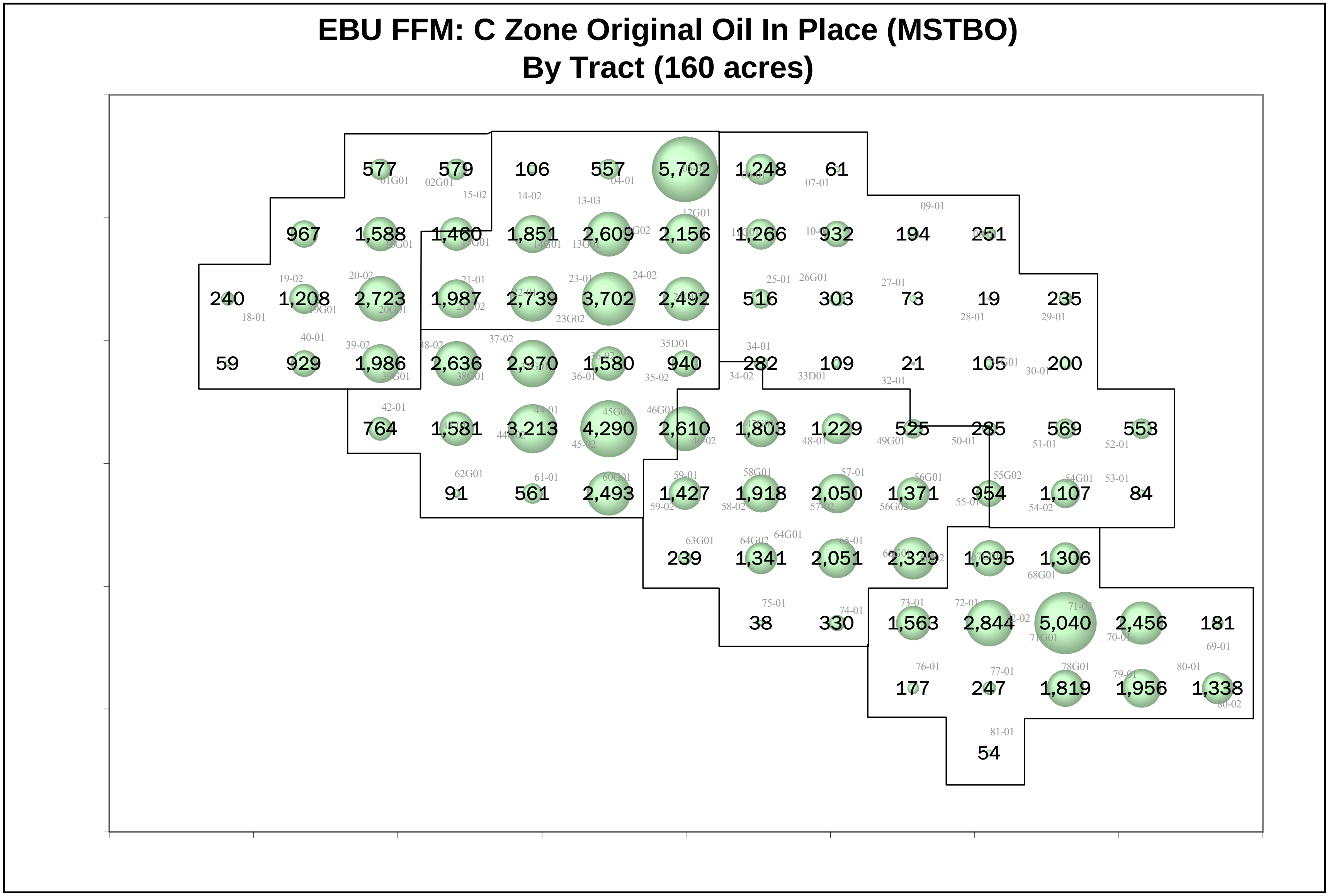

Figure 16. C Sand original oil in place by quarter section, calculated from the reservoir description in the final history-matched version of the full field model.

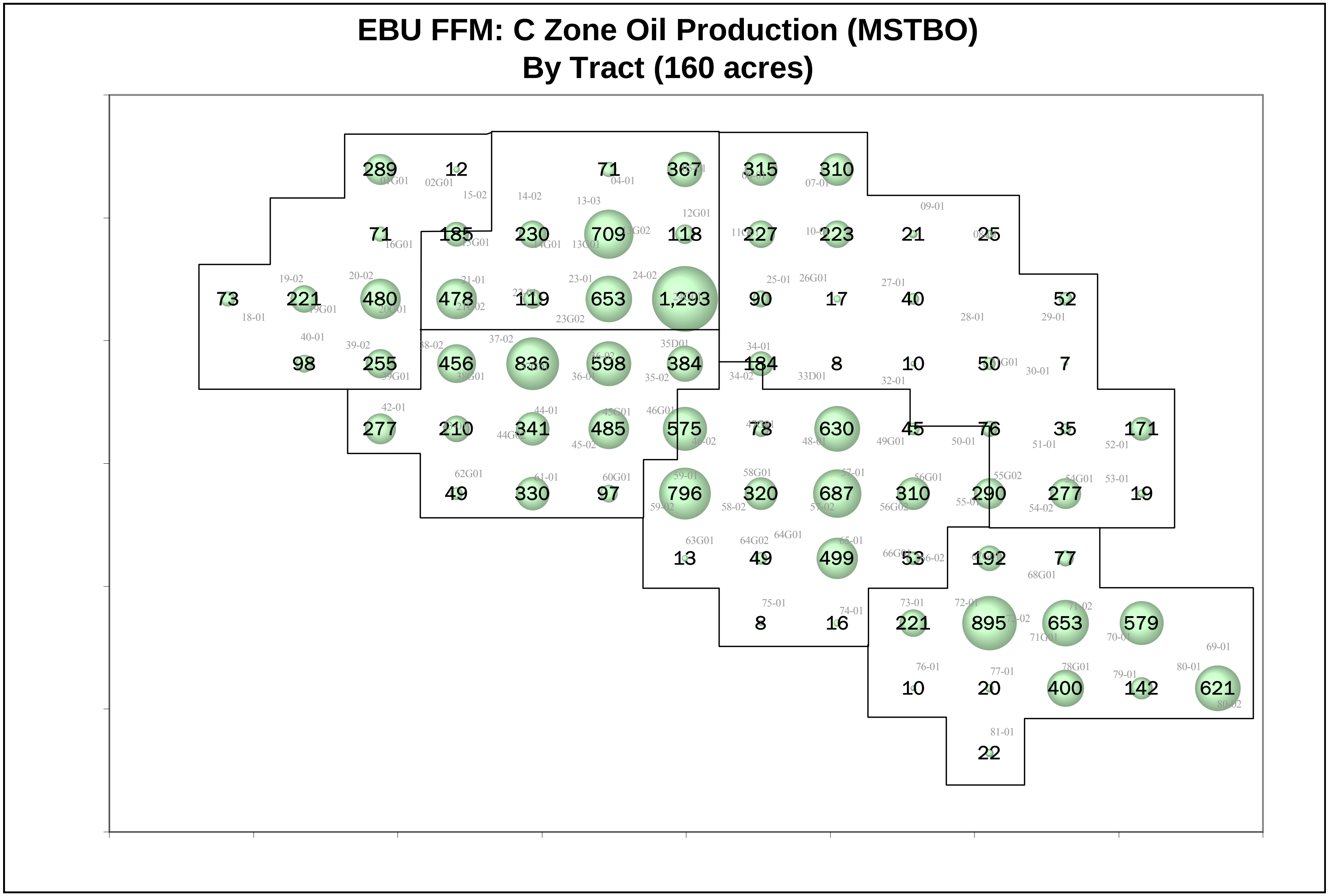

Figure 17. C Sand oil production by quarter section.

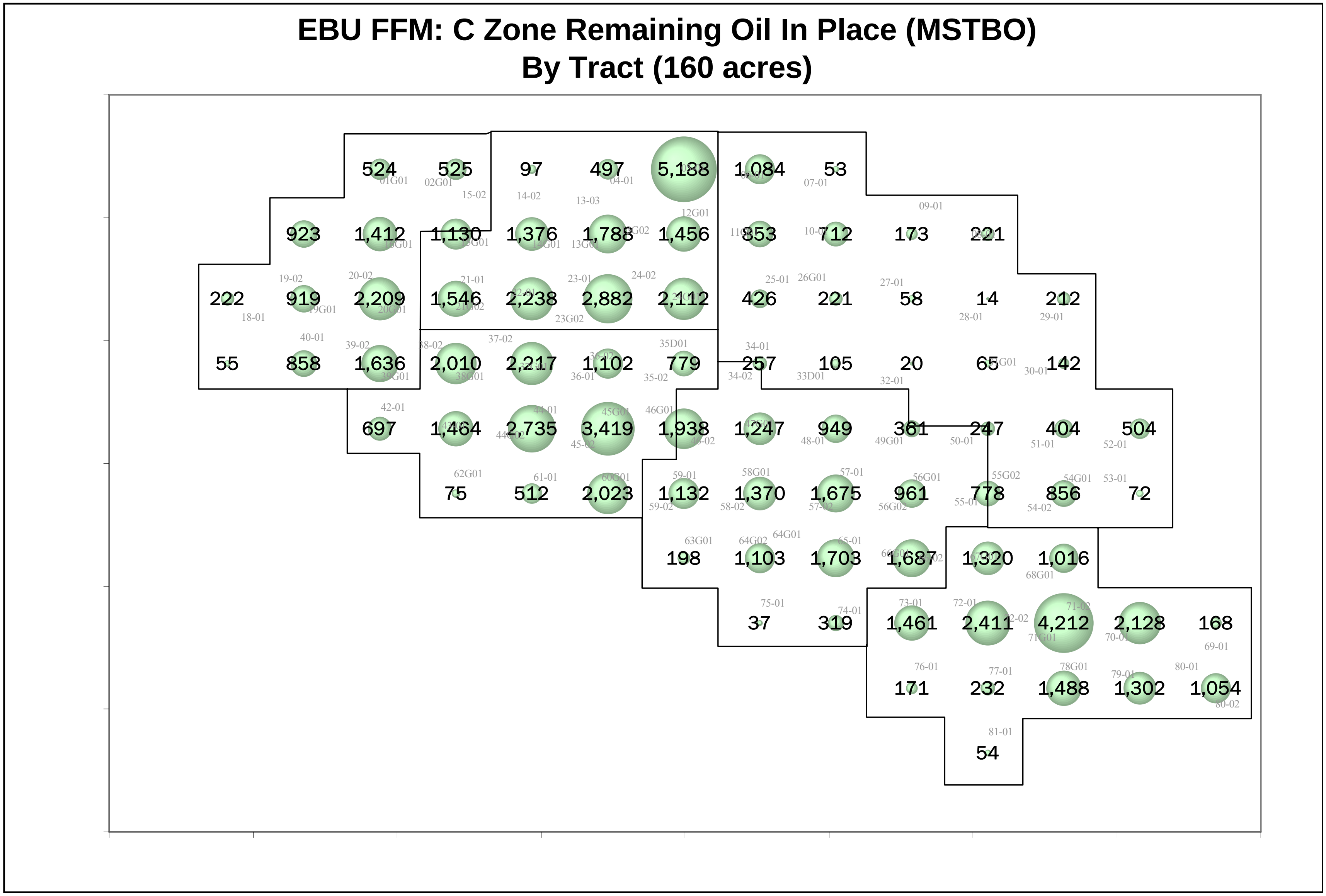

Figure 18. C Sand remaining oil in place by quarter section, calculated from the final history-matched version of the full field model.

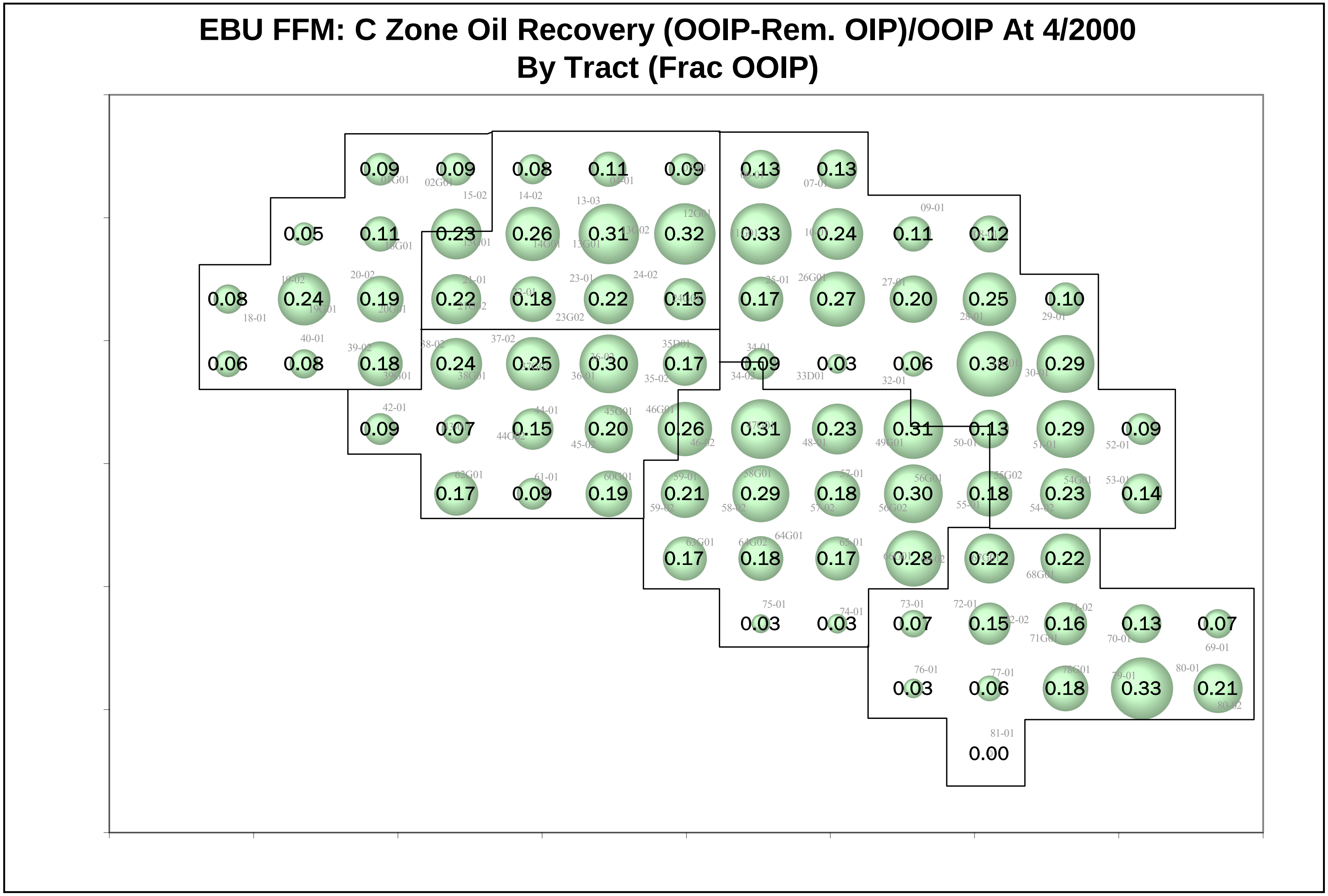

Figure 19. C Sand oil recovery by quarter section, calculated from the final history-matched version of the full field model.

Reservoir simulation activities had been initiated prior to the initiation of this project; as mentioned previously, model forecasts from those activities indicated the potential to improve recovery with horizontal wells. Therefore, concurrent with compiling wellbore integrity information, well completion information, and various performance parameters, efforts were conducted to update and improve the reservoir simulation model for continued use through the project.

Reservoir Simulation Activities

All simulation activities conducted during the project were performed by International Reservoir Technologies (IRT) of Lakewood, Colorado, a partner in the project. During Budget Period 1, a series of simulation activities were conducted. These included, in sequence: 1) updating the full field model built prior to the project initiation, 2) building a "pilot area" model with better simulation capabilities over the project area, and 3) simulating a variety of project alternatives with the pilot area model.

Updating and Validating the Full Field Model. The first of these activities was updating and validating the full field model with new injection and production data, pressure data, and profile data. A discussion of the pressure and profile data and its comparison to full field model prediction is presented above in the *Data Gathering* section of this report. There was also work done to validate vertical permeability (k_v) used in the model. The starting point for the geologic description in the full field model was a geologic model built by Phillips Petroleum Company, the prior operator of the East Binger Unit. During the course of the original history match, numerous changes were made to improve the quality of the match, but no adjustments were made to any k_v values. A review of the model input data led to a concern that the k_v values were too high.

Two things were done: first, IRT made a model run to test the sensitivity of the match to k_v. Whereas the original description and final history match had k_v values averaging about one-half the horizontal permeability (k_h) values (i.e., $k_v = 0.5*k_h$), the sensitivity run used k_v values of $0.02*k_h$. Unfortunately, the results indicated that model performance in history was not very sensitive to k_v; if there had been more difference, one could have more confidence in the values used. However, the overall quality of the match did improve, so lower values of k_v were used in future model runs. This was not completely unexpected, because the primary direction of fluid movement in history has been horizontal. Vertical permeability could have a much more significant impact on future performance with the use of horizontal wells.

The second thing done with respect to vertical permeability values was a review of the core and core measurements. From visual inspection of the core, it appears k_v would be much less than k_h due to the presence of very thin (1-5 mm) mud laminations or drapes. One would expect these thin features to be fairly small in area, but be a definite obstacle to vertical flow. Very few of the cored wells had measurements of k_v; from the limited data available – all plug measurements – an average k_v/k_h ratio of about 0.2 was calculated. Within the reservoir, one would expect a lower value due to the presence of the mud features.

Construction of the Pilot Area Model. IRT examined five potential model configurations to determine the optimum modeling approach – see **Figure 20**. The initial plan was to build a stand-alone pilot area model, with the exact size of the model and the gridding / cell size to be determined based on model run-times. Generally speaking, it was felt that the model of choice would be one with as many cells as could be run in a 12- to 16-hour simulation, as this would allow for the most efficient work process. As indicated in **Figure 20**, the first three configurations run (labeled Cases 1, 2, and 3) were stand-alone pilot area models. After running and reviewing these cases, and re-analyzing data from the full field model, it became apparent that significant reservoir flows were occurring near the pilot area model edges. Use of this type of model would therefore require special treatment of those edges to properly handle the interactions between the area within the model and the rest of the field. This led to the definition and construction of two additional configurations (Cases 4 and 5), both of which included the entire field. In order to better simulate performance in the pilot area than could be done with the existing full field model, these models utilized much coarser gridding outside the pilot area and much finer gridding within the model. The concern with this approach is that is would require more cells – or less gridding within the pilot area – and include many more wells.

Case **Model Type**		1 Pilot Area	2 Pilot Area	3 Pilot Area	4 FFM w/ Pilot LGR	5 FFM w/ Pilot LGR
Description		Local/stand alone	Local/stand alone	Local/stand alone	Full field coarse grid w/ pilot LGR	Full field coarse grid w/ pilot LGR
Original Root	x	19-30	19-30	17-30	Root 1-43; LGR 17-30	Root 1-43; LGR 17-30
Grid Limits	y	10-17	10-17	10-17	Root 1-18; LGR 10-17	Root 1-18; LGR 10-17
No. of Wells		32	32	36	36/107	36/107
Grid Refinement						
Horizontal Direction		2x	2x	2x	2x	2x
Vertical	**A/B Zones**	none	4L to 3L	4L to 3L	4L to 3L	4L to 3L
Direction	**C Zone**	none	2x	none	none	2x
Root Grid Coarsening						
Horizontal Direction		-na-	-na-	-na-	none	none
Vertical	**A/B Zones**	-na-	-na-	-na-	4L to 3L	4L to 3L
Direction	**C Zone**	-na-	-na-	-na-	none	none
Pilot Area **NX, NY, NZ**		72, 48, 12	72, 48, 19	84, 48, 11	84, 48, 11	84, 48, 19
Total Cells		41,472	65,664	44,352	53,865	86,112
Active Cells **(w/o edge mods)**		18,258	33,979	21,355	22,474	41,001
Active/Total **Cell Ratio**		0.44	0.52	0.48	0.42	0.48
Est. HM Run Time (hr) **(w/o edge mods)**		12	23	15	15	28

Figure 20. Pilot Model Configuration Options.

After considering the alternatives, a slightly modified version of Case 4 was chosen for the pilot area model. Cases 1, 2 and 3 were ruled out due to the concerns of the fluid flow occurring near the edges, and the error that might be introduced in trying to model it or ignore it. Case 4 was chosen over Case 5 because of run time; the 28-hour run time of Case 5 was thought to be simply too long to efficiently work the problem.

Including the entire field in coarsely gridded cells outside the pilot area increased the number of active cells by only 20% from the moderately-gridded stand-alone pilot area model of Case 3, with little change in run time – both approximately 15 hours. **Figure 21** shows the original full field model grid and the area that was finely gridded in the pilot model. Within the area bounded by the red outline, gridding in the map (x/y) plane was quadrupled: cell dimensions went from 400' x 400' (= 3.7 acres) to 200' x 200' (0.92 acres). Outside of that area, gridding became more coarse: 1200' x 1200' (33 acres).

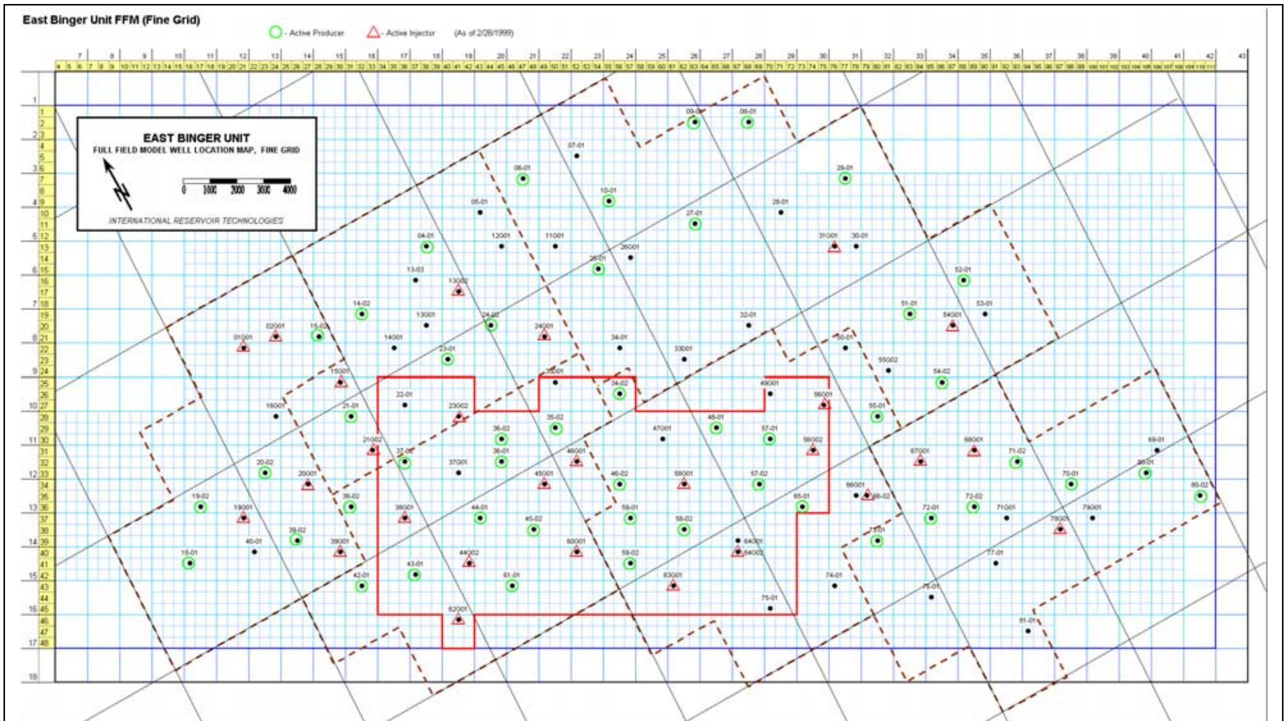

Figure 21. Original full field model grid. Area outlined in red was finely gridded in the pilot model.

Significant improvement was made in the match between the model's predicted reservoir pressures and pressures measured in the field. Additional work was also done on the reservoir description and completion definitions to improve the matches of injection profiles for wells in this area.

As discussed in the *Data Gathering* section above, the model's predicted average reservoir pressure has been close to the calculated average field pressure, but the pressure gradient between injectors and producers was found to be much greater in the field (average pressure drop of 2900 psi) than predicted by the full field model (average pressure drop of 1300 psi). A series of adjustments to the pilot model improved this match dramatically.

First, a correction was made in the pilot area model to the surface separation conditions operated in the field. This correction caused the model to over-predict gas production and under-predict oil production. Subsequent adjustments to the relative permeability data resulted in the predicted oil and gas production volumes both coming back in line with actual field data and a significant improvement to the pressure match. For wells in the focus area, the pilot area model's predicted average pressure drop between injectors and producers matches the measured average pressure drop measured in the field. See **Figure 22**.

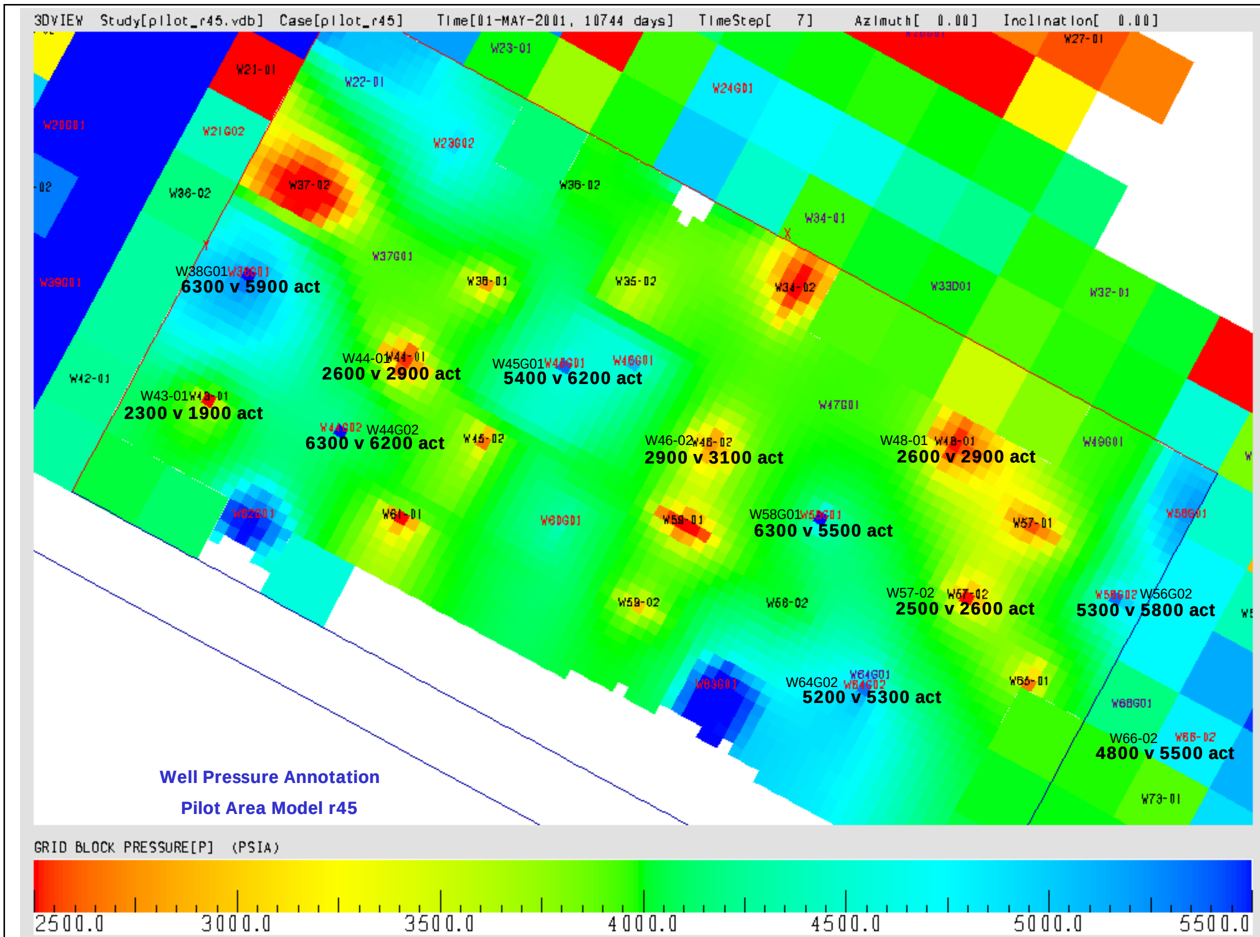

Figure 22. Display of model-predicted vs. field-measured reservoir pressures.

Figure 23 (EBU 38G-1), **Figure 24** (EBU 45G-1), and **Figure 25** (EBU 46G-1) show the improvements made in the model's predicted injection profiles compared to actual measured profiles for three injection wells in the focus area. One aspect of improving these matches was modifying the description of the A and B Sands that lie above the C Sand. The original description of these sands had many isolated, discontinuous sand bodies, as shown in **Figure 26**; hence, the model predicted little gas going into these sands. The new description, shown in **Figure 27**, has much more continuity, allowed the wells in the model to inject and produce more fluid from this interval, as the actual profiles from the field indicated they do.

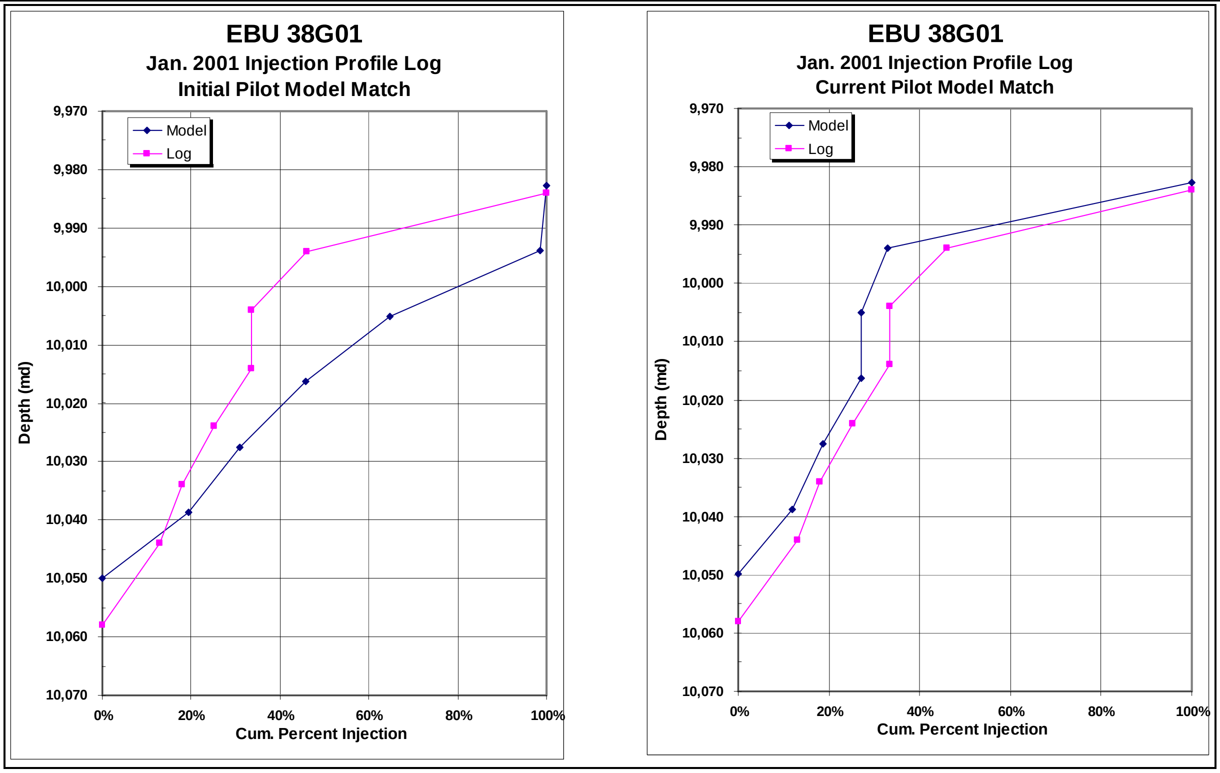

Figure 23. Comparison of model-predicted injection profile and field data for well 38G-1, before and after recent modifications to the model.

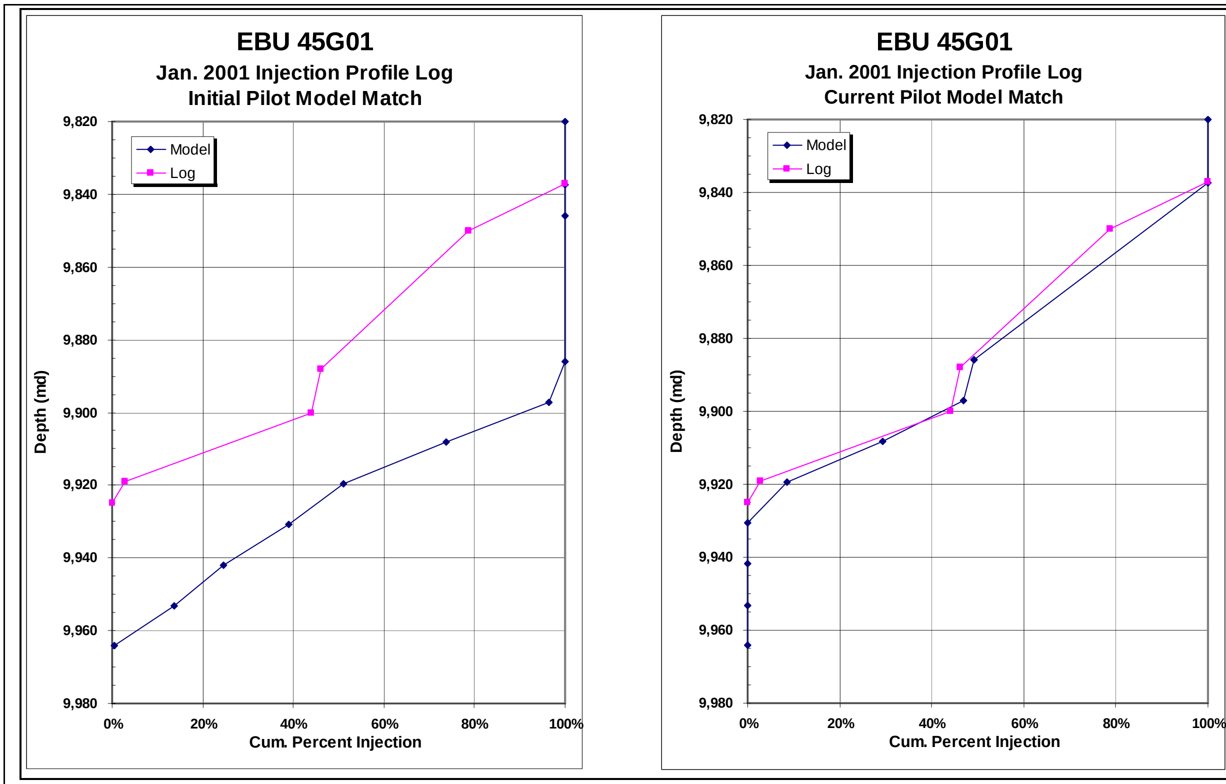

Figure 24. Comparison of model-predicted injection profile and field data for well 45G-1, before and after recent modifications to the model.

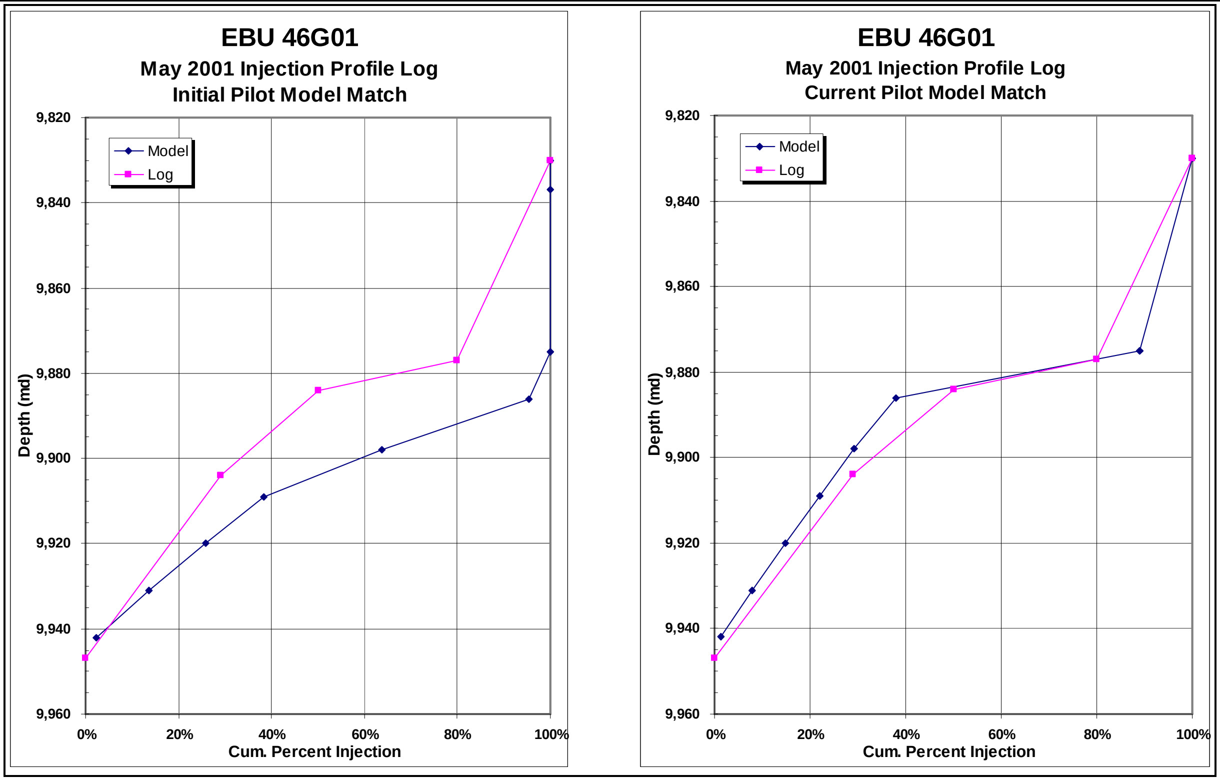

Figure 25. Comparison of model-predicted injection profile and field data for well 46G-1, before and after recent modifications to the model.

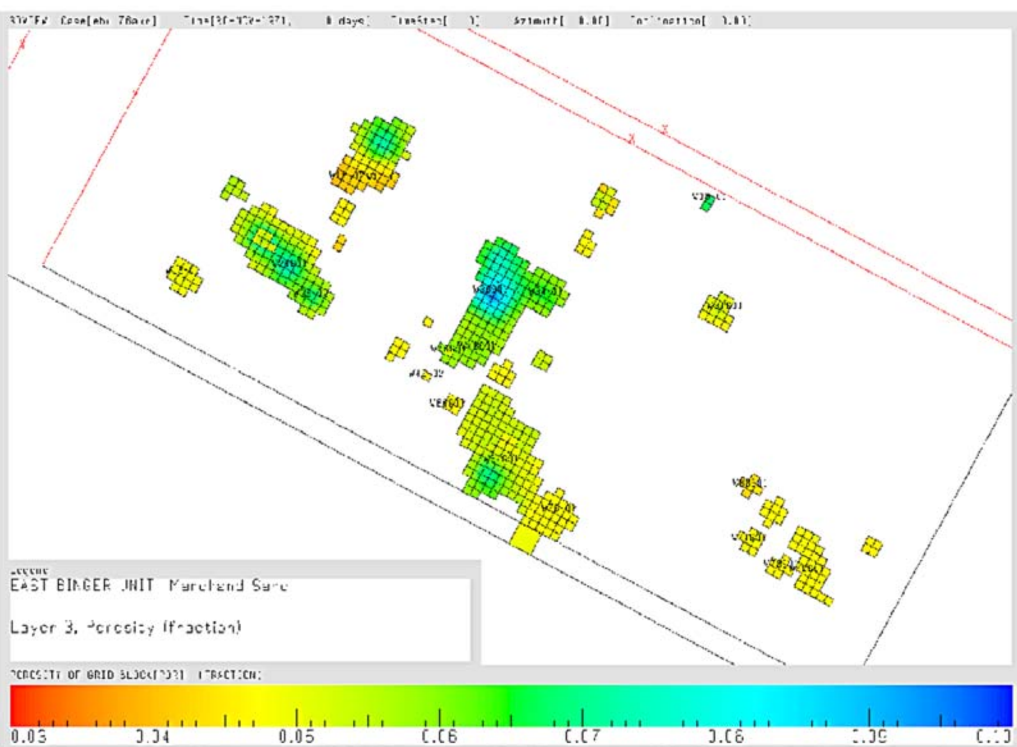

Figure 26. Map of upper sand from original simulation model – based on geologic model. Note discontinuity of sand.

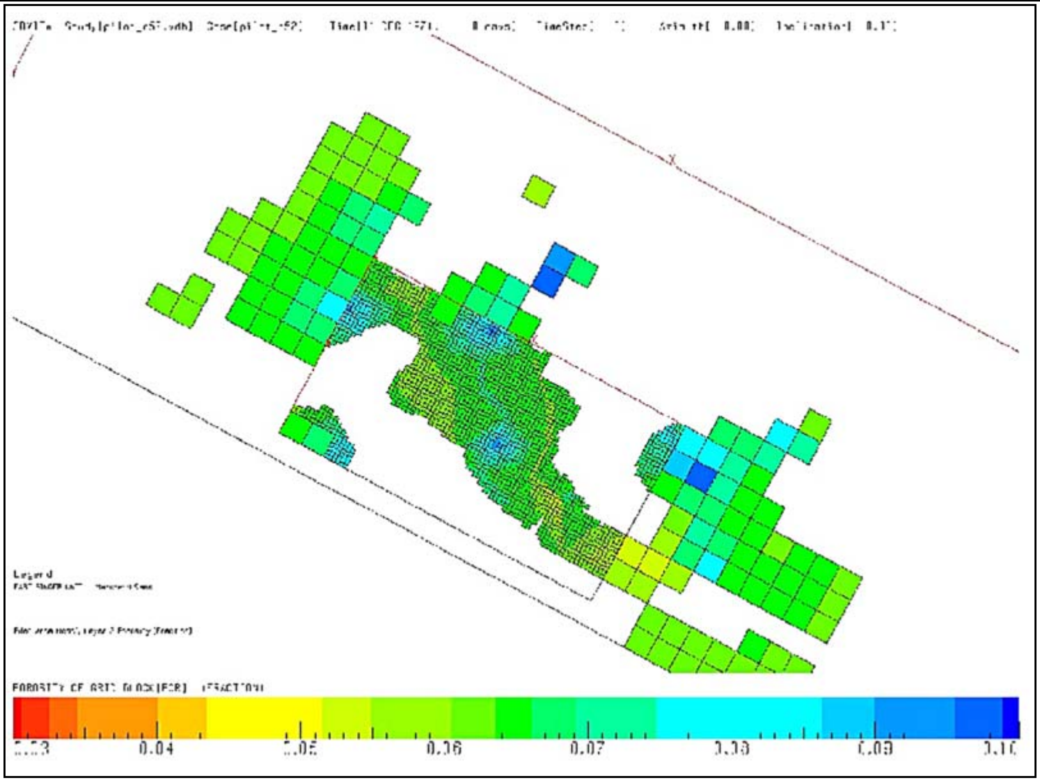

Figure 27. Map of upper sand in current simulation model. Sand is now continuous through central part of the model.

Evaluation of Project Alternatives with the Pilot Area Model. Toward the end of Phase I, as the first horizontal well was being completed, the pilot area model was being constructed, and options for project alternatives were being developed, it was determined that future horizontal wells should be drilled as new wells, instead of lateral sidetracks of existing wells. This conclusion resulted primarily from two realizations.

First, further investigation of wellbore configurations led to the realization that there will not be significant cost savings in drilling lateral sidetracks. Drilling rates of penetration in the East Binger Unit (EBU) slow substantially below about 7500’ TVD, and most of the cost of the drilling a new well occurs after reaching 7500’ TVD. Many of the potential sidetrack candidates would have required kicking off at or above 8000’. With the cost of abandoning the lower portion of the original hole, and the lost value of that wellbore as a vertical injection or production well, there did not appear to be much cost saving in sidetracking this type of well.

Second, the EBU had lost a number of wellbores due to casing corrosion over the life of the field. While most of these failures have been below the depth of probable sidetrack kickoff points, some had been shallower. One contributing factor to these failures was found to be a poor primary cement jobs. The increased likelihood of casing problem with an existing well, compared to a new well, would add significant risk of losing the investment associated with drilling a horizontal sidetrack from an existing wellbore.

Initial development alternatives therefore all contained new horizontal wells in the model. It was originally intended that the results of the model would be used almost exclusively for optimizing the development scenario. However, after running a number of forecast cases, it became apparent that there were issues with the model that would require additional work to make specific well forecasts more reliable. It was still used to guide the development plan, but other reservoir performance analysis was also used in the planning, and some aspects of the plan were not finalized until some time in Budget Period 2.

Four development scenarios were investigated with the pilot-area model:

(1) "HI-HP (Pat)" - drill horizontal producers and horizontal injectors in a pattern flood configuration;
(2) "HI-HP (Per)" - drill horizontal producers and horizontal injectors in a peripheral flood configuration;
(3) "VI-VP" - drill vertical producers and vertical injectors in a pattern flood configuration; and
(4) "VI-HP" - drill horizontal producers and vertical injectors in a pattern flood configuration.

The pattern configuration of Scenarios 1, 3, and 4 was a line drive, based on observed flow patterns in the field. The peripheral configuration of Scenario 2 involved placing injection wells in the thin peripheral areas of the reservoir and producing wells in the thick central portion of the reservoir. In all cases involving horizontal wells, horizontal producing wells were placed near the bottom of the reservoir, and horizontal injection wells were placed near the top. Each scenario also involves converting some existing producing wells to injection, with the specific wells varying depending on the scenario.

The specific well plans associated with each of the initial runs of these scenarios (or "Cases") are listed in a table provided as **Figure 28** and shown in **Figure 29** (Scenario 1), **Figure 30** (Scenario 2), **Figure 31** (Scenario 3), and **Figure 32** (Scenario 4).

Initial cases were run with no increase in injection or plant processing capacity. It was clear from these cases that plant expansion would be necessary to maximize benefit from additional development, as each of the cases actually resulted in lost reserves. This was in part due to constraints associated with simulator well-testing logic, but the conclusion from these cases was still that plant expansion would be required if a number of new wells were added to the injection and/or production capacity.

The next set of cases (labeled "1b" through "4b") included plant expansions. Injection capacity was increased from 19 MMCFD to 27 MMCFD and processing capacity was increased form 16 MMCFD to 24 MMCFD. Results of these cases, though positive and still limited by the testing logic, were still somewhat discouraging. All involved drilling nine new wells (horizontal or vertical), but added incremental reserves of only 900 MBOE (Scenario 1) to 2100 MBOE (Scenario 2), as shown in the table of **Figure 33**. This led to further review of the model to better understand these results.

Base Case	Case 1b HI-HP (Pat)	Case 2b HI-HP (Per)	Case 3b VI-VP	Case 4b VI-HP
Continue w/ Current Wells As Is	Horizontal Injectors, Horizontal Producers (Pattern)	Horizontal Injectors, Horizontal Producers (Peripheral)	Vertical Injectors, Vertical Producers (Pattern)	Vertical Injectors, Horizontal Producers (Pattern)
Conversions (0)	Conversions (5)	Conversions (3)	Conversions (5)	Conversions (5)
None	37-3H	36-2	37-3H	37-3H
	57-1	48-1	57-1	57-1
	59-1		59-1	59-1
	61-1	61-1	61-1	61-1
	65-1		65-1	65-1
New Prod (0)	New Prod (5)	New Prod (5)	New Prod (7)	New Prod (7)
None	44-3H (Horiz)	44-3H (Horiz)	44-3 (Vert)	44-3H (Horiz)
	45-3H (Horiz)	45-3H (Horiz)	45-3 (Vert)	45-3H (Horiz)
		46-3H (Horiz)	57-3 (Vert)	57-3H (Horiz)
	58-3H (Horiz)	58-3H (Horiz)	58-3 (Vert)	58-3H (Horiz)
	59-3H (Horiz)		59-3 (Vert)	59-3H (Horiz)
			60-2 (Vert)	60-2H (Horiz)
	65-2H (Horiz)	65-2H (Horiz)	65-2 (Vert)	65-2H (Horiz)
New Inj (0)	New Inj (4)	New Inj (4)	New Inj (2)	New Inj (2)
None	58G-4H (Horiz)	47G-3H (Horiz)	47G-3 (Vert)	47G-3 (Vert)
	59G-4H (Horiz)			
	60G-2H (Horiz)	60G-2H (Horiz)		
		64G-3H (Horiz)		
	74G-2H (Horiz)	74G-2H (Horiz)	74G-2 (Vert)	74G-2 (Vert)
Net Change (relative to Base Case)				
No. of Injectors	+9	+7	+7	+7
No. of Producers	0	+2	+2	+2
New Horizontal Wells	9	9	0	7
New Vertical Wells	0	0	9	2

Figure 28. Pilot Model Forecast Cases / Scenarios.

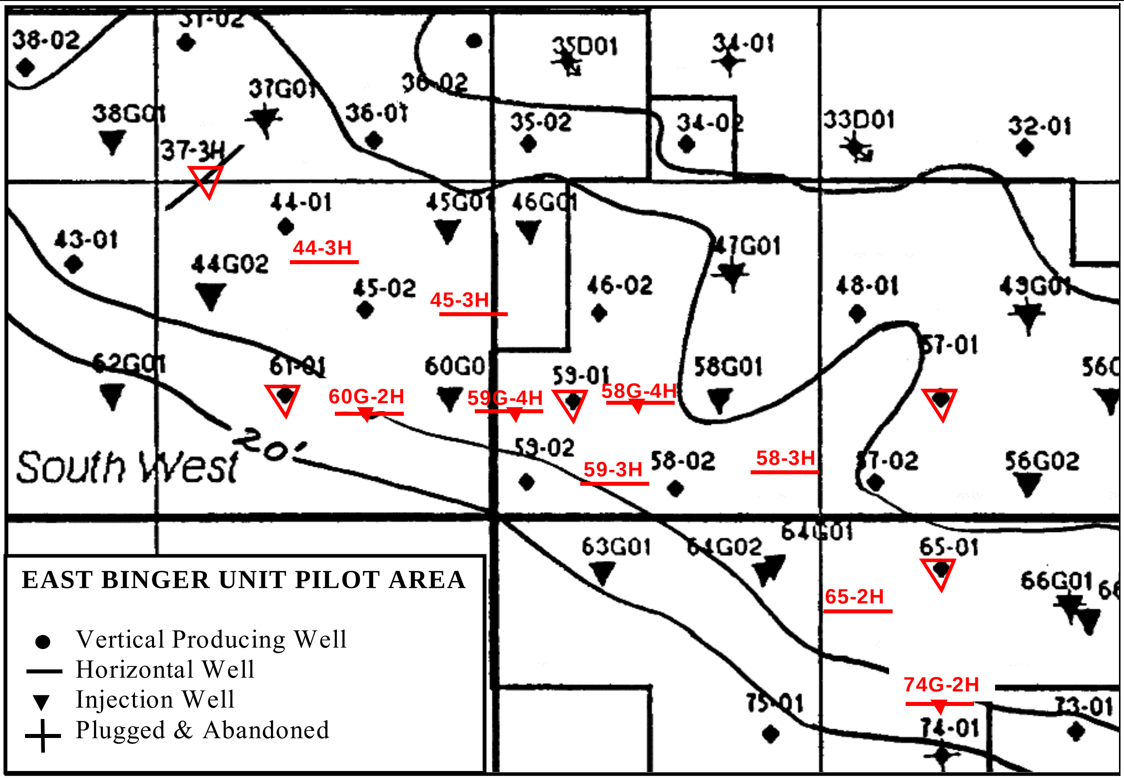

Figure 29. Pilot model forecast Scenario 1 – horizontal injectors and horizontal producers in a pattern flood.

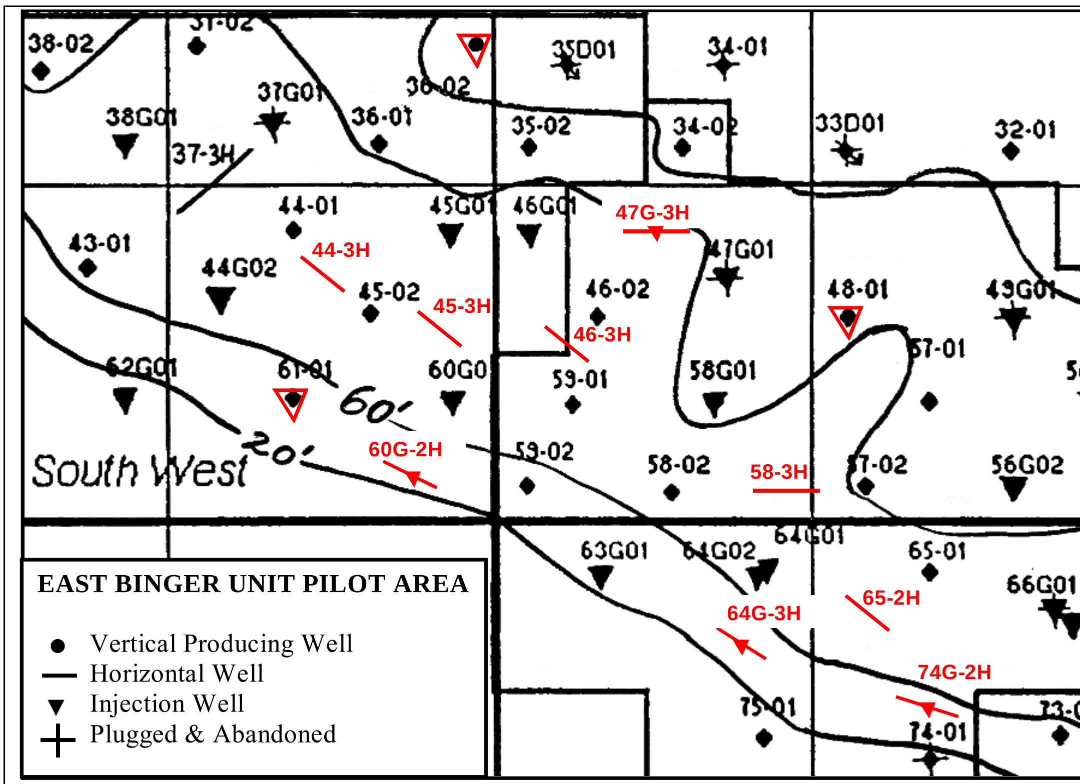

Figure 30. Pilot model forecast Scenario 2 – horizontal injectors and horizontal producers in a peripheral flood.

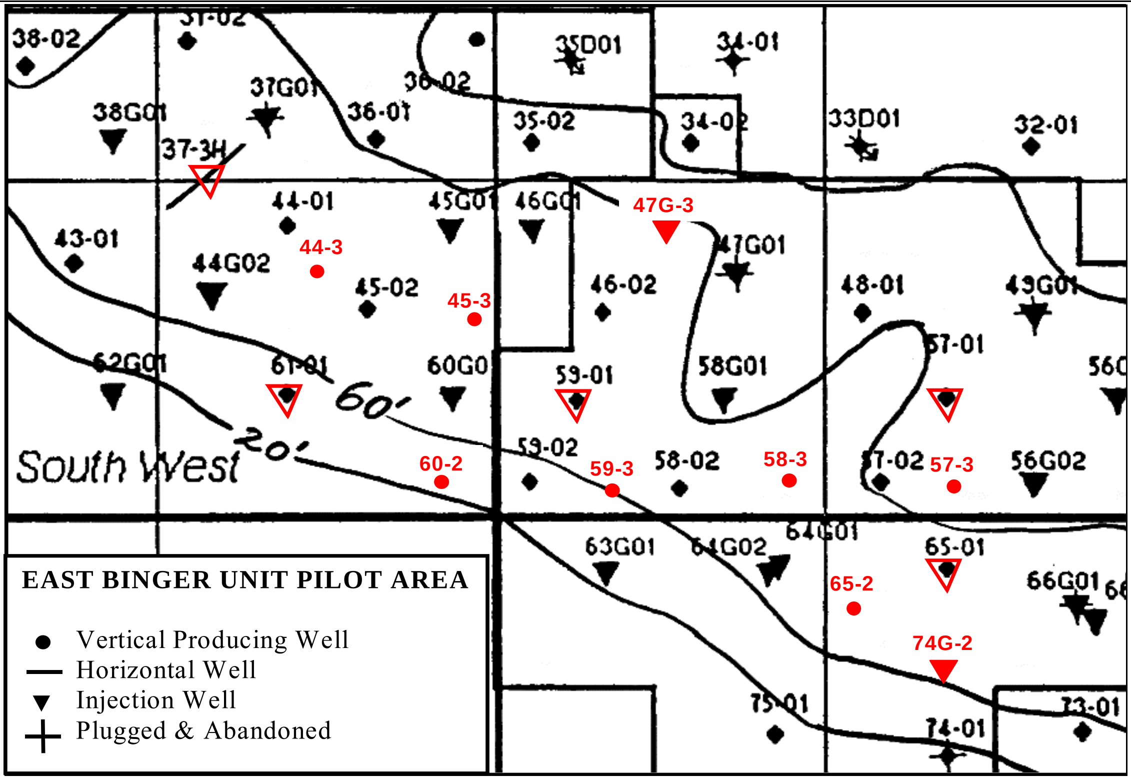

Figure 31. Pilot model forecast Scenario 3 – vertical injectors and vertical producers in a pattern flood.

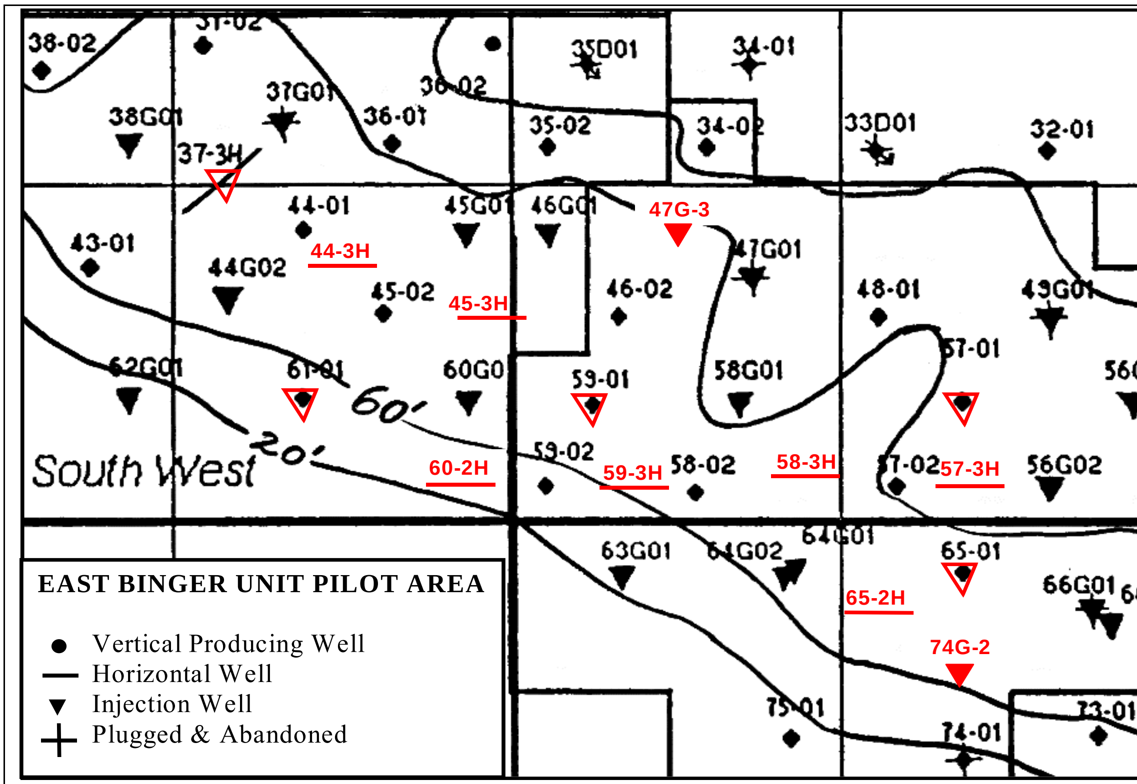

Figure 32. Pilot model forecast Scenario 4 – vertical injectors and horizontal producers in a pattern flood.

	Case 1b HI-HP (Pat)	Case 2b HI-HP (Per)	Case 3b VI-VP	Case 4b VI-HP
New Producers	5 - Horizontal	5 - Horizontal	7 - Vertical	7 - Horizontal
New Injectors	4 - Horizontal	4 - Horizontal	2 - Vertical	2 - Vertical
Conversions to Inj	5	3	5	5
Total Investment	$16,100,000	$15,900,000	$11,600,000	$15,100,000
Incremental Oil (Mbbl)	311	458	645	469
Incremental NGL (Mbbl)	346	886	738	612
Incremental Gas (MMcf)	1517	4525	3794	3072
Incremental BOE (MBOE)	909	2099	2016	1594
Economic Results (see note at bottom)				
Internal Rate of Return (%)	12	20	16	18
Net Present Value @ 10%	$615,000	$3,541,000	$2,489,000	$2,800,000
Development Cost ($/BOE)	17.70	7.58	5.75	9.48
Payout (years)	6.3	5.1	6.0	5.4
Project Life (years)	24	26	27	25

Economics based on flat pricing: $20/bbl oil, $15/bbl NGL, and $2.50/mcf gas; and non-escalating operating costs.

Figure 33. Pilot Model Forecast Results – Cases 1b – 4b.

Improved Reservoir Characterization and Understanding of Fluid Flow

Overall, the model's match of GOR in the pilot area is quite good, as shown in **Figure 34**. At the well level, the model over-predicts GORs in some wells, and under-predicts them in others, which is expected. Closer inspection of this data, however, combined with a review of other information, led to two conclusions: first, that the dominant flow direction in the field is roughly east-west, and second, that this had not been properly modeled due to incorrect initial assumptions when the model was constructed.

Within the pilot area, the model generally under-predicts the GORs of production wells roughly east or west of injection wells, and over-predicts the GORs of production wells that are not on an east-west line from an injection well. One particular well that exemplifies this problem is well 48-1, located in the northeast corner of the pilot area. **Figure 35** shows the comparison of model-predicted performance of this well's GOR with actual field data. While well 49G-1 to the east was on injection, the model under-predicted the GOR at 48-1. Later, after injection into 49G-1 was stopped (due to a casing failure), the predicted GOR of 48-1 kept increasing, while the actual GOR began to fall. The predicted GOR eventually exceeded the actual GOR. Combined with other predictions similar to this, the evidence became convincing that initial model assumptions had been incorrect.

When the model was initially created, the primary (x) axis of the grid was oriented in a northwest-southeast direction, in line with the orientation of the main sand body of the reservoir – see **Figure 36**. Further, and equally important, it was assumed that the orientation of hydraulic fractures was approximately northeast-southwest – perpendicular to the main sand body, or in the "y" direction of the grid.

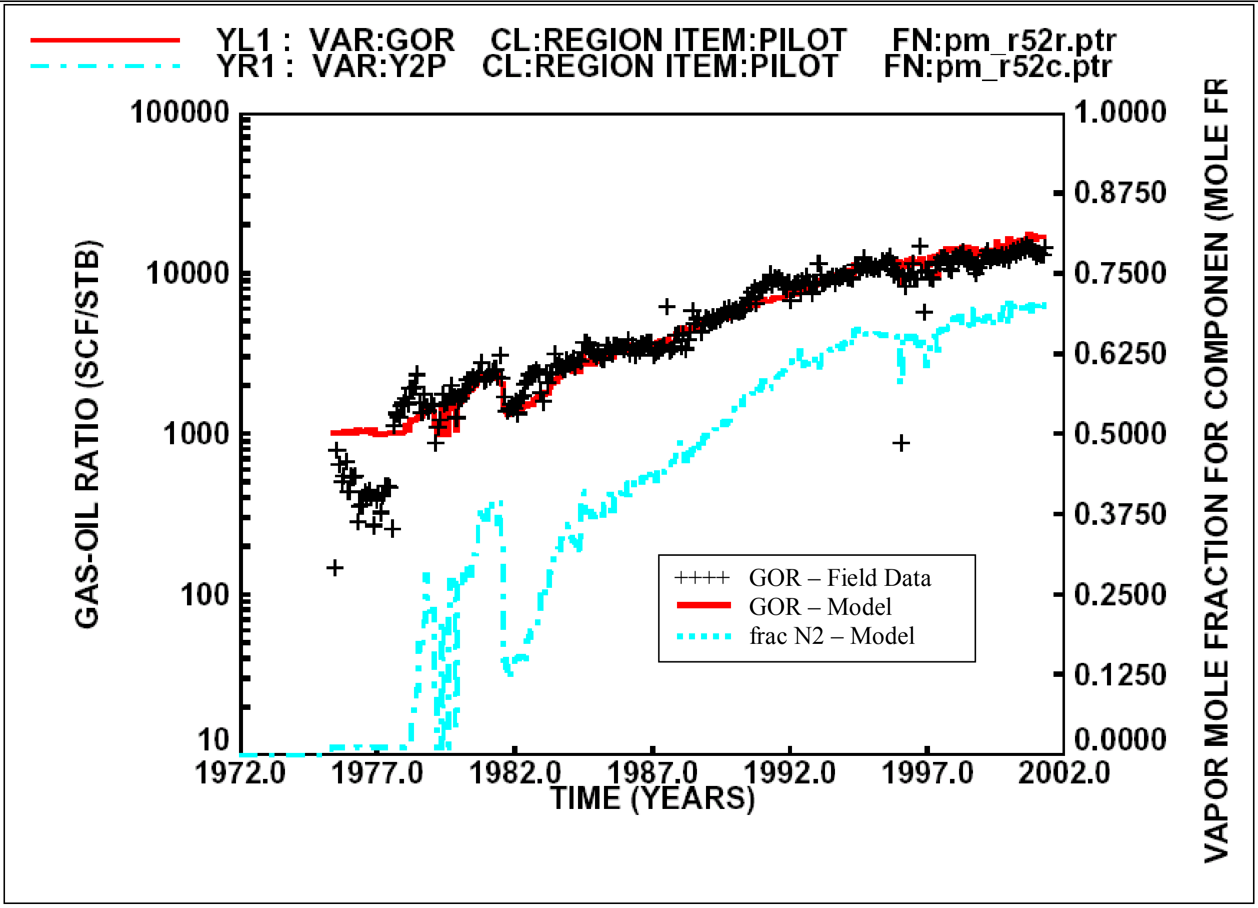

Figure 34. Pilot model history match of GOR for the entire pilot area.

During the history-matching process, one of the more difficult field performance parameters to match was the GOR; the model generally predicted less gas breakthrough and less gas production than was observed in the field. A number of modifications were made to the reservoir description to enhance the movement of gas from injectors to producers. These included increased permeabilities and decreased pore volumes. Within the pilot area, oil in place is about 40% lower than has been calculated volumetrically (with considerable variance from cell to cell). A reduced pore volume effectively increases the volumetric flood rate, causing a general increase in predicted GORs – the desired result when history matching. It was only after more detailed inspection of the model and other research that it was concluded that initial assumptions on dominant flow direction and fracture orientation were incorrect.

Supporting the conclusion that the dominant flow direction is approximately east-west are indications that fractures would be expected to propagate in this orientation. From wellbore enlargement data, the direction of maximum horizontal stress in the eastern Anadarko Basin (where the East Binger Unit is located) was estimated as North 78° East, or 12° north of directly east (Dart, 1989). Hydraulic fractures propagate in the direction of maximum horizontal stress.

Additional evidence of the expected frac orientation came from analysis of acoustic log data acquired in 1996 in East Binger Unit well 72-2. From this data, Doug Patterson of Western Atlas Logging concluded that the data in the Marchand C Sand shows a general east-northeast principal stress direction and the data in the Medrano Sand, which lies about 800' above the Marchand C Sand, displays an orientation just south of due east (Patterson, 1996). Patterson indicated the data in the Medrano Sand was more conclusive, and suggested a probable fracture system "running in the general east-west direction". Fracture orientation in the Marchand C Sand should be close to fracture orientation in the Medrano Sand, as orientation is controlled by regional stress regimes.

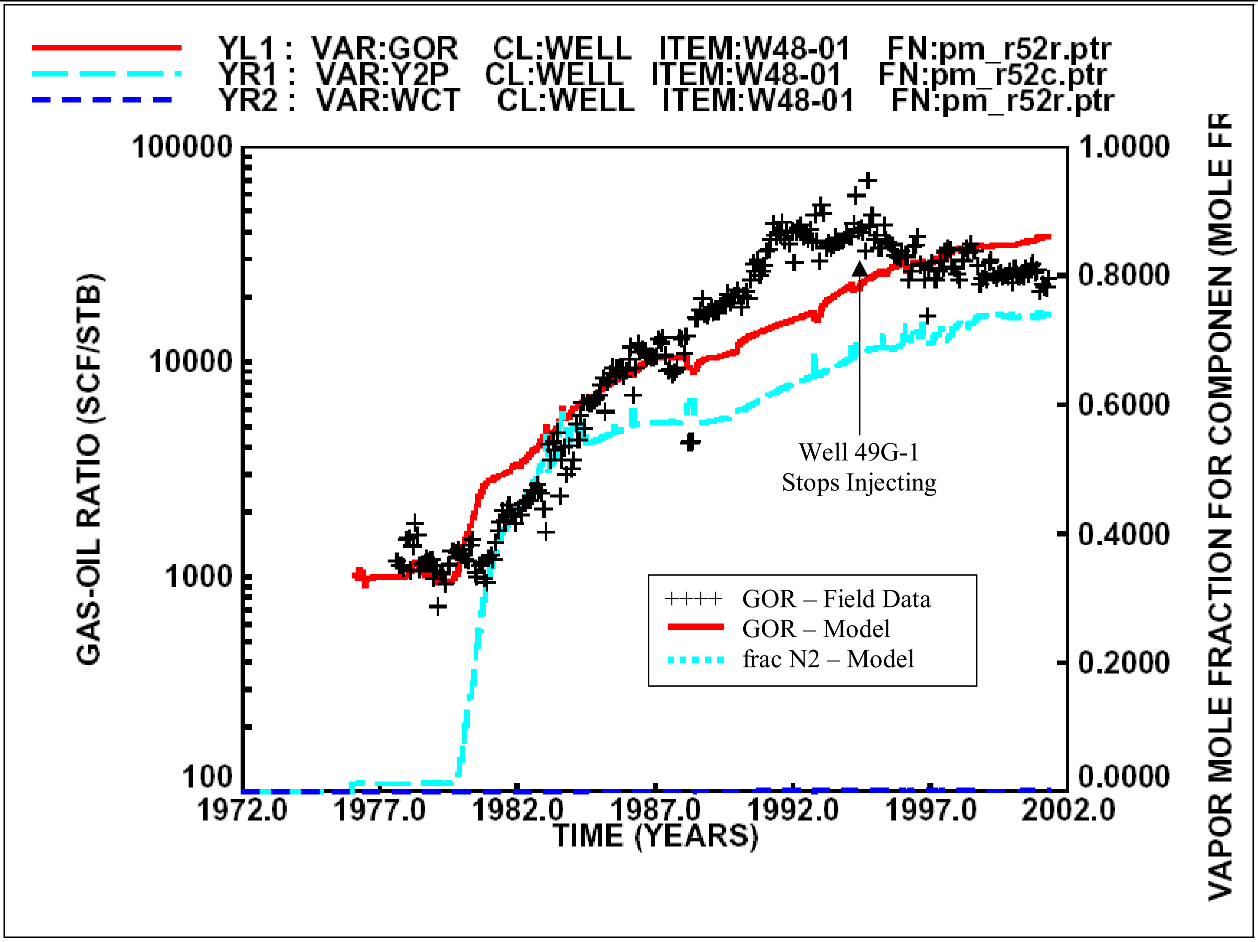

Figure 35. Pilot model history match of GOR for well 48-1. Note when well 49G-1 stopped injecting.

Given this improved understanding of the flow mechanisms in the reservoir, it was concluded that the ideal flood pattern should be a line drive, despite the fact that Scenario 2 yielded the most incremental recovery and the highest rate of return. The focus thus turned to Scenarios 1, 3, and 4. Scenarios 3 and 4 involved drilling two more producing wells – vertical in Scenario 3, horizontal in 4 – relative to Scenario 1, which had two more injection wells. As shown in **Figure 33**, Scenarios 3 and 4 out-performed Scenario 1 by a significant margin. However, the model's tendency to over-predict radial flow relative to east-west linear flow would have caused errors in predicted performances of individual wells. Specifically, it would have caused the model to over-predict recoveries of vertical wells and under-predict recoveries of horizontal wells drilled in an east-west orientation offset by injection to the north and/or south.

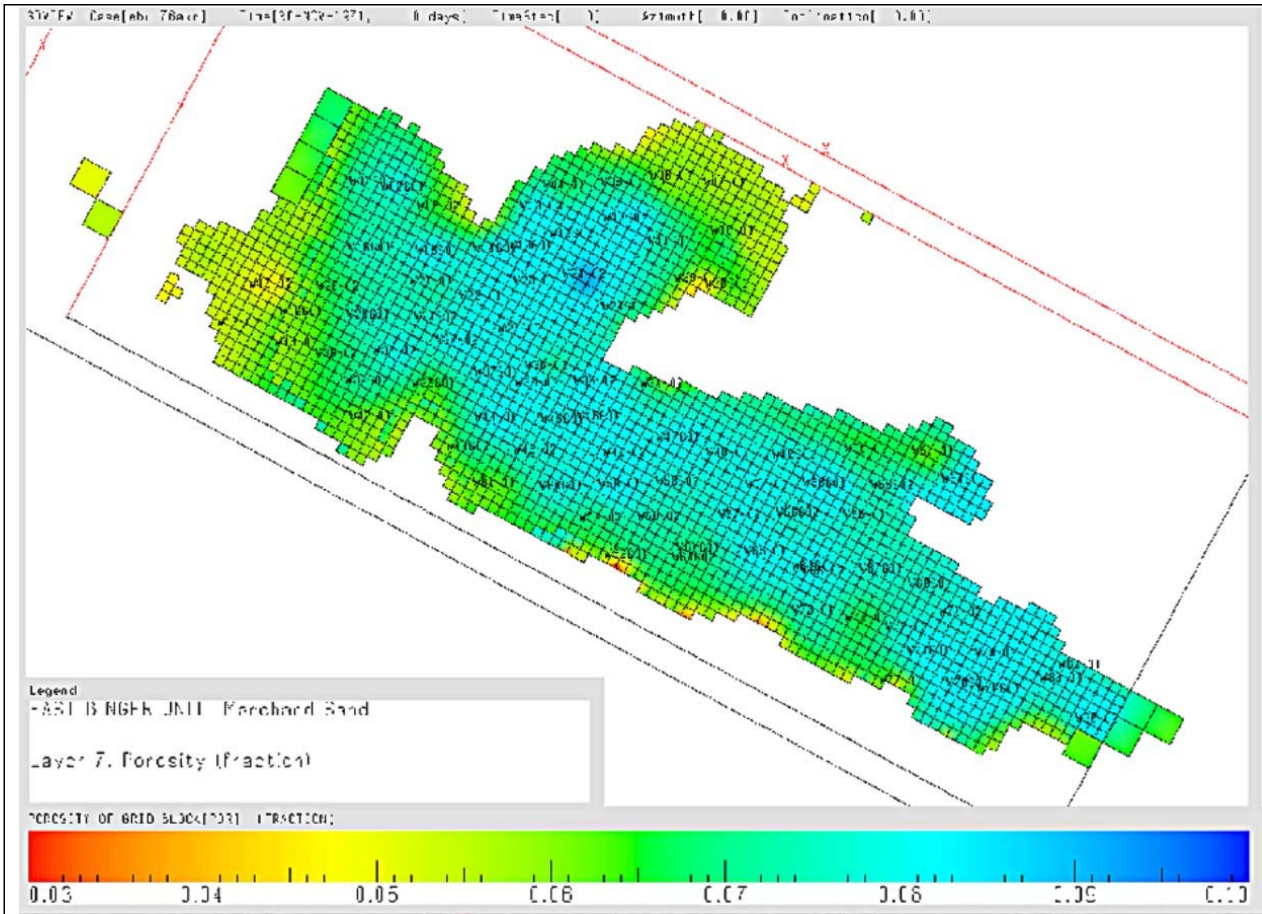

Figure 36. Model layer 7 porosity map, indicating the orientation of the grid on the field.

In addition to the directional flow bias effect, there was also the issue of the reduced pore volumes, discussed previously, which would caused predicted recoveries of all infill wells to be too low. The combined effects of the directional flow bias and the pore volume reductions are additive for east-west oriented horizontal wells, but they are offsetting for vertical wells. Thus, for the specific scenarios being evaluated, it was believed that the predicted recoveries in Scenarios 1 and 4 were too low, while the net effect on the predicted recoveries in Scenario 3 is unknown.

Two final cases were run in attempt to improve the performances of, and thus the comparison between, Scenarios 3 and 4. Three producing wells with low recovery – 57-3, 59-3, and 60-2 – were removed from each case. This improved the economic results of both scenarios, as shown in **Figure 37**. Note that this change improved Scenario 4 much more than it did Scenario 3. From these cases, it was concluded that new producing wells in the pilot development plan should be drilled as horizontal wells if they can be cost-effectively drilled. Future injection wells, if drilled rather than converted from producing wells, were planned as vertical wells.

	Case 3b VI-VP	Case 4b VI-HP	Case 3c VI-VP	Case 4c VI-HP
New Producers	7 - Vertical	7 - Horizontal	4 - Vertical	4 - Horizontal
New Injectors	2 - Vertical	2 - Vertical	2 - Vertical	2 - Vertical
Conversions to Inj	5	5	5	5
Total Investment	$11,600,000	$15,100,000	$8,300,000	$10,300,000
Incremental Oil (Mbbl)	645	469	850	755
Incremental NGL (Mbbl)	738	612	1015	1039
Incremental Gas (MMcf)	3794	3072	5288	5321
Incremental BOE (MBOE)	2016	1594	2747	2681
Economic Results (see note at bottom)				
Internal Rate of Return (%)	16	18	17	24
Net Present Value @ 10%	$2,489,000	$2,800,000	$3,029,000	$4,932,000
Development Cost ($/BOE)	5.75	9.48	3.02	3.84
Payout (years)	6.0	5.4	6.2	4.6
Project Life (years)	27	25	29	28

Economics based on flat pricing: $20/bbl oil, $15/bbl NGL, and $2.50/mcf gas; and non-escalating operating costs.

Figure 37. Pilot Model Forecast Results – Cases 3b, 4b, and 3c, 4c.

Finalize Pilot Project Development Plan

As discussed above, it was concluded that new producing wells in the pilot development plan should be drilled as horizontal wells if they could be cost-effectively drilled, and new injection wells were planned to be drilled as vertical wells. Finalizing the pilot development plan involved selecting the optimum configuration of new wells and conversions to maximize the potential benefit of the project at a cost close to the Budget Period 2 budget of just under $7,000,000. Approximate costs of various capital projects were estimated as follows:

New horizontal wells	$1,636,000. each
New vertical wells	1,048,000. each
Conversions to Injection	95,000. each
Plant injection capacity expansion	343,000. (for assumed size of expansion)
Plant processing capacity expansion	670,000. (for assumed size of expansion)

In addition to these costs, there would be costs in Budget Period 2 for additional modeling, initiating monitoring of the pilot project, technology transfer activities, project review, and reporting. Added together, these aspects of the project were expected to cost about $200,000, leaving about $6,800,000 for the above projects.

The final field implementation plan developed for Project Phase II (Budget Period 2) is shown in **Figure 38**. It included three new horizontal producing wells (total cost $4,908,000), one new vertical injection well ($1,048,000), five conversions of producers to injection ($475,000), and the expansion of plant injection capacity ($343,000). Expansion of plant processing capacity was not included. The total cost of these projects was expected to be just under $6,800,000.

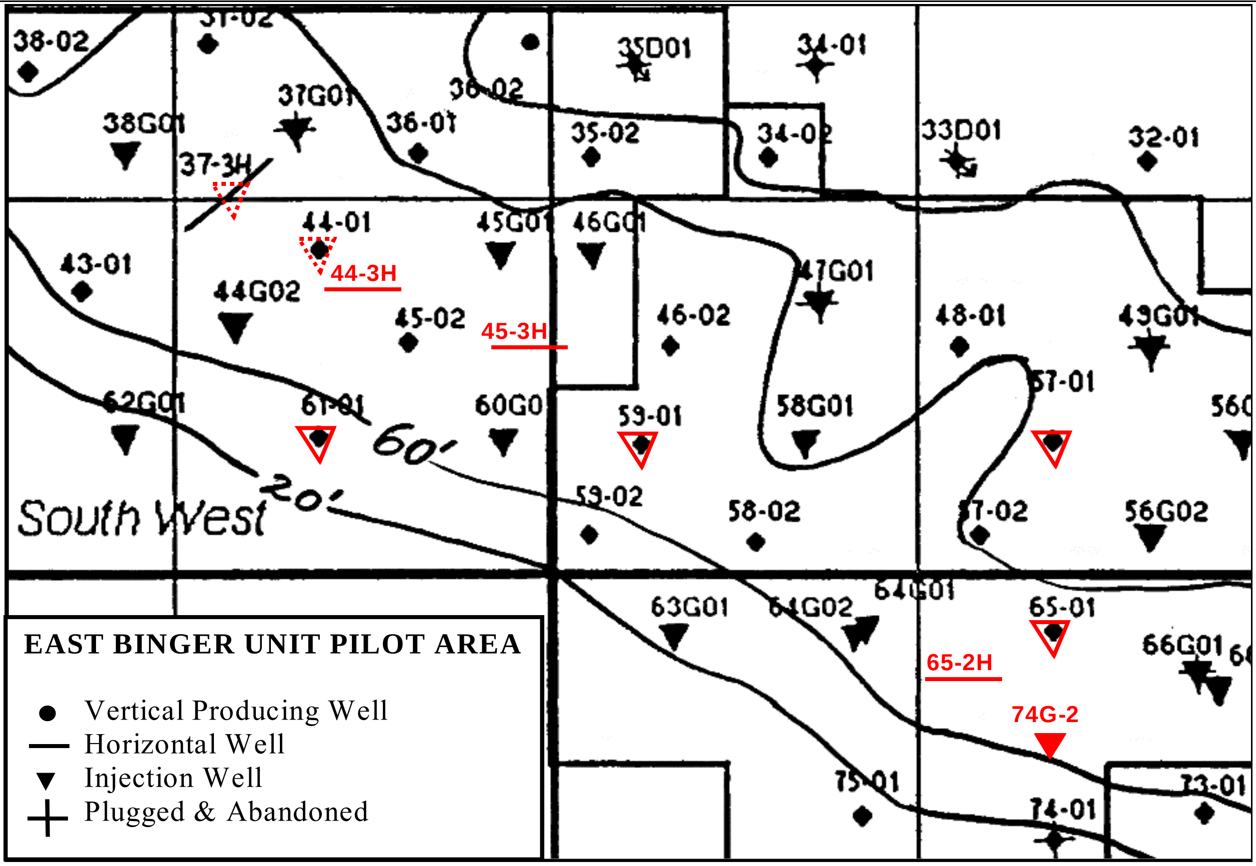

Figure 38. Fieldwork planned for the pilot - shown in red. The plan included converting either 37-3H or 44-1 to injection.

The three planned horizontal producing wells were EBU 65-2H (subsequently renamed 64-3H because of the surface location), EBU 45-3H, and EBU 44-3H. These three wells had the highest recoveries in the model forecasts. EBU 44-3H had the highest recovery, but was planned to be drilled last, as its predicted recovery was thought to be the most likely to be overly optimistic, and the recoveries of EBU 65-2H and EBU 45-3H were thought to be understated.

The one planned injection well was EBU 74G-2, southeast of EBU 65-2H. It was planned to support the production from EBU 65-2H. Eventually, another well was drilled in the area, and EBU 74-2 was left as a producer.

Five producer-to-injector conversions were also planned – EBU 57-1, EBU 59-1, EBU 61-1, EBU 65-1, and either EBU 37-3H or EBU 44-1. The conversions of wells EBU 57-1, EBU 59-1, and EBU 61-1 were designed to establish an east-west line of injection through the central part of the pilot area, and help support the production of wells EBU 45-2, EBU 45-3H, and EBU 46-2. The conversion of EBU 65-1 would follow the drilling of 65-2H, support that well's production, and establish another east-west line of injection in the southeastern end of the pilot area. It was recognized that additional injection would be needed in the northwestern end of the pilot area with the drilling of 37-3H, but the best candidate for injection had not yet been determined. Additional work conducted during Budget Period 2 would lead to the conversion of EBU 37-3H.

The expansion of plant injection capacity would be needed due to the planned producer-to-injector conversions, with the injection system currently operating at capacity without those conversions. **Figure 39** shows a very simplified flow diagram of the Nitrogen Management Facility (NMF, or "plant"). The NMF has three primary functions: 1) process and separate produced gas into NGLs for sales, methane residue for sales/power exchange, and nitrogen for re-injection, 2) manufacture nitrogen from air for injection, and 3) compress nitrogen for injection. The addition of numerous producing wells and new and converted injection wells were forecast to increase total injection well capacity and, eventually, the amount of gas to be processed at the NMF.

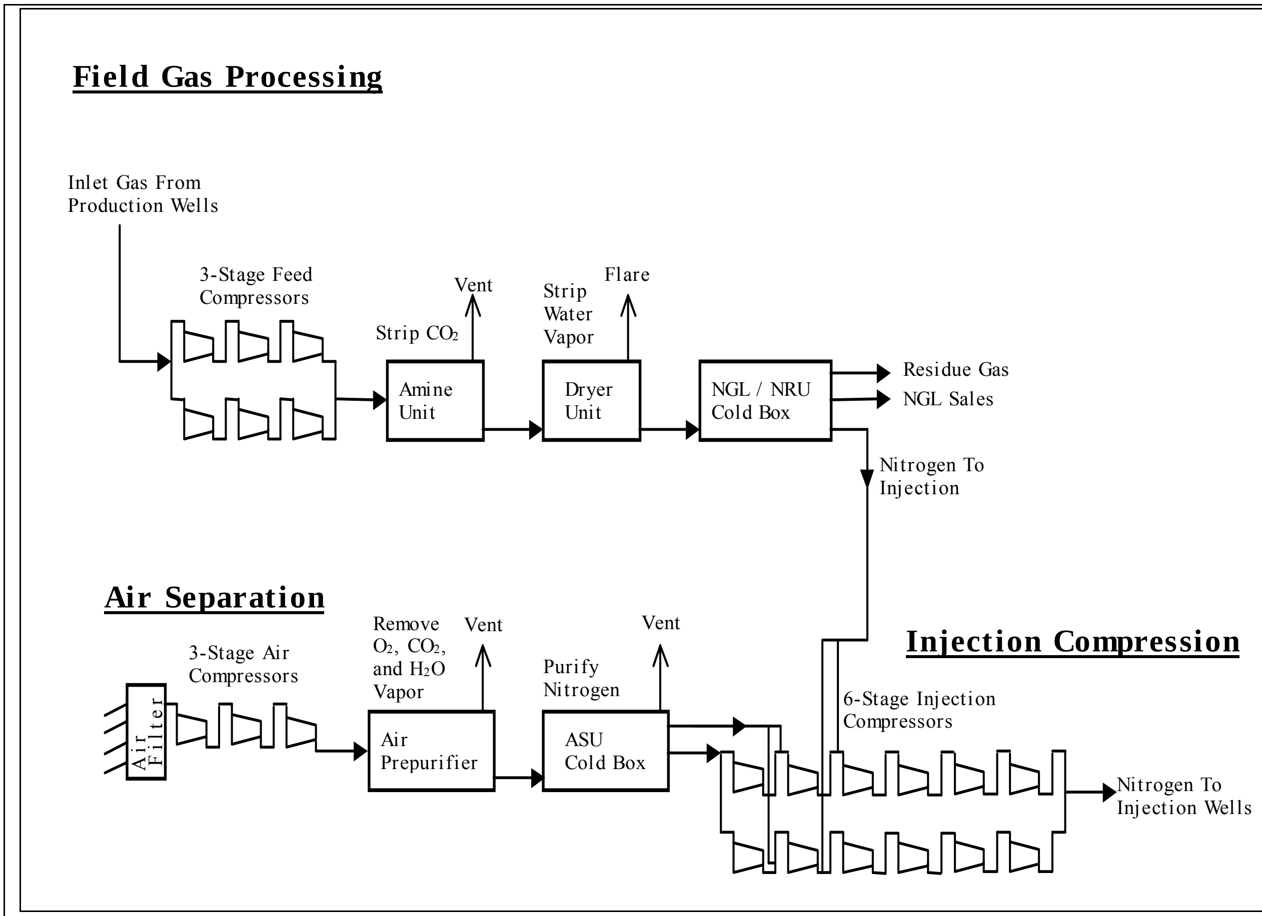

Figure 39. Simplified Nitrogen Management Facility (NMF) process diagram as it existed prior to the project.

The demand for additional injection capacity at the NMF was expected to occur first, with the planned producer-to-injector conversions. The added injectors were expected to increase injection demand by about 2 - 3 MMcfd after the wells' injection rates stabilized. There are two aspects to increasing injection capacity at the plant: adding injectant (nitrogen) supply and adding compression. Additional nitrogen supply was already available with the existing cryogenic air separation unit (CASU or ASU), which was operating below capacity. Additional compression was included in the project to increase injection compression capacity from about 19 MMcfd to about 23 MMcfd.

The existing NMF injection compression system consists of two six-stage compressors operated in parallel (see **Figure 39**). The first two stages of these compressors boost pure nitrogen from the ASU from about 35 psi to about 270 – 300 psi. Nitrogen from the Nitrogen Recovery Unit (NRU) is blended with nitrogen from the ASU between the second and third stages of compression. The final four stages of the injection compressors boost the ASU/NRU blended nitrogen from 270 – 300 psi to the injection pressure of 5000 psi.

The expansion of plant injection compression capacity would be achieved by adding a four-stage compressor in parallel with the final four stages of the injection compressors. This is shown in **Figure 40**.

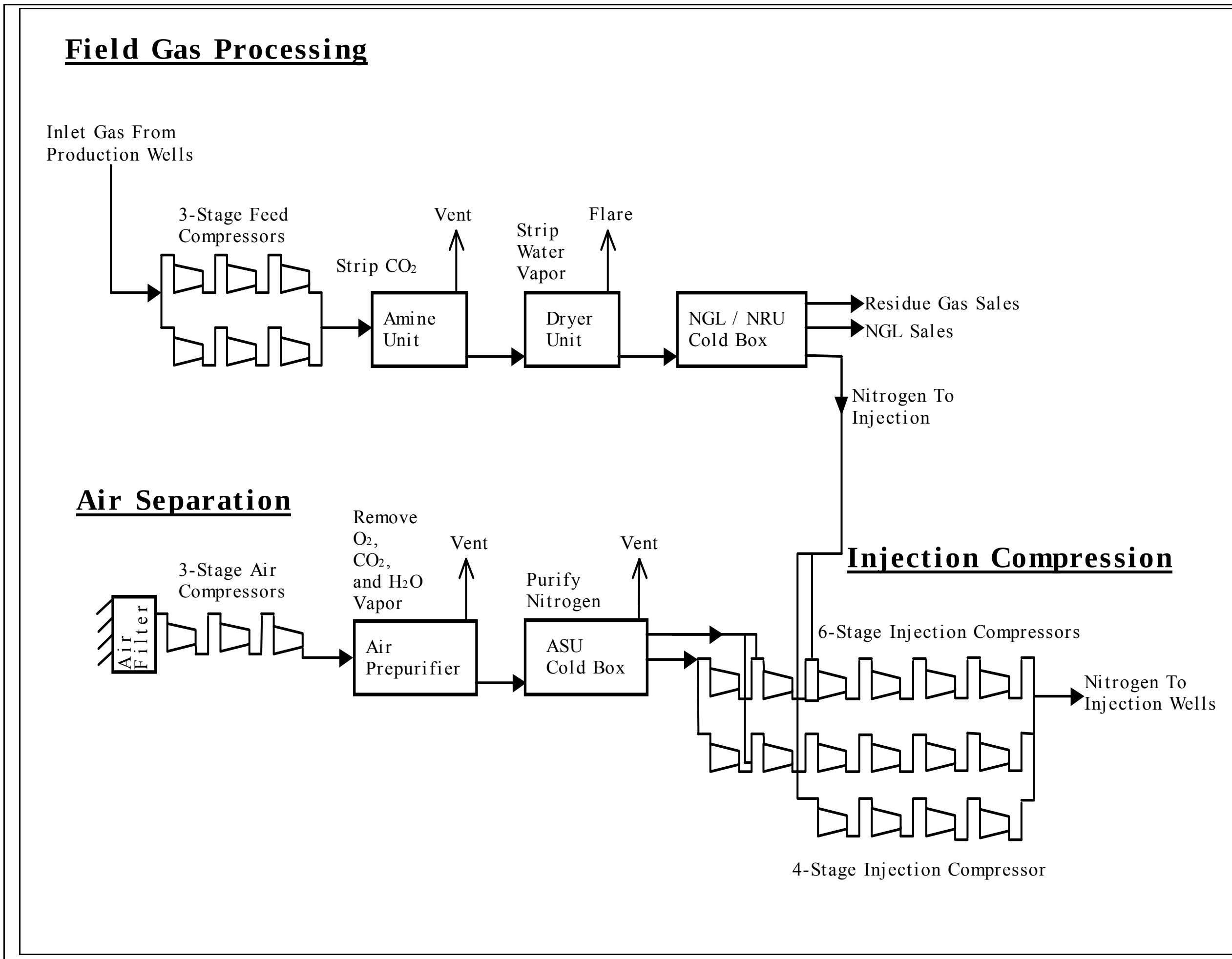

Figure 40. Simplified NMF process diagram after the injection compression expansion.

Project Phase II (Budget Period 2) – Project Implementation

As the project moved from Phase I planning to Phase II implementation, it was recognized that the original full field model and the original pilot area model were both flawed in the assumption of the orientation of fractures, both natural and hydraulic. It was and is believed that fracturing is the dominant reservoir characteristic which controls fluid flow.

While the general project plan was created taking this information into account, there were aspects of the plan which needed additional analysis and evaluation. Thus, an added component to Phase II of the project was additional evaluation of alternatives. This required a significant effort to reconstruct the pilot area simulation model to better honor the proper orientation of fractures. Project implementation began concurrent with the modeling efforts, with specific elements defined as the implementation progressed. Project monitoring also began during Phase II, and was beneficial in both validating the new understanding of fluid flow and finalizing project plans.

Reconstruction of the Pilot Area Simulation Model

As discussed previously (within the section titled *Improved Reservoir Characterization and Understanding of Fluid Flow*) and shown in **Figure 21** and **Figure 36**, the original model was constructed with the primary ("x") axis of the grid oriented in a northwest-southeast direction, in line with the orientation of the main sand body of the reservoir. Hydraulic fracture treatments were modeled as enhanced permeability in a northeast-southwest direction, in the "y" direction of the grid.

As further discussed, detailed model review and additional research led to the conclusion that the assumption of fracture orientation was incorrect, and that both it and the dominant flow direction in the field is approximately east-west. It was on this basis that the history match was reconstructed. After completing the revisions to the model, nearly all wells in the pilot area have an equivalent or better match in the new model, with many matches significantly better.

Figure 41, **Figure 42**, and **Figure 43** have plots of the model-predicted GOR and nitrogen cut versus field data for three wells in the pilot area, both from the original pilot model history match and the revised model history match. **Figure 41** has plots for EBU 44-1, located in the western end of the pilot area. In the original pilot model, gas produced at this well came predominantly from EBU 37G-1 to the north. Injection was stopped in EBU 37G-1 in 1994, and the model showed a declining GOR and nitrogen cut (upper plot of **Figure 41**). But in reality, the GOR and nitrogen cut continued to increase. The new pilot model matches these trends (lower plot of **Figure 41**). In the new pilot model, the primary source of the gas being produced at EBU 44-1 is EBU 45G-1 to the east.

Figure 42 has plots for EBU 45-2. In the original pilot model, the predicted GOR and nitrogen cut were fairly flat throughout its production history, with the nitrogen cut quickly rising to 60% and declining to 45% at the end of history (upper plot of **Figure 42**). In that model, the source of nitrogen was EBU 60G-1 to the southeast. Actual field data showed nitrogen cut rising much more gradually through history (lower plot of **Figure 42**). In the new pilot model, the nitrogen cut does not reach the level seen in the field, but is much closer to the trend seen in the field.

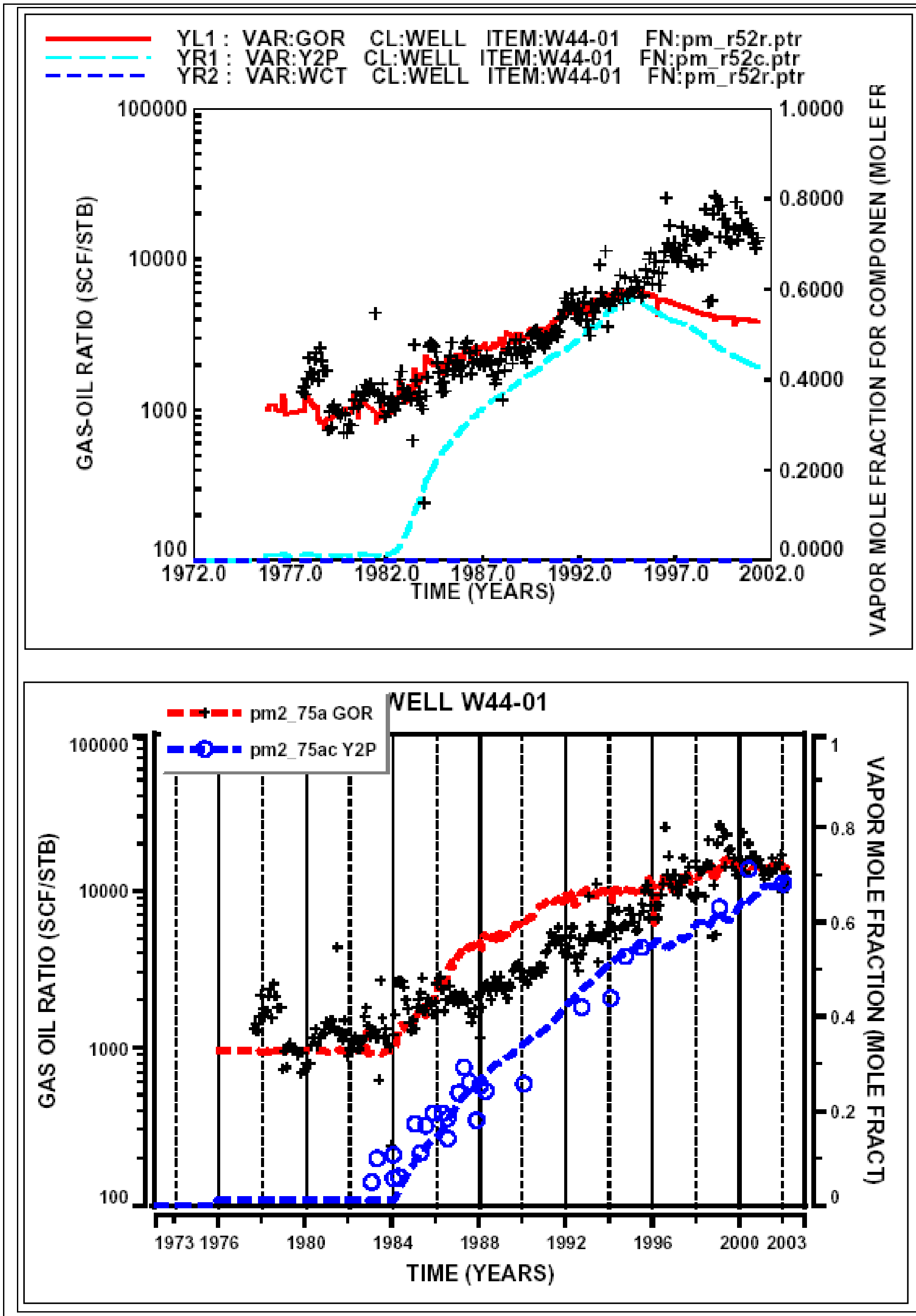

Figure 41. Simulation history match plots for EBU 44-1. The upper plot is the match from the original pilot model; the lower plot is from the current model. "Y2P" is the nitrogen content of produced gas. Symbols are field data; lines are model data.

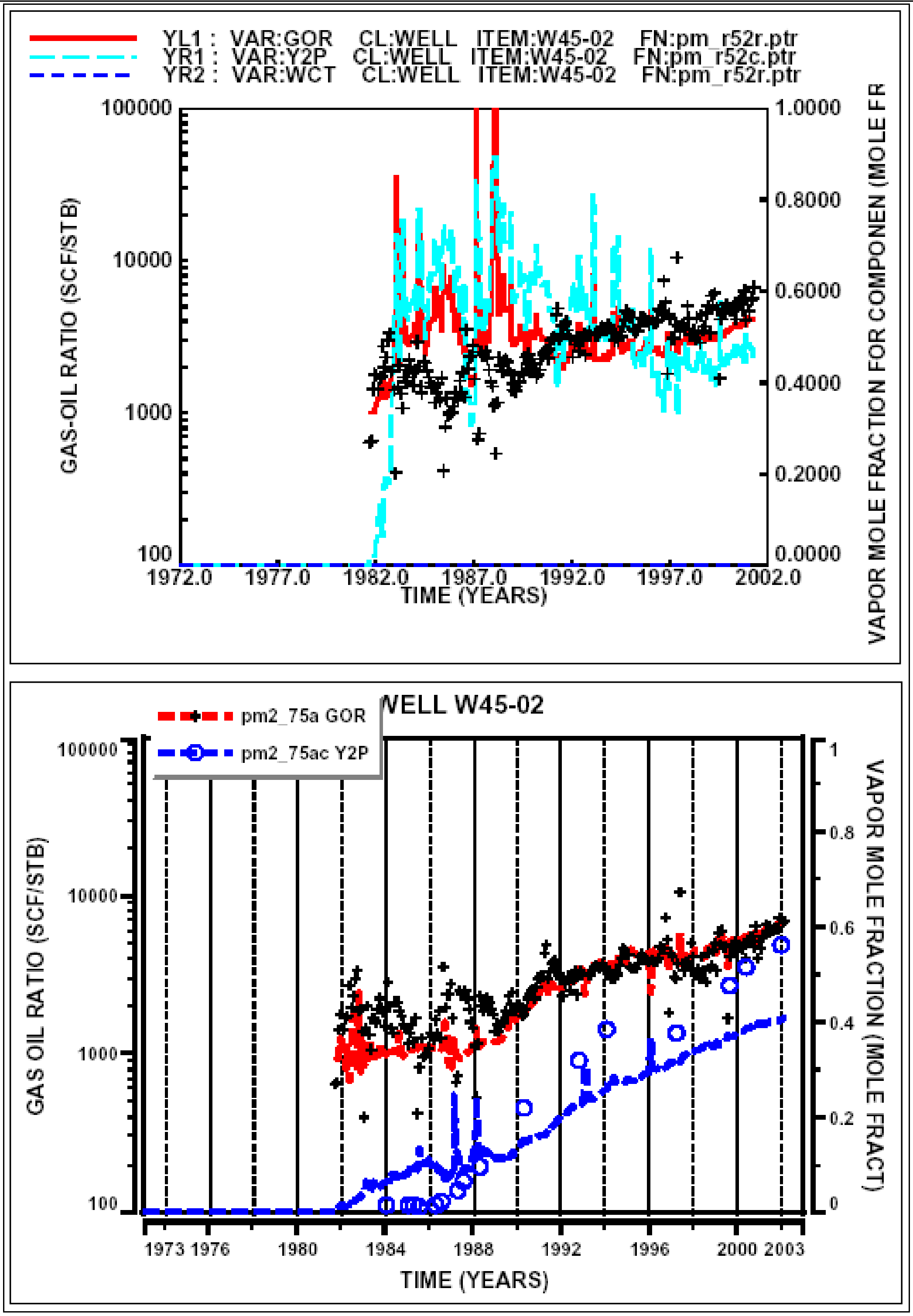

Figure 42. Simulation history match plots for EBU 45-2. The upper plot is the match from the original pilot model; the lower plot is from the current model. "Y2P" is the nitrogen content of produced gas. Symbols are field data; lines are model data.

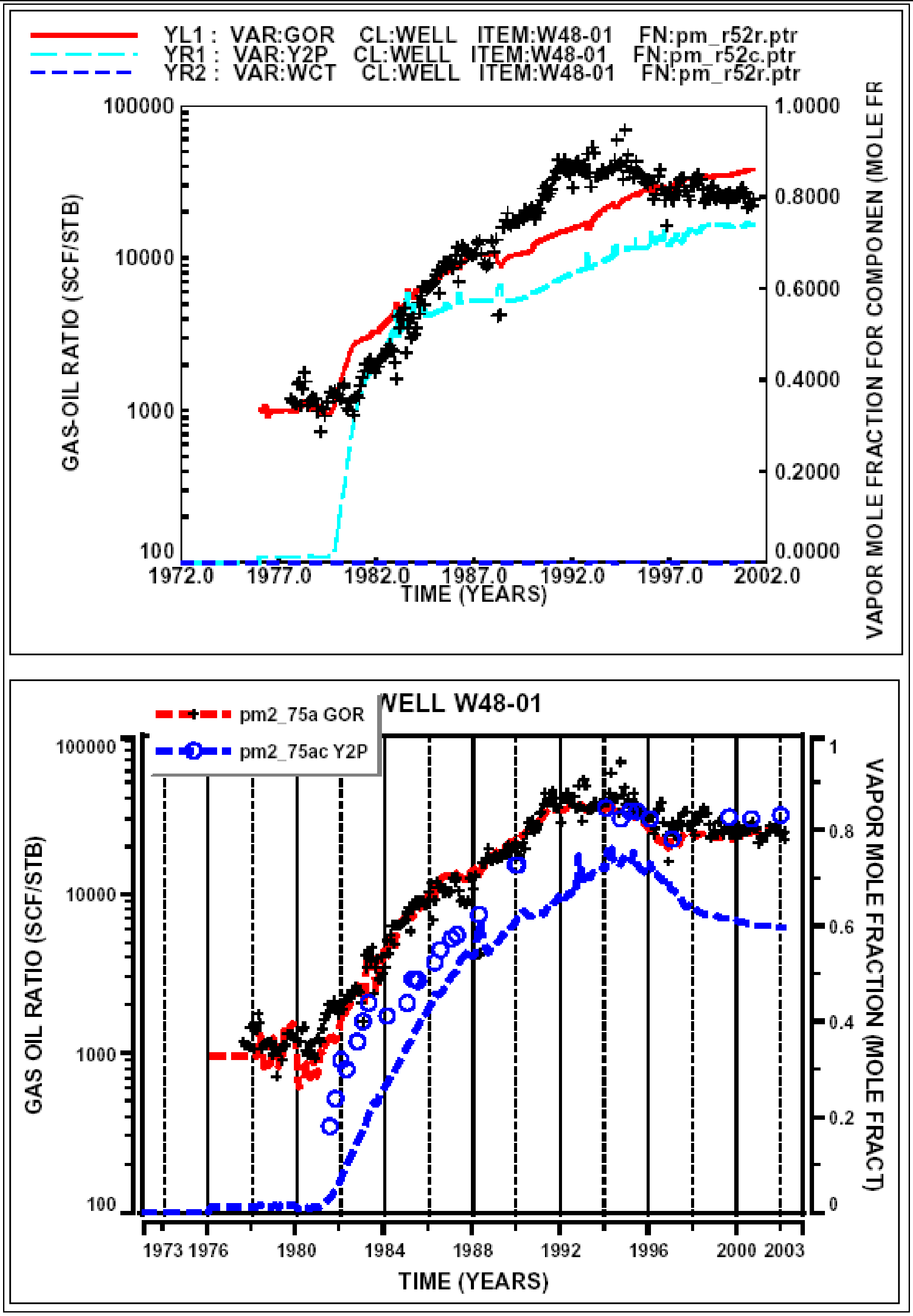

Figure 43. Simulation history match plots for EBU 48-1. The upper plot is the match from the original pilot model; the lower plot is from the current model. "Y2P" is the nitrogen content of produced gas. Symbols are field data; lines are model data.

Figure 43 has plots for EBU 48-1, which is located in the northeast part of the pilot area. Field data indicates a declining GOR since 1994, when injection was halted in EBU 49G-1 (directly east of EBU 48-1). The upper plot of **Figure 43** shows the history match of the original pilot model. In that model, gas production at EBU 48-1 came from three surrounding injection wells, but primarily from EBU 58G-1, southwest of EBU 48-1. Thus, the model continued to predict a rising GOR in the late 1990s, contrary to field data. The revised model, with more east-west fracture modeling, reflects EBU 49G-1 as the primary source of gas produced at EBU 48-1, and accurately predicts a declining GOR after injection is stopped in EBU 49G-1 (lower plot of **Figure 43**). Although the model-predicted nitrogen content of the produced gas is still below field data, the trends are clearly and significantly improved over the prior version of the model.

There were and are significant implications associated with the revised history match. The predicted distribution of remaining reserves is significantly altered. This had implications on the planned locations of horizontal wells planned for Project Phase II (Budget Period 2). **Figure 44** is a display of the predicted oil saturation at present time in model layer 8 (in the stratigraphic middle of the C Sand) of the original pilot model. One of the most promising locations for drilling a horizontal well was between EBU 44-1 and EBU 45-2. This location is in the heart of the reservoir and appeared to be unswept. As shown in **Figure 38**, EBU 44-3H was planned for this area. Because of earlier concerns with the model, however, this well was scheduled for drilling late in Budget Period 2.

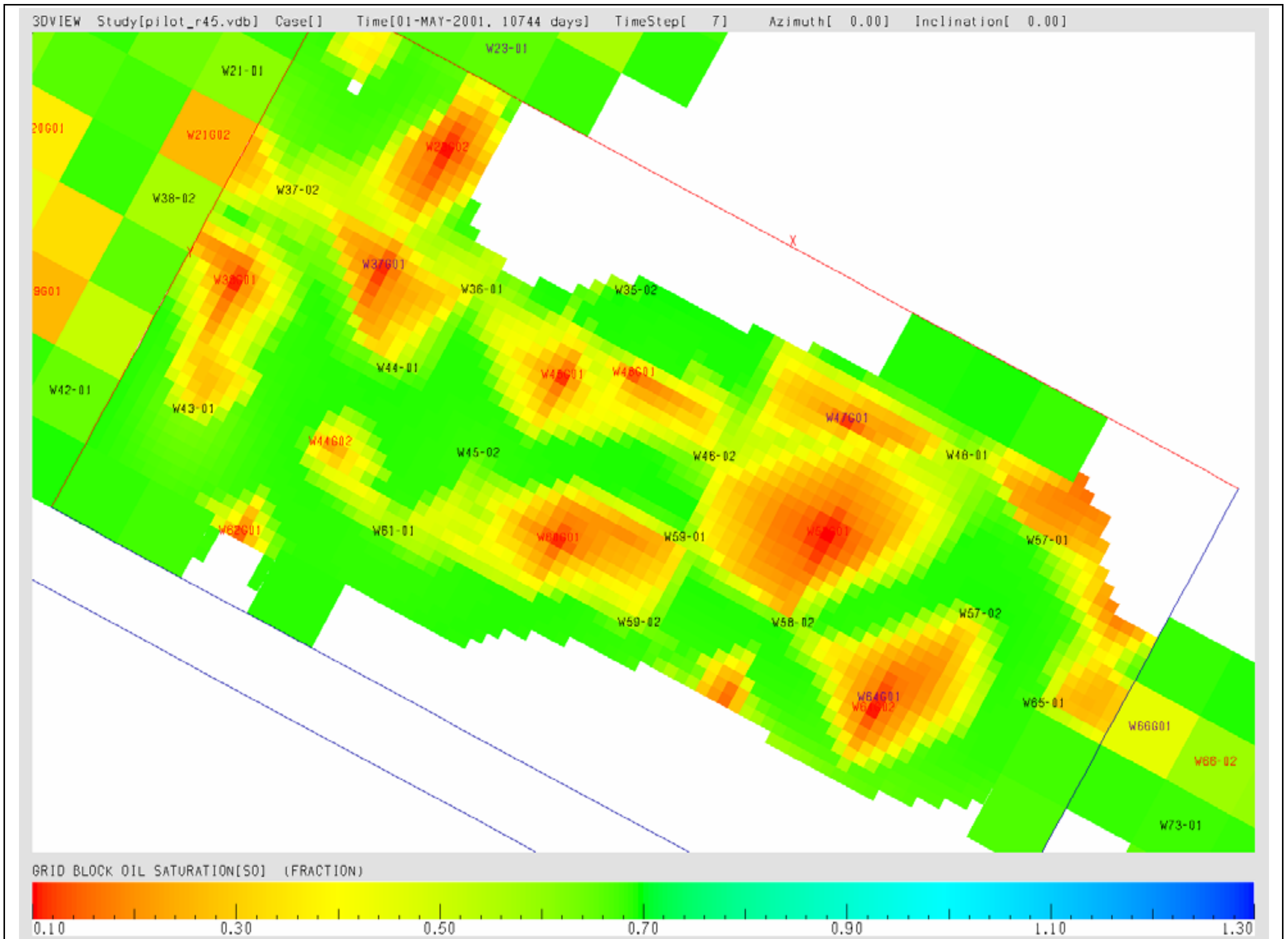

Figure 44. Original pilot model-predicted oil saturation for layer 8 (middle of C Sand) at current time.

The revised model predicted a very different distribution of remaining reserves, as shown in **Figure 45**. As can be seen in this display, the revised model projected the planned location of EBU 44-3H to be significantly more gas-swept than previously did the original pilot area model. Other possible locations appeared to be much more attractive. These included the area between EBU 43-1 and EBU 44-1, the area north of EBU 61-1, and areas around EBU 58-2. Evaluations of horizontal wells in these locations were completed with the revised model.

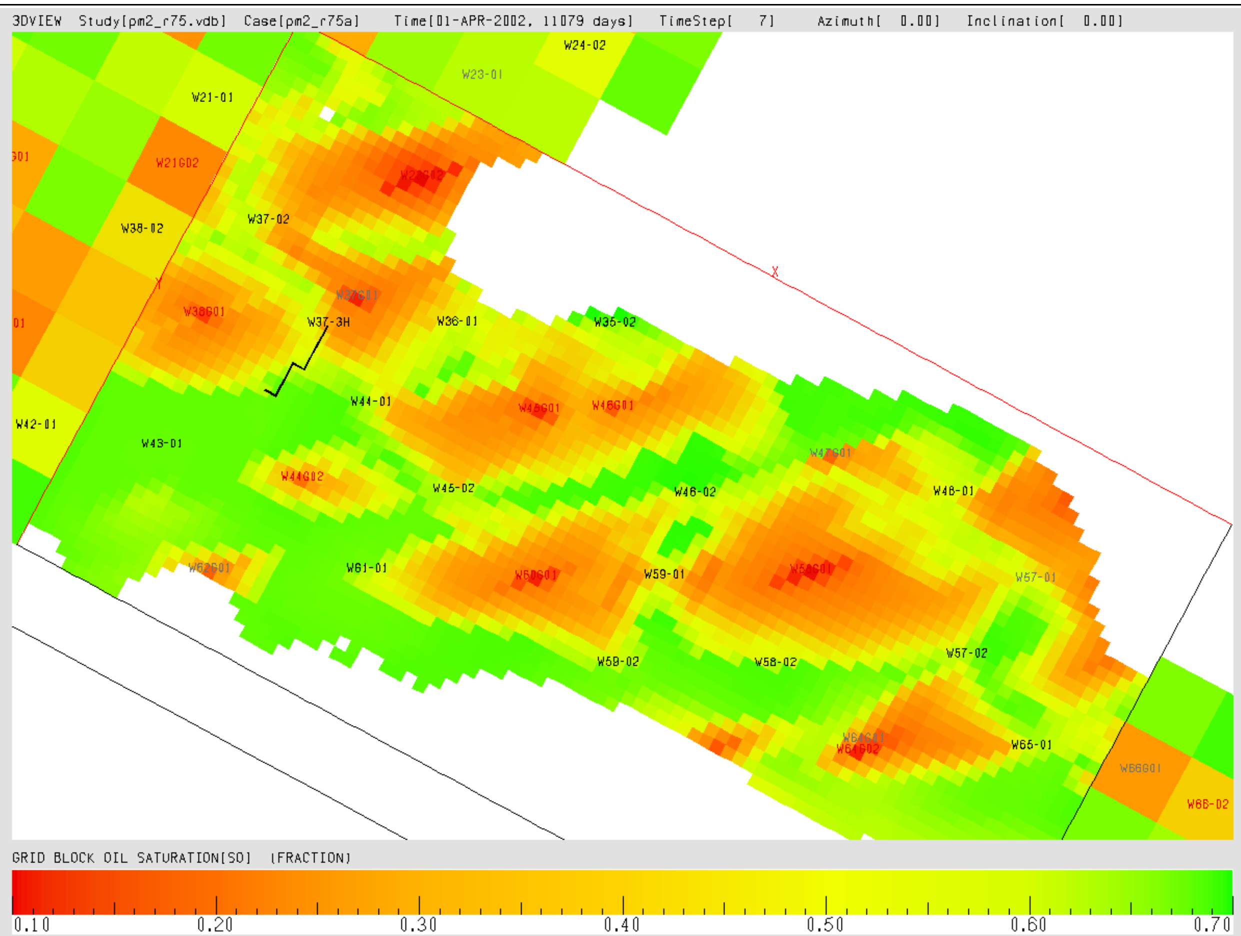

Figure 45. Current pilot model-predicted oil saturation for layer 8 (middle of C Sand) at current time.

The predicted vertical distribution of fluids was also altered. The original model predicted much more gas at the top of the C Sand than at the bottom. This can be seen by comparing the predicted oil saturation of model layer 5, shown in **Figure 46** (original model) and **Figure 47** (revised model), with the predicted oil saturation of model layer 8 (**Figure 44** and **Figure 45**). Layer 5 is near the top of the C Sand. The original model (**Figure 44** and **Figure 46**) predicted much more gas near the top of the reservoir than in the middle. The revised model (**Figure 45** and **Figure 47**) still predicted more gas near the top than in the middle, but with far less difference than predicted by the original model.

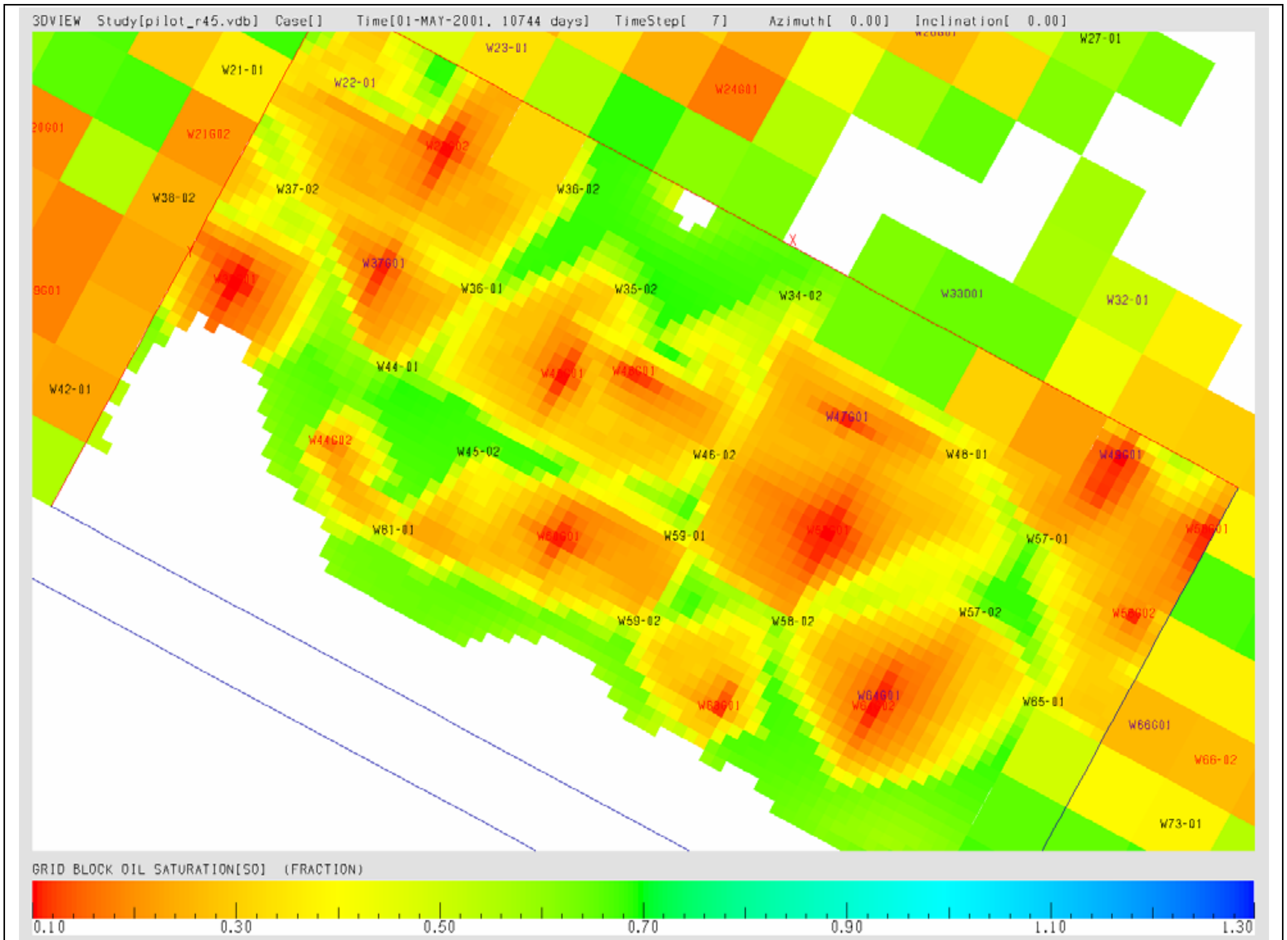

Figure 46. Original pilot model-predicted oil saturation for layer 5 (top of C Sand) at current time.

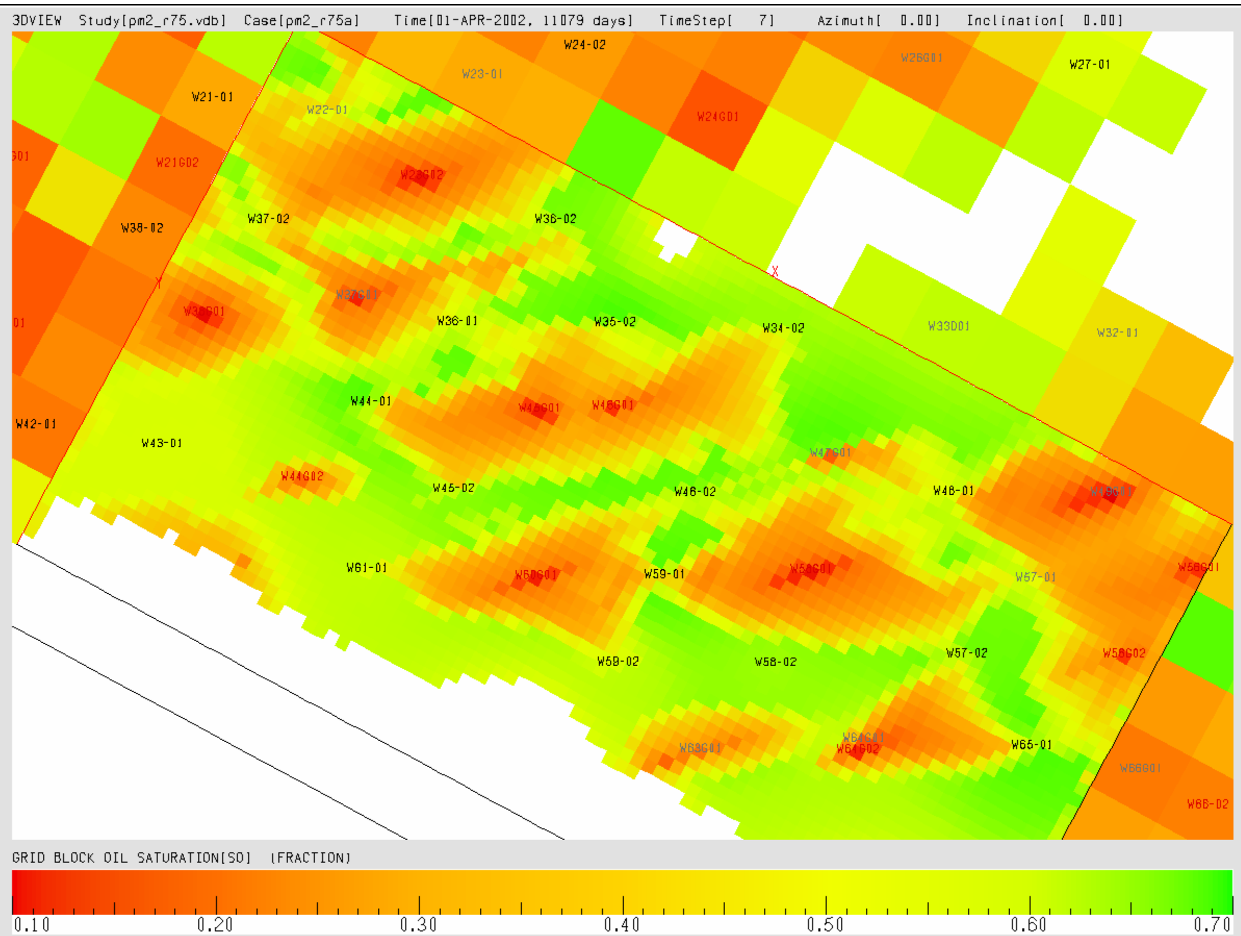

Figure 47. Current pilot model-predicted oil saturation for layer 5 (top of C Sand) at current time.

Project Evolution and Implementation

Potential drilling locations and conversion scenarios in the project area were evaluated using the updated and revised pilot area model. Through a series of evaluations, the specific drilling plans evolved to the final Project Phase II plan of drilling two horizontal wells (versus three in the original plan) and three vertical wells (versus one in the original plan). Producer-to-injector conversion plans were finalized without significant changes to the original plan. Decisions to drill horizontal producing well EBU 63-2H and vertical producing wells EBU 44-3 and EBU 46-3, as well as finalizing the plan to convert EBU 37-3H to injection, were all based on model forecasts. The final plan for Phase II is shown in **Figure 48**.

The first evaluation conducted with the model was a comparison of converting EBU 37-3H to injection versus converting EBU 44-1 to injection. Throughout the project, it was recognized that the northwestern end of the pilot area, specifically the area around EBU 37-3H, was in need of additional injection support. Of all pressure buildup measurements obtained in the few years prior to the project and the early years of the project, the lowest measured reservoir pressure was 1900 psi at EBU 43-1. Indeed, EBU 37-3H, drilled for data-gathering purposes as part of Budget

Period 1, was initially planned as an injection well with a different orientation. This plan was later modified, with EBU 37-3H completed as a producer and a second Budget Period 1 data-gathering lateral eliminated. Although Binger Operations believed it was still appropriate to convert EBU 37-3H to injection, the decision was made to defer the conversion until the revised pilot model could be used to evaluate the benefits and compare them with an alternative scenario of converting EBU 44-1.

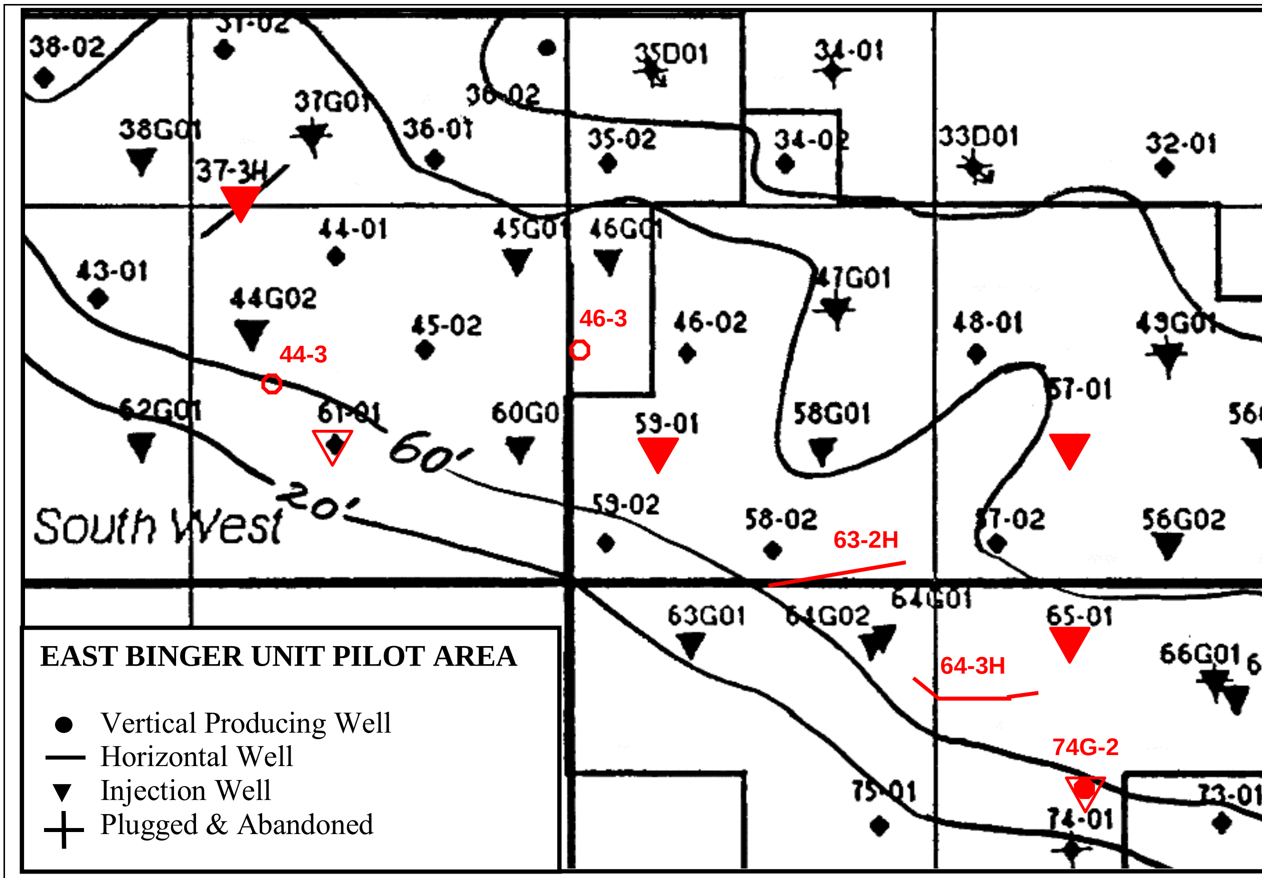

Figure 48. Revised plan for well projects - shown in red – to be completed in Project Phase II (Budget Period 2).

Tabulated results from predictive cases converting EBU 37-3H and (alternatively) EBU 44-1 to injection are presented in **Figure 49**. Although the conversion of EBU 44-1 was projected to provide a quicker investment payout (2.4 years versus 4.0 years) and a higher cumulative cash flow after five years ($422,000 versus $400,000), the predicted long term benefits clearly favored the conversion of EBU 37-3H. The conversion of EBU 37-3H was projected to result in significantly more oil (280,000 bbls versus 120,000 bbls) and NGL (48,000 bbls versus 6,000 bbls) recovery than was the conversion of EBU 44-1. Converting EBU 37-3H was also projected to cost less than converting EBU 44-1, due to the lesser amount of well work required to prepare it for injection as well as the proximity to existing gas injection lines. As shown in **Figure 49**, the incremental net present value of the simulation case with the EBU 37-3H conversion far exceeded that of the case with the EBU 44-1 conversion. Based on these results, the decision was made to convert EBU 37-3H.

East Binger Unit
Reservoir Simulation Study
Results of Predictive Cases

Case	Description	Incremental Gross Reserves: Oil (MBO)	NGL (Mbbls)	Methane (MMcf)	BOE (Mbbls)	Capital Investment ($M)	5-Year Cumulative Cash Flow ($M)	Investment Payout (Years)	Incremental Net Present Value: Undisc. ($M)	10% Disc ($M)	20% Disc ($M)
1	Convert 37-3H	280	48	(813)	193	$ 30	$ 400	4.0	1,042	807	365
2	Convert 44-1	120	6	(766)	(2)	$ 90	$ 422	2.4	(1,101)	(88)	62

Product Prices for Economic Evaluations

Oil	$25.00 / bbl (flat)
NGL	$17.00 / bbl (flat)
Gas	$3.00 / mcf (flat)

Figure 49. Comparison of simulation results – injection conversion cases.

A second set of forecast cases was run to evaluate the optimum location for the third horizontal well (second of Phase II). A variety of scenarios was evaluated – horizontal and vertical wells, with and without injection well sidetracks in certain cases. Locations of the wells evaluated are shown in **Figure 50**, and results are tabulated in **Figure 51**.

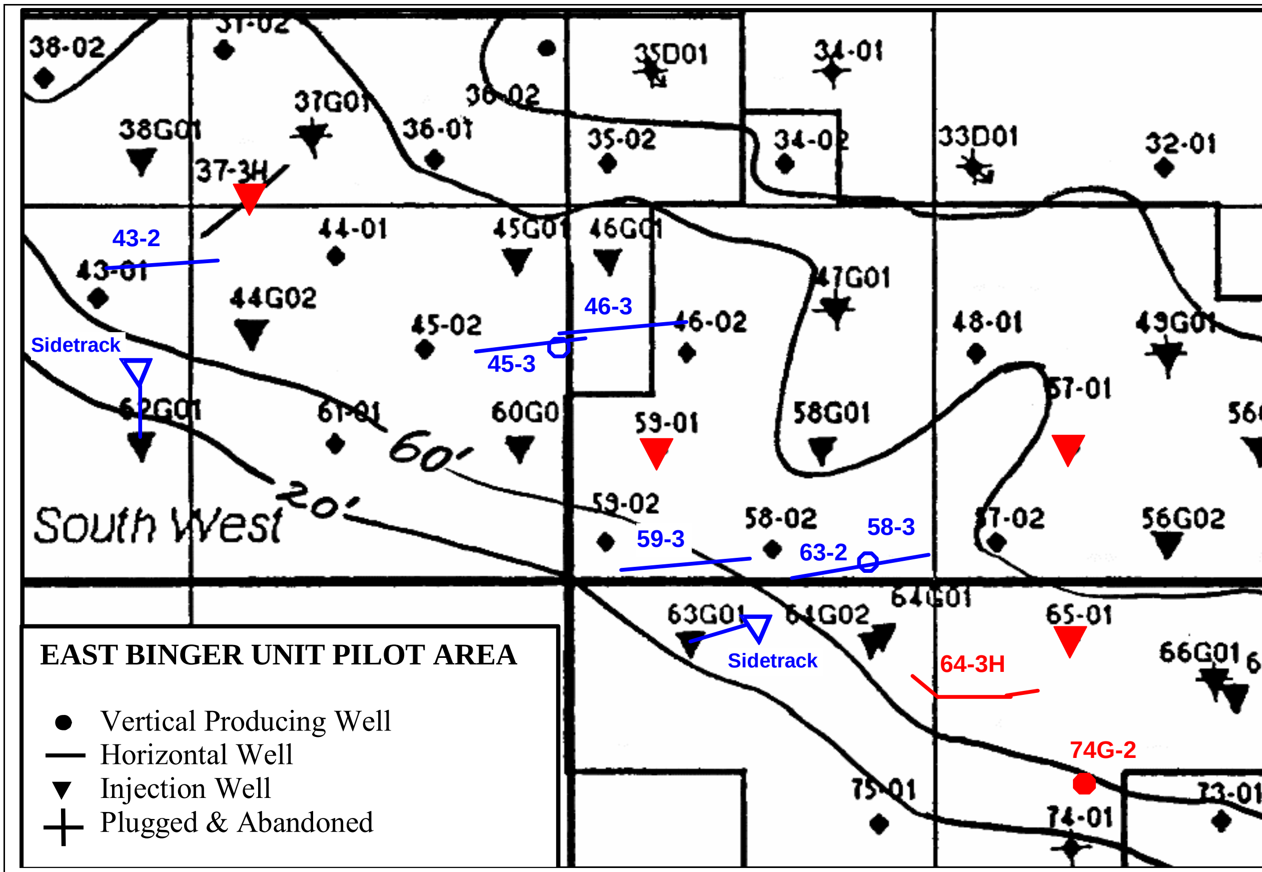

Figure 50. Potential drilling locations – shown in blue – evaluated with the simulation model. Items in red were completed.

East Binger Unit
Reservoir Simulation Study
Results of Predictive Cases

Case	Description	Incremental Gross Reserves Oil (MBO)	NGL (Mbbls)	Methane (MMcf)	BOE (Mbbls)	Capital Investment ($M)	5-Year Cumulative Cash Flow ($M)	Investment Payout (Years)	Incremental Net Present Value Undisc. ($M)	10% Disc ($M)	20% Disc ($M)
3c	Add 45-3H	(12)	69	123	77	$ 1,800	$ 397	1.7	$ (1,287)	$ (437)	$ (121)
3e	Add 46-3H	3	155	636	264	$ 1,800	$ 1,873	1.3	$ 2,533	$ 1,416	$ 1,095
3f	Add 45-3 (V)	18	94	361	172	$ 850	$ 1,049	1.5	$ 2,082	$ 843	$ 597
4c	Add 43-2H, ST 62G-1	75	129	783	334	$ 2,300	$ 935	2.9	$ 2,769	$ 928	$ 353
4d	Add 43-2H	4	117	345	178	$ 1,800	$ 1,399	2.1	$ 2,116	$ 979	$ 631
5c	Add 59-3H, ST 63G-1	77	104	660	291	$ 2,300	$ 977	2.1	$ 1,787	$ 848	$ 487
6c	Add 63-2H, ST 63G-1	140	102	665	353	$ 2,300	$ 1,794	1.8	$ 3,030	$ 1,580	$ 1,034
6d	Add 63-2H	31	186	878	364	$ 1,800	$ 2,281	1.5	$ 3,991	$ 2,143	$ 1,487
6e	Add 58-3(V), ST 63G-1	183	168	770	479	$ 1,350	$ 2,433	1.7	$ 6,937	$ 3,011	$ 1,805

H = Horizontal
(V) = Vertical
ST = Sidetrack

Product Prices for Economic Evaluations

Oil	$25.00 / bbl (flat)
NGL	$17.00 / bbl (flat)
Gas	$3.00 / mcf (flat)

Figure 51. Comparison of simulation results – infill drilling cases.

Initially, four horizontal well locations were evaluated: EBU 45-3H (case 3c), EBU 43-2H (case 4c, with a sidetrack of EBU 62G-1), EBU 59-3H (case 5c, with a sidetrack of EBU 63G-1) and EBU 63-2H (case 6c, also with a sidetrack of EBU 63G-1). EBU 44-3H, shown in **Figure 38** and originally planned as a development well in Budget Period 2, was eliminated from consideration based on predicted sweep in the area in which it was planned. This change in predicted sweep discussed in the previous section of this report.

As shown in the results table (**Figure 51**), case 6c was the best of these four development cases. It had the highest incremental oil and oil-equivalent (BOE) recovery, nearly the quickest payout, and the highest incremental net present value.

Most surprising among the model results was the relatively low projected recovery for EBU 45-3H, which had been planned as the next well to be drilled. The model projected incremental NGL and methane recovery, but a loss of oil recovery associated with the drilling of this well. The primary cause of this loss in oil recovery is a reduction in oil recovery at EBU 45-2, directly west of the planned location of EBU 45-3H. This is caused by increased gas influx from the injection wells to the north, EBU 45G-1 and EBU 46G-1, associated with the high drawdown of horizontal well EBU 45-3H. This northern gas is less extensive near EBU 46-2, so another case – case 6e – was run with this horizontal well moved slightly to the east. As shown in the table, the results of this case are much better, and on par with the other horizontal cases.

Additional cases (4d and 6d) were run to evaluate the value of the injection well sidetracks. The injection well sidetracks were initially included in many of these cases because EBU 62G-1 and EBU 63G-1 are located in thin pay and inject little to no gas in their present locations. It appears that these sidetracks are not justified without improvements in horizontal well productivity.

Case 4d includes the drilling of EBU 43-2H, like case 4c, but without the sidetrack of injection well EBU 62G-1. As shown in **Figure 51**, the lack of injection support from the sidetracked well leads to significantly less recovery, but the reduced capital cost improves the overall economics – quicker payout, higher 5-year cash flow, and higher discounted net present value.

Case 6d is a corollary to case 6c. Both include the drilling of EBU 63-2H. Case 6c includes a sidetrack of EBU 63G-1, while case 6d does not. Here the results are somewhat different than the case 4d versus case 4c comparison. Without the injection support from EBU 63G-1, there is significantly less oil recovery, but significantly *more* NGL and methane recovery, due to the higher formation gas production. On an equivalent barrel (BOE) basis, the recoveries are similar. With less capital required without the sidetrack, the economics clearly favor case 6d.

Results from the comparative cases involving injection well sidetracks suggest sidetracking these edge wells to support production from new horizontal wells is not justified – based on the model-projected productivity of the horizontal wells. This productivity was based on the productivity of horizontal wells drilled to date.

Finally, two cases (3f and 6e) were run to compare vertical infill wells with horizontal infill wells. Results suggested that unless horizontal well productivity could be improved (or sustained at a high level for a longer period of time through increased pressure support), or the cost of horizontal wells reduced, the additional cost and risk of horizontal wells is not justified. The first comparison is case 3f with cases 3c and 3e. Case 3f includes the drilling of EBU 45-3 as a vertical infill well, located approximately half way between the mid-points of the laterals of cases 3c (EBU 45-3H) and 3e (EBU 46-3H). Projected incremental recovery is approximately the average of the projected incremental recoveries of the two horizontal cases. Capital cost is less than half that of the horizontal well cases, resulting in an improved discounted net present value. The payout is similar because the vertical well does not have the high initial rate.

The second vertical versus horizontal comparison is case 6e versus case 6c. Here the vertical well case outperforms the horizontal well case by all measures – higher projected recovery, lower initial investment, quicker payout, and of course higher net present values. These projections were based on horizontal well productivities of the first two horizontal wells. With only two horizontal wells drilled to date, it was felt that more data was required before concluding that they are not justified in this field. Additional steps were taken on the third horizontal well in an effort to enhance productivity, but as will be discussed later, the performance did not improved significantly. Thus, it was ultimately determined that this preliminary conclusion – that horizontal wells are not justified in this setting – was valid.

Additional reservoir simulation work was later conducted to evaluate the benefits of a number of potential vertical infill drilling locations within the pilot area. **Figure 52** shows the locations evaluated, and **Figure 53** has a table of the results.

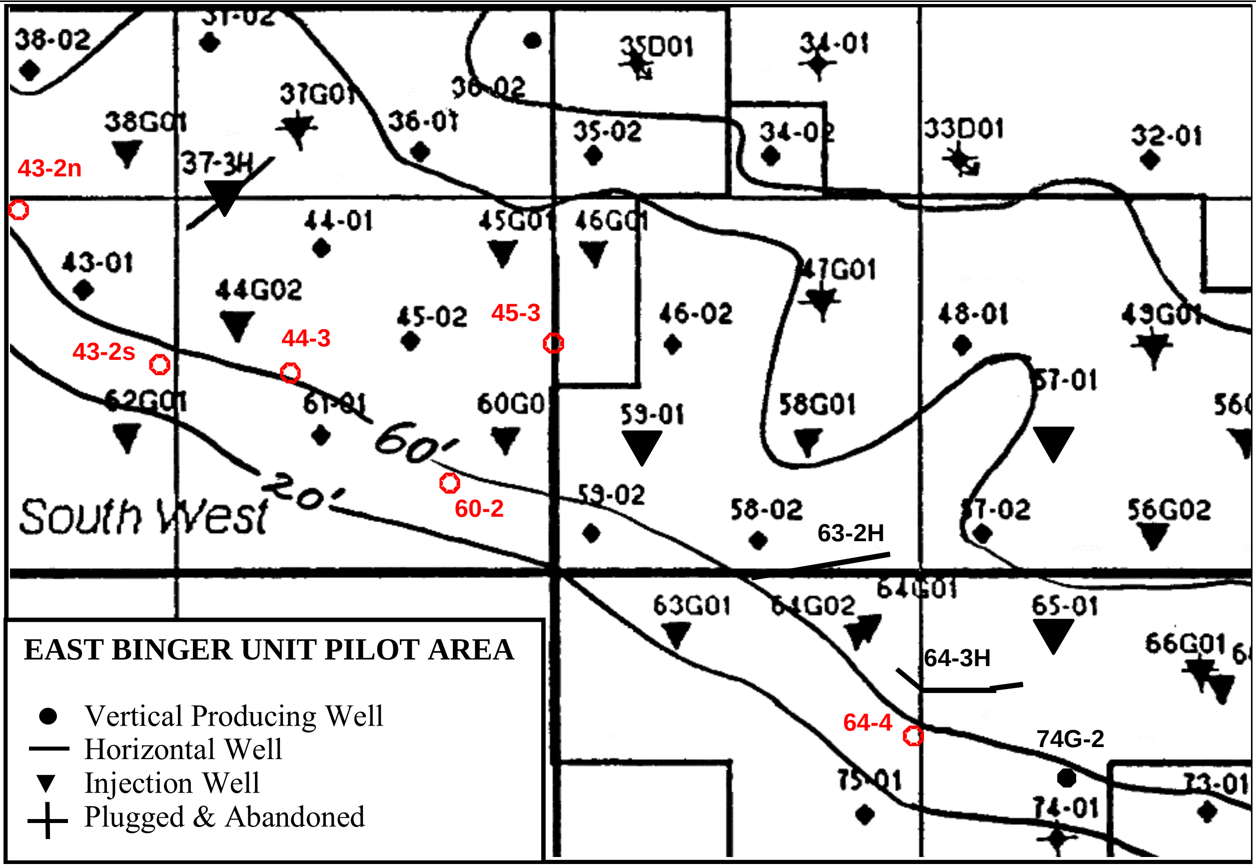

Figure 52. Infill drilling locations (open circles) evaluated with the simulation model.

East Binger Unit
Reservoir Simulation Study
Predicted Recoveries of Infill Wells

	Recovery After 10 Years			
Infill Location	**Oil (MBO)**	**NGL (Mbbls)**	**Methane (MMcf)**	**BOE (MBOE)**
EBU 43-2n *	23	57	213	116
EBU 43-2s	59	28	110	105
EBU 44-3	98	114	444	286
EBU 45-3	62	99	375	224
EBU 60-2	31	45	164	103
EBU 64-4	162	95	374	319

* Projection questionable due to grid effects.

Figure 53. Simulation-predicted recoveries of infill drilling locations.

The highest projected recoveries were for wells EBU 64-4 (162 MBO, 319 MBOE), EBU 44-3 (98 MBO, 286 MBOE), and EBU 45-3 (62 MBO, 224 MBOE). However, the model also projected losses at offset wells if these locations were drilled. With the drilling of EBU 64-4, offset horizontal well EBU 64-3H was projected to lose 100 MBO of recovery. With other potential wells, including EBU 44-3 and EBU 46-3, the offset losses are projected to be only about 10 MBO. Also, as footnoted in the table in **Figure 53**, the projection for EBU 43-2n was thought to be less reliable than the projections for the other wells due to grid effects. This location is on the edge of the fine grid area of the model. For a view of this gridding, see **Figure 47**.

Based on these results, EBU 44-3 and EBU 45-3 were added to the project. Due to surface issues, the locations were moved slightly (compare **Figure 52** with **Figure 48**). The location of EBU 45-3 had to be moved across a section line and will be drilled as EBU 46-3.

Ultimately, the following field projects were completed in Project Phase II:

- EBU 64-3H and 63-2H were drilled and completed as a horizontal producing wells,
- EBU 74-2, 44-3, and 46-3 were drilled and completed as vertical producing wells,
- EBU 57-1, 59-1, 65-2, and 37-3H were converted from producing to injection wells, and
- additional compression was added at the NMF to increase injection capacity.

EBU 74-2 was planned as an injection well, but another well – EBU 65-2 – was drilled in the area early in Budget Period 3 and subsequently converted to injection. This will be discussed later in this report.

The conversion of EBU 61-1 was deferred and ultimately removed from the project due to changes in the locations of drill wells.

For the most part, the field projects were implemented as planned, reasonably close to estimated cost. The most significant exception was EBU 64-3H, the first horizontal well drilled in Phase II and second overall. The drilling and completion of EBU 64-3H cost approximately 60% more than expected, mostly due to drilling problems necessitating a sidetrack.

After drilling into the pay zone, with the wellbore at about 64° inclination, a bit trip was made. A new directional mud motor was also run as the one being pulled had been in the hole for the entire curve and was near its recommended limit of hours in service. At or shortly after the start of additional drilling, the bend in the newly run directional mud motor released, causing the inclination of the hole to drop back toward vertical. Because the inclination measurement device was located about 65’ behind the bit, this was not recognized until over 100’ of additional hole had been drilled. Where the hole should have been at 71° inclination, it had fallen back to about 56°. It had, therefore, also gone deeper vertically into the section, making it virtually impossible to reach the targeted vertical depth without drilling out of the bottom of the zone.

The hole was subsequently plugged back and sidetracked. The sidetracked hole was successfully drilled and cased, and the lateral was drilled to its desired length. The exact cause of the tool failure was not determined, though service company records indicated the tool was assembled properly.

Each of the new drill wells – the two horizontal wells and the three vertical wells – encountered geology (pay thickness and quality) and reservoir conditions close to what was expected. All initially produced low GOR oil with low nitrogen content in its produced gas. Actual data is presented in the following section of this report.

The two horizontal wells were drilled with similar build radii as EBU 37-3H, the horizontal well drilled in Project Phase I. However, the lengths of the horizontal sections were increased, and the wells were completed differently.

EBU 37-3H contains approximately 1300’ of horizontal section. A liner was run through the curve after drilling the entire section, and the horizontal section was left open hole and hydraulically fracture stimulated (“frac’d”) with approximately 78,500 lbs of 20/40 intermediate strength ceramic proppant (ISP). See **Figure 12**.

EBU 64-3H, the second horizontal drilled and completed, contains over 1900’ of horizontal section. As described above, casing was run through the curve before the horizontal section was drilled. This horizontal section was also left open hole but was frac’d with 175,000 lbs of 20/40 ISP. See **Figure 54**.

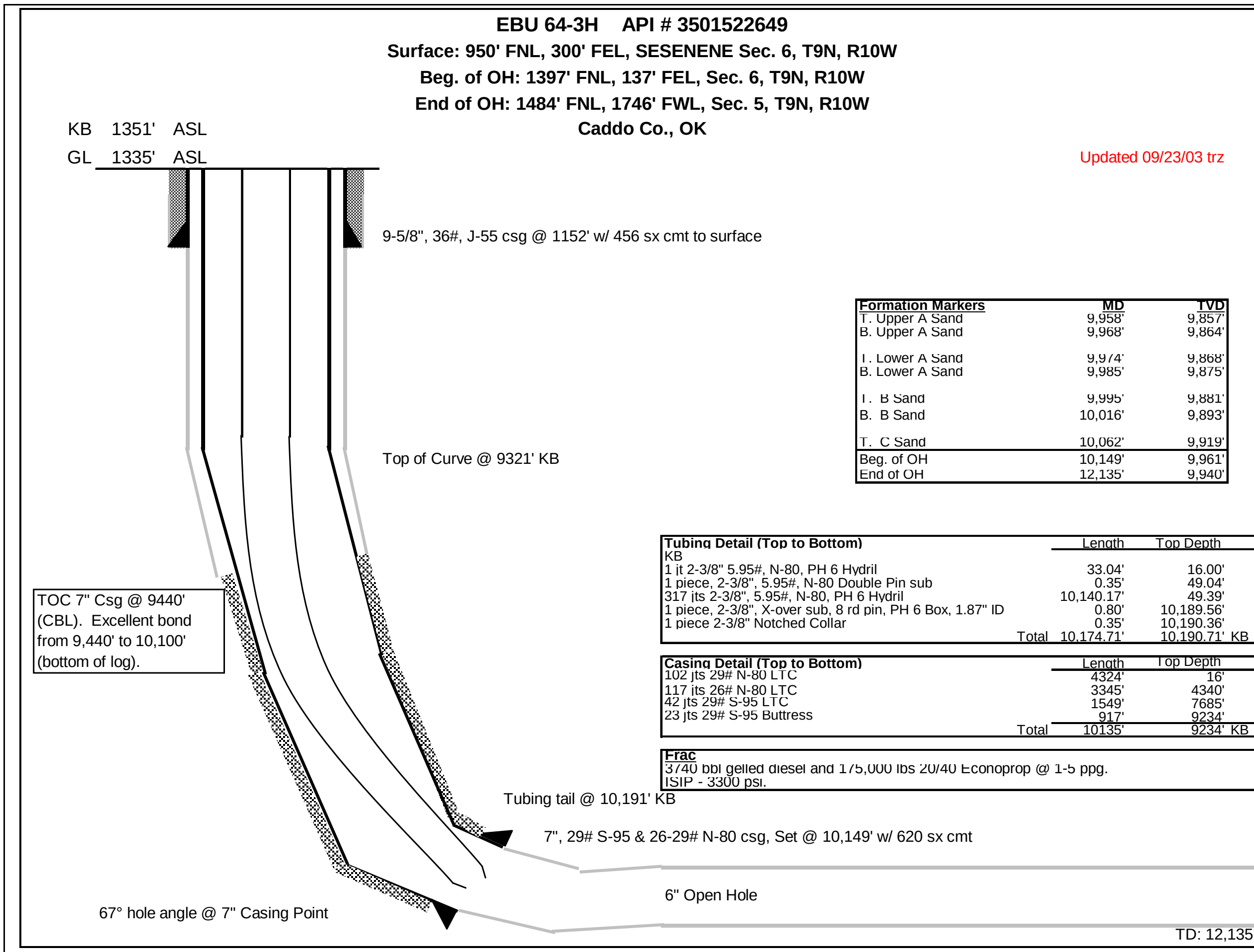

Figure 54. Wellbore schematic for EBU 64-3H.

EBU 63-2H, the third and final horizontal well, contains 2170' of horizontal section. Similar to EBU 64-3H, casing was run through the curve before the horizontal section was drilled. A different stimulation technique was used, however. A liner was run into the open hole, then perforated at four different points with different numbers of perforations and different perforation hole diameters. The well was then fracture stimulated with 210,000 lbs of 20/40 ISP. See **Figure 55**. The liner perforation technique was designed to create multiple fracture initiation points and provide better coverage over the length of the horizontal section. Others had reported success with this technique (Ellis et al, 2000). As will be shown in the next section, the performances of EBU 64-3H and EBU 63-2H have been nearly identical.

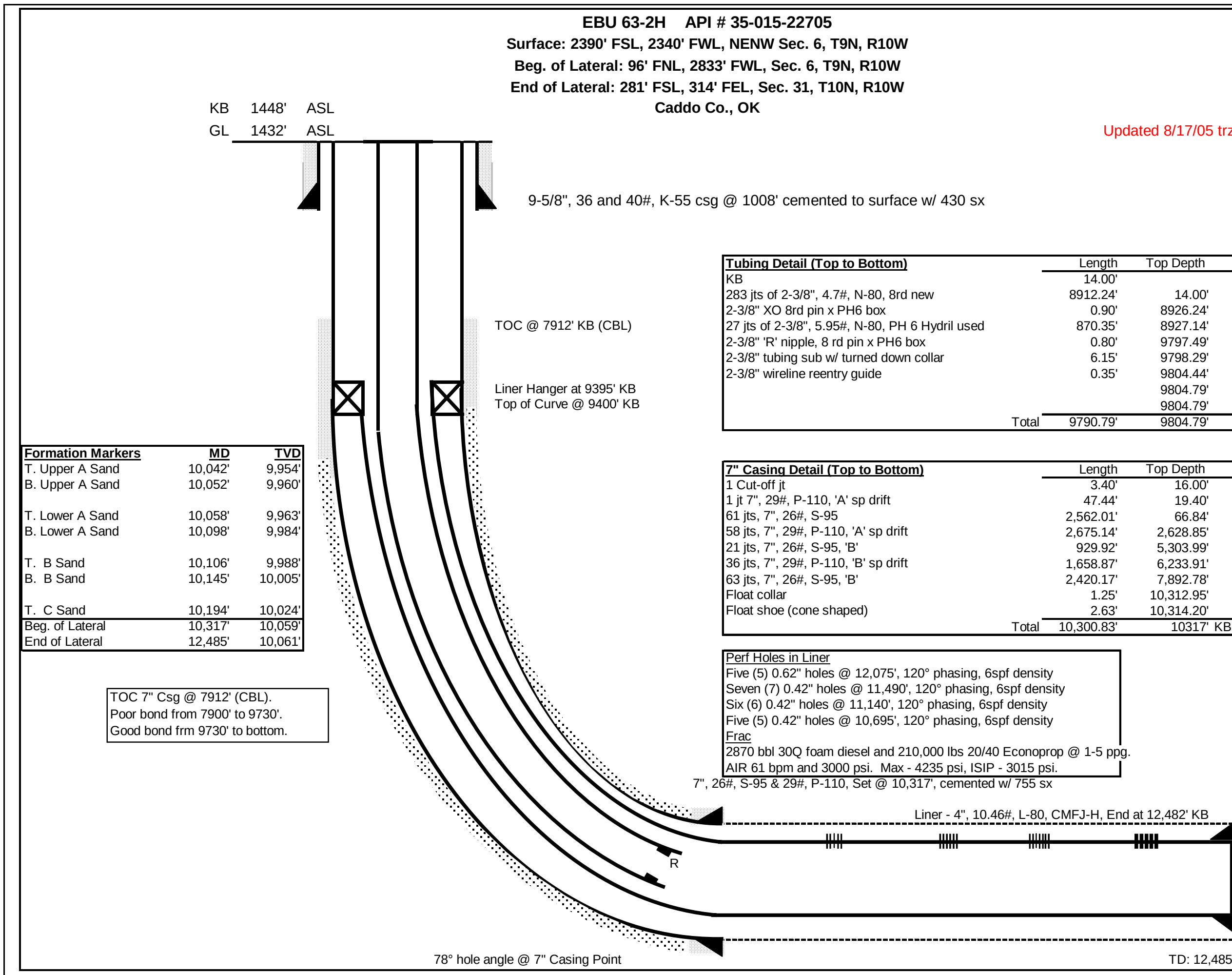

Figure 55. Wellbore schematic for EBU 63-2H.

The three vertical wells were also hydraulically fracture stimulated (as was every other East Binger well drilled through the field's history). EBU 74-2 encountered 45' of Marchand C Sand net pay and was frac'd with 95,000 lbs of 18/40 ISP. EBU 44-3 encountered 66' of Marchand C Sand net pay and was frac'd with 114,000 lbs of 18/40 ISP. And EBU 46-3 encountered 80' of Marchand C Sand net pay and was frac'd with 236,000 lbs of 18/40 ISP.

Project Monitoring

The primary activities of Project Phase II were the continued reservoir simulation and project implementation activities. A third component was the initiation of project monitoring, primarily through frequent sampling of produced gas and analysis for nitrogen content. Injection profiles had initially been thought to be an important component; however, with the revised understanding of fluid flow discussed previously, their importance and significance was deemed minor at best.

In addition for allowing for an overall determination of nitrogen recycle in the project area, the analysis of produced gas samples provided valuable data in two aspects of the project. First, changes in nitrogen contents in producing wells around EBU 37-3H, the horizontal well drilled in Project Phase I, were consistent with the revised understanding of dominant reservoir fluid flow mechanisms and therefore provided confirmation of that fluid flow model.

Figure 56 shows graphical trends of produced gas nitrogen contents (“N2 cuts”) for four producing wells near EBU 37-3H. The four wells are EBU 36-1 to the east (see **Figure 57**), EBU 37-2 to the north, EBU 43-1 to the southwest, and EBU 44-1 to the southeast. Changes in the long-term trends coincident with activities at EBU 37-3H are observable in each of these four offsetting producers.

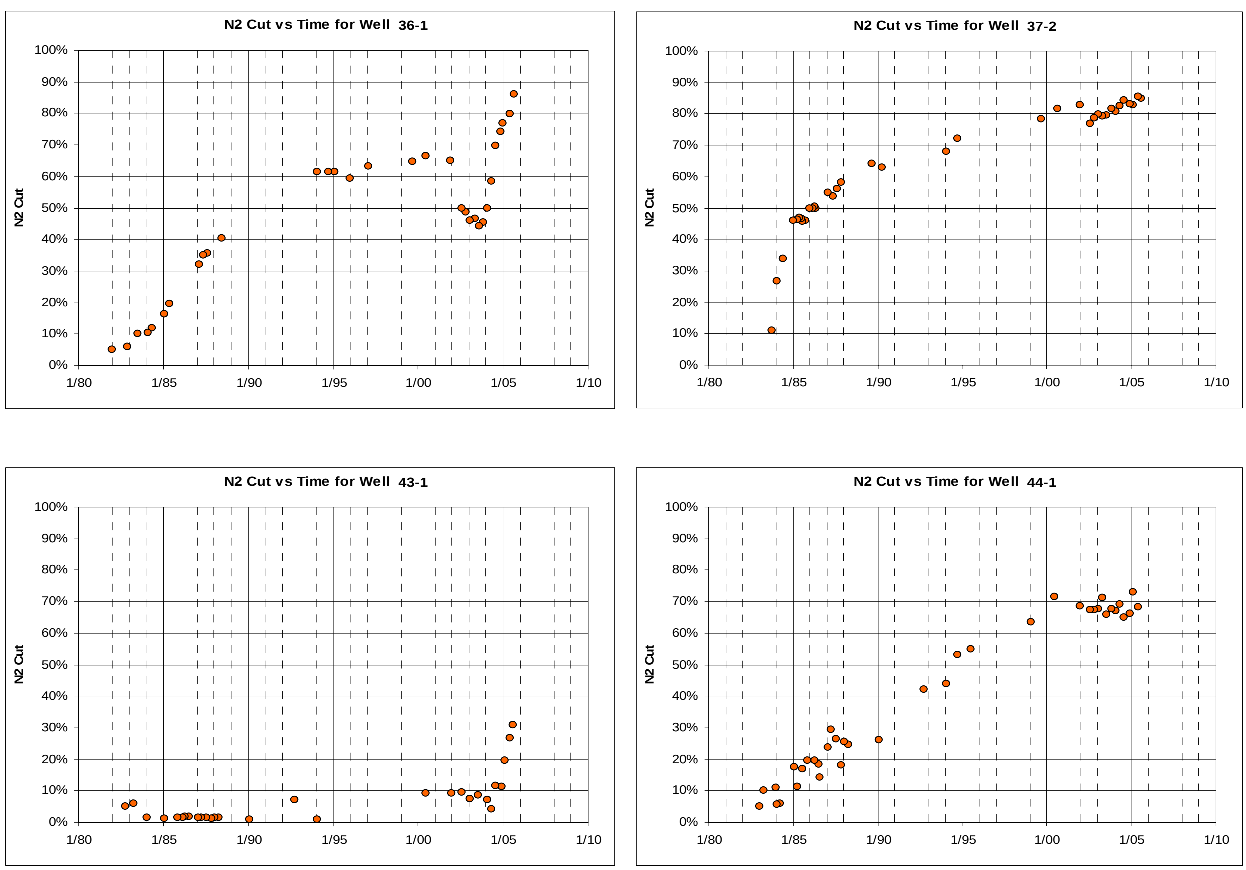

Figure 56. Percent nitrogen in produced gas for four wells near EBU 37-3H.

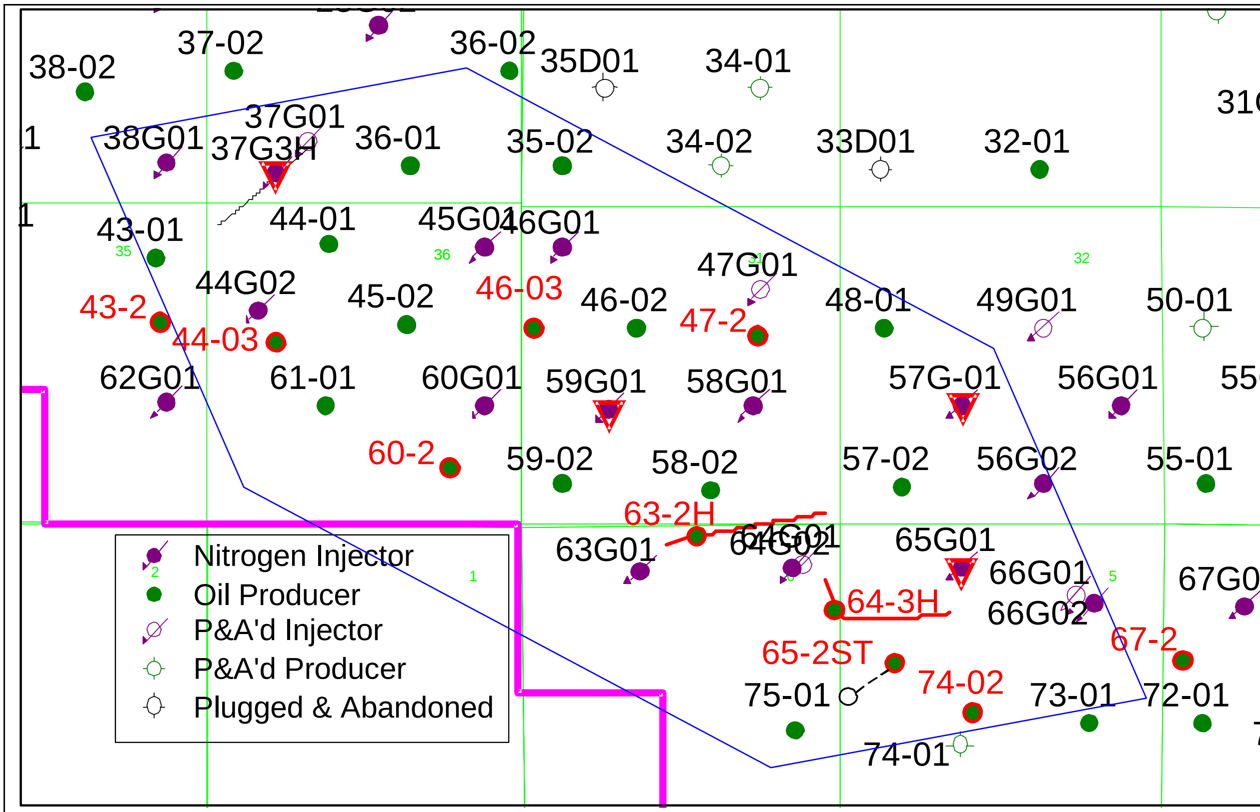

Figure 57. Map of the central portion of the East Binger Unit. Well work implemented in the Project is highlighted in red; the Pilot Area is indicated by the blue polygon.

The most significant impacts occurred at EBU 36-1. After EBU 37-3H was put on production in late 2001, the N2 cut at EBU 36-1 dropped from 65% to 45%, clearly indicating that the primary source of nitrogen at EBU 36-1 was EBU 38G-1 to the west, with that gas now being intercepted by EBU 37-3H. Later, after EBU 37-3H was converted to injection in late 2003, the N2 cut at EBU 36-1 rose rapidly. These changes are consistent with the dominant fluid flow direction being slightly north of east and slightly south of west.

A rapid increase in N2 cut has also occurred at EBU 43-1, delayed approximately nine months after EBU 37-3H was converted to injection, while the N2 cut at EBU 44-1 leveled off. Changes at EBU 37-2 were less dramatic. After dropping slightly with the onset of production at EBU 37-3H, the N2 cut resumed its prior trend.

The second aspect of the project validated by the gas sampling was the presence of areas of unswept oil within the reservoir. Some of the wells drilled during the project implementation penetrated areas with very little nitrogen. EBU 74-2 (8% N2 in produced gas initially), EBU 44-3 (4%), and EBU 46-3 (2%) all proved that there were unswept areas and that there is not an overriding gas cap of nitrogen throughout the reservoir.

Project Phase III (Budget Period 3) – Monitoring, Evaluation, and Additional Drilling

With confidence in a new reservoir characterization, Binger Operations, LLC moved forward into Project Phase III, the focus of which would be continuing project monitoring and evaluation. With the success of the drilling efforts conducted in Project Phase II, additional drilling was also added to the project. In all, five new wells were drilled in and around the project area during Project Phase III. Shown in **Figure 57**, they are EBU 43-2, EBU 47-2, EBU 60-2, EBU 65-2, and EBU 67-2. Results of these drilling efforts are discussed following an overall review of the project performance.

Pilot Area Performance

Overall, the project has proven very successful in improving oil rate and recovery and reducing cycling of injected nitrogen. At the conclusion of the project, significant increases in production were added as a result of the project. Oil rate within the pilot area has more than doubled, and the incremental rate of 259 bopd represents one third of the total EBU production:

	Project Area			Total Unit		
	Without Project	With Project	Increase	Without Project	With Project	Increase
Oil (bpd)	242	501	259 (107%)	518	777	259 (50%)
NGL (bpd)	156	256	100 (64%)	458	558	100 (22%)
Gas (Mcfd)	550	940	390 (71%)	1599	1989	390 (24%)

Production from the new wells in the project area added 301 bopd but was offset by the loss of 42 bopd from wells converted to injection. See
Figure 58 (all wells in pilot area), **Figure 59** (pre-existing wells), and **Figure 60** (new wells).

Figure 60 shows the component rate streams of various wells and packages of wells that have been brought on line throughout the project. The oil rate from the new wells increase approximately 75 bopd over the last six months of the project, driven largely by increases at two wells, EBU 46-3 and EBU 64-3H. EBU 46-3 increased following a period of lower than expected production associated with poor wellbore hydraulics, which was resolved by installing and lining out a rod pump. The increase at EBU 64-3H is a classical injection response; in addition to the increase in oil rate (from 40 to 60 bopd over a seven month period), the associated hydrocarbon gas has caused the overall nitrogen content in the well's produced gas to drop from 52% to 31%.

Gas cycling, though increasing, dropped far below pre-project levels and remains well below them, as shown in
Figure 58. Injection was impacted by problems at the nitrogen facility, but has leveled off at about 6.3 MMcfd, about 58% higher than before the project began. Meanwhile, total nitrogen produced from the pilot area has declined from 2.9 MMcfd (4.2 MMcfd total gas with a nitrogen content of 69%) to 2.5 MMcfd (4.3 MMcfd total gas with a nitrogen content of 59%).

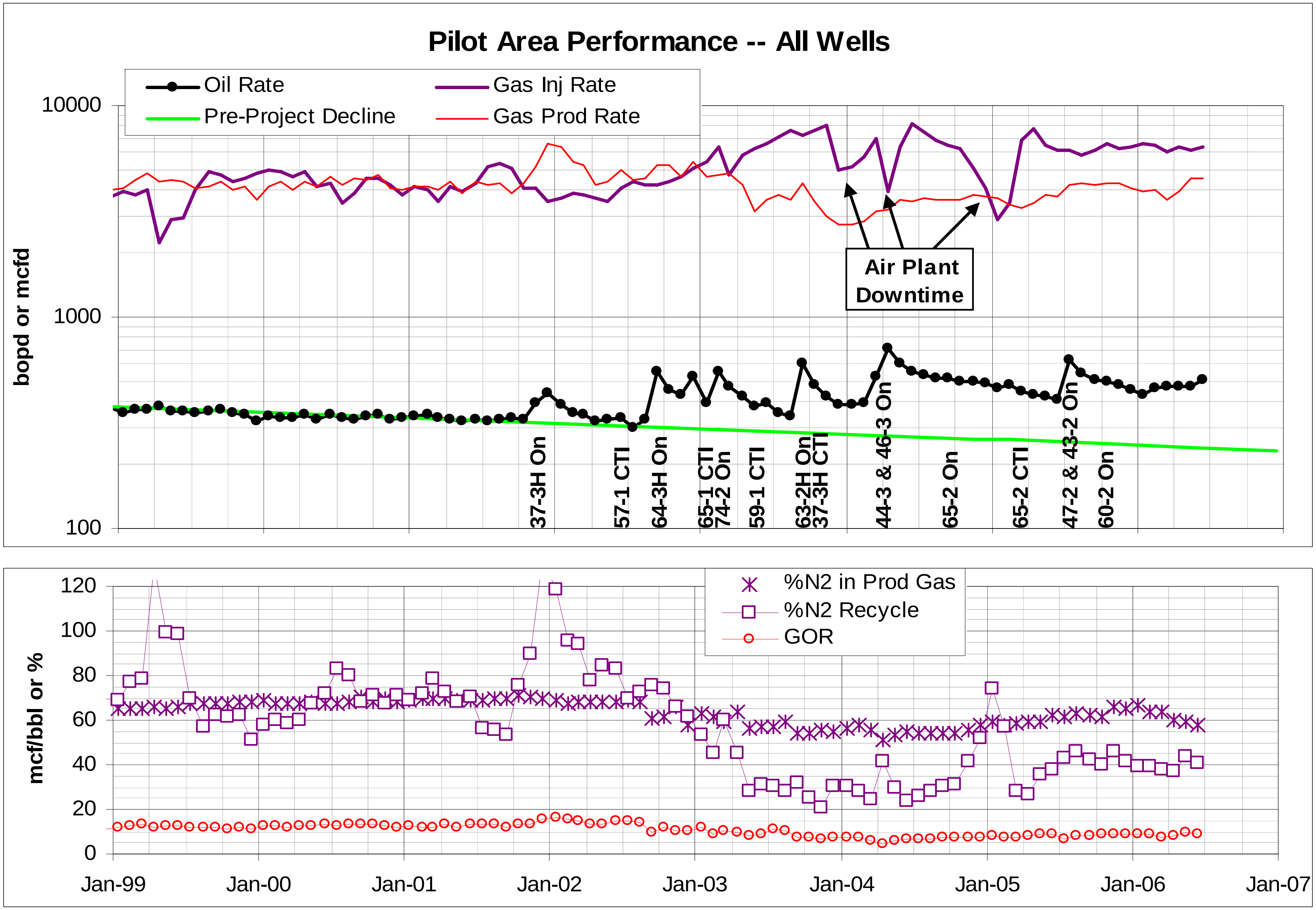

Figure 58. Production data for all wells in the pilot area.

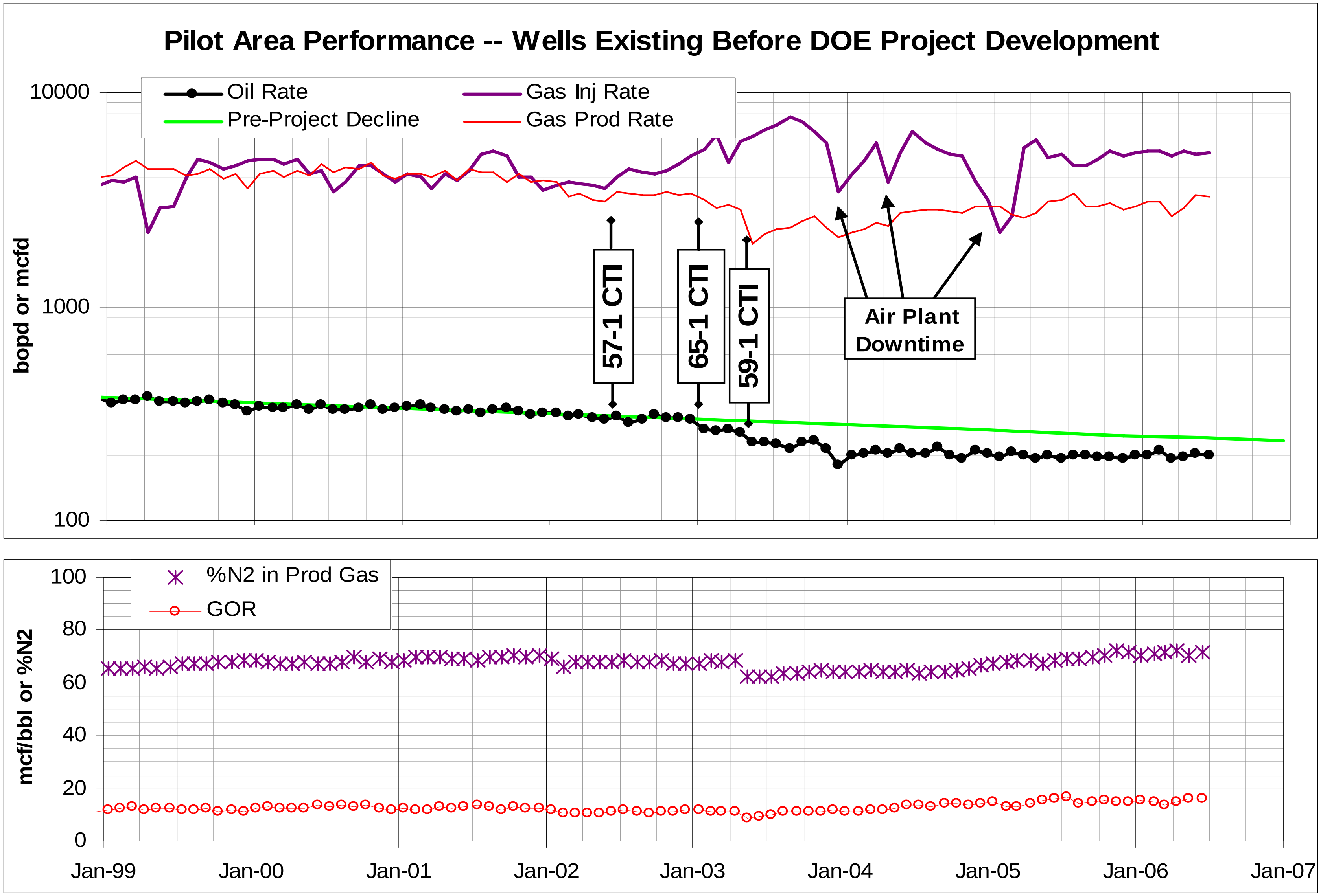

Figure 59. Production data for wells in the pilot area that existed before DOE Project development.

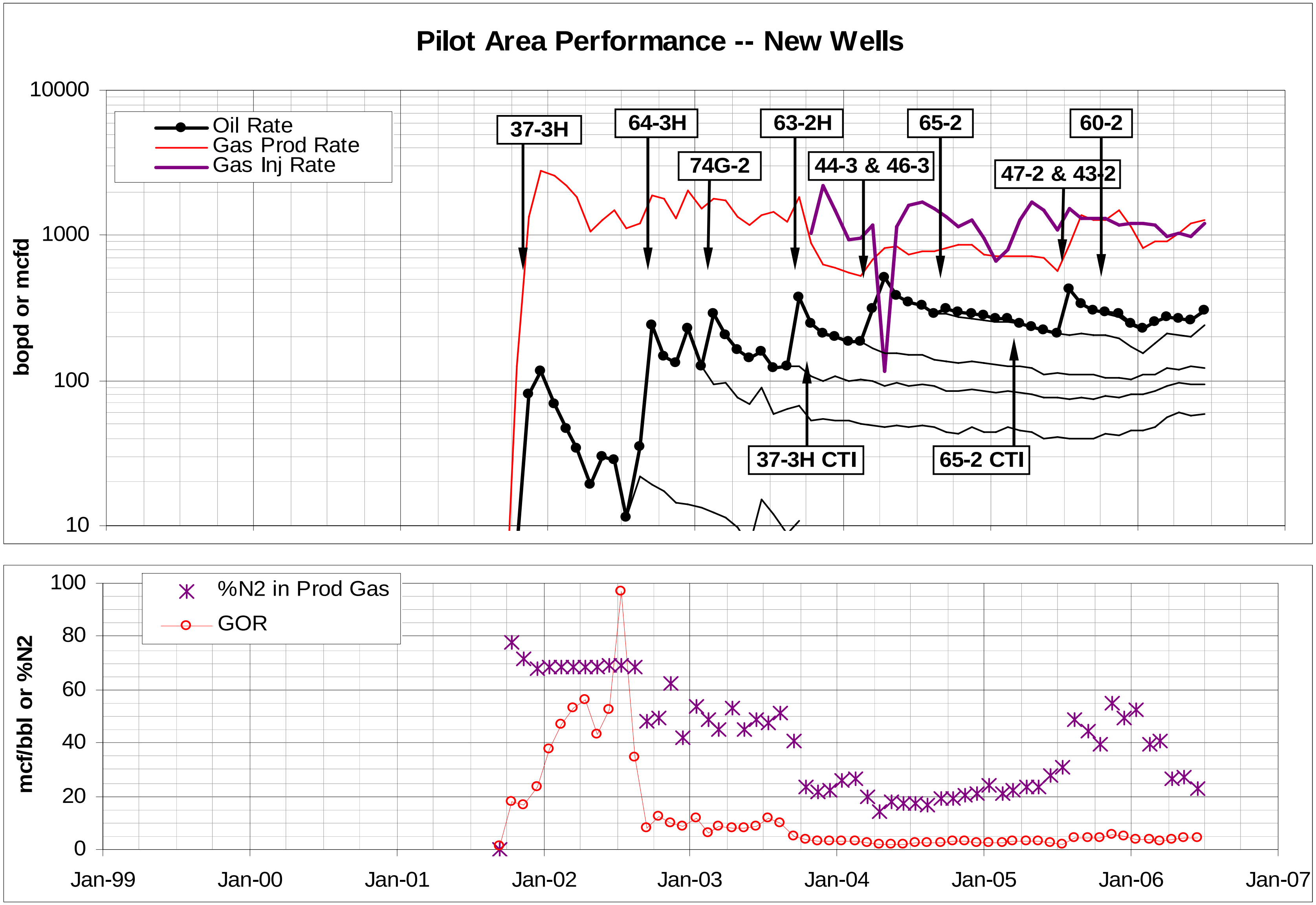

Figure 60. Production data for new wells in the pilot area.

As shown in the table that follows, this represents a total change in gas recycle from 72% prior to development to 40% at the conclusion of the project. Gas production and gas nitrogen content will continue rise, but this clearly represents an improvement in flood performance.

Pilot Area Gas Recycle

	[A] Total Gas Production Rate (MMcfd)	[B] Percent Nitrogen (%)	[C] = [A]*[B] Nitrogen Production Rate (MMcfd)	[D] Nitrogen Injection Rate (MMcfd)	[C] / [D] Percent Recycle (%)
Pre-Development Baseline (1H 2001)	4.2	69	2.9	4.0	72
First Quarter 2002	5.6	68	3.8	3.7	103
Second Quarter 2002	4.5	68	3.0	3.7	82
Third Quarter 2002	4.7	66	3.0	4.3	73
Fourth Quarter 2002	5.1	62	3.1	4.7	67
First Quarter 2003	4.6	61	2.8	5.4	52
Second Quarter 2003	3.6	59	2.1	6.2	34
Third Quarter 2003	3.9	57	2.2	7.3	30
Fourth Quarter 2003	3.1	55	1.7	6.9	25
First Quarter 2004	2.9	56	1.6	6.0	27
Second Quarter 2004	3.4	53	1.8	6.2	29
Third Quarter 2004	3.6	54	1.9	7.0	28
Fourth Quarter 2004	3.7	56	2.1	5.1 *	40
First Quarter 2005	3.4	58	2.0	4.4 *	46
Second Quarter 2005	3.7	60	2.2	6.8	33
Third Quarter 2005	4.3	62	2.6	6.1	44
Fourth Quarter 2005	4.2	64	2.7	6.4	42
First Quarter 2006	3.8	65	2.5	6.4	39
Second Quarter 2006	4.3	59	2.5	6.3	40

* Plant problems limited the supply of nitrogen for injection from November 2004 through February 2005.

Significant oil, NGL, and gas reserves have been added by the project. Through June 2006, the end of the project, development work has added incremental production of 298,000 barrels of oil, 136,000 barrels of NGLs, and 547,000 MCF of residue gas. Based on the pre-project decline and the rate at the end of the reporting period, the project will added ultimate reserves of 1,900,000 barrels of oil reserves, 800,000 barrels of NGL reserves, and 3,100,000 MCF of residue gas reserves. See **Figure 61**.

Horizontal vs. Vertical Well Performance

A secondary aspect of Pilot Area performance monitoring is the comparison of the performances of horizontal wells to vertical wells. **Figure 62** is a plot of the rate performances of the new wells drilled in the project, excluding EBU 37-3H, the horizontal well drilled in Budget Period 1, and EBU 43-2 and EBU 60-2, two recently completed vertical wells. As discussed previously in the review of EBU 37-3H and below, these three wells were drilled in areas with much higher gas saturation. All three have been converted to injection.

Comparisons of wells in similar reservoir environments – thickness and gas saturation – show that vertical wells have performed nearly as well as the horizontal wells in this setting. **Figure 63** shows the averages of the following horizontal and vertical wells:

Well	Net Pay	Average GOR & %N2 @ 6 - 9 Months (reflect gas saturation)	Average GOR & %N2 @ 15 - 18 Months (reflect gas saturation)
Horizontal			
EBU 63-2H	70' - 75'	4.3 Mcf/bbl & 21%	4.9 Mcf/bbl & 24%
EBU 64-3H	55' - 60'	5.6 Mcf/bbl & 17%	3.9 Mcf/bbl & 29%
Average Horizontal	*65'*	*5.0 Mcf/bbl & 19%*	*4.4 Mcf/bbl & 27%*
Vertical			
EBU 44-3	66'	2.4 Mcf/bbl & 3%	2.9 Mcf/bbl & 4%
EBU 46-3	80'	1.6 Mcf/bbl & 3%	1.3 Mcf/bbl & 4%
EBU 47-2	69'	5.9 Mcf/bbl & 54%	Not there yet
EBU 67-2	62'	11.6 Mcf/bbl & 50%	15.9 Mcf/bbl & 52%
EBU 74-2	45'	1.6 Mcf/bbl & 10%	1.7 Mcf/bbl & 17%
Average Vertical	*63'*	*4.6 Mcf/bbl & 24%*	*5.5 Mcf/bbl & 19%*

Most of the new wells have low GORs and nitrogen contents in produced gas, as indicated above and shown in **Figure 64**. As discussed previously, the relative lack of nitrogen at the infill well locations indicates poor areal sweep. For most new wells, current trends of nitrogen content data suggest it will be years before the nitrogen contents in their produced gas approach the current field average.

The similar performances of vertical and horizontal wells was somewhat surprising, given the growth in horizontal well drilling that has occurred over the past 20 years within the industry. But horizontal wells are not always the most economical choice, and Binger Operations, LLC ("BOL") believes they are not in this setting because of the nature of the reservoir rock and flood pattern employed in the miscible gas flood.

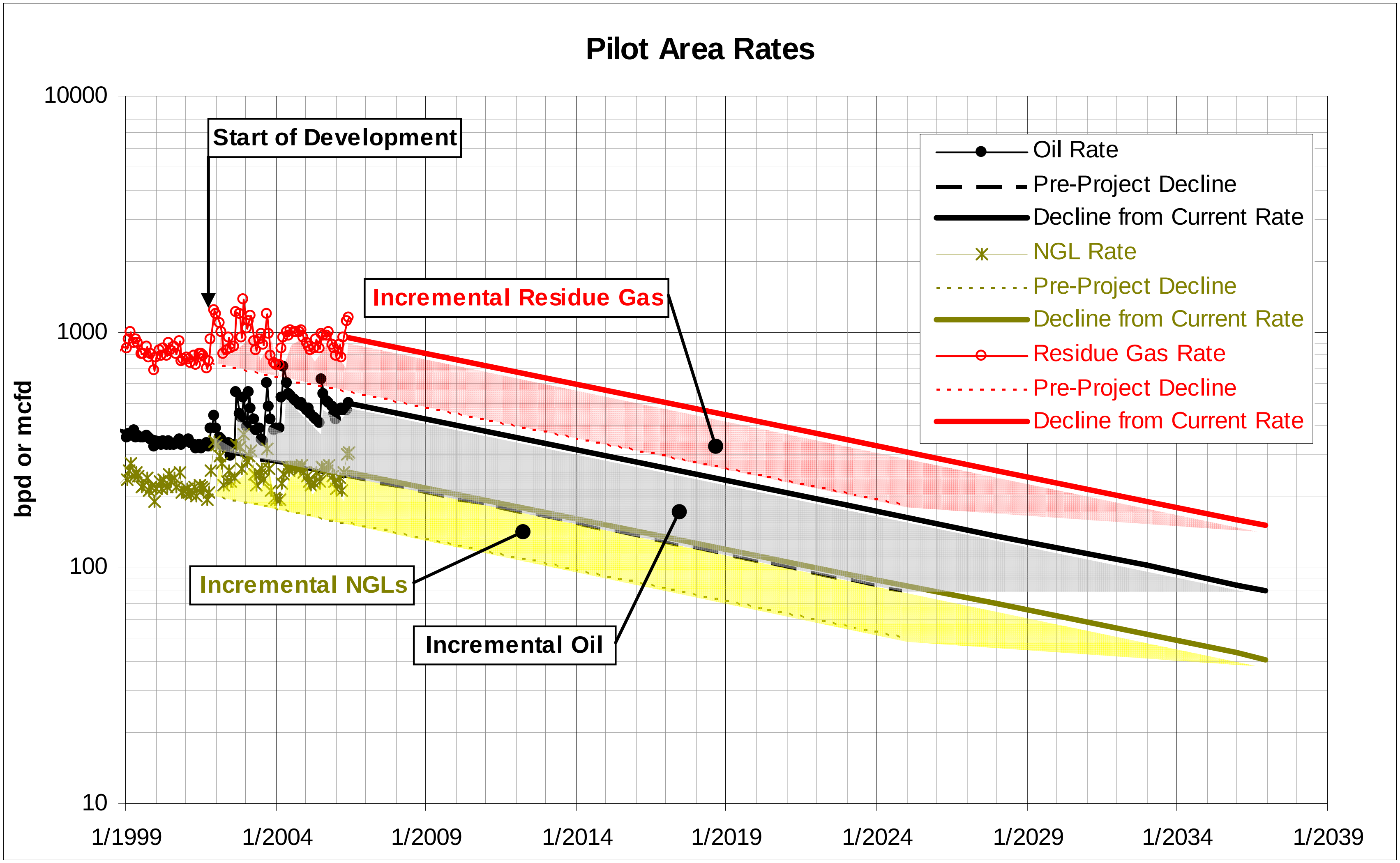

Figure 61. Oil, NGL, and Residue Gas forecasts without and with development. Shaded "wedges" reflect incremental reserves developed with the project.

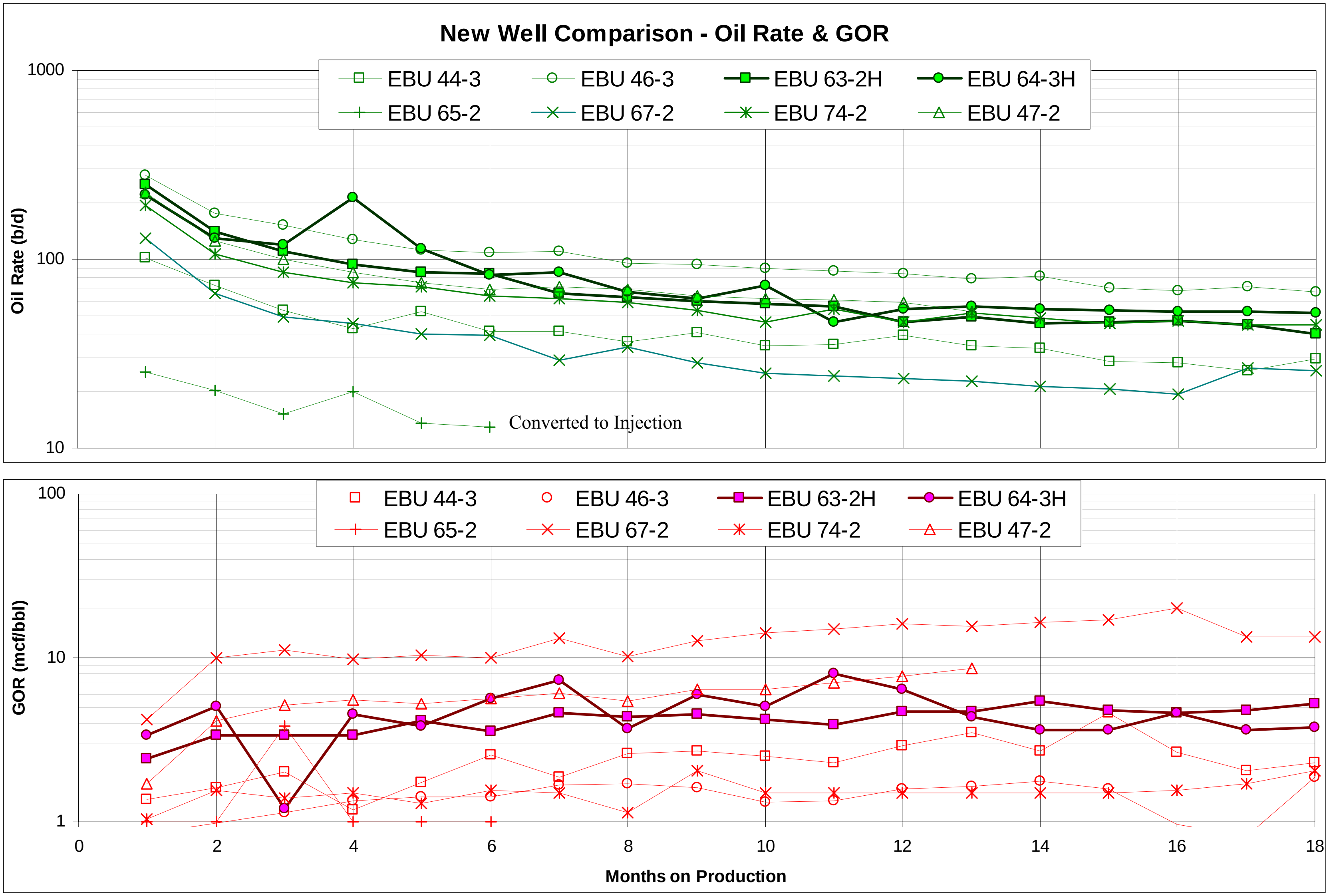

Figure 62. Comparison of production data for recent horizontal and vertical wells in or near the Pilot Area. Horizontal wells are designated with an "H" in their names.

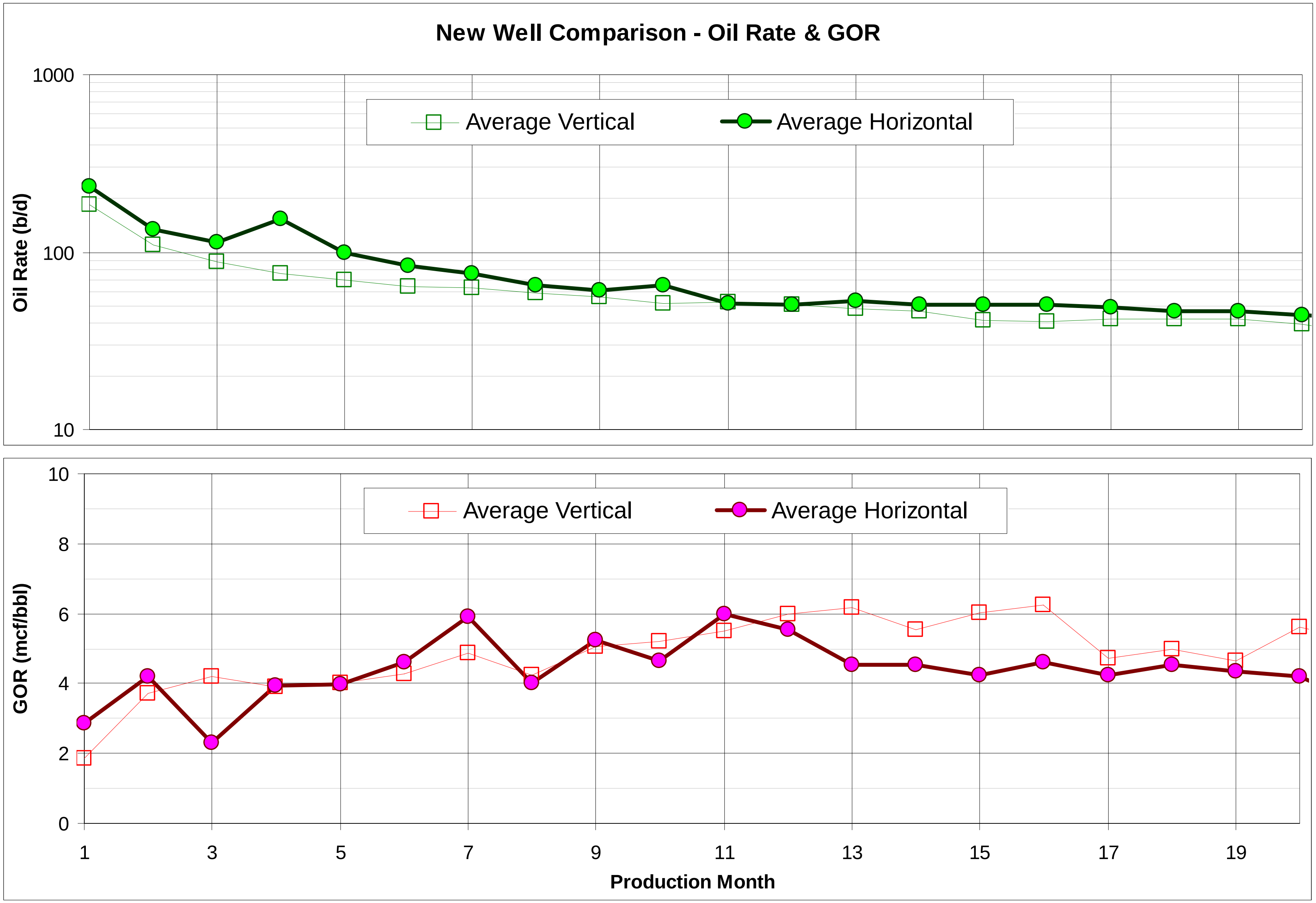

Figure 63. Comparison of average production data for two horizontal and five vertical wells in or near the Pilot Area.

East Binger Unit Pilot Area
Nitrogen Content in Produced Gas
Pilot Area Sample Data

Well	4th Qtr 2001	1st Qtr 2002	2nd Qtr 2002	3rd Qtr 2002	4th Qtr 2002	1st Qtr 2003	2nd Qtr 2003	3rd Qtr 2003	4th Qtr 2003	1st Qtr 2004	2nd Qtr 2004	3rd Qtr 2004	4th Qtr 2004	1st Qtr 2005	2nd Qtr 2005	3rd Qtr 2005	4th Qtr 2005	1st Qtr 2006	2nd Qtr 2006
Producing Wells Existing Prior to Project Implementation Phases II & III																			
35-2	**58%**	-	-	-	61%	-	63%	67%	63%	-	66%	-	67%	-	70%	-	-	68%	**75%**
36-1	**65%**	-	-	50%	49%	46%	47%	44%	45%	50%	58%	70%	74%	77%	80%	86%	-	82%	**83%**
36-2	**25%**	-	-	-	29%	-	20%	-	18%	-	22%	-	18%	-	20%	-	-	23%	**17%**
37-2	**83%**	-	-	77%	79%	80%	79%	80%	81%	81%	83%	84%	83%	83%	85%	85%	-	85%	**86%**
37-3H	**70%**	63%	66%	66%	69%	68%	70%	62%	CTI*	-	-	-	-	-	-	-	-	-	**-**
43-1	**9%**	-	-	10%	-	7%	-	6%	-	4%	4%	12%	11%	20%	27%	31%	-	33%	**32%**
44-1	**69%**	-	-	67%	67%	68%	71%	66%	68%	67%	69%	65%	66%	73%	68%	67%	-	70%	**74%**
45-2	**56%**	-	-	58%	-	57%	59%	60%	61%	62%	64%	64%	65%	64%	67%	67%	-	69%	**69%**
46-2	**62%**	-	-	-	-	68%	64%	61%	62%	64%	62%	62%	61%	63%	66%	66%	-	69%	**68%**
48-1	**83%**	-	-	83%	84%	84%	85%	86%	87%	87%	87%	87%	87%	87%	87%	86%	-	86%	**86%**
57-1	**81%**	-	CTI*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
57-2	**37%**	-	-	41%	39%	41%	45%	47%	40%	37%	39%	40%	43%	45%	45%	48%	-	51%	**52%**
58-2	**8%**	-	-	5%	-	6%	5%	-	-	12%	6%	6%	17%	5%	5%	-	-	6%	**12%**
59-1	**85%**	-	-	-	-	85%	CTI*	-	-	-	-	-	-	-	-	-	-	-	**-**
59-2	**44%**	-	-	-	-	48%	45%	43%	39%	45%	48%	49%	52%	54%	55%	53%	-	56%	**54%**
61-1	**56%**	-	-	-	-	-	56%	-	59%	-	63%	61%	-	60%	-	63%	-	63%	**63%**
65-1	**76%**	-	-	-	-	CTI*	-	-	-	-	-	-	-	-	-	-	-	-	**-**
73-1	**13%**	-	-	21%	-	21%	-	21%	-	19%	-	24%	-	18%	-	11%	-	11%	**-**
Avg	**54%**	**-**	**-**	**48%**	**60%**	**52%**	**55%**	**54%**	**57%**	**48%**	**52%**	**52%**	**54%**	**54%**	**56%**	**60%**	**-**	**55%**	**59%**
New Wells Drilled During Project Implementation Phases II & III																			
43-2	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	91%	93%	CTI*	**-**
44-3	**-**	-	-	-	-	-	-	-	-	4%	3%	3%	3%	4%	4%	4%	-	5%	**6%**
46-3	**-**	-	-	-	-	-	-	-	-	-	2%	3%	4%	4%	-	5%	-	4%	**5%**
47-2	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42%	54%	54%	**54%**
60-2	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	91%	94%	**95%**
63-2H	**-**	-	-	-	-	-	-	16%	19%	22%	20%	19%	23%	26%	20%	18%	-	29%	**21%**
64-3H	**-**	-	-	23%	18%	17%	16%	23%	25%	36%	36%	30%	43%	45%	-	52%	-	18%	**31%**
65-2	**-**	-	-	-	-	-	-	-	-	-	-	25%	22%	CTI*	-	-	-	-	**-**
74-2	**-**	-	-	-	-	8%	10%	10%	10%	19%	16%	16%	18%	24%	25%	28%	-	33%	**33%**
Avg	**-**	**-**	**-**	**23%**	**18%**	**13%**	**13%**	**16%**	**18%**	**20%**	**15%**	**16%**	**19%**	**21%**	**16%**	**34%**	**-**	**34%**	**35%**

*CTI = Conversion to Injection

Figure 64. Pilot Area gas sample data – percent nitrogen in produced gas. Limited data was obtained in the fourth quarter of 2005 due to a sampling problem.

It was previously discussed (in the section titled *"Improved Reservoir Characterization and Understanding of Fluid Flow"*) that fluid flow in the Marchand C Sand is controlled by natural and hydraulic fracturing, with a dominant flow direction of slightly north of east/south of west. In a reservoir with strong directional flow without secondary or tertiary recovery, horizontal wells should be drilled perpendicular to the directional of maximum permeability, to promote fluid flow into the wellbore. If, on the other hand, secondary or tertiary recovery flood techniques are being employed, the optimal flood pattern is a line drive or staggered line drive. Wells of a given type (producers or injectors) should be in a line parallel to the direction of maximum permeability, and horizontal wells should be also be drilled parallel to this line.

This is the case in the Marchand C Sand in the East Binger Unit. Horizontal wells can be economical in a line drive flood if the additional cost of drilling leads to higher production rates or lower completion costs. However, if the horizontal well must be hydraulically fracture stimulated to be as productive as a vertical well in the same setting, the likelihood of them being economically justified diminishes significantly, due to the high cost of fracture treatments. Hydraulic fractures generally follow the same trend as natural fractures – in the case of a horizontal well drilled parallel to this direction of maximum permeability (controlled by the fractures), the hydraulic fracture treatment would be a longitudinal fracture; that is, it would be in line with the horizontal wellbore, and though it might cover more area than a fracture treatment in a vertical wellbore, it would have a similar orientation. In summary, where a) both vertical and horizontal wells must be fracture stimulated to obtain commercially productive rates, b) directional permeability exists, and c) secondary or tertiary flood operations are being employed, it will be very difficult to economically justify drilling horizontal wells. BOL believes this is the case in the EBU.

Additional Drilling Activities

Five more wells were drilled in and around the project area in during Budget Period 3. Shown on the map in **Figure 57**, the five new wells are EBU 43-2, EBU 47-2, EBU 60-2, EBU 65-2, and EBU 67-2. Unfortunately, geologic/reservoir success was not as high, as three of the wells penetrated rock with unexpectedly low thickness or high gas saturation. As shown in the table above, EBU 47-2 and EBU 67-2 encountered partially swept rock, with higher GORs and N2 cuts than previous infill wells, but both were still very successful. The unexpectedly poor results came in EBU 65-2, EBU 43-2, and EBU 60-2.

The original wellbore of EBU 65-2 drifted to the southwest from the surface location to its location at total depth, and encountered low net pay. **Figure 57** shows the location (open circle) of the well at depth. Located between EBU 64-3H and EBU 75-1, it was expected to encounter 40' to 45' of net pay, but as shown in **Figure 65**, the Marchand C Sand is actually a combination of sand packages, and only the top sand lens, with 5' of net pay, was encountered in the original wellbore of EBU 65-2. The well was sidetracked as shown in **Figure 57** and **Figure 65**, and hit 42' of net pay.

EBU 43-2 encountered high pressure nitrogen with little oil, and was apparently drilled along the fracture/fluid flow trend from EBU 44G-2. EBU 44G-2 has been and is a low rate injector, so sweep was not expected at the EBU 43-2 location. EBU 43-2 was planned as a future injection well, so the conversion was done straight away.

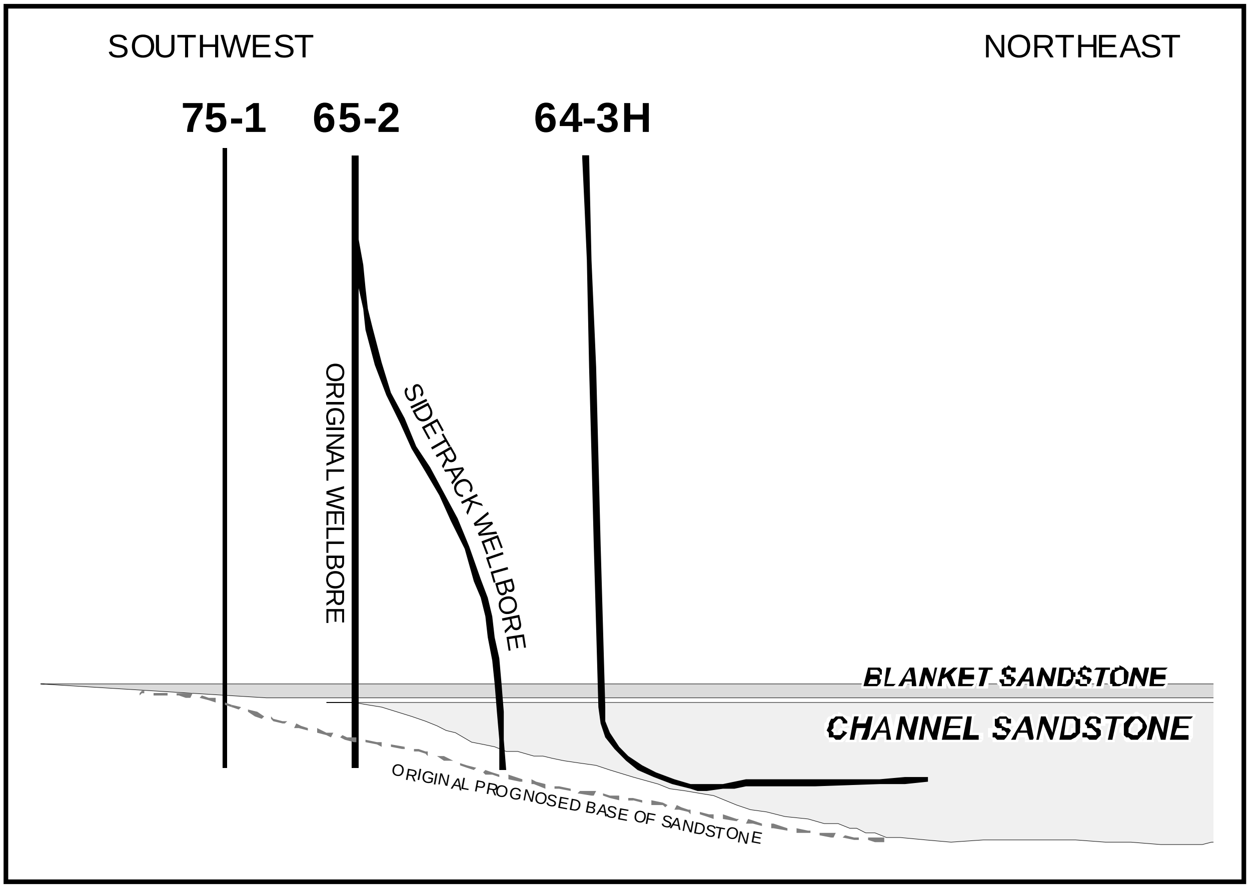

Figure 65. Diagram of the geology expected and encountered with the drilling of EBU 65-2.

EBU 60-2 also encountered high pressure nitrogen, and was perhaps the most surprising of the unexpectedly poor wells. The well is on flow trend with EBU 58G-1, but given the distance between the two wells, sweep was not expected. EBU 58G-1 is the most likely source of the injected gas encountered at EBU 60-2, but EBU 59G-1 (converted to injection in May 2003) ad EBU 60G-1 are also possibilities.

Despite the poorer performance of these recent wells, Binger Operations, LLC plans to continue with infill drilling efforts in the years to come.

Technology Transfer Activities

The material of this project was presented to the Big Horn Section of the Society of Petroleum Engineers in May 2006.

A project web site – www.eastbingerunit.com – was created to disseminate information to industry. The Project Proposal and all Quarterly Technical Progress Reports submitted to the U.S. Department of Energy are available on the web site.

The operator answered a number of inquiries about the project from individuals in industry who had discovered the web site and desired additional information.

Conclusion

Through enhance reservoir characterization and development drilling, significant oil and gas reserves have been added in the East Binger Unit. Over the course of the six-year project, three horizontal wells and seven vertical wells were drilled in the project area. Four producing wells were converted to injection service.

Together, these projects more than doubled the oil rate in the project area, adding 298,000 barrels of produced oil by the end of the project. New production from the project currently accounts for 33% of daily oil production from the Unit. Based on projections, the project will ultimately add 1.9 million barrels of oil reserves.

The project also increased production and estimated ultimate recovery of NGLs and plant residue (hydrocarbon) gas. As of the end of the project, development work has added incremental production of 136,000 barrels of NGLs and 547,000 MCF of residue gas. Based on the pre-project decline and the rate at the end of the reporting period, the project will added ultimate reserves of 800,000 barrels of NGL reserves and 3,100,000 MCF of residue gas reserves.

It was determined that poor areal sweep efficiency is the primary factor causing nitrogen cycling and limiting oil recovery. This is in contrast to the perception prior to the initiation of development, which was that high permeability channels and gravity segregation were causing poor *vertical* sweep efficiency. Although not true of all infill wells, most were drilled in areas with little sweep and came online producing gas with much lower nitrogen contents than previously drilled wells in the field and in the pilot area.

In a reservoir where both vertical and horizontal wells must be fracture stimulated to obtain commercially productive rates, where directional permeability exists, and where secondary or tertiary flood operations are being employed, it will be very difficult to economically justify drilling horizontal wells. Binger Operations, LLC (“BOL”) believes this is the case in the EBU.

Nitrogen recycle, defined as nitrogen production as a percentage of injection, decreased from 72% prior to initiation of the project to about 25% before rising back to a current rate of 40%. Injection into the pilot area increased 60% over levels prior to the project, while gas production and nitrogen content of produced gas have both decreased.

With an improved understanding of fluid flow in the EBU, BOL plans to continue developing additional oil and gas reserves with vertical infill wells in a line drive flood.

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