DOE/BC/14831--19-Vol.3

VOLUME III
CHARACTERIZATION OF REPRESENTATIVE RESERVOIRS - SOUTH MARSH ISLAND 73, B35K AND B65G RESERVOIRS

Mark A. Young, S. Philip Salamy*, T.K. Reeves*, W. Clay Kimbrell**, Walter K. Sawyer****

RECEIVED
JUL 28 1998
OSTI

MASTER

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

*BDM-Oklahoma, Inc.
220 North Virginia Ave.
Bartlesville, Oklahoma 74003

**Department of Petroleum Engineering
Louisiana State University
Baton Rouge, Louisiana 70803

***Mathematical & Computer Services, Inc.
325 Seminole Trail
Danville, VA 24540

SOUTH MARSH ISLAND BLOCK 73 FIELD
RESERVOIR SIMULATION STUDY
B-35 SAND, RESERVOIR K
B-65 SAND, RESERVOIR G
Assist in the Recovery of Bypassed Oil
From Reservoirs in the Gulf of Mexico

Contract Number DE-AC22-92BC14831

□

DISCLAIMER

Portions of this document may be illegible electronic image products. Images are produced from the best available original document.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

ABSTRACT

This report documents the results of a detailed study of two Gulf of Mexico salt dome related reservoirs and the application of a publicly available PC-based black oil simulator to model the performances of gas injection processes to recover attic oil. This work was performed by BDM Federal, Inc. and Louisiana State University in support of the Louisiana State University's Bypassed Oil Study, which is funded by the U.S. Department of Energy (DOE contract numberDE-AC22-92BC14831). The overall objective of the LSU research project is to assess the oil reserve potential that could result from the application of proven technologies to recover bypassed oil from reservoirs surrounding piercement salt domes in the Gulf of Mexico.

The objective of these reservoir simulation studies was to develop detailed calibration cases for use by the project team in the assessment of the oil recovery potential for Gulf of Mexico salt dome reservoirs. The specific study objective was to simulate the primary recovery and attic gas injection performance of the two subject reservoirs to: 1) validate the BOAST model; 2) quantify the attic volume; and 3) predict the attic oil recovery potential that could result from additional updip gas injection.

The simulation studies were performed on the B-35K Reservoir and the B-65G Reservoir in the South Marsh Island Block 73 Field using data provided by one of the field operators, Taylor Energy, a New Orleans based independent operator. Detailed studies were conducted on the reservoirs to define the parameters required to simulate the reservoirs' performance. A modified PC-version of the BOAST II model was used to match the production and injection performances of these reservoirs in which numerous gas injection cycles had been conducted to recover attic oil. The historical performances of the gas injection cycles performed on both the B-35 K Reservoir and B-65G Reservoir were accurately matched, and numerous predictive runs were made to define additional potential for attic oil recovery using gas injection. Predictive sensitivities were conducted to examine the impact of gas injection rate, injection volume, post-injection shut-in time, and the staging of gas injection cycles on oil recovery.

EXECUTIVE SUMMARY

This report documents the results of a detailed study of two Gulf of Mexico salt dome related reservoirs and the application of a publicly available PC-based black oil simulator to model the performances of gas injection processes to recover attic oil. The overall objective of the LSU research project is to assess the oil reserve potential that could result from the application of proven technologies to recover bypassed oil from reservoirs surrounding piercement salt domes in the Gulf of Mexico.

The objective of these reservoir simulation studies was to develop detailed calibration cases for use by the project team in the assessment of the oil recovery potential for Gulf of Mexico salt dome reservoirs. The specific study objective was to simulate the primary recovery and attic gas injection performance of the two subject reservoirs to:

1) validate the BOAST model;
2) quantify the attic volume; and
3) predict the attic oil recovery potential that could result from additional updip gas injection.

South Marsh Island 73 Field

The South Marsh Island Block 73 (SMI 73) Field is located approximately 77 miles south of Intercoastal City, LA in 135 feet of water in the Gulf of Mexico. Production from the field was initiated in 1964, and over time, a total of eight platforms were set and over 100 development wells were drilled. Taylor Energy Company purchased Exxon's interest in SMI Blocks 69, 72, and 73 in 1993 and assumed operatorship.

The field is predominantly oil productive and production peaked in 1971 at a rate of 16,900 BOPD and 68.MMCFD. The field is currently producing almost 2,000 BOPD, 5 MMCFD and 2,600 BWPD. The productive zones have been established at depths between 5,000 feet and 11,500 feet. The cumulative production from the field as of January 92 totaled 67 million barrels of oil (MMBO), 276 billion cubic feet of gas (BCF), and 46 million barrels of water (MMBW).

The SMI 73 Field is established by the simple piercement salt dome structure. The dome is relatively circular in shape, with a small area of overhang at the southeast corner. The current top-of-salt is approximately 364 feet below mean sea level. Drilling has been concentrated on the northern, eastern and southeastern portions of the structure, with twenty-five Miocene and Pliocene aged sands being productive from more than sixty reservoirs around those sides of the dome.

B-35K Reservoir

One of the two reservoirs in this study is the B-35 K Reservoir. The B-35 is a typical sand for the SMI 73 Field. The B-35 sand is relatively widespread around the southeastern flank of the dome, with a thickness, downdip, of 40 feet or more. Toward the salt, the sand begins to steepen, eventually pinching out to shale near the salt. Numerous faults radiate out from the salt, cutting the sand into discreet reservoirs.

Production from the B-35K Reservoir was initiated in October 1966 from the A-1 Well and the short-string completion of the dually completed A-3 Well (Well A-3D). Well A-3D produced until July 1971 when the well was reworked and put on production as a single completion in the B-35K Reservoir. Well A-3 produced from March 1972 through November 1982, when the well was shut-in due to sanding problems. In June 1983, the B-35K completion in the A-3 Well was abandoned, and the well was sidetracked and completed as a producer in the deeper D-5 Sand. The cumulative Well A-3D/A3 production from the B-35K Reservoir totaled 1.2 MMBO, 530 MMCF, and 69,000 BW. Well A-1, which is located downdip of Well A-3 in the B-35K Reservoir, watered out in October 1971, with cumulative production of 394,000 BO, 193 MMCF, and 43,000 BW. Well A-6D produced from the B-35K Reservoir from October 1966 through May 1976 when the well watered out and was recompleted as a single producer in the deeper D-5 Sand. Cumulative production from Well A-6D totaled 1.4 MMBO, 739 MMCF and 86,000 BW. The cumulative production for the B-35K Reservoir totals 3.0 MMBO, 1.5 BCF and 198,000 BW.

In 1992, the A-6 well was recompleted and tested in the B-35K zone, which came on initially with 100% oil and immediately went to water. During the productive life of the B-35K Reservoir, five attic gas injection cycles were conducted in the A-3D/A-3 Well to improve the oil recovery from the reservoir. The injection of gas into the attic of the reservoir resulted in the recovery of additional oil by causing the oil-water contact to move downdip, away from the producing wellbores. Water-free production was realized until the oil-water contact moved back up to the producing wells. The success of these gas injection cycles is readily apparent from the data, although wellbore mechanical problems influenced the results of some of the gas cycles.

The South Marsh Island B-35K Reservoir appears to be a candidate for additional gas injection cycles to recover attic oil that could not otherwise be recovered. The highest structural well has watered out due to the active water drive. The updip, or attic oil volume, which is the volume above the highest well, is unknown, as is the location of the original oil-water contact. Previous gas injection cycles have successfully recovered attic oil. The remaining question is whether additional attic oil can be recovered through gas injection. The development of the numerical simulation, which will be discussed later, that accurately matches the historical performance of the B-35K Reservoir, provided reasonable predictions of the performance which could be achieved through additional gas injection cycles.

B-65G Reservoir

The B-65G Reservoir is a long, north-south trending, steeply dipping sandstone, which pinches out just before encountering the piercement salt dome on its southeastern flank. Structure and trapping are all results of the piercement salt dome.

Overall it is a clean sand that averages 66 feet in gross thickness and 53 feet in net sand thickness. Material balance calculations indicated that the reservoir was originally at its bubble point with a small gas cap and contained about 12 MMSTB of oil. Its original reservoir pressure was 3457 psi at 7351 feet subsea.

The reservoir has produced 6.2 MMSTB of oil, 3.4 BCF of gas (which also accounts for all gas injected back into reservoir) and 820 MBBLS of water over a period of 27 years. Four wells produced from the reservoir; three injected 2 BCF of gas and one well injected no gas. A fifth downdip well, served as a primary gas injector and injected an additional 732 MMCF of gas.

The B-65G sand reservoir began production in October 1966 when the #B-1, #B-7, and #B-10D wells were put on line. The #B-12 was put on line in February 1967. The #B-11A (July 1974), #B-9D (April 1967), and #B-17 (April 1971) were all drilled south of the B-65G Reservoir and produced from the B-65GS Reservoir, which has been interpreted to be separated from the B-65G Reservoir by a sealing fault. Presently, the #B-12 and #B-1 wells are active in the B-65G Reservoir. The B-1 well is currently going through a gas injection stage.

The reservoir consists of approximately 10,100 acre-feet or an average net pay thickness of 38 feet over 267 acres. Porosity averages 28.5% and the original oil saturation was estimated at 73%, with an initial formation volume factor (FVF) of 1.3 res bbls/STB. Estimated volumetrically, the original in-place-oil is 12.6 MMSTB. Therefore, through March 1995, 49.8% of the original oil-in-place had been produced.

Conclusions

The results of this study have offered a set of technically feasible solutions to help improve the oil recovery from these reservoirs through additional attic gas injection cycles. For the B-35K Reservoir, the recommendations and conclusions are as follows:

1. The injection rate sensitivities indicate that relatively low injection rates accelerate the

production response from additional gas injection cycles due to improved segregation of the gas in the attic. The ultimate incremental recovery is improved only slightly at lower gas injection rates. An injection rate of about 500 MCFD appears to be optimum for recovery for this reservoir.

2. The injection volume sensitivities show that production is slightly accelerated at higher injection volumes and that incremental oil recovery tends to be higher, but there is a point of diminishing rectums. The optimum gas injection volume appears to be between 150 and 300 million cubic feet.
3. The post-injection shut-in time sensitivity indicates that a three month shut-in time yields an optimum incremental oil recovery.
4. The injection volume staging sensitivity indicates that higher incremental recovery can be achieved by dividing the total injection cycle into two stages, with a short production stage between. This improved recovery is most likely due to better segregation of the injected gas in the attic.

In addition to the technical solutions, the results of the sensitivity cases could be analyzed from an economic point of view to determine the optimum injection volume, injection rate, and shut-in period, based on operating conditions and costs.

The study of the B-65G reservoir indicates that BOAST III is able to accurately describe the history of a steeply dipping reservoir with a past gas injection project. Through history matching and predictive simulation runs, it has been shown that the gas injection cycles were very successful in moving attic oil down to be produced by the downdip wells in the B-65G reservoir in South Marsh Island Block 73 Field. Recommendations to the operator, based upon this study, would be to recover the remaining reserves of 400 MSTB of oil available from the B-12 well and then blowdown the gas cap, which is estimated to contain 1.0 BCF of gas

I. INTRODUCTION

Secondary recovery by downdip gas injection in steeply dipping oil reservoirs has been used successfully since the 1950s. The technique is used primarily around piercement salt dome reservoirs. Most of the reservoirs, some with gas caps and some without, around these piercement salt domes have active water drives. Reservoirs with both an active water drive and a gas cap will have higher natural recoveries than reservoirs without a gas cap. Because of this, operators in the 1950s began experimenting with creating artificial gas caps to increase their recoveries in both reservoirs with no natural gas cap and those with small natural gas caps.

Because older processed seismic data does not provide the clarity that recent 3-dimensional and newly processed or reprocessed 2-dimensional seismic data provide, operators, in the past, gave themselves plenty of room away from the salt dome in locating wells. This was in order not to penetrate the salt which created drilling and completion problems and in some cases resulted in dry holes. However, because of this safety factor in the location of the wells, all or a portion of the upstructure portion of the reservoir cannot be drained. Because these upstructure volumes are usually insufficient to support the drilling of an additional well updip, these volumes become bypassed reserves.

If a reservoir has reasonable permeability and dip, gas injected into a lower structural position will migrate upward and create an artificial gas cap. This artificial gas cap works just as a natural gas cap would. As the reservoir is produced and the reservoir pressure declines (assuming that the reservoir is not steady state), the gas cap expands and pushes the oil downward toward the downdip well. Methane and nitrogen have been the primary gases used. To illustrate present day situations or reservoirs that may have up dip oil reserve potential, two reservoirs in the South Marsh Island Block 73 Field in the Gulf of Mexico were analyzed. This report presents the results of the simulation studies of the Taylor Energy B-35K and B-65G reservoirs in the South Marsh Island Block 73 Field.

II. FIELD INFORMATION

II.1 Data

All necessary and available data were collected from Taylor Energy, which purchased the field from Exxon in 1993. All well logs, core analysis, historical, production and injection histories were available. Measured pressure-volume-temperature (PVT) data was calculated.

II.2 Field History

The South Marsh Island Block 73 (SMI 73) Field is located approximately 77 miles south of Intercoastal City, LA in 135 feet of water in the Gulf of Mexico (see Figure 1). The field was discovered in 1963 by Exxon when the #1 Well SMI 69 was drilled. Several other exploratory wells were drilled by Exxon and Shell on this block and the surrounding blocks (see Figure 2). The field was subsequently developed by Shell (SMI 57 and 58) and Exxon (SMI 69, 72, and 73). Production from the field was initiated in 1964, and over time, a total of eight platforms were set and over 100 development wells were drilled. Taylor purchased the Exxon interest in SMI Blocks 69, 72, and 73 in 1993 and assumed operatorship (see Figure 3).

The field is predominantly oil productive and production peaked in 1971 at a rate of 16,900 BOPD and 68.MMCFD. The field is currently producing almost 2,000 BOPD, 5 MMCFD and 2,600 BWPD (see Figure 4). The productive zones have been established at depths between 5,000 feet and 11,500 feet. The cumulative production from the field as of January 92 totaled 67 million barrels of oil (MMBO), 276 billion cubic feet of gas (BCF), and 46 million barrels of water (MMBW). The gas from the field has not been sold; rather, it has been used for fuel or reinjected to improve oil recovery. The cumulative production from the Taylor blocks total 45 MMBO and 36 BCF.

II.3 Field and Reservoir Geology

The SMI 73 Field is established by the simple piercement salt dome structure, as shown in Figure 2. The dome is relatively circular in shape, with a small area of overhang at the southeast corner. The current top-of-salt is approximately 364 feet below mean sea level. This dome formed in relatively shallow water, with salt movement having been initiated prior to the deposition of many of the key reservoir units. Sedimentation continued during the movement of the salt. The source for the main reservoir sands was apparently predominantly from the north and east. Drilling has been concentrated on the northern, eastern and southeastern portions of the structure, with twenty-five Miocene and Pliocene aged sands being productive from more than

Location of SMI Block 73 Field in the Gulf of Mexico

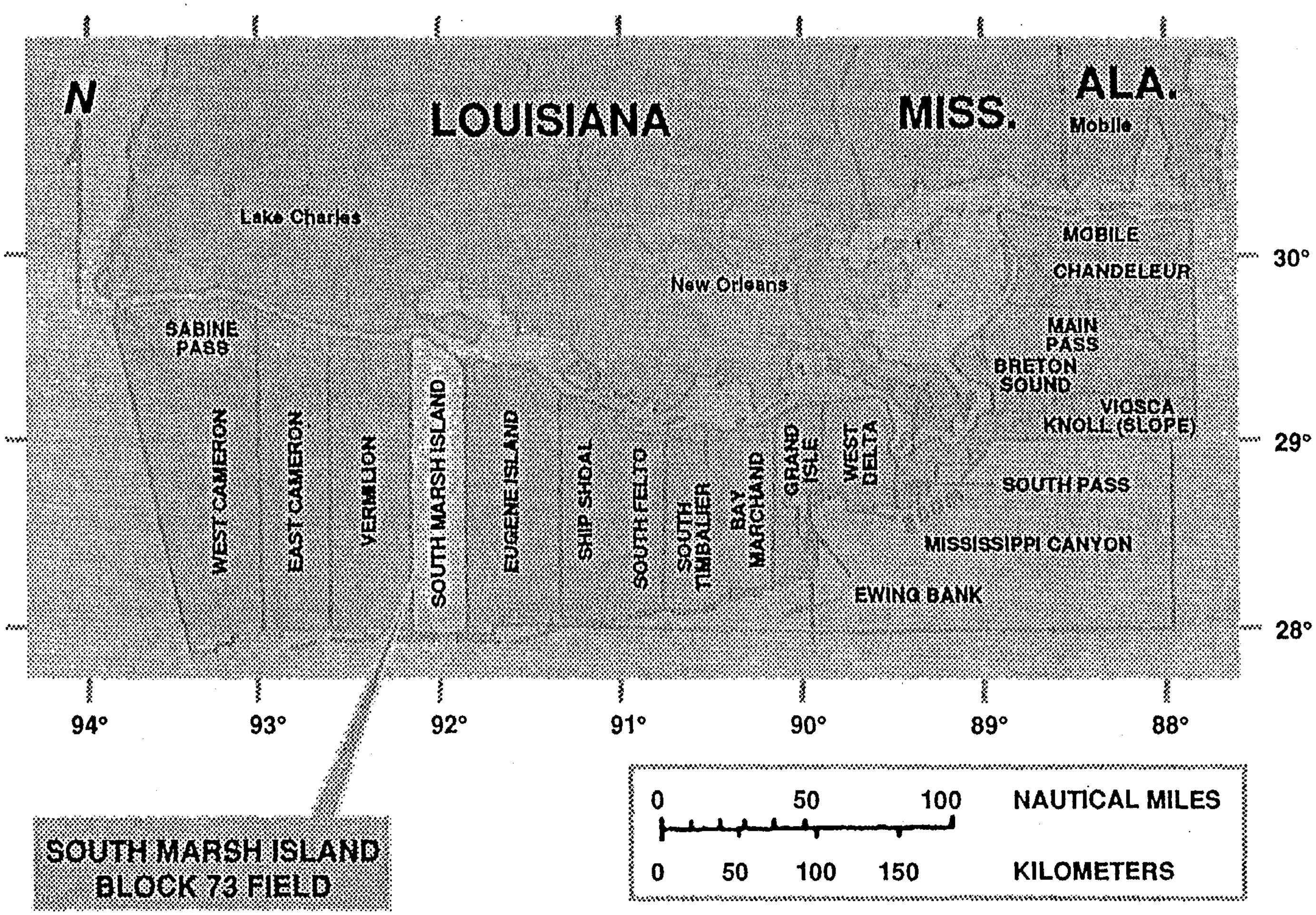
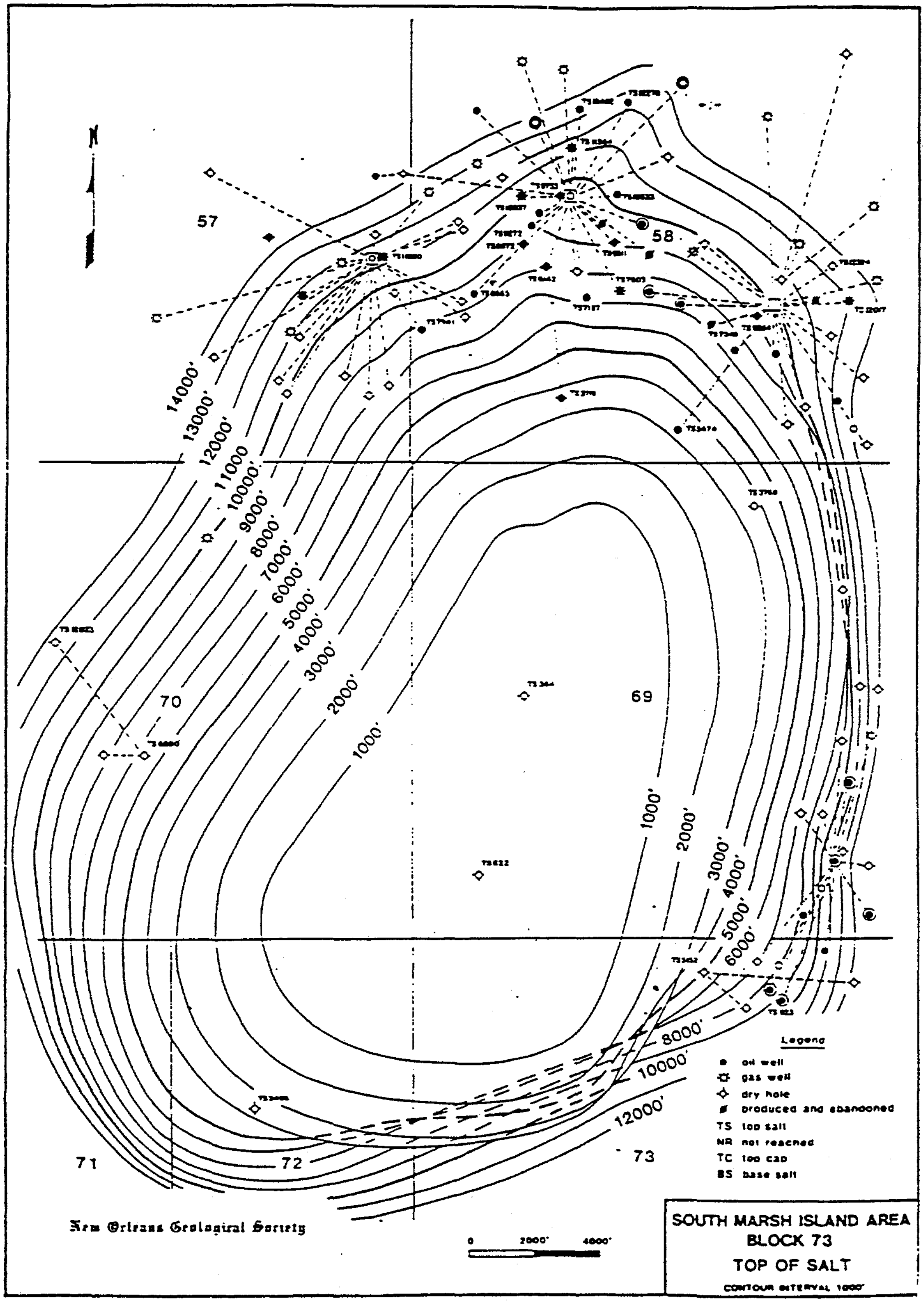


Figure1 Location of South Marsh Island Block 73 Field in the Gulf of Mexico



Waguespack, S.J., "Salt Domes of South Louisiana," The New Orleans Geological Society, Volume III, 1983, pp. 58-59.

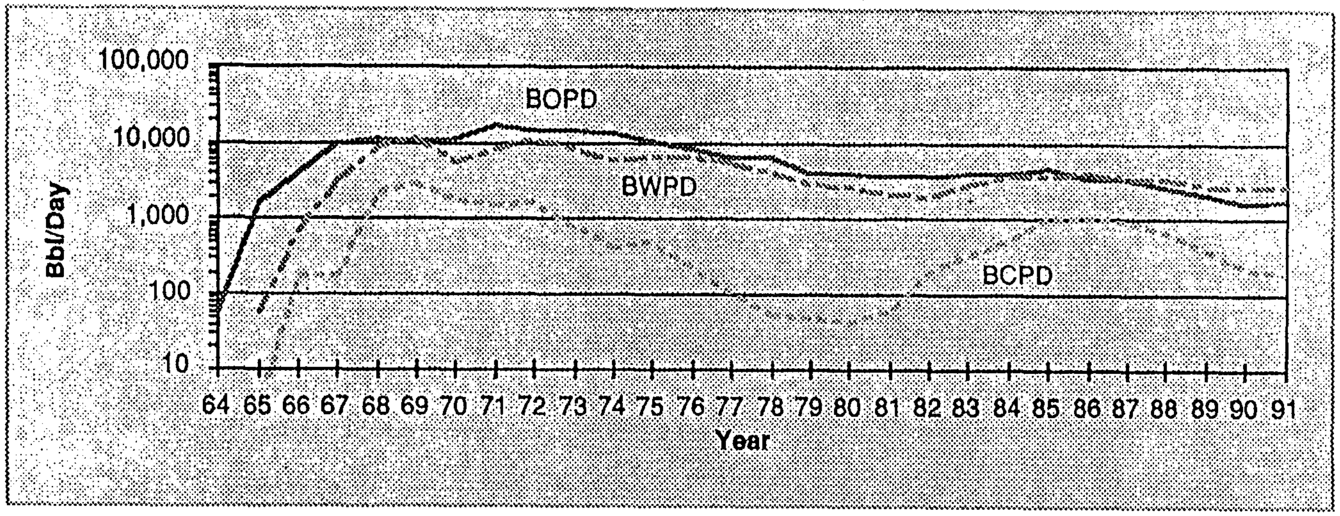
Figure2 Structure Map on the Top of Salt for South Marsh Island 73 Field

SMI Block 73 Field Production Statistics

Discovery:	1964	(Exxon SMI 69 #1)	
Ownership:	Taylor	(SMI 69, 72, 73)	
	Shell	(SMI 57, 58)	
Initial Production:		1964	
Peak Production (1971):		16,900 BOPD, 68 million scfd	
Current (1/92):		1800 BOPD	4.6 million scfd
Cumulative Production (1/92) Field:		67	million Bbl Oil
		276	billion scf Gas
		46	million Bbl Water
Taylor Blocks:		45	million Bbl Oil
		36	billion scf Gas

Figure3 South Marsh 73 Field Production Statistics

SMI 73 Field Production History



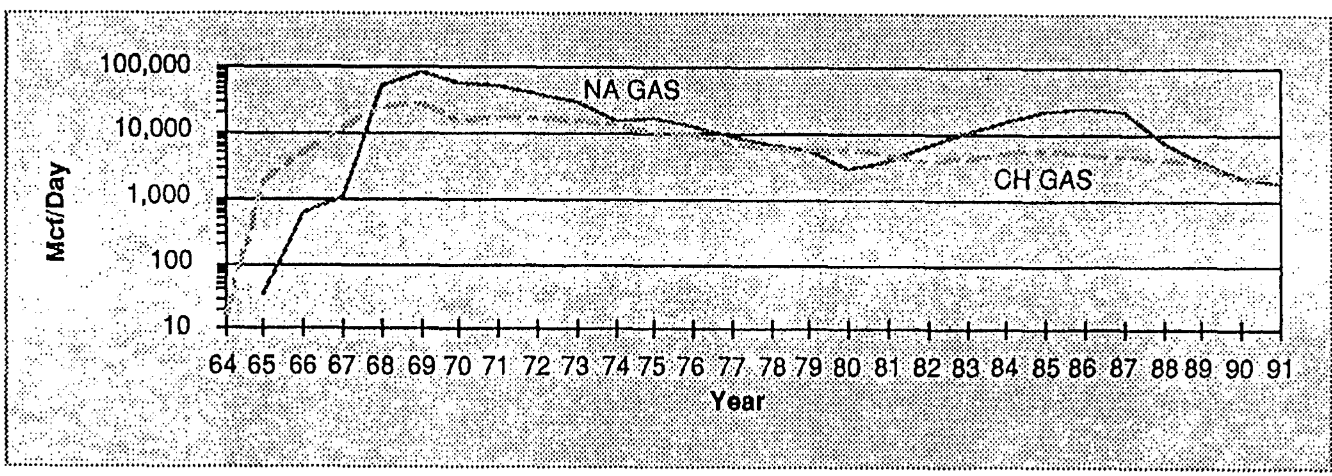


Figure4 South Marsh Island 73 Field Production History

sixty reservoirs around those sides of the dome. Exploratory drilling on the western side of the structure indicates that area was on the lee side during deposition and was sheltered from most of the sand-laden currents. The rate of sediment influx appears to have been low and the material was very fine-grained during the deposition of most of the key reservoirs, with sands having been limited to deeper-water areas around the growing dome, and shale having been deposited atop the structure in a more-or-less starved environment. This helps to account for the facts that many of the reservoirs pinch out updip, toward the salt, and that most of the dome is wrapped in a shale sheath.

Both reservoir sands, B35K and B65G, in the South Marsh Island area were deposited well offshore, in an open marine environment, in moderately deep water. The region had a hummocky, irregular bottom at the time of deposition, which controlled the flow of oceanfloor currents through the area. Salt movement took place concurrently with deposition of the reservoir sands and the enclosing shales. The syndepositional growth of the salt domes created a number of highs on the seafloor as sediments accumulated in the area.

Coarser-grained sediments were carried into the region by density currents, which spread out across the area, following channels along the deeper portions of the seafloor. Fine-grained sands were deposited in these deep areas between the domes, while shale and mud accumluated on the upslope areas and crests of the highs. The growing domes shielded some deeper portions of the seafloor from the density currents, with little sand reaching the lee side of the highs. Thus, sands and shale interfinger in a highly complex manner around the flanks of the domes, marking a period of sand pulses and density flows, alternating with periods of quiet deposition on the exposed side of the structure, and starved-basin conditions with fine-grained sediments on the sheltered side of the dome.

III. RESERVOIR INFORMATION

III.1 B-35K Reservoir

III.1a Reservoir Characteristics

One of the two reservoirs in this study is the B-35 K Reservoir, shown in Figure 5. The B-35 is a typical sand for the SMI 73 Field. The B-35 sand is relatively widespread around the southeastern flank of the dome, with a thickness, downdip, of 40 feet or more. Toward the salt, the sand begins to steepen, eventually pinching out to shale near the salt. Numerous faults radiate out from the salt, cutting the sands into discreet reservoirs. The study area is isolated on the east and west ends by two sealing faults, each with 150 to 200 feet of throw. Exxon had initially identified and interpreted the geology of this block using a series of older 2-D seismic lines. The B-35 K Reservoir was originally developed with a series of five wells. This gave limited control for a geologic interpretation. Four wells from the "A" platform cut the sand and provided isopach data. The C-6 well penetrated the projected sand updip from the other wells and encountered shale at the position of the B-35 zone.

Based on the seismic data and a conservative interpretation of the shale-out position, Exxon developed a reservoir model for the B-35 K Reservoir. The position of the shale-out against the salt has previously been inferred as half way between the estimated position of the salt and the most updip well control. The position of the shale-out was adjusted during the simulation

SMI Block 73 Field: B-35 Sand Structure Map

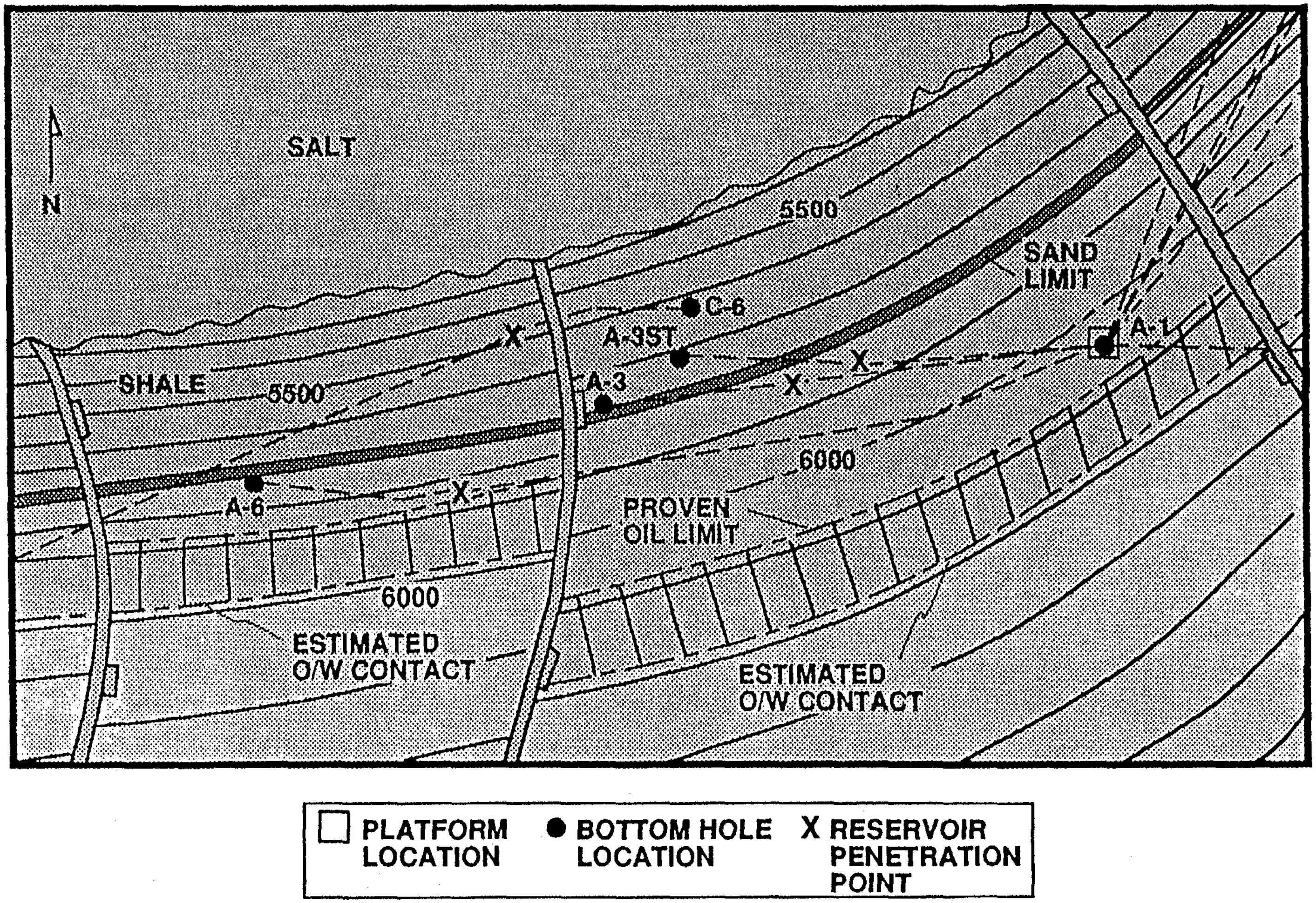


Figure5 South Marsh Island 73 Field B-35 Sand Structure Map

of the reservoir in order to obtain a history match. As will be discussed later, simulation of the reservoir actually indicated that the shale was closer to the position of the salt face, thus making the reservoir larger than previously thought. This is a good example of where 3-dimensional seismic might confirm adjusted positions of both the salt interface and the shale-out of this and other sands.

To determine the downdip oil limit, Exxon used an arbitrary 100-feet-below-the-lowest-proven-oil standard to set a hypothetical oil-water contact. Exxon also mapped a small fault that seemed to show up on the 2-D seismic data, thus compartmentalizing the B-35 K into two separate reservoirs. The fault was assumed to be sealing.

Figure 6a shows the B-35K Reservoir net sand isopach contours, the internal fault, and the shale-out line, as mapped by Exxon. A detailed analysis of the production histories of the wells and of the reservoir pressure over time were conducted. The data and analyses did not support the concept of an internal fault in the center of the block. No direct evidence for the fault could be found. The original seismic data was not available and the well logs did not show the sort of missing or duplicated geologic sections that would be expected in wells that penetrate fault zones.

Based on the actual reservoir performance, the geologic model was reinterpreted (Figure 6b). Primarily, the internal fault was removed. If such a fault exists, offsets appear to be minor and the fault is apparently not sealing, making it irrelevant, in terms of the modeling. The updip limit of the sand was extremely conservative originally, and required an unnatural pinching together of the contours in the updip area. This left a large reservoir volume above the original shale-out line, which could help to explain the overproduction from this reservoir. Moving the pinchout line updip, closer to the C-6 control point, made the thinning rate of the sand appear to be much more normal and to fit the production model quite well. In the downdip direction, the oil-water contact was analyzed, and adjusted slightly to fit the actual well production histories better.

The geologic interpretation and reservoir engineering analysis were used synergistically to identify a model that fits the evidence and available data better and that provides a closer fit to the actual production information for the B-35K Reservoir.

The B-35K Reservoir is located at a depth of about 5,800 feet subsea. The average net thickness of the oil column is approximately 22 feet, and the sand shales out in the updip direction and thickens in the down-dip direction. The average porosity in the reservoir is 29.5%, the water saturation is 16.5 %, and the permeability is 1,150 millidarcies. The reservoir exhibits an active natural water drive and is believed to have been initially at saturated conditions with no initial gas cap. The initial reservoir pressure was estimated to be 2,712 psia, and the pressure history is shown in Figure 7. This pressure performance indicates the presence of a strong water drive in the reservoir.

None of the development wells that penetrated the B-35K Reservoir encountered an oil-water contact, so the exact location of the contact is unknown. The A-1 Well encountered oil at the lowest structural point in the reservoir, and the down-dip A-6 (#2 Sidetrack) was wet in this zone, as shown in Figure 5. Therefore, the location of the oil-water contact is somewhere between these two structural levels. Likewise, the exact updip limit of the reservoir is unknown. The A-3 (Sidetrack) encountered oil at the highest structural position in the reservoir, but at the updip location of Well C-6, the sand is completely shaled out. Thus, the updip limit of the reservoir lies somewhere between these two structural points (see Figure 6a and 6b).

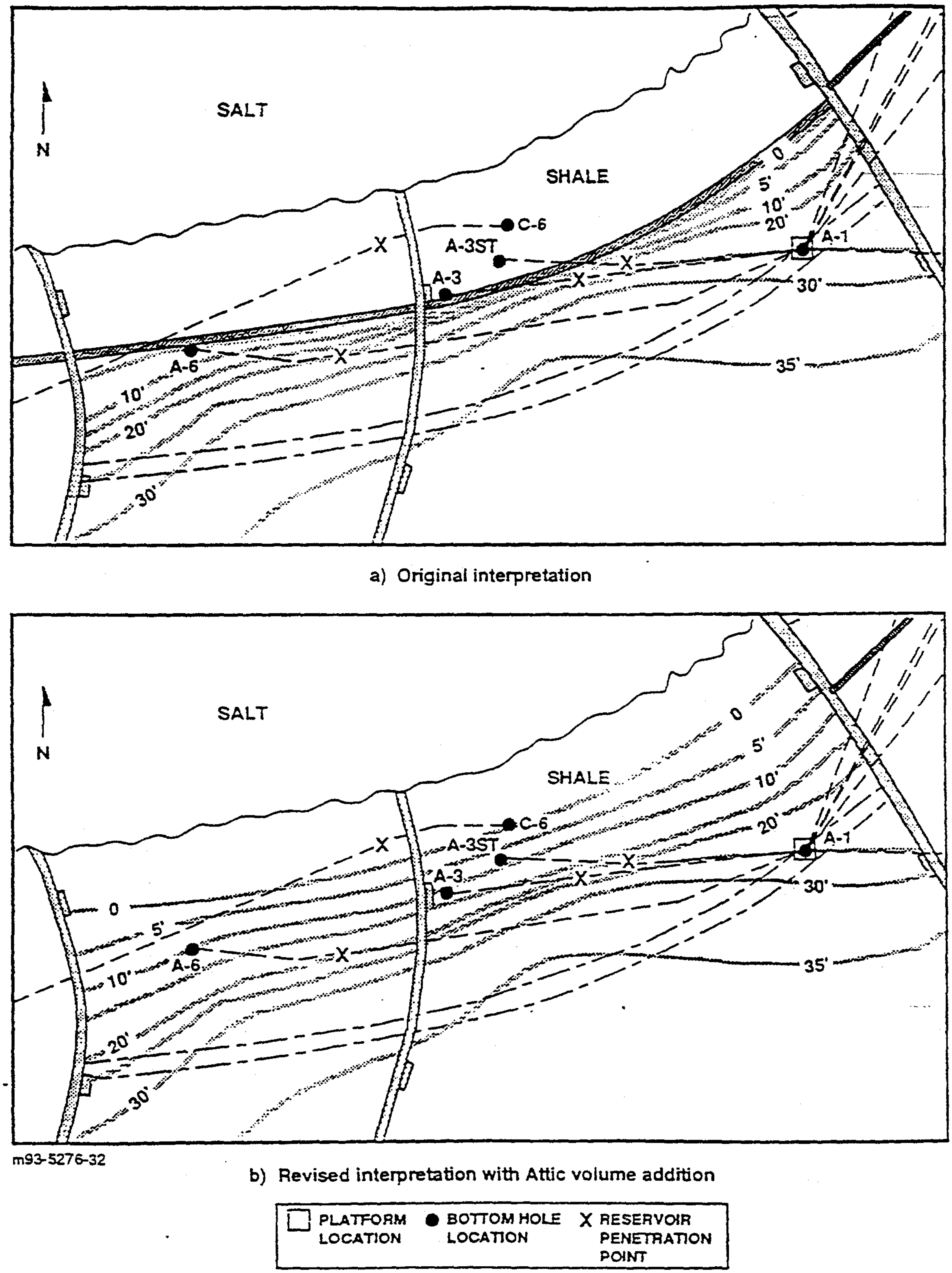


Figure 6. B-35K Reservoir Net Sand Isopachous Map

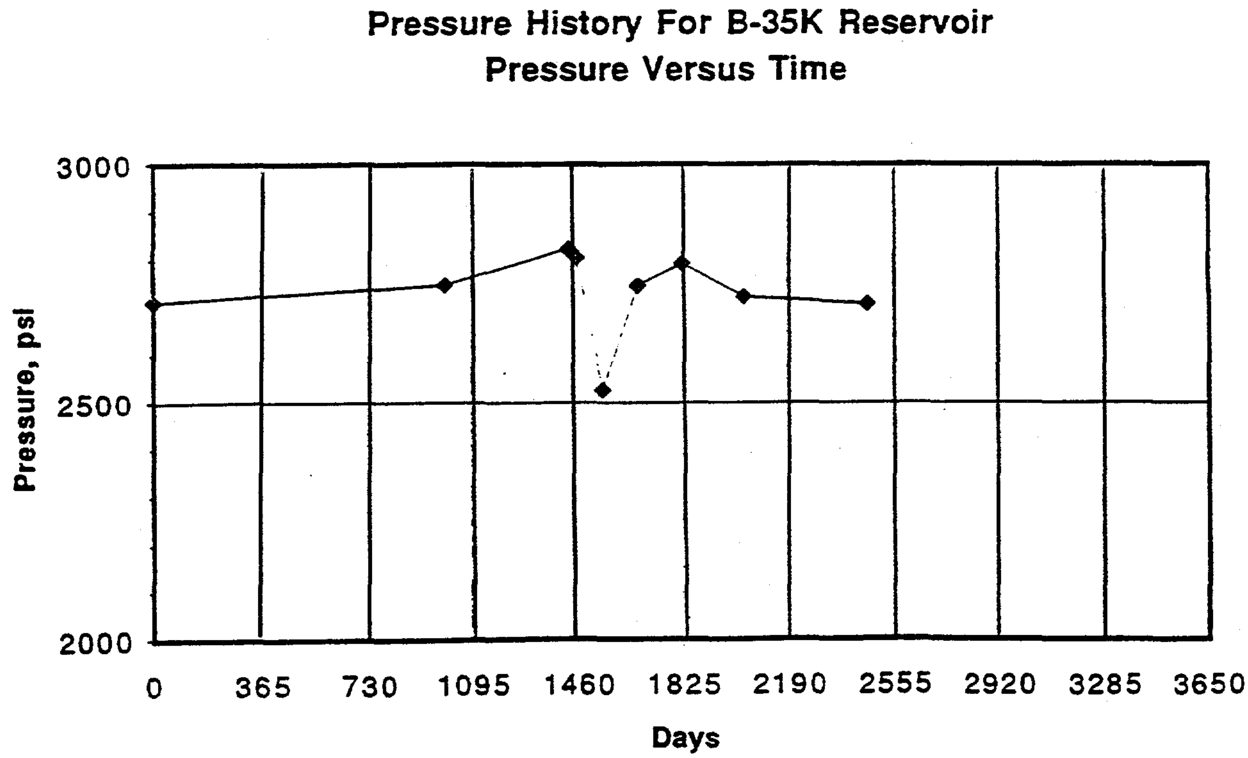


Figure 7 - Pressure History for the B-35 Reservoir

III.1b Reservoir Production and Injection History

Production from the B-35K Reservoir was initiated in October 1966 from the A-1 Well and the short-string completion of the dually completed A-3 Well (Well A-3D). Well A-3D produced until July 1971 when the well was reworked and put on production as a single completion in the B-35K Reservoir. Well A-3 produced from March 1972 through November 1982, when the well was shut-in due to sanding problems. In June 1983, the B-35K completion in the A-3 Well was abandoned, and the well was sidetracked and completed as a producer in the deeper D-5 Sand. The cumulative Well A-3D/A3 production from the B-35K Reservoir totaled 1.2 MMBO, 530 MMCF, and 69,000 BW. Well A-1, which is located downdip of Well A-3 in the B-35K Reservoir, watered out in October 1971, with cumulative production of 394,000 BO, 193 MMCF, and 43,000 BW. Well A-6D produced from the B-35K Reservoir from October 1966 through May 1976 when the well watered out and was recompleted as a single producer in the deeper D-5 Sand. Cumulative production from Well A-6D totaled 1.4 MMBO, 739 MMCF and 86,000 BW. The cumulative production for the B-35K Reservoir totals 3.0 MMBO, 1.5 BCF and 198,000 BW. The B-35K Reservoir production history is displayed in Figure 8 and the production history for the individual wells are displayed in Figures 9 through 11. The cumulative production data are shown in Table 1.

In 1992, the A-6 well was recompleted and tested in the B-35K zone, which came on initially with 100% oil and immediately went to water. Taylor is tentatively planning to inject gas into this well and produce the additional attic oil.

During the productive life of the B-35K Reservoir, five attic gas injection cycles were conducted in the A-3D/A-3 Well to improve the oil recovery from the reservoir. The injection of gas into the attic of the reservoir resulted in the recovery of additional oil by causing the oil-water

Daily Production Rates for B-35K Reservoir

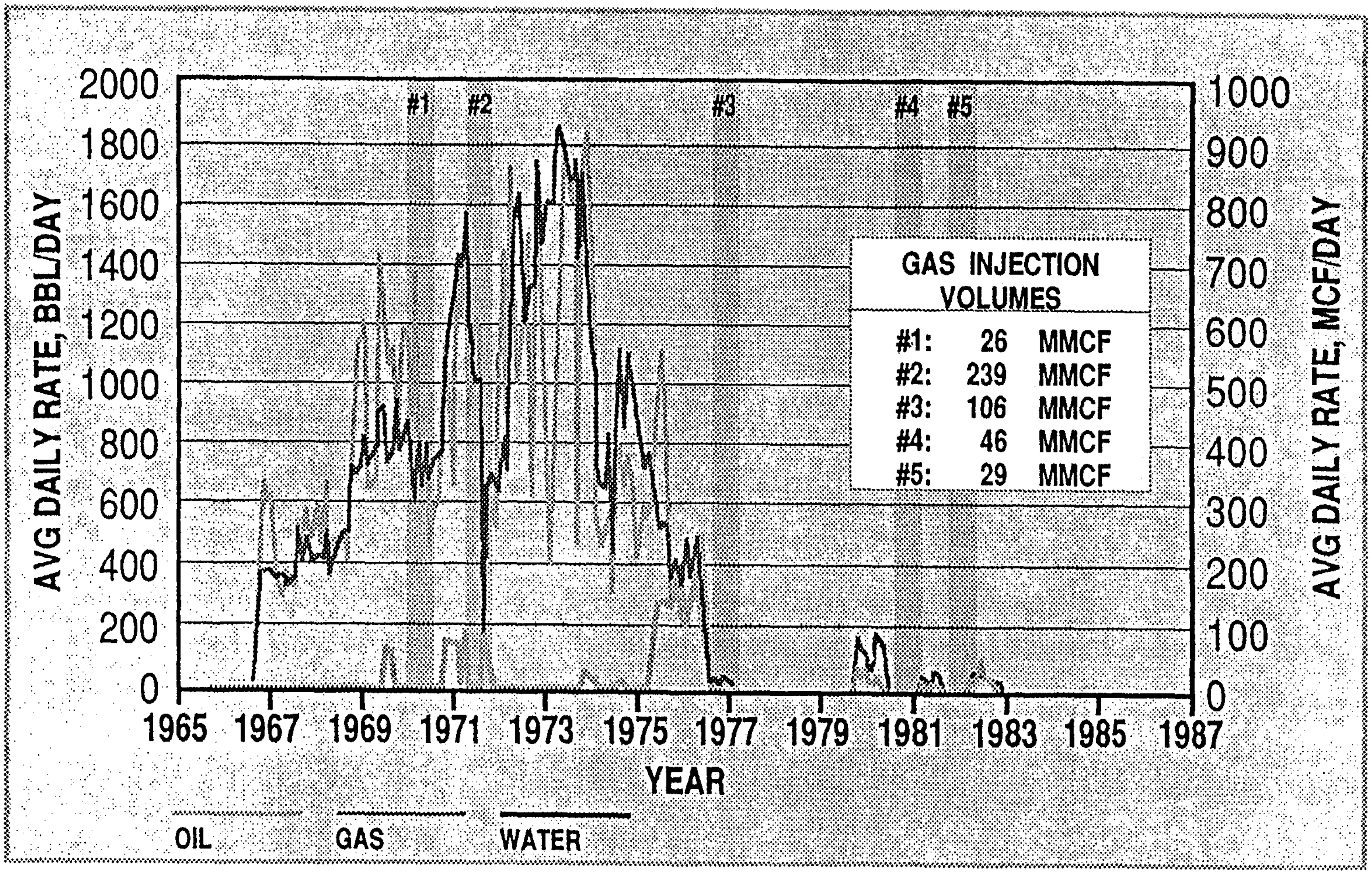


Figure8 Daily Production Rates for B-35K Reservoir

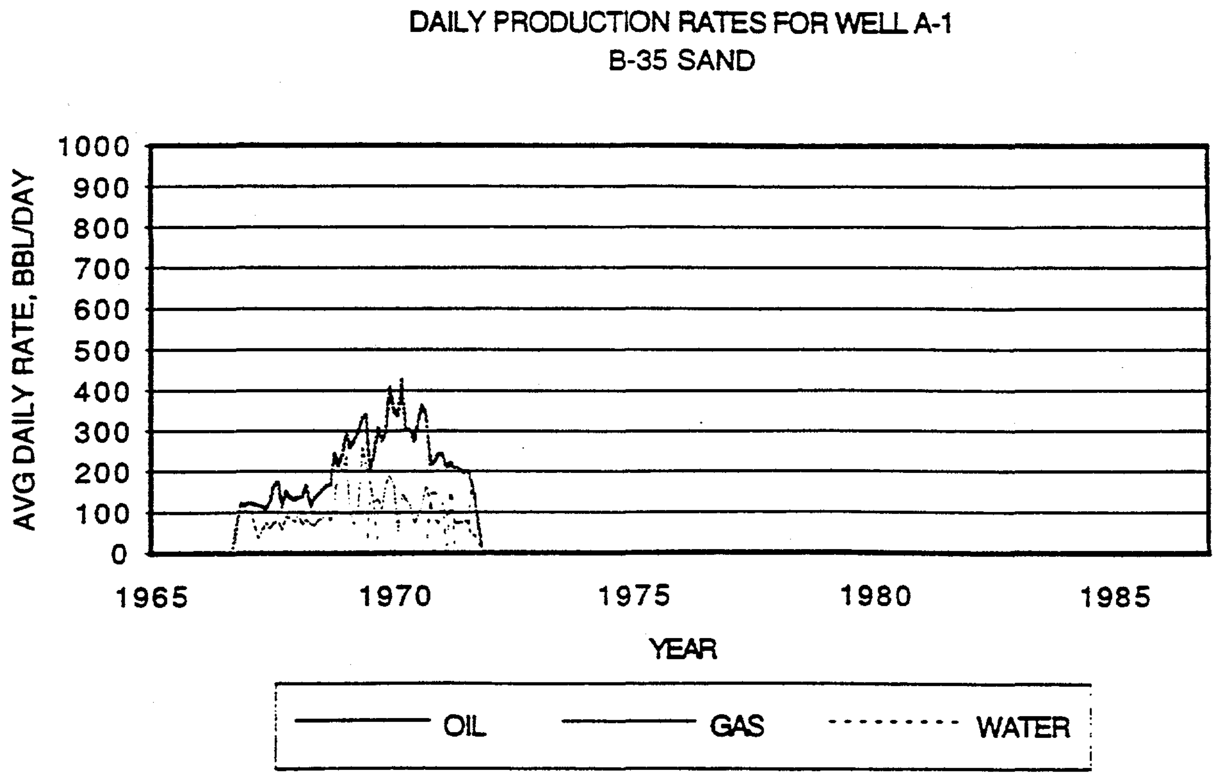


Figure 9 - Production History for SMI 73, Well A-1

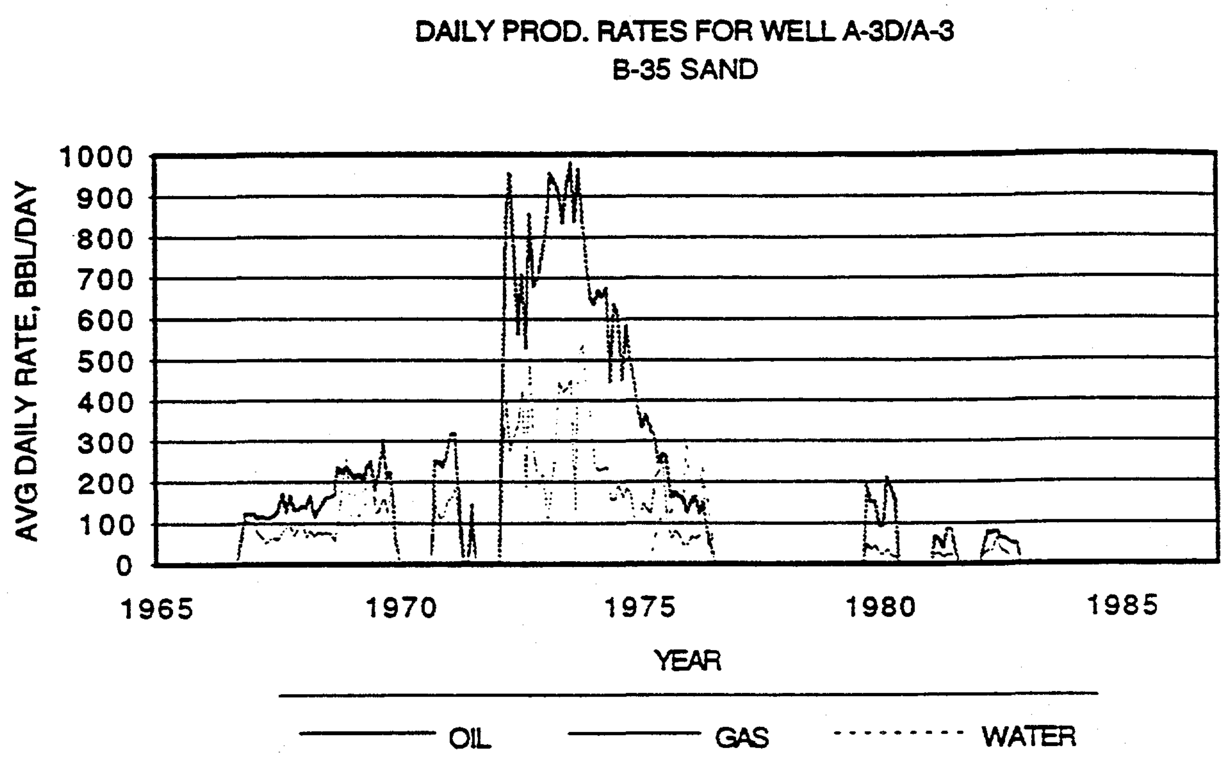


Figure 10 - Production History for SMI 73, Well A-3D/A-3

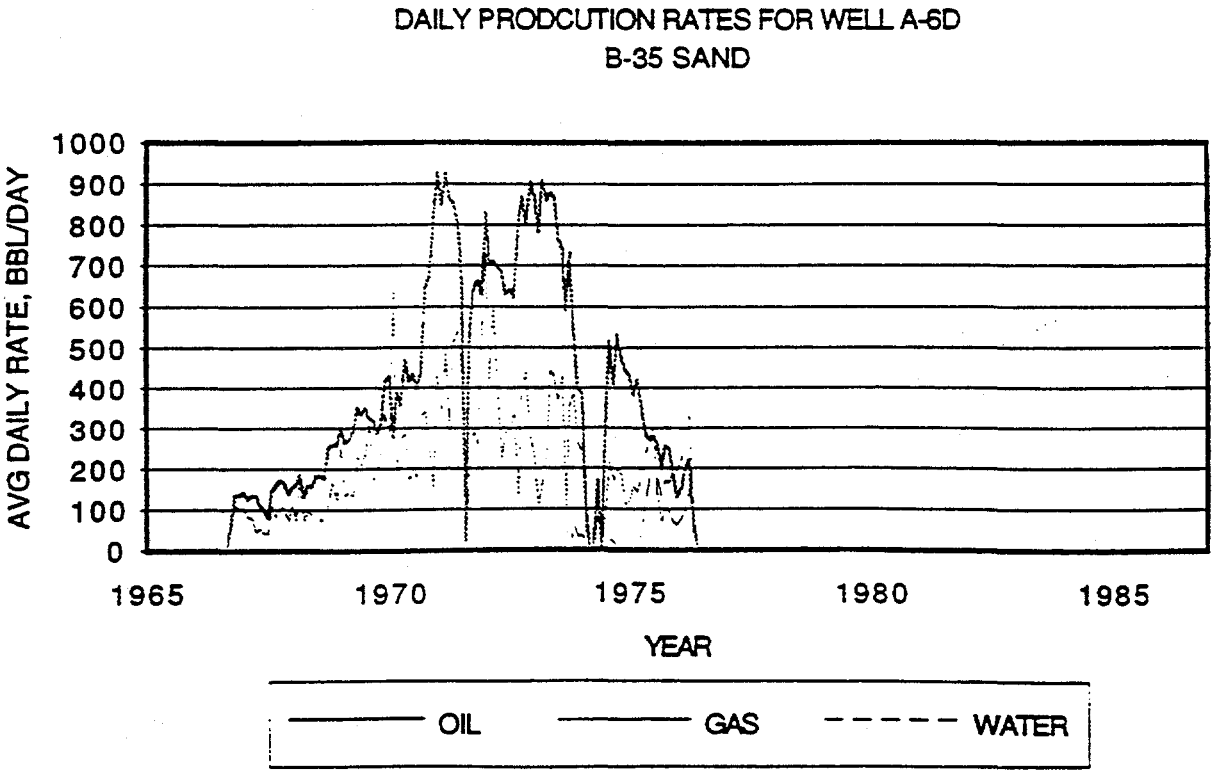


Figure 11 - Production History for SMI 73, Well A-6D

CUMULATIVE PRODUCTION FOR B-35K RESERVOIR

Well	Oil (1000 Bbl)	Gas (million scf)	Water (1000 Bbl)	Gas Injection (million scf)
A-1	394	193	43	—
A-3D, A-3	1,184	530	69	446
A-6D	1,446	739	86	—
Total	3,024	1,462	198	446

Table 1 - Cumulative Production for the B-35K Reservoir

contact to move downdip, away from the producing wellbores. Water-free production was realized until the oil-water contact moved back up to the producing wells. The success of these gas injection cycles is readily apparent from the data, although wellbore mechanical problems influenced the results of some of the gas cycles. A total of 452 MMCF of gas was reinjected into the reservoir, which resulted in the incremental recovery of 1.2 MMBO, or 2,191 BO/MMCF. The results of the gas injection cycles are indicated in Figure 8 and are summarized in Table 2. The results of the attic gas injection cycles were generally favorable and additional cycles would undoubtedly be beneficial.

GAS INJECTION DATES	INJECTION VOLUME (MMCF)	INCREMENTAL OIL RECOVERY (1,000 BO)	RECOVERY PER MMCF (BO/MMCF)
12/69 - 05/70	32	59	1,845
04/71 - 07/71	239	866	3,264
08/76 - 11/76	106	38	353
09/80 - 11/80	46	11	241
09/81 - 11/81	29	17	580
TOTAL	**452**	**1,184**	**2,191**

Table 2 - B-35K Reservoir Gas Injection History Summary

III.1c Original Oil-In-Place Calculations

The average reservoir properties were used, along with the net pay isopachous maps, to calculate three volumetric oil-in-place (OOIP) values for the B-35K Reservoir, as summarized in Table 3. The first OOIP calculation is the "Proven Oil Limit" case, which assumes that the shale-out is above the highest take point in the reservoir and that the oil-water contact is just below the lowest take point. This conservative case yields an OOIP of 3.5 MMBO, which means that recovery to date equals 86% of the OOIP. This recovery value is unreasonably large, meaning that the OOIP must be higher. If the oil-water contact is assumed to be 100 feet below the low proven point, then the OOIP increases to 7.3 MMBO, and the percent recovery decreases to 41% of the OOIP. If the sand is assumed to gradually thin in the updip direction to a zero value at the C-6 well, then the OOIP increases by 1.3 MMBO to 8.6 MMBO, reducing the recovery value to 35% of the OOIP. Also shown in this table is the original oil-in-place for the final model history match case, where the original oil-water contact was assumed to be at 6,176 feet subsea. The OOIP for this case is 6.3 MMBO and the recovery value is 48% of the OOIP.

Original Oil in Place Calculations

	Acre-Feet	OOIP Million BO	Percent Recovery
Proven Oil Limit	2,396	3.5	86%
With Estimated O/W Contact	4,961	7.3	41%
With Estimated O/W Contact and Updip Potential	5,807	8.6	35%

Assumptions:

Porosity	=	29.5%
Water Saturation	=	16.5%
Oil Formation Volume Factor	=	1.29 STB/Bbl
Initial Pressure	=	2,712 psia
Oil in Place per AF	=	1,481 B/AF

Table3 Summary of Original Oil-In-Place Calculations For the B-35K Reservoir

III.1d Summary

The South Marsh Island B-35K Reservoir appears to be a candidate for additional gas injection cycles to recover attic oil that could not otherwise be recovered. The highest structural well has watered out due to the active water drive. The updip, or attic oil volume, which is the volume above the highest well, is unknown, as is the location of the original oil-water contact. Previous gas injection cycles have successfully recovered attic oil. The remaining question is whether additional attic oil can be recovered through gas injection. The development of the numerical simulation, which will be discussed later, that accurately matches the historical performance of the B-35K Reservoir, provided reasonable predictions of the performance which could be achieved through additional gas injection cycles.

III.2 B-65G Reservoir

III.2a Reservoir Characteristics

The B-65G Reservoir is a long, north-south trending, steeply dipping sandstone, which pinches out just before encountering the piercement salt dome on its southeastern flank, as illustrated by the structure map of the sand in Figure 12. Its dip rate averages 19 degrees. Structure and trapping are all results of the piercement salt dome. The location of the pinch-out of the sand along the salt face was the portion of the reservoir for which there was the least control. This parameter is the one for which major modifications were made for a history match during computer simulation. The position of the shale-out against the salt has previously been inferred as half way between the estimated position of the salt and the most updip well control. The position of the shale-out was adjusted during the simulation of the reservoir in order to obtain a history match. Unlike the adjustments made for the B-35K reservoir, where the shale-out was moved closer to the salt face, the adjustments for the shale-out of the B-65G varied. In some locations it was necessary to move the shale-out into the reservoir, effectively making the volume of the reservoir smaller. However, at some locations it was necessary to move the shale-out closer to the salt face as was done for the B-35K reservoir. These adjustments will be discussed in detail later.

Numerous faults radiate out from the salt and isolate the sand into several reservoirs, including two that are adjacent to the B-65-G reservoir. These two adjacent reservoirs are believed to be isolated from the B-65-G reservoir by faulting because of differences observed in the bottomhole pressure histories of producing wells.

Overall it is a clean sand that averages 66 feet in gross thickness and 53 feet in net sand thickness. Material balance calculations indicated that the reservoir was originally at its bubble point with a small gas cap and contained about 12 MMSTB of oil. Its original reservoir pressure was 3457 psi at 7351 feet subsea. Simulation work assumed that this original reservoir pressure was the bubble point. The reservoir exhibits strong water drive support. These and other reservoir characteristics have been summarized in Table 4.

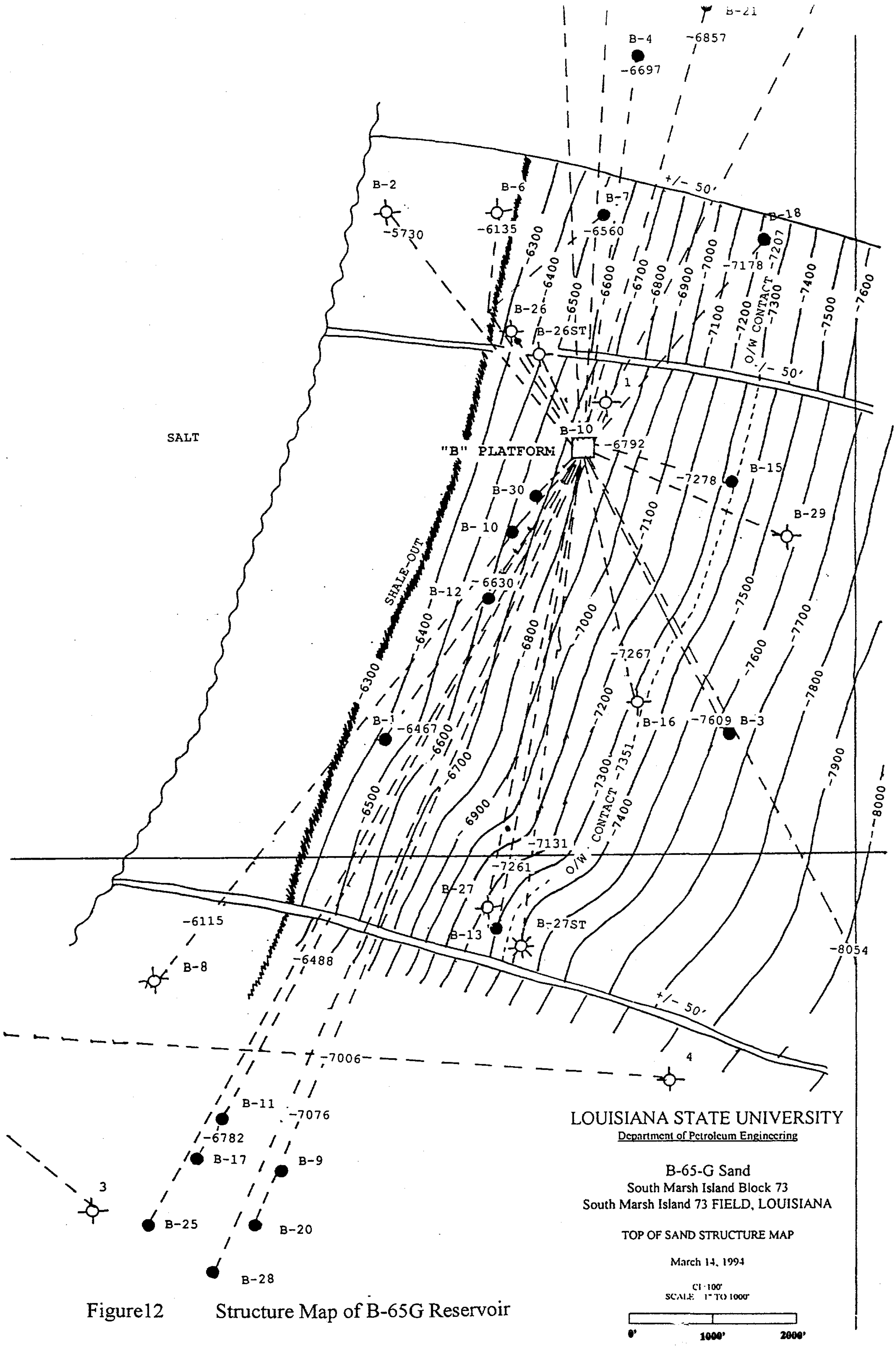


Figure12 Structure Map of B-65G Reservoir

Table 4
South Marsh Island Block 73 Field
B-65-G Reservoir Characteristics

Original Reservoir Pressure	3457 psi
Datum	7351 feet subsea
Average Porosity	28.5%
Original Water Saturation	23%
Average Thickness	37 feet
Areal Extent	267 acres
Average Horizontal Permeability	620 md
Average Horizontal/Vertical Permeability Ratio	0.1
Initial Gas-Oil Ratio	867 SCF/STB
Initial FVF	1.3 Res bbl/STB

III.2b Reservoir Production and Injection History

The reservoir has produced 6.2 MMSTB of oil, 3.4 BCF of gas (which also accounts for all gas injected back into reservoir) and 820 MBBLS of water over a period of 27 years. Four wells produced from the reservoir; three injected 2 BCF of gas and one well injected no gas. A fifth downdip well, served as a primary gas injector and injected an additional 732 MMCF of gas.

The B-65G sand reservoir began production in October 1966 when the #B-1, #B-7, and #B-10D wells were put on line. The #B-12 was put on line in February 1967. Production from these wells is shown graphically in Figures 13 through 16. The #B-11A (July 1974), #B-9D (April 1967), and #B-17 (April 1971) were all drilled south of the B-65G Reservoir and produced from the B-65GS Reservoir, which has been interpreted to be separated from the B-65G Reservoir by a sealing fault. Presently, the #B-12 and #B-1 wells are active in the B-65G Reservoir. The B-1 well is currently going through a gas injection stage. Table 5 shows the cumulative production and gas injection values through March 1995.

III.2c Original Oil-in-place Calculations

The reservoir consists of approximately 10,100 acre-feet or an average net pay thickness of 38 feet over 267 acres. Porosity averages 28.5% and the original oil saturation was estimated at 73%, with an initial formation volume factor (FVF) of 1.3 res bbls/STB. Estimated volumetrically, the original in-place-oil is 12.6 MMSTB. Therefore, through March 1995, 49.8% of the original oil-in-place had been produced. In later documentation, material balance methods confirm this amount.

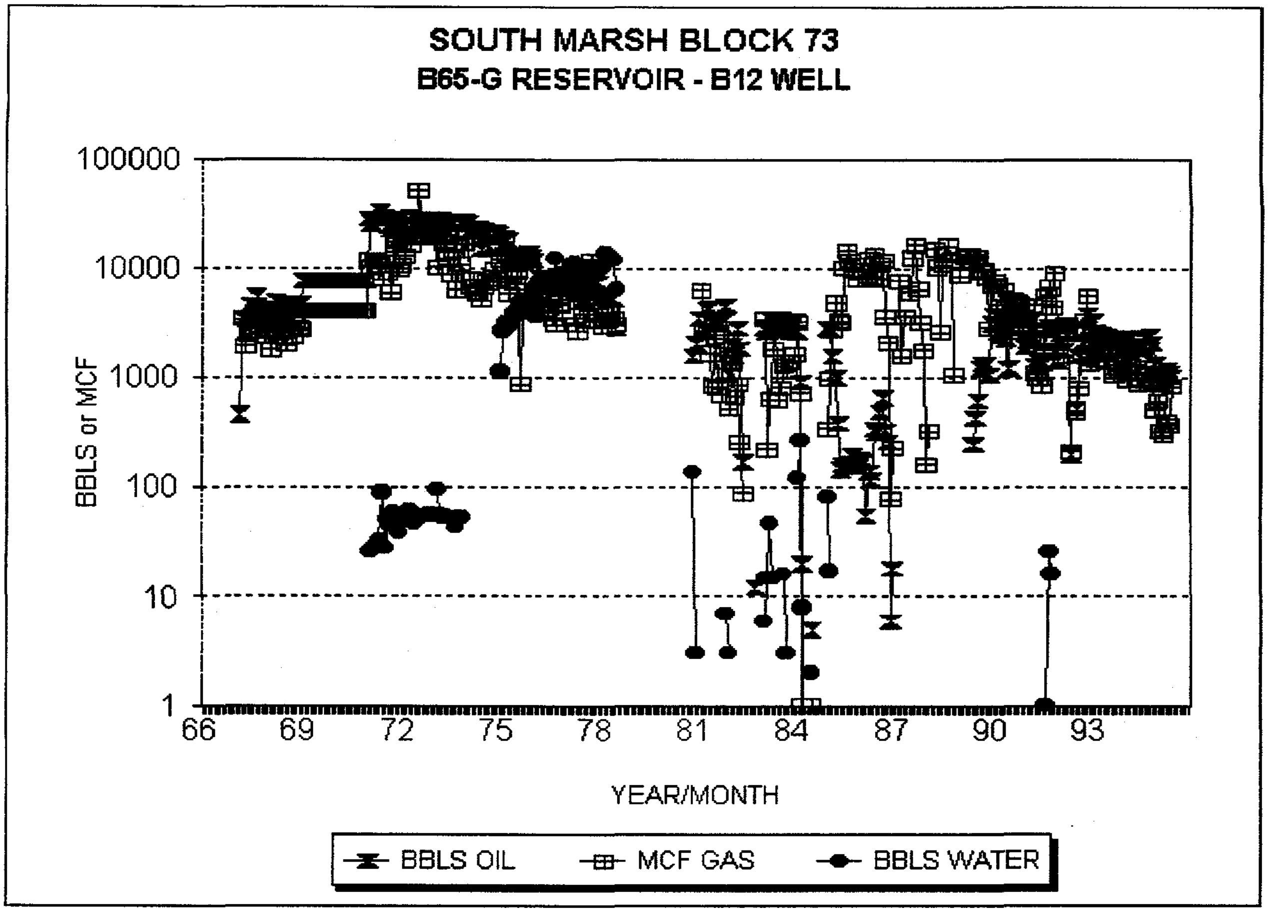


Figure 13 - Production History for SMI 73, Well B-12, B-65G Reservoir

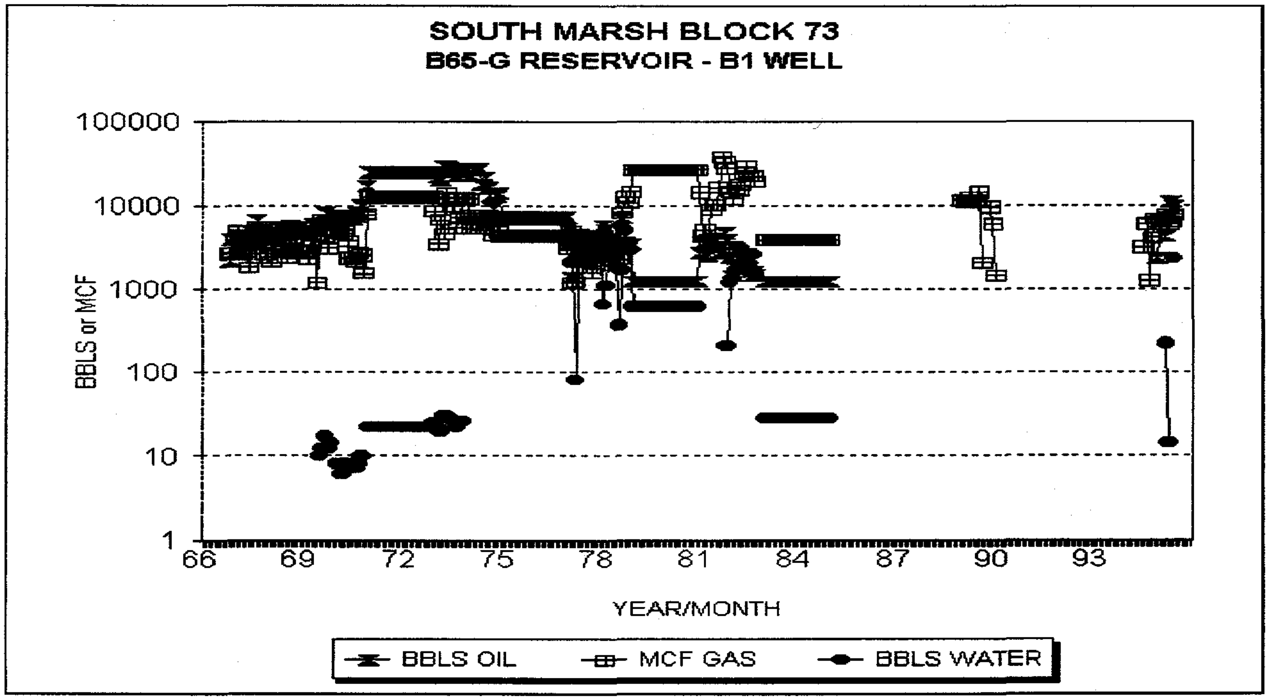


Figure 14 - Production History for SMI 73, Well B-1, B-65G Reservoir

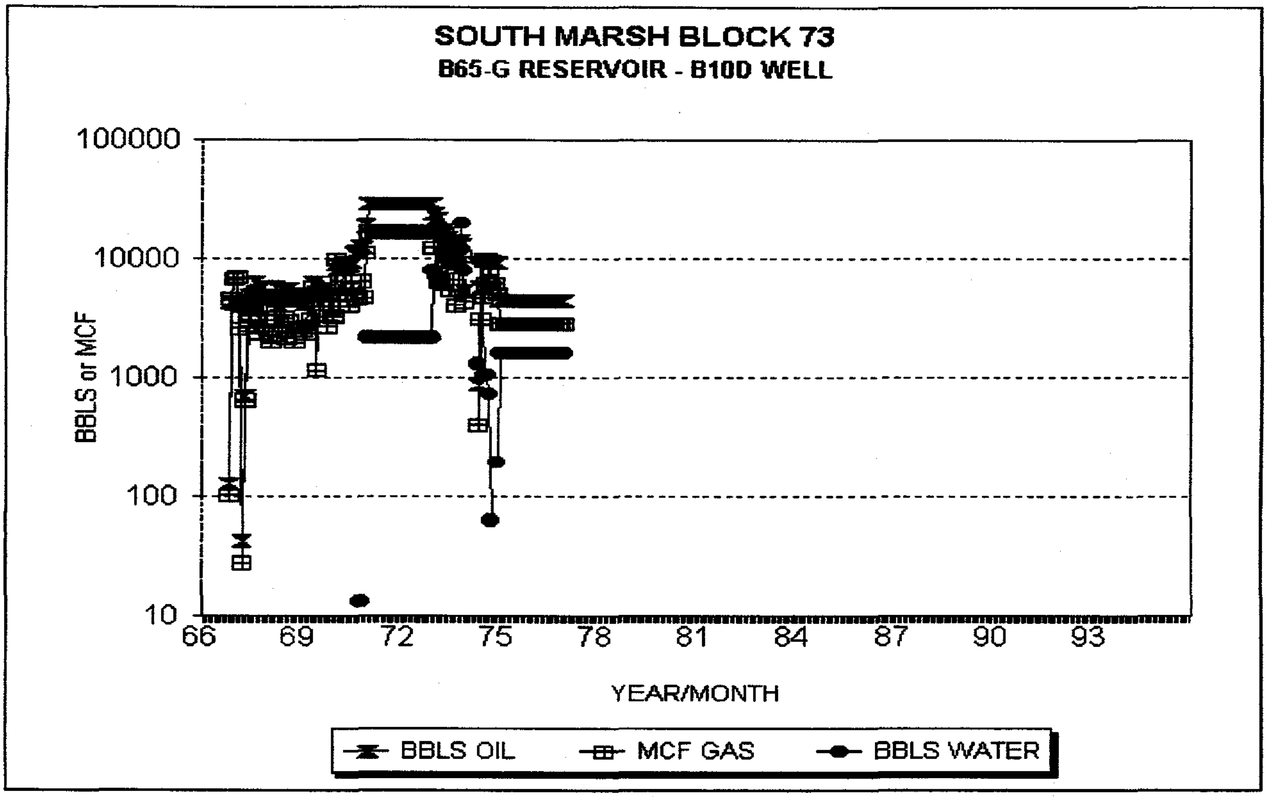


Figure 15 - Production History for SMI 73, Well B-10D, B-65G Reservoir

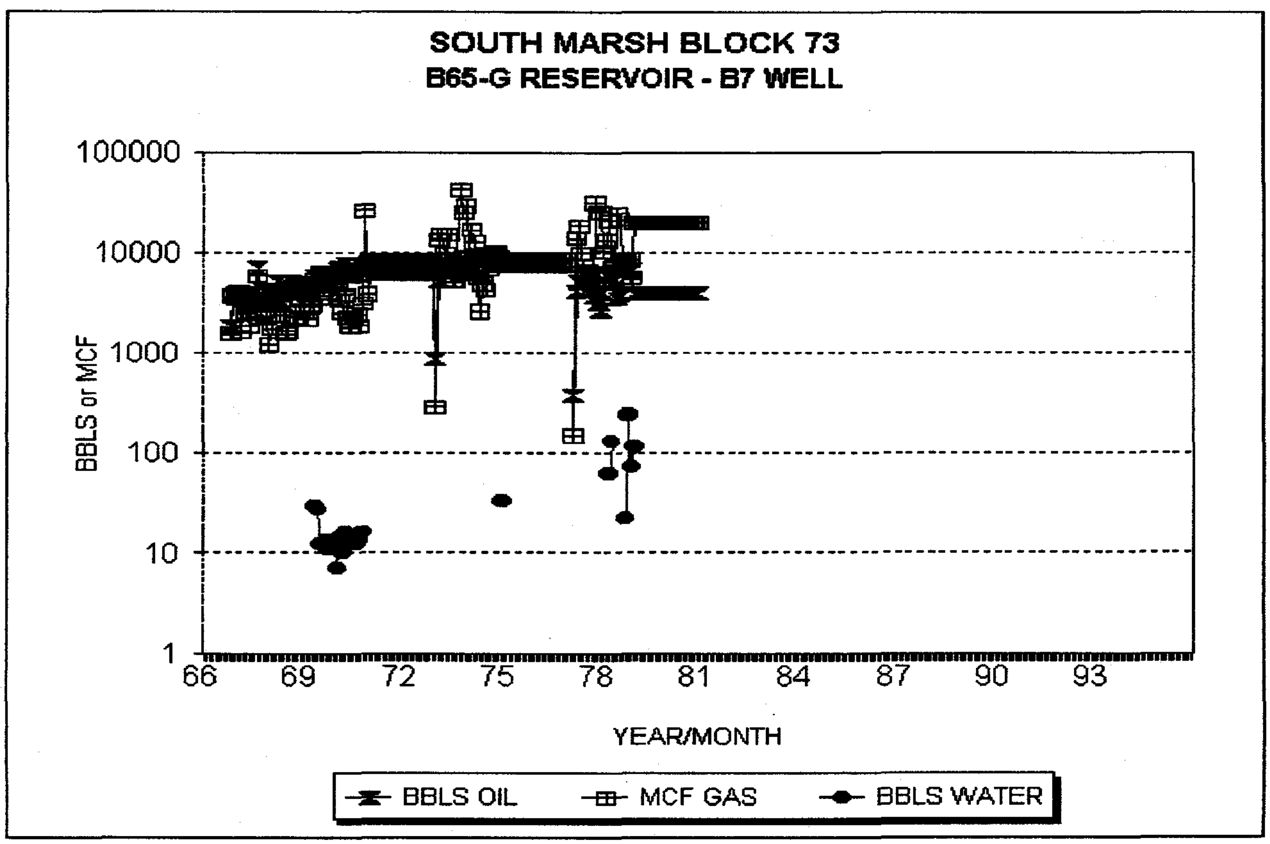


Figure 16 - Production History for SMI 73, Well B-7, B-65G Reservoir

TABLE 5
Cumulative Production and Gas Injection, B-65G Reservoir

WELL	OIL-MSTB	GAS-MMCF	WATER-MBBLS	GASINJ-MMCF
B-1	1827	2115	259	672
B-7	1020	1576	1	0
B-10D	1325	792	220	11
B-12	2108	3980	341	1348
B-15	0	0	0	732
TOTAL	*6280*	*8463*	*821*	*2763*

III.2d Summary

The B-65G Reservoir structural interpretation was inadequate. The exact placement of the southernmost fault was in question, and the northernmost fault's sealing properties were also in question. The updip, or attic oil, volume is unknown. Previous gas injection cycles have successfully recovered attic oil. The remaining questions are: Can additional attic oil be recovered through gas injection, and, if so, how much? The development of the numerical simulation, which will be discussed later, that accurately matches the historical performance of the B-65G Reservoir, provided reasonable predictions of the performance that could be achieved through additional gas injection cycles.

IV. BOAST3-PC BLACK OIL SIMULATOR

IV.1 Introduction

BOAST3-PC [1] is a Black Oil Applied Simulation Tool used routinely for performing evaluation and design work in modern petroleum reservoir engineering. In 1982 the U.S. Department of Energy released the original black oil model called BOAST[2]. BOAST II[3], released in 1987, was designed to provide more flexibility and to overcome some of the limitations of the original BOAST. Many features were added to improve the versatility of the model.

BOAST3, a modified, PC-version of BOAST II, is more efficient than its predecessor and is designed to run in a 386/486 PC-based environment. Streamlined code and use of a 32-bit Fortran compiler makes BOAST3 3.7 times faster than BOAST II.

---

[1] Sawyer, W. K., "BOAST3-A Modified Version of Handbook for Personal Version of BOAST II: A Three-Dimensional, Three-Phase Black Oil Applied Simulation Tool," Department of Energy Report Contract Number DE-AC22-92BC14831: 1996
[2] Franchi, J.R., Harpole, K.J., and Bujnowski, S.W., "BOAST: A Three-Dimensional, Three-Phase Black Oil Applied Simulation Tool," U.S. Department of Energy Report Contract Number DOE/BC/1033-3, Volumes 1 and 2: 1982.
[3] Franchi, J.R., Kennedy, J.E., and Dauben, D.L., "BOAST II: A Three-Dimensional, Three-Phase Black Oil Applied Simulation Tool," U.S. Dedpartment of Energy Report Contract Number DOE/BC-88/2/SP: 1987.

BOAST3 simulates isothermal, darcy flow in three dimensions. It assumes that reservoir fluids can be described by three fluid phases (oil, gas, and water) of constant composition with physical properties that depend on pressure only. This PC version of BOAST is limited by a maximum grid dimension of 30x28x7 or 30x7x28 in the X, Y, and Z directions.

BOAST3 has a wide range of applicability. It can simulate oil and/or gas recovery by fluid expansion, displacement, gravity drainage, and capillary imbibition mechanisms. Some of the typical field production problems that can be handled by BOAST3 include but are not limited to:

- Primary depletion studies;
- Pressure maintenance by water and/or gas injection; and
- Evaluation of waterflooding, operations.

BOAST3 is a finite-difference, implicit pressure/explicit saturation (IMPES) numerical simulator. It includes options for both direct and iterative solution techniques for solving systems of algebraic equations. The main features of BOAST3 are exhibited in Figure 17. Some of the features and options of the BOAST3 model include:

- An option for simulating steeply dipping reservoirs;
- Allowances for multiple rock and PVT regions;
- A bubble point tracking scheme;
- An automatic time step control method;
- Material balance check on solution stability;
- Allowances for multiple wells per grid block; and
- An option for rate or pressure constraints on well performance.

In addition, BOAST3 includes two post processors: B3PLOT and COLORGRID. B3PLOT is a line graphics package used to plot data, such as production, pressure, and saturation, versus time. The package has two modes: (1) Plotting simulated data, allowing comparison of the results from up to five different simulation runs; and (2) History matching, using oil, water, or gas production data, GOR, or WOR; the average reservoir pressure or bottomhole well pressure can also be matched.

COLORGRID is used to view the finite difference grid on the screen as either a plan or elevation. The range of the parameter selected determines the color of the grid. Various arrays (maps) of input or output data may be represented by a 12 band color legend. An annotation option, which displays the numerical values of the parameter selected within each grid block, is provided. Any portion of the grid may be expanded to fill the entire screen.

IV.2 General Model Input Data Analysis

Extensive data were required to perform the modeling study using BOAST3-PC. Most of the data were provided by Taylor Energy (as discussed previously) and included reservoir pressure data and production histories (oil, gas, and water production) over the lives of the reservoirs.

Geophysical well logs were provided and analyzed for porosity and water saturation values and were used as input values for the models. In addition, core data were analyzed to predict the permeability of the different zones/layers within the two reservoirs.

OVERVIEW OF BOAST3 MODEL

- Designed to run in a 386/486 PC-based environment (3.7 times faster than BOAST II)
- Three dimensional, three phase flow model with a wide range of applicability to simulate oil and/or gas recovery by:
  - Fluid expansion
  - Displacement
  - Gravity drainage
  - Capillary imbibition
- BOAST3 is a finite-difference, implicit pressure/explicit saturation (IMPES) numerical simulator
- Multiple rock and PVT regions can be defined
- Three different aquifer models are available as options
- Maximum grid dimension limits: 20x20x21

Figure17 Overview of BOAST3 Model Features

The following sections will focus upon the analysis of the different reservoir input parameters and will discuss the basis for the assumptions made in order to perform the simulation study. Because Taylor Energy's field data set was incomplete in terms of the requirements for modeling the reservoir, several assumptions based on similar producing reservoirs, field histories, and published data were made to meet the model requirements.

IV.2a Relative Permeability Curves

BOAST3-PC requires relative permeability curves as part of the input data set to simulate the three-phase flow of oil, gas, and water in the reservoir. Because measured relative permeability data were not available from the Taylor field, published data representing similar reservoirs derived from Strickland and Morse (1979) were used. Figure 18 exhibits the relative permeability curves derived from this publication. Early history match simulation runs for each reservoir indicated the need to modify the relative permeability data, as will be shown later.

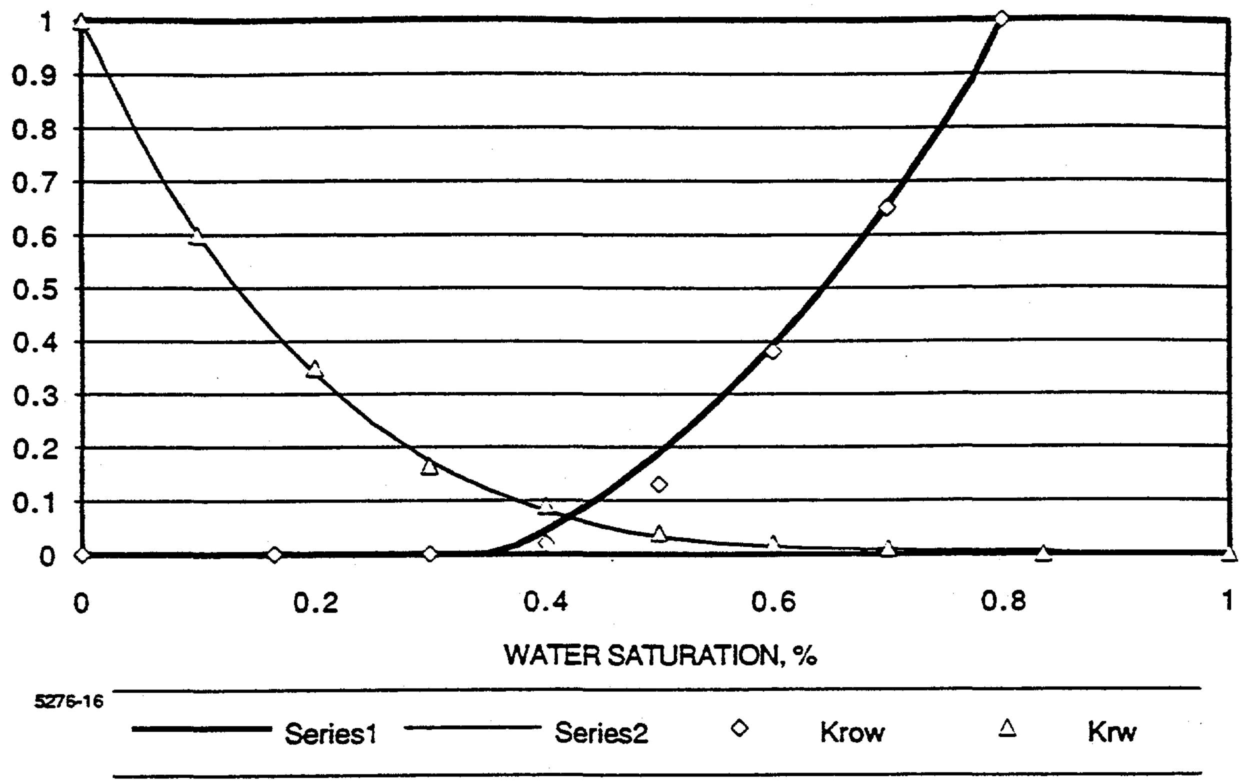


Figure 18 - Relative Permeability Curves

IV.2b PVT Data Analysis

The input data set required to run BOAST3 and simulate oil recovery includes a set of PVT (Pressure,Volume, Temperature) data representative of the fluid properties that reflect the inter-relationship among the various reservoir/fluid properties.

In the case of the Taylor field study, PVT data were not available for modeling, history matching, and predicting of the reservoirs performance. However, certain initial reservoir and fluid properties were recorded in the early life of the two reservoirs.

The need to derive a set of PVT data using initial reservoir conditions required the evaluation of several empirical PVT correlations for application in the Gulf of Mexico (Sutton and Farshad, 1990). These correlations were used to determine values for bubble point pressure, solution gas-oil ratio, formation volume factor, and viscosity. The various correlation techniques were reviewed and tested.

V.2c Productivity Index (PID) Calculations

A value of the layer flow index, PID, can be estimated as follows:

$$PID = \frac{0.00708kh}{\ln \frac{0.121(dxdy)^{1/2}}{r_w} + S} \qquad (4)$$

Where, k = Layer absolute permeability, md
h = Layer thickness, ft
dx = X-direction grid block thickness, ft
dy = Y-direction grid block thickness, ft
r = wellbore radius, ft
S = Layer skin factor

In principle, the layer flow index could be related to measured values. In practice, however, the terms r, S, and $k_{ro} / m_o B_o$ are seldom known, especially for a multiphase flowing well. For expediency, therefore, an estimate of the equivalent radius (r) and productivity index (PI) are often used for an initial estimate to model the fluid flow from the reservoir to the wellbore.

The equivalent radius, r_0, depends upon the block geometry and permeability anisotropy. The following equations were used to estimate r_0 and PI for non-fractured wells in the study area:

$$PI = \frac{0.00708 k_{avg} ds}{\ln(r_0/r_w) + S} \qquad (5)$$

For vertical wells:
ds = dz = h
S = 0 (assumed for this calculation)
$k_{avg} = (k_x k_y)^{1/2}$
$r_0 = 0.28 \frac{(R^{1/2} d1^2 - R^{-1/2} d2^2)^{1/2}}{R^{1/4} + R^{-1/4}}$

Where, R= ky/kx
d1 = dx
d2 = dy

[4] Peaceman, D.W.; "Interpretation of Well-Block Pressures in Numerical Simulation", Society of Petroleum Engineer's Journal, (1978) pp. 183-194.
[5] Ibid, 183-194.

V.2d Water-Oil Ratio and Gas-Oil Ratio Constraints

Maximum gas/oil (GOR) and water/oil (WOR) ratios are input by the user and apply to every oil production well. WOR is defined as total water production divided by total oil production for all active well completion intervals. If WOR for the well exceeds WORMAX, then the completion interval (layer) with the highest WOR will be shut-in. If more than one layer has the same maximum WOR, the deepest layer will be shut-in first. This same concept applies to the GOR, where the maximum GOR controls the performance of the reservoir.

V. SIMULATION

V.1 B-35K Reservoir

V.1a Reservoir Model Grid Dimensions and Geometry

A 14x11x3 grid was generated and superimposed on the structural map for elevation readings and on the isopach map for reading thickness values for each of the grid blocks. The elevation values were read at the midpoint of each grid block. Using the elevation values, an angle of inclination (Alpha) greater than zero for downward dip in the x-direction was computed by the simulator. Figure 19 exhibits the grid used for simulating the B-35 Reservoir. The option of reading a depth value for each grid block in layer one (part of the input data set) was used. The elevations to the midpoints of the grid blocks in layers two and three were computed by the simulator using the elevations of the grid blocks in layer one and the thickness values for layers two and three.

V.1b Porosity, Water Saturation, and Permeability Distribution

Geophysical well logs and sidewall core data were provided by Taylor to assist in evaluating the reservoir parameters in terms of porosity, water saturation, and permeability. A review of the geology and core data indicated that a three-layer model described the B-35 Reservoir adequately. The top and bottom layers had high permeability values and were separated by a shaley streak with a much lower permeability. An evaluation of the geophysical well logs revealed porosity and water saturation values that are comparable with other Gulf of Mexico reservoirs. Figure 20, which illustrates a representative log, summarizes the results of the log analysis and lists the estimated thickness, porosity and water saturation for each layer.

The core analysis performed on well A-3D/A-3/A-3ST generated a list of permeability versus porosity values at different depths. A plot of these data was generated using a best-fit curve, as shown in Figure 21. A value of average permeability for each layer was read from Figure 21 for each porosity value determined from the geophysical well log interpretations. As Figure 20 illustrates, both layer one and layer three were separated by a thin, lower permeability layer. Using this geological interpretation, a constant thickness per block of five and six feet for layers two and three, respectively, was assumed. The thickness of each grid block in layer one was calculated by subtracting the sum of the thicknesses of layers two and three from the value of total net thickness values obtained from the modified isopach.

RESERVOIR SIMULATION GRID SCHEME

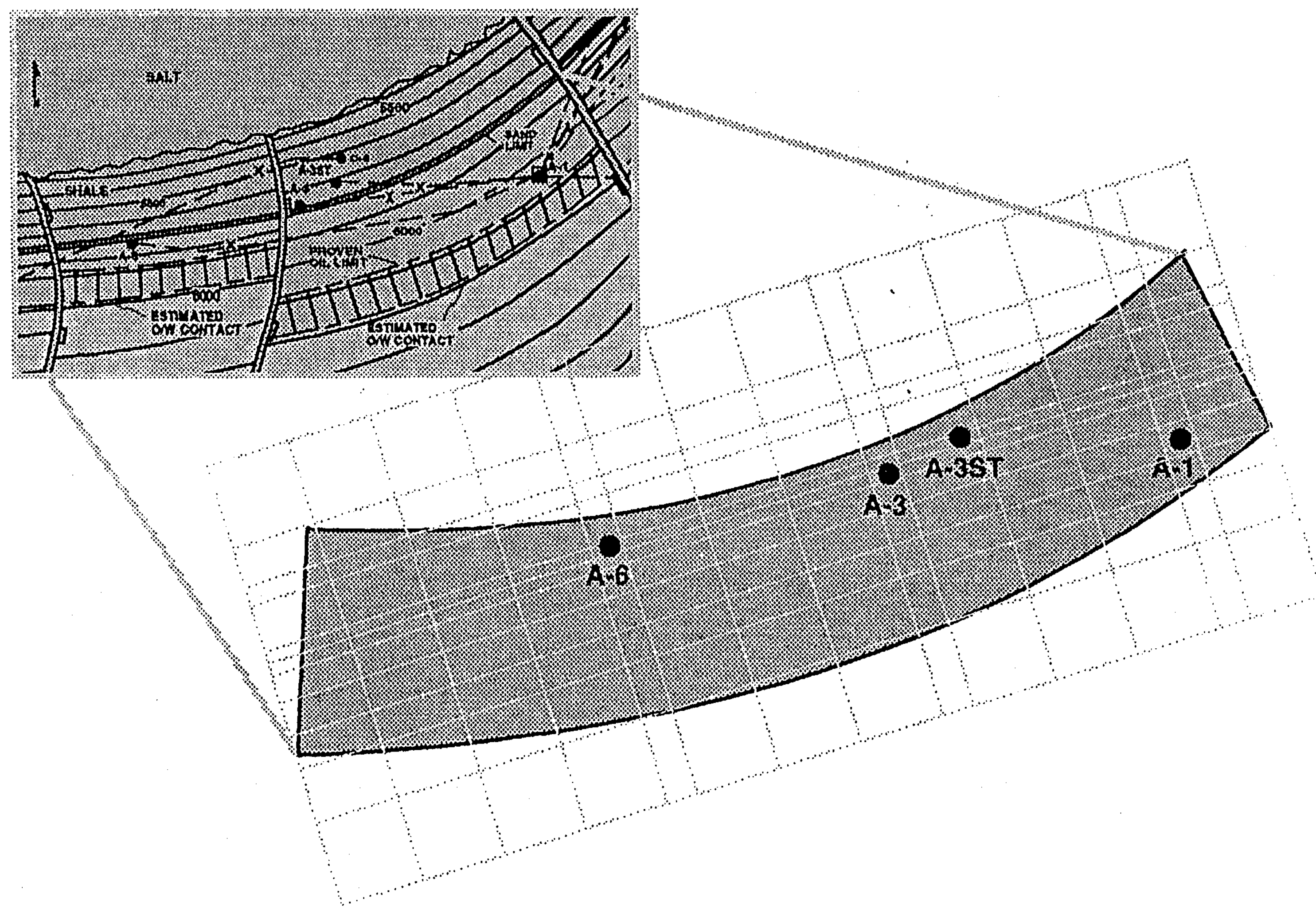
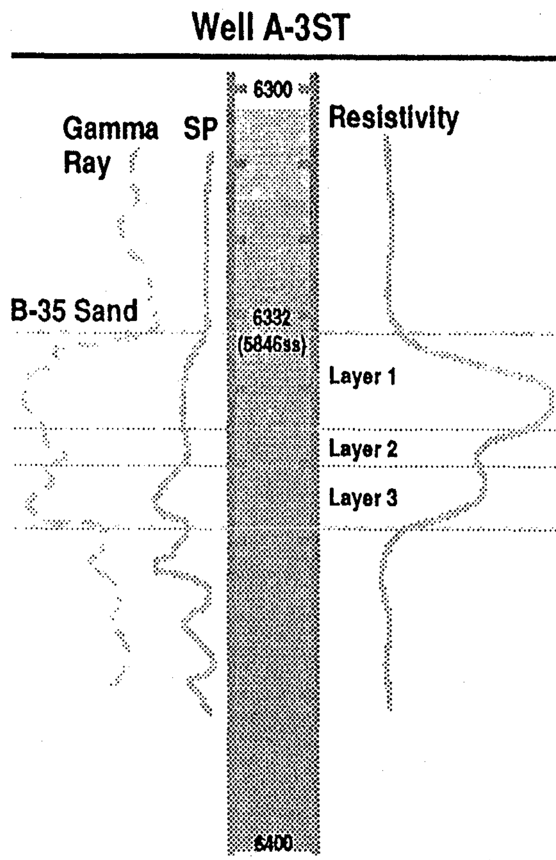


Figure19 Reservoir Simulation Grid Scheme

RESERVOIR SIMULATION LAYERS AND DATA



Layer	Average Thickness (ft)	Porosity (%)	Water Saturation (%)	Permeability (md)
1	11	33	18.5	1440
2	5	29	24.7	570
3	6	32	20.5	1125

Figure20 Reservoir Simulation Layers and Data

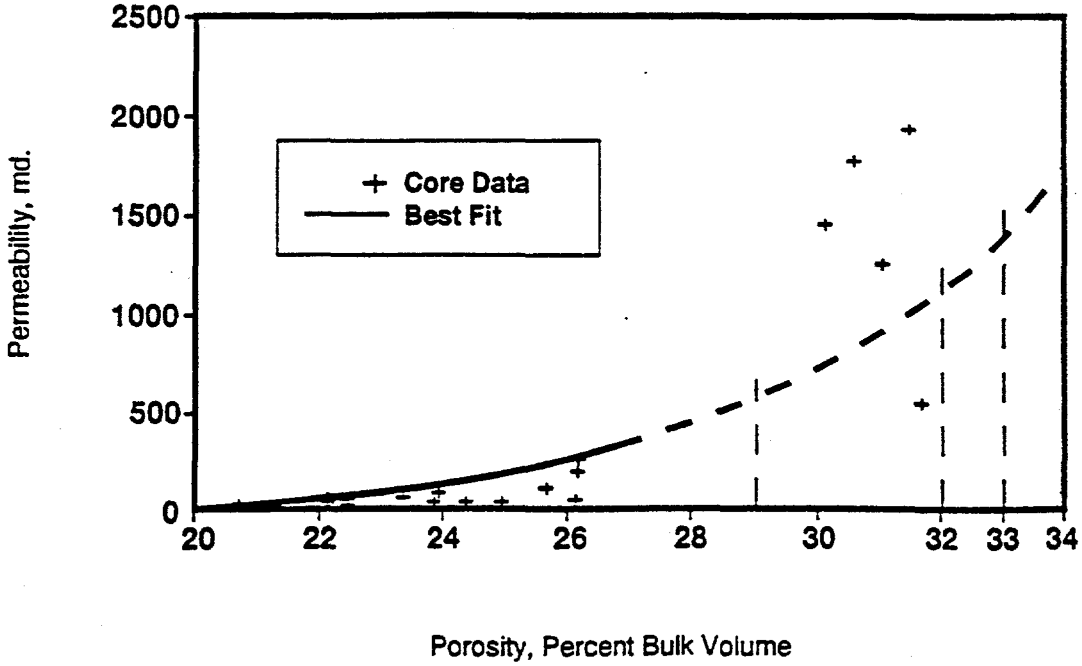


Figure 21 - Correlation of Porosity versus Permeability

V.1c Relative Permeability Curves

Figure 22 illustrates the modified relative permeability curves used to arrive at a final history match of the actual pressure and production data for the B-35K Reservoir. The results of the early simulation runs indicated that the relative permeability curves are critical data elements in terms of impact on simulation performance. Unfortunately, relative permeability curves are often among the missing, or poorer quality, data. Relative permeability data are affected significantly by alterations in wettability conditions in the core. In principle, three-phase relative permeabilities should be used when oil, water, and gas are flowing simultaneously. As a practical matter, the difficulty of accurately measuring three-phase relative permeabilities often makes their use meaningless. It is often sufficient to work with two-phase relative permeability curves only. For these studies, BOAST3 computed a three-phase oil relative permeability curve using water-oil and gas-oil relative permeability curves.

V.1d PVT Data Analysis

The bubble point pressure of the B-35K Reservoir was estimated by constructing a plot of reservoir voidage versus reservoir pressure, as shown in Figure 23. From this plot, the bubble point pressure was estimated to be 2,723 psig.

Glaso' s method was used for calculating bubble point pressure, oil formation volume factor, and solution gas-oil ratio and dead oil viscosity correlations. The Calhoun correlation was determined to explain most accurately the oil compressibility, which is dependent on the bubble point pressure estimate. The Vasquez and Beggs correlation was used to derive the viscosity of the undersaturated oil. Table 6 tabulates the results of the empirically derived PVT data using the different correlation methods.

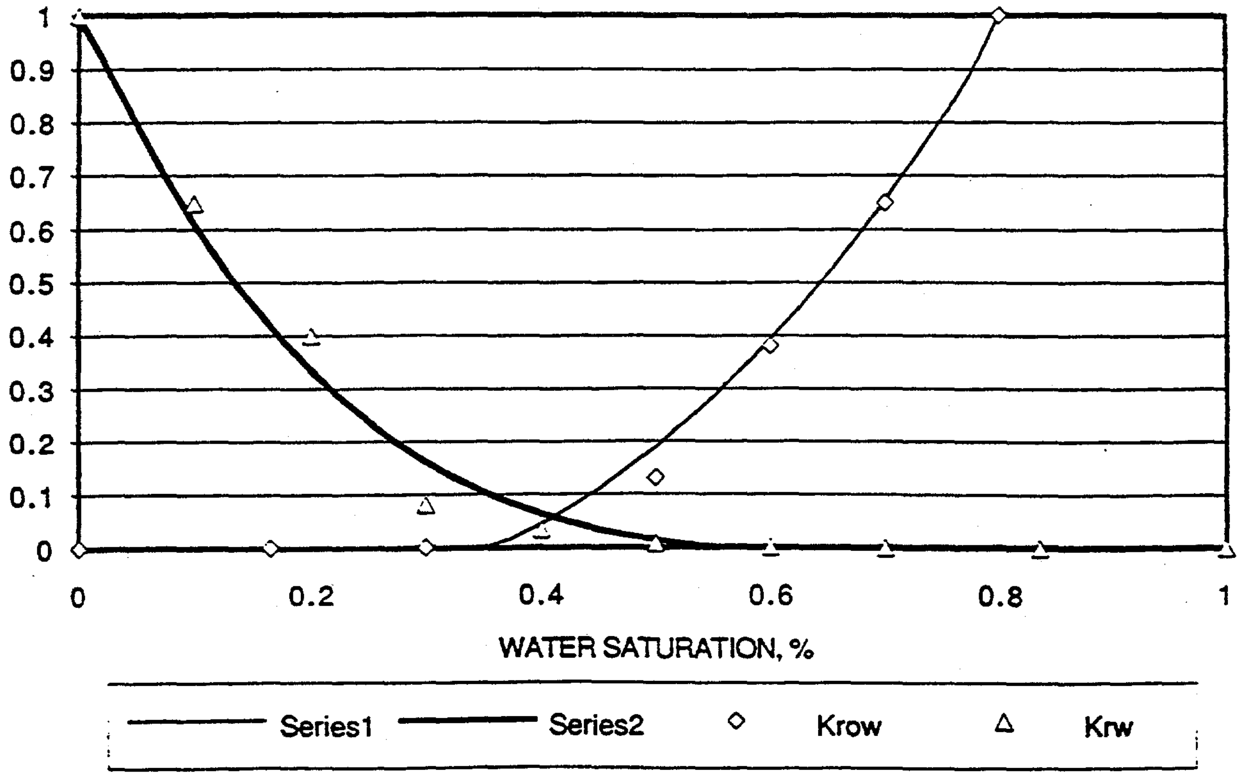


Figure 22 - Modified Relative Permeability Curves for B-35K Reservoir

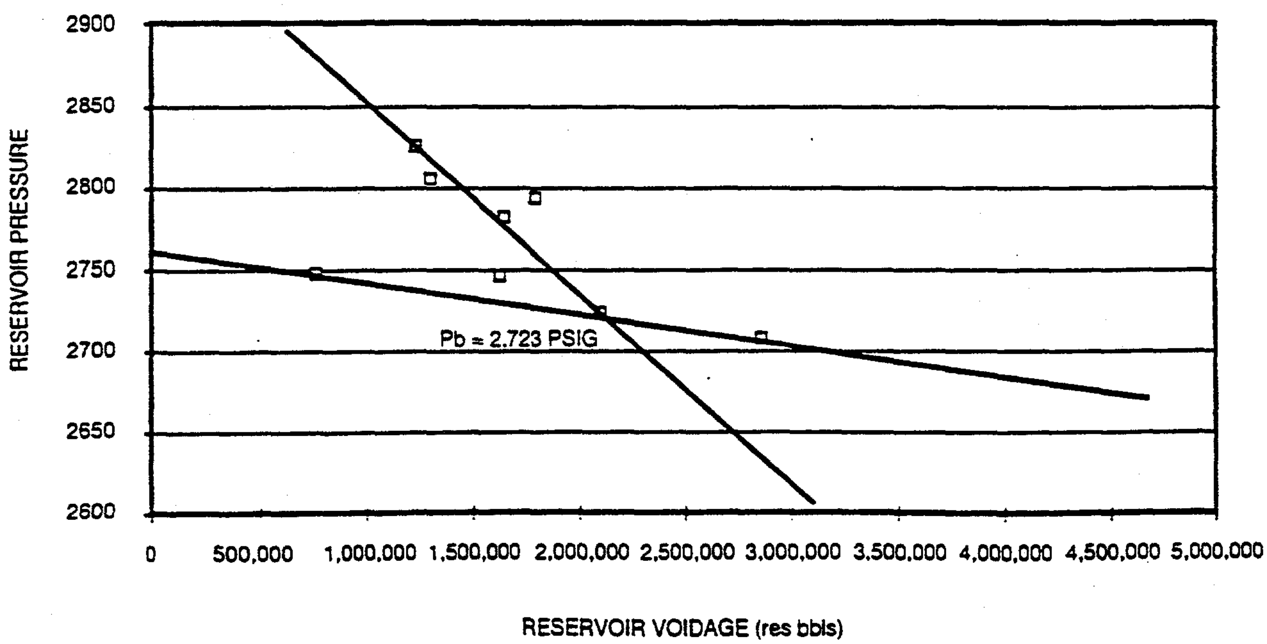


Figure 23 - Reservoir Voidage versus Pressure for B-35K Reservoir

TABLE 6. PVT DATA SUMMARY TABLE B-35K RESERVOIR

SOLUTION GOR & BUBBLE POINT PRESSURE CORRELATION (GLASO'S)

Pb, psig	*Pb**	*Rs*
3000.00	17.85	546.08
2900.00	17.25	523.70
2800.00	16-65	501.69
2700.00	16.07	480.06
2600.00	15.48	458.79
2500.00	14.91	437.89
2400.00	14.33	417.34
2300-00	13.76	397.14
2200.00	13.20	377.28
2100.00	12.64	357.76
2000.00	12.08	338.57
1900.00	11.53	319.72

OIL FORMATION VOLUME FACTOR (GLASO'S)

Rs	*Bob'*	*Bob*
480.00	540.23	1 510

PRESS, PSI	*Bo*
2808.00	1.2035
2800.00	1.2024
2700.00	1.51038
2600.00	1.2053
2500-00	1.2067
2400.00	1.51082
2300.00	1.51096
2200.00	1.2111
2100-00	1.2125
2000-00	1.2140

COMPRESSIBILITY CORRELATION (CALHOUN)

Gob	*Pb*	*COMPRES*
0.71	2723.00	1.20E-05

DEAD OIL VISCOSITY CORRELATION (GLASCO'S)

TEMP,°F	*API*	*VISC, cp*
146.00	34.30	2.588

GAS SATURATED OIL VISCOSITY (BEGGS & ROBINSON)

Rs	*mod*	*a*	*b*	*Mob*
480.00	2.588	0.404	0.616	0.726

UNDERSATURATED OIL VISCOSITY (VASQUEZ & BEGGS)

Mob = 0.726
Pob = 2723.00

PRESS	*m*	*MO*
3000.00	0.27	0.745
2900.00	0.26	0.738
2800.00	0.25	0.731
2700.00	0.24	0.725
2600.00	0.23	0.718
2500.00	0.22	0.712
2400.00	0.22	0.707
2300.00	0.21	0.701
2200.00	0.20	0.696
2100.00	0.19	0.691
2000.00	0.18	0.687

Key: Pb = Bubble point pressure (psig)
Pb' = Correlating number for Pb calculation
Rs = Soluton gas-oil ratio (scf/STB)
Bob = Oil formation volume factor at Pb (Bbl/STB)
Bob* = Correlating number for Bob calculation
Bo = Oil formation volume factor
Gob = Correlation of isothermal oil compressibility (g/cc)
COMPRESS = Oil compressibility
Mod = Viscosity of dead oil (cp)
a,b,m = Correlation constants
Mob = Viscosity of gas saturated oil (cp)
Mo = Viscosity of undersaturated oil (cp)

V.1e Aquifer Model

Modeling the actual reservoir behavior required the simulation of the aquifer that was contributing to the production performance of each of the producing wells in the reservoir. To simplify the solution methods and to account for the aquifer strength in terms of the water influx, the aquifer was assumed to be steady-state in order to maintain an essentially constant reservoir pressure.

A spreadsheet was developed to compute the water influx (W_e) for an undersaturated oil reservoir with a water drive using initial reservoir conditions and parameters. The spreadsheet was generated using Slider's method for computing the water influx. Figure 24 lists the required input data and shows the results of Slider's method for calculating the water influx.

The model's steady-state aquifer option allowed the following model equation to be used to simulate the rate of influx:

$$qwss = SSAQ\,(P_c - P_{n+1}) \qquad (6)$$

Where, q_{wss} = Water influx rate for steady state flow. scf/d
SSAQ = Model constant, scf/day/psi
Po = Initial grid block pressure, psi
P_{n+1} = grid block pressure at a future time, psi

From the above generated spreadsheet (***Figure 24***):

$$W_e = \frac{BQw(Po - P\,n+1)}{2.0} \qquad (7)$$

Simplifying equation 7 and dividing by time value t:

$$\frac{We}{t} = \frac{BQw(P0 - Pn+1)}{2.0t}$$

$$qwss = \frac{BQw(P0 - Pn+1)}{2.0t} \qquad (8)$$

Where, q_{wss} = Water influx rate for steady state flow, bpd (Slider)

To convert qwss to scf/day, which satisfies the model requirements by assuming that:

$$SSAQ = \frac{BQtD}{11.23t} \qquad (9)$$

$$q_{wss} = \frac{BQtD(P0 - P_{n+1})}{11.23t} \qquad (10)$$

---

[6] Ibid, 183-194.
[7] Ibid, 183-194
[8] Ibid, 183-194.
[9] Ibid, 183-194.
[10] Ibid, 183-194.

Initial Data

Initial Reservoir Pressure	2712 psi	Porosity, Ø	29.5 %
Saturation Pressure	2712 psi	Permeability, k	1.275 Darcy
Reservoir External Radius	1224 ft	Water compressibility	3E-6 psi^{-1}
Aquifer External Radius	20000 ft	Oil compressibility	7.7E-6 psi^{-1}
Reservoir Thickness, h	22 ft	Formation Compressibility	4E-6 psi^{-1}
Water Viscosity, μ_w	0.56 cp	Init. Oil Form. Vol. Factor	1/29 bbl/stb
Connate Water Sat., S_w	16.5 %	Production Rate, q_o	250 bbl/day

Water Influx Calculations at Time = 1027 days

$$B = 1.12\Phi hcr^2 = 76.23$$

$$\text{diffusivity}, \eta = \frac{6.33k}{\Phi\mu c} = 6,979,202.70$$

$$t_{D(1027\ days)} = \frac{\eta t}{r^2} = 4,784.25$$

$$r_{De} = \frac{r_{aquifer}}{r_{reservoir}} = 16.34$$

$Q_{tD(4,784)}$ from Table 3.2 (Slider, p. 110) = 1,146.68

$$B_{op} = B_{oi} + c_o(p_i - p)B_{oi} = 1.31699$$

$$N = \frac{\Pi r^2 h\Phi(1 - S_w)}{5.615B} = 3,500,000 \text{ bbls}$$

$$B\left(\frac{p_{n-1} - p_{1027\ days}}{2}\right)Q_{tD} = N_pB_o + W_p - N(B_o - B_{oi}) + (c_f + c_wS_w)\left[\frac{\Delta pB_{oi}N}{(1 - S_w)}\right]$$

$$p_{1027\ days} = 2705 \text{ psi}$$

$$W_{e(1027\ days)} = \left[\frac{BQ_{tD}(p_i - p_{1027\ days})}{2}\right] = 271,318.75 \text{ bbls}$$

Figure24 Summary of Water Influx Calculations

Equation (10) is equal to equation (6) and, therefore, the SSAQ value can be calculated.

To calculate SSAQ for the model, use the generated data from the spreadsheet at t=1027 days.

$$SSAQ = \frac{1146.68 * 76.23}{11.23 * 1027} = 7.58$$

Finally, the above SSAQ value was used as an initial value to history match the reservoir pressure and production and quantify/model the aquifer.

V.1f Productivity Index Calculations (PID)

The following Table 7 summarizes the results of the PI calculations per well required for simulating the B-35 sand reservoir.

TABLE 7
SUMMARY OF CALCULATED PI VALUES BY LAYER FOR EACH WELL

	PI VALUES		
WELL#	**LAYER 1**	**LAYER 2**	**LAYER 3**
A-1	29.60	4.50	10.67
A-3D/A-3	28.18	4.85	11.49
A-6	20.40	4.76	11.27

V.1g Water-Oil Ratio and Gas-Oil Ratio Constraints

In this study the WOR was the controlling factor in terms of the wells shut-in schedule. Using the available field data, the pressure and production histories were matched using a WORMAX of 2.0 as the cut-off point. If WOR exceeds the WORMAX of 2.0, then the well is shut-in.

When simulating and predicting the reservoir performance due to future gas injections a WORMAX of 1.5 was used as the cut-off point. Based on this assumption, the results of these predictions were conservative in nature.

V.1h Recurrent Data

In an attempt to simulate the actual production and pressure history of the reservoir, several solution methods were reviewed and tested to determine the optimum setup of the data leading to accurate results. After reviewing the data, it was determined that using oil production rates with an implicit rate calculation option should result in accurate predictions of the reservoir performance when simulating the actual history. Since the oil rate per well was specified, the reservoir's pressure, gas production, and water were simulated and compared to actual reservoir pressure and production values. Average oil rates were computed over specified time periods with each average oil rate represented by a recurrent data set. Small initial time steps and time increments were used to control any computational errors associated with the time step size.

When simulating/projecting the reservoir performance due to future gas injection cycles, pressure and productivity index constants were used to simulate the additional oil, gas, and water production using the implicit pressure calculation option.

Appendix A provides a listing of the input data set used for history matching the actual pressure and production data, and for simulating the performance of the reservoir due to future injection cycles. It is worth noting that in the history matching stage, the four injection cycles that were performed during, the life of the reservoir were simulated using gas injection rate specified option using implicit rate calculation.

In terms of the model's solution method, the Line Successive Over-Relaxation (LSOR) option with z-direction tridiagonal algorithm was recommended and used as the optimum solution method for solving two or three dimensional problems. The LSOR solution method in the z-direction will account for the flow between the different layers and thereby model the actual performance of the reservoir. Certain parameters associated with the LSOR-Z solution method are listed in the BOAST3-PC manual and their values are exhibited in the input data set (Appendix A).

V.1i Additional Reservoir Simulation Assumptions

In addition to the available input parameters for the model that were used and discussed above in simulating the B-35K Reservoir, additional parameters were assumed and estimated based on geologic and engineering data (See Figure 25).

An initial reservoir pressure of 2,712 psig measured at a datum point of 5,846 feet was used as a model input parameter. This pressure value was measured in the early life of the reservoir. Additional reservoir shut-in measurements were not available to provide the basis for a pressure build-up analysis in order to estimate the initial reservoir pressure.

Permeability anisotropy was another input parameter required by the model. Based on the provided geologic data, the permeability values in the X and Y- directions were assumed equal, whereas the permeability in the Z - direction was different ($K_x = K_y + K_z$).

Based on the available and assumed reservoir parameters a model representing this reservoir was developed to simulate the actual reservoir performance as detailed in the following sections.

V.1j History Match

History matching the production performance of the B-35K Reservoir was refined by modifying the water-oil relative permeability curve, the down-dip location of the estimated oil-water contact, and the estimated attic volume of the reservoir. The final values for these variables in the model were used to accurately match the primary performance of the reservoir as well as the performance of the reservoir as a result of the five attic gas injection cycles. The gas production, oil production, and pressure data were relatively easy to match. However, a match of the water production history, necessitated modifying the water-oil relative permeability curves, the oil-water contact location, and the attic oil volume. The details of five of the most significant history match cases are presented in detail in Appendix B.

Additional Reservoir Simulation Assumptions

- Initial reservoir pressure = 2,712 psig
  Reservoir datum = 5,846 ft
- Estimated PVT data based on values at initial conditions
- Estimated/modified relative permeability curves taken from "Gas Injection for Upstructure Oil Drainage," Strickland and Morse, JPT October 1979, pp 1323-1331
- $Kx - Ky \neq Kz$
- Wells producing from three different layers with variable formation properties
- Initially, used proven oil limit with "water-oil contact" at 6,076 ft
- Wells producing at historical average oil production rates

Figure25 Additional Reservoir Siinulation Assumption

The location of the oil-water contact had a significant impact on the production performance indicated by the simulator. Since the sand thickens in the down-dip direction (see Figure 6), the original oil-in-place in the reservoir increases significantly as the oil- water contact is pushed down-dip. If the water-oil contact is assumed to be at the proven oil limit of 6,076 feet subsea, as defined by Well A-1, the original oil-in-place is estimated at 3.5 million barrels of oil. By moving the water-oil contact 100 feet downdip to 6,176 feet subsea, the original oil-in-place more than doubles to 7.3 million barrels of oil. (This case is Run 2, included in Appendix B.) The downward movement of the oil-water contact in the simulator significantly impacts the water production rate since the water level is moved away from the production well take points. Comparison of the simulated cumulative water production from these two cases illustrates the impact of the water-oil contact movement, as shown in Figure 26. The producing well waters out much too soon in Run I and too late in Run 2, as compared to the actual data. The optimum match of water production performance was achieved in the final history match by assuming that the water-oil contact was approximately 60 feet below the proven oil limit (Run 5).

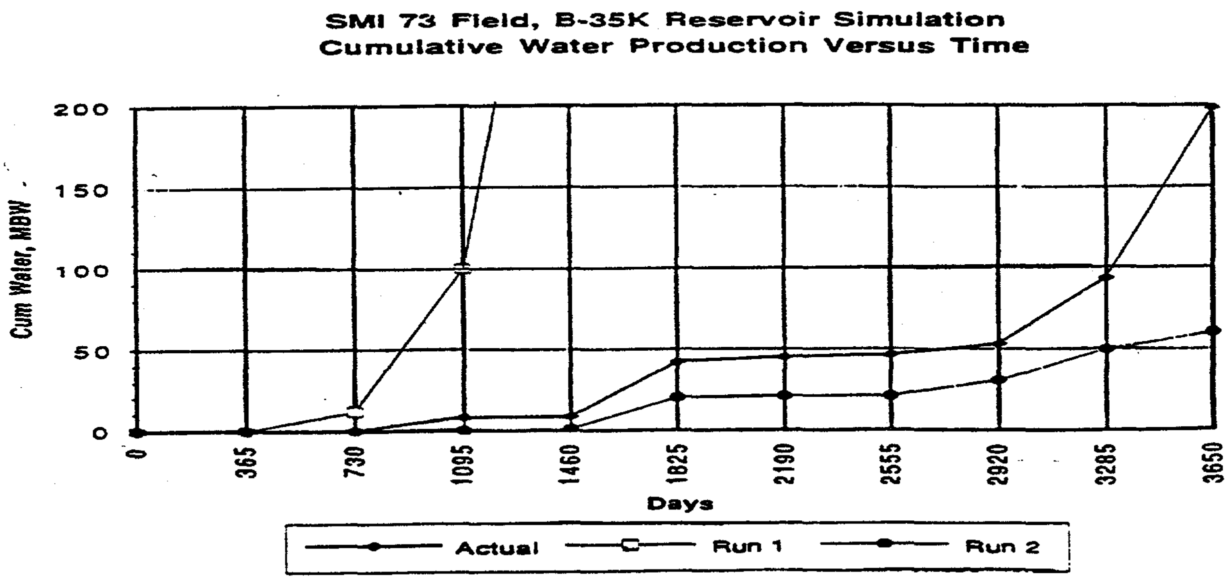


Figure 26 - Comparison of Cumulative Water Production for History Match Runs 1 and 2

The addition of an attic oil volume also impacted the simulated reservoir performance. The original oil-in-place is not significantly impacted since the sand appears to thin in the up-dip direction (see Figure 6), but the production performance is impacted. By moving the sand limit up-dip approximately 200 feet structurally, the original oil-in-place in the reservoir increases from 7.3 to 8.6 million barrels of oil, so the assumed attic volume is approximately 1.3 million barrels of oil. The impact of the addition of the attic oil volume is illustrated in Figure 27 by comparing the cumulative water production values from Run 3 and Run 4. The results of Run 3 match the actual water data fairly well, until the later time frame, at which point water production is too low. When the attic oil volume is added, Run 4, the water production falls below the actual data. This problem was solved in Run 5, the final history match case, by assuming that the oil-water contact was at an elevation of 6,137 feet subsea, or approximately 60 feet below the proven oil

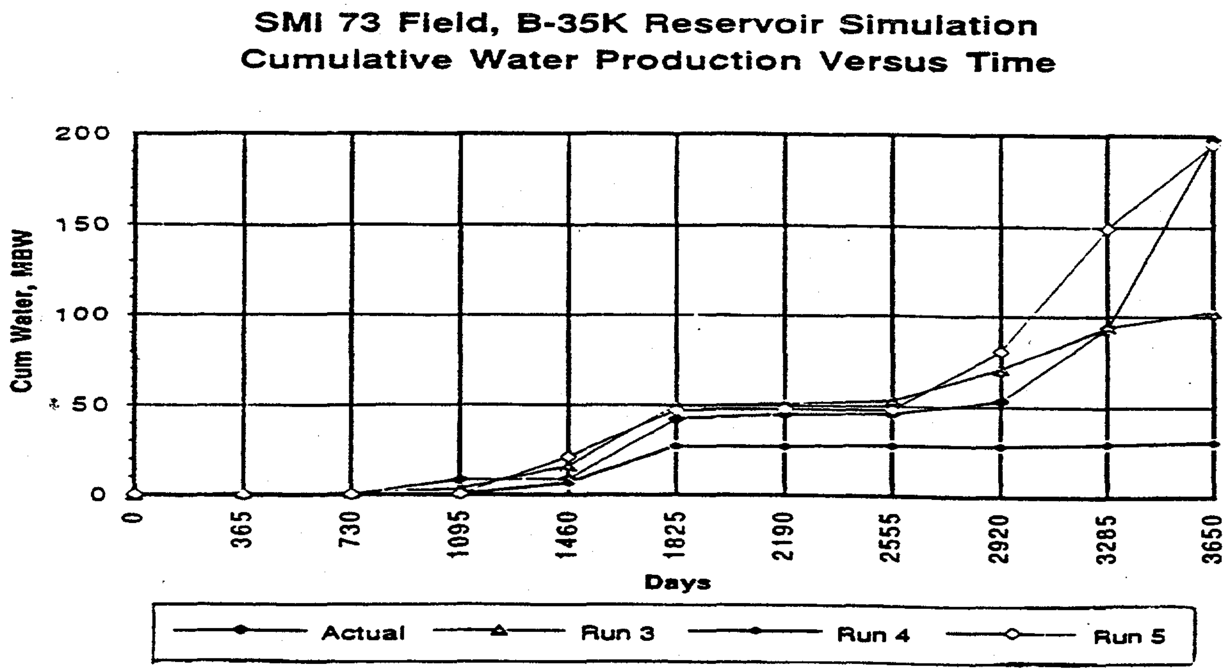


Figure 27 - Comparison of Cumulative Water Production for History Match Runs 3, 4, and 5

limit. The work indicates that an attic volume is probably necessary to obtain the best match, but the exact volume is difficult to define since both the up-dip and down-dip limits are unknown. In other words, multiple combinations of oil-water contact and attic volume will yield a reasonable history match.

The results of the final history match, which are excellent, are displayed in Figures 28 through 31, which illustrate the actual reservoir pressure, oil production, gas production, and water production data versus the simulation results. These results are also included in Appendix B, Run 5. Using the final history match assumptions, the volumetric original oil-in-place for the reservoir is calculated at 6.3 million barrels of oil, which indicates that 48% recovery has been realized to date.

V.1k Gas Injection Sensitivities

The final history match assumptions were used to test various model sensitivities and to examine the results of additional gas injection into the reservoir through Well A-6. The sensitivity tests were conducted to evaluate the impact of gas injection rate, post-injection shut-in period, gas injection volume, and gas injection cycle staging. The incremental oil recovery results of these sensitivity cases are presented in Table 8 and Figures 32 through 36, as discussed below. Detailed results of the sensitivity cases are presented in Appendix C.

V.1l Injection Rate Sensitivity

The first sensitivity case performed was to evaluate the impact of the gas injection rate on the incremental oil recovery. Figure 32 compares the results of injecting 300 million cubic feet of gas in one stage at three different injection rates, 250, 500, and 1,000 MCFD, followed by a three month shut-in period. The data indicate that lower injection rates improve the performance of the gas injection cycle by accelerating the production response after the shut-in period. In addition, the incremental recovery is higher for the lower injection rates. These effects could be attributed to reduced gas fingering and a higher segregation rate.

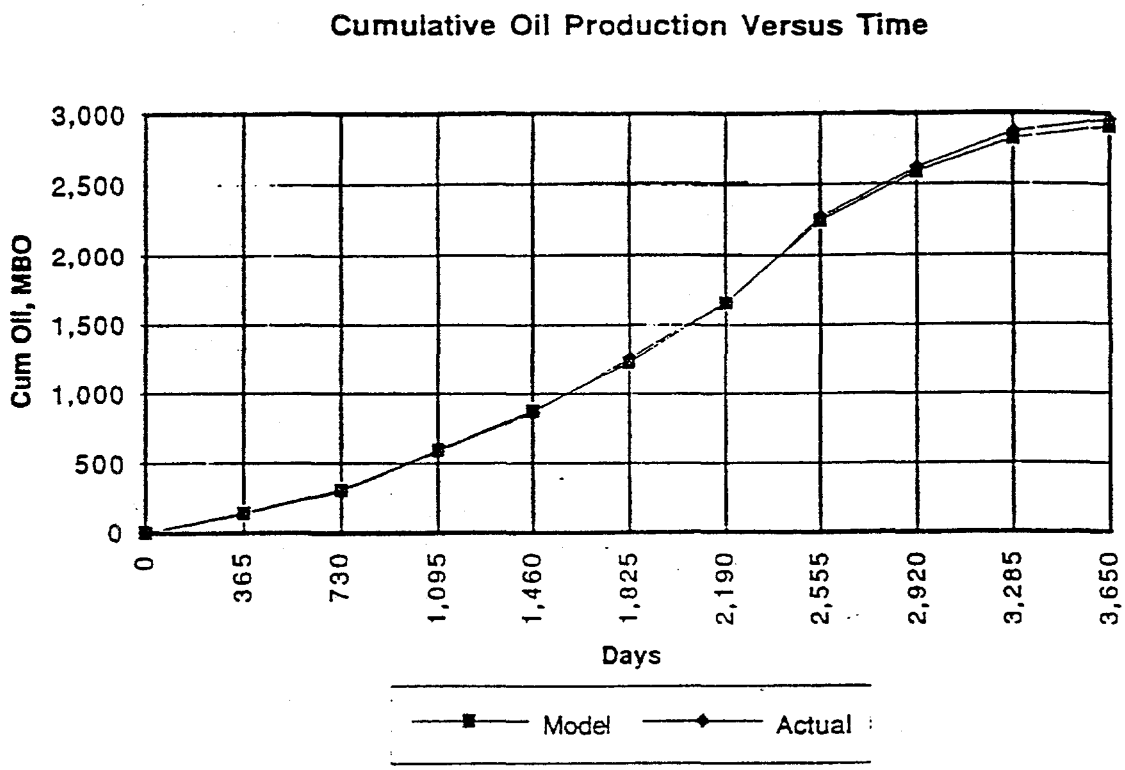


Figure 28 - Final History Match Results - Cumulative Oil Production versus Time

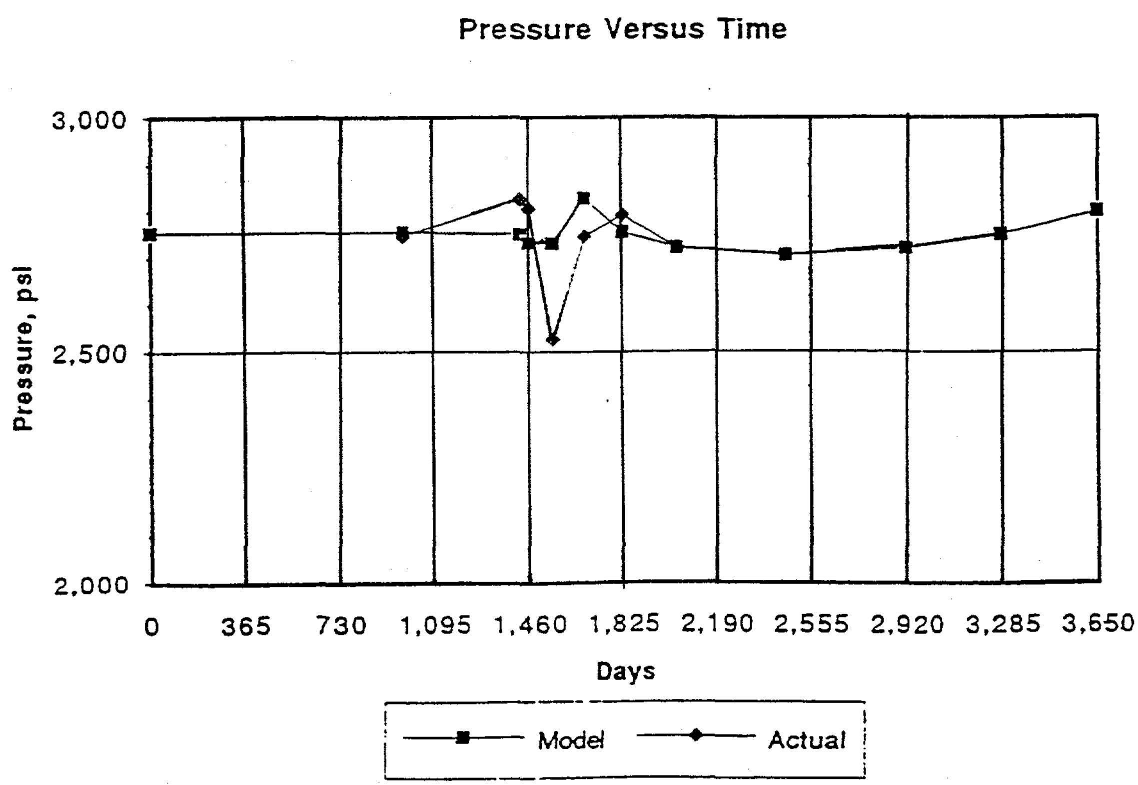


Figure 29 - Final History Match Results - Pressure versus Time

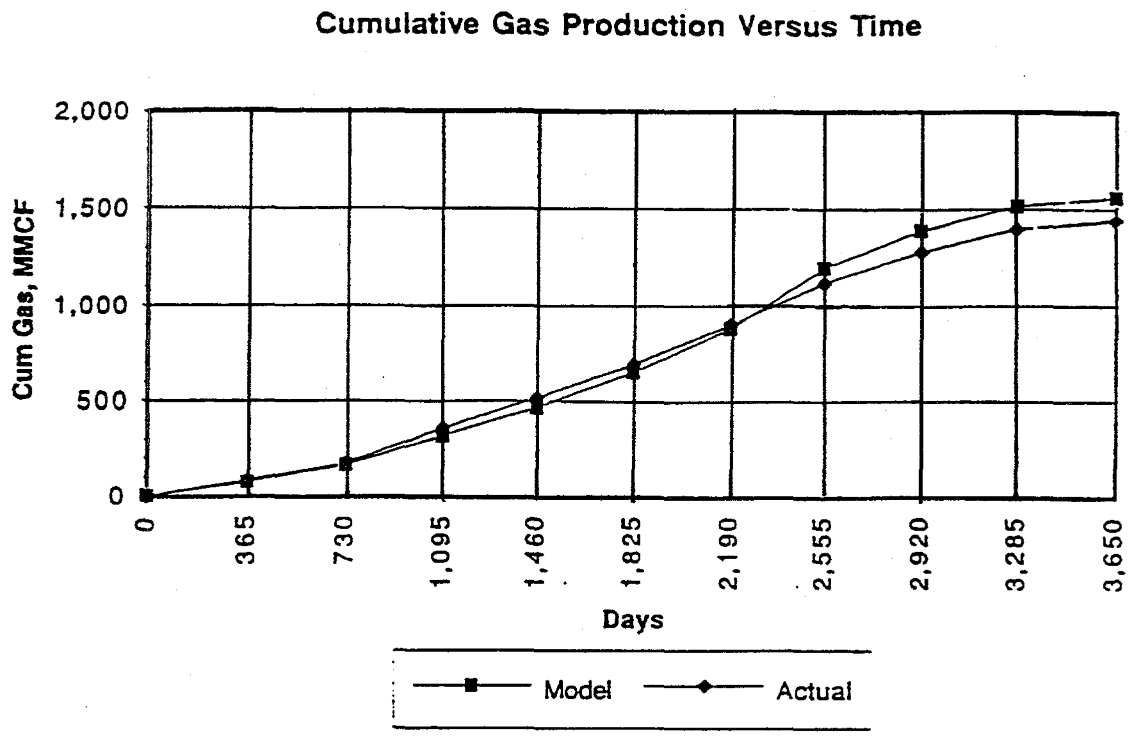


Figure 30 - Final History Match Results - Cumulative Gas Production versus Time

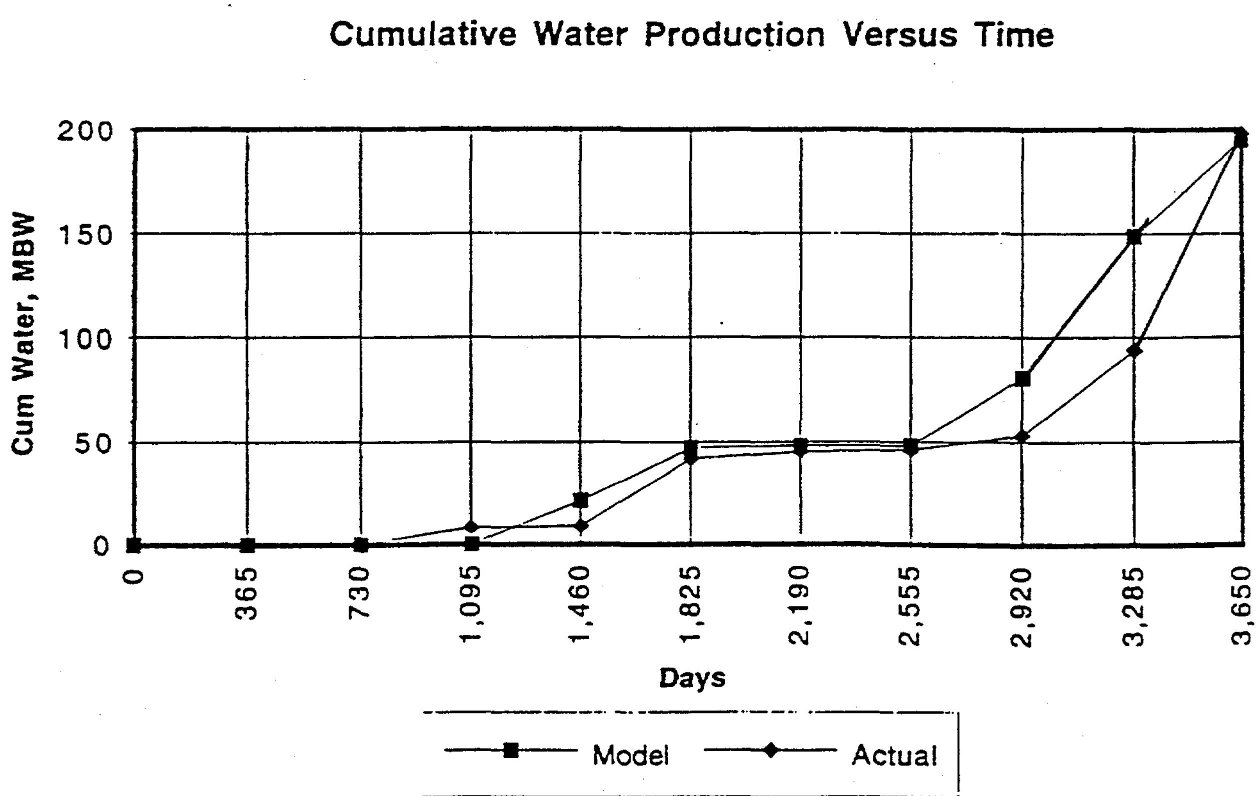


Figure 31 - Final History Match Results - Cumulative Water Production versus Time

Simulation Results of Additional Oil Recovery Due to Injecting Different Gas Volumes at Different Rates With Different Shut-In Periods (WOR = 1.5)
(MSTB OF OIL)

Shut-in Time (Months)	Injection Volumes (mmcf): 75, Rate (mcfd): 250	75: 500	150, Rate (mcfd): 250	150: 500	300, Rate (mcfd): 250	300: 500	300: 1000	400, Rate (mcfd): 500	74[illegible], Rate (mcfd): 3000
Zero				213					
Three									
1 Stage	203	212		219	236	227	226	229	260
2 Stage			225	238					
3 Stage				230					
Six				220					

One Stage: Inject total volume at a specified rate, shut-in for 3 months then produced to a WOR = 1.5.

Two Stage: Inject half the volume at a specified rate, shut-in for 3 months, produced for 6 months, then inject the remaining volume at the same rate, shut-in for 3 months then produced to a WOR = 1.5.

Three Stage: Inject a third of the volume at a specified rate, shut-in for 3 months, produced for 6 months; inject another third, shut-in for 3 months, produce for 6 months; inject the remaining volume, shut-in for 3 months then produce to a WOR of 1.5.

Table 8 - Summary of Oil Production for Various Gas Injection Prediction Sensitivites for B-35K Reservoir

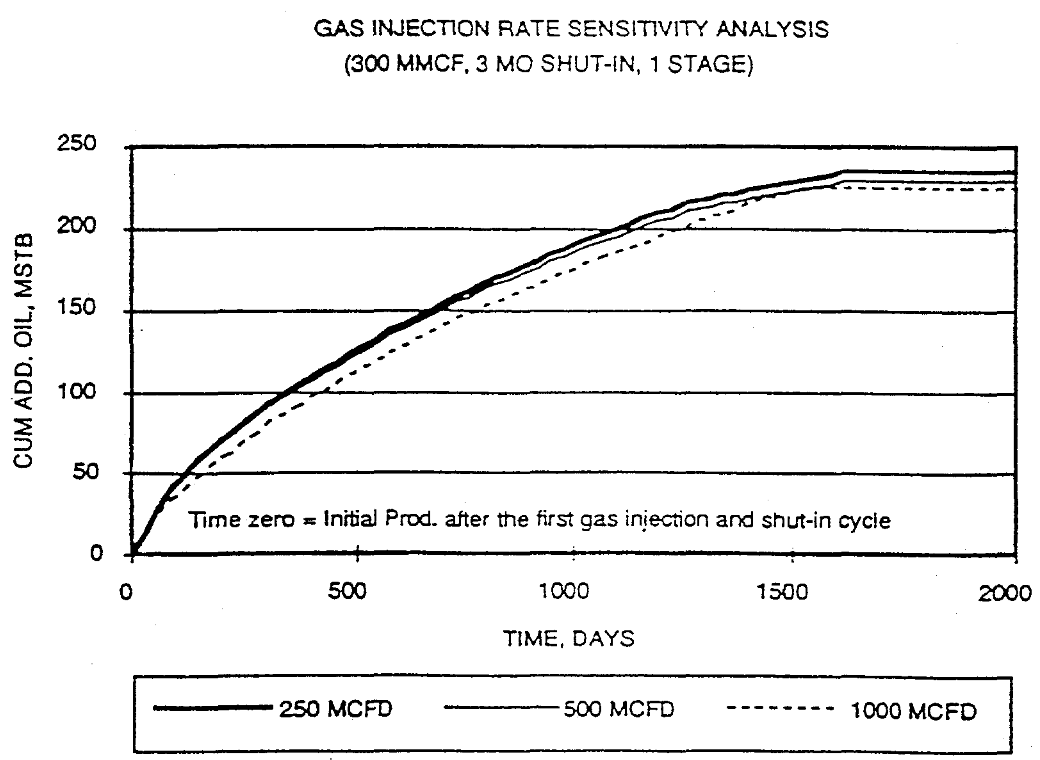


Figure 32 - Gas Injection Rate Sensitivity Analysis Results

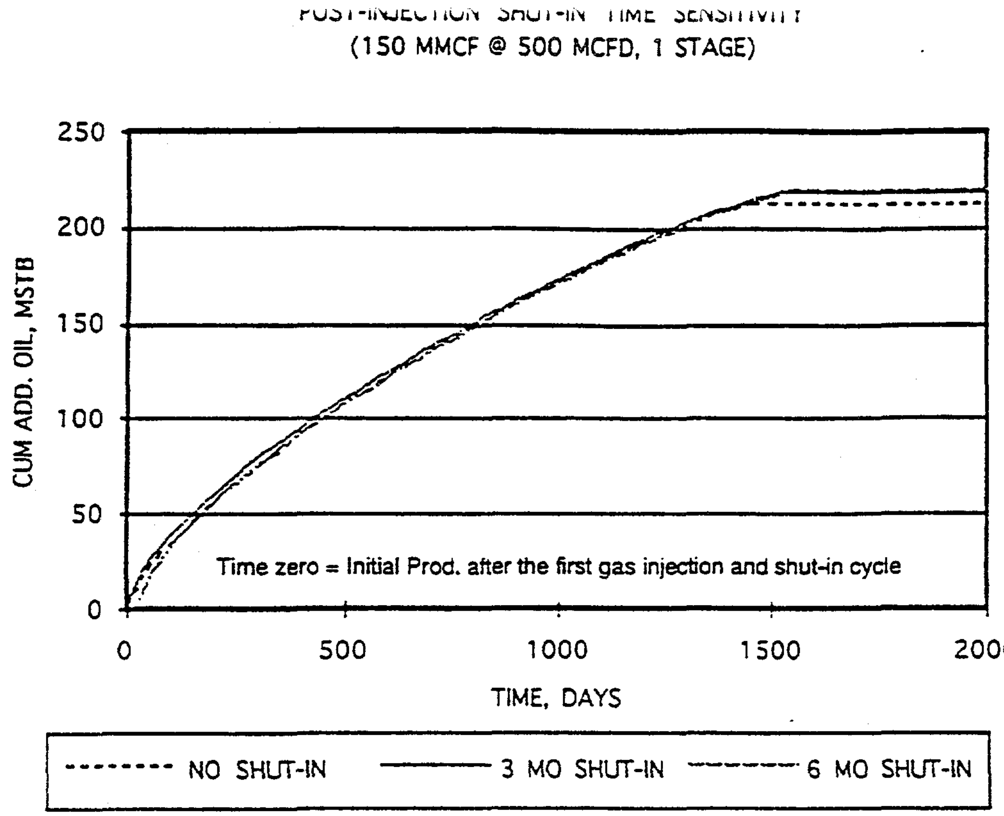


Figure 33 - Post Injection Sheet-In Time Sensitivity Analysis Results

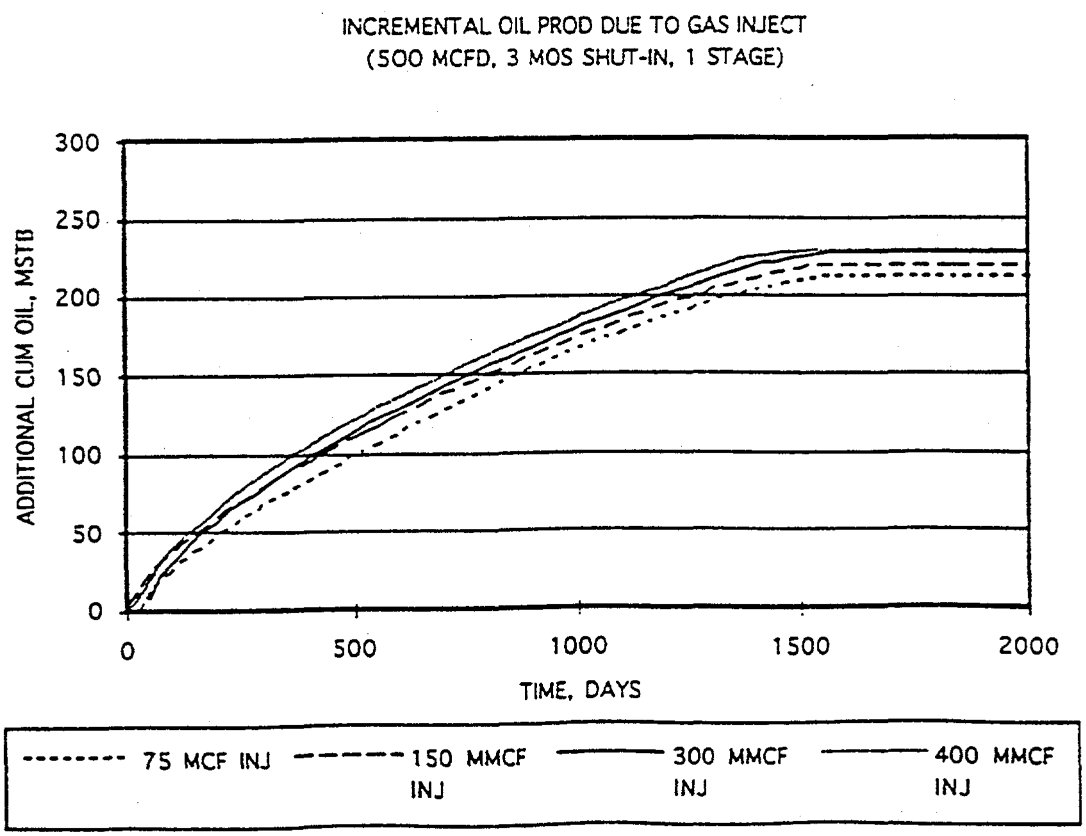


Figure 34 - Gas Injection Volume Sensitivity Analysis Results

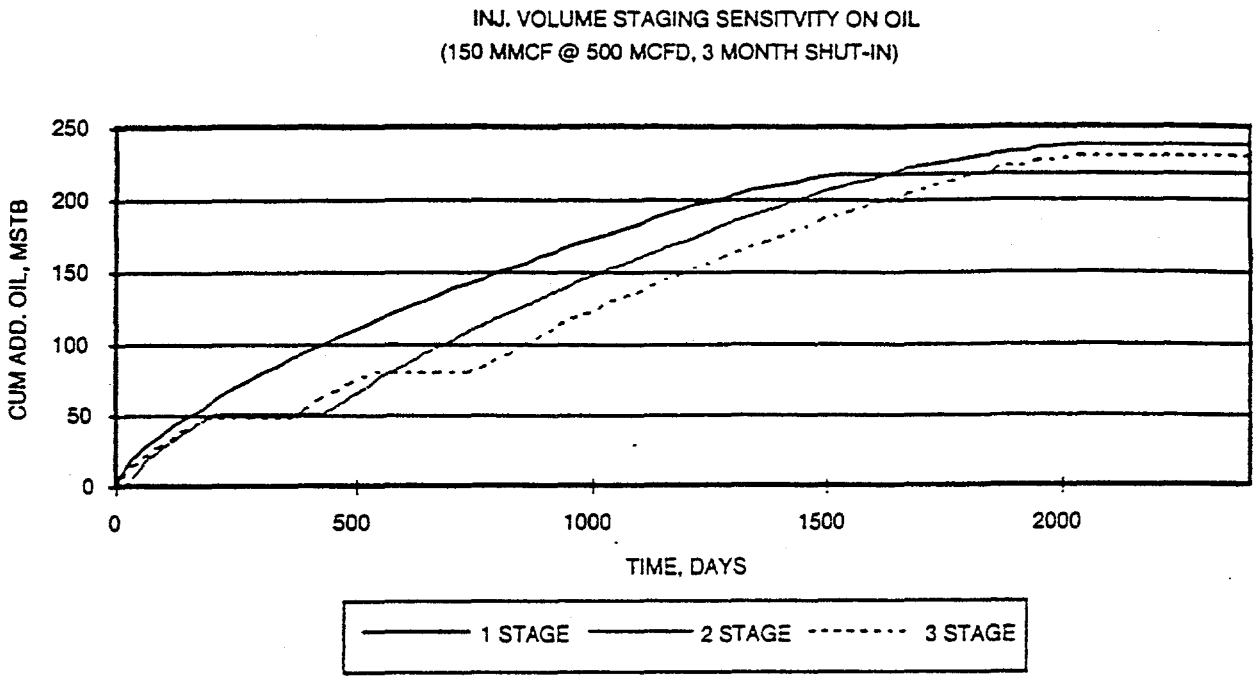


Figure 35 - Injection Volume Staging Sensitivity Analysis - Oil

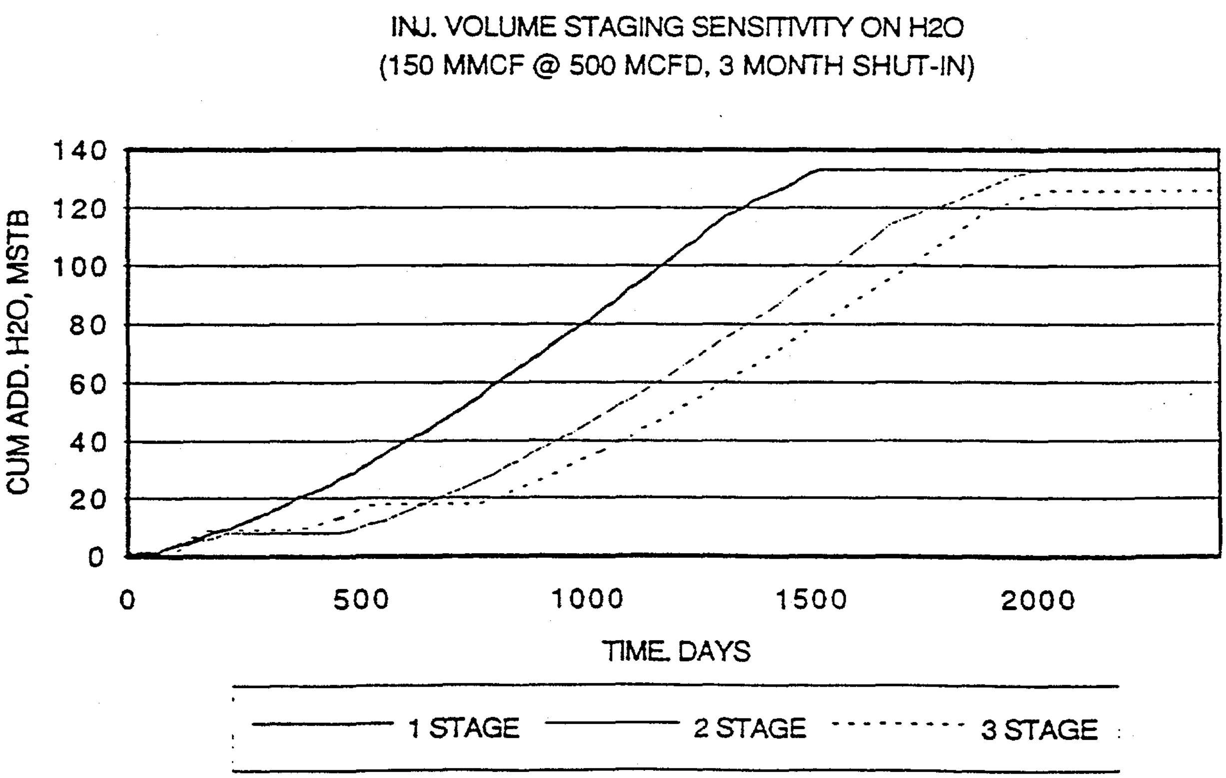


Figure 36 - Injection Volume Staging Sensitivity Analysis - Water

V.1m Post-Injection Shut-In Time Sensitivity

The impact of the post injection shut-in time was also evaluated. The cases evaluated used a total injection volume of 150 million cubic feet of gas at 500 MCFD in one stage, and the shut-in period varied between zero and six months. As shown in Figure 33, the best predictive performance of the reservoir was achieved using the three month shut-in period. Although the results of the three cases are similar, the three month shut-in case yields slightly accelerated oil production, and the six month shut-in case has slightly higher incremental recovery. Economic analysis of the results will probably indicate that the three month shut-in case is economically optimum.

V.1n Injection Volume Sensitivity

Figure 34 illustrates the incremental recovery over time for gas injection volumes between 75 and 400 million cubic feet. Comparison of the four cases shown on this figure shows that production is slightly accelerated at higher injection volumes and that incremental oil recovery tends to be higher for the larger injection volumes. However, a point of diminishing returns is apparent and very little difference exists between the 300 and 400 million cubic foot cases. The optimum gas injection volume is probably in the range of 150 to 300 million cubic feet of gas.

V.1o Injection Volume Staging Sensitivity

An additional sensitivity was conducted to investigate the results of gas injection cycle staging. The effects of two and three injection stages were compared to the 150-million-cubic-foot injection volume case where the injection rate was 500 MCFD and the shut-in period after injection was three months. The two stage injection occurs thus: first half of the gas is injected, then a three month shut-in period was followed by six months of production, then the other half of the gas was injected with production initiated after a three month shut-in period. The three stage injection was performed with similar shut-in and production stages in between.

Figures 35 and 36 exhibit the results of injecting gas in stages, and compare a single state case with two- and three-stage injection cases. Figure 9 indicates that the two-stage injection case produces more oil than the one stage or three stage injection cases. Figure 10 indicates that the water production is held off by staging the gas injection. A two- stage injection scenario is probably an optimum because the production duration between the first and the second stage was only six months. This relatively short duration contributes to the gas segregation phenomena and thereby enhances the oil recovery by lowering the associated water production rate than for one stage.

V.2 B-65G Reservoir

V.2a Porosity, Water Saturation, and Permeability Distribution

Geophysical well logs and sidewall core data were provided by Taylor to assist in evaluating the reservoir parameters in terms of porosity, water saturation, and permeability. A review of the geology and core data determined that a three layer model could also describe the B-65G Reservoir. The top and middle layers had high permeability values, averaging 680 md and 1056 md respectively, while the bottom layer averaged 125 md. In some areas of the reservoir, the three layers are separated by shales. The geophysical well logs, when evaluated, revealed porosity and water saturation values that are comparable to Gulf of Mexico reservoirs and averaged 28.5% and 23%, respectively. These values were modified slightly, as will be explained in detail later, to obtain a history match.

V.2b Relative Permeability Curves

Figure 38 illustrates the modified relative permeability curves that were used to arrive at a final history match of the actual pressure and production data for the B-65G Reservoir. The unmodified relative permeability curves were the same as those unmodified curves used for the beginning simulation runs for the B-35K Reservoir.

Again, the results of the early simulation runs illustrated that the relative permeability curves are critical data elements in terms of impact on simulation performance. For this simulation, as in the B-35K Reservoir simulation, BOAST3 exercised the option for computing a three-phase oil relative permeability curve by using water-oil and gas-oil relative permeability curves.

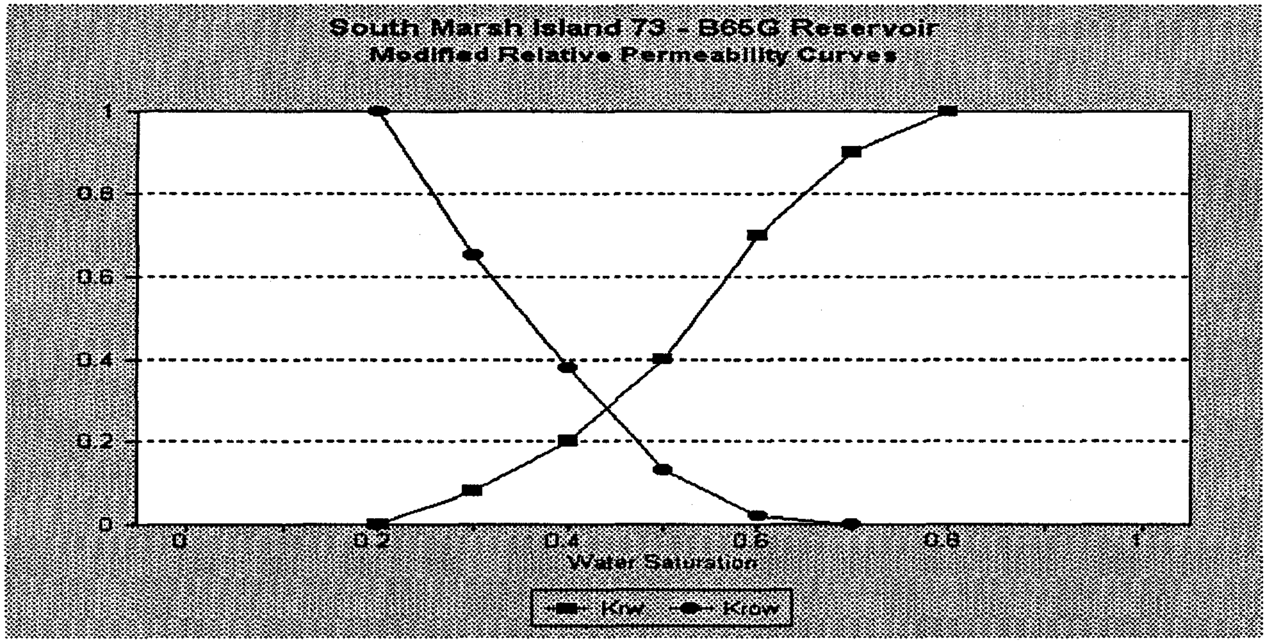


FIGURE 38

VI.2c PVT Data Analysis

PVT data was generated empirically using the techniques and formulas described by Glasco, Beggs, Robinson, Sutton and Farshad.[11] Historical production, injection and pressure data were input. From this information the producing gas-oil ratios (Rp), gas compressibility factors (z), oil formation volume factors and gas formation factors were calculated. The saturated oil viscosity, solution gas-oil ratio (Rs) were also calculated. The bubble point pressure of the B-65G Reservoir was estimated to be the initial reservoir pressure of 3457 psia.

Glaso' s correlations were used for calculating oil formation volume factor, solution gas-oil ratio and dead oil viscosity. The Calhoun correlation was determined to offer the best explanation for the oil compressibility which is dependent on the bubble point pressure estimate. The Vasquez and Beggs correlation was used to derive the viscosity of the undersaturated oil. Table 9 tabulates the results of the empirically derived PVT data.

VI.2d Material Balance and Water Influx Analysis

Material balance studies of this reservoir followed, using the techniques described by Havlena and Odeh.[12] A spreadsheet of these calculations has been presented in Table 10. From these studies, the water influx was calculated to be 7.8 million barrels after 9125 days of production. This calculation agreed very closely with the final computer simulation history match, which arrived at a value of 6.8 million barrels of water influx, or 87% of that value calculated from material balance. The 6.8 million barrels of water influx calculated by computer simulation was generated after many modifications and fine-tuning of the reservoir characteristics used to obtain a history match.

However, as a starting point,, the reservoir was assumed to have no gas cap and no water drive. As follows:

$$F = Np * \{Bt+\{Bg*(Rp-Rs)] + Wp - Wi - (Gi*Bgi) \qquad ([13])$$

where

F = Net production in reservoir barrels
Np = Net production in stock tank barrels
Bt = Total formation volume factor in reservoir
Bg = Gas formation volume factor in reservoir
Rp = Producing gas-oil ratio in standard cubic
Rs = Solution gas-oil ratio in standard cubic feet
Wp = Produced water in barrels
Wi = Injected water in barrels
Gi = Injected gas in standard cubic feet
Bgi = Injected gas formation volume factor in

---

[11] Sutton, R.P. and Farshad, F., "Evaluation of Empirically Derived PVT Properties for Gulf of Mexico Crude Oils," <u>SPE Reservoir Engineering</u>, February, 1990, pp. 79-86.
[12] Havlena, D. and Odeh, A.S., "The Material Balance as an Equation of a Straight Line," <u>Journal of Petroleum Technology</u>, August, 1963, pp 896-900.
[13] Havlena, D. and Odeh, A.S., "The Material Balance as an Equation of a Straight Line-Part II, Field Cases," <u>Journal of Petroleum Technology</u>, July, 1964, pp 815-822.

SOUTH MARSH ISLAND - B65G RESERVOIR
PVT DATA ANALYSIS

B=	92.88	
PORE=	0.285	
Ce=	8E-06	PSI-1
Rw=	1862	FEET
K=	620	

DAYS	MTH	YEAR	BHP	dP	CUM OIL	CUM GAS	CUM WATER	CUM WATER(SCF)	CUM GAS INJ	CORR CUM GAS	GOR (Rp)	Z	TOTAL FVF	GAS FVF(scf/SCF)	GAS FVF(bbl/SCF)	Glaso Bo	Beggs & Robinson SAT VISC	Rs
0	1	66	3457		0	0	0	0	0	0		0.845	1.376978	0.0041074919583454	0.00073176951113682	1.376978	0.47594	718
578	7	67	3262	97.5	122813	105918	0	0	0	105918	862	0.845	1.4167369	0.0043530348559166	0.00077551416309013	1.3771856	0.495454	667
1065	12	68	3106	175.5	417340	302109	0	0	0	302109	724	0.835	1.3819266	0.0045175650676111	0.00080482601416613	1.3086874	0.512344	627
1185	4	69	3058	102	502121	351812	0	1291	0	351812	701	0.832	1.3880268	0.0045719896402878	0.00081452201438849	1.304131	0.517717	615
1520	3	70	3089	8.5	785272	549196	230	1381	11201	537995	699	0.832	1.3890552	0.0045261069342829	0.00080634778892846	1.3116458	0.514564	622
1550	4	70	3080	-11	811843	566166	246	1510	11201	554965	697	0.832	1.3906634	0.0045393325714286	0.000808704	1.3114104	0.51546	620
1580	5	70	3077	6	843621	587365	269	2297	11201	576164	696	0.832	1.3880974	0.0045437583100422	0.00080949246668833	1.3079576	0.515909	619
1763	11	70	2867	106.5	1038193	672316	409	2297	11201	661115	648	0.823	1.4216284	0.004823824897105	0.00085938768050227	1.2927203	0.540303	568
1795	12	70	2919	79	1075214	708987	409	51377	11201	697786	659	0.825	1.4059755	0.0047494054470709	0.00084612949640288	1.2892097	0.534289	580
1945	5	71	2627	120	1485167	922037	9150	101115	11201	910836	621	0.82	1.4650315	0.005245334297678	0.00093448161400837	1.2715938	0.571543	511
2065	9	71	2595	162	1848015	1101832	18008	113518	11201	1090631	596	0.82	1.4623164	0.0053100166473988	0.0009460050867052	1.2589253	0.576321	503
2095	10	71	2663	-18	1932148	1142974	20217	126001	11201	1131773	592	0.82	1.4418555	0.0051744247840781	0.00092184874202028	1.2584076	0.566869	519
2125	11	71	2594	0.5	2022775	1194359	22440	482160	11201	1183158	590	0.82	1.4623355	0.0053120636854279	0.00094636977640709	1.258866	0.576321	503
2670	5	72	2613	25	3544117	2145164	85870	1167291	178871	1597505	605	0.82	1.4577761	0.0052734378874856	0.00093948840413318	1.259544	0.573919	507
3065	6	73	2549	22.5	4407968	2660625	207888	2448988	547659	2071926	604	0.82	1.4882433	0.0054058427618674	0.00096307697136132	1.271551	0.582445	493
3710	3	75	2708	-47.5	5220674	3166596	436151	4798804	656778	2477937	607	0.82	1.4319986	0.0050884391432792	0.00090652998522895	1.261571	0.560605	530
4715	12	77	2915	-183	5802450	3824906	854640	4816064	744090	2933204	659	0.825	1.3918794	0.0047559226415094	0.00084729056603774	1.274106	0.534783	579
4745	1	78	2809	-50.5	5812761	3845207	857714	4893905	744090	2916605	662	0.82	1.4205993	0.0049054799572802	0.00087393492346031	1.277274	0.547553	554
5415	10	79	2705	105	5926486	4874101	871577	4901710	1241139	2782427	822	0.82	1.5866623	0.0050940825138632	0.00090753537892791	1.4151381	0.561167	529
5780	10	80	2911	-51	6009961	5132103	872967	5016531	2091662	3040429	854	0.825	1.5339218	0.0047624577464789	0.0008484548265201	1.4151381	0.535279	578
6145	10	81	3003	-149	6048263	5358103	893416	5018490	2091662	3243962	886	0.83	1.4047004	0.0046445340659341	0.00082744615384615	1.3078892	0.524179	601
6480	9	82	3090	-89.5	6087300	5406205	893765	5022578	2091662	3180305	888	0.832	1.4091245	0.0045246421747573	0.00080608683495146	1.3325462	0.514118	623
6845	9	83	3007	-2	6114837	5461623	894493	5023595	2225888	3165829	893	0.83	1.4273428	0.0046383557698703	0.00082634546059195	1.3314867	0.523711	602
7180	8	85	3114	-12	6127848	5525808	894674	5023595	2468037	3057759	902	0.835	1.4083573	0.0045059592485549	0.00080275838150289	1.3369118	0.511462	629
7300	1	86	3089	-41	6128529	5564693	894674	5023595	2468037	3096644	908	0.832	1.4255387	0.0045261069342829	0.00080634778892846	1.3481294	0.514564	622
9125	12	90	3122	-4	6176318	6244425	894674	5023595	2745312	3499101	1011	0.835	1.4910431	0.0044944129083921	0.00080070134529148	1.4205814	0.511023	630

days = Actual days of production from reservoir from day 1
mth and year - date of test
bhp - measured pressure from test
cum oil - cumulative oil produced STB
cum gas - cumulative gas produced MCF
cum water - cumulative water produced Bbls
cum gas inj - cumulative gas injected MCF
Corr cum gas - cum gas - cum gas inj
GOR (Rp) - cumulative produced gas-oil ratio
Z - gas z factor
(Marshall B. Standing and Donald L. Katz, "Density of Natural Gases," Trans. AIME, (1942), 146, 144.)
Total FVF - [(Rsi-Rs)*Bg]+Bo
(B.C. Craft and M.F. Hawkins, "Applied Petroleum Engineering," 1959, pp 24.)
Gas FVF (scf/SCF) - [0.02829*z*Tf(degrees R)]/BHP
(B.C. Craft and M.F. Hawkins, "Applied Petroleum Engineering," 1959, pp 24.)
Gas FVF (bbl/SCF) - [0.00504*z*Tf(degrees R)]/BHP (B.C. Craft and M.F. Hawkins, "Applied Petroleum Engineering," 1959, pp 24.)
(B.C. Craft and M.F. Hawkins, "Applied Petroleum Engineering," 1959, pp 24.)
Glaso Bo - Bob=1.0+antilog[-6.58511+2.91329xlogBob#-0.27683x(logBob#)sq] where Bob#=Rsx(sgg/sgo)power0.526 + 0.968xT
(Sutton R.P., "Evaluation of Empirically Derived PVT Properties for Gulf of Mexico Crude Oils", SPE Reservoir Engineering, Feb. 1990, pp 79-86.
Beggs&Robinson Sat Viscosity=ax(dead oil visc)power b where a=10.715x(Rs = 100)power -0.515 and b=5.44x(Rs + 150)power -0.338
(Sutton R.P., "Evaluation of Empirically Derived PVT Properties for Gulf of Mexico Crude Oils", SPE Reservoir Engineering, Feb. 1990, pp 79-86.
Dead oil viscosity - (3.141x10power10)Tpower-3.444(logAPI)power[10.313(logT)-36.447]
(Sutton R.P., "Evaluation of Empirically Derived PVT Properties for Gulf of Mexico Crude Oils", SPE Reservoir Engineering, Feb. 1990, pp 79-86.
Rs - sgg[Npb(APIpower(0.989/Tpower0.172)]1.2255 where Npb=antilog[2.8869-(14.1811-3.3093logpb)power0.5]
(Sutton R.P., "Evaluation of Empirically Derived PVT Properties for Gulf of Mexico Crude Oils", SPE Reservoir Engineering, Feb. 1990, pp 79-86.

Table9 Spreadsheet of Empirically Generated PVT Data For B-65G Reservoir

SOUTH MARSH ISLAND - B65G RESERVOIR
Material Balance Spreadsheet

DEAD OIL V= 1.85

F	Td	Q(t)	CUM Q(t)	DELTAPxQ	SUM dP	F/Eo	q/eo	Eo	We	delta We	dWe/dT	Pi-P	bpd/psi	m	Et	F/Et	EdPQ(dTd)/Et
0				0				0									
187749.97928515	1866.3079429	503	503	49042.5	97.5	4722218.543	1233498.953	0.0397589	-411555	172805.98049537	299	195	1.533191	0.1	0.047944375	3,915,996	1,022,904
578712.21424005	3325.425634	832	1335	364455	273	116944837.2	73648230.65	0.0049486	345612	384632.41969158	790	351	2.250141	0.1	0.01864802	31,033,440	19,543,898
690092.20595084	3661.7187188	905	2240	840000	375	62458532.36	76026314.64	0.0110488	357710	199394.75604338	1662	399	4.164469	0.1	0.026572166	25,970,491	31,612,025
1070203.9745716	4725.6643218	1134	3374	1293929	383.5	88613381.78	107137916.9	0.0120772	744401	198756.79633646	593	368	1.612239	0.1	0.02606292	41,062,320	49,646,356
1106675.5380961	4810.562155	1152	4526	1685935	372.5	80865520.46	123192396.1	0.0136854	755224	40881.262824142	1363	377	3.614612	0.1	0.028114306	39,363,431	59,967,158
1147511.8426863	4899.3991477	1171	5697	2156314.5	378.5	103199226.9	193923915.2	0.0111194	826164	-104506.2450858	-3484	380	-9.167214	0.1	0.025696628	44,656,126	83,914,300
1403880.8121973	5220.038394	1238	6935	3363475	485	31441584.46	75329032.47	0.0446504	546211	-3830.5118601145	-21	590	-0.035478	0.1	0.068613567	20,460,688	49,020,553
1458076.8280386	5374.6157678	1271	8206	4628184	564	50282795.57	159606150.7	0.0289975	818503	-41676.447749542	-1302	538	-2.420797	0.1	0.050466628	28,891,901	91,707,811
2048499.5300485	5444.1429074	1285	9491	6491844	684	23264264.02	73726144.72	0.0880535	462858	54229.701193524	362	830	0.43558	0.1	0.126142656	16,239,547	51,464,304
2499111.7588711	5732.1108663	1344	10835	9166410	846	29284741.06	107412540.6	0.0853384	926962	425158.7682981	3543	862	4.110197	0.1	0.125595231	19,898,142	72,983,743
2572777.3219241	5912.3516058	1382	12217	10115676	828	39655927.35	155919639.5	0.0648775	1313176	113829.31664543	3794	794	4.778729	0.1	0.100590276	25,576,799	100,563,160
2789088.2034549	5898.6613031	1379	13596	11264286	828.5	32675372.88	131965975.4	0.0853575	1154621	948987.8242214	31633	863	36.65461	0.1	0.125682975	22,191,456	89,624,597
4831032.7653099	7442.514607	1694	15290	13050015	853.5	59791450.04	161513978	0.0807981	3211152	1333056.0544265	2446	844	2.898074	0.1	0.11982906	40,316,037	108,905,261
5983166.2658877	8418.5002626	1890	17180	15049680	876	53773865.42	135259397.9	0.1112653	3820733	1239999.3817513	3139	908	3.457312	0.1	0.154733612	38,667,528	97,261,867
7207786.5055456	10587.076305	2318	19498	16154093	828.5	131001509.1	293600616.3	0.0550206	5691150	1866627.6182706	2894	749	3.863813	0.1	0.087851778	82,044,856	183,878,954
8014423.5892977	14104.671299	2994	22492	14518586	645.5	537830652	974310939.2	0.0149014	7553988	803954.33643596	800	542	1.475931	0.1	0.036588899	219,039,760	396,803,034
8191933.8803965	13863.380349	2948	25440	15136800	595	187796528.9	347004570.6	0.0436213	7299059	-438802.43615139	-14627	648	-22.57214	0.1	0.070320954	116,493,497	215,253,052
9711580.4874577	15437.093141	3246	28686	20080200	700	46315250.12	95763968.26	0.2096843	6676383	-262222.67812455	-391	752	-0.520448	0.1	0.24270456	40,014,001	82,735,157
9030691.3900792	17274.55212	3592	32278	20948422	649	57540931.26	133477234.3	0.1569438	6774614	625780.40969109	1714	546	3.140049	0.1	0.178850303	50,493,017	117,128,244
8499255.1344119	18754.29932	3865	36143	18071500	500	306584351.7	651873490.5	0.0277224	7927944	634768.53916431	1739	454	3.830599	0.1	0.045676947	186,073,190	395,637,217
8620917.1487514	20163.737845	4125	40268	16530014	410.5	268176137.3	514209245.6	0.0321465	8044151	-55541.175349541	-166	367	-0.451756	0.1	0.046083078	187,073,381	358,700,304
8668446.6574117	20909.37034	4260	44528	18189688	408.5	172113171.9	361158696.8	0.0503648	7816862	-77610.191565013	-213	450	-0.472513	0.1	0.068112296	127,266,986	267,054,393
8447552.5398078	22457.9257	4558	49086	19462599	396.5	269207834	620236938.1	0.0313793	7888930	-9370.1624598806	-28	343	-0.081547	0.1	0.04468978	189,026,498	435,504,474
8579952.1565324	22695.624704	4585	53671	19080040.5	355.5	176684919.5	392910747.9	0.0485607	7798122	-60750.36641364	-506	368	-1.375688	0.1	0.062546442	137,177,301	305,053,969
9354787.721395	28566.106325	5643	59314	20848871	351.5	82012691.53	182780419.7	0.1140651	7767430					0.1	0.126988653	73,666,328	164,179,008

F - Cum oil x (Bt+[Bgx(Rp-Rsi)]) + cumwater - (Ginj x Bg)
Havlena and Odeh, "The Material Balance as an Equation of a Straight Line", Journal of Petroleum Technology, August, 1963, pp 896-900.
Td - Dimensionless time - 6.323x10power-3 x (kt/(pore x xvisc x ce x rwpower2)
(B.C. Craft and M.F. Hawkins,"Applied Petroleum Engineering," 1959, pp 218.)
Qt - dimensionless influx - "Infinite Aquifer Values of Dimensionless Water Influx for Values of Dimensionless Time"
(B.C. Craft and M.F. Hawkins,"Applied Petroleum Engineering," 1959, pp 212.)
CUM Qt - cumulative Qt
DeltaPxQt - Cumulative deltaP x cumulative Qt
Sum dP - Cumulative dP
Eo - Bt-Bti
q/Eo - DeltaPxQt / Eo
We - Water influx=(CumOil x [Bt + ((Rp-Rsi) x Bg)]) - (N x Eo) + Cum Water + (Ginj*Bg)
(B.C. Craft and M.F. Hawkins,"Applied Petroleum Engineering," 1959, pp 154, Eq 4.6.)
delta We - 1/2 * (We2-We1)
dWe/dT - delta We / dtime
Pi-P - Initial pressure - present pressure
bpd/psi - barrels of water influx per day per psi drop in pressure

Table10 Spreadsheet Illustrating Havlena & Odeh Straight Line Material BalanceAnalysis
For B-65G Reservoir

versus

$$Eo = Bt - Bti \qquad (14)$$

where

Eo = the expansion of oil reservoir barrels per
Bt = Present total formation volume factor in
Bti = Initial total formation volume factor in

If this calculation had generated a straight line on the plot, a reservoir without a water drive and without a gas cap would have been confirmed. However, the plot did not result in a straight line, as shown in Figure 39, indicating that the reservoir's drive mechanisms included water and/or a gas cap.

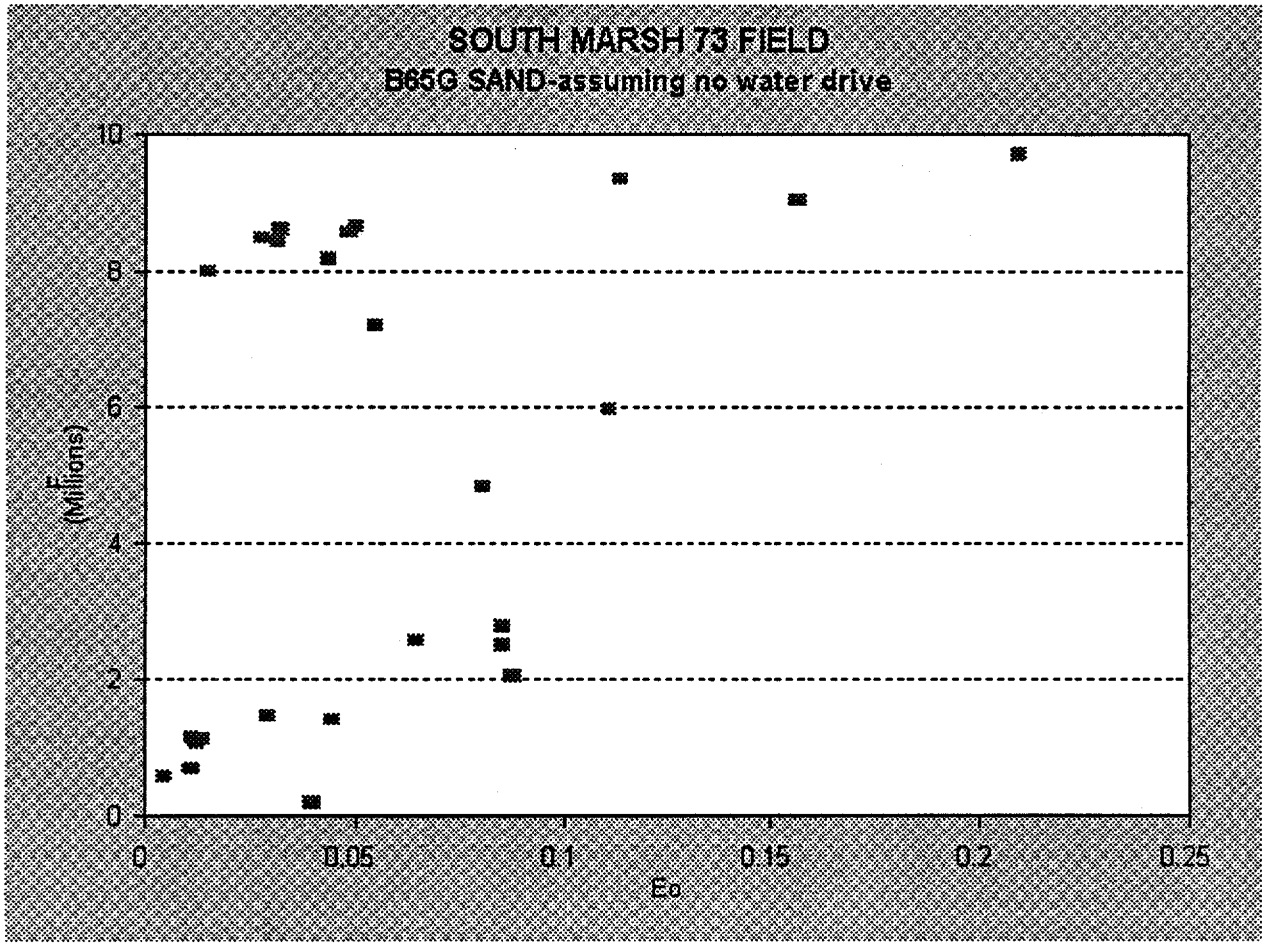


Figure 39

[14] Ibid: 815-822.

At this point, the reservoir was assumed to have a small gas cap and water drive. Again, following the outline given by Havlena and Odeh, another plot was constructed as follows:

F/Et [15]

where

F = Net production in reservoir barrels

Et = [m*Bti*(Bg-Bgi)/Bgi] + Bt - Bti

where m = ratio of gas cap volume versus oil volume (assumed to be 0.1)

delta p = reservoir pressure change

versus

Sum of delta p * Q(delta tD) / Et [16]

where

Q(delta tD) = van Everdingen-Hurst function

This plot resulted in a straight line (Figure 40) and confirmed the assumption of a gas cap and water drive reservoir. The y-intercept of this plot defined the original oil in-place of the reservoir as approximately 12 million stock tank barrels. This agreed very well with the estimate for oil-in-place that was generated by volumetric methods explained earlier.

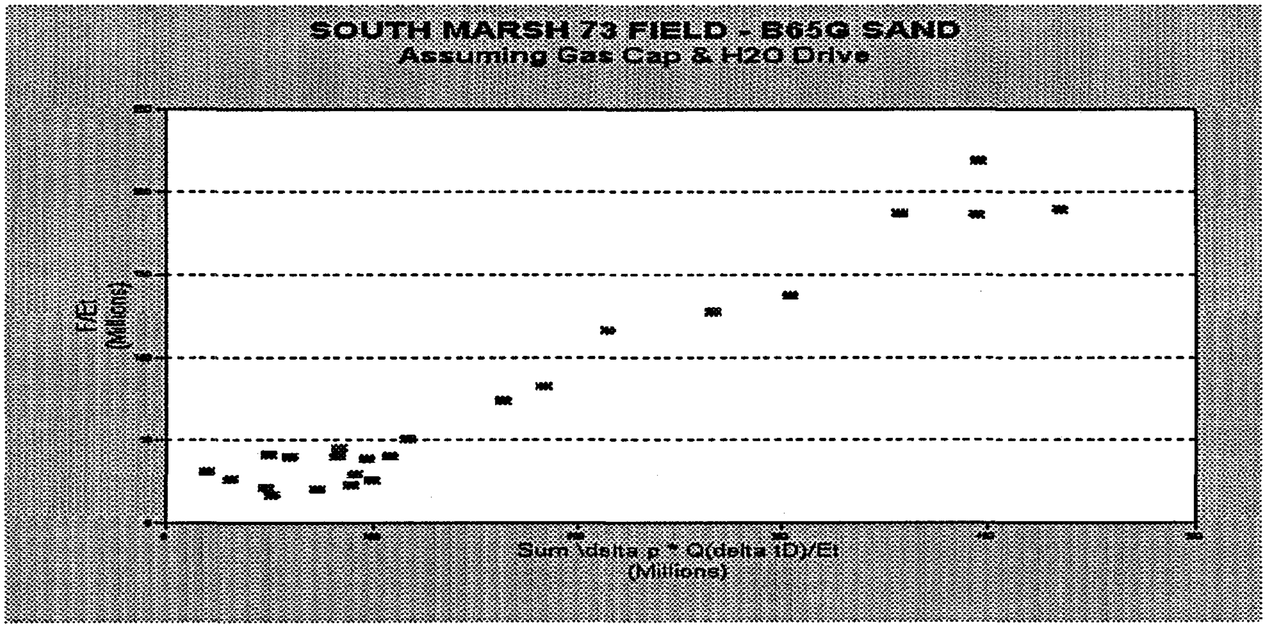


FIGURE 40

[15] Ibid: 815-822.

[16] Ibid: 815-822.

VI.2e Reservoir Model Grid Dimensions and Geometry

Once the material balance work had indicated a reservoir with a water drive and a small gas cap, the computer simulation of this reservoir was performed. The reservoir model was developed by integrating geologic and engineering data.

The model consisted of 12 rows and 12 columns, oriented northeast-southwest over the reservoir, as illustrated in Figure 41. Grid block lengths averaged 425 feet and grid block widths averaged 224 feet. Grid block dimensions around well bores were about 150 feet by 150 feet.

The sand was subdivided into three flow-unit layers. These flow-unit layers were defined by alternating layers of low and high permeability (alternating sand-shale sequences) as observed on electric logs and as illustrated in Figure 42. Average values for porosity and permeability were assigned to each layer initially. Vertical permeability was taken to be 1/10 of the horizontal permeability. Detailed modifications were made to these values as the history match was obtained. On average, the layers were 22 feet in gross thickness and 10 feet in net thickness.

VI.1f Productivity Index Calculations (PID)

Table 11 summarizes the results of the PI calculations per well required for simulating the B-65G Reservoir.

TABLE 11
SUMMARY OF CALCULATED PI VALUES BY LAYER PERFORATED FOR EACH WELL

		PI VALUES	
WELL#	**LAYER 1**	**LAYER 2**	**LAYER 3**
B1	not perfed	not perfed	14.7
B7	24.98	not perfed	not perfed
B10D	not perfed	not perfed	6.1
B12	25.0	not perfed	not perfed

VI.2g Recurrent Data

As in the simulation of the B-35K Reservoir, using oil production rates with an implicit rate calculation option was determined to result in accurate predictions of the reservoir performance when simulating the actual history. Since the oil rate per well was specified, the reservoir's pressure, gas production, and water were simulated and compared to actual reservoir pressure and production values. Average oil rates were computed over specified time periods with each average oil rate represented by a recurrent data set. Appendix D includes a listing of the input data set used for the final history matching of the actual pressure and production data.

Just as in the case of the B-35K Reservoir, in terms of the model's solution method, the Line Successive Over-Relaxation (LSOR) option with a z-direction tridiagonal algorithm was used as the optimum solution method for solving two- or three-dimensional problems.

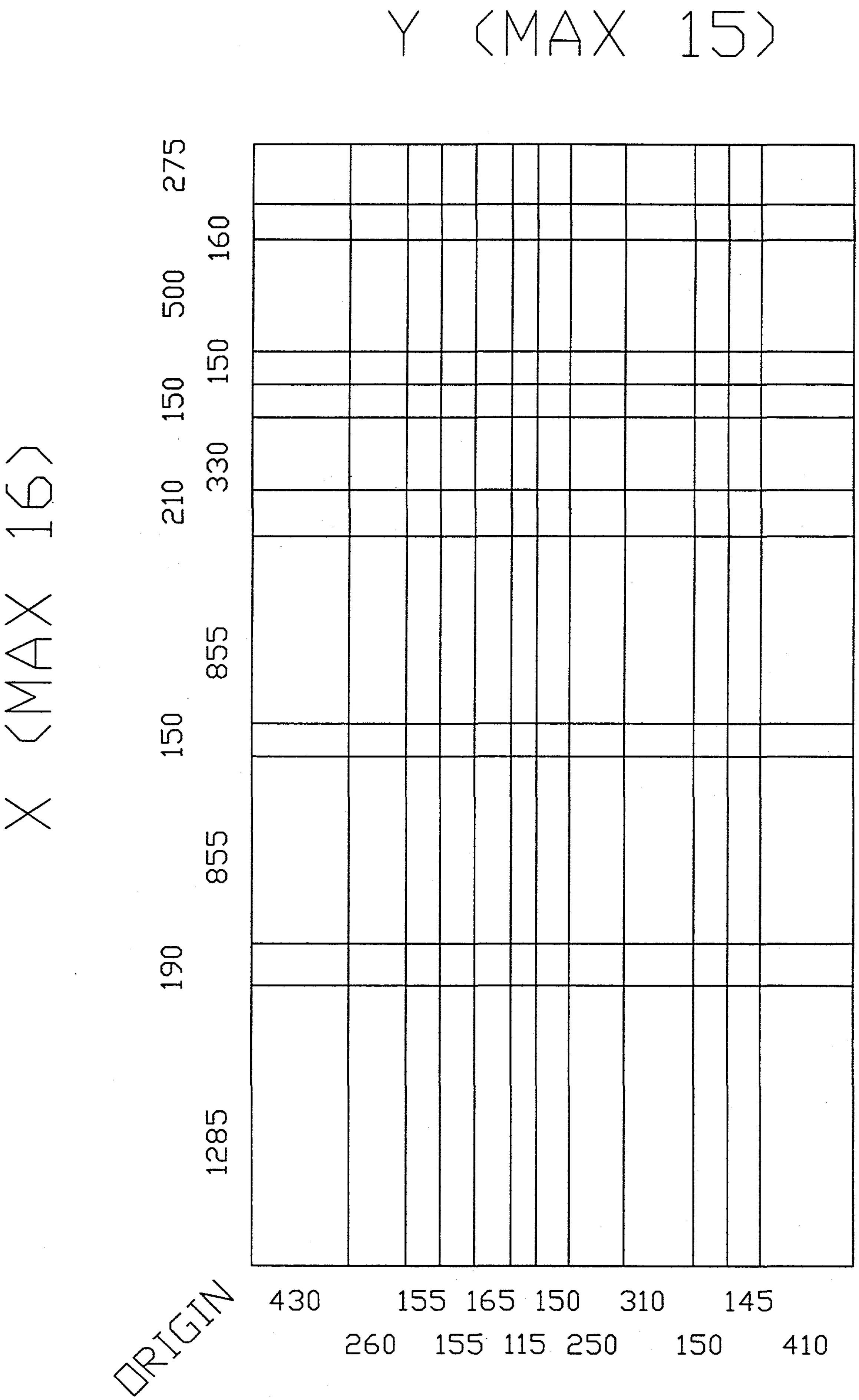


Figure41 Grid Layout of B-65G Reservoir

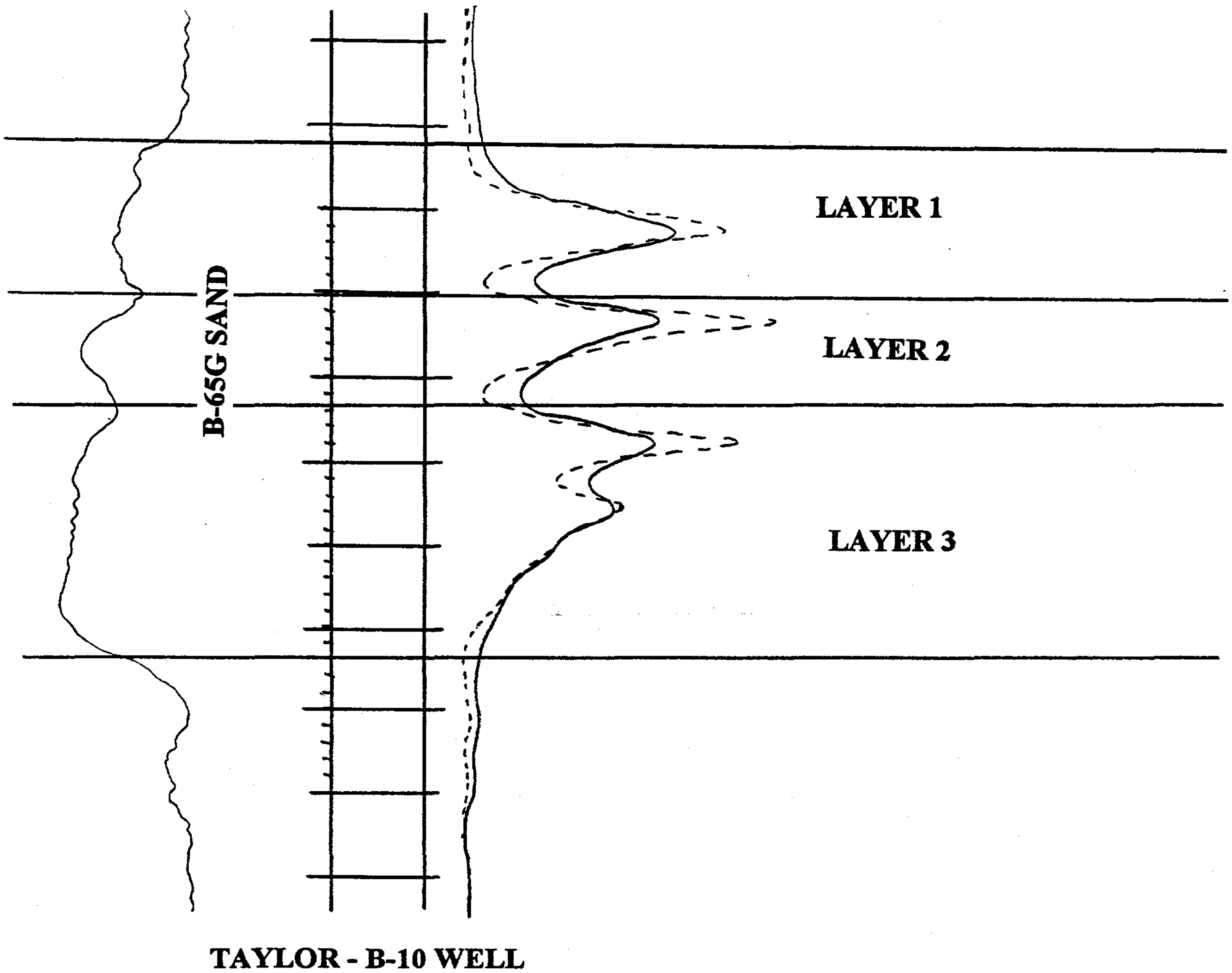


Figure 42 - Type Log of B-65G Reservoir Illustrating Simulator Layering

VI.2h History Matching

Approximately 30 runs were made from start to finish for this reservoir before an adequate history match was obtained. Primary modifications to the original data set included adjustments to the gas cap size, adjustments to the position of the updip pinchout, relative permeability curve modifications, localized net sand thickness variations, localized permeability variations, variations in strength and location of water influx and overall oil saturation.

The reservoir characterization for the initial run AA, in which oil production data were entered, included a very weak water drive and no gas cap. The strength of the water drive was the most important factor. The simulation reservoir pressure fell drastically in comparison to the actual, which stayed nearly the same. Also the overall simulated gas production was much higher than actual, and the simulated water production was much lower than actual. These comparisons are shown in Figures 43 and 44.

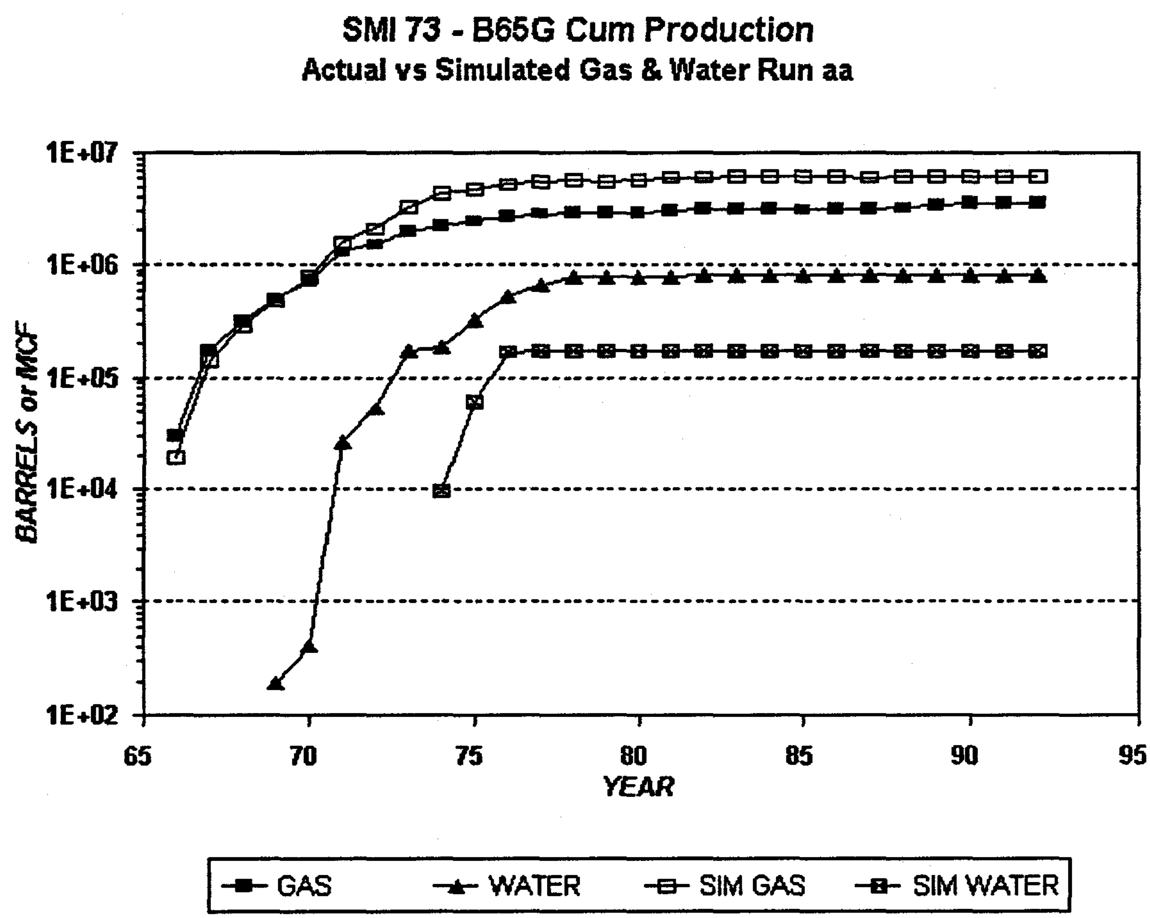


FIGURE 43

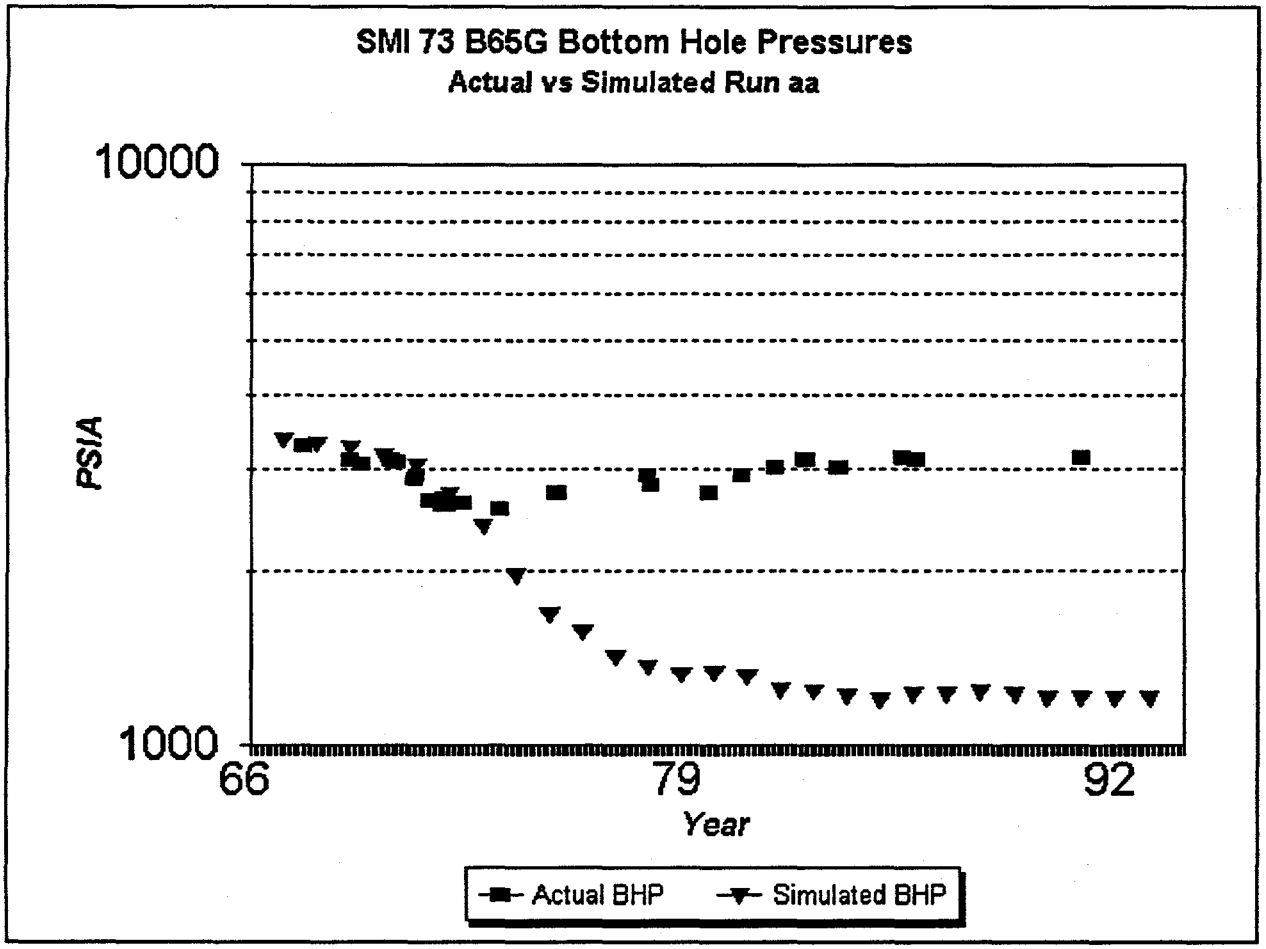


FIGURE 44

The results from run AA indicated that there was not sufficient material to replace the voidage created by the production, therefore several modifications were made for the next run AB. The detailed modifications are included in Appendix E.

The simulation reservoir pressure for run AB was higher than actual before mid-life and was lower than actual after mid-life. Overall, however, the pressure match was an improvement over run AA. The overall simulated gas production was lower than actual and the simulated water production was much lower than actual. Therefore, the gas match flip-flopped from run AA, while the water match remained about the same. Since the pressure match improved, the overall material balance was much closer. The following modifications were made from run AB to run AC are included in Appendix E.

Gas and water production from run AC were still much lower than actual, especially from the B-12 and B-1 wells. Pressures remained essentially unchanged from run AB. The detailed modifications were made from run AC to run AD are included in Appendix E.

The overall simulated gas and water production in run AD matched much better with actual figures than that of previous runs. Pressures were much lower than before, however. This difference was believed to indicate insufficient oil volume, so the only modification from run AD through run AG (runs AE and AF failed) was to increase the original oil saturation from 77% to 78%.

Run AG resulted in a good overall history match. The focus of the testing shifted to individual well matches at this point, resulting in run AT, which is the final history match. Numerous runs were made between run AG and run AT, but only slight modifications resulted. Modifications made from run AG to run AT are included in Appendix E.

Graphs of the comparisons of actual production and pressures versus the simulated production and pressures are illustrated in Figures 45 and 46. Data input sets for the initial run AA and the final run AT have been included in Appendix D.

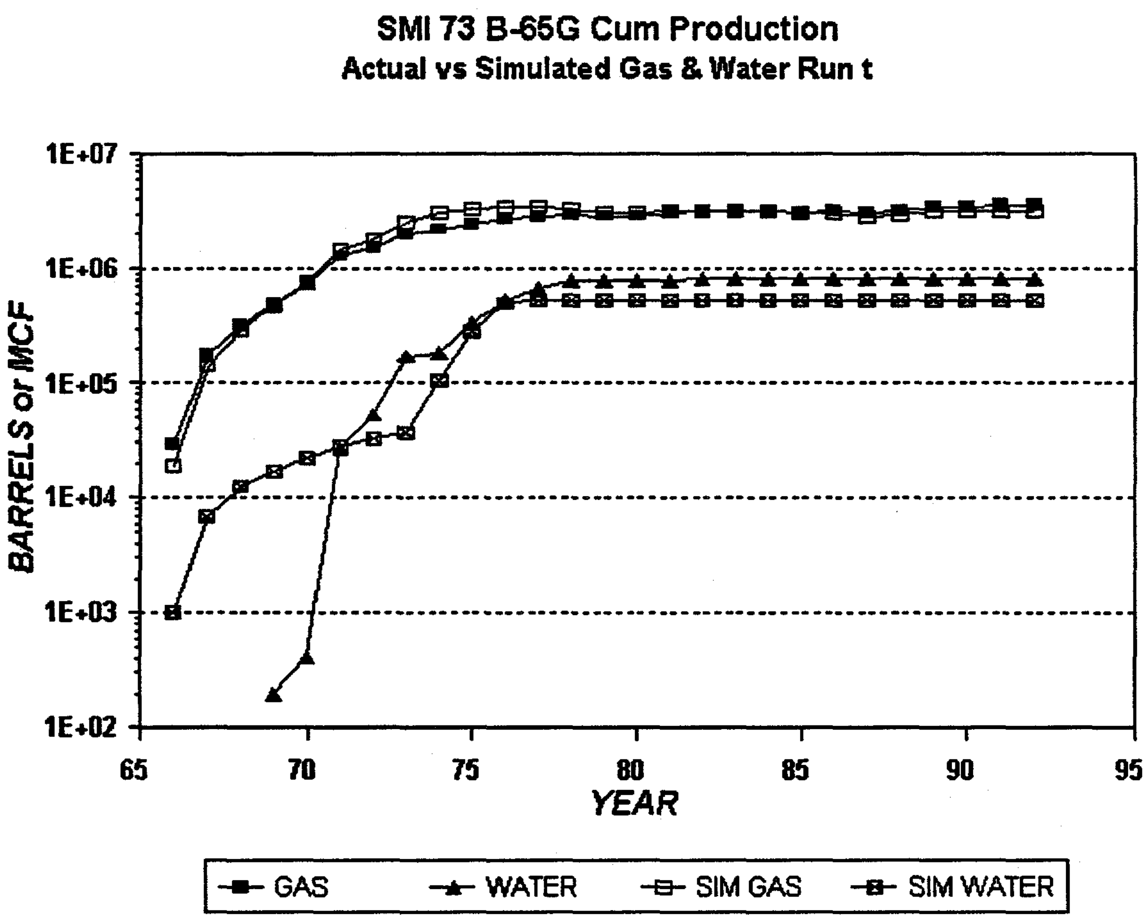


FIGURE 45

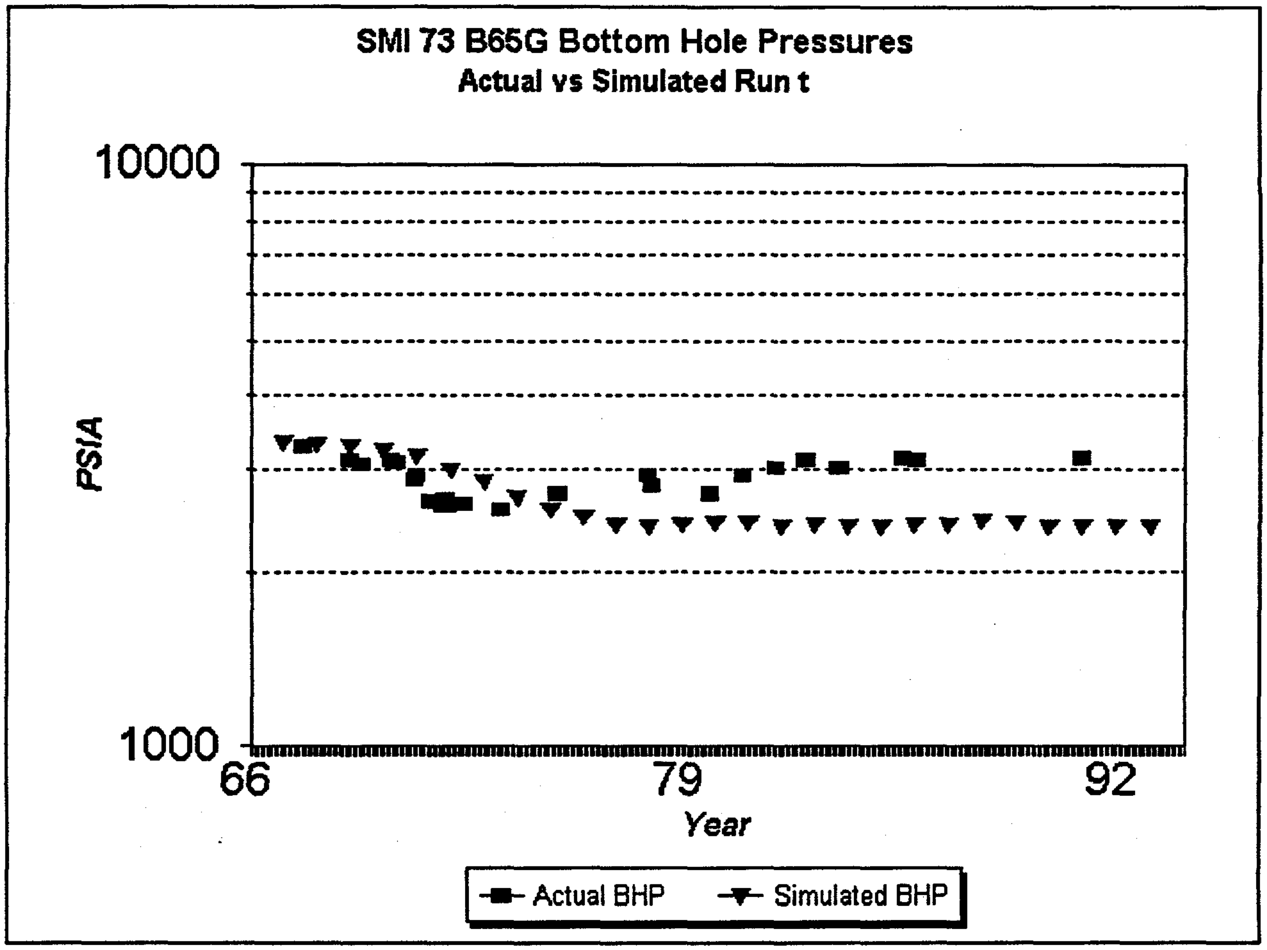


FIGURE 46

VI.2i Prediction Runs

Because the reservoir initially had a gas cap in place, because the amount of gas injection that took place and because of the performance of the wells, limited bypassed oil reserves were anticipated. Based on several predictive runs under varying scenarios the limited remaining oil reserves are approximately 400 MSTB. After this, only the gas cap, of approximately 1 BCF of gas remains to be blown down. Oil reserves which remain should be produced from the B-12 well, which was producing 72 BOPD of 32.6 degree API gravity, 0 BWPD, 50 MCFD on a 14/64" choke at 100 psi flowing tubing pressure, as of July 14, 1994.

VI. CONCLUSIONS

The reservoir simulation studies which are documented in this report provided the LSU Bypassed Oil Study team with calibration cases for use in the evaluation of the oil recovery potential of Gulf of Mexico salt dome reservoirs. The BOAST3 model used in this study can accurately simulate the performance of gas injection projects for recovering attic oil and provide reasonable predictive results.

VI.1 B-35K Reservoir

The results of this study have offered a set of technically feasible solutions to help improve the oil recovery from this reservoir through additional attic gas injection cycles as follows:

1 The injection rate sensitivity studies indicate that relatively low injection rates will accelerate the production response from additional gas injection cycles due to improved segregation of the gas in the attic. The ultimate incremental recovery is improved only slightly at lower gas injection rates. An injection rate of about 500 MCFD appears to be optimum for recovery for this reservoir.
2 The injection volume sensitivity studies show that production is slightly accelerated at higher injection volumes and that incremental oil recovery tends to be higher, but there is a point of diminishing rectums. The optimum gas injection volume appears to be between 150 and 300 million cubic feet.
3 The post-injection shut-in time sensitivity study indicates that a three month shut-in time yields an optimum incremental oil recovery.
4 The injection volume staging sensitivity study indicates that higher incremental recovery can be achieved by dividing the total injection cycle into two stages, with a short production stage between. This improved recovery is most likely due to better segregation of the injected gas in the attic.

In addition to the technical solutions, the results of the sensitivity cases could be analyzed from an economic point of view to determine the optimum injection volume, injection rate, and shut-in period, based on operating conditions and costs.

VI.2 B-65G Reservoir

Primarily, the study of this reservoir indicates that BOAST III is able to accurately describe the history of a steeply dipping reservoir with a past gas injection project.

History matching and predictive simulation runs have shown that the gas injection cycles were very successful in moving attic oil down to be produced by the downdip wells in the B-65G reservoir in South Marsh Island Block 73 Field. Recommendations to the operator, based upon this study, would be to recover the remaining reserves of 400 MSTB of oil available from the B-12 well and then blowdown the gas cap, which is estimated to contain 1.0 BCF of gas

REFERENCES

1. Broom, J.C. and Dawsey, A.L. Jr.,"Gas Injection for Attic Oil Recovery," Petroleum Engineer, February, 1959, pp. B19-B22.

2. Beggs, H.D. and Robinson, J.R., "Estimating the Viscosity of Crude Oil Systems," Journal of Petroleum Technology, September, 1975, pp. 1140-1141.

3. Bleakley, W.B.,"Engineering, Geology Hike Black Bayou Reserves," The Oil and Gas Journal, January 4, 1971, pp. 71-74.

4. Bourdarot G. and Daviau F., "Vertical Permeability: Field Cases," SPE 19777, 64th Annual Technical Conference and Exhibition, October 8-11, 1989.

5. Bleakley, W.B.,"Chevron's Attic Oil Recovery in South Louisiana Looks Good," The Oil and Gas Journal, November 13, 1967, pp. 132-134.

6. Combs, G.D. and Knezek, R.B.,"Gas Injection for Upstructure Drainage," Journal of Petroleum Technology, March, 1971, pp. 361-372.

7. Craft B.C. and Hawkins M.F., Applied Petroleum Reservoir Engineering, Prentice-Hall, Inc., Englewood Cliffs, New Jersey, 1959.

8. Dake L.P., Fundamentals of Reservoir Engineering, Elsevier Science Publishers B.V., Amsterdam, The Netherlans, 1978

9. Duckett, M., Banks,R and Limb, D'"Using Nitrogen to Enhance Oil and Gas Recovery," World Oil, July, 1983, pp. 125-130.

10. Franklin, L.O., Koederitz, W.A. and Walker, D.,"First Report on Field Performance in Recovering Attic Oil," The Oil and Gas Journal, July 24, 1961, pp 65-70.

11. Glasco, O,"Generalized Pressure-Volume-Temperature Correlations," Journal of Petroleum Technology, May, 1980, pp. 785-795.

12. Godbold, F.S.,"Inert Gas Helps Recover Attic Oil," Oil and Gas Journal, April, 1963.

13. Godbold, F.S.,"Humble Recovers Attic Oil With Unique Inert Gas System," World Oil, May, 1965, pp. 151-154.

14. Havlena, D. and Odeh, A.S.,"The Material Balance as an Equation of a Straight Line," Journal of Petroleum Technology, August, 1963, pp 896-900.

15. Havlena, D. and Odeh, A.S.,"The Material Balance as an Equation of a Straight Line-Part II, Field Cases," Journal of Petroleum Technology, July, 1964, pp 815-822.

16. Harvey, A. Herbert,"A Comparison of Nitrogen and Methane Injection for Attic Oil Recovery," Unsolicited SPE Paper #18603, November, 1988.

17. Morrow, R.M.,"Updip Oil Recovery By Downdip Gas Injection," The Petroleum Engineer, April, 1957, pp. B28-B32.

18. Peaceman, D.W.; "Interpretation of Well-Block Pressures in Numerical Simulation", Society of Petroleum Engineer's Journal, (1978) pp. 183-194.

19. Slider, H.C., Practical Petroleum Reservoir Engineering Methods: An Energy Conservation Science, Petroelum Publishing Company, Tulsa, Oklahoma, 1976

20. Sawyer, W. K., "BOAST3-A Modified Version of Handbook for Personal Version of BOAST II: A Three-Dimensional, Three-Phase Black Oil Applied Simulation Tool," Department of Energy Report Contract Number DE-AC22-92BC14831: 1996

21. Franchi, J.R., Harpole, K.J., and Bujnowski, S.W., "BOAST: A Three-Dimensional, Three-Phase Black Oil Applied Simulation Tool," U.S. Department of Energy Report Contract Number DOE/BC/1033-3, Volumes 1 and 2: 1982.

22. Franchi, J.R., Kennedy, J.E., and Dauben, D.L., "BOAST II: A Three-Dimensional, Three-Phase Black Oil Applied Simulation Tool," U.S. Dedpartment of Energy Report Contract Number DOE/BC-88/2/SP: 1987.

23. Stapp, L.G. and Allison, E.C., "Handbook for Personal Version of BOAST II: A Three-Dimensional, Three-Phase Black Oil Applied Simulation Tool," Department of Energy Report: December, 1989.

24. Strickland, R.F.,"Numerical Simulation of Gas Injection for Upstructure Drainage," Dissertation, Texas A&M University, December, 1976.

25. Strickland R.F. and Morse R.A., "Gas Injection for Upstructure Oil Drainage," Journal of Petroleum Technology, October, 1979, pp 1323-1331.

26. Sutton, R.P. and Farshad, F., "Evaluation of Empirically Derived PVT Properties for Gulf of Mexico Crude Oils," SPE Reservoir Engineering, February, 1990, pp. 79-86.

27. Sutton, R.P. and Farshad, F., "Evaluation of Empirically Derived PVT Properties for Gulf of Mexico Crude Oils," SPE 13172, 59th Annual Technical Conference and Exhibition, September,16-19, 1984.

28. Waguespack, S.J., "Salt Domes of South Louisiana," The New Orleans Geological Society, Volume III, 1983, pp. 58-59.

APPENDIX A
B-35K RESERVOIR
MODEL INPUT DATA

SMI 73 Simulation
B-35 K Reservoir Input Data

NOTE: See BOAST User's Manual for definitions of the keywords which art used in the input dataset.

```
ID1: LSU PROJECT- ACTUAL FIELD STUDY TAYLOR ENERGY-BOAST III (04/05/93)
ID2:ACTUAL RESERVOIR WITH 3-WELLSIREPRS:0--->1
ID3:A-1, A-3, AND A-6              (b) DIP = 27 degrees down!
ID4:modified Krw (mod #5N, USING CASE 13N),MODIFIED KRG (MOD#4), WOC @ 6137 FT
AND ATTIC RESOVOIR
ID5: SMI 73 BLOCK, 3-layer set up, thickness by grid block, well producing @ constant rate
RESTART AND POST-RUN CODES
-10
GRID DATA: NUMBER OF GRID BLOCKS X, Y, Z
14 11 3
GRID BLOCK LENGTHS: dimensions in feet, with thickness varied by grid block
0 0 1 1
375.500.500.500.125.594.500.500.125.406.500.500.125.563.
250. 250. 125. 125. 62.5 31.25 125. 125. 204. 250. 500.
0. 0. 0. 0. 0. 0. 0. 0. 0. 0. 0. 0. 0. 0.
1. 1.5 3. 1.5 0. 0. 0. 0. 0. 0 0. 1. 1.5 2.5
3 4.5 6. 6. 5.5 4.5 5. 5. 4.5 4.5 5. 5. 5.5 5.5
5. 6.5 8. 7. 7. 6. 7. 7.5 7.5 6.5 6.5 6.5 6.5 7.5
6.5 8. 10. 9. 8.5 8.0 8.5 8.5 8.5 8.5 8.5 8.0 8.0 9.0
7.0 9.0 11.5 11.5 9.58.5 10. 11. 11.5 9.0 9.0 11.5 8.5 9.5
9.0 11.0 14. 14.5 14. 13. 15. 16.5 16.5 16. 12.5 14. 10.5 11.
12.5 14. 19. 18.5 18. 18. 19. 20. 20. 20. 19. 14. 13. 13.5
16.5 19. 21. 21.5 21. 21. 21.5 21.5 21.5 21.5 21. 19. 16.5 17.
21. 22. 23. 24. 24. 23. 23. 23. 23. 23. 22.5 21.5 20.5 20.
25.5 26. 26.5 26.5 26.5 26.5 26.5 26.5 26.5 26. 26.5 24. 23. 23.
5. 5. 0. 0. 0. 0. 0. 0 0. 0. 0. 4. 5. 5.
5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5.
5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5.
5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5.
5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5.
5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5.
5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5.
5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5.
5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5.
5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5.
5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5. 5.
0. 0. 0. 0. 0. 0. 0. 0. 0. 0. 0. 0. 1. 5.
6. 6. 6. 6. 5. 1. 0. 2.5 5. 5. 5. 6. 6. 6.
6. 6. 6. 6. 6. 6. 6. 6. 6. 6. 6. 6. 6. 6.
6. 6. 6. 6. 6. 6. 6. 6. 6. 6. 6. 6. 6. 6.
6. 6. 6. 6. 6. 6. 6. 6. 6. 6. 6. 6. 6. 6.
6. 6. 6. 6. 6. 6. 6. 6. 6. 6. 6. 6. 6. 6.
6. 6. 6. 6. 6. 6. 6. 6. 6. 6. 6. 6. 6. 6.
```

SMI 73 Simulation
B-35 K Reservoir Input Data
(Continued)

6. 6. 6. 6. 6. 6. 6. 6. 6. 6. 6. 6. 6. 6.
6022.6058.6093.6140.
6113.6108.6104.6087.6082.6083.6065.6060.6068.6078.6093.6132.6160.6200.
6207.6192.6175.6160.6158.6154.6160.6167.6175.6187.6215.6244.6274.6308.
POROSITY AND PERMEABILITY DISTRIBUTIONS
1 0 0 0
0.066 0.314 0.165 0.033 0.0 0.0 0.0 0.0 0.0 0.0 0.132 0.297 0.33 0.165 0.06 0.33 0.33 0.33
0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.264
0.132 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.297
0.198 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.297
0.198 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.314
0.231 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33
0.264 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33
0.297 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.231
0.33 0.264 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.281 0.33 0.33
0.33 0.33 0.33 0.33 0.33 0.264 0.297 0.314 0.297 0.264 0.33 0.33 0.33 .33
0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33
0.058 0.276 0.145 0.029 0.0 0.0 0.0 0.0 0.0 0.0 0.116 0.261 0.29 0.145
0.058 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.032
0.116 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.261
0.116 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.261
0.174 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.276
0.203 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29
0.232 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29
0.261 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.203
0.290 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29
0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29
0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29 0.29
0.064 0.304 0.16 0.032 0.0 0.0 0.0 0.0 0.0 0.0 0.128 0.288 0.320 0.16
0.064 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.256
0.128 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.288
0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.288
0.192 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.304
0.224 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.320
0.256 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32
0288 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.224
0.32 0.256 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.272 0.32 0.32
0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32
0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32 0.32
1440. 570. 1125.
1440. 570. 1125.
14.4 5.7 11.25
POROSITY AND PERMEABILITY MODIFICATIONS
0 0 0 0 0 0 0 0

SMI 73 Simulation
B-35 K Reservoir Input Data
(Continued)

TRANSMISSIBILITY MODIFICATIONS
0 0 0 1
ROCK PVT: number of rock regions and PVT data sets
1 1

SAT	KROW	KRW	KRG	KROG	PCOW	PCGO	
0.00	0.00	0.00	0.00	0.00	0.00	0.00	relative perm data
0.165	0.00	0.00	0.00	0.00	0.00	0.00	and capillary
0.30	0.00	0.0035	0.035	0.00	0.00	0.00	pressure values.
0.40	0.02	0.0055	0.09	0.00	0.00	0.00	
0.50	0.13	0.01	0.18	0.01	0.00	0.00	
0.60	0.38	0.05	0.32	0.04	0.00	0.00	
0.70	0.65	0.09	0.42	0.12	0.00	0.00	
0.80	1.00	0.48	0.64	0.26	0.00	0.00	
0.90	1.00	0.65	0.85	0.60	0.00	0.00	
1.00	1.00	1.00	1.00	1.00	0.00	0.00	

ITHREE SWR
1 .165
PBO PBODAT PBGRAD: bubble point pressure and datum at which that value was measured
2870.0 6324. 0.000

VSLOPE	BSLOPE	RSLOPE	PMAX	REPRS
.000046	-.0000232	0.	3000.	0 <--- "ON"

P	MUO		BO	RSO
2000.	0.6869	1.215	338.75	PVT data for the three phases oil,
2100.	0.6914	1.213	357.76	gas, and water. It includes viscosity
2200.	0.6962	1.212	377.28	solution GOR, formation volume
2000.	0.7013	1.211	397.14	factors, and density values.
2400.	0.7067	1.209	417.34	
2500.	0.7124	1.208	437.89	
2600.	0.7184	1.206	458.79	
2700.	0.7247	1.205	480.06	
2800.	0.7313	1.204	501.69	
2900.	0.7381	1.203	523.69	
3000.	0.7452	1.202	546.08	

P	MUW	BW	RSW
100.	0.56	1.000	0.00
3000.	0.56	0.9228	0.00

GAS AND ROCK PROP
0

P	MUG	BG	PSI	CR
100.	.0163	.13729	0.	0.000003
200.	.0164	.06381	0.	0.000003
300.	.0165	.04014	0.	0.000003
400.	.0168	.02884	0.	0.000003
500.	.0171	.02222	0.	0.000003

SMI 73 Simulation
B-35 K Reservoir Input Data
(Continued)

800. .0183 .01273 0. 0.000003
1000. .0238.00785 0. 0.000003
1600. .0497.00573 0. 0.000003
2000. .0604.00480 0. 0.000003
3000. .0700.00300 0. 0.000003
RHOSCO RHOSCW RHOSCG
53.415 62.238 0.047
Initialization Option Codes
0 1 6137. 0.00 [KPI KSI PDATUM GRAD]
NR Pwoc WOC Pgoc GOC Soi Swi Sgi
1 2804. 6137. 0.0 5100. 0.835 0.165 0.0
Initilization by Layer (NZ Records)
1 2816 0.815 0.185 0.0 [Pi Soi Swi Sgi]
2 2816 0.753 0.247 0.0 [Pi Soi Swi Sgi]
3 2816 0.795 0.205 0.0 [Pi Soi Swi Sgi]
INITIAL OIL SATURATION FOR GRID(oil saturation per grid block for each layer)
0.815 0.815 0.815 0.815 0.00 0.00 0.00 0.00 0.00 0.00 0.815 0.815 0.815 0.815
0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815
0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0,815 0.815 0.815 0.815
0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815
0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815
0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815
0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815
0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815
0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.693
0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.815 0.734 0.408 0.082
0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000
0.753 0.753 0.753 0.753 0.000 0.00 0.00 0.00 0.00 0.00 0.753 0.753 0.753 0.753
0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753
0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753
0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753
0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753
0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753
0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753
0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753
0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.640
0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.753 0.677 0376 0.075
0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.0000.000 0.000
0.795 0.795 0.795 0.795 0.00 0.00 0.00 0.00 0.00 0.00 0.795 0.795 0.795 0.795
0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795
0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795
0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795
0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795
0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795

SMI 73 Simulation
B-35 K Reservoir Input Data
(Continued)

0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795
0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795
0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.675
0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.795 0.715 0.397 0.079
0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000
INITIALIZE WATER SATURATION (water saturation per grid block for each layer)
0.185 0.185 0.185 0.185 0.00 0.00 0.00 0.00 0.00 0.00 0.1850.185 0.185 0.185
0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185
0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185
0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185
0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185
0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185
0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185
0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185
0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.307
0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.185 0.266 0.592 0.918
1.000 1.000 1.000 1.000 1.000 1.000 1.000 1.000 1.000 1.000 1.000 1.000 1.000 1.000
0.247 0.247 0.247 0.247 0.00 0.00 0.00 0.00 0.00 0.00 0.247 0.247 0.247 0.247
0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247
0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247
00247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247
0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247
0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247
0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247
0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247
0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.360
0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.247 0.323 0.624 0.925
1.000 1.000 1.000 1.000 1.000 1.000 1.000 1.000 1.000 1.000 1.000 1.000 1.000 1.000
0.205 0.205 0.205 0.205 0.00 0.00 0.00 0.00 0.00 0.00 0.205 0.205 0.205 0.205
0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205
0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205
0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205
0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205
0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205
0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205
0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205
0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.325
0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.205 0.285 0.603 0.921
1.000 1.000 1.000 1.000 1.000 1.000 1.000 1.000 1.000 1.000 1.000 1.000 1.000 1.000
KSN1 KSM1 KCO1 KCOF KSKIP KOUT (print control codes)
0 0 0 0 1 0
NMAX FACT1 FACT2 TMAX WORMAX GORMAX PAMIN PAMAX (Model control codes)
9999 1.25 0.5 1500. 2.00 500000 150. 5000.
KSOL MITR OMEGA TOL TOLI DSMAX DPMAX
4 250 1.7 .020 0.00 .025 150.0

SMI 73 Simulation
B-35 K Reservoir Input Data
(Continued)

NUMDIS IRK THRUIN
0 0 .6
AQUIFER DATA
2
2
1 9 11 11 1 3 7.58
10 14 11 11 1 3 7.58
WELL AND NODE DATA
TAYLOR FIELD PRODUCING WELLS
3
WELL NUMBER AND NODE
1 3 PROD1
2 3 PROD3
3 3 PROD6
WELL NODE AND DIRECTION
1 13 8 1 1
1 13 8 2 1
1 13 8 3 1
2 9 6 1 1
2 9 6 2 1
2 9 6 3 1
3 5 5 1 1
3 5 5 2 1
3 5 5 3 1
RECURRENT DATA: control the production performance of each well with time.

C========================DATA SET1=================================

0 2 1 [ICHANG IOMETH IWLCNG-> NOTE: ICHANG not used if IOMETH>0]
1.0 30.2 [Times for output - IOMETH values]
1 1 1 0 0 0 [IPMAP,ISOMAP,ISWMAP,ISGMAP,IBPMAP,IAQMAP]
0 0 0 0 0 0 0 [KROMP,KRWMP,KRGMP,IRSOMP,PCOWMAP,PCOGMAP,PHIMAP]
0.01 0.01 15.0 [DT,DTMIN,DTMAX]
HEADER-> Beginning of data read by NODES-if IWLCNG=1]
3 0 [NWELLN= No. of new wells,NWELLO= No. of old wells]
---NEW WELLS---
PROD 1 13 8 1 3 [FORMATTED:A5,S13 - WELLID,IDWELL,I,J,PERF1,NLAYER,]
29.6 4.50 10.67
0.00 0.00 0.000
PROD 1 1 109.6 0.00 0.00 0.000. [FORMATTED: A5,2I3,4F10.0]
PROD 3 9 6 1 3 [FORMATTED: A5,S13 - WELLID,IDWELL,I,J,PERF1,NLAYER]
28.18 4.85 11.49
0.00 0.00 0.000
PROD 3 1 12.03 0. 0000. 000. [FORMATTED: A5,S13,4F10.0]
PROD 6 5 5 1 3 [FORMATTED: A5,S13 - WELLID,IDWEE,I,J,PERF1,NLAYER]

SMI 73 Simulation
B-35 K Reservoir Input Data
(Continued)

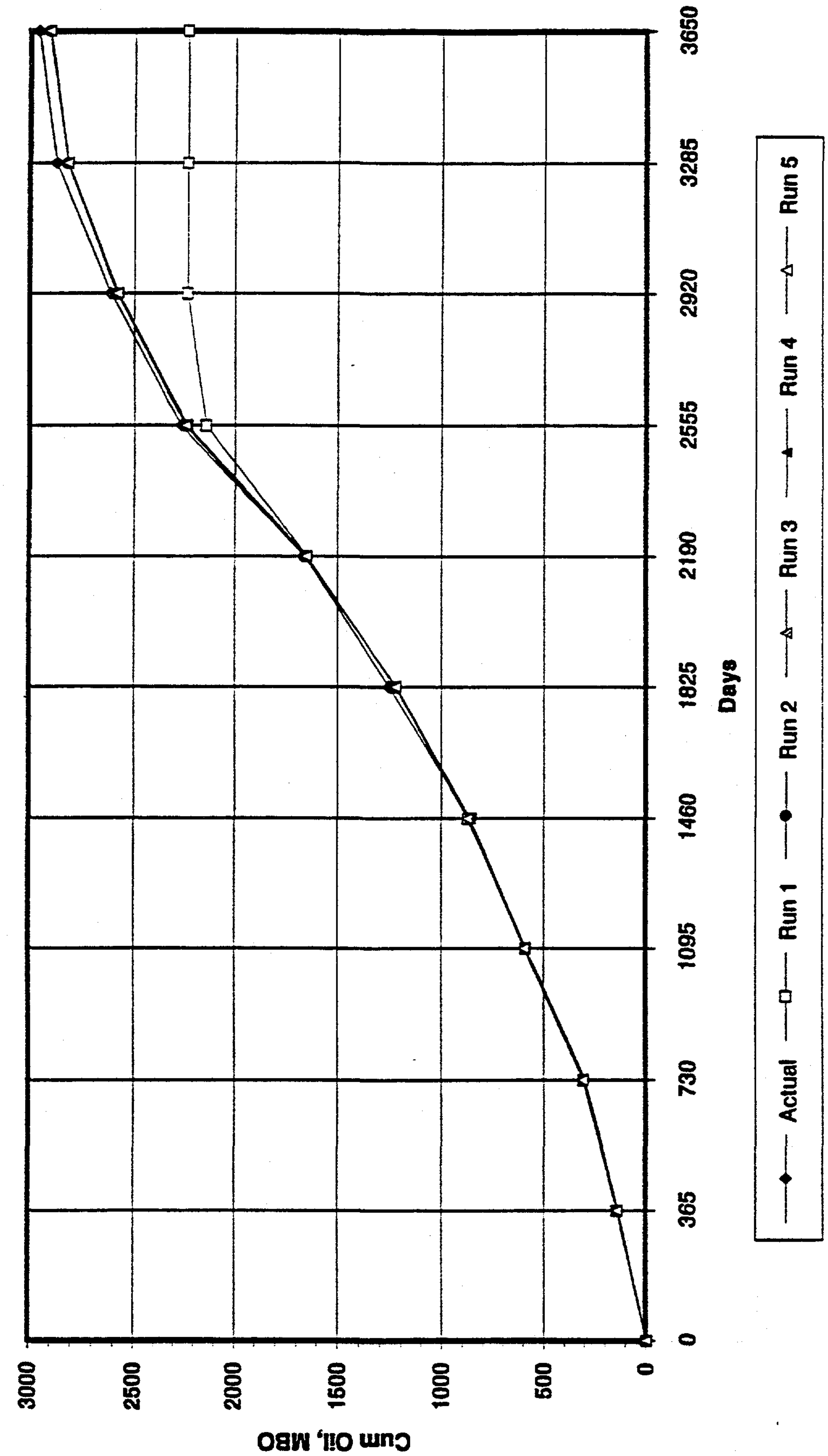
```
20.5 4.76 11.27
0.00 0.00 0.000
PROD 6 1 93.6 0. 0000. 000. [FORMATTED: A5,2I3,4F10.0]
C========================DATA SET====================================
0 7 1 [ICHANG IOMETH IWLCNG-> NOTE: ICHANG not used if IOMETH>0]
30.5 31.0 35.0 60.0 90.0 182.0 213.0 [Times for output - IOMETH values]
1 1 1 0 0 0 [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
0 0 0 0 0 0 0 [KROMP, KRWMP, KRGMP, IRSOMP]
0.01 0.01 15.0 [DT,DTMAX,DTMIN]
HEADER -> Beginning of data read by NODES - if IWLCNG = 1]
3 0 [NWELLN=No. of new wells,NWELLO=No. of old wells]
---NEW WELLS---
PROD 1 13 8 1 3 [FORMATTED: AS,S13 - WELLID,IDWELL,I,J,PERFI,NLAYER]
29.60 4.50 10.67
0.00 0.00 0.000
PROD 1 1 109.6 0. 0000. 000. [FORMATTED: A5,2I3,4F10.0]
PROD 3 9 6 1 3 [FORMATTED: A5,S13 - WELLID,IDWELL,I,J,PER1,NLAYER]
28.18 4.85 11.49
0.00 0.00 0.000
PROD 3 1 133.33 0. 0000. 000. [FORMATTED: A5,2I3,4F10.0]
PROD 6 5 5 1 3 [FORMATTED: A5,S13 - WELLID,IDWELL,I,J,NLAYER]
20.5 4.76 1127
0.00 0.00 0.000
PROD 6 1 139.72 0. 0000. 000. [FORMATTED: A5,2I3,4F10.0]
C===========================DATA SET==================================
0 8 1 [ICHANG IOMETH IWLCNG-> NOTE: ICHANG not used if IOMETH>0]
214.0 215. 220. 240. 300. 365. 426 517. [Times for output-IOMETH values]
1 1 1 0 0 0 [IPMAP,ISOMAP,ISWMAP,ISGMAP,IBPMAP,IAQMAP]
0 0 0 0 0 0 0 (KROMP,KRWMP,KRGMP,IRSOMP]
0.01 0.01 30.0 [DT,DTMIN,DTMAX]
HEADER -> Beginning of data read by NODES - if IWLCNG = 1]
3 0 [NWELLN=No. of new wells,NWELLO=No. of old wells]
---NEW WELLS---
PROD 1 13 8 1 3 [FORMATTED: A5,5I3,IDWELI,I,J,PERF1,NLAYER]
29.6 4.50 10.67
0.00 0. 0.000
PROD 1 1 138.7 0. 0000. 000. [FORMATTED: A5,2I3,4F10.0]
PROD 3 9 6 1 3 [FORMATTED: A5,5I3-WELLID,IDWELL,I,J,PERF1,NLAYER]
28.18 4.85 11.49
0.00 0.00 0.000
PROD 3 1 133.33 0. 0000. 000. [FORMATTED: A5,2I3.4F10.0]
PROD 6 5 5 1 3 [FORMATTED: A5,5I3-WELLID,IDWELL,I,J,PERF1,NLAYER]
20.5 4.76 11.27
0.00 0.00 0.000
PROD 6 1 139.72 0. 0000. 000. [FORMATTED: A5,2I3,4F10.0]
```

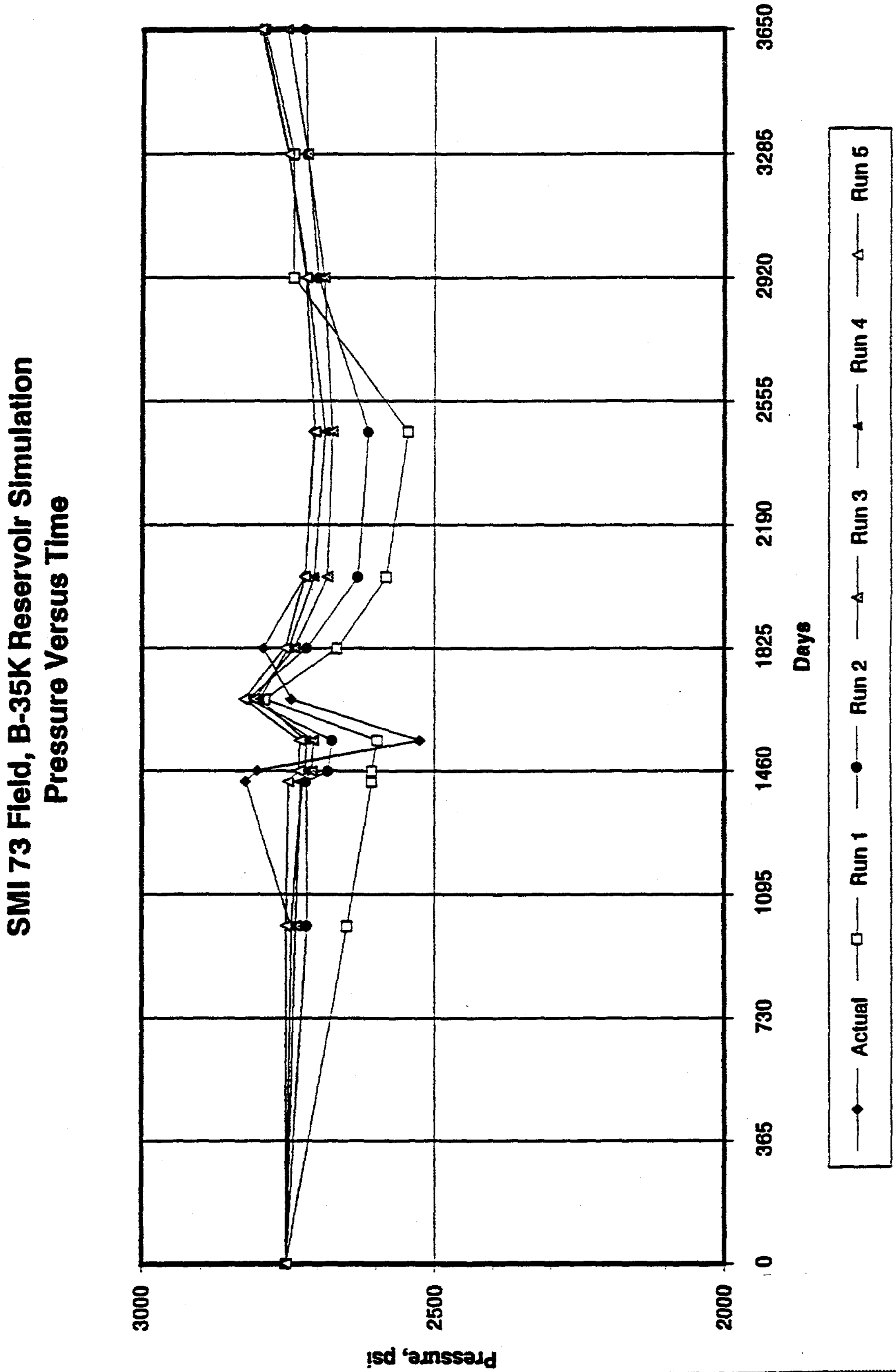
APPENDIX B
B-35K RESERVOIR
HISTORY MATCH RESULTS

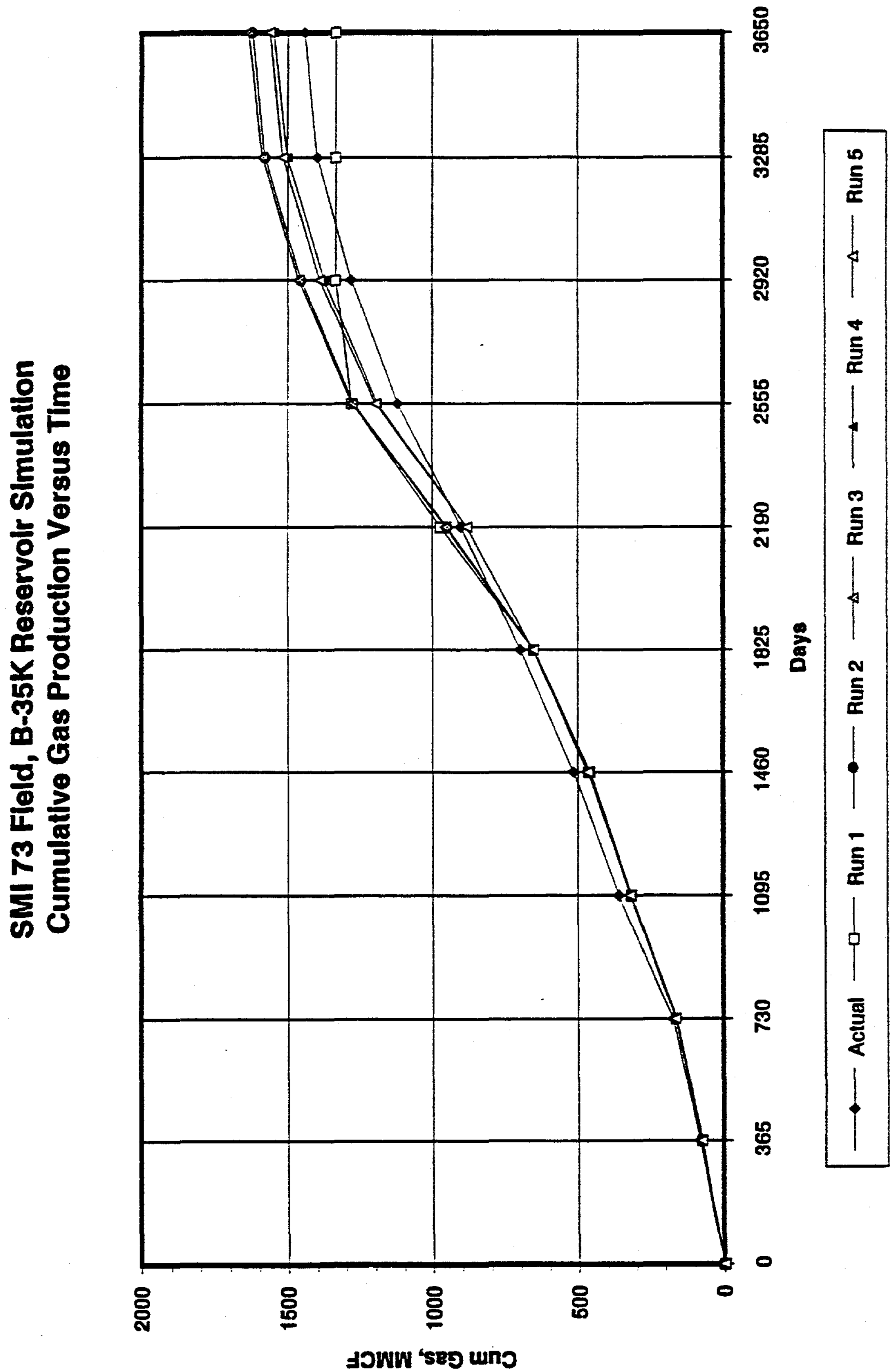
SMI 73 Simulation Results
Summary of History Match Cases

RUN	CASE NAME	CASE DESCRIPTION
Run 1	Proven Oil Case	Assumes that the original oil-water contact is at -6,076 feet subsea as defined by Well A-1
Run 2	Estimated O/W Contact Case	Assumes that the original oil-water contact is at -6,176 feet subsea, or 100 feet below the proven limit
Run 3	Modified Krw Case	This is the same case as Run 2 with a modified water-oil relative permeability curve.
Run 4	Attic Oil Volume Case	This is the same case as Run 3 with an additional attic oil volume of 1.3 MMBO.
Run 5	Final History Match Case	This is the same case as Run 4 with the original oil-water contact at -6,137 feet subsea

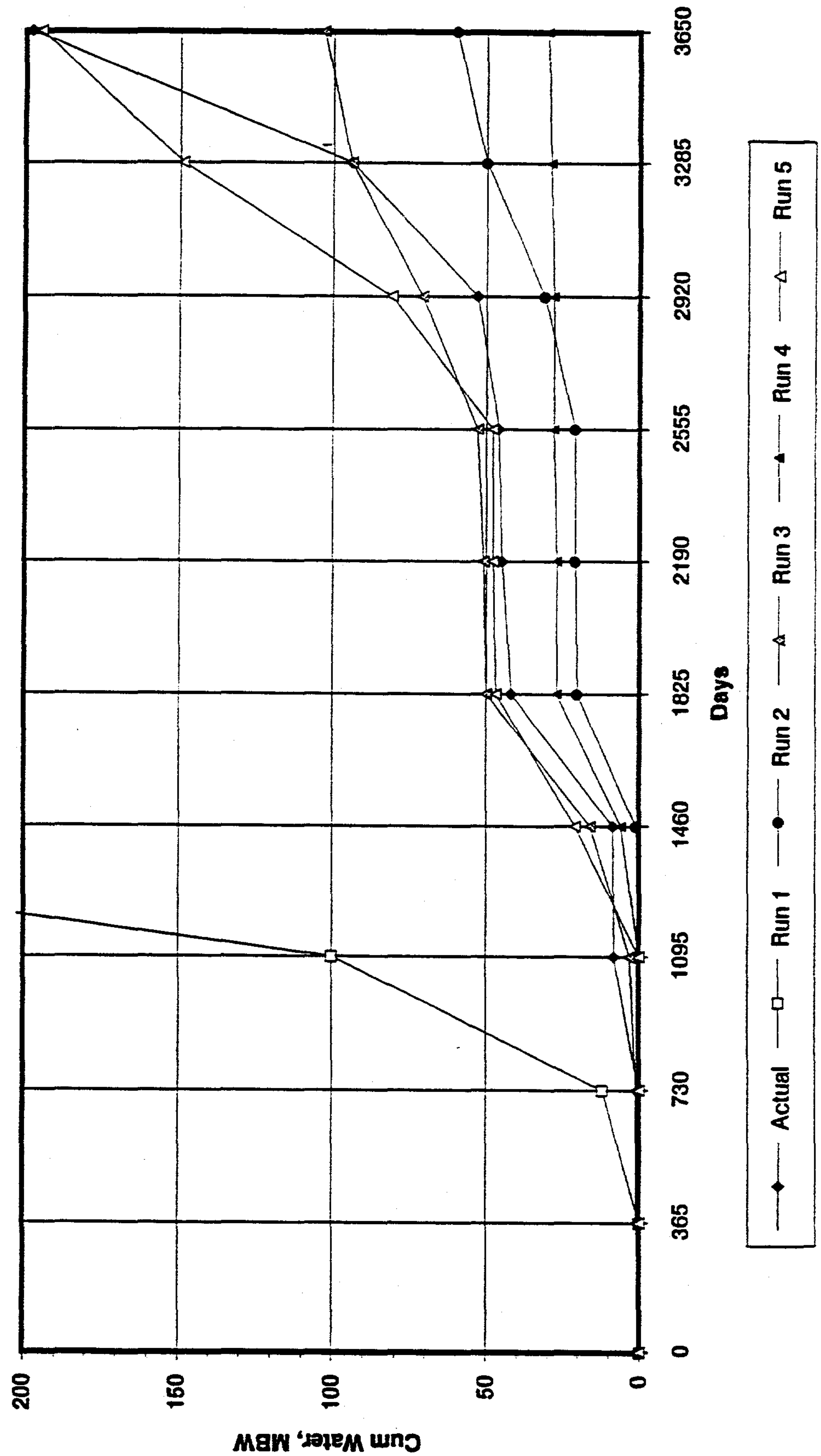
SMI 73 Field, B-35K Reservoir Simulation
Cumulative Oil Production Versus Time




SMI 73 Field, B-35K Reservoir Simulation
Pressure Versus Time
Pressure, psi
3000
2500
2000
Days
0
365
730
1095
1460
1825
2190
2555
2920
3285
3650
Actual
Run 1
Run 2
Run 3
Run 4
Run 5


SMI 73 Field, B-35K Reservoir Simulation
Cumulative Gas Production Versus Time
Cum Gas, MMCF
0
500
1000
1500
2000
Days
0
365
730
1095
1460
1825
2190
2555
2920
3285
3650
Actual
Run 1
Run 2
Run 3
Run 4
Run 5

SMI 73 Field, B-35K Reservoir Simulation
Cumulative Water Production Versus Time

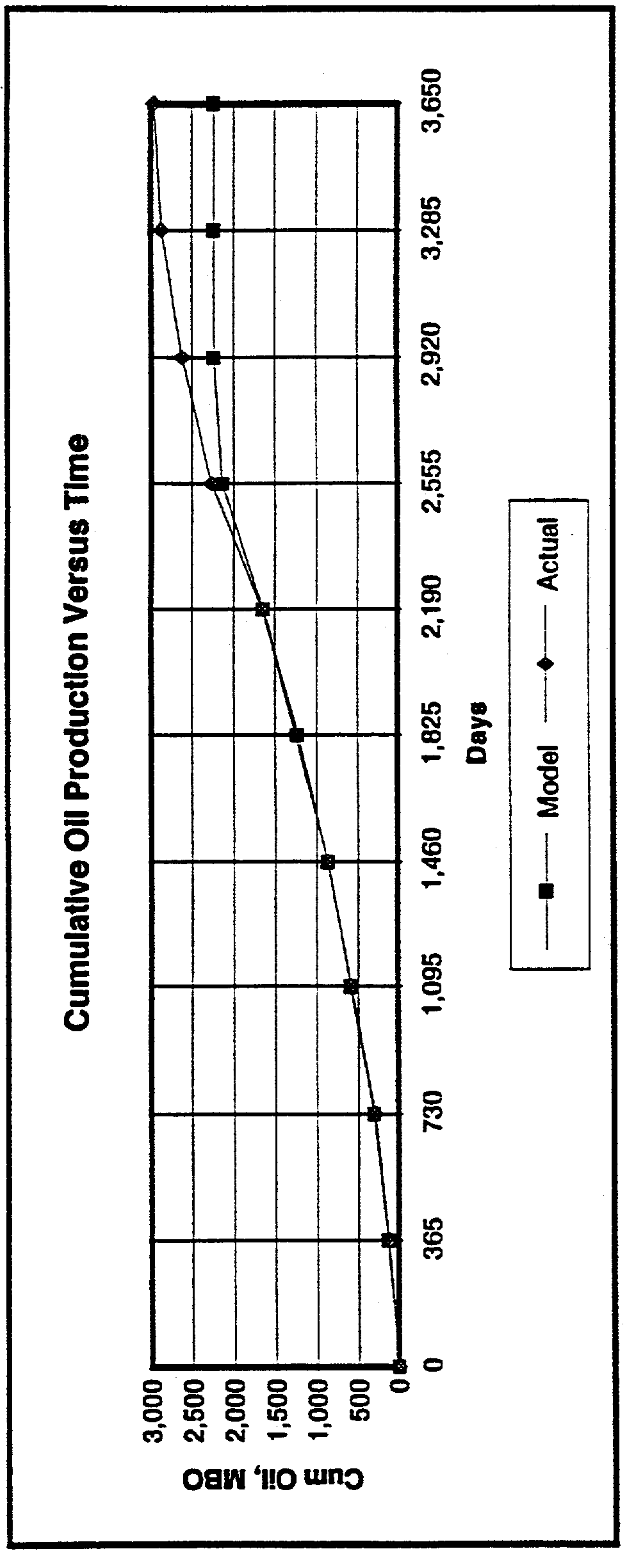


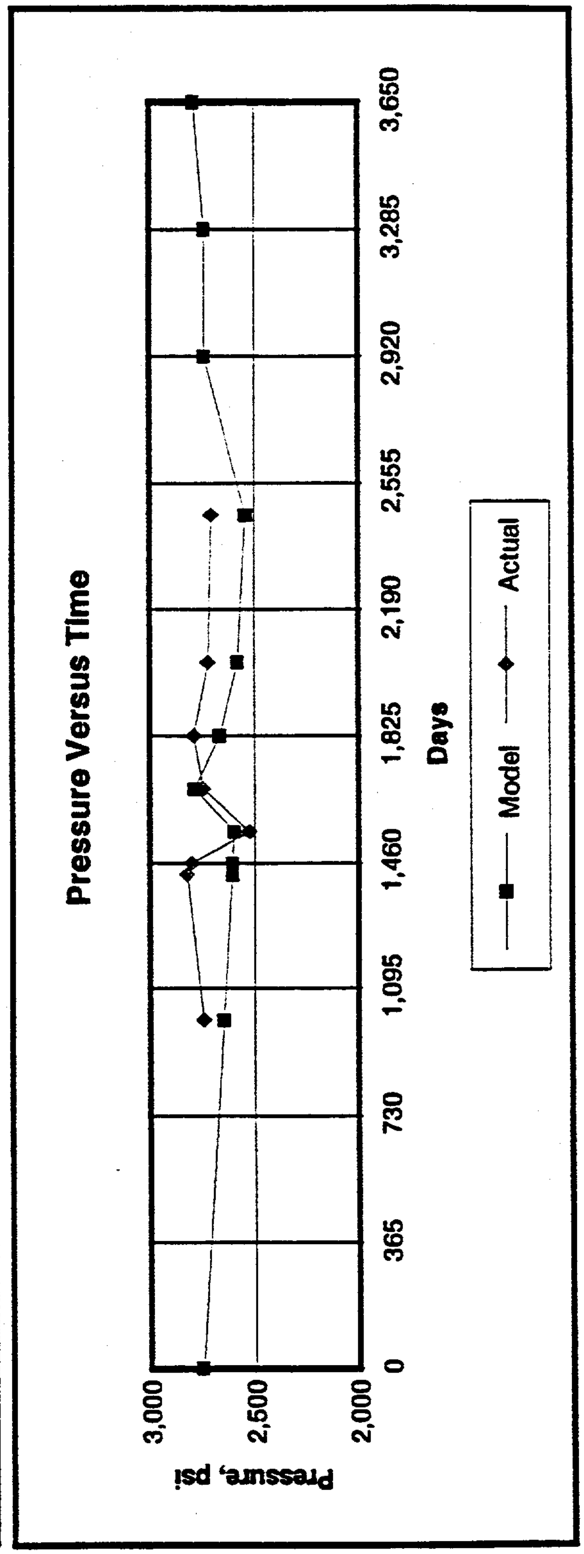
B-35K RESERVOIR SIMULATION HISTORY MATCH RESULTS
PROVEN OIL LIMIT CASE - RUN 1

Time (Days)	HISTORY MATCH DATA			ACTUAL FIELD DATA		
	Cum Oil (MBO)	Cum Gas (MMSCF)	Cum Water (MSTB)	Cum Oil (MBO)	Cum Gas (MMSCF)	Cum Water (MSTB)
0	0	0	0	0	0	0
365	139	74	0	131	83	0
730	307	164	12	296	175	0
1,095	589	315	100	587	359	8
1,460	870	463	419	863	516	9
1,825	1,226	653	796	1,257	698	42
2,190	1,646	973	838	1,656	902	45
2,555	2,140	1,279	1,164	2,266	1,120	46
2,920	2,231	1,335	1,262	2,616	1,281	53
3,285	2,231	1,335	1,262	2,875	1,400	94
3,650	2,231	1,335	1,262	2,960	1,443	198

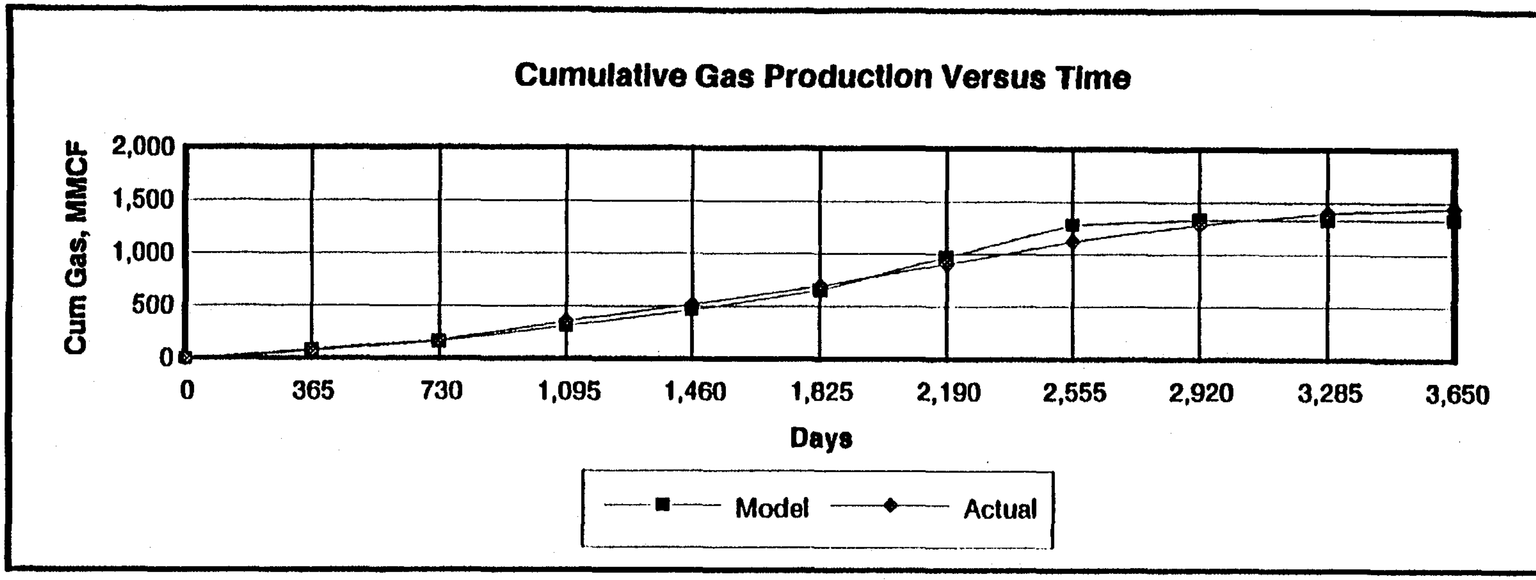
Time (Days)	Model		Actual	
	Pressure (psi)	Cum Oil (MBO)	Pressure (psi)	Cum Oil (MBO)
0	2,755	0		
1,003	2,650	791	2,747	863
1,428	2,608	1,226	2,825	863
1,460	2,608	1,240	2,805	897
1,551	2,598	1,301	2,526	1,015
1,673	2,791	1,470	2,746	1,171
1,825	2,667	1,692	2,793	1,279
2,038	2,582	2,036	2,723	1,496
2,464	2,545	2,231	2,708	2,170
2,920	2,742			
3,285	2,742			
3,650	2,793			

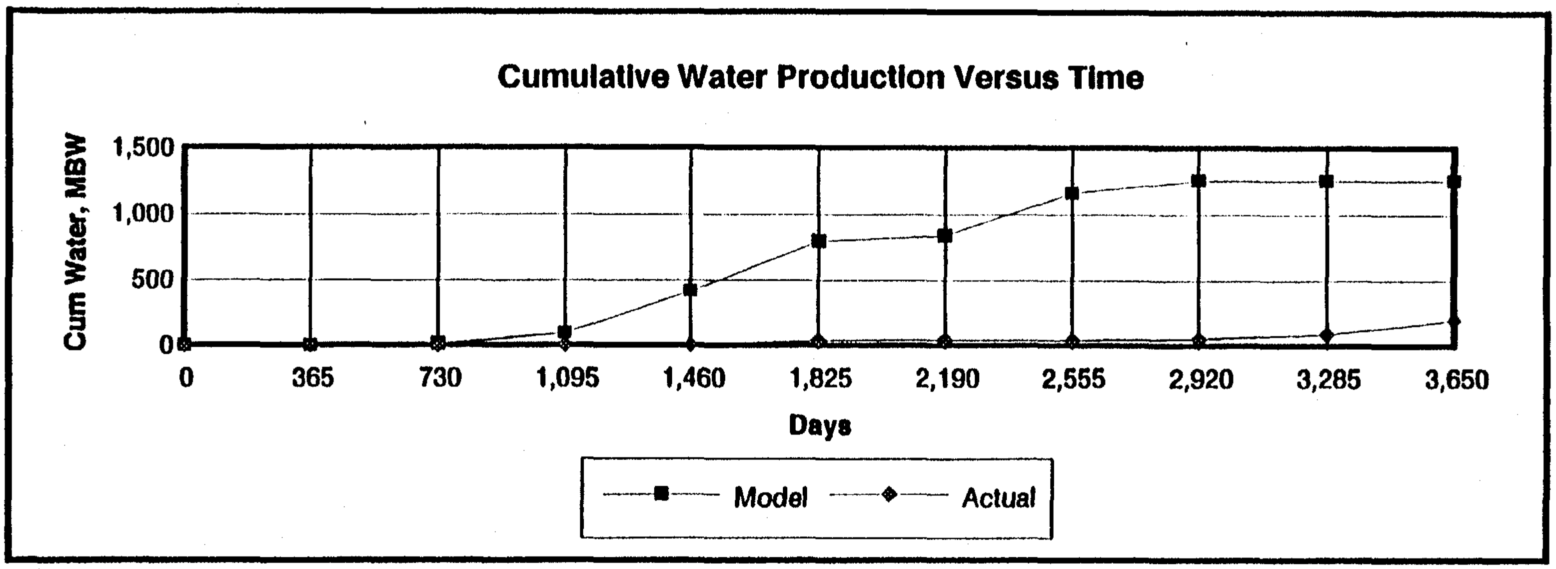
PROVEN OIL LIMIT CASE - RUN 1





B-35K RESERVOIR SIMULATION HISTORY MATCH RESULTS
PROVEN OIL LIMIT CASE - RUN 1



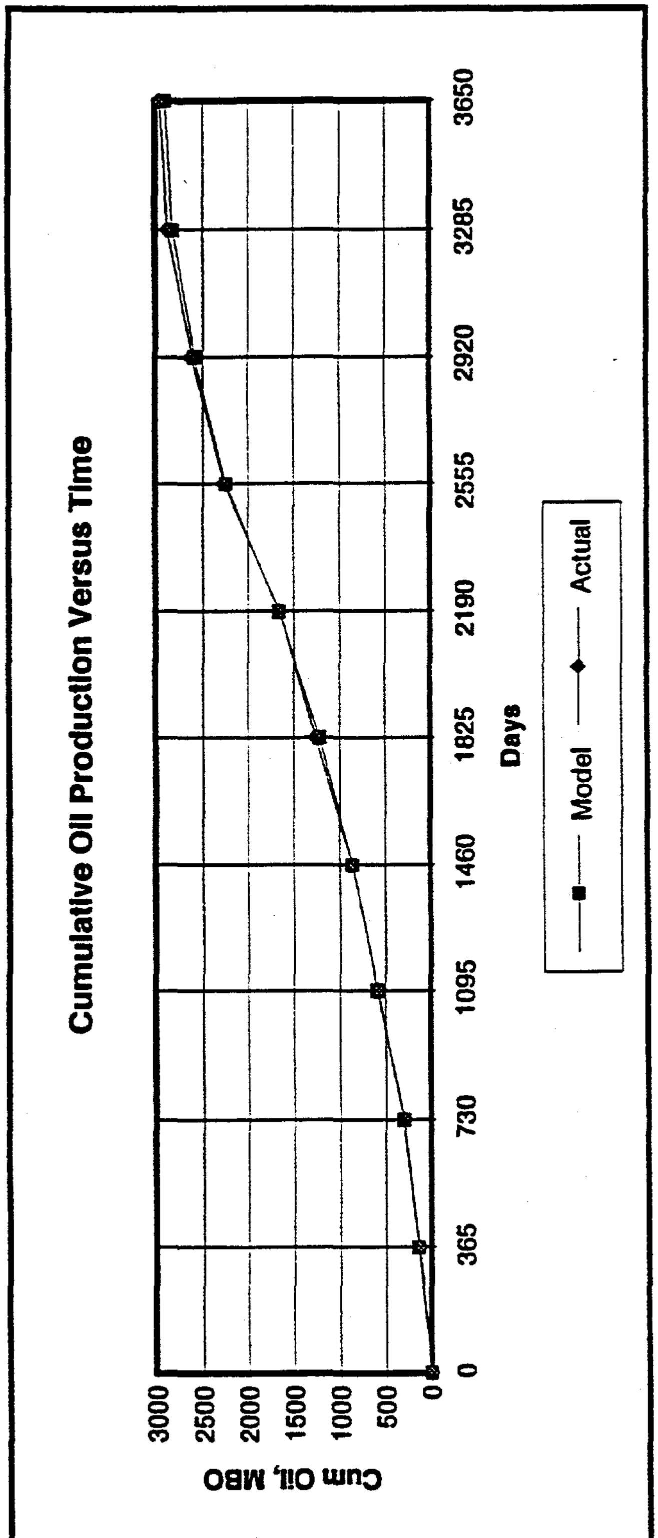


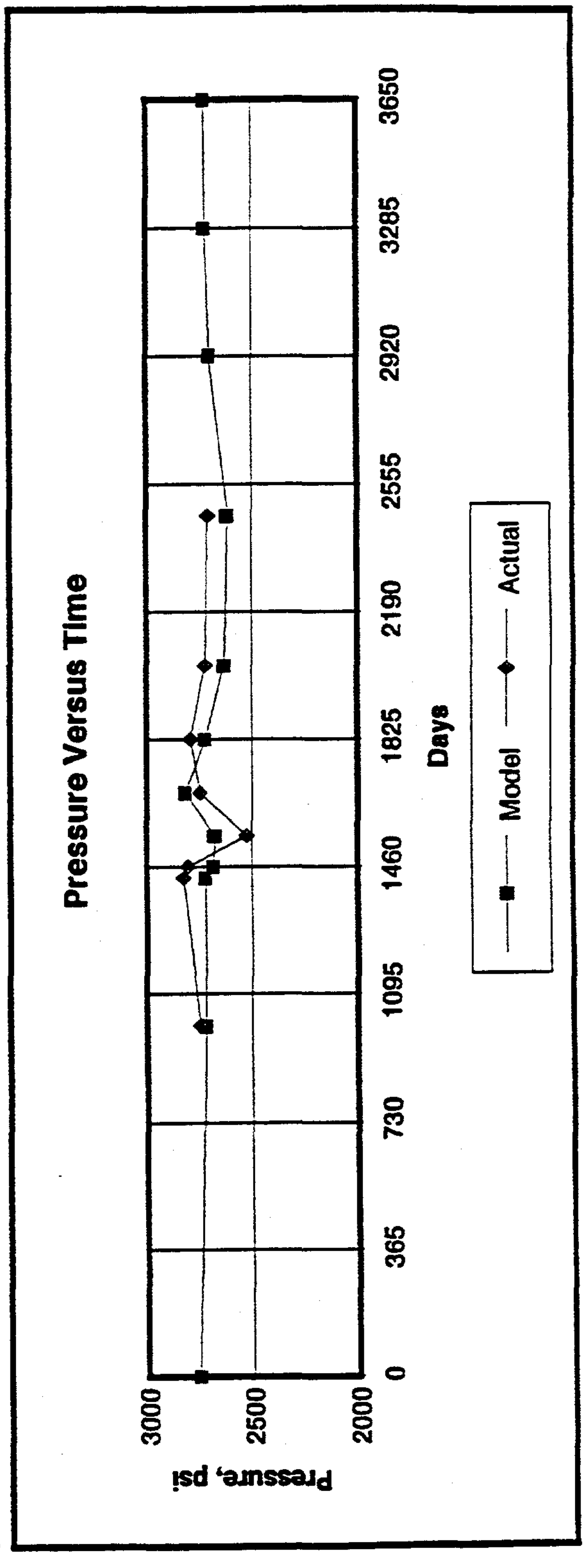
B-35K RESERVOIR SIMULATION HISTORY MATCH RESULTS
ESTIMATED OIL/WATER CONTACT CASE - RUN 2

Time (Days)	HISTORY MATCH DATA			ACTUAL FIELD DATA		
	Cum Oil (MBO)	Cum Gas (MMSCF)	Cum Water (MSTB)	Cum Oil (MBO)	Cum Gas (MMSCF)	Cum Water (MSTB)
0	0	0	0	0	0	0
365	139	74	0	131	83	0
730	301	161	0	296	175	0
1,095	589	315	0	587	359	8
1,460	859	459	1	863	516	9
1,825	1,220	650	20	1,257	698	42
2,190	1,662	950	21	1,656	902	45
2,555	2,245	1,274	21	2,266	1,120	46
2,920	2,587	1,455	31	2,616	1,281	53
3,285	2,822	1,579	50	2,875	1,400	94
3,650	2,905	1,623	60	2,960	1,443	198

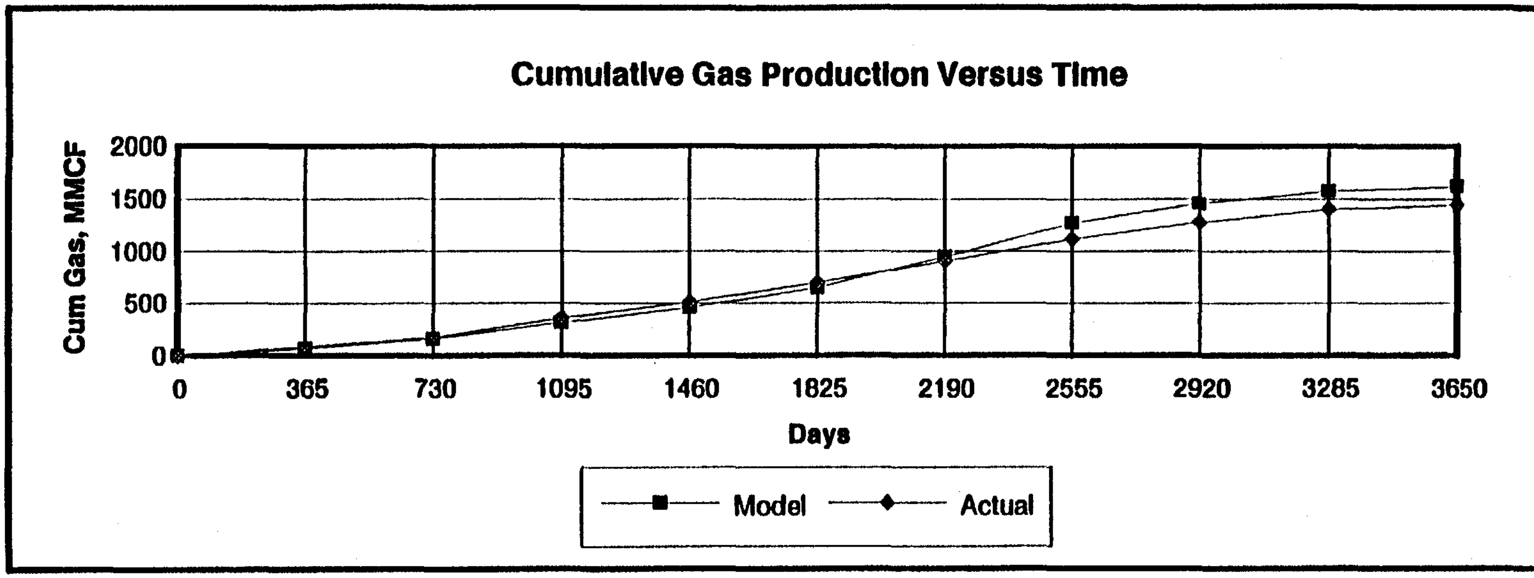
Time (Days)	Model		Actual	
	Pressure (psi)	Cum Oil (MBO)	Pressure (psi)	Cum Oil (MBO)
0	2,755	0		
1,003	2,719	791	2,747	863
1,428	2,720	1,226	2,825	863
1,460	2,683	1,240	2,805	897
1,551	2,676	1,301	2,526	1,015
1,673	2,820	1,470	2,746	1,171
1,825	2,719	1,692	2,793	1,279
2,038	2,632	2,036	2,723	1,496
2,464	2,614	2,231	2,708	2,170
2,920	2,700			
3,285	2,719			
3,650	2,725			

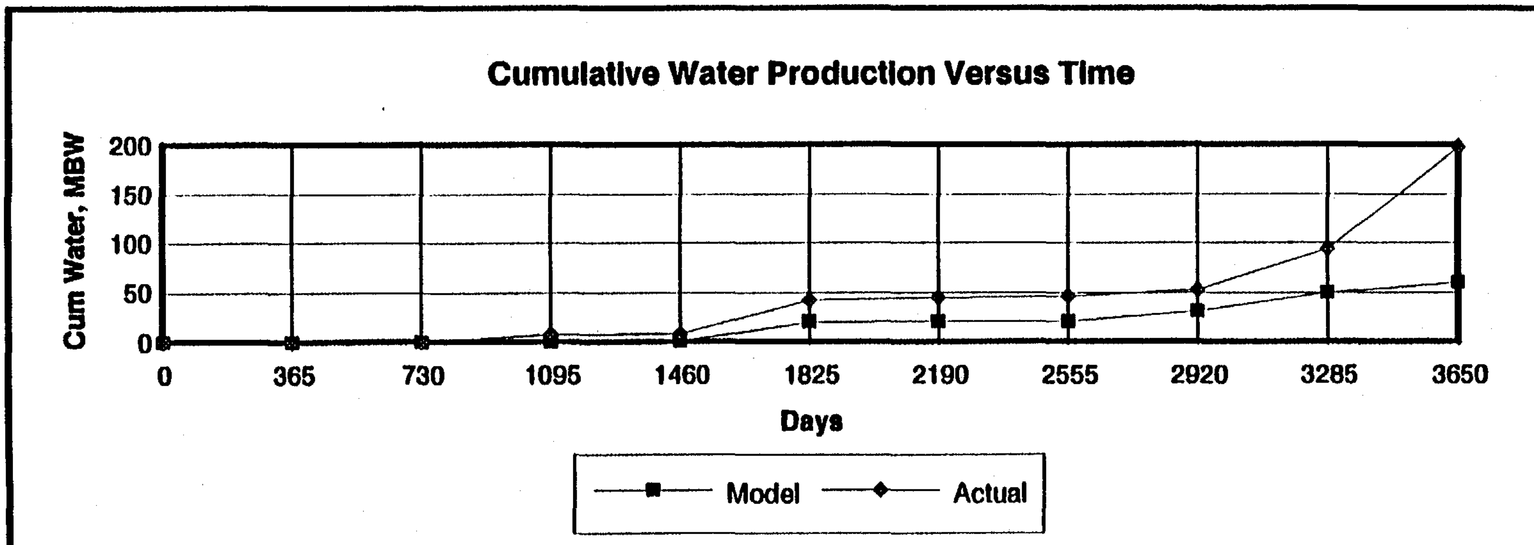
B-35K RESERVOIR SIMULATION HISTORY MATCH RESULTS
ESTIMATED OIL/WATER CONTACT CASE - RUN 2





B-35K RESERVOIR SIMULATION HISTORY MATCH RESULTS
ESTIMATED OIL/WATER CONTACT CASE - RUN 2



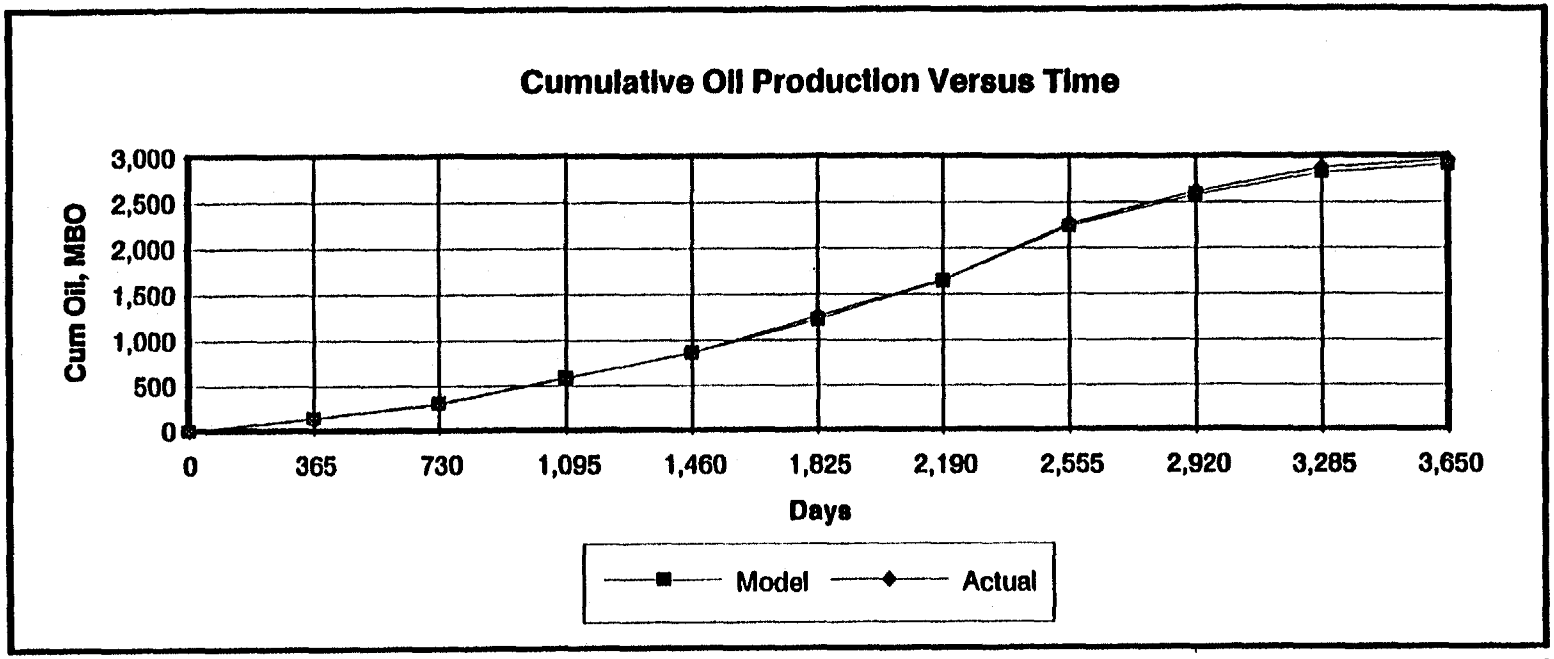


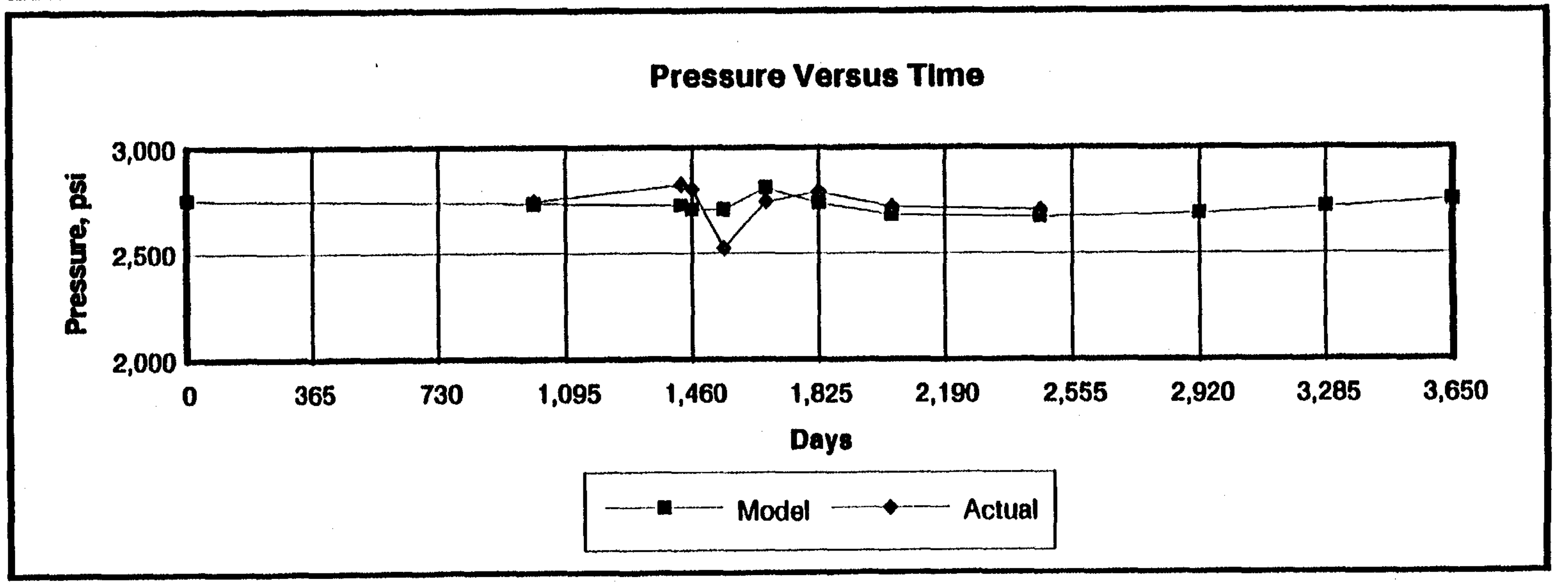
B-35K RESERVOIR SIMULATION HISTORY MATCH RESULTS
MODIFIED Krw CASE - RUN 3

Time (Days)	HISTORY MATCH DATA			ACTUAL FIELD DATA		
	Cum Oil (MBO)	Cum Gas (MMSCF)	Cum Water (MSTB)	Cum Oil (MBO)	Cum Gas (MMSCF)	Cum Water (MSTB)
0	0	0	0	0	0	0
365	139	74	1	131	83	0
730	310	165	1	296	175	0
1,095	590	315	3	587	359	8
1,460	860	460	16	863	516	9
1,825	1,227	654	50	1,257	698	42
2,190	1,646	954	51	1,656	902	45
2,555	2,236	1,279	53	2,266	1,120	46
2,920	2,580	1,463	71	2,616	1,281	53
3,285	2,822	1,589	94	2,875	1,400	94
3,650	2,910	1,637	103	2,960	1,443	198

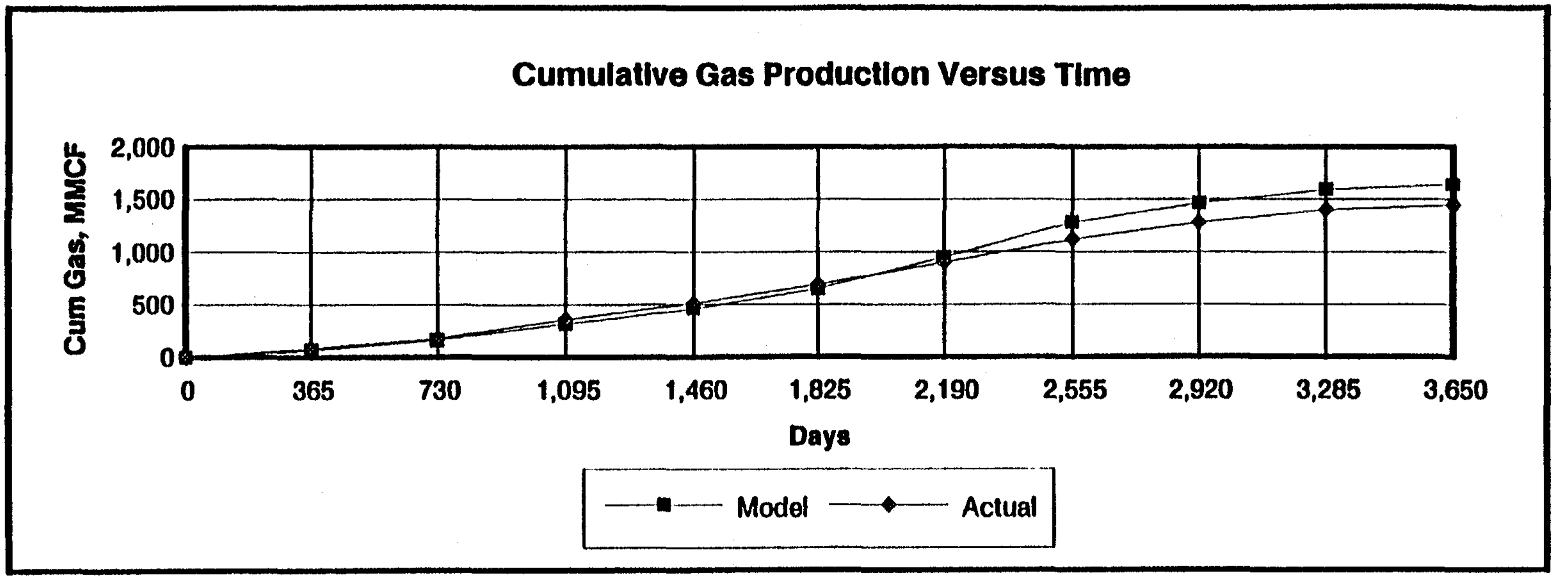
Time (Days)	Model		Actual	
	Pressure (psi)	Cum Oil (MBO)	Pressure (psi)	Cum Oil (MBO)
0	2,755	0		
1,003	2,738	791	2,747	863
1,428	2,730	1,226	2,825	863
1,460	2,711	1,240	2,805	897
1,551	2,709	1,301	2,526	1,015
1,673	2,810	1,470	2,746	1,171
1,825	2,740	1,692	2,793	1,279
2,038	2,684	2,036	2,723	1,496
2,464	2,676	2,231	2,708	2,170
2,920	2,690			
3285	2719			
3650	2755			

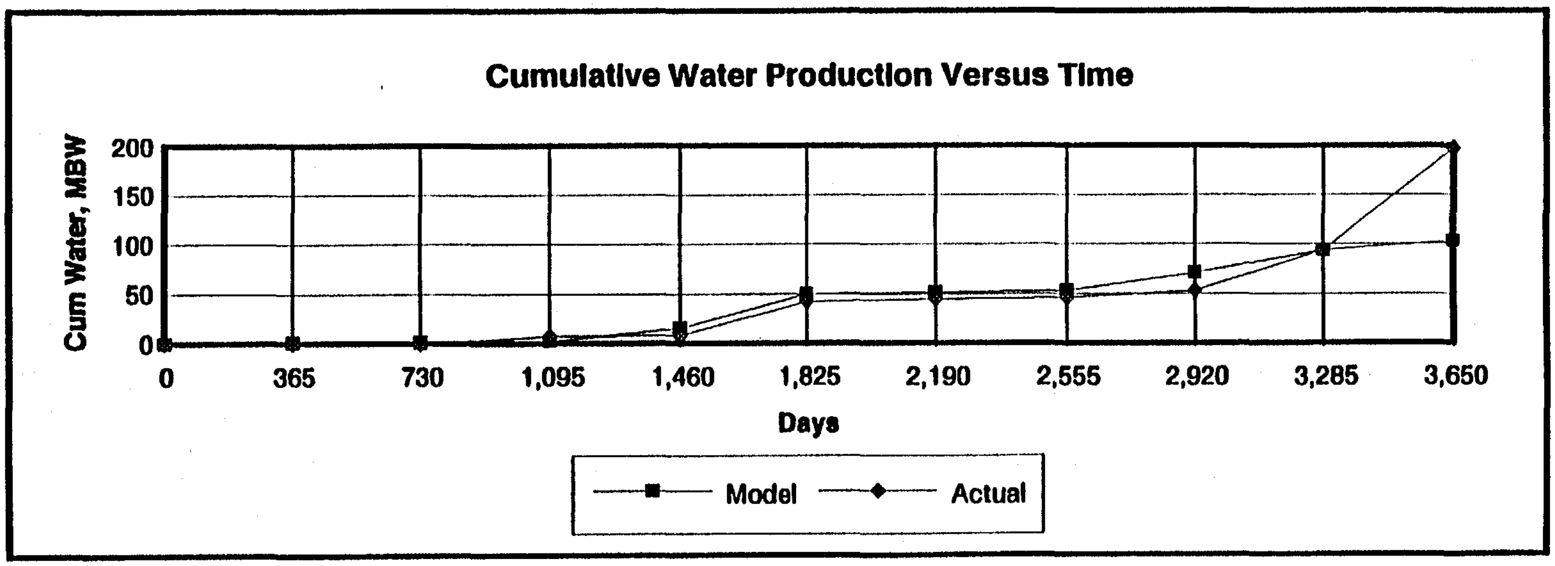
B-35K RESERVOIR SIMULATION HISTORY MATCH RESULTS
MODIFIED Krw CASE - RUN 3





B-35K RESERVOIR SIMULATION HISTORY MATCH RESULTS
MODIFIED Krw CASE - RUN 3



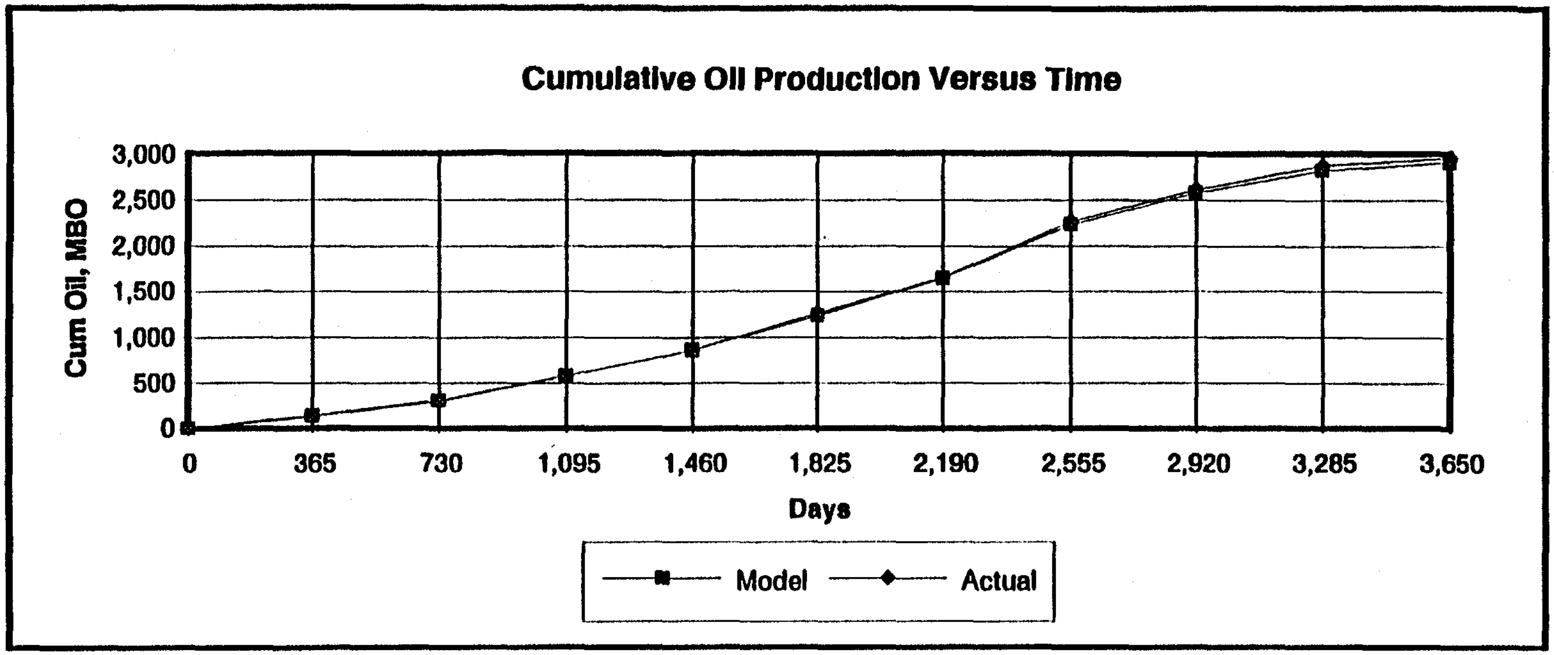


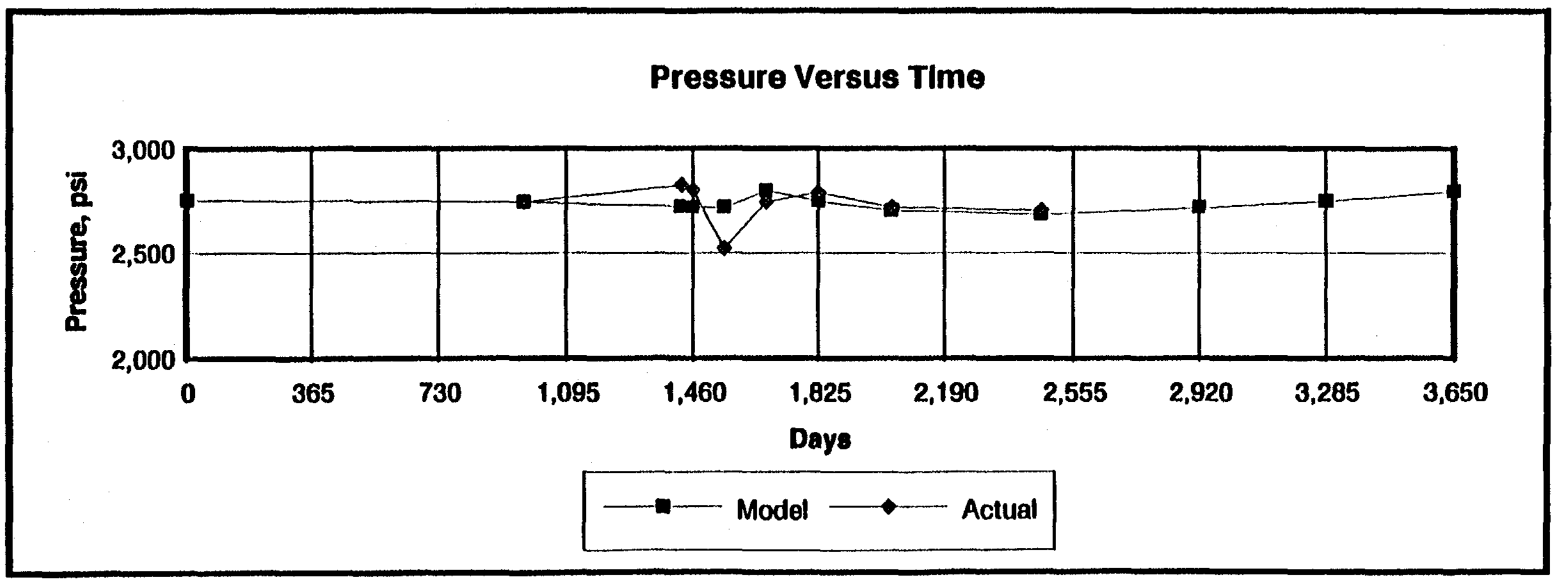
B-35K RESERVOIR SIMULATION HISTORY MATCH RESULTS
ATTIC VOLUME CASE - RUN 4

Time (Days)	HISTORY MATCH DATA			ACTUAL FIELD DATA		
	Cum Oil (MBO)	Cum Gas (MMSCF)	Cum Water (MSTB)	Cum Oil (MBO)	Cum Gas (MMSCF)	Cum Water (MSTB)
0	0	0	0	0	0	0
365	139	74	0	131	83	0
730	310	165	0	296	175	0
1,095	587	314	0	587	359	8
1,460	866	463	6	863	516	9
1,825	1,229	656	27	1,257	698	42
2,190	1,646	880	27	1,656	902	45
2,555	2,232	1,191	28	2,266	1,120	46
2,920	2,580	1,375	28	2,616	1,281	53
3,285	2,821	1,503	29	2,875	1,400	94
3,650	2,910	1,550	30	2,960	1,443	198

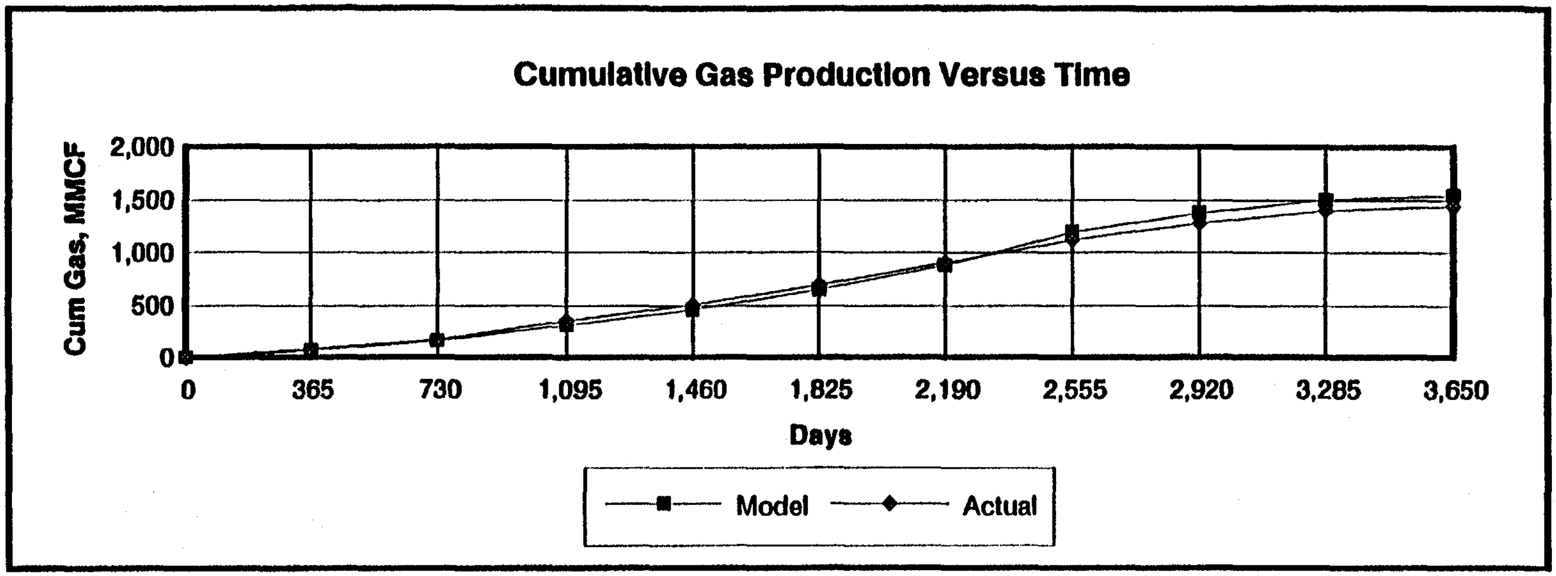
Time (Days)	Model		Actual	
	Pressure (psi)	Cum Oil (MBO)	Pressure (psi)	Cum Oil (MBO)
0	2,755	0		
974	2,746	791	2,747	863
1,428	2,727	1,226	2,825	863
1,460	2,722	1,240	2,805	897
1,551	2,721	1,301	2,526	1,015
1,673	2,800	1,470	2,746	1,171
1,825	2,750	1,692	2,793	1,279
2,038	2,707	2,036	2,723	1,496
2,464	2,688	2,231	2,708	2,170
2,920	2,719			
3,285	2,751			
3,650	2,797			

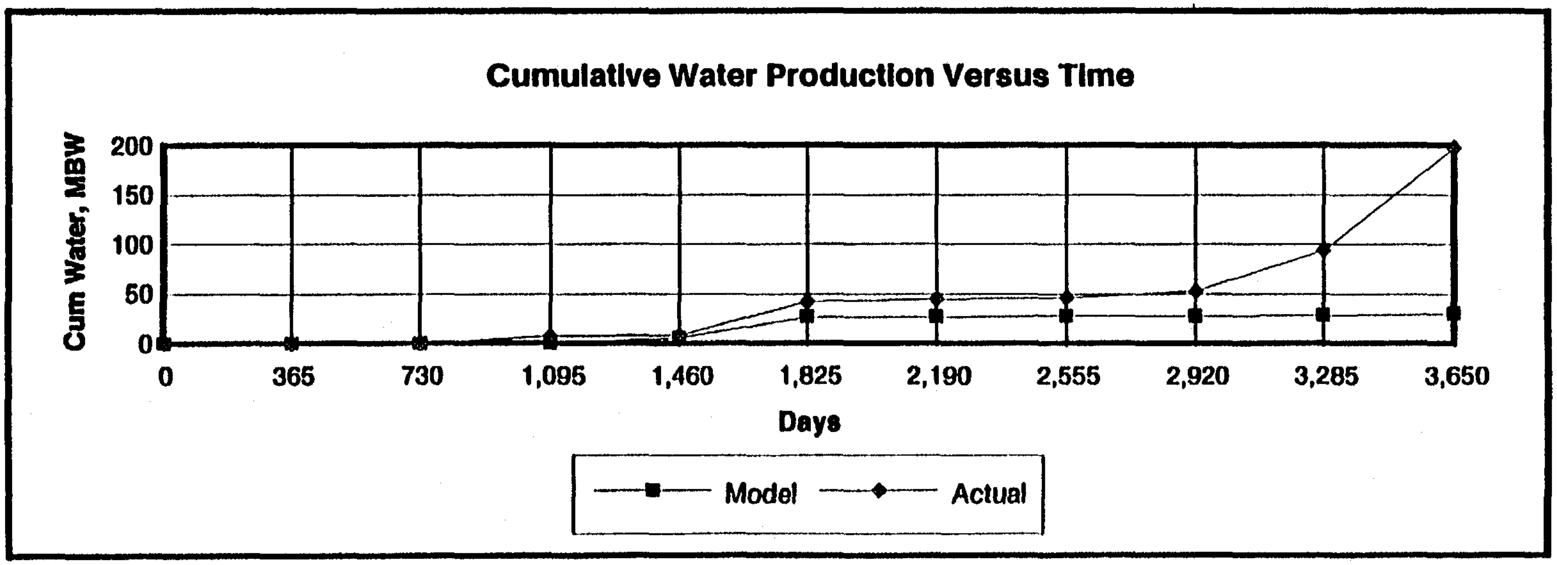
B-35K RESERVOIR SIMULATION HISTORY MATCH RESULTS
ATTIC VOLUME CASE - RUN 4





B-35K RESERVOIR SIMULATION HISTORY MATCH RESULTS
ATTIC VOLUME CASE - RUN 4



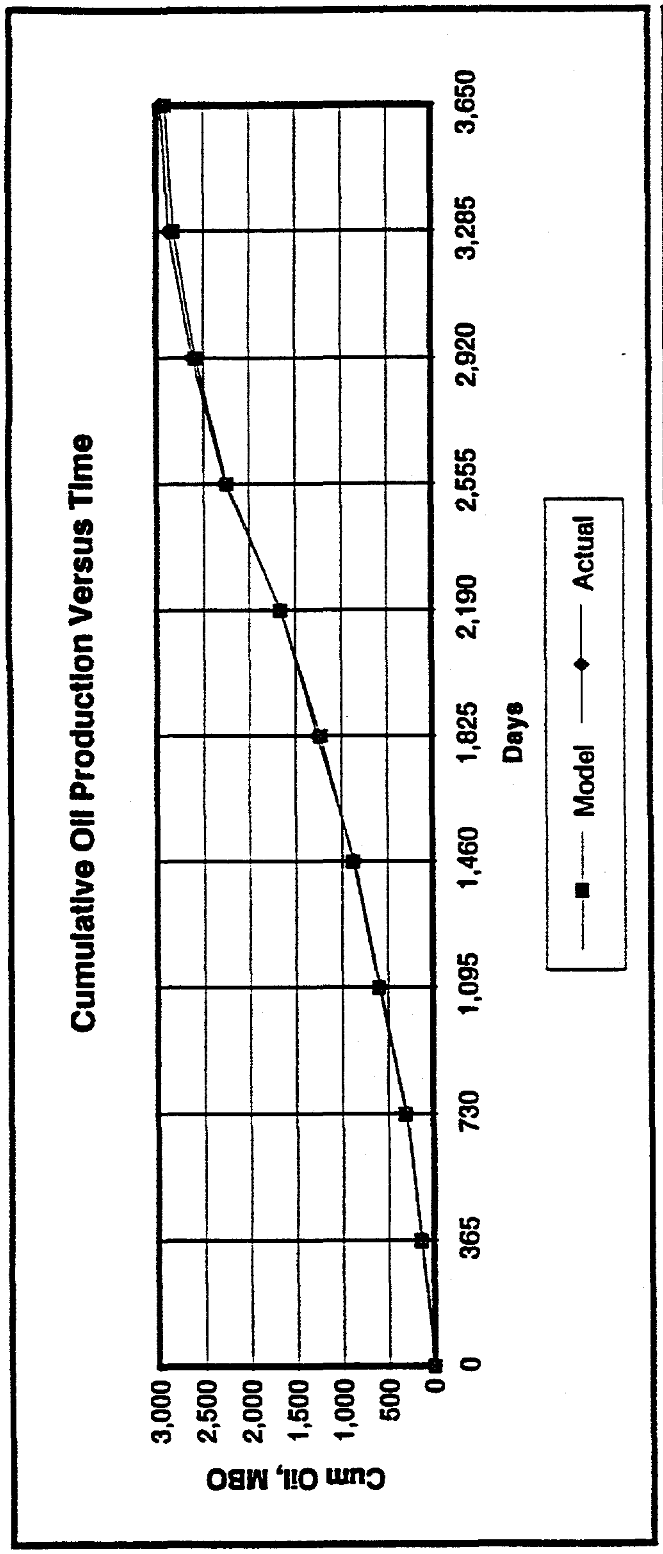


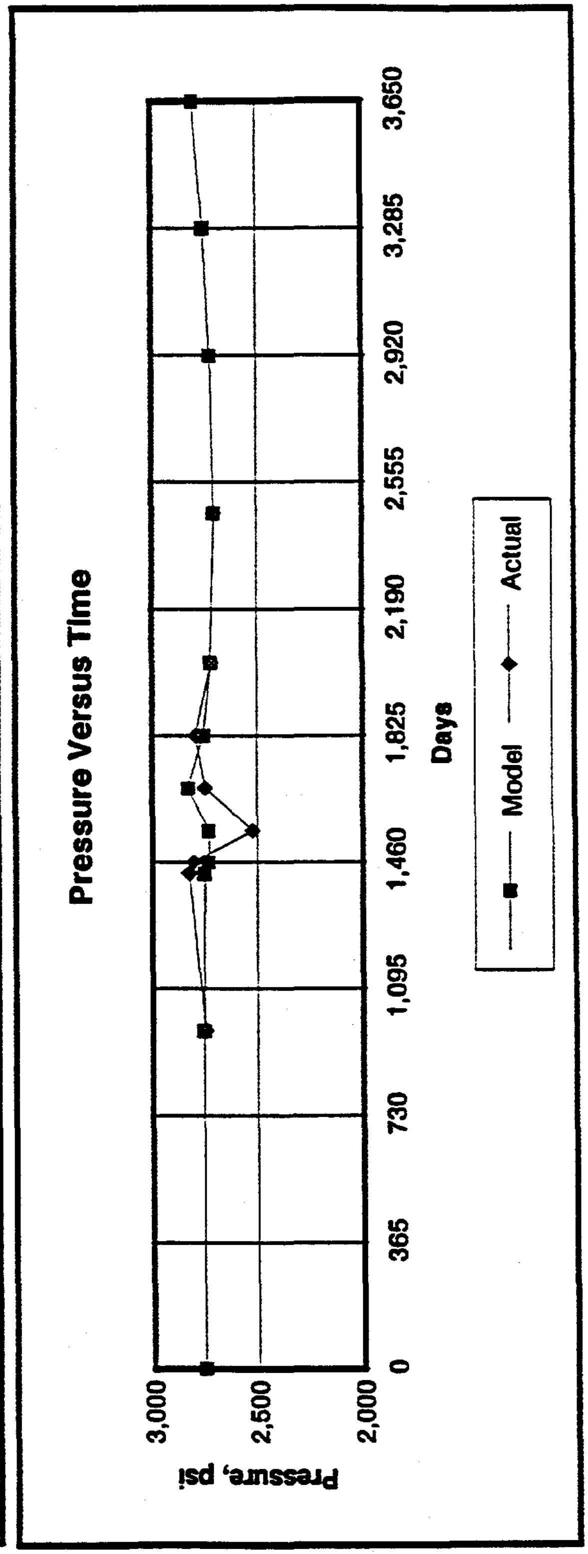
B-35K RESERVOIR SIMULATION HISTORY MATCH RESULTS
FINAL HISTORY MATCH - RUN 5

Time (Days)	HISTORY MATCH DATA			ACTUAL FIELD DATA		
	Cum Oil (MBO)	Cum Gas (MMSCF)	Cum Water (MSTB)	Cum Oil (MBO)	Cum Gas (MMSCF)	Cum Water (MSTB)
0	0	0	0	0	0	0
365	139	75	0	131	83	0
730	310	166	0	296	175	0
1,095	598	320	0	587	359	8
1,460	877	469	21	863	516	9
1,825	1,226	655	47	1,257	698	42
2,190	1,652	883	48	1,656	902	45
2,555	2,242	1,198	48	2,266	1,120	46
2,920	2,584	1,390	81	2,616	1,281	53
3,285	2,823	1,518	149	2,875	1,400	94
3,650	2,910	1,564	195	2,960	1,443	198

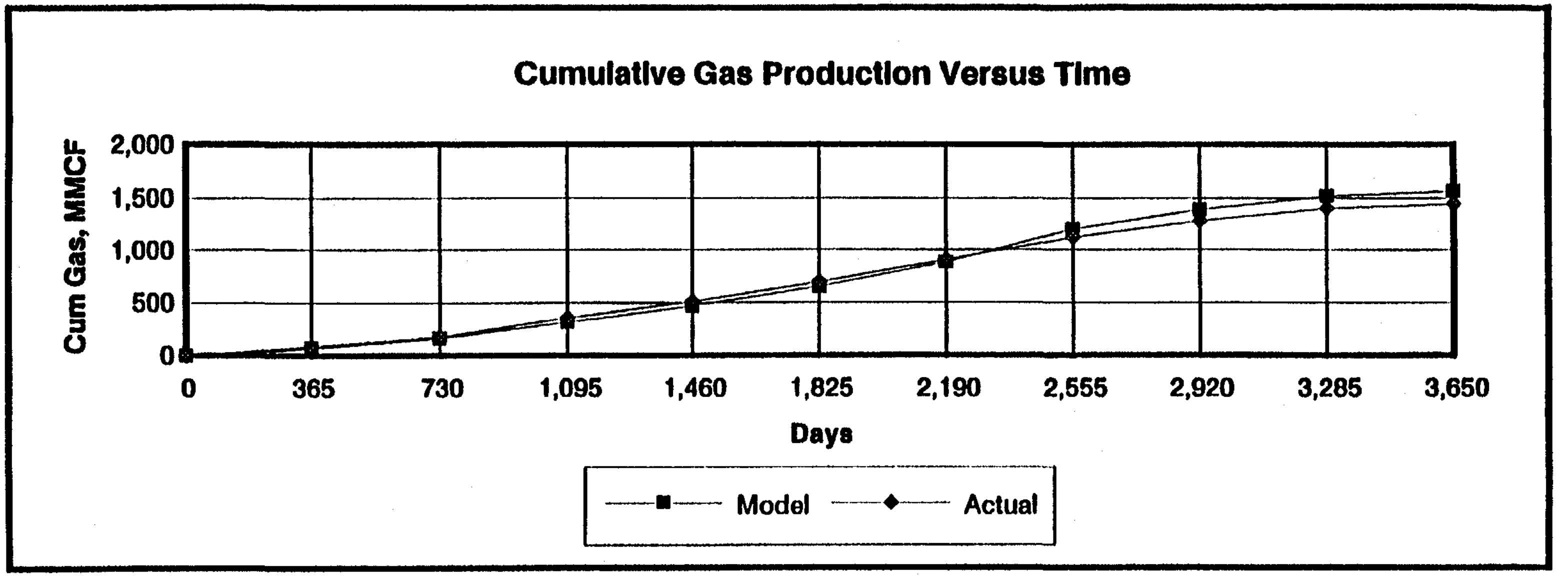
Time (Days)	Model		Actual	
	Pressure (psi)	Cum Oil (MBO)	Pressure (psi)	Cum Oil (MBO)
0	2,755	0		
974	2,755	791	2,747	863
1,428	2,751	1,226	2,825	863
1,460	2,733	1,240	2,805	897
1,551	2,732	1,301	2,526	1,015
1,673	2,828	1,470	2,746	1,171
1,825	2,756	1,692	2,793	1,279
2,038	2,723	2,036	2,723	1,496
2,464	2,706	2,231	2,708	2,170
2,920	2,722			
3,285	2,752			
3,650	2,800			

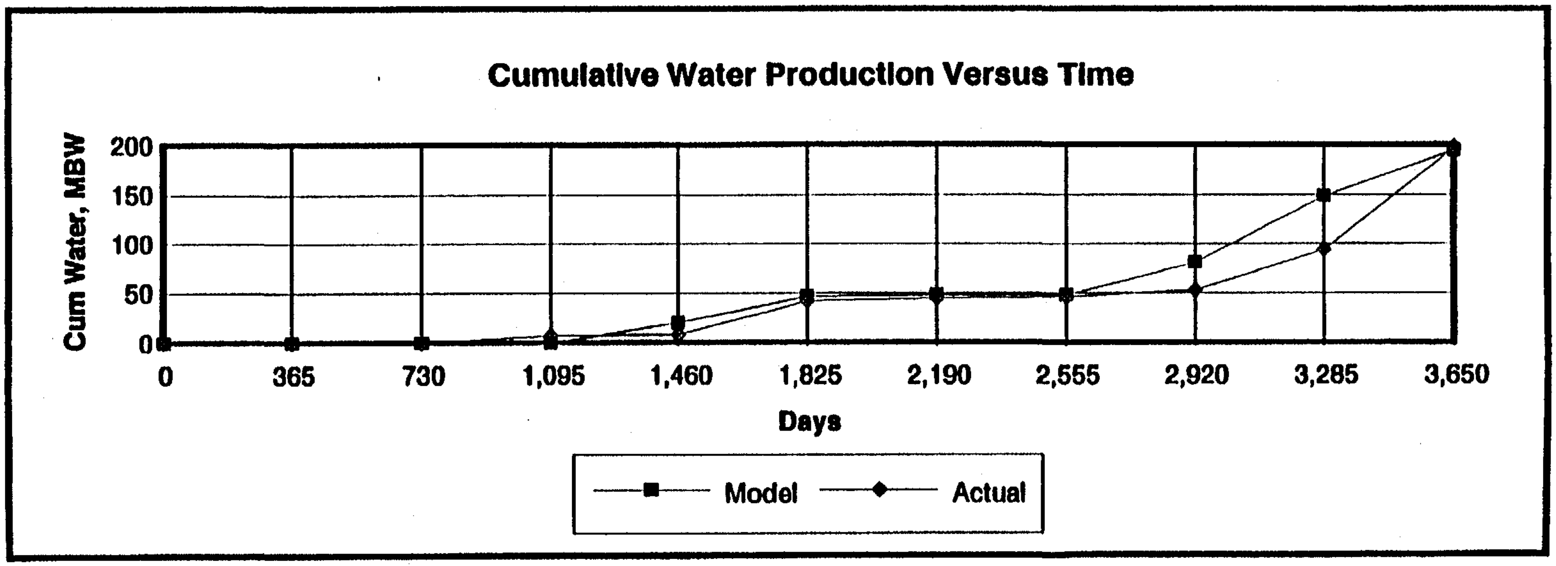
B-35K RESERVOIR SIMULATION HISTORY MATCH RESULTS
FINAL HISTORY MATCH - RUN 5





B-35K RESERVOIR SIMULATION HISTORY MATCH RESULTS
FINAL HISTORY MATCH - RUN 5





APPENDIX C
B-35K RESERVOIR
PREDICTION RESULTS

SMI 73 Simulation Results
Summary of Prediction Sensitivity Cases

Text Reference	Sensitivity Name	Case Name	Case Description
Figure 27	Injection Rate	500 MMCFD Rate	Inject 300 MMCF @ 500 MCFD, Shut-In For 3 Months
		1000 MMCFD Rate	Inject 300 MMCF @ 500 MCFD, Shut-In For 3 Months
		250 MMCFD Rate	Inject 300 MMCF @ 250 MCFD, Shut-In For 3 Months
Figure 28	Post-Injection Shut-In Period	3 Month Shut-In Period	Inject 150 MMCF @ 500 MCFD, Shut-In For 3 Months
		No Shut-In Period	Inject 150 MMCF @ 500 MCFD, No Shut-In Period
		6 Month Shut-In Period	Inject 150 MMCF @ 500 MCFD, Shut-In For 3 Months
Figure 29	Injection Volume	150 MMCF Injection	Inject 150 MMCF @ 500 MCFD, Shut-In For 3 Months
		300 MMCF Injection	Inject 300 MMCF @ 500 MCFD, Shut-In For 3 Months
		75 MMCF Injection	Inject 75 MMCF @ 500 MCFD, Shut-In For 3 Months
		400 MMCF Injection	Inject 400 MMCF @ 500 MCFD, Shut-In For 3 Months
Figure 30,31	Injection Volume Staging	Single Stage	Inject 150 MMCF @ 500 MCFD, Shut-In For 3 Months
		Two Stage	Stage 1: Inject 75 MMCF @ 500 MCFD, Shut-In For 3 Months, Produce for 6 Months Stage 2: Inject 75 MMCF @ 500 MCFD, Shut-In For 3 Months,
		Three Stage	Stage 1: Inject 75 MMCF @ 500 MCFD, Shut-In For 3 Months, Produce for 6 Months Stage 2: Inject 75 MMCF @ 500 MCFD, Shut-In For 3 Months, Produce for 6 Months Stage 3: Inject 75 MMCF @ 500 MCFD, Shut-In For 3 Months,

SMI 73 SIMULATION RESULTS
INJECTION RATE SENSITIVITY ANALYSIS RESULTS

500 MMCFD CASE	INJECT 300 MMCF @ 500 MCFD, SHUT-IN FOR 3 MOS
1000 MMCFD CASE	INJECT 300 MMCF @ 1000 MCFD, SHUT-IN FOR 3 MOS
250 MMCFD CASE	INJECT 300 MMCF @ 250 MCFD, SHUT-IN FOR 3 MOS

500 MMCFD Case				1000 MMCFD Case				250 MMCFD Case			
Time Step (Days)	Cumulative Production			Time Step (Days)	Cumulative Production			Time Step (Days)	Cumulative Production		
	Oil (MBO)	Gas (MMCF)	Water (MBBL)		Oil (MBO)	Gas (MMCF)	Water (MBBL)		Oil (MBO)	Gas (MMCF)	Water (MBBL)
13	8	10	0	0	3	7	0	0	0	0	0
45	23	31	1	32	16	33	1	31	15	15	0
73	33	44	1	61	26	47	1	60	29	31	1
104	42	53	2	92	34	57	1	90	41	42	1
134	50	60	3	122	42	65	3	121	50	49	2
164	57	66	4	154	49	72	4	151	58	55	3
195	65	72	6	184	56	78	5	182	66	60	5
225	71	78	7	214	62	83	7	213	73	66	6
255	77	83	9	244	69	89	8	243	80	70	8
287	84	88	11	275	75	94	10	273	86	75	10
317	89	92	12	306	81	99	11	304	93	79	11
347	95	96	14	336	86	103	13	334	98	83	13
377	100	100	16	368	92	108	15	365	104	86	15
407	105	104	18	396	97	111	17	395	109	90	17
439	110	108	21	427	102	116	19	425	114	93	20
468	115	111	23	457	107	119	20	456	119	97	22
500	120	115	25	488	111	123	22	486	124	100	24
530	124	119	28	519	116	127	24	517	128	103	27
560	128	122	30	548	120	131	27	548	133	107	29
592	133	126	33	579	125	135	29	577	138	110	32
621	137	129	35	610	129	138	31	609	142	114	34
651	141	133	38	640	133	142	33	638	146	117	37
681	145	136	40	672	137	146	36	669	150	121	40
712	149	140	43	700	141	150	38	700	154	125	43
742	153	143	46	732	145	154	41	730	158	128	45
773	157	147	49	761	148	157	43	761	162	132	48
803	160	150	52	793	152	161	46	790	166	135	51
834	164	154	55	823	156	165	49	822	170	139	55
864	167	157	58	853	159	168	51	851	173	143	57
894	171	161	61	883	163	172	54	883	177	146	61
925	175	164	64	913	166	175	57	913	180	150	64
956	178	168	68	944	170	179	59	942	184	154	67
987	182	171	71	974	173	182	62	973	187	157	70
1016	185	174	74	1005	176	186	65	1004	191	161	74
1047	188	177	77	1037	180	189	68	1035	194	164	77
1078	191	181	81	1067	183	193	71	1064	197	168	80
1107	194	184	84	1097	186	196	74	1095	200	171	84
1139	198	187	87	1127	189	199	77	1125	203	174	87
1168	201	190	91	1158	192	203	80	1156	207	178	91
1200	204	194	94	1187	195	206	83	1188	210	181	94
1230	207	197	98	1218	198	209	86	1216	212	184	97
1260	209	200	101	1249	201	213	89	1249	216	188	101
1290	212	204	105	1279	204	216	92	1278	217	189	103
1320	215	207	108	1310	207	219	95	1310	219	190	105
1353	218	210	112	1340	210	223	98	1340	221	191	107
1382	220	212	115	1370	212	226	101	1370	222	191	109
1413	221	213	117	1401	215	229	105	1400	224	192	110
1442	223	214	118	1431	218	232	108	1430	226	193	112
1474	224	215	120	1463	220	236	111	1460	227	194	114
1505	226	215	122	1493	223	239	115	1490	229	195	116
1535	227	216	124	1523	225	241	118	1521	230	196	118
1568	227	216	124	1554	226	242	119	1554	232	196	120
1596	227	216	124	1590	226	242	120	1583	233	197	122
1629	227	216	124	1616	226	242	120	1613	235	198	124

SMI 73 SIMULATION RESULTS
INJECTION RATE SENSITIVITY ANALYSIS RESULTS
(CONTINUED)

500 MMCFD Case				1000 MMCFD Case				250 MMCFD Case			
Time	Cumulative Production			Time	Cumulative Production			Time	Cumulative Production		
Step (Days)	Oil (MBO)	Gas (MMCF)	Water (MBBL)	Step (Days)	Oil (MBO)	Gas (MMCF)	Water (MBBL)	Step (Days)	Oil (MBO)	Gas (MMCF)	Water (MBBL)
1669	227	216	124	1653	226	242	120	1643	236	199	126
1689	227	216	124	1693	226	242	120	1676	236	199	126
1729	227	216	124	1713	226	242	120	1711	236	199	126
1749	227	216	124	1753	226	242	120	1748	236	199	126
1789	227	216	124	1773	226	242	120	1768	236	199	126
1809	227	216	124	1813	226	242	120	1808	236	199	126
1849	227	216	124	1833	226	242	120	1828	236	199	126
1869	227	216	124	1873	226	242	120	1868	236	199	126
1909	227	216	124	1893	226	242	120	1888	236	199	126
1929	227	216	124	1933	226	242	120	1928	236	199	126
1969	227	216	124	1953	226	242	120	1948	236	199	126
2009	227	216	124	1993	226	242	120	1988	236	199	126
2029	227	216	124	2013	226	242	120	2008	236	199	126
2069	227	216	124	2053	226	242	120	2048	236	199	126
2089	227	216	124	2073	226	242	120	2068	236	199	126
2129	227	216	124	2113	226	242	120	2108	236	199	126
2149	227	216	124	2133	226	242	120	2148	236	199	126
2189	227	216	124	2173	226	242	120	2168	236	199	126
2209	227	216	124	2193	226	242	120	2208	236	199	126
2249	227	216	124	2233	226	242	120	2228	236	199	126
2269	227	216	124	2253	226	242	120	2268	236	199	126

SMI 73 SIMULATION RESULTS
POST-INJECTION SHUT-IN PERIOD SENSITIVITY ANALYSIS RESULTS

3 MONTH SHUT-IN PERIOD CASE — INJECT 150 MMCF @ 500 MCFD, SHUT-IN FOR 3 MOS

NO SHUT-IN PERIOD CASE — INJECT 150 MMCF @500 MCFD, NO SHUT-IN PERIOD

6 MONTH SHUT-IN PERIOD CASE — INJECT 150 MMCF @ 500 MCFD, SHUT-IN FOR 6 MOS

3 MONTH SHUT-IN CASE				NO SHUT-IN PERIOD CASE				6 MONTH SHUT-IN PERIOD CASE			
Time Step (Days)	Cumulative Production			Time Step (Days)	Cumulative Production			Time Step (Days)	Cumulative Production		
	Oil (MBO)	Gas (MMCF)	Water (MBBL)		Oil (MBO)	Gas (MMCF)	Water (MBBL)		Oil (MBO)	Gas (MMCF)	Water (MBBL)
0	4	3	0	0	3	14	0	0	0	0	0
31	19	18	1	31	17	30	1	28	5	4	0
61	29	25	1	61	26	37	1	58	20	15	1
93	37	30	3	90	33	41	3	89	30	22	1
122	44	33	4	122	40	45	4	118	38	26	3
153	51	37	6	151	47	49	6	149	45	30	4
183	57	41	8	182	54	53	8	179	52	34	6
214	64	44	9	212	60	56	10	209	59	37	8
245	70	47	11	243	66	59	11	240	65	41	9
274	75	50	13	273	71	62	13	270	71	44	11
306	81	53	15	305	77	65	16	301	76	47	13
335	86	56	17	334	82	68	18	331	82	50	15
366	91	59	20	365	87	70	20	362	87	53	18
398	96	61	22	395	92	73	22	393	92	55	20
427	101	64	24	425	97	75	24	423	97	58	22
457	105	66	27	456	102	78	27	453	102	60	24
488	110	69	29	487	106	81	30	484	106	63	27
518	114	71	32	518	111	83	32	514	111	65	30
548	118	73	35	548	115	85	35	544	115	68	32
579	123	76	38	577	120	88	37	575	119	70	35
610	127	78	41	608	124	90	40	606	124	73	38
641	131	81	43	639	128	92	43	635	128	75	40
670	135	83	46	670	132	94	46	666	132	78	43
700	139	86	49	699	136	96	49	696	136	80	46
731	143	88	52	730	140	99	52	728	140	83	49
761	146	90	55	760	144	101	55	757	143	85	52
792	150	93	59	791	148	103	58	788	147	87	55
822	154	96	62	821	151	106	61	818	151	90	59
853	157	98	65	851	155	108	64	848	155	92	62
883	161	101	68	882	159	110	68	879	158	95	65
913	164	103	71	912	162	113	71	909	162	97	68
945	168	106	75	943	166	115	74	940	165	100	71
975	171	108	78	973	169	117	77	971	169	102	75
1006	175	111	81	1005	173	120	81	1002	172	105	78
1036	178	113	85	1034	176	122	84	1031	175	107	81
1066	181	116	88	1064	179	124	87	1062	179	110	85
1096	184	118	92	1097	183	127	91	1093	182	113	88
1127	188	121	95	1125	186	129	94	1122	185	115	91
1158	191	123	99	1156	189	132	98	1153	188	117	95
1187	194	126	102	1189	192	134	102	1184	191	120	98
1218	197	129	106	1217	195	136	105	1214	194	122	102
1248	199	131	109	1249	198	139	109	1244	197	125	106
1279	202	134	113	1277	200	141	112	1275	200	128	109
1310	205	136	117	1308	203	144	116	1306	203	130	113
1341	207	138	119	1339	206	146	119	1336	206	133	116
1370	209	139	122	1370	208	147	122	1366	208	135	120
1400	211	140	124	1399	210	149	124	1397	210	136	122
1431	213	142	126	1430	212	150	127	1428	212	138	125
1461	215	142	128	1460	213	151	129	1457	214	139	127
1492	217	144	131	1501	213	151	129	1490	216	140	129
1523	219	144	133	1535	213	151	129	1519	218	141	131
1556	219	145	133	1555	213	151	129	1548	220	142	133
1594	219	145	133	1595	213	151	129	1582	220	142	134
1614	219	145	133	1615	213	151	129	1619	220	142	134

SMI 73 SIMULATION RESULTS
POST-INJECTION SHUT-IN PERIOD SENSITIVITY ANALYSIS RESULTS
(CONTINUED)

3 MONTH SHUT-IN CASE				NO SHUT-IN PERIOD CASE				6 MONTH SHUT-IN CASE			
Time	Cumulative Production			Time	Cumulative Production			Time	Cumulative Production		
Step (Days)	Oil (MBO)	Gas (MMCF)	Water (MBBL)	Step (Days)	Oil (MBO)	Gas (MMCF)	Water (MBBL)	Step (Days)	Oil (MBO)	Gas (MMCF)	Water (MBBL)
1654	219	145	133	1655	213	151	129	1653	220	142	134
1674	219	145	133	1675	213	151	129	1673	220	142	134
1714	219	145	133	1715	213	151	129	1713	220	142	134
1754	219	145	133	1735	213	151	129	1733	220	142	134
1774	219	145	133	1775	213	151	129	1773	220	142	134
1814	219	145	133	1795	213	151	129	1793	220	142	134
1834	219	145	133	1835	213	151	129	1833	220	142	134
1874	219	145	133	1875	213	151	129	1853	220	142	134
1894	219	145	133	1895	213	151	129	1893	220	142	134
1934	219	145	133	1935	213	151	129	1933	220	142	134
1954	219	145	133	1955	213	151	129	1953	220	142	134
1994	219	145	133	1995	213	151	129	1993	220	142	134
2014	219	145	133	2015	213	151	129	2013	220	142	134
2054	219	145	133	2055	213	151	129	2053	220	142	134

SMI 73 SIMULATION RESULTS
INJECTION VOLUME SENSITIVITY ANALYSIS RESULTS

150 MMCF INJECTION CASE INJECT 150 MMCF @ 500 MCFD, SHUT-IN FOR 3 MOS

300 MMCF INJECTION CASE INJECT 300 MMCF @ 500 MCFD, SHUT-IN FOR 3 MOS

75 MMCF INJECTION CASE INJECT 75 MMCF @ 500 MCFD. SHUT-IN FOR 3 MOS

400 MMCF INJECTION CASE INJECT 400 MMCF @ 500 MCFD, SHUT-IN FOR 3 MOS

150 MMCF INJECTION CASE				300 MMCF INJECTION CASE				75 MMCF INJECTION CASE				400 MMCF INJECTION CASE			
Time	Cumulative Production			Time	Cumulative Production			Time	Cumulative Production			Time	Cumulative Production		
Step (Days)	Oil (MBO)	Gas (MMCF	Water (MBBL)	Step (Days)	Oil (MBO)	Gas (MMCF	Water (MBBL)	Step (Days)	Oil (MBO)	Gas (MMCF	Water (MBBL)	Step (Days)	Oil (MBO)	Gas (MMCF	Water (MBBL)
0	4	3	0	13	8	10	0	30	2	1	0	0	0	0	0
31	19	18	1	45	23	31	1	61	17	12	1	31	14	26	0
61	29	25	1	73	33	44	1	91	25	17	2	60	27	49	1
93	37	30	3	104	42	53	2	122	32	21	4	92	38	68	1
122	44	33	4	134	50	60	3	153	39	24	5	121	47	80	1
153	51	37	6	164	57	66	4	182	45	28	7	152	55	89	2
183	57	41	8	195	65	72	6	213	52	31	9	182	62	97	4
214	64	44	9	225	71	78	7	243	57	34	11	212	70	105	5
245	70	47	11	255	77	83	9	274	63	37	13	243	76	112	7
274	75	50	13	287	84	88	11	305	69	40	15	273	83	118	8
306	81	53	15	317	89	92	12	336	74	43	17	304	89	124	10
335	86	56	17	347	95	96	14	365	79	45	20	334	95	130	11
366	91	59	20	377	100	100	16	396	84	48	22	366	101	136	13
398	96	61	22	407	105	104	18	427	89	51	24	395	106	141	15
427	101	64	24	439	110	108	21	456	93	53	27	426	111	145	17
457	105	66	27	468	115	111	23	488	98	56	29	457	116	150	19
488	110	69	29	500	120	115	25	517	102	58	32	486	120	155	21
518	114	71	32	530	124	119	28	548	107	60	35	518	125	159	23
548	118	73	35	560	128	122	30	578	111	63	38	547	130	164	26
579	123	76	38	592	133	126	33	609	116	65	40	578	134	168	28
610	127	78	41	621	137	129	35	639	120	67	43	608	138	172	30
641	131	81	43	651	141	133	38	669	124	70	46	639	143	176	33
670	135	83	46	681	145	136	40	701	129	72	49	669	147	180	35
700	139	86	49	712	149	140	43	730	133	74	52	699	151	184	38
731	143	88	52	742	153	143	46	761	137	76	55	730	155	188	41
761	146	90	55	773	157	147	49	791	141	78	58	760	159	192	43
792	150	93	59	803	160	150	52	823	145	80	61	791	163	196	46
822	154	96	62	834	164	154	55	852	149	82	64	823	167	200	49
853	157	98	65	864	167	157	58	883	153	85	67	852	170	204	52
883	161	101	68	894	171	161	61	913	156	87	70	882	174	207	55
913	164	103	71	925	175	164	64	943	160	89	73	912	177	211	58
945	168	106	75	956	178	168	68	974	164	91	77	943	180	215	61
975	171	108	78	987	182	171	71	1004	167	92	80	974	184	219	65
1006	175	111	81	1016	185	174	74	1036	171	94	84	1005	187	222	68
1036	178	113	85	1047	188	177	77	1065	174	96	87	1034	190	226	71
1066	181	116	88	1078	191	181	81	1095	177	98	90	1066	194	230	75
1096	184	118	92	1107	194	184	84	1126	180	100	94	1095	197	233	78
1127	188	121	95	1139	198	187	87	1157	183	102	97	1125	200	237	81
1158	191	123	99	1168	201	190	91	1188	186	104	101	1156	203	240	84
1187	194	126	102	1200	204	194	94	1217	189	106	105	1186	206	244	88
1218	197	129	106	1230	207	197	98	1249	192	108	108	1218	209	247	91
1248	199	131	109	1260	209	200	101	1278	195	110	112	1247	212	251	95
1279	202	134	113	1290	212	204	105	1309	198	112	116	1279	215	254	98
1310	205	136	117	1320	215	207	108	1339	200	113	118	1308	218	258	102
1341	207	138	119	1353	218	210	112	1369	202	114	121	1338	220	261	105
1370	209	139	122	1382	220	212	115	1400	204	116	124	1369	223	264	109
1400	211	140	124	1413	221	213	117	1430	206	117	126	1399	225	265	111
1431	213	142	126	1442	223	214	118	1465	208	117	128	1434	226	266	113
1461	215	142	128	1474	224	215	120	1491	210	118	130	1460	227	266	114

SMI 73 SIMULATION RESULTS
INJECTION VOLUME SENSITIVITY ANALYSIS RESULTS
(CONTINUED)

150 MMCF INJECTION CASE				300 MMCF INJECTION CASE				75 MMCF INJECTION CASE				400 MMCF INJECTION CASE			
Time Step (Days)	Cumulative Production			Time Step (Days)	Cumulative Production			Time Step (Days)	Cumulative Production			Time Step (Days)	Cumulative Production		
	Oil (MBO)	Gas (MMCF	Water (MBBL)		Oil (MBO)	Gas (MMCF	Water (MBBL)		Oil (MBO)	Gas (MMCF	Water (MBBL)		Oil (MBO)	Gas (MMCF	Water (MBBL)
1492	217	144	131	1505	226	215	122	1522	211	119	133	1492	228	267	115
1523	219	144	133	1535	227	216	124	1553	212	120	134	1523	229	267	116
1556	219	145	133	1568	227	216	124	1582	212	120	134	1555	229	267	116
1594	219	145	133	1596	227	216	124	1615	212	120	134	1588	229	267	116
1614	219	145	133	1629	227	216	124	1655	212	120	134	1626	229	267	116
1654	219	145	133	1669	227	216	124	1675	212	120	134	1645	229	267	116
1674	219	145	133	1689	227	216	124	1715	212	120	134	1685	229	267	116
1714	219	145	133	1729	227	216	124	1735	212	120	134	1705	229	267	116
1754	219	145	133	1749	227	216	124	1775	212	120	134	1745	229	267	116
1774	219	145	133	1789	227	216	124	1795	212	120	134	1765	229	267	116
1814	219	145	133	1809	227	216	124	1835	212	120	134	1805	229	267	116
1834	219	145	133	1849	227	216	124	1875	212	120	134	1825	229	267	116
1874	219	145	133	1869	227	216	124	1895	212	120	134	1865	229	267	116
1894	219	145	133	1909	227	216	124	1935	212	120	134	1905	229	267	116
1934	219	145	133	1929	227	216	124	1955	212	120	134	1925	229	267	116
1954	219	145	133	1969	227	216	124	1995	212	120	134	1965	229	267	116
1994	219	145	133	2009	227	216	124	2015	212	120	134	1985	229	267	116
2014	219	145	133	2029	227	216	124	2055	212	120	134	2025	229	267	116
2054	219	145	133	2069	227	216	124	2075	212	120	134	2045	229	267	116

APPENDIX D
Model Input Data for South Marsh Island 73, B-65G Reservoir

South Marsh Island 73 B-65G Reservoir Initial Run Input Data

```
ID1: LSU PROJECT- ACTUAL FIELD STUDY TAYLOR ENERGY-BOAST III 12/08/93 aa]
ID2: B-65 G RESERVOIR WITH 5-WELLS        IREPRS:0--->1
ID3: B-1, B-7, B10D, B12, B15 (b) DIP = 47 degrees down!
ID4: WOC @ -7351 SS FT AND ATTIC RESERVIOR.
ID5: SMI 73 BLOCK, 3-layer set up, thickness by grid block, WELL PRODUCING AT CONSTANT Qo
RESTART AND POST-RUN CODES
-1 0
GRID DATA
 12 12 3
GRID BLOCK LENGTHS
 0 0 0 0
1285. 190. 855. 150. 855. 210. 330. 150. 150. 500. 160. 275.
430. 260. 155. 155. 165. 115. 150. 250. 310. 150. 145. 410.
20. 19. 27.
17. 16. 20.
GRID BLOCK LENGTH MODIFICATIONS
3*0 18 0
3 12 1 1 1 3 0      [shale-out]
4 4 5 5 1 1 12      [B-12]
3 3 4 4 1 1 4       [B-12]
3 3 6 6 1 1 5       [B-12]
5 5 4 4 1 1 5       [B-12]
5 5 6 6 1 1 6       ]B-12]
3 5 2 3 1 1 0       [B-12]
3 5 4 6 2 2 4       [B-12]
3 5 4 6 3 3 2       [B-12]
1 3 1 1 1 1 13      [B-1]
1 2 2 3 1 1 15      [B-1]
1 2 1 3 2 2 15      [B-1]
1 2 2 3 3 3 4       [B-1]
11 11 5 5 1 1 6     [B-7]
10 11 4 4 1 3 0     [B-7]
10 11 2 3 1 3 0     [B-7]
12 12 2 4 1 3 0     [B-7]
6 7 6 8 3 3 8       [B-10]
DIP TO BE CALCULATED BASED ON ELEVATIONS OF EACH BLOCK.
1 00.0
6200. 6*6100. 5*6000.
6400. 6325. 5*6300. 5*6250.
6500. 6450. 5*6400. 5*6350.
6600. 6550. 5*6500. 5*6450.
6700. 6650. 5*6600. 5*6550.
6825. 6*6700. 6600. 6625. 3*6650.
6950. 3*6800. 6750. 6790. 6750. 5*6700.
7100. 3*6925. 2*6900. 2*6875. 2*6800. 2*6850.
7300. 7150. 7125. 5*7100. 2*7050. 2*7075.
7400. 7300. 7275. 7250. 4*7200. 7175. 2*7200. 7225.
7450. 2*7350. 7325. 2*7275. 2*7300. 7250. 3*7300.
7600. 2*7500. 7475. 4*7450. 7400. 3*7425.
POROSITY AND PERMEABILITY DISTRIBUTIONS
```

South Marsh Island 73, B-65G Reservoir - Initial Run Input Data (Continued)

```
 0 0 0 0
.28  .29 .25
680. 1056. 125.
680. 1056. 125.
68. 106. 12.5
POROSITY AND PERMEABILITY MODIFICATIONS
0 2 3 0 0
8 9 3 3 1 3 3000
9 11 5 5 1 3 3000
9 9 3 5 1 3 3000
6 7 8 8 2 3 12.5
11 11 6 6 1 3 12.5
TRANSMISSIBILITY MODIFICATIONS
0 0 0 1
ROCK PVT
1 1
SAT  KROW   KRW  KRG   KROG   PCOW  PCGO
0.00 0.00   0.00  0.00   0.00   0.00  0.00
0.20 0.00   0.00  0.03   0.00   0.00  0.00
0.30 0.00   0.08  0.15   0.001  0.00  0.00
0.40 0.02   0.2   0.3   0.01   0.00  0.00
0.50 0.13   0.4   0.5   0.04   0.00  0.00
0.60 0.38   0.7   0.7   0.12   0.00  0.00
0.70 0.65   0.9   1.00   0.26   0.00  0.00
0.80 1.00   1.00  1.00   0.60   0.00  0.00
0.90 1.00   1.00  1.00   1.00   0.00  0.00
1.00 1.00   1.00  1.00   1.00   0.00  0.00
ITHREE SWR
 1  .2
PBO  PBODAT  PBGRAD
3457.0 6400.  0.000
VSLOPE  BSLOPE  RSLOPE  PMAX  REPRS
.000046  -.0000232  0.   3500.0  0   <---- "ON"
 P    MUO   BO   RSO
 100.  0.91  1.00   16.0
 500.  0.845  1.04   52.0
 1000.  0.785  1.09   110.0
 1500.  0.72  1.13   233.0
 2000.  0.655  1.2   367.0
 2500.  0.59  1.260  483.0
 3000.  0.53  1.320  600.0
 3500.  0.465  1.3647  718.0
 P    MUW   BW    RSW
 100.  0.56  1.000  0.00
 3100.  0.56  0.9928  0.00
 3500.  0.56  0.9928  0.00
GAS AND ROCK PROP
0
 P    MUG   BG   PSI   CR
100.  .0163  .13729  0.0  .000003
```

South Marsh Island 73, B-65G Reservoir - Initial Run Input Data (Continued)

```
500.  .0171 .02222  0.0 .000003
800.  .0183 .01273  0.0 .000003
1200.  .0238 .00785  0.0 .000003
1600.  .0497 .00573  0.0 .000003
2000.  .0604 .00555  0.0 .000003
2500   .065  .00541  0.0 .000003
3100.  .0700 .0047   0.0 .000003
3500   .075  .0041   0.0 .000003
RHOSCO RHOSCW RHOSCG
53.415 62.238 0.047
Initialization Option Codes
 0 1 6782. 0.00    [KPI KSI PDATUM   GRAD]
 NR Pwoc  WOC Pgoc GOC   Soi   Swi   Sgi [Initialization by Rock Region]
  1  3457. 7351. 0.0  4500.  0.75  0.25   0.0
Initialization by Layer (NZ Records)
 1 3058 0.815 0.185 0.0  [Pi Soi Swi Sgi]
 2 3058 0.753 0.247 0.0  [Pi Soi Swi Sgi]
 3 3058 0.795 0.205 0.0  [Pi Soi Swi Sgi]
INITIAL OIL SATURATION FOR GRID
12*.8
12*.8
12*.8
12*.8
12*.8
12*.8
12*.8
12*.8
12*.8
12*.8
12*.8
12*0.0
12*.8
12*.8
12*.8
12*.8
12*.8
12*.8
12*.8
12*.8
12*.8
12*.8
12*.8
12*0.0
12*.8
12*.8
12*.8
12*.8
12*.8
12*.8
```

South Marsh Island 73, B-65G Reservoir - Initial Run Input Data (Continued)

12*.8
12*.8
12*.8
12*.8
12*.8
12*0.0
INITIALIZE WATER SATURATION
12*.2
12*.2
12*.2
12*.2
12*.2
12*.2
12*.2
12*.2
12*.2
12*.2
12*.2
12*1.0
12*.2
12*.2
12*.2
12*.2
12*.2
12*.2
12*.2
12*.2
12*.2
12*.2
12*.2
12*1.0
12*.2
12*.2
12*.2
12*.2
12*.2
12*.2
12*.2
12*.2
12*.2
12*.2
12*.2
12*1.0
KSN1 KSM1 KCO1 KCOF KSKIP KOUT
0 0 0 0 0 0
NMAX FACT1 FACT2 TMAX WORMAX GORMAX PAMIN PAMAX
9999 1.25 0.5 10313. 30.00 1000000. 150. 5000.
KSOL MITR OMEGA TOL TOL1 DSMAX DPMAX
4 250 1.7 .020 0.00 .025 150.0

South Marsh Island 73, B-65G Reservoir - Initial Run Input Data (Continued)

```
NUMDIS IRK THRUIN
 0  0  .6
AQUIFER DATA
1
1
1  12  12  12 1  3    500
WELL AND NODE DATA
NUMBER OF WELLS
5
WELL#    NODES    WELLNAME
1        1        B1
2        1        B7
3        1        B10D
4        1        B12
5        1        B15
WELL#    NODE     DIRECTION
1        2 3 3    1
2        11 5 1   1
3        6 7 3    1
4        4 5 1    1
5        6 11 2   1
RECURRENT DATA
C===================== DATA SET 1
==========================================
 0  2  1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
 1.0  365            [Times for output - IOMETH values]
 0  0  0  0  0  0            [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0  0  0  0  0  0  0         [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1  0.1  30.0             [DT,DTMIN,DTMAX]
HEADER -----> 1966 - Beginning of data read by NODES - if IWLCNG=1]
3  0  [NWELLN=No. of new wells, NWELLO=No. of old wells]
---NEW WELLS---
B1    1  2  3  3  1  [FORMATTED: A5,5I3 - WELLID, IDWELL, I, J, PERF1, NLAYER]
14.7
0.00
B1    1  1     28.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B7    2  11  5  1  1  [FORMATTED: A5,5I3 - WELLID, IDWELL, I, J, PERF1, NLAYER]
24.98
0.00
B7    2  1     25.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B10D   3  6  7  3  1  [FORMATTED: A5,5I3 - WELLID, IDWELL, I, J, PERF1, NLAYER]
6.1
0.00
B10D   3  1     23.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C===================== DATA SET 2
==========================================
 0  1  1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
 730.0     [Times for output - IOMETH values]
 0  0  0  0  0  0            [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
```

South Marsh Island 73, B-65G Reservoir - Initial Run Input Data (Continued)

```
 0 0 0 0 0 0 0        [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0         [DT,DTMIN,DTMAX]
HEADER -----> 1967 - Beginning of data read by NODES - if IWLCNG=1]
1  3   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---NEW WELLS---
B12   4  4  5  1  1  [FORMATTED: A5,5I3 - WELLID, IDWELL, I, J, PERF1, NLAYER]
25.0
0.00
B12   4  1     107.      0.     0000.     000.  [FORMATTED: A5,2I3,4F10.0]
OLD WELLS
B1    1  1     146.      0.     0000.     000.  [FORMATTED: A5,2I3,4F10.0]
B7    2  1     127.      0.     0000.     000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3  1     127.      0.     0000.     000.  [FORMATTED: A5,2I3,4F10.0]
C======================== DATA SET 3
========================================
 0  1  1      [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
1095.0  [Times for output - IOMETH values]
 0 0 0 0 0 0          [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0        [KROMP, KRWMP, KRGMP,IRSOMP]
0.1 0.1 30.0          [DT,DTMIN,DTMAX]
HEADER -----> 1968 - Beginning of data read by NODES - if IWLCNG=1]
0  4   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1  1     167.      0.     0000.     000.  [FORMATTED: A5,2I3,4F10.0]
B7    2  1     145.      0.     0000.     000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3  1     160.      0.     0000.     000.  [FORMATTED: A5,2I3,4F10.0]
B12   4  1     144.      0.     0000.     000.  [FORMATTED: A5,2I3,4F10.0]
C======================== DATA SET 4
========================================
 0  1  1      [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
1430.0                [Times for output - IOMETH values]
 0 0 0 0 0 0          [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0        [KROMP, KRWMP, KRGMP,IRSOMP]
0.1 0.1 30.0          [DT,DTMIN,DTMAX]
HEADER -----> 1969 except for December - Beginning of data read by NODES - if IWLCNG=1]
0  4   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1  1     195.      0.     0000.     000.  [FORMATTED: A5,2I3,4F10.0]
B7    2  1     175.      0.     0000.     000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3  1     175.      0.     0000.     000.  [FORMATTED: A5,2I3,4F10.0]
B12   4  1     253.      0.     0000.     000.  [FORMATTED: A5,2I3,4F10.0]
C======================== DATA SET 5
========================================
 0  1  1      [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
1445.0                [Times for output - IOMETH values]
 0 0 0 0 0 0          [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0        [KROMP, KRWMP, KRGMP,IRSOMP]
0.1 0.1 30.0          [DT,DTMIN,DTMAX]
HEADER -----> 1/2 December, 1969 - Beginning of data read by NODES - if IWLCNG=1]
```

South Marsh Island 73, B-65G Reservoir - Initial Run Input Data (Continued)

```
0 1   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B10D  3 3      0.      0.    -746.     000.  [FORMATTED: A5,2I3,4F10.0]
C===================== DATA SET 6
==================================================
 0  1  1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
1460.0                      [Times for output - IOMETH values]
 0 0 0 0 0 0                [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0              [KROMP, KRWMP, KRGMP,IRSOMP]
0.1 0.1 30.0                [DT,DTMIN,DTMAX]
HEADER -----> 2/2 December, 1969 - Beginning of data read by NODES - if IWLCNG=1]
0 1   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B10D  3 3      0.      0.    0000.     000.  [FORMATTED: A5,2I3,4F10.0]
C===================== DATA SET 7
==================================================
 0  1  1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
1825.0                          [Times for output - IOMETH values]
 0 0 0 0 0 0                [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0              [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0               [DT,DTMIN,DTMAX]
HEADER -----> January-Dec, 1970 - Beginning of data read by NODES - if IWLCNG=1]
0 4   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1     1 1    283.     0.    0000.     000.  [FORMATTED: A5,2I3,4F10.0]
B7     2 1    223.     0.    0000.     000.  [FORMATTED: A5,2I3,4F10.0]
B10D   3 1     344.     0.    0000.     000.  [FORMATTED: A5,2I3,4F10.0]
B12    4 1    253.     0.    0000.     000.  [FORMATTED: A5,2I3,4F10.0]
C===================== DATA SET 8
==================================================
 0  1  1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
2190.0                          [Times for output - IOMETH values]
 0 0 0 0 0 0                [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0              [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0               [DT,DTMIN,DTMAX]
HEADER -----> 1971 - Beginning of data read by NODES - if IWLCNG=1]
0 4   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1     1 1    820.     0.    0000.     000.  [FORMATTED: A5,2I3,4F10.0]
B7     2 1    274.     0.    0000.     000.  [FORMATTED: A5,2I3,4F10.0]
B10D   3 1     934.     0.    0000.     000.  [FORMATTED: A5,2I3,4F10.0]
B12    4 1    890.     0.    0000.     000.  [FORMATTED: A5,2I3,4F10.0]
C===================== DATA SET 9
==================================================
 0  1  1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
2555.0                      [Times for output - IOMETH values]
 0 0 0 0 0 0                [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0              [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0               [DT,DTMIN,DTMAX]
```

South Marsh Island 73, B-65G Reservoir - Initial Run Input Data (Continued)

```
HEADER -----> Jan-Dec 1972 - Beginning of data read by NODES - if IWLCNG=1]
1 4   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---NEW WELLS---
B15   5 6 11  2  1  [FORMATTED: A5,5I3 - WELLID, IDWELL, I, J, PERF1, NLAYER]
64.6
0.00
B15   5 3      0.       0.    -1205.     000.  [FORMATTED: A5,2I3,4F10.0]
---OLD WELLS---
B1     1 1     821.      0.    0000.     000.  [FORMATTED: A5,2I3,4F10.0]
B7     2 1     274.      0.    0000.     000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1      935.      0.    0000.     000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1      856.      0.    0000.     000.  [FORMATTED: A5,2I3,4F10.0]
C============================ DATA SET 10
====================================================
 0  1  1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
2920.0                     [Times for output - IOMETH values]
 0 0 0 0 0 0               [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0              [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0              [DT,DTMIN,DTMAX]
HEADER -----> Jan-Dec 1973 - Beginning of data read by NODES - if IWLCNG=1]
0 5   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1     1 1     843.      0.    0000.     000.  [FORMATTED: A5,2I3,4F10.0]
B7     2 1     210.      0.    0000.     000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1      496.      0.    0000.     000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1      852.      0.    0000.     000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 3       0.       0.    -264.     000.  [FORMATTED: A5,2I3,4F10.0]
C============================ DATA SET 11
====================================================
 0  1  1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
3285.0                     [Times for output - IOMETH values]
 0 0 0 0 0 0               [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0              [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0              [DT,DTMIN,DTMAX]
HEADER -----> January-Dec 1974 - Beginning of data read by NODES - if IWLCNG=1]
0 5   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1     1 1     642.      0.    0000.     000.  [FORMATTED: A5,2I3,4F10.0]
B7     2 1     275.      0.    0000.     000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1      163.      0.    0000.     000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1      696.      0.    0000.     000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 3       0.       0.    -269.     000.  [FORMATTED: A5,2I3,4F10.0]
C============================ DATA SET 12
====================================================
 0  1  1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
3650.0                     [Times for output - IOMETH values]
 0 0 0 0 0 0               [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0              [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0              [DT,DTMIN,DTMAX]
```

South Marsh Island 73, B-65G Reservoir - Initial Run Input Data (Continued)

```
HEADER -----> January-Dec 1975 - Beginning of data read by NODES - if IWLCNG=1]
0 5  [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1   240.   0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1   249.   0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1   143.   0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1   453.   0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 3   0.     0.   -116.   000.  [FORMATTED: A5,2I3,4F10.0]
C======================== DATA SET 13
===========================================
 0 1 1         [ICHANG IOMETH IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
4015.0                 [Times for output - IOMETH values]
 0 0 0 0 0 0           [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0         [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0          [DT,DTMIN,DTMAX]
HEADER -----> 1976 - Beginning of data read by NODES - if IWLCNG=1]
0 5  [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1   240.   0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1   249.   0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1   143.   0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1   249.   0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 3   0.     0.   -23.    000.  [FORMATTED: A5,2I3,4F10.0]
C======================== DATA SET 14
===========================================
 0 1 1         [ICHANG IOMETH IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
4380.0                 [Times for output - IOMETH values]
 0 0 0 0 0 0           [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0         [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0          [DT,DTMIN,DTMAX]
HEADER -----> Jan-Dec 1977 - Beginning of data read by NODES - if IWLCNG=1]
0 5  [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1   115.   0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1   128.   0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1   0.     0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1   231.   0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 3   0.     0.   -129.   000.  [FORMATTED: A5,2I3,4F10.0]
C======================== DATA SET 15
===========================================
 0 1 1         [ICHANG IOMETH IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
4560                   [Times for output - IOMETH values]
 0 0 1 1 0 0           [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0         [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0          [DT,DTMIN,DTMAX]
HEADER -----> Jan-July 1978 - Beginning of data read by NODES - if IWLCNG=1]
0 5  [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1   136.   0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
```

South Marsh Island 73, B-65G Reservoir - Initial Run Input Data (Continued)

```
B7    2 1    183.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1      0.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1     98.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 3      0.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C===================== DATA SET 16
=========================================
 0  1  1       [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
4745                 [Times for output - IOMETH values]
 0 0 0 0 0 0           [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0          [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0          [DT,DTMIN,DTMAX]
HEADER -----> Aug-Dec 1978 - Beginning of data read by NODES - if IWLCNG=1]
0 1  [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B12   4 3      0.    0.  -1516.    000.  [FORMATTED: A5,2I3,4F10.0]
C===================== DATA SET 17
=========================================
 0  1  1       [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
5110                 [Times for output - IOMETH values]
 0 0 0 0 0 0           [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0          [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0          [DT,DTMIN,DTMAX]
HEADER -----> Jan-Dec 1979 - Beginning of data read by NODES - if IWLCNG=1]
0 5  [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1     41.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1    128.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1      0.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 3      0.    0.  -1612.    000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 3      0.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C===================== DATA SET 18A
=========================================
 0  1  1       [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
5171                 [Times for output - IOMETH values]
 0 0 0 0 0 0           [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0          [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0          [DT,DTMIN,DTMAX]
HEADER -----> Jan-Feb 1980 - Beginning of data read by NODES - if IWLCNG=1]
0 5  [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1     41.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1    128.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1      0.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 3      0.    0.  -3068.    000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 3      0.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C===================== DATA SET 18B
=========================================
 0  1  1       [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
5201                 [Times for output - IOMETH values]
```

South Marsh Island 73, B-65G Reservoir - Initial Run Input Data (Continued)

```
 0 0 0 0 0 0            [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0          [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0           [DT,DTMIN,DTMAX]
HEADER -----> Mar 1980 - Beginning of data read by NODES - if IWLCNG=1]
0 1  [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B12   4 3     0.     0.     0.     000.  [FORMATTED: A5,2I3,4F10.0]
C============================ DATA SET 18C
================================================
 0  1  1       [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
5291                    [Times for output - IOMETH values]
 0 0 0 0 0 0            [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0          [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0           [DT,DTMIN,DTMAX]
HEADER -----> Apr-Jun 1980 - Beginning of data read by NODES - if IWLCNG=1]
0 1  [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B12   4 3     0.     0.  -2427.    000.  [FORMATTED: A5,2I3,4F10.0]
C============================ DATA SET 18D
================================================
 0  1  1       [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
5321                    [Times for output - IOMETH values]
 0 0 0 0 0 0            [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0          [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0           [DT,DTMIN,DTMAX]
HEADER -----> Jul 1980 - Beginning of data read by NODES - if IWLCNG=1]
0 1  [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B12   4 3     0.     0.     0.     000.  [FORMATTED: A5,2I3,4F10.0]
C============================ DATA SET 18E
================================================
 0  1  1       [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
5381                    [Times for output - IOMETH values]
 0 0 0 0 0 0            [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0          [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0           [DT,DTMIN,DTMAX]
HEADER -----> Aug-Sep 1980 - Beginning of data read by NODES - if IWLCNG=1]
0 1  [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B12   4 3     0.     0.  -2831.    000.  [FORMATTED: A5,2I3,4F10.0]
C============================ DATA SET 19
================================================
 0  1  1       [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
5391                    [Times for output - IOMETH values]
 0 0 0 0 0 0            [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0          [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0           [DT,DTMIN,DTMAX]
HEADER -----> Oct 1980 - Beginning of data read by NODES - if IWLCNG=1]
0 1  [NWELLN=No. of new wells, NWELLO=No. of old wells]
```

South Marsh Island 73, B-65G Reservoir - Initial Run Input Data (Continued)

```
---OLD WELLS---
B12   4 1     0.      0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C======================== DATA SET 19A
==========================================
 0  1  1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
5410                  [Times for output - IOMETH values]
 0 0 0 0 0 0            [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0           [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0           [DT,DTMIN,DTMAX]
HEADER -----> Oct 1980 - Beginning of data read by NODES - if IWLCNG=1]
0 1    [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B12   4 3     0.      0.   2500.    000.  [FORMATTED: A5,2I3,4F10.0]
C======================== DATA SET 20
==========================================
 0  1  1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
5445                  [Times for output - IOMETH values]
 0 0 0 0 0 0            [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0           [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0           [DT,DTMIN,DTMAX]
HEADER -----> Nov 1980 - Beginning of data read by NODES - if IWLCNG=1]
0 1    [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B12   4 1     51.     0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C======================== DATA SET 21
==========================================
 0  1  1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
5475                  [Times for output - IOMETH values]
 0 0 0 0 0 0            [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0           [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0           [DT,DTMIN,DTMAX]
HEADER -----> Dec 1980 - Beginning of data read by NODES - if IWLCNG=1]
0 1    [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B12   4 1     67.     0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C======================== DATA SET 22
==========================================
 0  1  1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
5840                  [Times for output - IOMETH values]
 0 0 0 0 0 0            [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0           [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0           [DT,DTMIN,DTMAX]
HEADER -----> Jan-Jul 1981 - Beginning of data read by NODES - if IWLCNG=1]
0 5    [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1    111.     0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1     0.      0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1     0.      0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1    112.     0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
```

South Marsh Island 73, B-65G Reservoir - Initial Run Input Data (Continued)

```
B15   5 3     0.     0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C===================== DATA SET 23
========================================
 0  1 1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
6144                   [Times for output - IOMETH values]
 0 0 0 0 0 0           [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0          [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0          [DT,DTMIN,DTMAX]
HEADER -----> Jan-Oct 1982 - Beginning of data read by NODES - if IWLCNG=1]
0 5   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1    58.     0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1     0.     0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1     0.     0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1    23.     0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 3     0.     0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C===================== DATA SET 24
========================================
 0  1 1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
6205                   [Times for output - IOMETH values]
 0 0 0 0 0 0           [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0          [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0          [DT,DTMIN,DTMAX]
HEADER -----> Nov-Dec 1982 - Beginning of data read by NODES - if IWLCNG=1]
0 1   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 3     0.     0.  -1123.    000.  [FORMATTED: A5,2I3,4F10.0]
C===================== DATA SET 25
========================================
 0  1 1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
6295                   [Times for output - IOMETH values]
 0 0 0 0 0 0           [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0          [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0          [DT,DTMIN,DTMAX]
HEADER -----> Jan-Mar 1983 - Beginning of data read by NODES - if IWLCNG=1]
0 5   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 3     0.     0.   -990.    000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1     0.     0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1     0.     0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1   101.     0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 3     0.     0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C===================== DATA SET 25
========================================
 0  1 1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
6570                   [Times for output - IOMETH values]
 0 0 0 0 0 0           [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0          [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0          [DT,DTMIN,DTMAX]
```

South Marsh Island 73, B-65G Reservoir - Initial Run Input Data (Continued)

```
HEADER -----> Apr-Dec 1983 - Beginning of data read by NODES - if IWLCNG=1]
0 5   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1    54.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1    0.      0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1    0.      0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1    101.    0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 3    0.      0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C===================== DATA SET 26
==========================================
 0  1  1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
6660                     [Times for output - IOMETH values]
 0 0 0 0 0 0             [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0           [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0            [DT,DTMIN,DTMAX]
HEADER -----> Jan-Mar 1984 - Beginning of data read by NODES - if IWLCNG=1]
0 5   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 3    0.      0.    -705.    000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1    0.      0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1    0.      0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1    18.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 3    0.      0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C===================== DATA SET 26
==========================================
 0  1  1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
6935                     [Times for output - IOMETH values]
 0 0 0 0 0 0             [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0           [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0            [DT,DTMIN,DTMAX]
HEADER -----> Apr-Dec 1984 - Beginning of data read by NODES - if IWLCNG=1]
0 5   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1    54.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1    0.      0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1    0.      0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1    18.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 3    0.      0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C===================== DATA SET 27
==========================================
 0  1  1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
7087                     [Times for output - IOMETH values]
 0 0 0 0 0 0             [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0           [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0            [DT,DTMIN,DTMAX]
HEADER -----> Jan-May 1985 - Beginning of data read by NODES - if IWLCNG=1]
0 5   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 3    0.      0.    -1028.   000.  [FORMATTED: A5,2I3,4F10.0]
```

South Marsh Island 73, B-65G Reservoir - Initial Run Input Data (Continued)

```
B7    2 1     0.     0.   0000.    000. [FORMATTED: A5,2I3,4F10.0]
B10D  3 1     0.     0.   0000.    000. [FORMATTED: A5,2I3,4F10.0]
B12   4 1    19.     0.   0000.    000. [FORMATTED: A5,2I3,4F10.0]
B15   5 3     0.     0.   0000.    000. [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 28
=========================================
 0 1 1       [ICHANG IOMETH IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
7300               [Times for output - IOMETH values]
 0 0 0 0 0 0        [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0      [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0      [DT,DTMIN,DTMAX]
HEADER -----> Jun-Nov 1985 - Beginning of data read by NODES - if IWLCNG=1]
0 1  [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1     0.     0.   0000.    000. [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 29
=========================================
 0 1 1       [ICHANG IOMETH IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
7633               [Times for output - IOMETH values]
 0 0 0 0 0 0        [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0      [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0.     [DT,DTMIN,DTMAX]
HEADER -----> Jan-Jul 1986 - Beginning of data read by NODES - if IWLCNG=1]
0 5  [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1     0.     0.   0000.    000. [FORMATTED: A5,2I3,4F10.0]
B7    2 1     0.     0.   0000.    000. [FORMATTED: A5,2I3,4F10.0]
B10D  3 1     0.     0.   0000.    000. [FORMATTED: A5,2I3,4F10.0]
B12   4 1     8.     0.   0000.    000. [FORMATTED: A5,2I3,4F10.0]
B15   5 3     0.     0.   0000.    000. [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 30
=========================================
 0 1 1       [ICHANG IOMETH IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
7665               [Times for output - IOMETH values]
 0 0 0 0 0 0        [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0      [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0      [DT,DTMIN,DTMAX]
HEADER -----> Dec 1986 - Beginning of data read by NODES - if IWLCNG=1]
0 1  [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 3     0.     0.   -357.    000. [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 31
=========================================
 0 1 1       [ICHANG IOMETH IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
8030               [Times for output - IOMETH values]
 0 0 0 0 0 0        [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0      [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0      [DT,DTMIN,DTMAX]
HEADER -----> Jan-May 1987 - Beginning of data read by NODES - if IWLCNG=1]
```

South Marsh Island 73, B-65G Reservoir - Initial Run Input Data (Continued)

```
0 5   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 3    0.    0.   -730.    000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1    0.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1    0.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 3    0.    0.   575.     000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 3    0.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C====================== DATA SET 32
===========================================
 0  1  1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
8395                    [Times for output - IOMETH values]
 0 0 0 0 0 0            [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0          [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0           [DT,DTMIN,DTMAX]
HEADER -----> Jan-Oct 1988 - Beginning of data read by NODES - if IWLCNG=1]
0 5   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1    0.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1    0.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1    0.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 3    0.    0.   250.     000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 3    0.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C====================== DATA SET 33
===========================================
 0  1  1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
8760                    [Times for output - IOMETH values]
 0 0 0 0 0 0            [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0          [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0           [DT,DTMIN,DTMAX]
HEADER -----> Jan-Dec 1989 - Beginning of data read by NODES - if IWLCNG=1]
0 5   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 3    0.    0.   277.     000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1    0.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1    0.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1    26.   0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 1    0.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C====================== DATA SET 34
===========================================
 0  1  1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
9125                    [Times for output - IOMETH values]
 0 0 0 0 0 0            [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0          [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0           [DT,DTMIN,DTMAX]
HEADER -----> Jan-Dec 1990 - Beginning of data read by NODES - if IWLCNG=1]
0 5   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 3    0.    0.   4.       000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1    0.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
```

South Marsh Island 73, B-65G Reservoir - Initial Run Input Data (Continued)

```
B10D  3 1     0.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1    97.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 1     0.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 35
=========================================
 0  1  1      [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
9490                 [Times for output - IOMETH values]
 0 0 0 0 0 0          [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0        [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0         [DT,DTMIN,DTMAX]
HEADER -----> Jan-Dec 1991 - Beginning of data read by NODES - if IWLCNG=1]
0  5  [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 3     0.     0.     0.    000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1     0.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1     0.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1    73.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 1     0.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 36
=========================================
 0  1  1      [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
9855                 [Times for output - IOMETH values]
 1 1 1 1 0 1          [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0        [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0         [DT,DTMIN,DTMAX]
HEADER -----> Jan-Dec 1992 - Beginning of data read by NODES - if IWLCNG=1]
0  5  [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 3     0.     0.     0.    000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1     0.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1     0.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1    19.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 1     0.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
```

South Marsh Island 73, B-65G Reservoir - Final Run Input Data

ID1: LSU PROJECT- ACTUAL FIELD STUDY TAYLOR ENERGY-BOAST III 2/1/94 at-pc]
ID2: B-65 G RESERVOIR WITH 5-WELLS IREPRS:0--->1
ID3: B-1, B-7, B10D, B12, B15 (b) DIP = 47 degrees down!
ID4: WOC @ -7351 SS FT AND ATTIC RESERVIOR.
ID5: SMI 73 BLOCK, 3-layer set up, thickness by grid block, WELL PRODUCING AT CONSTANT Qo
RESTART AND POST-RUN CODES
-1 0
GRID DATA
12 12 3
GRID BLOCK LENGTHS
0 0 0 0
1285. 190. 855. 150. 855. 210. 330. 150. 150. 500. 160. 275.
430. 260. 155. 155. 165. 115. 150. 250. 310. 150. 145. 410.
20. 19. 27.
17. 16. 20.
GRID BLOCK LENGTH MODIFICATIONS
2*0 5 26 0
1 2 1 1 1 1 28 [B1]
1 2 2 3 1 1 28 [B1]
1 2 1 3 2 2 28 [B1]
1 2 2 3 3 3 38 [B1]
5 7 6 8 3 3 55 [B-10D]
3 12 1 1 1 3 0 [shale-out]
4 4 5 5 1 1 5 [B-12]
3 3 4 4 1 1 5 [B-12]
3 3 6 6 1 1 5 [B-12]
5 5 4 4 1 1 5 [B-12]
5 5 6 6 1 1 6 [B-12]
4 4 3 3 1 1 0 [B-12]
3 3 2 2 1 1 0 [B-12]
3 3 3 3 1 1 0 [B-12]
5 5 2 2 1 1 0 [B-12]
5 5 3 3 1 1 10 [B-12]
4 4 2 2 1 1 0 [B-12]
3 5 4 6 2 2 3 [B-12]
3 5 4 6 3 3 1 [B-12]
4 4 4 4 1 1 1 [B-12]
3 3 5 5 1 1 3 [B-12]
1 2 1 1 1 1 28 [B1]
1 2 2 3 1 1 28 [B1]
1 2 1 3 2 2 28 [B1]
1 2 2 3 3 3 38 [B1]
11 11 5 5 1 1 6 [B7]
10 11 4 4 1 3 0 [B7]
10 11 2 3 1 3 0 [B7]
12 12 2 4 1 3 0 [B7]
5 7 6 8 1 3 19 [B10D]
5 7 6 8 3 3 55 [B10D]
DIP TO BE CALCULATED BASED ON ELEVATIONS OF EACH BLOCK.

South Marsh Island 73, B-65G Reservoir - Final Run Input Data (Continued)

```
1 00.0
6200. 6*6100. 5*6000.
6400. 6325. 5*6300. 5*6250.
6500. 6450. 5*6400. 5*6350.
6600. 6550. 5*6500. 5*6450.
6700. 6650. 5*6600. 5*6550.
6825. 6*6700. 6600. 6625. 3*6650.
6950. 3*6800. 6750. 6790. 6750. 5*6700.
7100. 3*6925. 2*6900. 2*6875. 2*6800. 2*6850.
7300. 7150. 7125. 5*7100. 2*7050. 2*7075.
7400. 7300. 7275. 7250. 4*7200. 7175. 2*7200. 7225.
7450. 2*7350. 7325. 2*7275. 2*7300. 7250. 3*7300.
7600. 2*7500. 7475. 4*7450. 7400. 3*7425.
POROSITY AND PERMEABILITY DISTRIBUTIONS
 0 0 0 0
.28  .29 .25
680. 1056. 125.
680. 1056. 125.
68. 106. 12.5
POROSITY AND PERMEABILITY MODIFICATIONS
0 2 2 0 0 0 0 0
6 6 8 8 3 3 0
5 5 7 8 3 3 0
6 6 8 8 3 3 0
5 5 7 8 3 3 0
TRANSMISSIBILITY MODIFICATIONS
0 0 0 1
ROCK PVT
1 1
SAT  KROW   KRW   KRG    KROG   PCOW  PCGO
0.00 0.00   0.00  0.00   0.00   0.00  0.00
0.10 0.00   0.00  0.005  0.00   0.00  0.00
0.20 0.00   0.00  0.08   0.00   0.00  0.00
0.30 0.02   0.08  0.20   0.00   0.00  0.00
0.40 0.13   0.2   0.38   0.001  0.00  0.00
0.50 0.38   0.4   0.56   0.01   0.00  0.00
0.60 0.65   0.7   0.8    0.04   0.00  0.00
0.70 1.00   0.9   1.00   0.12   0.00  0.00
0.80 1.00   1.00  1.00   0.26   0.00  0.00
0.90 1.00   1.00  1.00   0.60   0.00  0.00
1.00 1.00   1.00  1.00   1.00   0.00  0.00
ITHREE SWR
 1  .2
 PBO  PBODAT PBGRAD
3457.0 6400.  0.000
VSLOPE  BSLOPE  RSLOPE  PMAX  REPRS
.000046 -.0000232  0.   3500.0  0   <---- "ON"
  P    MUO   BO   RSO
 100.  0.91  1.00   16.0
 500.  0.845 1.04   52.0
 1000. 0.785 1.09   110.0
```

South Marsh Island 73, B-65G Reservoir - Final Run Input Data (Continued)

```
 1500.  0.72   1.13    233.0
  2000.  0.655  1.2     367.0
  2500.  0.59   1.260   483.0
  3000.  0.53   1.320   600.0
  3500.  0.465  1.3647  718.0
   P    MUW    BW      RSW
  100.  0.56   1.000   0.00
  3100.  0.56  0.9928  0.00
  3500.  0.56  0.9928  0.00
GAS AND ROCK PROP
0
   P    MUG    BG      PSI   CR
 100.   .0163  .13729  0.0  .000003
 500.   .0171  .02222  0.0  .000003
 800.   .0183  .01273  0.0  .000003
1200.   .0238  .00785  0.0  .000003
1600.   .0497  .00573  0.0  .000003
2000.   .0604  .00555  0.0  .000003
2500    .065   .00541  0.0  .000003
3100.   .0700  .0047   0.0  .000003
3500    .075   .0041   0.0  .000003
RHOSCO RHOSCW RHOSCG
53.415  62.238  0.047
Initialization Option Codes
 0  1  6782.  0.00    [KPI  KSI  PDATUM   GRAD]
 NR  Pwoc   WOC  Pgoc  GOC    Soi   Swi   Sgi  [Initialization by Rock Region]
  1  3457.  7351.  0.0  4500.  0.75  0.25   0.0
Initialization by Layer (NZ Records)
 1  3058  0.815  0.185  0.0  [Pi  Soi  Swi  Sgi]
 2  3058  0.753  0.247  0.0  [Pi  Soi  Swi  Sgi]
 3  3058  0.795  0.205  0.0  [Pi  Soi  Swi  Sgi]
INITIAL OIL SATURATION FOR GRID
12*0.0
12*0.0
4*.77 8*0.0
4*.77 4*0.0 4*.77
12*.77
12*.77
12*.77
12*.77
12*.77
2*0.0 10*.77
4*0.0 8*.77
12*0.0
12*.77
12*.77
12*.77
12*.77
12*.77
12*.77
```

South Marsh Island 73, B-65G Reservoir - Final Run Input Data (Continued)

12*.77
12*.77
12*.77
2*0.0 10*.77
4*0.0 8*.77
12*0.0
12*.77
12*.77
12*.77
12*.77
12*.77
12*.77
12*.77
1*0.0 11*.77
2*0.0 10*.77
3*0.0 9*.77
4*0.0 8*.77
12*0.0
INITIALIZE WATER SATURATION
12*.23
12*.23
12*.23
12*.23
12*.23
12*.23
12*.23
12*.23
12*.23
2*1.0 10*.23
4*1.0 8*.23
12*1.0
12*.23
12*.23
12*.23
12*.23
12*.23
12*.23
12*.23
12*.23
12*.23
2*1.0 10*.23
4*1.0 8*.23
12*1.0
12*.23
12*.23
12*.23
12*.23
12*.23
12*.23
12*.23

South Marsh Island 73, B-65G Reservoir - Final Run Input Data (Continued)

```
1*1.0 11*.23
2*1.0 10*.23
3*1.0 9*.23
4*1.0 8*.23
12*1.0
KSN1 KSM1 KCO1 KCOF KSKIP KOUT
 0  0  0  0  0  0
NMAX FACT1 FACT2 TMAX  WORMAX  GORMAX     PAMIN  PAMAX
9999 1.25 0.5 10313. 1500.00 100000000. 150. 5000.
KSOL MITR OMEGA TOL  TOL1  DSMAX  DPMAX
4  250  1.7 .020 0.00  .025   150.0
NUMDIS IRK THRUIN
 0  0 .6
AQUIFER DATA
1
2
1  4  12  12 1  3   1500
8  12  12  12 1  3   1500
WELL AND NODE DATA
NUMBER OF WELLS
5
WELL#   NODES   WELLNAME
1       1      B1
2       1      B7
3       1      B10D
4       1      B12
5       1      B15
WELL#  NODE    DIRECTION
1      2 3 3   1
2      11 5 1   1
3      6 7 3   1
4      4 5 1   1
5      6 11 2   1
RECURRENT DATA
C====================== DATA SET 1
==========================================
 0  2  1       [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
 1.0  365          [Times for output - IOMETH values]
 0  0  0  0  0  0          [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0  0  0  0  0  0  0          [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1  0.1  30.0          [DT,DTMIN,DTMAX]
HEADER -----> 1966 - Beginning of data read by NODES - if IWLCNG=1]
5  0  [NWELLN=No. of new wells, NWELLO=No. of old wells]
---NEW WELLS---
B1    1  2  3  3  1  [FORMATTED: A5,5I3 - WELLID, IDWELL, I, J, PERF1, NLAYER]
14.7
0.00
B1    1  1    28.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B7    2  11  5  1  1  [FORMATTED: A5,5I3 - WELLID, IDWELL, I, J, PERF1, NLAYER]
24.98
```

South Marsh Island 73, B-65G Reservoir - Final Run Input Data (Continued)

```
0.00
B7    2 1     25.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 6 7 3 1  [FORMATTED: A5,5I3 - WELLID, IDWELL, I, J, PERF1, NLAYER]
6.1
0.00
B10D  3 1     23.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 4 5 1 1  [FORMATTED: A5,5I3 - WELLID, IDWELL, I, J, PERF1, NLAYER]
25.0
0.00
B12   4 1     0.      0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 6 11 2 1  [FORMATTED: A5,5I3 - WELLID, IDWELL, I, J, PERF1, NLAYER]
64.6
0.00
B15   5 3     0.      0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 2
=======================================
 0  1  1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
 730.0      [Times for output - IOMETH values]
 0 0 0 0 0 0              [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0             [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0            [DT,DTMIN,DTMAX]
HEADER -----> 1967 - Beginning of data read by NODES - if IWLCNG=1]
0 4   [NWELLN=No. of new wells, NWELLO=No. of old wells]
OLD WELLS
B1    1 1    146.    0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1    127.    0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1    127.    0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1    107.    0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 3
=======================================
 0  1  1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
1095.0  [Times for output - IOMETH values]
 0 0 0 0 0 0              [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0             [KROMP, KRWMP, KRGMP,IRSOMP]
0.1 0.1  30.0           [DT,DTMIN,DTMAX]
HEADER -----> 1968 - Beginning of data read by NODES - if IWLCNG=1]
0 4   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1    167.    0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1    145.    0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1    160.    0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1    144.    0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 4
=======================================
 0  1  1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
1430.0                  [Times for output - IOMETH values]
 0 0 0 0 0 0              [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0             [KROMP, KRWMP, KRGMP,IRSOMP]
0.1  0.1  30.0           [DT,DTMIN,DTMAX]
HEADER -----> 1969 except for December - Beginning of data read by NODES - if IWLCNG=1]
```

South Marsh Island 73, B-65G Reservoir - Final Run Input Data (Continued)

```
0 4   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1    195.    0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1    175.    0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1    175.    0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1    253.    0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 5
====================================
 0 1 1       [ICHANG IOMETH IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
1445.0              [Times for output - IOMETH values]
 0 0 0 0 0 0         [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0       [KROMP, KRWMP, KRGMP,IRSOMP]
0.1 0.1 30.0         [DT,DTMIN,DTMAX]
HEADER -----> 1/2 December, 1969 - Beginning of data read by NODES - if IWLCNG=1]
0 1   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B10D  3 3     0.     0.   -746.   000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 6
====================================
 0 1 1       [ICHANG IOMETH IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
1460.0              [Times for output - IOMETH values]
 0 0 0 0 0 0         [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0       [KROMP, KRWMP, KRGMP,IRSOMP]
0.1 0.1 30.0         [DT,DTMIN,DTMAX]
HEADER -----> 2/2 December, 1969 - Beginning of data read by NODES - if IWLCNG=1]
0 1   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B10D  3 3     0.     0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 7
====================================
 0 1 1       [ICHANG IOMETH IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
1825.0              [Times for output - IOMETH values]
 0 0 0 0 0 0         [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0       [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0        [DT,DTMIN,DTMAX]
HEADER -----> January-Dec, 1970 - Beginning of data read by NODES - if IWLCNG=1]
0 4   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1    283.    0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1    223.    0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1    344.    0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1    253.    0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 8
====================================
 0 1 1       [ICHANG IOMETH IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
2190.0              [Times for output - IOMETH values]
 0 0 0 0 0 0         [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0       [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0        [DT,DTMIN,DTMAX]
HEADER -----> 1971 - Beginning of data read by NODES - if IWLCNG=1]
```

South Marsh Island 73, B-65G Reservoir - Final Run Input Data (Continued)

```
0 4   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1    820.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1    274.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1    934.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1    890.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C======================= DATA SET 9
==========================================
 0  1  1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
2555.0                   [Times for output - IOMETH values]
 0 0 0 0 0 0             [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0           [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0            [DT,DTMIN,DTMAX]
HEADER -----> Jan-Dec 1972 - Beginning of data read by NODES - if IWLCNG=1]
0 5   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1    821.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1    274.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1    935.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1    856.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 3      0.     0.   -1205.    000.  [FORMATTED: A5,2I3,4F10.0]
C======================= DATA SET 10
==========================================
 0  1  1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
2920.0                   [Times for output - IOMETH values]
 0 0 0 0 0 0             [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0           [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0            [DT,DTMIN,DTMAX]
HEADER -----> Jan-Dec 1973 - Beginning of data read by NODES - if IWLCNG=1]
0 5   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1    843.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1    210.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1    496.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1    852.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 3      0.     0.    -264.    000.  [FORMATTED: A5,2I3,4F10.0]
C======================= DATA SET 11
==========================================
 0  1  1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
3285.0                   [Times for output - IOMETH values]
 0 0 0 0 0 0             [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0           [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0            [DT,DTMIN,DTMAX]
HEADER -----> January-Dec 1974 - Beginning of data read by NODES - if IWLCNG=1]
0 5   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1    642.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1    275.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1    163.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1    696.     0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
```

South Marsh Island 73, B-65G Reservoir - Final Run Input Data (Continued)

```
B15   5 3     0.     0.   -269.    000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 12
======================================
 0  1  1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
3650.0                  [Times for output - IOMETH values]
 0 0 0 0 0 0            [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0          [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0           [DT,DTMIN,DTMAX]
HEADER -----> January-Dec 1975 - Beginning of data read by NODES - if IWLCNG=1]
0 5  [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1    240.    0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1    249.    0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1    143.    0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1    453.    0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 3     0.     0.   -116.     000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 13
======================================
 0  1  1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
4015.0                  [Times for output - IOMETH values]
 0 0 0 0 0 0            [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0          [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0.          [DT,DTMIN,DTMAX]
HEADER -----> 1976 - Beginning of data read by NODES - if IWLCNG=1]
0 5  [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1    240.    0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1    249.    0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1    143.    0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1    249.    0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 3     0.     0.    -23.    000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 14
======================================
 0  1  1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
4380.0                  [Times for output - IOMETH values]
 0 0 0 0 0 0            [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0          [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0           [DT,DTMIN,DTMAX]
HEADER -----> Jan-Dec 1977 - Beginning of data read by NODES - if IWLCNG=1]
0 5  [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1    115.    0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1    128.    0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1      0.    0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1    231.    0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 3     0.     0.   -129.    000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 15
======================================
 0  1  1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
4560                    [Times for output - IOMETH values]
```

South Marsh Island 73, B-65G Reservoir - Final Run Input Data (Continued)

```
 0 0 1 1 0 0          [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0         [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0         [DT,DTMIN,DTMAX]
HEADER -----> Jan-July 1978 - Beginning of data read by NODES - if IWLCNG=1]
0 5  [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1    136.    0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1    183.    0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1      0.    0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1     98.    0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 3      0.    0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 16
========================================
 0  1  1      [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
4745                  [Times for output - IOMETH values]
 0 0 0 0 0 0          [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0         [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0         [DT,DTMIN,DTMAX]
HEADER -----> Aug-Dec 1978 - Beginning of data read by NODES - if IWLCNG=1]
0 1  [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B12   4 3      0.    0.  -1516.   000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 17
========================================
 0  1  1      [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
5110                  [Times for output - IOMETH values]
 0 0 0 0 0 0          [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0         [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0         [DT,DTMIN,DTMAX]
HEADER -----> Jan-Dec 1979 - Beginning of data read by NODES - if IWLCNG=1]
0 5  [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1     41.    0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1    128.    0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1      0.    0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 3      0.    0.  -1612.   000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 3      0.    0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 18A
========================================
 0  1  1      [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
5171                  [Times for output - IOMETH values]
 0 0 0 0 0 0          [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0         [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0         [DT,DTMIN,DTMAX]
HEADER -----> Jan-Feb 1980 - Beginning of data read by NODES - if IWLCNG=1]
0 5  [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1     41.    0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1    128.    0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1      0.    0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
```

South Marsh Island 73, B-65G Reservoir - Final Run Input Data (Continued)

```
B12   4 3    0.     0.  -3068.    000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 3    0.     0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 18B
==========================================
 0  1  1       [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
5201                  [Times for output - IOMETH values]
 0 0 0 0 0 0           [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0          [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0          [DT,DTMIN,DTMAX]
HEADER -----> Mar 1980 - Beginning of data read by NODES - if IWLCNG=1]
0  1   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B12   4 3    0.     0.     0.    000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 18C
==========================================
 0  1  1       [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
5291                  [Times for output - IOMETH values]
 0 0 0 0 0 0           [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0          [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0          [DT,DTMIN,DTMAX]
HEADER -----> Apr-Jun 1980 - Beginning of data read by NODES - if IWLCNG=1]
0  1   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B12   4 3    0.     0.  -2427.    000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 18D
==========================================
 0  1  1       [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
5321                  [Times for output - IOMETH values]
 0 0 0 0 0 0           [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0          [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0          [DT,DTMIN,DTMAX]
HEADER -----> Jul 1980 - Beginning of data read by NODES - if IWLCNG=1]
0  1   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B12   4 3    0.     0.     0.    000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 18E
==========================================
 0  1  1       [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
5381                  [Times for output - IOMETH values]
 0 0 0 0 0 0           [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0          [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0          [DT,DTMIN,DTMAX]
HEADER -----> Aug-Sep 1980 - Beginning of data read by NODES - if IWLCNG=1]
0  1   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B12   4 3    0.     0.  -2831.    000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 19
==========================================
 0  1  1       [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
5391                  [Times for output - IOMETH values]
```

South Marsh Island 73, B-65G Reservoir - Final Run Input Data (Continued)

```
 0 0 0 0 0 0           [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0          [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0          [DT,DTMIN,DTMAX]
HEADER -----> Oct 1980 - Beginning of data read by NODES - if IWLCNG=1]
0  1   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B12   4 1      0.      0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C========================= DATA SET 19A
==========================================
 0  1  1       [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
5410                   [Times for output - IOMETH values]
 0 0 0 0 0 0           [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0          [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0          [DT,DTMIN,DTMAX]
HEADER -----> Oct 1980 - Beginning of data read by NODES - if IWLCNG=1]
0  1   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B12   4 3      0.      0.    2500.    000.  [FORMATTED: A5,2I3,4F10.0]
C========================= DATA SET 20
==========================================
 0  1  1       [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
5445                   [Times for output - IOMETH values]
 0 0 0 0 0 0           [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0          [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0          [DT,DTMIN,DTMAX]
HEADER -----> Nov 1980 - Beginning of data read by NODES - if IWLCNG=1]
0  1   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B12   4 1     51.      0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C========================= DATA SET 21
==========================================
 0  1  1       [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
5475                   [Times for output - IOMETH values]
 0 0 0 0 0 0           [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0          [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0          [DT,DTMIN,DTMAX]
HEADER -----> Dec 1980 - Beginning of data read by NODES - if IWLCNG=1]
0  1   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B12   4 1     67.      0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C========================= DATA SET 22
==========================================
 0  1  1       [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
5840                   [Times for output - IOMETH values]
 0 0 0 0 0 0           [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0          [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0          [DT,DTMIN,DTMAX]
HEADER -----> Jan-Jul 1981 - Beginning of data read by NODES - if IWLCNG=1]
0  5   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
```

South Marsh Island 73, B-65G Reservoir - Final Run Input Data (Continued)

```
B1    1 1   111.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1     0.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1     0.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1   112.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 3     0.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 23
==========================================
 0  1  1      [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
6144                [Times for output - IOMETH values]
 0 0 0 0 0 0         [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0        [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0        [DT,DTMIN,DTMAX]
HEADER -----> Jan-Oct 1982 - Beginning of data read by NODES - if IWLCNG=1]
0 5   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1    58.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1     0.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1     0.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1    23.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 3     0.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 24
==========================================
 0  1  1      [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
6205                [Times for output - IOMETH values]
 0 0 0 0 0 0         [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0        [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0        [DT,DTMIN,DTMAX]
HEADER -----> Nov-Dec 1982 - Beginning of data read by NODES - if IWLCNG=1]
0 1   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 3     0.    0.   -1123.   000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 25
==========================================
 0  1  1      [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
6295                [Times for output - IOMETH values]
 0 0 0 0 0 0         [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0        [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0        [DT,DTMIN,DTMAX]
HEADER -----> Jan-Mar 1983 - Beginning of data read by NODES - if IWLCNG=1]
0 5   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 3     0.    0.   -990.    000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1     0.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1     0.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1   101.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 3     0.    0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 25
==========================================
 0  1  1      [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
6570                [Times for output - IOMETH values]
```

South Marsh Island 73, B-65G Reservoir - Final Run Input Data (Continued)

```
0 0 0 0 0 0        [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0      [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0       [DT,DTMIN,DTMAX]
HEADER -----> Apr-Dec 1983 - Beginning of data read by NODES - if IWLCNG=1]
0 5   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1   54.    0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1   0.     0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1   0.     0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1   101.   0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 3   0.     0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 26
=====================================
 0  1  1      [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
6660                [Times for output - IOMETH values]
 0 0 0 0 0 0        [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0      [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0       [DT,DTMIN,DTMAX]
HEADER -----> Jan-Mar 1984 - Beginning of data read by NODES - if IWLCNG=1]
0 5   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 3   0.     0.   -705.   000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1   0.     0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1   0.     0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1   40.    0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 3   0.     0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 26
=====================================
 0  1  1      [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
6935                [Times for output - IOMETH values]
 0 0 0 0 0 0        [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0      [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0       [DT,DTMIN,DTMAX]
HEADER -----> Apr-Dec 1984 - Beginning of data read by NODES - if IWLCNG=1]
0 5   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1   54.    0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1   0.     0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1   0.     0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1   11.    0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 3   0.     0.   0000.   000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 27
=====================================
 0  1  1      [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
7087                [Times for output - IOMETH values]
 0 0 0 0 0 0        [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0      [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0       [DT,DTMIN,DTMAX]
HEADER -----> Jan-May 1985 - Beginning of data read by NODES - if IWLCNG=1]
0 5   [NWELLN=No. of new wells, NWELLO=No. of old wells]
```

South Marsh Island 73, B-65G Reservoir - Final Run Input Data (Continued)

```
---OLD WELLS---
B1    1 3     0.     0.   -1028.    000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1     0.     0.   0000.     000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1     0.     0.   0000.     000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1     20.    0.   0000.     000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 3     0.     0.   0000.     000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 28
==========================================
 0  1  1     [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
7300                [Times for output - IOMETH values]
 0 0 0 0 0 0        [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0      [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0       [DT,DTMIN,DTMAX]
HEADER -----> Jun-Dec 1985 - Beginning of data read by NODES - if IWLCNG=1]
0  1   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1     0.     0.   0000.     000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 29
==========================================
 0  1  1     [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
7633                [Times for output - IOMETH values]
 0 0 0 0 0 0        [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0      [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0       [DT,DTMIN,DTMAX]
HEADER -----> Jan-Jul 1986 - Beginning of data read by NODES - if IWLCNG=1]
0  5   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1     0.     0.   0000.     000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1     0.     0.   0000.     000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1     0.     0.   0000.     000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1     10.    0.   0000.     000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 3     0.     0.   0000.     000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 30
==========================================
 0  1  1     [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
7665                [Times for output - IOMETH values]
 0 0 0 0 0 0        [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0      [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0       [DT,DTMIN,DTMAX]
HEADER -----> Dec 1986 - Beginning of data read by NODES - if IWLCNG=1]
0  1   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 3     0.     0.   -357.     000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 31
==========================================
 0  1  1     [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
8030                [Times for output - IOMETH values]
 0 0 0 0 0 0        [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0      [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0       [DT,DTMIN,DTMAX]
```

South Marsh Island 73, B-65G Reservoir - Final Run Input Data (Continued)

```
HEADER -----> Jan-Dec 1987 - Beginning of data read by NODES - if IWLCNG=1]
0 5   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 3    0.    0.    -730.    000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1    0.    0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1    0.    0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 3    0.    0.    164.     000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 3    0.    0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 32
==========================================
 0  1  1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
8395                    [Times for output - IOMETH values]
 0 0 0 0 0 0            [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0          [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0           [DT,DTMIN,DTMAX]
HEADER -----> Jan-Dec 1988 - Beginning of data read by NODES - if IWLCNG=1]
0 5   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1    0.    0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1    0.    0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1    0.    0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 3    0.    0.    250.     000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 3    0.    0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 33
==========================================
 0  1  1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
8760                    [Times for output - IOMETH values]
 0 0 0 0 0 0            [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0          [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0           [DT,DTMIN,DTMAX]
HEADER -----> Jan-Dec 1989 - Beginning of data read by NODES - if IWLCNG=1]
0 5   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1    0.    0.    277.     000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1    0.    0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1    0.    0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 3    0.    0.    347.     000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 1    0.    0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 34
==========================================
 0  1  1        [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
9125                    [Times for output - IOMETH values]
 0 0 0 0 0 0            [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0          [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0           [DT,DTMIN,DTMAX]
HEADER -----> Jan-Dec 1990 - Beginning of data read by NODES - if IWLCNG=1]
0 5   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1    0.    0.    4.       000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1    0.    0.    0000.    000.  [FORMATTED: A5,2I3,4F10.0]
```

South Marsh Island 73, B-65G Reservoir - Final Run Input Data (Continued)

```
B10D  3 1    0.     0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1   97.     0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 1    0.     0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 35
========================================
 0  1  1     [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
9490                 [Times for output - IOMETH values]
 0 0 0 0 0 0          [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 0 0 0        [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0         [DT,DTMIN,DTMAX]
HEADER -----> Jan-Dec 1991 - Beginning of data read by NODES - if IWLCNG=1]
0 5   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1    0.     0.     0.     000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1    0.     0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1    0.     0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1   73.     0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 1    0.     0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
C==================== DATA SET 36
========================================
 0  1  1     [ICHANG  IOMETH  IWLCNG -> NOTE: ICHANG not used if IOMETH>0]
9855                 [Times for output - IOMETH values]
 1 1 1 1 0 1          [IPMAP,ISOMAP,ISWMAP,ISGMAP,IPBMAP,IAQMAP]
 0 0 0 0 1 1 1        [KROMP, KRWMP, KRGMP,IRSOMP]
 0.1 0.1 30.0         [DT,DTMIN,DTMAX]
HEADER -----> Jan-Dec 1992 - Beginning of data read by NODES - if IWLCNG=1]
0 5   [NWELLN=No. of new wells, NWELLO=No. of old wells]
---OLD WELLS---
B1    1 1    0.     0.     0.     000.  [FORMATTED: A5,2I3,4F10.0]
B7    2 1    0.     0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B10D  3 1    0.     0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B12   4 1   75.     0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
B15   5 1    0.     0.   0000.    000.  [FORMATTED: A5,2I3,4F10.0]
```

APPENDIX E
Run Modifications Made for South Marsh Island 73, B-65G Reservoir

Run Modifications Made for South Marsh Island 73, B-65G Reservoir

The exact modifications made from run AA to run AB are as follows:

- The placement and strength of the aquifer were changed by increasing the strength of the aquifer from 500 SCF/psia to 1500 SCF/psia.
- The net sand thickness of the third layer at and to the northwest of the well B-10D was increased from 8 feet to 20 feet.
- The x-direction permeability was decreased from 3000 md to 680 md, 1056 md and 125 md for layers 1 through 3 respectively for columns 8 and 9, row 3 and columns 9 through 11, row 5.
- The y-direction permeability for column 9, rows 3 through 5, for layer 1 through 3 was decreased from 3000 md to 680 md, 1056 md, and 125 md, respectively.
- For columns 6 and 7, row 8, for layers 2 and 3, the y-permeability was increased from 12.5 md to 1056 md and 125 md, respectively.
- For column 11, row 6 for layers 1 and 3 the y-direction permeability was increased from 12.5 md to 680 md, 1056 md and 125 md, respectively.

The exact modifications made from run AB to run AC are as follows:

- For column 4, row 5, layer 1, the net thickness was decreased from 12 feet to 5 feet. This is in the vicinity of the B-12 well and was expected to improve the individual well match as well as the overall reservoir match.
- For column 6, row 8, layer 3, the horizontal permeability was set at zero md, in an attempt to modify the fluid movement around the B-10D well.
- The average oil saturation was decreased to 78% from 80% in an attempt to produce more water.
- The one main aquifer in run "ab" was modified to two separate aquifers, the first ranging from column 1 to 4, row 12, layers 1 to 3 and the second ranging from column 8 to 12, row 12, layers 1 to 3. Both were assigned a strength of 2500 ft^3/psi.

The exact modifications made from run AC to run AD are as follows:

- Net sand in the vicinity of the B-12 and B-1 wells were reduced 1 to 3 feet.
- Overall original oil saturation was reduced from 78% to 77%.
- Aquifer strengths were reduced to 1500 ft^3/psi from 2500 ft^3/psi.

The exact modifications made from run AG to run AT are as follows:

- No changes were made to primary shale-out (pinch-out) against salt.
- Around well B-12, layer 1 was thickened slightly in grid blocks adjacent to the well.
- Grid Block 5 5 3 3 layer 1 was thickened from 0 feet to 10 feet.
- x and y permeability in layer 3 south of well B-10 (on strike) and northeast of well B-12 (downdip) was reduced to 0.
- Gas cap was placed in layer 1, rows 1 through 2 (for grids not shaled-out). This places a variably thick gas cap in the uppermost portions of the reservoir, but it is no deeper than 6428 subsea.