TOPICAL REPORT: REVISIONS ON MASTER (Miscible Applied Simulation Techniques for Energy Recovery)

IMPROVING CO2 EFFICIENCY FOR RECOVERING OIL IN HETEROGENEOUS RESERVOIRS

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EXPLANATION

For a number of years New Mexico Petroleum Recovery Research Center, a research division of New Mexico Institute of Mining and Technology has been using MASTER (Miscible Applied Simulation Techniques for Energy Recovery) that was developed by the DOE. This document, MASTER Version 3.0, was prepared using as much as possible the manual developed for MASTER Version 2.0. Accompanying this document will be a code for MASTER containing all the revisions and code added during the last dozen years while under several Department of Energy contracts related to improving fossil fuel recovery. It is hoped that other engineers and scientist will benefit from our experience and updates in this simulator that models various fluid flow processes in petroleum reservoirs.

FOSSIL ENERGY

MISCIBLE APPLIED SIMULATION TECHNIQUES FOR ENERGY RECOVERY VERSION 3.0

USER'S GUIDE – February 1991

By
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TECHNICAL MANUAL

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MISCIBLE APPLIED SIMULATION TECHNIQUES FOR ENERGY RECOVERY

July 2005 USER'S Guide - VERSION 3.0
(Modifications of Version 2.0 by Zhengwen Zeng, Reid B. Grigg, and Shih-Hsien Chang 2005
New Mexico Petroleum Recovery Research Center)

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Users' Guide 1991:

We thank Dr. W. N. Sams, J. H. Dean, J. S. Hancock, S. M. Reddy, and Dr. K. Hemanth Kumar for their assistance with this work. We also acknowledge W. K. Sawyer for his work on the original version of MASTER.

Technical Manual 1991:

The authors would like to thank Dr. K. Hemanth Kumar and J. H. Dean for their assistance with this work. We would also like to acknowledge W. K. Sawyer for his work on the original version of MASTER.

Revisions 2005:

During the use of MASTER at the New Mexico Petroleum Recovery Research Center (PRRC) as research division of New Mexico Institute of Mining and Technology a number of modification have been made to the original MASTER. We have worked at minimizing bugs and incorporating a foaming option for water injection alternating with gas (WAG). The original work was performed by or under the direction of Dr. Shih-Hsien Chang. The final modification and completion of the documentation were performed by Dr. Zhengwen Zeng. Both worked under Dr. Reid B. Grigg in the Gas Flooding Processes and Flow Heterogeneities Section of PRRC. This work is not intended to have any long-term support. We thank the Department of Energy for the original development of this program and the availability for our use.

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1.0 INTRODUCTION

This User's Guide is meant to serve as a manual for users of the multicomponent, pseudomiscible simulator MASTER. In Section 2, "Model Overview," the development history of MASTER and the type of problems that can be simulated are discussed. In Section 3, "Data Preparation and Description," the required format for the input file is shown, while in Section 4, "Interpretation of Model Output," various output formats are shown. In Section 5, "Conventional Model Features," and in Section 6, "Special Model Features," certain options and calculations in the code that the user should know to make the correct choice of variable values and options are discussed. Lastly, Section 7, "Example Problems," validation runs and examples of correct input and output files are presented. The information contained in this manual should be sufficient for the user to complete a successful simulation run with MASTER. If the user would like detail on the mathematics of the code, refer to the accompanying Technical Manual.

MASTER 3.0 was developed on a Personal Computer System (Dell Dimension 8300 Pentium 4 CPU 3.20 GHz, 3.19GHz 2.0 GB of RAM) and was written in standard FORTRAN 77/90 It was compiled and tested using Digital Visual Fortran compiler (Professional Edition 5.0A) under Microsoft Developer Studio environment. The simulator should run with minor or no modification on machines designed to handle standard FORTRAN 77/ 90.

In order to avoid confusion in this manual, the term "natural gas" refers to a mixture of light hydrocarbons as in a conventional black-oil model, and the term "gas" without any modifier refers to a vapor phase of any composition (i.e., natural gas, solvent, or both) either in the reservoir or at the surface.

2.0 MODEL OVERVIEW

The reservoir simulator Miscible Applied Simulation Techniques for Energy Recovery (MASTER) was developed specifically for the U.S. Department of Energy to support the Gas Miscible Displacement Enhanced Oil Recovery Program at the Morgantown Energy Technology Center (METC). Lewin & Associates, Inc., and Mathematical & Computer Services, Inc. (1985), developed the original version of MASTER under U.S. Department of Energy Contract No. DE-AC21-84MC21138. The code was later revised at METC.

MASTER is a multicomponent, pseudomiscible simulator that simultaneously tracks stock tank oil, natural gas, water, up to four solvent species, and a surfactant. Natural gas and solvent 1 are allowed to partition between the gas, oil, and aqueous phases while solvents 2, 3, and 4 partition among the gas and oil phases only. The surfactant exists in the aqueous phase only. The code is an extension of the black-oil model, Black-Oil Applied Simulation Tool (BOAST) (Fanchi et al., 1982), and is based on ideas found in the Todd, Dietrich, and Chase (TDC), Inc., multicomponent reservoir simulator (Chase and Todd, 1984). MASTER is similar to the TDC simulator in that it uses a mixing parameter, a programmed switch from immiscible to miscible conditions, and a water blocking option.

Extensive modifications and additions were made to BOAST in order to permit simulation of miscible processes, including the unique features associated with gas miscible flooding (Lewin & Associates, 1985). The major modifications were:

1. The addition of four conservation equations to permit simulation of oil, water, gas, and up to four different solvents, and
2. The addition of the mixing parameter approach (Todd and Longstaff, 1972; Watkins, 1982).

Revisions were made to the original version of MASTER because the code was inadequate for gas injection problems. Modification to the code required reformulating the pressure equation to incorporate a variable switching technique (Thomas et al., 1976). An iterative implicit-in-pressure, explicit-in-saturation (IMPES) solution scheme was added to eliminate possible errors that can occur by approximating the coefficients in the pressure equation by their values at time n and solving the equation only once (as in noniterative IMPES techniques). In addition, the FORTRAN code was restructured to allow run-time dimensioning, to accommodate simulations with larger storage requirements, and to reduce central processing unit (CPU) time during execution.

MASTER also includes four additional features:

1. Fluid properties that are based on both pressure and the amounts of soluble components in solution;
2. An option to use upstream fluid properties instead of average fluid properties;
3. The capability to use up to ten relative permeability/capillary pressure tables; and
4. The option to use either of four solution techniques, including a conjugate gradient-like technique for large simulation runs.

A three-phase relative permeability option using the (industry standard) modified Stone equation (Rosenzweig et al., 1986), and a pressure and saturation initialization option based on capillary-gravity equilibrium data are available. Output data, with various levels of detail, can be printed as often as every time step. These data include well and summary reports, and pressure and fluid distribution maps. The well schedule section offers many injection and production well selections, including rate-controlled wells, and implicit and explicit pressure-controlled wells.

For conventional oil-water-gas simulations, the miscible features can be easily bypassed, giving essentially a standard black-oil model. In this mode, MASTER can be used to simulate most of the common primary and secondary recovery mechanisms such as solution-gas drive, water flood, and immiscible gas injection. Due to the large saturation changes usually associated with well-bore coning, MASTER is not recommended for coning problems.

With the miscible features engaged, MASTER can be used to simulate a wide range of immiscible-to-miscible gas-injection recovery processes. MASTER uses the mixing-rule approach introduced by Todd and Longstaff (1972) and later extended by Watkins (1982) to calculate effective fluid densities and viscosities. MASTER can also account for five gas miscible flooding phenomena:

1. The loss of solvent to the aqueous phase;
2. Mobility control, which reduces solvent mobility as a function of local surfactant concentration (Bernard, 1980);
3. The degree that water blocks oil from contacting injected solvent (Raimondi and Torcaso, 1963; Tiffin and Yellig, 1983);
4. The precipitation of asphaltene with subsequent permeability reduction (Shelton and Yarborough, 1977; Chase and Todd, 1984); and
5. The foam feature using resistance factor table with the consideration of surfactant adsorption onto reservoir rocks (Chang and Grigg, 1996).

3.0 DATA PREPARATION AND DESCRIPTION

3.1 Data Input Requirements

This section provides a detailed description of the input data required to execute MASTER. All input data for the simulator is contained in a single input file. This file may be divided into two categories:

1. Data initialization and
2. Recurrent data.

Data initialization consists of all time-independent data beginning with grid dimensions and ending with transmissibility modifications. This includes reservoir geometry, rock porosity and permeability, initial pressure and saturation data, relative permeability and capillary pressure tables, and fluid pressure-volume-temperature (PVT) data. Also included in this section are the necessary run control parameters for specifying reservoir production and pressure limits, miscibility options, and the solution algorithm. The data initialization section is free-format. Therefore, each variable must be assigned a value even if the value is zero.

Recurrent data sets consist of time-step size and control data, and location and production control information for all wells. A well may be added, recompleted, or shut-in at any time during the course of a simulation. Each well may be produced against a specified bottom-hole pressure, at a specified oil production rate, or at a specified total voidage rate. Both injection and production pressure controlled wells can be modeled using either an explicit or implicit formulation. See Section 3.15 and Section 5.2 for details. The recurrent data section is free-format, thus, each variable must be assigned a value even if the value is zero.

Throughout the description of input data, the letter “I” refers to an integer format, the letter “F” refers to a real format, and the term "header" refers to specific input data records. The header record can be used for spacing or to conveniently identify specific data items on the subsequent records.

3.2 Dimensioning and Running the Program

3.2.1 Parameter Statements

The MASTER model consists of one FORTRAN file, MASTER.f. It was developed and tested using Digital Visual Fortran (Professional Edition 5.0A). There are parameter statements in the program that may need to be changed for efficient computer usage and successful reservoir simulation. These parameter statements either directly or indirectly control the number of grid blocks and the number of wells that the model can process.

A parameter statement controls the maximum number of x-direction grid blocks (NXMAXX), y-direction grid blocks (NYMAXX), and z-direction grid blocks (NZMAXX) that MASTER can model correctly; however, these numbers cannot override the capabilities of the computer. The product of the parameter values NXMAXX, NYMAXX, and NZMAXX must be greater than or equal to the product of the x-direction grid blocks (NX), y-direction grid blocks (NY), and z-direction grid blocks (NZ) in the input data file, MASTER.d. These parameters are set in the main program in the parameter statement

```
PARAMETER (NXMAXX = 16, NYMAXX = 16, NZMAXX = 7).
```

Even though these dimensions are set correctly, an error can occur when using either the direct solution technique (D4) or planar successive over relaxation solution technique (SSOR). The program error message will report that array bounds have been exceeded. The memory requirements of these solution techniques are approximated in the main program by the parameter statement

```
PARAMETER (MAXAA = MXROWW  *  MAXX / 2),
```

where MAXX is the product of NXMAXX times NYMAXX times NZMAXX. If the dimensions are inadequate, program execution is halted, and an error message is placed in the output file. This error can usually be corrected by increasing the NYMAXX or NZMAXX value in the parameter statement.

The additional parameter value, MXROWW, which is also assigned in the main program, is used when either the D4 or SSOR solution techniques are used. MXROWW should be set greater than or equal to the product of the two smallest grid-block dimensions, i.e., MXROWW > the minimum of (NX times NY, NY times NZ, or NX times NZ). MXROWW and MAXAA are only used if either the D4 or the SSOR solution techniques are selected. Hence, a value of one may be assigned to MXROWW and MAXAA if neither of these solution techniques is being used. MXROWW is set in the main program with the parameter statement

```
PARAMETER (MXROWW = 400).
```

With the MXROWW value of 400 and the parameter assigned gridblock definitions above, any reservoir simulation problem with 1792 or fewer grid blocks can be executed.

The main program also allows the opportunity to dictate the maximum number of wells that can be monitored by modifying the NWELL value assigned in the parameter statement

```
PARAMETER (NWELLL = 40, NWLL = 16).
```

3.2.2. Compiling the Program

MASTER3.0 was developed using Digital Visual Fortran (Professional Edition 5.0A) under Microsoft Developer Studio environment. It can be modified for specific requirements, such as change of the maximum numbers of grid blocks, wells and band width for the equation matrix so as to meet the resolution requirements or to overcome the restrictions of the computer system. There can be various methods to modify the program. In the Microsoft Developer Studio, open the source code file, MASTER.f, at first. After proper modification, save MASTER.f in the same folder as MASTER executable file. Under BUILD submenu, compile MASTER.f, and then build MASTER.exe.

3.2.3 File Names

Input and output file names used in MASTER and a description of each of these files are given in Table 1. The input data file must be named MASTER.D. Names of the primary output file, MASTER.OUT, the executive summary table, MASTER.SUM, and the material balance error report, MASTER.MBE, are assigned within the MASTER program.

Table 1. File Names and Descriptions

File Names	File Description
MASTER.D	Input Data File -- All input data required to run MASTER is contained in this file.
MASTER.OUT	Primary Output File -- Echoed data input, well and summary reports, and pressure and fluid distribution maps are printed to this file. See Section 4.1.
MASTER.SUM	Executive Summary Table -- A one-line production summary for the entire field is given for each time step. See Section 4.2.
MASTER.MBE	Material Balance Error Report -- The largest, local material balance error for each component and the grid blocks in which these errors occur are printed each iteration of every time step. See Section 4.3.

These files can be edited and analyzed using Microsoft Developer Studio, or Notepad, or other text editor.

3.3 Grid Dimensions and Geometry

3.3.1 Grid Dimensions

1. Header (A80)

2. Number of grid blocks (see Figure 1 for grid block numbering) . . . . . .(3I)

   II Number of x-direction grid blocks
   JJ Number of y-direction grid blocks
   KK Number of z-direction grid blocks

3. Header (A80)

4. Codes for inputting grid-block dimensions (see Table 2). . . . . .(3I)

   KDX Code for specifying x-direction grid dimensions
   KDY Code for specifying y-direction grid dimensions
   KDZ Code for specifying z-direction grid dimensions

5. X-direction grid dimensions (ft) . . . . . (10F)

   DX See Table 2 for the number of values required. When KDX = 0 or 1, data must be input in the following order:

J = 1, I = 1, 2 II
J = 2, I = 1, 2 II
. . . . .
. . . . .
J = JJ, I = 1, 2 . . . . . II.

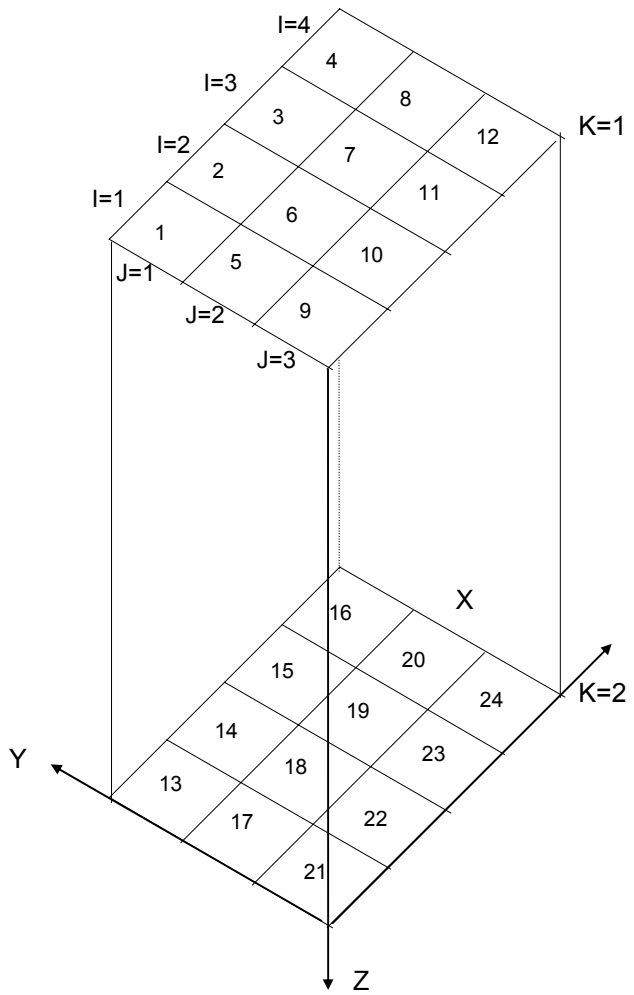


FIGURE 1. Numbering of the Grid System

Table 2. Options for Grid-Block Geometry

Code	Value	Grid Dimension Specifications
KDX	-1	X-direction grid dimensions are the same for all grid blocks; input only one DX value.
KDX	0	X-direction dimensions are read for each grid block in the first row (J = 1) of layer one (K = 1); input II values of DX. These same x-direction dimensions are assigned to all other rows and all other layers in the model grid.
KDX	1	X-direction dimensions are read for every grid block in layer one (K = 1); input II x JJ values of DX. These same x-direction dimensions are assigned to all other layers in the model grid.
KDY	-1	Y-direction grid dimensions are the same for all grid blocks; input only one DY value.
KDY	0	Y-direction dimensions are read for each grid block in the first column (J = 1) of layer one (K = 1); input JJ values of DY. These same y-direction dimensions are assigned to all other columns and all other layers in the model grid.
KDY	1	Y-direction dimensions are read for every grid block in layer one (K = 1); input II x JJ values of DY. These same y-directions dimensions are assigned to all other layers in the model grid.
KDZ	-1	Z-direction grid dimensions are the same for all grid blocks; input only one DZ value.
KDZ	0	A constant value of thickness is read for each layer in the grid; input KK values of DZ.
KDZ	1	Z-direction grid dimensions are read for every grid block; input II x JJ x KK values of DZ.

6. Y-direction grid dimensions (ft) . . . . . (10F)

DY See Table 2 for the number of values required. When KDY = 0 or 1, data must be input in the following order:

```
I = 1,  J = 1, 2, . . . . . JJ
I = 2,  J = 1, 2, . . . . . JJ
  .      .     .  .          .
  .      .     .  .          .
I = II, J = 1, 2, . . . . . JJ.
```

7. Z-direction grid dimensions (ft) . . . . . (10F)

DZ See Table 2 for the number of values required. When KDZ = 0, the order of input must be as follows:

K = 1, 2, ... KK.

When KDZ = 1, the order of input must be as indicated in Item 5 above with layer order

K = 1, 2, . . . , KK.

3.3.2 Modifications to Grid Dimensions

This section, when used in conjunction with the Grid Dimension and Geometry section, can minimize the combined input data of these two sections. For example, a 22 x 2 x 1 grid is being used to model a core flood and the x-direction block dimensions are 0.25 feet except the two end blocks which are 0.5 feet. The x-direction grid dimensions can be set constant at 0.25 feet for all blocks and the grid dimension modification card can be used for Blocks 1 and 22.

1. Header (A80)

2. Grid dimension modifications . . . . . (4I)

NUMDX - Number of grid blocks that will have the x-direction grid dimension altered.
NUMDY - Number of grid blocks that will have the y-direction grid dimension altered.
NUMDZ - Number of grid blocks that will have the z-direction grid dimension altered.
IDCODE - Print code for grid dimension alterations
If IDCODE = 0, do not print modified grid dimensions
If IDCODE = 1, print modified grid dimensions

3. X-direction grid dimension modifications . . . . .(3I,1F)

I - X-coordinate of block to be modified
J - Y-coordinate of block to be modified
K - Z-coordinate of block to be modified
DX - New x-direction grid dimension (ft) for block (I, J, K)

NOTE: NUMDX records must be read.

4. Y-direction grid dimension modifications . . . . .(3I,1F)

I - X-coordinate of block to be modified
J - Y-coordinate of block to be modified
K - Z-coordinate of block to be modified
DY - New y-direction grid dimension (ft) for block (I,J,K)

NOTE: NUMDY records must be read.

5. Z-direction grid dimension modifications . . . . .(3I,1F)

I - X-coordinate of block to be modified
J - Y-coordinate of block to be modified
K - Z-coordinate of block to be modified
DZ - New z-direction grid dimension (ft) for block (I, J, K)

NOTE: NUMDZ records must be read.

3.3.3 Elevations to Top of Grid Blocks in Layer 1

Remember that with the coordinate system used here, z-direction values increase going down. Thus, elevations must be read as depths below the user-selected reference datum. Negative values will be interpreted as heights above the datum.

1. Header (A80)
2. Code for inputting grid-block elevations . . . . .(1I)

   KEL - Input code

   REMARKS: (a) If KEL = 0, a single constant value is read for the elevation at the top of all grid blocks in layer 1 (i.e., horizontal plane).

   (b) If KEL = 1, a separate elevation value must be read for each grid block in layer 1. II x JJ values must be read.

3. Depth values . . . . .(8F)

   ELEV Elevation to top of grid block (ft)

   REMARKS: (a) When KEL = 1, II x JJ values must be read in the following order:

   J = 1, I = 1, 2, ... II
   J = 2, I = 1, 2, ... II
   . . . . .
   . . . . .
   J = JJ, I = 1, 2, ... II

   (b) Elevations to the top of grid blocks in layers below layer 1 will be calculated by adding the layer thickness to the preceding layer elevation, i.e.,

   Top(I,J,K+1) = Top(I,J,K) + DZ(I,J,K)

3.4 Porosity and Permeability Distributions

3.4.1 Porosity and Permeability

1. Header (A80)

2. Codes for inputting porosity and permeability data (see Table 3.). . . . . (4I)

   KPH - Code for controlling porosity data
   KKX - Code for controlling x-direction permeability data
   KKY - Code for controlling y-direction permeability data
   KKZ - Code for controlling z-direction permeability data

3. Porosity values (fraction) . . . . .(10F)

PHI - See Table 2 for the number of values required. When KPH = 1, the order of input must be as indicated below with layer order K = 1, 2, ..., KK.

```
J = 1,  I = 1, 2, . . . . . II
J = 2,  I = 1, 2, . . . . . II
  .      .    .   .        .
  .      .    .   .        .
J = JJ, I = 1, 2, . . . . . II
```

MASTER has the capability to model null or zero porosity grid blocks. This capability is convenient for irregular grid boundaries, pinchouts, and shale barriers. Zero porosity values are entered like other porosity values.

Table 3. Options for Grid-Block Properties

Code	Value	Porosity and Permeability Specifications
KPH	-1	Porosity is uniform over the grid; input only one PHI value.
KPH	0	Porosity varies by layer; input KK values of PHI.
KPH	1	Porosity varies over the entire grid; input II x JJ x KK values of PHI.
KKX	-1	X-direction permeability is uniform over the grid; input only one KX value.
KKX	0	X-direction permeability varies by layer; input KK values of KX.
KKX	1	X-direction permeability varies over the entire grid; input II x JJ x KK values of KX.
KKY	-1	Y-direction permeability is uniform over the grid; input only one KY value.
KKY	0	Y-direction permeability varies by layer; input KK values of KY.
KKY	1	Y-direction permeability varies over the entire grid; input II x JJ x KK values of KY.
KKZ	-1	Z-direction permeability is uniform over the grid; input only one KZ value.
KKZ	0	Z-direction permeability varies by layer; input KK values of KZ.
KKZ	1	Z-direction permeability varies over the entire grid; input II x JJ x KK values of KZ.

4. X-direction permeability (md) . . . . .(10F)

KX - See Table 3 for the number of values required. When KKX = 1, the order of input must be as indicated in Item 3 above with layer order K = 1, 2, ... KK.

5. Y-direction permeability (md) . . . . . (10F)

KY - See Table 3 for the number of values required. When KKY = 1, the order of input must be as indicated in Item 3 above with layer order K = 1, 2, ..., KK.

6. Z-direction permeability (md) . . . . . (10F)

KZ - See Table 3 for the number of values required. When KKZ = 1, the order of input must be as indicated in Item 3 above with layer order K = 1, 2, ..., KK.

3.4.2 Modifications to Porosity and Permeability Distributions

This section, when used in conjunction with the Porosity and Permeability Distributions section, can be used to minimize the combined input data of these two sections. Also, this section can be used when adjusting porosity and permeability data when history matching.

1. Header (A80)

2. Porosities and permeabilities . . . . . (5I)

NUMP - Number of grid blocks that will have the porosity (PHI) data altered
NUMKX - Number of grid blocks that will have the x-direction permeability data (KX) altered
NUMKY - Number of grid blocks that will have the y-direction permeability data (KY) altered
NUMKZ - Number of grid blocks that will have the z-direction permeability data (KZ) altered
IPCODE - Print code for porosity and permeability alterations
If IPCODE = 0, do not print modified porosity and permeability distributions.
If IPCODE = 1, print modified porosity and permeability distributions.

3. Porosity modifications . . . . .(3I,1F)

I - X-coordinate of block to be modified
J - Y-coordinate of block to be modified
K - Z-coordinate of block to be modified
PHI - New porosity (fraction) for block (I,J,K)

REMARKS: (a) NUMP records must be read.

4. X-direction permeability (KX) modifications . . . . . (3I,1F)

I - X-coordinate of block to be modified
J - Y-coordinate of block to be modified
K - Z-coordinate of block to be modified
KX - New x-direction permeability (md) for block (I,J,K)

NOTE: NUMKX records must be read.

5. Y-direction permeability (KY) modifications . . . . . (3I,1F)

I - X-coordinate of block to be modified
J - Y-coordinate of block to be modified
K - Z-coordinate of block to be modified
KY - New value of y-direction permeability (md) for block (I,J,K)

NOTE: NUMKY records must be read.

6. Z-direction permeability (KZ) modifications . . . . . (3I,1F)

I - X-coordinate of block to be modified
J - Y-coordinate of block to be modified
K - Z-coordinate of block to be modified
KZ - New value of z-direction permeability (md) for block (I,J,K)

NOTE: NUMKZ records must be read.

3.5 Relative Permeability and Capillary Pressure

1. Header (A80)

2. Three-phase relative permeability switch . . . . .(1I)

KR3P - Switch for determining oil relative permeability
If KR3P = 0, use KROW as oil relative permeability
If KR3P = 1, use KROG as oil relative permeability
If KR3P = 2, use KROW, KROG, KRW, and KRG in modified Stone equation (Rosenzweig et al., 1986; Dietrich and Bondor, 1976; and Stone, 1973) to determine oil relative permeability as a function of water and gas saturation

REMARKS:

(a) If the system being simulated is primarily an oil-water system, specify KR3P = 0; KROW will be used to determine oil relative permeability as a function of water and gas saturations (i.e., k_{ro} = KROW @ SWT = 1 - S_O); KROG will not be used.

(b) If the system being simulated is primarily an oil-gas system, specify KR3P = 1; KROG will be used to determine oil relative permeability as a function of water and gas saturations (i.e., k_{ro} = KROG @ SGT = 1 - S_O); KROW will not be used.

(c) If all three phases (oil, water, and gas) are flowing in the system being simulated, specify KR3P = 2; KROW, KROG, KRW, and KRG will be used to determine oil relative permeability as a function of water and gas saturations using the modified Stone equation (Rosenzweig et al., 1986):

$$k_{ro} = k_{ro} [(k_{row}/k_{rom} + k_{rw}) \cdot (k_{rog}/k_{rom} + k_{rg}) - k_{rg} - k_{rw}].$$

Here k_{ro} is the oil relative permeability at zero gas saturation and irreducible water saturation (i.e., KROW at SWT = S_{wr}).

(d) For miscible simulations, KROW is used as the non-aqueous phase relative permeability; however, KR3P is used to determine oil relative permeability for grid blocks below miscibility pressure, PMISC. See Section 6.0 for further detail.

(e) Single-point, upstream relative permeability weighting is used for oil, water, gas, and solvents.

3. Relative permeability/capillary pressure tables

ITABS - Code for controlling relative permeability data input

ITABS = 1 Code for assigning one oil-water and one gas-oil relative permeability/capillary pressure table for the entire reservoir

ITABS = 2 Code for assigning one oil-water and one gas-oil relative permeability/capillary table for each layer

ITABS = 3 Code for assigning one (out of no more than 10) oil-water and one (out of no more than 10) gas-oil relative permeability/capillary pressure table for each grid block

4. Assigning total number of tables to be used during simulation

NTABS - Code for identifying the number of oil-water and gas-oil relative permeability/capillary pressure tables for the simulation.

NTABS = 1	Use only when ITABS = 1
NTABS = KK	Use only when ITABS = 2
$1 \leq$ NTABS ≤ 10	Use only when ITABS = 3

5. Assigning tables to each layer

IDUMMY - Enter only when ITABS = 2. Code for assigning one oil-water and one gas-oil relative permeability/capillary pressure table to each layer. Tables are assigned a number according to the order in which they are read. The data must be input in the following order:

K = 1, 2, 3, ... KK

6. Assigning tables to each grid

NTABIJK Enter only when ITABS = 3. Code for assigning one oil-water and one gas-oil relative permeability/capillary pressure table to each grid block. Tables are assigned a number according to the order in which they are read. The data input order of NTABIJK must be as follows with layer order K = 1, 2, 3, ... KK.

J = 1, I = 1, 2, 3, ... II
J = 2, I = 1, 2, 3, ... II
.
.
.
J = JJ, I = 1, 2, 3, ... II

7. Header (A80)

8. Oil-water relative permeability/capillary pressure table format . . . . .(4F) (functions of water saturation)

SWT_1	$KROW_1$	KRW_1	$PCOW_1$
.	.	.	.
.	.	.	.
SWT_n	$KROW_n$	KRW_n	$PCOW_n$

SWT - Water saturation
KROW - Oil phase relative permeability in a two-phase, oil-water system as a function of water saturation, SWT
KRW - Water phase relative permeability as a function of water saturation, SWT
PCOW - Oil-water capillary pressure (psi) as a function of water saturation, SWT

9. Header (A80)

10. Gas-oil relative permeability/capillary pressure table format . . . . .(4F) (functions of gas saturation; water phase is at irreducible water saturation)

SGT_1	$KROG_1$	KRG_1	$PCGO_1$
.	.	.	.
.	.	.	.
SGT_n	$KROG_n$	KRG_n	$PCGO_n$

SGT - Gas saturation
KROG - Oil phase relative permeability in a two-phase, gas-oil system as a function of gas-saturation, SGT
KRG - Gas-phase relative permeability as a function of gas saturation, SGT
PCGO - Gas-oil capillary pressure (psi) as a function of gas saturation, SGT

REMARKS:

(a) Input saturations and relative permeabilities as fractions; however, the terminal values SWT_n and SGT_n must be 1.10.

(b) The first table entry for gas saturation must be zero to account for grid block pressures above the bubble point pressure.

(c) There <u>must</u> be table entries for irreducible water saturation (S_{wr}) and residual oil saturation (S_{orw}); e.g., if S_{wr} = 0.25 and S_{orw} = 0.20, then you must include entries SWT = 0.25 and SWT = 0.80.

(d) There <u>must</u> be table entries for residual gas saturation (S_{gr}) and residual oil saturation (S_{org}); e.g., if S_{gr} = 0.05 and S_{org} = 0.25, then you must include entries for SGT = 0.05 and SGT = 0.75.

(e) When KR3P = 2, KROG at SGT = 0.0 <u>must</u> be equal to KROW at SWT = S_{wr}, since the gas-oil relative permeability table assumes an irreducible water saturation is present.

(f) If NSLUGS > 0, gas-oil capillary pressure will only be used at nodes that are below miscibility pressure, PMISC.

(g) If ITABS > 1, enter NTABS oil-water relative permeability/capillary pressure tables and then enter NTABS gas-oil relative permeability/capillary pressure tables. Each table must begin with a header. The number of entries in all tables must be constant.

3.6 Pressure-Volume-Temperature (PVT) Tables for Oil. Water. and Natural Gas

1. Header (A80)

2. Bubble point pressure and maximum pressure data . . . . .(5F)

PBO	-	Initial reservoir oil bubble point pressure, psia
VOSLOPE	-	Slope of oil viscosity versus pressure curve for pressures above PBO, cp/psi
BOSLOPE	-	Slope of oil formation volume factor versus pressure curve for pressures above PBO, bbl/STB/psi
BWSLOPE	-	Slope of water formation volume factor versus pressure curve for pressures above PBO, bbl/ STB/psi
PMAX	-	Maximum pressure entry for all PVT tables, psia

REMARKS:

(a) VOSLOPE, BOSLOPE, and BWSLOPE are used only for under saturated oil and water.

(b) BOSLOPE should be a negative number and is related to undersaturated oil compressibility, c_o, by

$$BOSLOPE = -BO \cdot c_o \ .$$

The reference volume BO may be BO_1, BO_2, or an average of BO_1 and BO_2 (Craft and Hawkins, 1959).

(c) BWSLOPE should be a negative number and is related to undersaturated water compressibility, c_w, by

$$BWSLOPE = -BW \cdot c_w \ .$$

The reference volume BW may be BW_1, BW_2, or an average of BW_1 and BW_2 (Craft and Hawkins 1959).

(d) If no natural gas exists, set PBO to 14.7.

(e) The slope of the solution natural gas-oil ratio versus pressure curve for pressures above PBO is assumed to be zero.

3. Header (A80)

4. Oil PVT data . . . . . (4F)

P_1	MUO_1	BO_1	RSO_1
.	.	.	.
.	.	.	.
.	.	.	.
P_n	MUO_n	BO_n	RSO_n

P - Pressure, psia
MUO - Oil viscosity, cp
BO - Oil formation volume factor, bbl/STB
RSO - Solution natural gas-oil ratio, scf/STB

REMARKS: (a) The last pressure entry (P_n) must be PMAX as specified in Item 2 above.

(b) Oil properties must be entered as saturated data over the entire pressure range. Laboratory saturated oil data will generally have to be extrapolated beyond the measured bubble point pressure to cover the maximum pressure range anticipated during a simulation run. Saturated oil data are required because of the bubble point tracking scheme.

(c) Saturated oil data above the initial bubble point pressure will only be used if the local reservoir pressure rises above the initial bubble point pressure and free gas is introduced. An example of this would be pressure maintenance by gas injection into the oil zone.

5. Header (A80)

6. Water PVT data . . . . .(4F)

P_1	MUW_1	BW_1	RSW_1
.	.	.	.
.	.	.	.
.	.	.	.
P_n	MUW_n	BW_n	RSW_n

P - Pressure, psia
MUW - Water viscosity, cp
BW - Water formation volume factor, bbl/STB
RSW - Solution natural gas-water ratio, scf/STB

REMARKS: (a) The last pressure entry (P_n) must be PMAX as specified in Item 2 above.

(b) The assumption is often made in black-oil simulations that the solubility of gas in reservoir brine can be neglected. This model incorporates water PVT data to handle such situations as CO_2 solubility in water, gas production from geopressured aquifers, or any other case where gas solubility in water is considered to be of significance to the solution of the problem.

(c) Water properties must be entered as saturated data over the entire pressure range if the solution natural-gas water ratio is nonzero.

7. Header (A80)

8. Natural gas PVT data and rock compressibility . . . . .(4F)

P_1	MUG_1	BG_1	CR_1
.	.	.	.
.	.	.	.
.	.	.	.
P_n	MUG_n	Bg_n	CR_n

P - Pressure, psia
MUG - Natural gas viscosity, cp
BG - Natural gas formation volume factor, ft^3/scf
CR - Rock compressibility, psi^{-1}

NOTE: The last pressure entry, P_n, must be PMAX as specified in Item 2 above.

9. Header (A80)

10. Stock tank fluid densities . . . . . (3F)

RHOSCO - Stock tank oil density, lb_m/ft^3
RHOSCW - Stock tank water density, lb_m/ft^3
RHOSCG - Natural gas density at standard conditions, lb_m/ft^3

REMARKS: (a) Stock tank conditions are 14.7 psia and 60º F.

(b) If no natural gas exists, set RHOSCG = 0.0.

3.7 PVT and other Data for Miscible Solvents

1. Header (A80)

2. Number of "miscible" solvents and number of PVT data tables for these solvents . . . . .(2I)

NSLUGS - Number of solvents for the current simulation run
NSREAD - Number of solvents for which PVT data follows

REMARKS: (a) <u>If NSREAD = 0, OMIT ALL OF THE FOLLOWING SOLVENT INPUT DATA AND PROCEED TO PRESSURE AND SATURATION INITIALIZATION</u>.

(b) NSREAD must be equal to or greater than NSLUGS.

(c) NSREAD is provided as a convenience. PVT data for one to four solvents can be left in place for an oil-water-natural gas run by setting NSREAD = 1 to 4, and NSLUGS = 0.

3.7.1 Base Solvent Solubility

1. Header (A80)

2. Parameters for base solvent solubility in oil . . . . .(3F)

PBO1 - Initial base solvent-oil bubble point pressure, psia

VO1OPE - Undersaturated slope of oil viscosity curve, cp/psi

BO1OPE - Undersaturated slope of oil formation volume factor curve, bbl/STB/psi

3. Header (A80)

4. Parameters for base solvent solubility in water . . . . .(3F)

PBW1 - Initial base solvent-water bubble point pressure, psia
VW1OPE - Undersaturated slope of water viscosity curve, cp/psi

BW1OPE - Undersaturated slope of water formation volume factor curve, bbl/STB/psi

3.7.2 Mixing Parameters

1. Header (A80)

2. Mixing rule parameters for miscible displacement . . . . .(2F)

MEG1 - Value of "omega" for natural gas-solvent miscibility
MEG2 - Value of "omega" for oil-gas-solvent miscibility

REMARKS: (a) Only MEG1 is used if local pressure is below the multicontact miscibility pressure defined by

PMCM = FPMISC x PMISC

(b) Only MEG2 is used if local pressure exceeds the miscibility pressure, PMISC.

(c) Both MEG1 and MEG2 are used if local pressure is in the multicontact miscibility pressure range defined by

PMCM < P < PMISC

3. Header (A80)

4. Miscibility pressure, solid precipitation, and water blocking parameters . . . . . (7F)

PMISC - Miscibility pressure, psia
FPMISC - Fraction of PMISC for calculating multicontact miscibility pressure, PMCM
SOMIN - Minimum oil saturation for solid precipitation (greater than zero only if SORM is zero), fraction
REDK - Relative permeability reduction factor for solid precipitation, fraction
BETA - Parameter for water blocking function
SORM - Miscible region residual oil saturation (greater than zero only if SOMIN is zero), fraction
VSMISC - Total solvent fraction required to obtain full miscibility, fraction

3.7.3 Miscibility Pressure

REMARKS: (a) When local pressure exceeds PMISC and local solvent in place exceeds VSMISC, all oil, natural gas, and solvents present in the grid block are assumed to be fully miscible. All oil above saturation SORM or SOMIN is recoverable in this pressure range.

(b) When local pressure is less than PMCM, all natural gas and solvents present in the grid block are assumed to be fully miscible. Oil is treated as immiscible with the natural gas-solvent mixture.

(c) Additional detail on the use of MEG1, MEG2, PMISC, FPMISC, and VSMISC can be found in Section 6.1.

3.7.4 Solid Precipitation

REMARKS: (a) If SOMIN $\leq$ 0.0, the solid precipitation option is off.

(b) If SOMIN > 0.0, the solid precipitation option is on. SOMIN must be less than DSMAX (see Section 3.11) for saturation convergence if automatic time-step control is on.

(c) When SOMIN > 0.0 and the grid-block oil saturation, SO, drops below SOMIN, the following modifications will be made on a grid block basis:

(i) Stock tank volume of oil “precipitated" will be calculated as Pore Volume x SO / BO

(ii) Oil relative permeability will be set to zero.

(iii) Water and gas relative permeabilities will be reduced by the user-specified variable, REDK.

3.7.5 Water Blocking

REMARKS: (a) If BETA is negative, the water blocking option is off.

(b) If BETA is $\geq$ 0, the water blocking option is on.

(c) When the water blocking option is on, the following modifications are made on a grid-block basis:

(i) Residual oil saturation (S_{orw}) is determined from the relative permeability table.

(ii) Water-blocked oil saturation (S_{twb}) (Chase and Todd 1984) is determined from the relationship

$$S_{twb} = \frac{S_{orw}}{1 + BETA \cdot k_{rn} / k_{rw}}$$

where k_{rn} and k_{rw} are the non-aqueous and aqueous phase relative permeabilities, respectively.

(iii) S_{twb} (and also SORM) are used in the calculations of mixture viscosities and densities and of final effective relative permeabilities.

(iv) The following values of BETA are recommended:

Use BETA = 1.0 for highly water-wet sandstones.
Use BETA = 5.0 for mixed-wetability systems.

(v) Note that BETA = 0.0 implies that no oil is contacted by invading CO_2, while a very large value of BETA (e.g., BETA = 50) essentially means that water blocking does not occur.

3.7.6 Solvent PVT Tables

1. Header (A80)

2. Stock tank densities of solvents . . . . . (4F)

RHOSC1 - Stock tank density of base solvent, lb_m/ft^3
RHOCS2 - Stock tank density of solvent 2, lb_m/ft^3
RHOCS3 - Stock tank density of solvent 3, lb_m/ft^3
RHOCS4 - Stock tank density of solvent 4, lb_m/ft^3

3. Header (A80)

4. Header (A80)

5. Base solvent PVT and solubility data . . . . . (9F)

P_1	$MUS1_1$	$BS1_1$	$RSOS1_1$	$RSWS1_1$	$BO1_1$	$MUO1_1$	$BW1_1$	$MUW1_1$
.	.	.	.	.	.	.	.	.
.	.	.	.	.	.	.	.	.
P_n	$MUS1_n$	$BS1_n$	$RSOS1_n$	$RSWS1_n$	$BO1_n$	$MUO1_n$	$BW1_n$	$MUW1_n$

P - Pressure, psia
MUS1 - Viscosity of base solvent, cp
BS1 - Formation volume factor of base solvent, bbl/STB
RSOS1 - Solubility of base solvent in oil, scf/STB
RSWS1 - Solubility of base solvent in water, scf/STB
BO1 - Formation volume factor of oil with base solvent, bbl/STB
MUO1 - Viscosity of oil with base solvent, cp
BW1 - Formation volume factor of water with base solvent, bbl/STB
MUW1 Viscosity of water with base solvent, bbl/STB

REMARKS: (a) The last pressure entry (P_n) must be PMAX (see Section 3.6).

(b) Base solvent PVT data is required if NSREAD > 0.

(c) Base solvent PVT data is used only if NSLUGS > 0.

(d) The oil and water properties must be entered as saturated data over the entire pressure range. Laboratory saturated (with base solvent) data will generally have to be extrapolated beyond the measured bubble point pressure to cover the maximum pressure range anticipated during a simulation run. Saturated oil and water data are required because of the bubble point tracking scheme. Saturated data above the initial oil or water bubble point pressure will be used to determine new bubble points as the local reservoir pressure rises above the current bubble point pressure due to base solvent injection.

(e) Oil-solvent properties should be determined with a dead oil (no solution gas) fully saturated with solvent at each pressure. A convenient way to determine these values is by using a phase property package.

6. Header (A80)

7. Header (A80)

8. Solvent 2 PVT and oil solubility data . . . . . (4F)

P_1	$MUS2_1$	$BS2_1$	$RSOS2_1$
.	.	.	.
.	.	.	.
P_n	$MUS2_n$	$BS2_n$	$RS0S2_n$

P - Pressure, psia
MUS2 - Viscosity of solvent 2, cp
BS2 - Formation volume factor of solvent 2, bbl/STB
RSOS2 - Solubility of solvent 2 in oil, scf/STB

REMARKS: (a) The last pressure entry (P) must be PMAX (see Section 3.6).

(b) Solvent 2 PVT data is required if NSREAD > 1

(c) Solvent 2 PVT data is used only if NSLUGS > 1

9. Header (A80)

10. Header (A80)

11. Solvent 3 PVT and oil solubility data . . . . . (4F)

P_1	$MUS3_1$	$BS3_1$	$RSOS3_1$
.	.	.	.
.	.	.	.
Pn	$MUS3_n$	$BS3_n$	$RSOS3_n$

P - Pressure, psia
MUS3 - Viscosity of solvent 3, cp
BS3 - Formation volume factor of solvent 3, bbl/STB
RSOS3 - Solubility of solvent 3 in oil, scf/STB

REMARKS: (a) The last pressure entry (P_n) must be PMAX (see Section 3.6).

(b) Solvent 3 PVT data is required if NSREAD > 2

(c) Solvent 3 PVT data is used only if NSLUGS > 2

12. Header (A80)

13. Header (A80)

14. Solvent 4 PVT and oil solubility data . . . . . (4F)

P_1	$MUS4_1$	$BS4_1$	$RSOS4_1$
.	.	.	.
.	.	.	.
P_n	$MUS4_n$	$BS4_n$	$RSOS4_n$

P - Pressure, psia
MUS4 - Viscosity of solvent 4, cp
BS4 - Formation volume factor of solvent 4, bbl/STB
RSOS4 - Solubility of solvent 4 in oil, scf/STB

REMARKS: (a) The last pressure entry (P_n) must be PMAX (see Section 3.6).

(b) Solvent 4 PVT data is required if NSREAD = 4

(c) Solvent 4 PVT data is used only if NSLUGS = 4

3.7.7 Mobility Control

1. Header (A80)

2. Mobility control parameters . . . . . (2I,1F)

NOMOB -Number of entries in the mobility reduction table
MOBCTL -Mobility control switch: 0 for no mobility control
1 for mobility control
CSN - Surfactant concentration index (multiplier for mobility reduction values FRCO2 below)

3. Header (A80)

4. Mobility reduction table . . . . . (2F)

NSC Normalized surfactant concentration

FRCO2 Fractional mobility reduction of base solvent

REMARKS: (a) If MOBCTL is 0, the mobility control option is off.
(b) If MOBCTL is 1, the mobility control option is on.
(c) A typical range for the mobility control agent is 0.1 to 1.0 percent concentration of surfactant in injected water (Bernard et al. 1980). Reservoir water and injected water that contains surfactant are assumed to be completely miscible.

(d) If MOBCTL = 1, gas phase mobility is reduced as determined by the local concentration of water that contains surfactant and the mobility reduction table.

(e) Water that contains surfactant is injected whenever the switch KSIS = 1 (see Section 3.15).

(f) The ratio of the volume of water that contains surfactant to the total water volume is x_s. Surfactant water saturation, S_c, is given by $S_c = X_s \cdot s_w$

(g) Using S_c as the normalized surfactant concentration (NSC) in the mobility reduction table, the fractional mobility reduction is determined by FRCO2·CSN where FRCO2 is the mobility reduction at NSC = Sc

3.8 Pressure and Saturation Initialization

MASTER contains two options for pressure and saturation initialization. In the first option, initial pressure and saturation distributions can be calculated based on equilibrium conditions using the elevations of and pressures at the natural gas-oil and water-oil contacts. In the second option, the initial pressure distribution can be read on a block-by-block basis; saturations can be read as constant values for the entire grid, or the entire saturation distributions can be read on a block-by-block basis.

1. Header (A80)

2. Codes for pressure and saturation initialization . . . . . (2I)

KPI - Code for controlling pressure and saturation initialization. Specify 0 for pressure <u>and</u> saturation initialization based on equilibrium conditions. Specify 1 for manual input for both initial pressures and saturations.

KSI - Code for controlling manual saturation distributions (used only when KPI = 1). Specify 0 for constant saturations over the entire grid. Specify 1 for variable saturations over the entire grid. (If KPI = 0, KSI is not used and can be set to either 0 or 1.)

3. Equilibrium pressure <u>and</u> saturation initialization data (KPI = 0) . . . . . (4F)

PWOC - Pressure at the water-oil contact, psia
PGOC - Pressure at the natural gas-oil contact, psia
WOC - Elevation of the water-oil contact, ft
GOC - Elevation of the natural gas-oil contact, ft

REMARKS:

(a) <u>Input this record only if KPI = 0</u>. You must enter this record NTABS (see Section 3.5) times. To maintain equilibrium conditions in a reservoir, the elevation of the WOC, as well as the elevation of the GOC, must be equal for adjacent blocks in communication.

(b) Elevation means distance <u>below</u> the datum plane.

(c) PWOC and PGOC data are used together with grid block elevation data to calculate the initial <u>oil</u> phase pressure at each grid block midpoint.

(d) WOC data are used together with grid block elevation data and eater-oil capillary pressure data to calculate initial water saturation at each grid-block midpoint.

(e) GOC is used in a similar manner to calculate initial natural gas saturations.

(f) Oil saturation is initialized by setting SO = 1 - SW - SG.

(g) If NSLUGS = 0, a natural gas-water system may be initialized by specifying PWOC = PGOC and WOC = GOC + 1.

(h) If NSLUGS > 0, the program assumes that no solvents are present at initialization, i.e., the gas phase is 100 percent natural gas. If solvents are present at initial conditions, use Record 4, and Record 5 or Record 6 below.

(i) Whenever the WOC and/or GOC are within the reservoir closure, grid-block top/bottom boundaries should coincide with these contacts as closely as possible, assuring greater accuracy in establishing initial saturations.

4. Initial reservoir pressures, psia (KPI = 1) . . . . . (10F)

P - Pressures for the entire grid. The order of input must be as indicated below with layer order K = 1, 2, ..., KK.

```
J  =  1,   I  =  1,  2, ..... II
J  =  2,   I  =  1,  2, ..... II
   .       .     .          .
   .       .     .          .
J = JJ,   I = 1, 2, ..... , II
```

REMARKS: (a) Input this record only if KPI = 1. Saturations will be constant for the entire grid.

(b) This record is used with either Record 5 or Record 6 (KPI = 1 and KSI = 0, or KPI = 1 and KSI = 1).

5. Saturation constants (KPI = 1 and KSI = 0) . . . . . (7F)

SOI - Initial oil saturation
SWI - Initial water saturation
SGI - Initial gas saturation
VS1I - Initial base solvent fraction in the gaseous phase
VS2I - Initial solvent 2 fraction in the gaseous phase
VS3I - Initial solvent 3 fraction in the gaseous phase
VS4I - Initial solvent 4 fraction in the gaseous phase

REMARKS: (a) Input this record only if KPI = 1 and KSI = 0. Saturations will be constant for the entire grid.

(b) Input all saturation values as fractions.

(c) If NSLUGS = 0, do not input solvent fractions in the gaseous phase.

(d) If NSLUGS > 0, input VS1I ...., VSMI where M = NSLUGS.

(e) SOI + SWI + SGI = 1.

(f) If NSLUGS > 0, VS1I + VS2I + VS3I + VS4I = 1.0 - VGG, where VGG is the fraction of natural gas in the gaseous phase.

6. Initial reservoir saturations (KPI = 1 <u>and</u> KSI = 1) . . . . . (10F)

SO - Oil saturations for the entire grid. The order of input must be as indicated in Record 4 above with layer order K = 1, 2, ...,, KK.

SW - Water saturations for the entire grid. The order of input must be as indicated in Record 4 above with layer order K = 1, 2, ..., KK.

VS1 - Base solvent fraction in the gaseous phase for the entire grid (only if NSLUGS $\geq$ 1). The order of input must be as indicated in Record 4 above with layer order K = 1, 2, ..., KK.

VS2 - Solvent 2 fraction in the gaseous phase for the entire grid (only if NSLUGS $\geq$ 2). The order of input must be as indicated in Record 4 above with layer order K = 1, 2, ..., KK.

VS3 - Solvent 3 fraction in the gaseous phase for the entire grid (only if NSLUGS $\geq$ 3). The order of input must be as indicated in Record 4 above with layer order K = 1, 2, ..., KK.

VS4 - Solvent 4 fraction in the gaseous phase for the entire grid (only if NSLUGS $\geq$ 4). The order of input must be as indicated in Record 4 above with layer order K = 1, 2, ..., KK.

REMARKS: (a) <u>Input this record only if KPI = 1 and</u> KSI = 1.

(b) Input all saturation values as a fraction.

(c) If NSLUGS = 0, do not input solvent fractions in the gaseous phase.

(d) If NSLUGS > 0, input VS1 ..., VSM where M = NSLUGS.

(e) Gas saturation distribution will be calculated as SG = 1 - SO - SW.

(f) If NSLUGS > 0, VS1 + VS2 + VS3 + VS4 = 1.0 -VGG, where VGG is the fraction of natural gas in the gaseous phase.

Specifications for the options for pressure and saturation initialization are shown in Table 4.

Table 4. Options for Pressure and Saturation Initialization Code Values

KPI	KSI	Pressure and Saturation Specifications
0	(0 or 1)	Equilibrium pressure and saturation initialization is used; input pressure and elevation values at the water-oil and gas-oil contacts. Arrays P, SW, and SG are initialized and SO is set to 1 - SW - SG. The program assumes no solvents are present at initialization.
1	0	Non-equilibrium pressure and saturation initialization is used; input II x JJ x KK values of P: input constant initial oil, water, and gas saturations (SOI, SWI. SGI); input constant initial solvent fractions in gaseous phase, VS1I .... VSMI where M = NSLUGS.
1	1	Non-equilibrium pressure and saturation initialization is used; input II x JJ x KK values of P; input II x JJ x KK values of SO and SW: SG is set to 1 - SW - SO; input II x JJ x KK values of VS1 ..., VSM where M = NSLUGS.

3.9 Print Codes for Additional Reports

Several print codes have been added to control the printing of additional reports. To print a specified report, set the code equal to 1; otherwise set the code to 0.

1. Header (A80)

2. Print codes for additional reports . . . . . (3I)

   KSW1 - A material balance report is written to a separate file (MASTER.MBE). This report gives the largest, local material balance error for each component and the grid blocks in which the local material balance error occurs for each iteration of each time-step. The elapsed time is shown at the beginning of each time-step.

   KSW2 - The same information for print code KSW1 is printed to the primary output file (MASTER.OUT).

   KSW3 - The number of iterations required for convergence of the iterative solution techniques (SSOR, LSOR, and ORTHOMIN) is printed in the primary output file (MASTER.OUT). If KSW3 and KSW1 = 1, this information is also printed to MASTER.MBE.

3.10 Run Control Parameters

1. Header (A80)

2. Run control parameters . . . . . (1I,7F)

NMAX	-	Maximum number of time-steps per simulation run.
FACT1	-	Factor for increasing time-step size when using automatic time-step control.
FACT2	-	Factor for decreasing time-step size when using automatic time-step control.
TMAX	-	Maximum simulation time per run, days.
WORMAX	-	Limiting maximum field water-oil ratio (WOR), STB/STB; simulation will be terminated if total producing WOR exceeds WORMAX.
GORMAX	-	Limiting maximum field gas-oil ratio (GOR), scf/STB; simulation will be terminated if total producing GOR exceeds GORMAX.
PAMIN	-	Limiting minimum field average pressure, psia; simulation will be terminated if average reservoir pressure falls below PAMIN.
PAMAX	-	Limiting maximum field average pressure, psia; simulation will be terminated if average reservoir pressure exceeds PAMAX.

REMARKS:

(a) GORMAX applies to the total natural gas plus solvent-oil ratio.

(b) For fixed time-step size, specify FACT1 = 1.0 and FACT2 = 1.0 <u>and/or</u> specify DTMIN = DTMAX = DT (see Section 3.15).

(c) For automatic time-step control, set FACT1 > 1.0 and FACT2 < 1.0; typical values are FACT1 = 1.25 and FACT2 = 0.5.

(d) For more detail on automatic time-step control, see Section 5.4.

3.11 Solution Method Specifications

1. Header (A80)
2. Solution method control parameters . . . . . (2I,2F,1I,2F,1I,1F,1I)

KSOL -- Solution method code.

If KSOL = 1, an iterative solution, slice (planar) successive overrelaxation (SSOR), is used. Use this method for two- and three-dimensional problems.

If KSOL = 2, an iterative solution, line successive overrelaxation (LSOR) (Young 1971), is used. Use this method for two- and three-dimensional problems.

If KSOL = 3, a direct solution algorithm, D4 (Price and Coats 1973), is used. Use this method for two-dimensional problems and medium-sized (less than 1,000 grid blocks} three-dimensional problems.

If KSOL = 4, an iterative preconditioned conjugate gradient algorithm is used. This method is preferred over SSOR and LSOR for large two- and three-dimensional problems.

REMARKS: The following four parameters are used only for iterative methods. However, a value must be input even if KSOL = 3.

MITR - For KSOL = 1 and 2, maximum number of SOR iterations for convergence. A typical value is 100.
For KSOL = 4, maximum number of conjugate gradient iterations for convergence. A typical value is 50.

OMEGA - For KSOL = 1 and 2, initial SOR acceleration parameter. The initial value for OMEGA <u>must</u> be in the range 1.0 to 2.0. A typical initial value for OMEGA is 1.20. The model will attempt to optimize OMEGA as the solution proceeds if NCYCLE $\neq$ 0.
For KSOL = 4, not used. However, a value must be input.

TOL - For KSOL = 1 and 2, maximum acceptable SOR pressure convergence tolerance. A typical value is 0.001 psi.
For KSOL = 4, pressure convergence tolerance. Typically between 0.001 and 0.0001 psi.

NCYCLE - For KSOL = 1 and 2, number of SOR iteration cycles for determining when to change (i.e., optimize) OMEGA. A typical value is 12. If NCYCLE = 0, the initial value for OMEGA will be used for the entire simulation.
For KSOL = 4, not used. However, a value must be input.

DSMAX - Maximum saturation change (fraction) permitted over a time step. The time-step size will be reduced by FACT2 (see Section 3.10) if the saturation change of any phase or any component in any grid block exceeds DSMAX <u>and</u> the current step size is greater than DTMIN. If the resulting step size is less than DTMIN, the time step will be repeated with step size DTMIN. A typical value for DSMAX is 0.05.

DPMAX - Maximum pressure change (psi) permitted over a time step. The time-step size will be reduced by FACT2 if the pressure change in any grid block exceeds DPMAX <u>and</u> the current step size is greater than DTMIN. If the resulting step size is less than DTMIN, the time step will be repeated with step size DTMIN. A typical value for DPMAX is 100 psi.

ITMAX - Maximum number of Newton-Raphson iterations per time-step for convergence. A typical value is 5.

RTOL - Maximum acceptable residual for Newton-Raphson convergence. A typical value is 0.001. ITMAX overrides RTOL if RTOL is not reached.

NERR - Material balance error (mbe) control technique code (see Section 5.6). If NERR = 1, the mbe control technique is on. If NERR = 0, the mbe control technique is off. NERR = 1 is suggested.

3.12 Fluid Property Weighting Factor

1. Header (A80)
2. Fluid property weighting factor . . . . .(1F)

   WEIGHT - weighting factor used for formation volume factor and viscosity of oil, water, natural gas, and solvents; solubility of natural gas and Solvents 1-4 in oil; solubility of natural gas and Solvent 1 in water. If WEIGHT = 1.0, upstream properties are used. If WEIGHT = 0.5, average properties are used.

3.13 Transmissibility Modifications

1. Header (A80)
2. Transmissibility modifications . . . . . (5I)

   NUMTX - Number of grid blocks where x-direction transmissibility (TX) is to be changed
   NUMTY - Number of grid blocks where y-direction transmissibility (TY) is to be changed
   NUMTZ - Number of grid blocks where z-direction transmissibility (TZ) is to be changed
   ITCODE - Print code for transmissibility alterations
   If ITCODE = 0, do not print modified transmissibilities
   If ITCODE = 1, print modified transmissibilities
   IPRINT - Print code for transmissibility arrays
   If IPRINT = 1, the transmissibility arrays are printed. These arrays include any modifications.
   If IPRINT = 0, transmissibility arrays are not printed.

3. X-direction transmissibility modifications . . . . . (3I,F)

   I - X-coordinate of block to be modified
   J - Y-coordinate of block to be modified
   K - Z-coordinate of block to be modified
   TX - New x-direction transmissibility (md · ft) for block (I, J, K)

   NOTE: NUMTX records must be read.

4. Y-direction transmissibility modifications . . . . .(3I,F)

   I - X-coordinate of block to be modified
   J - Y-coordinate of block to be modified
   K - Z-coordinate of block to be modified
   TY - New y-direction transmissibility (md · ft) for block (I, J, K)

   NOTE: NUMTY records must be read.

5. Z-direction transmissibility modifications . . . . . (3I,F)

   I - X-coordinate of block to be modified
   J - Y-coordinate of block to be modified
   K - Z-coordinate of block to be modified
   TZ - New z-direction transmissibility (md · ft) for block (I, J, K)

NOTE: NUMTZ records must be read.

REMARKS: It is extremely important to keep in mind the directional convention used in specifying transmissibility modifications. For example, in grid block (I,J,K)

TX(I,J,K) refers to flow across the boundary between blocks (I-1,J,K) and (I,J,K),

TY(I,J,K) refers to flow across the boundary between blocks (I,J-1,K) and (I,J,K), and

TZ(I,J,K) refers to flow across the boundary between blocks (I,J,K-1) and (I,J,K).

CALCULATIONS:

$$TX(I,J,K) = \frac{.012656 * AREA(I,J,K) * KX(I,J,K) * AREA(I-1,J,K) * KX(I-1,J,K)}{\Delta X(I-1,J,K) * AREA(I,J,K) * KX(I,J,K) + \Delta X(I,J,K) * AREA(I-1,J,K) * KX(I-1,J,K)}$$

where

AREA(I,J,K) = DY(I,J,K)*DZ(I,J,K) and
AREA(I-1,J,K) = DY(I-1,J,K)*DZ(I-1,J,K)

For TY(I,J,K), substitute DX for DY, KY for KX, and ΔY for ΔX in the three equations above. Replace (I-1,J,K) with (I,J-1,K)

For TZ(I,J,K), substitute DX for DZ, KZ for KX, and ΔZ for ΔX in the three equations above. Replace (I-1,J,K) with (I,J,K-1)

DX, DY, and DZ are in feet; ΔX, ΔY, and ΔZ are in feet; and KX, KY, and KZ are in millidarcies (mD).

Use the transmissibility modification cards for low permeability barriers, hydraulic fractures (increasing the flow between two blocks), and history matching. Carefully examine the problem to determine which modification cards (porosity and permeability or transmissibility) can best be used.

3.14 Foam Data

3.14.1 Control Codes

1. Header (C80)

2. Foam option . . . . . (1I)

   IFOAM - Input code for foam data
   If IFOAM = 0, do not perform foam calculations
   If IFOAM = 1, read foam-related data

3. Header (C80)

4. Foam calculation method . . . . . (1I)

JCHFM	-	Input code for type of calculation process If JCHFM = 0, use foam equation (reserved for future development) If JCHFM = 1, use table lookup

5. Header (C80)

6. Run control . . . . . (1I, 2F)

MAXITER	-	Maximum number of iterations
EPSC	-	Maximum acceptable error in surfactant equation
EPSN	-	Maximum acceptable error in bubble population balance equation

7. Header (C80)

8. Initial surfactant concentration . . . . . (1F)

CS0	-	Initial concentration in g/g

9. Header (C80)

10. Surfactant adsorption constants . . . . . (4F)

ROR	-	Density of rock in g/cm^3
DELTA	-	Surface area of rock per unit mass in cm^2/g
CKS	-	Absorption factor in g/g
AS	-	Adsorption factor in g/cm^2

11. Header (C80)

12. Header (C80)

13. Limiting conditions for foam formation and foam parameters. . . . . (8F) [

CSLIM	-	Minimum surfactant concentration in the water phase (ppm).
SOLIM	-	Maximum oil saturation
SWLIM	-	Minimum water saturation
SGLIM	-	Minimum gas saturation
QUALIM	-	Minimum quality, volume percent of gas phase
VGLIM	-	Critical gas interstitial velocity (ft/day) [minimum velocity]
RMOBMI	-	Minimum nonzero acceptable foam relative mobility (1/cp) [mobility is defined as permeability divided by viscosity where here what is referred to as relative mobility is related to the relative permeability divided by the viscosity – see section 6.3 for more detail]
FSCAL	-	Scaling factor for the resistance factor

3.14.2 Resistance Factor Tables

1. Header (C80)

2. Header (C80)

3. Number of parameters . . . . . (4I)

NPER	-	Number i of $TPER_n$ permeability entries
NQUA	-	Number j of $TQUA_n$ foam quality entries
NCON	-	Number k of $TCON_n$ brine surfactant concentration entries
NVEL	-	Number l of $TVEL_n$ velocity entries

4. Find below a general example of how a resistance factor look up table (also see example in Section 7.5) will appear in the input: (1) the first permeability will be specified, (2) the first foam quality will be specified, (3) each surfactant concentration will be specified, and (4) each velocity will be specified with the corresponding resistant value for each concentration at the permeability and foam quality indicated. Then the second foam quality will be listed etc. until all qualities are indicated. Finally, the second permeability and so on. The values in the table are arranged as follows with the variables defined in steps 5-12 below:

e.g.: Headers
$TPER_1$
Headers
$TQUA_1$
Headers

	$TCON_1$	$TCON_2$ …	$TCON_k$

Headers

$TVEL_1$	$TRES_{1111}$	$TRES_{1121}$ …	$TRES_{11k1}$
$TVEL_2$	$TRES_{1112}$	$TRES_{1122}$ …	$TRES_{11k2}$
…			
$TVEL_l$	$TRES_{111l}$	$TRES_{112l}$…	$TRES_{11kl}$

Headers
$TQUA_2$
Headers

	$TCON_1$	$TCON_2$ …	$TCON_k$

Headers

$TVEL_1$	$TRES_{1211}$	$TRES_{1221}$ …	$TRES_{12k1}$
$TVEL_2$	$TRES_{1212}$	$TRES_{1222}$ …	$TRES_{12k2}$
…			
$TVEL_l$	$TRES_{121l}$	$TRES_{122l}$…	$TRES_{12kl}$

....

Headers
$TQUA_j$
Headers

	$TCON_1$	$TCON_2$ …	$TCON_k$

Headers

$TVEL_1$	$TRES_{1j11}$	$TRES_{1j21}$ …	$TRES_{1jk1}$
$TVEL_2$	$TRES_{1j12}$	$TRES_{1j22}$ …	$TRES_{1jk2}$
…			
$TVEL_l$	$TRES_{1j1l}$	$TRES_{1j2l}$…	$TRES_{1jkl}$

...

Headers
$TPER_i$
Headers
$TQUA_1$

....

3. Header (C80)

4. Header (C80)

5. Permeability. . . . . (1F)

   TPER - Permeability

6. Header (C80)

7. Header (C80)

8. Foam Quality. . . . . (1F)

   TQUA - Quality
   (Note: NQUA number of TQUA entries for each TPER entry)

9. Header (C80)

10. Header (C80)

11. Concentration . . . . . (1F)

    TCON - Concentration of surfactant in brine
    (Note: must have NCON number of values in TCON.)

12. Header (C80)

13. Header (C80)

14. Velocity and resistance factors . . . . . (5F)

    TVEL - Velocity in ft/day (Note: must have NVEL lines)
    TRES - Resistance factor
    (Note: each line must contain NCON resistance factors, and each table must contain NVEL lines.)

3.15 Recurrent Data

During the course of a simulation run, it is conventional to be able to

1. Add or delete injection or production wells,
2. Control injection and production rates and bottom-hole pressure constraints at all existing wells, and
3. Specify the types and frequency of output.

These types of controls and output specifications are accomplished in this model by recurrent data records.

3.15.1 Control Codes and Time-step Data

The parameter IWREAD of the first recurrent data record specifies whether or not to read well information. If IWREAD = 0, only output control codes and time-step control data are read. If IWREAD = 1, well information is read immediately following the time-step control data. In either case, the simulator advances until the specified elapsed time has occurred. During this period, all print codes and the latest well information apply. Thus, output control codes and time-step control data can be changed during a simulation without restating the well information.

1. Header (A80)

2. Well information and output control codes . . . . . (14I5)

IWREAD	-	If IWREAD = 0, well information is not read this step If IWREAD = 1, well information is read this step
ICHANG	-	Number of time steps for calculating the time period "ITIME" for which the output control codes, time-step control data, and well information will apply
IWLREP	-	Output code for printing well report
ISUMRY	-	Output code for printing summary report
IPMAP	-	Output code for printing pressure distribution
ISOMAP	-	Output code for printing oil saturation distribution
ISWMAP	-	Output code for printing water saturation distribution
ISGMAP	-	Output code for printing total gas saturation distribution
IPBMAP	-	Output code for printing bubble point pressure distribution
IRSMAP	-	Output code for printing natural gas solubility distribution
IS1MAP	-	Output code for printing base solvent fraction distribution
IS2MAP	-	Output code for printing solvent 2 fraction distribution
IS3MAP	-	Output code for printing solvent 3 fraction distribution
IS4MAP	-	Output code for printing solvent 4 fraction distribution

REMARKS:

(a) Output control codes, time-step control data, and well information will apply for the time period ITIME, where <u>ITIME = ICHANG x DT</u>. DT is the time-step size as read on the following record. If ICHANG = 6 and DT = 10 days, ITIME = 60 days. At the end of this time period, a new set of output control codes, time-step control data, and well information must be specified. If no new well information is specified (IWREAD = 0), the latest well information will apply.

(b) Set the output code = 1 to print the information each time-step during this period. If the information is not desired, set the output code = 0.

(c) The actual number of time-steps used may differ from ICHANG if automatic time-step control is on.

(d) If NSLUGS = 0, IS1MAP, IS2MAP, IS3MAP, and IS4MAP are not used.

(e) If NSLUGS > 0 and MOBCTL = 1 (see Section 3.7), setting ISWMAP = 1 also gives surfactant water distributions, x_s and S_c.

(f) Solvent fraction is defined as the ratio of the total amount of solvent present (in both the gaseous phase and the solution gas) to the maximum possible amount of solvent that would exist if the solvent was the only soluble component present at those conditions.

3. Time-step control data . . . . . (3F10.0)

DT	-	Time-step size (days) for this period
DTMIN	-	Minimum time-step size (days) for this period
DTMAX	-	Maximum time-step size (days) for this period

REMARKS: (a) If the automatic time-step control is on, DT will be the initial time-step size. If the automatic time-step control is off, ICHANG time-steps of size DT days will be taken.

(b) Common values for DTMIN and DTMAX are 0.1 and 30.0 days, respectively.

(c) Automatic time-step control can be overridden by specifying DTMIN = DTMAX = DT. However, it is more convenient to set FACT1 = FACT2 = 1.0 (see Section 3.10) and specify values for DTMIN and DTMAX. In this way, automatic time-step control can easily be turned on by changing FACT1 and FACT2.

NOTE: Well information and output control codes, time-step control data, and well information should be input until the cumulative time, as given by the summation of ICHANG x DT, exceeds the maximum desired simulation time. The simulation will terminate if EOF (end-of-file) is encountered due to no more recurrent data or when NMAX or TMAX are exceeded (see Section 3.10).

3.15.2 Well Information Records

If IWREAD = 1, well information is read and should immediately follow the time-step control data. If IWREAD = 0, the previous well information applies; well information records should not appear in the input data file.

1. Header (A80)

2. Number of wells; surfactant injection code . . . . . (2I5)

NVQN	-	Number of wells for which information is to be read
KSIS	-	Surfactant-water injection code

REMARKS: (a) Wells may be added or recompleted at any time during the simulation. However, once a well has been specified, it must be included when well information is read, even if the well is shut in during that time-step.

(b) If KSIS = 1 <u>and</u> KIP = 2, -2, or -12, injected water is assumed to contain surfactant for use as a gas phase mobility control agent.

3. Well name (A5)

WELLID	-	Five alphabetical and/or numerical well name

4. Well location and control information . . . . . (5I5, 5F10.0)

I	-	X-coordinate of grid block containing the well
J	-	Y-coordinate of grid block containing the well
PERF1	-	Layer number of the uppermost layer completed
NLAYER	-	Number of <u>consecutive</u> completion layers (including PERF1)
KIP	-	Code for specifying type of well control (see Tables 5a and 5b)
QO	-	Oil rate: STB/d (nonzero only if KIP = 1 and QT = 0.0)
QW		Water rate: STB/d (nonzero only if KIP= 2)
QG	-	Natural gas rate: Mcf/d (nonzero only if KIP = 3)
QT	-	Total rate: STB/d (nonzero only if KIP = 1 and QO = 0.0)
QS	-	Solvent rate: Mcf/d (nonzero only if KIP = 100, 200, 300, or 400)

REMARKS:

(a) Tables 5a and 5b summarizes all well control options.

(b) Section 5.2 gives detail on the mathematics of the well options.

(c) NLAYER must include all layers from PERF1 to the lowermost layer completed. For example, in a 5-layer model, if a well is completed in layers 2, 3, and 5, specify PERF1 = 2 and NLAYER = 4. Layer 4 may be shut in by specifying PI = 0.0 (see Record 5 below).

(d) Record 4 must appear NLAYER times to complete the required input data for a well.

(e) Negative rates indicate fluid injection; positive rates indicate fluid production.

(f) QT is the total reservoir voidage rate of oil, water, natural gas, and solvents at stock tank conditions.

(g) Only one of the five values (QO, QW, QG, QT, or QS) may be nonzero if KIP > 0. If KIP < 0, all five values should be zero.

(h) For KIP = -1 through -7, explicit pressure calculations are performed to determine well rates. For KIP = -11 through -17, implicit pressure calculations are performed to determine well rates.

(i) For most applications, implicit pressure calculations are recommended.

(j) If KIP = 2, -2, or -12, <u>only</u> <u>water</u> will be injected; if KIP = 3, -3, or -13, <u>only</u> <u>gas</u> will be injected.

(k) If KIP =100, 200, 300, 400, -4 to -7, or -14 to -17, <u>only</u> solvents will be injected.

(l) Solution gas is not considered if $2 \leq KIP \leq 400$. Therefore, the option of specifying the rate (QW, QG, or QS) as a positive number (indicating a production well) is not recommended.

(m) Production wells (KIP 1, -1, or -11) appear on both the output well summary report and the solvent injection/production summary report.

(n) Wells with KIP = 2, 3, -2, -3, -12, or -13 appear only on the output well summary report.

(o) Wells with KIP = 100, 200, 300, 400, -4, -5, -6, -7, -14, -15, -16, or -17 appear only on the output solvent injection/production report.

Table 5a. Options for Controlling Well Performance

Code	Value	Well	Rate Specifications
KIP	1	Production well:	Specify oil production rate, QO, or total production rate, QT
KIP	2	Water injection well:	Specify water injection rate, QW
KIP	3	Natural gas injection well:	Specify gas injection rate, QG
KIP	100	Solvent injection well:	Specify base solvent injection rate, QS
KIP	200	Solvent injection well:	Specify solvent 2 injection rate, QS
KIP	300	Solvent injection well:	Specify solvent 3 injection rate, QS
KIP	400	Solvent injection well:	Specify solvent 4 injection rate, QS

Table 5b. Options for Controlling Well Performance: Explicit Calculations

Code	Value	Well	Rate Specifications
KIP	-1	Production well	Oil, water, gas, and solvent production rates will be calculated based on individual fluid mobilities of each layer and PI and PWF (see Item 6 below and remarks at the end of the section) of each layer. The well will be shut in if block pressure < PWF.
KIP	-2	Water injection well:	Water injection rate will be calculated based on total mobility (oil, water, gas, and solvents) of each layer and PI and PWF of each layer. The well will be shut in if block pressure > PWF.
KIP	-3	Gas injection well:	Gas injection rate will be calculated based on total mobility (oil, water, gas, and solvents) of each layer and PI and PWF of each layer. The well will be shut in if block pressure > PWF.
KIP	-4 -5 -6 -7	Solvent injection well:	Solvent injection rate will be calculated based on total mobility (oil, water, gas, and solvents) of each layer and PI and PWF of each layer. The well will be shut in if block pressure > PWF. Solvent 1 will be injected if KIP = -4 Solvent 2 will be injected if KIP = -5 Solvent 3 will be injected if KIP = -6 Solvent 4 will be injected if KIP = -7
KIP	-11	Production well:	Oil, water, gas, and solvent production rates will be calculated based on individual fluid mobilities of each layer and PI and PWF (see item 6 below and remarks at the end of the section) of each layer. The well will be shut in if block pressure < PWF.
KIP	-12	Water injection well:	Water injection rate will be calculated based on total mobility (oil, water, gas, and solvents) of each layer and PI and PWF of each layer. The well will be shut in if block pressure > PWF.
KIP	-13	Natural gas inj. well:	Gas injection rate will be calculated based on total mobility (oil, water, gas, and solvents) of each layer and PI and PWF of each layer. The well will be shut in if block pressure > PWF.
KIP	-14 -15 -16 -17	Solvent injection well:	Solvent injection rate will be calculated based on total mobility (oil, water, gas, and solvents) of each layer and PI and PWF of each layer. The well will be shut in if block pressure > PWF. Solvent 1 will be injected if KIP = -14 Solvent 2 will be injected if KIP = -15 Solvent 3 will be injected if KIP = -16 Solvent 4 will be injected if KIP = -17

5. Well direction input codes . . . . . (3I) [enter on same line as well location and control information in Item 4 above].

IDIR - Direction code
If IDIR = 1: Well axis along i-direction (x-direction) (horizontal well, not extensively tested),
If IDIR = 2: Well axis along j-direction (y-direction) (horizontal well feature, not extensively tested),
If IDIR = 3: Well axis along k-direction (z-direction) (vertical well)

IWM - Code for method of calculation of the productivity index
If IWM = 1: use Babu et al (1991) scheme
If IWM = 0: use Peaceman (1978) scheme

ISWITH - Flag for changing well type
If ISWITH = 1: change
If ISWITH = 2: no change

6. Pressure and well radius information . . . . . (2F)

RW - Well radius in ft

PWF - Layer flowing bottom-hole pressure, psia

7. Foam input . . . . . (nF where n ≤ NVQN)

This data is required if IFOAM = 1

XSI - Surfactant concentration in ppm (use if KIP(I) = +2,-2,-12).
Note: This list must contain NWINJ number of values, where NWINJ is the number of water injection wells at which surfactant is added. Depending on the way the input data is organized, NWINJ may vary from 1 to NVQN. For water injection wells that injection rate is zero or surfactant is not added, XSI = 0.0.

-and / or-

BNF - Bubble density, number of bubbles per ft^3 (use if KIP(I) = +1,-1,-11).
Note: This list must contain NSINJ number of values, where NSINJ is the number of solvent injection wells at which foam is added. Depending on the way the input data is organized, NSINJ may vary from 1 to NVQN. For solvent injection wells when the injection rate is zero or foam is not added, BNF = 0.0.

REMARKS: (a) When a rate is specified (i.e., KIP > 0) for a well <u>and</u> PI is nonzero, the specified rate and PI will be used to calculate and print a flowing bottom-hole pressure. However, the calculated pressure will not be used to control well performance.

(b) When a well is specified as a pressure-controlled well (i.e., KIP < 0) and multiple layers are completed, use a fluid gradient to calculate layer PWF's below the top producing layer.

(c) Once a well is completed in any layer, that well and that layer must be specified each time well information cards are read.

(d) To shut in a layer, set the layer PI = 0.0. To shut in a well, set its injection or production rate = 0.0; do <u>not</u> set all its layer PI's = 0.0.

(e) The layer PI can be calculated from the following equation:

$$PI = \frac{0.00708(kh)}{\ln\left(r_{eq}/r_w\right) + s} \quad ,$$

where r_{eq} is the equivalent radius of the well block in ft, r_w (RW) is the wellbore radius in ft, h is the z-dimension of the block in ft, k is the mean x-y permeability in md, and s is the layer skin factor. For a well centered in a square ($\Delta x = \Delta y$) or rectangular ($\Delta x \neq \Delta y$) grid blocks with the following geometry,

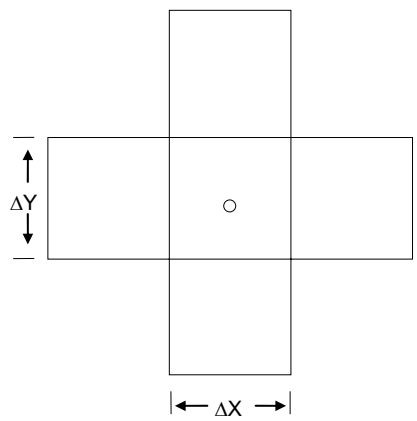


FIGURE 2.
Grid System for Five-Point Formation Formulation
(After Peaceman, 1982)

the radius r_{eq} may be calculated (Peaceman, 1982) according to the following equations:

Isotropic Medium: $k_x = ky$

$$r_{eq} = 0.14\ (\Delta x^2 + \Delta y^2)^{1/2}$$

Anisotropic Medium: $k_x \neq k_y$

$$r_{eq} = 0.28 \frac{\left[\left(k_y / k_x\right)^{1/2} \Delta x^2 + \left(k_x / k_y\right)^{1/2} \Delta y^2\right]^{1/2}}{\left(k_x / k_y\right)^{1/4} + \left(k_y / k_x\right)^{1/4}}$$

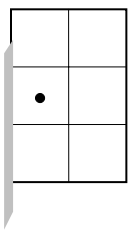
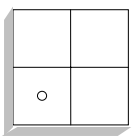
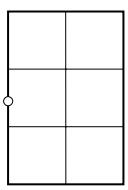
where

Δx = x-direction grid block length in ft,
Δy = y-direction grid block length in ft,

k_x = x-direction permeability in md, and
k_y = y-direction permeability in md.

For square ($\Delta x = \Delta y$), isotropic (kx = ky grid blocks with the following geometries, the radius r_{eq} may be calculated (Kuniansky and Hillestad, 1980) from the following table:

Table 6. Calculated Equivalent Radii for Square Grid Blocks (After Kuniansky and Hillestad 1980)

Well Placement	r_{eq}
	$e^{-(2\pi - \ln 4)/3} \cdot \Delta x = 0.1955 \cdot \Delta x$
	$e^{-(2\pi - \ln 20)/2} \cdot \Delta x = 0.1932 \cdot \Delta x$
	$e^{-(\pi - \ln 15 + 3\ln 2)/3} \cdot \Delta x = 0.4327 \cdot \Delta x$
	$e^{-(\pi/2. - \ln 2.5)/2} \cdot \Delta x = .72 \cdot \Delta x$

where Δx = the length in ft of a side of the square grid block. When several wells are located in one block, r_{eq} can be determined by the methods described Kuniansky and Hillestad (1980).

4.0 INTERPRETATION OF MODEL OUTPUT

4.1 Primary Output File: MASTER.OUT

Output data are available at user-specified levels of detail for any given simulation run with MASTER. During model start-up, essentially all data input is echoed in the primary output file (MASTER.OUT). In addition to providing a complete, stand-alone report, this provides an excellent opportunity to quickly check for input data errors. Except for the echoed data, all output printed to the primary output file is controlled with print codes. Controls for the well and summary reports and distribution maps are found in the recurrent data section (see Section 3.14). These data can be printed as often as every time-step or can be completely turned off. The output data may include the following reports and/or maps:

1. Well report.
2. Summary report.
3. Reservoir pressure distribution.
4. Fluid saturation (oil, water, and total gas) distribution.
5. Solvent fraction distribution.
6. Hydrocarbon gas solubility distribution.
7. Bubble-point pressure distribution.

In addition, the maximum material balance error over each time-step for each component may be printed each time-step (see Section 3.9).

4.1.1 Echoed Input Data

A list of the input data that is echoed at model start-up is given below.

1. Grid-block dimensions.
2. Grid-block midpoint elevations.
3. Porosity and permeability distributions.
4. Relative permeability and capillary pressure data.
5. Oil-water-natural gas PVT data.
6. Slopes calculated from oil-water-natural gas PVT data for use in determining fluid compressibilities.
7. The number of solvents.
8. Mixing parameters and miscibility control options.
9. Solvent PVT datasets and calculated slopes for compressibility calculations.

10. Mobility reduction table.

11. Solubility weighting, solution method parameters, and run control parameters.

12. Initial fluids in place by layer and total fluid in all layers.

13. Initial reservoir pressure, fluid saturation, hydrocarbon gas solubility, and bubble-point pressure distributions.

14. Initial well locations and well control information.

4.1.2 Well Report

A well report may be specified at any time-step during the simulation by setting IWLREP = 1 (see Section 3.15) in the input file. Each time a well report is specified, oil, water, and natural gas production and injection rates and cumulative oil, water, and natural gas production and injection for each layer of each well are tabulated. If one or more solvents are included in the simulation, a solvent report accompanies the well report. This solvent report is comprised of solvent production and injection rates and cumulative solvent production and injection for each layer of each well. Several examples of well reports and solvent reports can be found in Section 9.0.

4.1.3 Summary Report

The summary report may be specified at any time-step during the simulation by setting ISUMRY = 1 (see Section 3.15) of the input file. The summary report contains all pertinent field injection and production performance information including:

1. Average reservoir pressure;
2. Total field oil, water, gas, and solvent production rates and cumulative production;
3. Total field water, gas, and solvent injection rates and cumulative injection;
4. Current and cumulative total field water-oil, gas-oil (natural gas and solvent), and base solvent-oil producing ratios;
5. Time-step and cumulative material balances for oil, water, gas, and each solvent; and
6. Maximum pressure and maximum oil, water, gas, and solvent saturation changes for the current time-step.

Several examples of summary reports can be found in Section 9.0.

The summary report file provides useful warning messages, such as maximum pressure and maximum fluid saturation changes, and material balance errors. Excessive changes in pressure or saturation, usually greater than 150 psi and 0.05, respectively, and large material balance errors usually indicate a problem in the simulation run. The most common causes for these errors are either large time-steps or large fluid injection and production rates. Both causes result in a large volume of fluid moving through a given grid block, which cannot be handled by IMPES.

4.1.4 Pressure and Saturation Distribution Maps

The following distribution maps can be printed at any time-step during the simulation by setting the appropriate MAP codes = 1 (see Section 3.15) in the input file:

1. Reservoir pressure;
2. oil, water, and total gas saturation;
3. solvent 1 through 4 fractions; and
4. bubble-point pressure.

If the mobility control option is on, then in addition to the water saturation distribution, distribution maps of the fraction of water-containing mobility control agent and the concentration of mobility control agent are also printed. Examples of the distribution maps are given in Section 9.0.

The distribution maps can also provide warning messages. Signs of problems with the simulation run are negative saturations, abrupt changes in fluid saturations between neighboring grid blocks, and fluid saturation summations that are greater than 1 for a grid block. For large two- and three-dimensional problems, an enormous output file can be generated if the distribution maps are printed frequently. Therefore, use discretion when printing these maps.

4.2 Executive Summary Table: MASTER. SUM

In addition to the primary output file (MASTER.OUT), an executive summary output file that contains pertinent field performance information is generated. A one-line production summary for the entire field is given for each time step. This file is written to MASTER.SUM and is not controlled by the user. This file is most useful for quickly evaluating reservoir performance and determining if simulation problems exist. If production rates, or gas-oil or water-oil ratios, fluctuate with each time-step, problems may exist in the simulation. These fluctuations are usually a sign that a reduced time-step size is needed. An example of the executive summary table has been provided in Section 9.0. The variables and their units are defined in the list below.

N	=	Time-step number.
TIME	=	Cumulative simulation time, days.
OPR	=	Oil production rate for current time-step, STB/d.
CUMOIL	=	Cumulative oil production, STB.
WPR	=	Water production rate for current time-step, STB/d.
CUMWAT	=	Cumulative water production, STB.
WOR	=	Water-oil ratio for current time-step, STB/STB.
GPR	=	Gas production rate for current time-step, Mcf/d.
CUMGAS	=	Cumulative gas production, Mcf.
GOR	=	Gas (natural gas and solvent)-oil ratio for current time-step, scf/STB.
S1PR	=	Solvent 1 production rate for current time-step, Mcf/d.
CUMS1	=	Cumulative solvent 1 production, Mcf.
S1OR	=	Solvent 1 gas-oil ratio for current time-step, scf/STB.

4.3 Material Balance Error Report: MASTER.MBE

An option is also available to generate a material balance error report that can be printed as part of the primary output file (MASTER.OUT) or as a separate file written to MASTER.MBE (see Section 3.9). The material balance error that is reported is the largest, local material balance error for each component. The block number in which these errors occur and the magnitude of the error are printed each iteration of every time-step. The elapsed time is also printed at the beginning of each time-step. The block number, L (see Figure 1), is calculated as

$$L = i + (j-1)I + (k-1)IJ,$$

where, I = total number of grid blocks in the x-direction,
J = total number of grid blocks in the y-direction, and
i,j,k = indices of the current grid block.

5.0 CONVENTIONAL MODEL FEATURES

This section contains descriptions of the conventional features that are included in MASTER. These features include: (1) a pressure and saturation initialization algorithm, (2) well specification and control options, (3) a bubble-point tracking scheme, (4) an automatic time-step control feature, and (5) material balance calculations for each fluid phase or component. These options and calculations are discussed in order to allow the correct choice of variable values and options to be made.

5.1 Pressure and Saturation Initialization

MASTER contains an option to calculate both pressure and saturation initialization based on gravity-capillary pressure equilibrium. Gas-oil and water-oil capillary pressure curves, initial locations of the gas-oil and water-oil contacts, initial pressures at these contacts, and grid-block midpoint elevations are used to calculate the initial pressure and saturation distributions if this option is invoked.

For illustrating the procedure used to initialize pressure and saturations, the following notation will be used (variable names from Section 3.0 are used where possible):

WOC	=	Elevation of water-oil contact, ft
GOC	=	Elevation of gas-oil contact, ft
EL	=	Grid-block midpoint elevation, ft
PWOC	=	Pressure at water-oil contact, psia
PGOC	=	Pressure at gas-oil contact, psia
P	=	Initial grid-block oil phase pressure, psia
RW_{WOC}	=	Water density at water-oil contact, lbm/ft^3
RO_{WOC}	=	Oil density at water-oil contact, lbm/ft^3
RO_{GOC}	=	Oil density at gas-oil contact, lbm/ft^3
RG_{GOC}	=	Gas density at gas-oil contact, lbm/ft^3
PCOW	=	Water-oil capillary pressure, psi
PCGO	=	Gas-oil capillary pressure, psi
SWI	=	Initial grid-block water saturation, fraction
SGI	=	Initial grid-block gas saturation, fraction
SOI	=	Initial grid-block oil saturation, fraction
S_{wr}	=	Irreducible water saturation, fraction
SLI	=	Initial grid-block liquid saturation, fraction

Typical water-oil and gas-oil capillary pressure curves are shown below in Figure 3 and Figure 4.

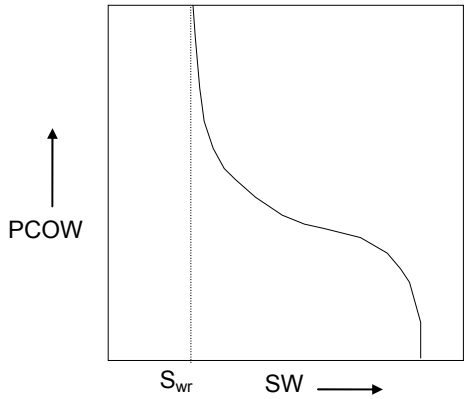


FIGURE 3.
Water-Oil Capillary Pressure Curve

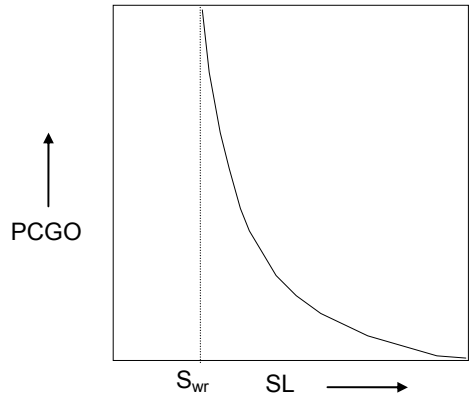


FIGURE 4.
Gas-Oil Capillary Pressure Curve

The general form of the capillary pressure equation is:

$$P_c = \Delta\rho g h$$

where $\Delta\rho$ is the difference between the densities of the two fluids in the system, water and oil or gas and oil. The oil and water densities at the water-oil contact are calculated based on the user-input pressure at that contact, PWOC. Similarly, the oil and gas densities at the gas-oil contact are calculated based on the user-input pressure at the gas-oil contact, PGOC. The water-oil capillary pressure is then calculated for the grid block at midpoint elevation EL as:

$$PCOW = (RW_{WOC} - ROWOC)/144 \cdot (WOC - EL) \quad .$$

Note that the elevations WOC, GOC, and EL are the distances <u>below</u> the reference datum. The initial water saturation for the grid block at midpoint elevation EL is calculated based on PCOW as follows:

If PCOW $\geqq$ PCOW @ S_{wr}, SWI = SWR

If PCOW $\leqq$ PCOW @ SW = 100%, SWI = 100%

If PCOW @ SW = 100% < PCOW < PCOW @ S_{wr} , SWI = interpolated value from the user-input water-oil capillary pressure table.

The oil-gas capillary pressure is then calculated for the grid block at midpoint elevation EL from the following equation:

$$PCGO = (RO_{GOC} - RG_{GOC})/144 \cdot (GOC - EL)$$

The initial gas and oil saturations for the grid block at midpoint elevation EL are calculated based on PCGO and the previous calculation of SWI as follows:

If PCGO $\geqq$ PCGO @ SL = 100% , SGI = 0.0 and SOI = 1.0 - SWI - SGI .

If PCGO @ SL = 100% < PCGO < PCGO @ SL = S_{wr} , SGI = interpolated value from the user-input gas-oil capillary pressure table, and SOI = 1.0 - SWI - SGI.

If PCGO $\geqq$ PCGO @ SL = S_{wr} , SGI = 1.0 - SWI and SOI = 0.0 .

The initial reservoir oil phase pressure, P, is calculated using one of three equations based on the outcome of the saturation calculations.

Case 1: If SWI = 100%
P = PWOC + RW_{WOC} · (EL - WOC)/144 + PCOW
@ SW = 100%

Case 2: If SOI > 0%
P = PWOC - RO_{WOC} · (WOC - EL)/144

Case 3: If SGI > 0% <u>and</u> SOI = 0%
P = PWOC + RO_{WOC} (EL - WOC)/144 +
RO_{GOC} (GOC-EL/144 + RG_{GOC} (EL-GOC)/114 - PCGO @ SG = 100%

When using the pressure and saturation initialization routine or when initializing pressure and saturations manually, be certain that the system is in equilibrium (if the system is representing a virgin reservoir). When using the initialization routine, be aware of the following: (1) the pressure at the gas-oil contact, PGOC, should be equal to (and actually is) the bubble-point pressure, (2) since the oil column is continuous between the oil-water contact and the gas-oil contact, PGOC = PWOC + RO_{WOC} (WOC-GOC), (3) at midpoint elevations where the oil phase is no longer continuous, the initial oil phase pressure is based on the water or gas phase gradient (see Cases 1 and 3) and the capillary pressure at 100 percent fluid saturation, and (4) if the total thickness of a grid-block is within a transition zone, use pseudo-capillary curves. Transition zone thickness is calculated using the following equation:

$$\Delta Z_{TRANS} = \frac{PCWO\ @\ SW = S_{wr} - PCWO\ @\ SW = 100\%}{|\gamma_w - \gamma_o|}$$

where γ is the fluid gradient in psi/ft (substitute gas for water to calculate ΔZ_{TRANS} for the oil-gas region).

5.2 Well Specification and Control Options

Well representation and control are an integral part of any reservoir simulator. When simulating three-phase flow in three dimensions, a major task is to provide options for all the well constraint cases that may be imposed in actual oil field operations.

Basically, a well may be either rate- or pressure-controlled. An injection well is rate-controlled by specifying the injection rate of a component at stock tank conditions. A production well is rate-controlled by specifying either the oil production rate or the total production rate at stock tank conditions. The bottom-hole injection or producing pressure is normally calculated and printed for rate-controlled wells.

Wells are pressure-controlled by specifying the bottom hole flowing pressure. At injection wells, the injection rate of the phase or component is calculated based on total fluid mobility within the grid block containing the well. At production wells, the production rate of each component is calculated based on the specified pressure and the local mobility of each component. Source terms generated by pressure-controlled wells may be treated either explicitly or implicitly.

MASTER includes all the well control options for oil, water, and natural gas injection or production wells, with extensions to provide for solvent injection and production of soluble components at oil

production wells. The mathematical basis for these options is presented below. Unless otherwise specified, all mobilities, formation volume factors, and solubilities are evaluated at time level n. Also, the factor 5.615 is used with the productivity index (PI) in the code to convert each source term from STB/d to stock tank ft^3/d. The following notation and definitions are used throughout (variable names from Section 3.0 are used where possible):

Notation

BJ	=	Formation volume factor of component J (oil, water, natural gas, and solvent), res vol/stock tank vol
K	=	Number of layers through which well is completed
M	=	Mobility, 1/cp
P	=	Layer grid-block pressure, psia
PI	=	Layer productivity index, bbl/psi
PWF	=	Bottom-hole flowing pressure, psia
QJ	=	Production or injection rate @ stock tank conditions for component J (oil, water, natural gas, and solvent), ft^3/d
r_{eq}	=	Equivalent radius of grid block, ft
r_w	=	Wellbore radius, ft
RSO	=	Solution natural gas-oil ratio, scf/STB
RSOSJ	=	Solution gas-oil ratio for solvents (J = 1, 2, 3, 4), scf/STB
RSW	=	Solution natural gas-water ratio, scf/STB
RSWSJ	=	Solution gas-water ratio for solvents (zero for J > 1), scf/STB
v	=	Volume fraction of soluble component, fraction

Subscripts

g	=	Gas
k	=	General layer number (i.e., k = 1, 2, ..., K)
o	=	Oil
sj	=	Solvent j (j = 1, 2, 3, or 4)
w	=	Water

Operators

$SUM[(X)_k] = X_1 + X_2 + ... + X_K$

Case 1: Rate-Controlled Well -- Oil production rate, QO, specified

Oil, water, gas, and solvent production rates for layer k are obtained as follows:

Oil:

$$QO_k = QO \cdot (PI \cdot M_o/BO)_k/SUM[(PI \cdot M_o/BO)_k] \quad 5\text{-}1$$

Water:

$$QW_k = (M_w/BW)_k/(M_o/BO)_k \cdot QO_k \quad 5\text{-}2$$

Gas:

$$QG_k = (M_g/BG)_k/(M_0/BO)_k \cdot Qo_k + vg \cdot (RSO_k \cdot QO_k + RSW_k \cdot QW_k) \qquad 5\text{-}3$$

Solvents:

$$QS_{sjk} = (M_{sj}/BS_{sj})_k/(M_o/BO)_k \cdot QO_k + v_{sj} \cdot (RSOSJ_k \cdot QO_k + RSWSJ_k \cdot QW_k) \qquad 5\text{-}4$$

Case 2: Rate-Controlled Well -- Total production rate, QT, specified

The total oil production rate is first calculated from

$$QO = [SUM(M_O)_k/(SUM(M_O)_k + SUM(M_w)_k + SUM(M_g)_k + SUM(M_{sj})_k)] \cdot QT$$

Then we proceed to use Equations 5-1 to 5-4 as in Case 1 to calculate individual rates for each layer.

Case 3: Rate-Controlled Well -- Injection rate specified

Note that the allocation of the injection fluid to each layer is based on the ratio of total oil, water, natural gas, and solvent mobility of a layer to the total oil, water, natural gas, and solvent mobilities for all layers. This is done to avoid the unrealistic case at the beginning of injection wherein calculated injection rates could be zero because of zero relative permeability to the injected fluid. After a few time-steps, the mobility of the injected fluid will dominate. Thus, the small error introduced by this technique will normally be insignificant.

Water Injection Well -- Rate QW specified

$$QW_k = QW \cdot (PI \cdot (M_0+M_w+M_g+M_{sj}))_k/SUM[(PI \cdot (M_o+M_w+M_{sj}))_k]$$

Gas Injection Well -- Rate QG specified

$$QG_k = QG \cdot (PI \cdot (M_0+M_w+M_g+M_{sj}))_k/SUM[(PI \cdot (M_o+M_w+M_g))_k]$$

Solvent Injection Well -- Rate QS_{sj} specified

$$QS_{sjk} = QS_{sj} \cdot (PI \cdot (M_0+M_w+M_g+M_{sj}))_k/SUM[(PI \cdot (M_o+M_w+M_g+M_{sj}))_k]$$

Case 4: Explicit Pressure-Controlled Well -- PWF specified

Production Well

$$QO_k = (PI_k \cdot M_{ok}/BO_k)^n \cdot (P^n - PWF)_k$$

Water, gas, and solvent rates are obtained from Equations 5-2 to 5-4, where all mobilities and formation volume factors are evaluated at time-level n.

Water Injection Well

$$QW_k = [(PI \cdot (M_0+M_w+M_g+M_{sj}))_k/BW_k]^n \cdot (P^n - PWF)_k$$

Gas Injection Well

$$QG_k = [(PI \cdot (M_0+M_w+M_g+M_{sj}))_k/BG_k]^n \cdot (P^n - PWF)_k$$

Solvent Injection Well

$$QS_{sjk} = [(PI \cdot (M_0+M_w+M_g+M_{sj}))_k/BS_{sjk}]^n \cdot (P^n - PWF)_k$$

Note that the allocation of the injection fluids is based on the total oil, water, natural gas, and solvent mobility of the layer. This procedure is used to avoid the unrealistic case at the beginning of injection as discussed above for rate-controlled injection wells.

Case 5: Implicit Pressure-Controlled Well -- PWF specified

Production Well

$$QO_k = (PI_k \cdot M_{ok}/BO_k)^n \cdot (P^{n+1} - PWF)_k \qquad 5\text{-}5$$

$$QW_k = (PI_k \cdot M_{wk}/BW_k)^n \cdot (P^{n+1} - PWF)_k \qquad 5\text{-}6$$

$$QG_k = (PI_k \cdot M_{gk}/BG_k)^n \cdot (P^{n+1} - PWF)_k + vg \cdot (RSO_k \cdot QO_k + RWS_k \cdot QW_k) \qquad 5\text{-}7$$

$$QS_{sjk} = (PI_k \cdot M_{sjk}/BS_{sjk})^n \cdot (P^{n+1} - PWF)_k + v_{sj} \cdot (RSOSJ_k \cdot QO_1 + RSWSJ \cdot QW_k) \qquad 5\text{-}8$$

The right-hand sides of Equations 5-5 to 5-8 are used to replace the source terms in the pressure equation when implicit controlled wells are specified. Collecting terms and simplifying, the source terms are treated implicitly by modifying the main diagonal, E, and the right-hand side vector, B, of the resulting seven-diagonal system of linear equations. These modifications are detailed in the Technical Manual.

After modifying the main diagonal and right-hand side vector, B, and solving for new pressures, P^{n+1}, at each node, Equations 5-5 to 5-8 are used to calculate implicit production rates for each layer. Natural gas and solvent solubilities in Equations 5-7 and 5-8 are evaluated at time-level n to be consistent with n-level mobilities and formation volume factors.

Injection Wells

For water, natural gas, and solvent injection wells, the same basic procedure described above for production wells is used. However, solubilities are zero, and care must be taken to retain only the appropriate terms when modifying arrays E and B.

Water Injection Well

$$QW_k = [PI_k \cdot (M_0+M_w+M_g+M_{sj})_k/BW_k]^n \cdot (P^{n+1} - PWF)_k$$

Gas Injection Well

$$QG_k = [PI_k \cdot (M_0+M_w+M_g+M_{sj})_k/BG_k]^n \cdot (P^{n+1} - PWF)_k$$

Solvent Injection Well

$$QS_{sjk} = [PI_k \cdot (M_0+M_w+M_g+M_{sj})_k/BS_{sjk}]^n \cdot (P^{n+1} - PWF)_k$$

Note that the allocation of the injected fluid is based on the total oil, water, natural gas, and solvent mobility of the layer. This procedure is used to avoid the unrealistic case at the beginning of injection as discussed above for explicit pressure-controlled injection wells.

5.3 Bubble-Point Tracking

When gas is injected into a reservoir, the bubble-point pressure of the oil will change as gas goes into solution. The degree of change will depend on whether the oil was undersaturated or saturated and on the amount of gas injected. When water is injected into saturated oil reservoirs, the increase in pressure will cause the free gas to go into solution, changing the bubble-point pressure. In both cases, the bubble-point pressure will vary throughout the field, depending on the reservoir pressure and the volumes of gas available (Thomas et al. 1976). Therefore, a new bubble-point pressure must be calculated to obtain the correct fluid properties and, thus, the correct solution to the pressure equation.

Thomas et al. (1976) presented the fundamental ideas behind the use of a variable switching technique for variable bubble-point problems. This technique has been incorporated into MASTER. If a grid block is saturated, the state of the block is fully specified by the primary variables: oil pressure, water saturation, gas saturation, and solvent fractions. However, if a block is undersaturated, bubble-point pressure is substituted for gas saturation.

The state of the grid block is determined at the beginning of each iteration, based on the relative values of the oil pressure and the bubble-point pressure. If the oil pressure is greater than the bubble-point pressure, the block is undersaturated; otherwise the block is saturated. At the end of each iteration, the saturated blocks are tested for a change of state. If the gas saturation has become negative, the gas saturation is set to zero and the bubble-point pressure is set slightly (.01 psi or .069 kPa) below the oil pressure. If no change of state is indicated, the bubble-point pressure is set equal to the oil pressure. Blocks that begin an iteration as undersaturated do not require any special switching logic.

5.4 Automatic Time-Step Control (ATSC)

At the end of each time-step, maximum pressure and saturation changes are determined over the finite-difference grid. Whenever ATSC is on, one of the following actions is taken in an effort to maintain a step size that is large enough for the problem being simulated, yet small enough to avoid pressure and/or saturation oscillations and give acceptable solutions.

1. If, at the completion of a time step, the maximum saturation change of oil, water, natural gas, or solvents 1 through 4 exceeds the maximum user-specified saturation change <u>or</u> if the maximum pressure change exceeds the maximum user-specified pressure change, the time-step size will be decreased by a user-specified ratio, FACT2, and the time step will be repeated. In addition to ratios for increasing and decreasing time-step size, the user also specifies a maximum and a minimum time-step size. The time-step will not be repeated after the minimum time-step size, DTMIN, is reached.

2. If, at the beginning of a time step, the maximum grid-block pressure <u>and</u> saturation changes from the previous step are less than the maximum user-specified changes, the size of the current step will be increased by a user-specified ratio, FACT1. However, the time-step size is not allowed to be greater than the user-specified maximum time-step size, DTMAX.

3. If, at the beginning of a time step, the maximum grid-block pressure <u>or</u> any maximum saturation change from the previous time step is greater than the maximum user-specified changes (but the previous time step was not repeated because the minimum time-step size was reached), the size of the current step will be decreased by a user-specified ratio.

Automatic time-step control is on whenever ratios are specified for increasing and decreasing step size <u>and</u> maximum and minimum step sizes are given. Maximum recommended saturation changes are 5 to 10 percent for typical problems. Maximum pressure change is normally less

critical and typically may be 150 to 200 psi. In order to help determine if saturation and pressure changes are acceptably small, the user should examine these changes at the beginning of a simulation or when fluids are injected or produced at large rates. This is when the maximum changes should occur and when smaller time-step sizes are required to reduce oscillations in pressure and saturations.

5.5 Material Balance Calculations

The material balance equations for each component being tracked by the simulator result from combining the continuity equation and Darcy's law. Numerical solutions of these partial differential equations are obtained by discretizing them in both space and time using finite differences. After discretization, there is a balance equation for each component for each grid block in the following form for the oil and water species (see the Technical Manual for soluble species):

$$\frac{1}{\Delta t}\left(M_i^{n+1} - M_i^n\right) + q_i^{n+1} = \Delta A_i^{n+1} \cdot \Delta\Phi_i^{n+1}$$

where M_i = volume of component i in a grid block
A_i = component i phase transmissibility
$\Delta\Phi_i$ = phase i flow potential
qi = phase i injection or production rate
t = time
n = time step

It is convenient to write the equations in residual form.

$$R_i^\ell = \frac{1}{\Delta t}\left(M_i^\ell - M_i^n\right) + q_i^\ell - \Delta A_i^n \cdot \Delta\Phi_i^\ell$$

where ℓ is the iteration level.

The solution process to the system of equations consists of finding those values of the primary variables for which the residuals for each component, R_i^ℓ, are zero in all blocks. However, due to computer round-off errors and the limitation on the number of iterations (computer time) the residuals are never zero, but can be made very small. The values of the residuals are a measure of the material balance errors (mbe). In particular, local mbe = $\Delta t\, R_i^\ell$.

In the solution process, the system of equations will be considered solved when

$$\left|\Delta t R_i^\ell\right| / M_i^\ell < \varepsilon$$

Here, ε is a user-specified convergence tolerance. Generally, the local material balance errors will vary in sign from block to block with the result that the global material balance errors, which are obtained by summing the local material balance errors over all blocks, can be orders of magnitude smaller than the largest of the local material balance errors. This demonstrates that small global material balance errors are not sufficient for a good solution. In MASTER, both time step material balance errors and cumulative global material balance errors have been about the magnitude of ε for the test cases run.

When differential equations are integrated over many time steps, small errors at each time step may accumulate to produce a significant overall error. In the field of reservoir simulation, Nolen

and Berry (1972) and Spillette et al. (1973) have proposed techniques for controlling the accumulation of material balance errors. MASTER incorporates such a technique as a user option. The following discussion summarizes the idea underlying the technique used in MASTER.

When Newton's method for the solution of the material balance equations has met the convergence criterion ε, there are still small component material balance errors that may approach ε in magnitude. If ε is not kept very small, significant errors may accumulate over the period of many time steps. In order to control the accumulation of such errors without using values of ε that lead to large numbers of iterations, MASTER implements a scheme that uses fictitious production and injection terms. For example, if at the end of a time step a component material balance error is positive, it means that the solution results in an excess of that component in place. This can be corrected on the next time step by a fictitious production term of the right size to remove exactly the amount of the component that is in excess. In a similar manner, a negative material balance is corrected by a fictitious injection term. The production or injection rate is simply the amount of material in excess or deficit divided by the time step length. According to Nolen and Berry (1972), this technique effectively limits the cumulative error to that made on the current time step.

The following test was conducted to verify the logic of this mbe control technique. Examples 1 through 3 from Section 7, “Example Problems," were used in three runs: (Run 1) the tolerance was set to 10^{-5} and the technique turned off; (Run 2) the tolerance was set to 10^{-3} and the technique turned off; and (Run 3) the tolerance was set to 10^{-3} and the technique turned on.

The difference between cumulative oil production for Runs 1 and 2 averaged 0.051 percent while the difference between Runs 1 and 3 averaged 0.0008 percent, an improvement by a factor of 60. This strongly supports the assertion made that this mbe control technique allows the program to be run with a looser tolerance than otherwise might be used and still give results approaching those using a tight tolerance. For Example Problems 1 through 3, 21 percent more iterations were required with the technique turned off (Run 1) requiring approximately 16 percent additional CPU time when compared to Run 3. An option is available to the user, however, to turn the mbe control technique off, though we suggest that you leave the option on.

6.0 SPECIAL MODEL FEATURES

6.1 Treatment of Miscibility

An important feature in MASTER is the capability to simulate the miscible flow of oil, natural gas, and up to four different solvents. The mixing parameter approach by Watkins (1982) has been extended to multiple solvents, allowing effective component properties to be calculated for either gas-solvent or oil-gas-solvent miscible phases. Injected solvents are assumed to be miscible with natural gas at all reservoir pressures. Above a user-specified minimum miscibility pressure, PMISC (see Section 3.7), injected solvents are fully miscible with both reservoir oil and natural gas. PMISC is that pressure on the oil recovery versus pressure curve for slim tube displacement experiments where the curve becomes virtually horizontal. PMCM (see Section 3.7) is the pressure where the oil recovery versus pressure curve begins to bend over (usually between 85 and 95 percent oil recovery). The pressure range between PMCM and PMISC is treated as a zone of transition from immiscible to fully miscible conditions.

In MASTER, the calculation of effective viscosities and effective densities is a function of the reservoir pressure, p, using a weight factor, α, determined from

$$\alpha = \frac{P - PMCM}{PMISC - PMCM} \text{ for } PMCM \le P \le PMISC .$$
$$\alpha = 0 \text{ for } P \le PMCM, \text{ and}$$
$$\alpha = 1 \text{ for } P \ge PMISC .$$

The effective fluid properties are computed using an adaptation of Chase and Todd's method (1984). The following relations are used for the calculation of effective viscosities and effective densities:

$$\mu_I^e = (I - \alpha)\mu_i^1 + \alpha\mu_i^2 \text{ , and}$$
$$\rho_i^e = (I - \alpha)\rho_i^1 + \alpha\rho_i^2 .$$

Here i = o, g, 1, ..., N_s, and superscript 1 denotes effective properties for P $\le$ PMCM and superscript 2 denotes effective properties for P $\ge$ PMISC.

Even for P < PMCM, the soluble species in the gas phase are miscible with one another and the properties of a perfectly mixed gas phase are computed from the pure component properties by simple but commonly used mixing rules:

$$\mu_{mgs}^{-1/4} = v_g\mu_g + \sum_{j=1}^{N_s} v_j\mu_j^{-1/4} \text{ and}$$
$$\rho_{mgs} = v_g\rho_g + \sum_{j=1}^{N_s} v_j\rho_j .$$

The possibility of incomplete mixing is accounted for by use of a mixing parameter, ω_1 (see Section 3.7.2), which relates the effective properties to the pure component properties and perfectly mixed properties by the following equations:

$$\mu_i^1\mu_i^{(1-\omega_1)}\mu_{mgs}^{\omega_1} , \qquad i = g, 1, ..., N_s, \text{ and}$$

$$\rho_I^1 = (1 - \omega_1)\rho_i + \omega_1\rho_{mgs} , \qquad I = g, 1, ..., N_s .$$

A value of one for the mixing parameter corresponds to complete mixing and a value of zero corresponds to complete segregation.

For P > PMISC the soluble species are miscible with one another and with the oil phase. The following mixture properties are defined by the following equations:

$$\mu_{mos}^{-1/4} = \frac{1}{S_o + \left(1 - v_g\right) S_g} \left(S_o \mu_o^{-1/4} + S_g \sum_{j=1}^{N_s} v_j \mu_j^{-1/4} \right),$$

$$\mu_m^{-1/4} = \frac{1}{1 - S_w} \left(S_o \mu_o^{-1/4} + S_g \mu_{mgs}^{-1/4} \right),$$

$$\rho_{mos} = \frac{1}{S_o + \left(1 - v_g\right) S_g} \left(S_o \rho_o + S_g \sum_{j=1}^{N_s} v_j \rho_j \right), \text{ and}$$

$$\rho_m = \frac{1}{1 - S_w} \left(S_o \rho_o + S_g \rho_{mgs} \right).$$

Then, a second mixing parameter, ω_2 (see Section 3.7.2), is used to compute the effective properties:

$$\mu_o^2 = \mu_o^{(1-\omega_2)} \mu_{mos}^{\omega_2},$$

$$\mu_g^2 = \mu_g^{(1-\omega_2)} \mu_{mgs}^{\omega_2},$$

$$\mu_i^2 = \mu_i^{(1-\omega_2)} \mu_m^{\omega_2}, \qquad i = 1 \ldots, N_s,$$

$$\rho_o^2 = \left(1 - \omega_2\right) \rho_o + \omega_2 \rho_{mos},$$

$$\rho_g^2 = \left(1 - \omega_2\right) \rho_g + \omega_2 \rho_{mgs}, \text{ and}$$

$$\rho_i^2 = \left(1 - \omega_2\right) \rho_i + \omega_2 \rho_m, \qquad i = 1, \ldots, N_s.$$

The calculation of effective relative permeabilities and effective capillary pressure for oil and gas is a function of the reservoir pressure (the weight factor α) and a function of composition. The weight factor α_m is determined from the following equation:

$$\alpha_m = \alpha \cdot \min\left(\left(1 - v_g\right) / \text{VSMISC}, \ 1 \right)$$

Then effective relative permeabilities and effective capillary pressure are calculated using the following equations:

$$k_{ro}^e = \left(1 - \alpha_m\right) k_{ro} + \alpha_m \left(\frac{S_o}{1 - S_w} \right) k_{rn},$$

$$k_{rg}^e = \left(1 - \alpha_m\right) k_{rg} + \alpha_m \left(\frac{S_g}{1 - S_w} \right) k_{rn}, \text{ and}$$

$$p_{co}^e = \left(1 - \alpha_m\right) p_{cg}.$$

Here VSMISC is a user-specified parameter that gives the total fraction required to obtain full miscibility and k_{rn} is the total nonaqueous phase relative permeability.

For a more detailed discussion of the fluid property calculations, refer to the accompanying Technical Manual.

6.2 Mobility Control

A mobility control option permits solvent mobility to be reduced as a function of local surfactant concentration. This option provides a method for matching field performance and projecting future oil recovery for various surfactant injection schemes. According to the work of Bernard et al. (1980), injected water containing 0.1 to 1 percent surfactant may significantly reduce carbon dioxide mobility. A trace injection technique (described below) and laboratory-determined solvent mobility reduction tables are used.

Injected water that contains surfactant is assumed to be completely miscible with reservoir brine. The ratio of the volume of water that contains surfactant to the total water volume is x_s. Surfactant water saturation S_c is given by $S_c = x_s \cdot S_w$ with the above notation and assumptions, water that contains surfactant is tracked by incorporating x_s into the water mass balance equation. Gas phase mobility is reduced on a grid-block basis by using an input table that consists of fractional mobility reduction versus S_c.

6.3 Foam

A semi-empirical approach is used to calculate the gas mobility in the presence of foam instead of using a mechanistic, bubble-population-balance approach. The gas mobility in the presence of foam is modeled based on the resistance factor data which are readily available or measured once the surfactant selection is complete (Chang and Grigg, 1994).

The following major assumptions were used in the foam model (Chang and Grigg, 1996):

1. Foam affects only the gas mobility.
2. Foam will not exist if any of the following conditions are not met:

$$C_s > C_s^{lim}$$
$$S_g < S_g^{lim}$$
$$S_O < S_O^{lim}$$
$$S_W < S_W^{lim}$$

   where C_s is the surfactant concentration in the water phase, and S_g, S_O, and S_W are the gas-, oil-, and water-phase saturations, respectively. The variables with superscript *lim* correspond to the limiting value of each variable.
3. Foam generation will occur only if the gas-liquid volumetric ratio is greater than limiting ratio, the gas saturation is increasing, and the above foam existing conditions are satisfied.
4. Surfactant adsorption on the rock can be modeled with a Langmuir-type model and is unaffected by the presence of foam.

By definition, the resistance factor R_f can be written as

$$R_f = \frac{M_{CO2+BR}}{M_{CO2+SS}}$$

where, M_{CO2+BR} is the total mobility of CO_2/brine mixture obtained from the experiment of simultaneous injection of CO_2 and surfactant-free brine, M_{CO2+SS} is the total mobility of the CO_2/surfactant solution obtained from the experiment of simultaneous injection of CO_2 and surfactant solution, and both mobility measurements are conducted at the same gas-liquid volumetric ratio. The resistance factor data depends on interstitial velocity, gas-liquid volumetric ratio, surfactant concentration, and rock permeability, and are input as lookup tables in the simulator. The total mobility of the CO_2/brine mixture is a combination of the mobility of CO_2 (gas-phase) and the mobility of surfactant-free brine (water-phase), hence,

$$M_{CO2+BR} = M_w + M_g$$

where M_w is the water mobility and M_g is the gas mobility. Similarly, the total mobility of the CO_2/surfactant solution is equal to the sum of the mobility of surfactant solution (water-phase) and mobility of CO_2 (gas-phase) in the presence of foam. Because the water mobility is not affected by the presence of foam, therefore, the gas mobility in the presence of foam is:

$$M_g^{foam} = 1/R_f(M_w + M_g) - M_w$$

If foam can be generated, the foam resistance factor is determined from lookup tables, and then the gas mobility in the presence of foam is calculated. The calculated value of the gas mobility in the presence of foam will not be modified until foam ceases to exist. Gas mobility can be altered by changing either the gas relative permeability or viscosity or changing both together. For convenience, the effect of foam on gas mobility is represented by altering the gas relative permeability only.

6.4 Water Blocking

MASTER can consider the effect of water that blocks the oil from being contacted by injected solvent (Raimondi and Torcaso 1963; Tiffin and Yellig 1983). Based on Chase and Todd's method (1984), parameter β is input to calculate the water-blocked oil saturation, S_{twb}. This represents oil that is blocked from contact with the encroaching solvent by the intervening water saturation. The water-blocked oil saturation is calculated from

$$S_{twb} = \frac{S_{orw}}{1 + \beta \cdot k_{rn} / k_{rw}} .$$

By rearranging the equation, the equivalent equation presented by Raimondi and Torcaso (1963) can be obtained. Chase and Todd (1984) recommend β = 1.0 for highly water-wet sandstones and β = 5.0 for mixed-wettability systems. Note that β = 0.0 implies that no oil is contacted by the invading solvent, while a very large value of β means that essentially all the oil can be contacted by the solvent.

6.5 Solid Precipitation

Precipitation of a semisolid or asphaltene has been recognized as a phenomenon that is characteristic of carbon dioxide displacement processes (Shelton and Yarborough 1977). To rigorously model such behavior would require a compositional model in which a heavy (asphaltene) component could be isolated and tracked.

In the present model, an attempt has been made to approximate the phenomenon of asphaltene precipitation with a user-specified minimum effective oil saturation. Such precipitation is assumed to occur from the transfer of light and intermediate hydrocarbons from the oil into the solvent phase in regions swept by solvent. Solid precipitation of oil occurs when the oil saturation in a grid block becomes less than the minimum effective oil saturation. Relative permeability to oil is set to zero and water and gas relative permeabilities are reduced by a user-specified fraction in regions where precipitation has occurred.

7.0 EXAMPLE PROBLEMS

This section contains sample input data files and selected portions of output files. The input data files are provided to illustrate the required format of the input file necessary to run MASTER. Portions of the output files are included for comparison of results to be certain that the code is performing properly. The input and output samples are also provided to show the types of problems that can be simulated and the results that can be obtained by using the MASTER model.

The example problems presented in this section were part of a validation study conducted to determine if MASTER is accurately predicting expected reservoir performance. The First and Fifth Society of Petroleum Engineers (SPE) Comparative Solution Projects were chosen for the study. The First Comparative Solution Project (Odeh 1981) involves immiscible gas injection into an undersaturated oil reservoir. Odeh (1981) presents two cases to show the importance of being able to simulate a varying bubble-point pressure: Case 1, in which the bubble-point pressure is held constant, and Case 2, in which the bubble-point pressure is allowed to vary. The input data file and results are presented here only for Case 2.

The Fifth Comparative Solution Project (Killough and Kossack 1987) presents the results of comparing four-component simulators such as MASTER and fully compositional reservoir simulators. Killough and Kossack (1987) present three cases which vary from scenarios dominated by immiscible conditions to a scenario in which the miscibility pressure is maintained throughout the simulation. Results from all three scenarios are presented; however, only the Scenario 1 input data file is presented because only the recurrent data section (injection and production schedules) changes among the three scenarios.

7.1 Example 1

This problem is taken from the SPE First Comparative Solution Project, Case 2 (Odeh 1981). Gas is injected into a corner injection well at a rate of 100,000 Mscf/d. In the opposite corner of the reservoir, the production well is produced at a rate of 20,000 STB/d with a minimum bottom hole flowing pressure (bhfp) of 1,000 psia. The simulation is terminated at 10 years or when the maximum producing gas-oil ratio is exceeded.

Table 7 shows a list of the companies that participated in this study. Figures 5 through 7 show the results predicted by MASTER compared to the range of results predicted by the seven industry participants' models. Figure 5 shows pressure at the injection node versus time, Figure 6 shows oil production rate versus time, and Figure 7 shows gas-oil ratio versus time. The results predicted by MASTER fall within the range of the results predicted by the industry models. CPU time required to run this problem was 156 seconds on a VAX 8650. The input data file, a sample of the output file for the results at 5 years, and a sample of the executive summary table are given in Section 9.1.

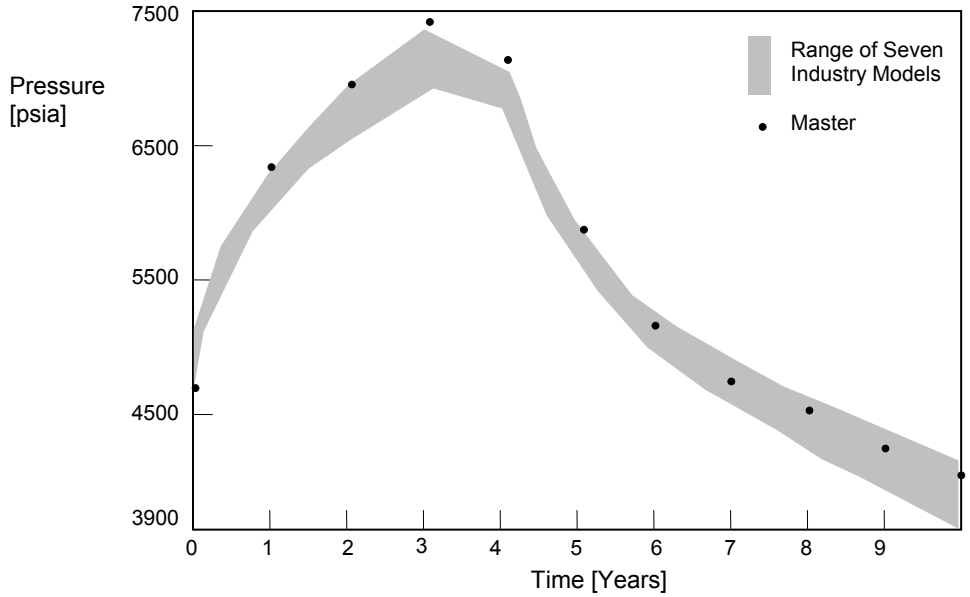


FIGURE 5. Gas Injection Problem, Case 2: Comparison of Pressure at the Injection Node

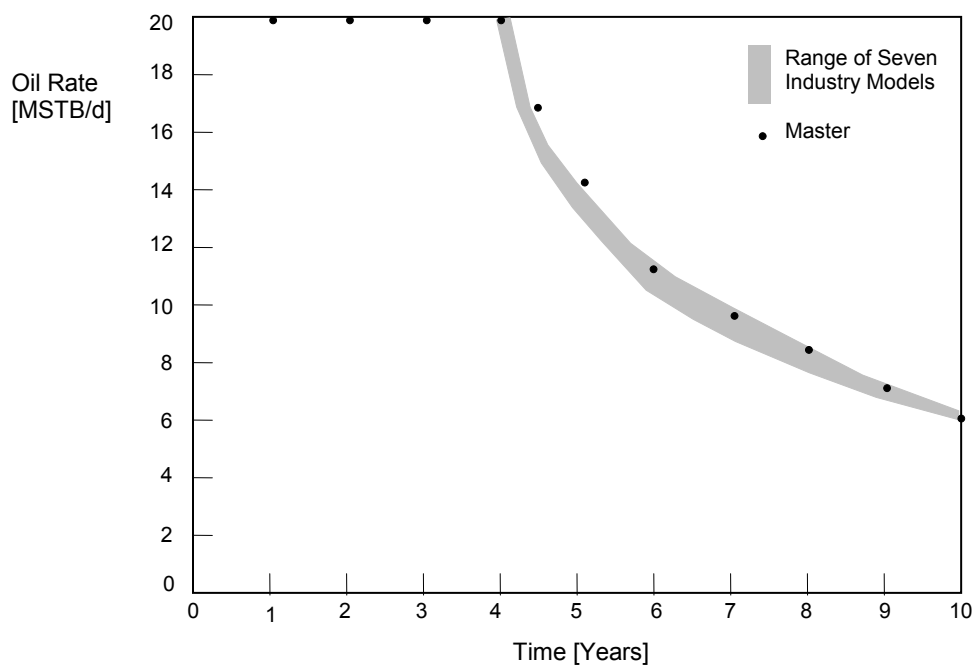


FIGURE 6. Gas Injection Problem, Case 2: Comparison of Producing Oil Rate

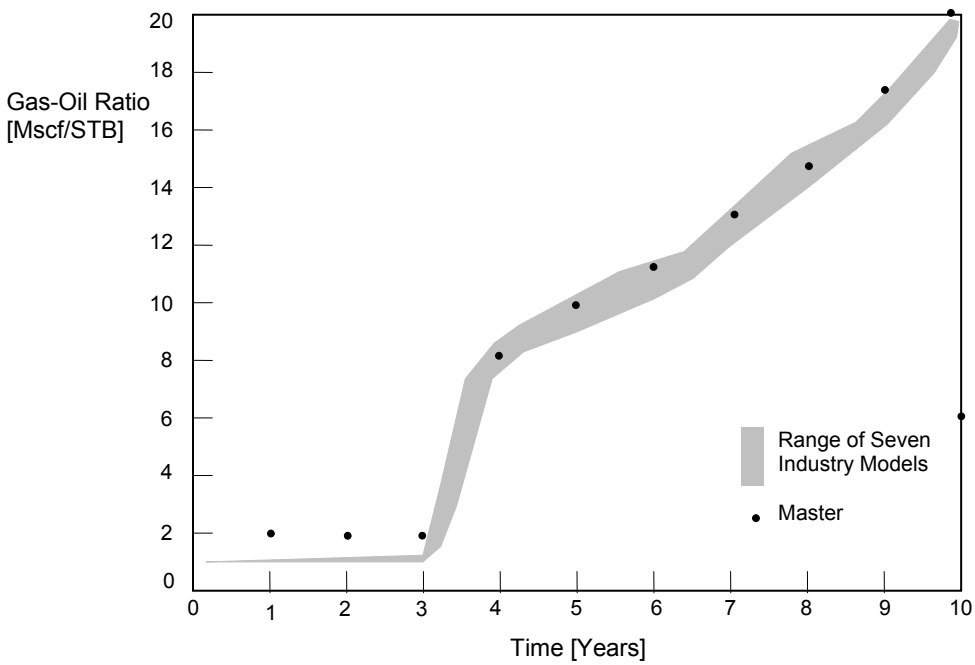


FIGURE 7. Gas Injection Problem, Case 2: Comparison of Producing Gas-Oil Ratio

Table 7. Participants of the First Comparative Solution Project

Participant
Amoco Production Company
Exxon Production Research Company
Intercomp Resource Development and Engineering, Inc.
Computer Modeling Group of Calgary
Mobil Research and Development Corporation
Shell Development Company
Scientific Software Corporation

7.2 Example 2

Example problems 2 through 4 are taken from the SPE Fifth Comparative Solution Project, Scenarios 1 through 3, respectively (Killough and Kossack 1987). Table 8 shows a list of the companies that participated in this study.

Table 8. Participants of the Fifth Comparative Solution Project

Participant	Four-Component Model	Compositional Model
ARCO Oil and Gas Company	X	X
British Petroleum		X
Chevron Oil Field Research Company	X	X
Computer Modeling Group	X	X
Energy Resource Consultants Limited	X	
Reservoir Simulation Research Corporation		X
Todd, Dietrich, and Chase, Inc.	X	X

In most of the four-component models, there are three to five parameters that control the models' calculation of the change from immiscible to miscible conditions and the calculations of fluid properties at miscible conditions. In MASTER, these parameters are PMISC, PMCM, MEG1, MEG2, and VSMISC. Since different values for these parameters were chosen by most of the participants, the values of these parameters in MASTER were made to correspond to those chosen by ARCO. The results predicted by MASTER are compared to the results predicted by ARCO's four-component model (4CP) and ARCO's compositional model (Comp).

In Scenario 1, the well produces at an oil rate of 12,000 STB/d with a minimum bottom hole flowing pressure (bhfp) of 1,000 psia for 2 years. The average reservoir pressure declines rapidly below both the miscibility pressure (3,000 psia) and the saturation pressure (2,300 psia). A 1-year, water-alternating-gas (WAG) cycle is started at an injection well while maintaining a bhfp of 1,000 psia at the production well. This production/injection schedule maintains the average reservoir pressure around 1,700 psia, well below the miscibility and saturation pressures for almost the entire simulation. The run is terminated at 20 years or when the maximum gas-oil ratio or water-oil ratio is exceeded.

Figures 8 through 10 compare the results predicted by MASTER to those predicted by ARCO's four-component model and ARCO's compositional model for cumulative oil production, gas-oil ratio, and average reservoir pressure versus time. The results of the other participants are not shown for convenience. MASTER compares well (within 5 percent) with ARCO's four-component model. The four-component models tended to be pessimistic compared to the fully compositional model because condensable liquids carried in the gaseous phase are not considered in the four-component models (Killough and Kossack 1987). The input data file and samples of the output files for the results at 10 years are given in Section 9.2.

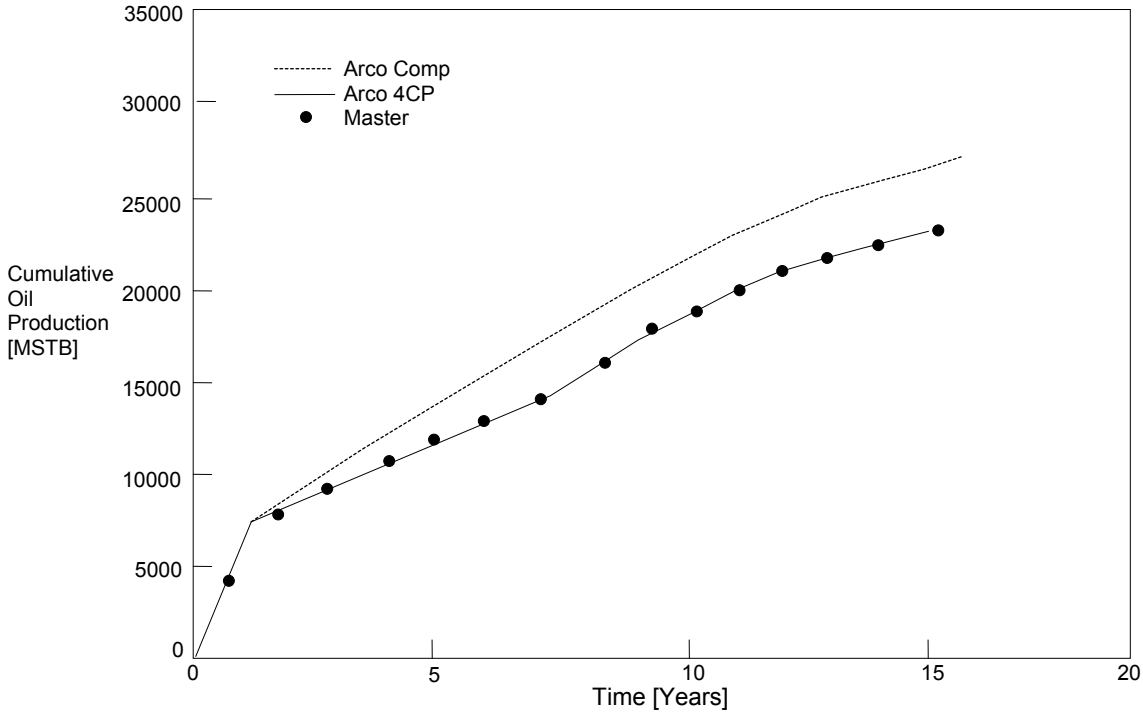


FIGURE 8. Scenario 1: Comparison of Cumulative Oil Production

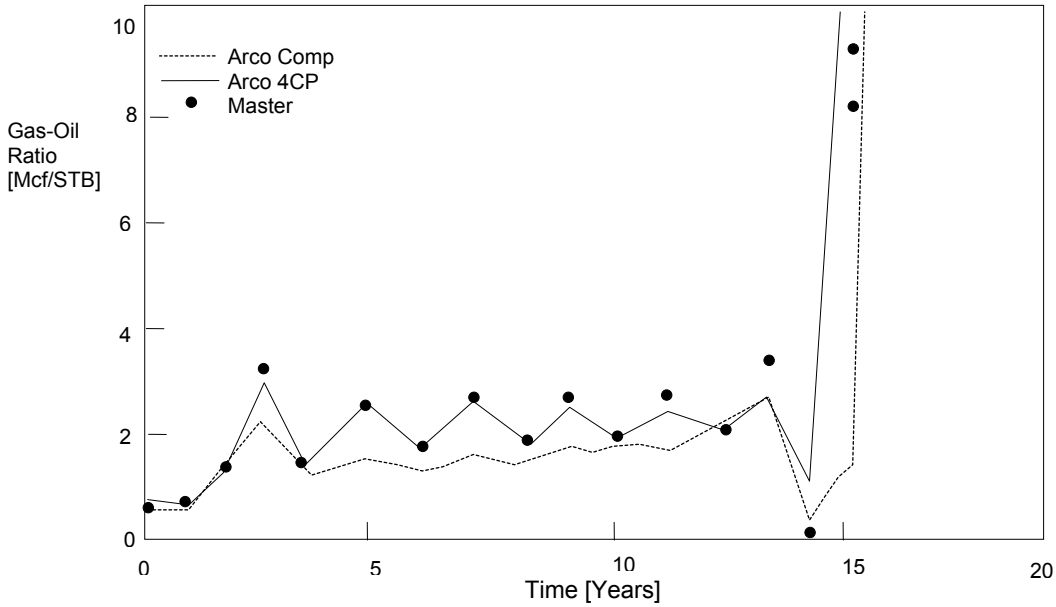


FIGURE 9. Scenario 1: Comparison of Producing Gas-Oil Ratio

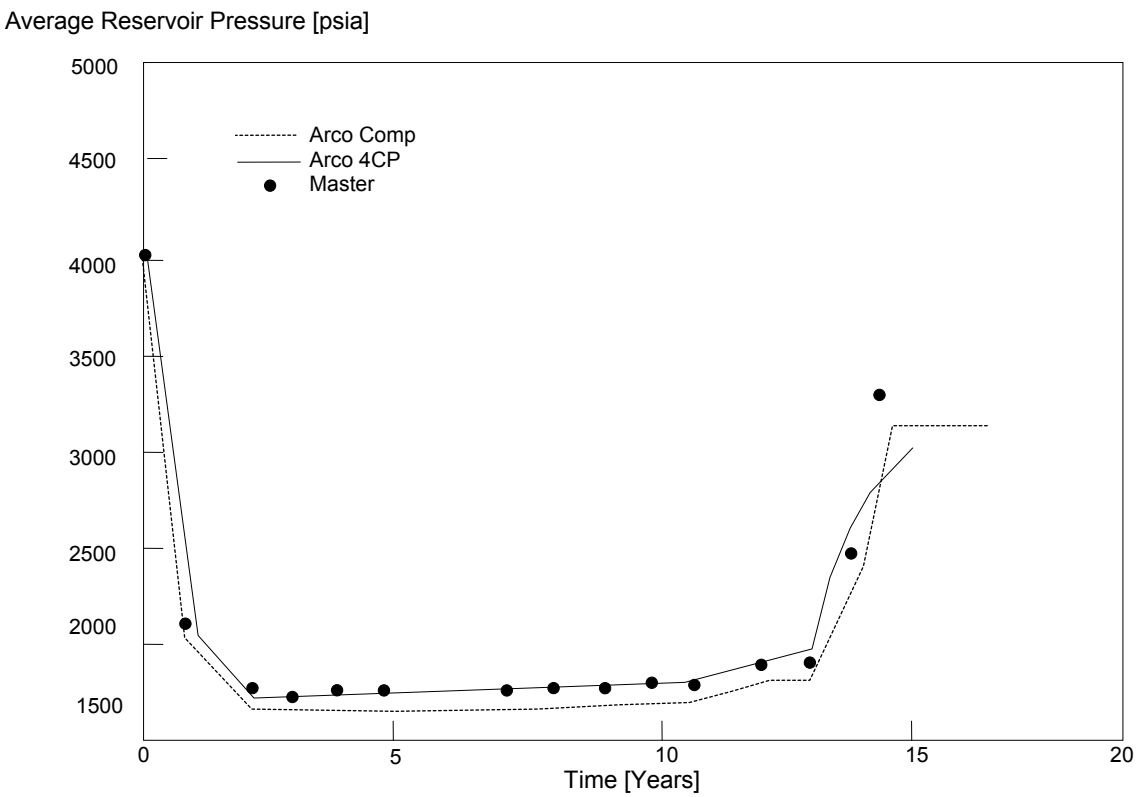


FIGURE 10. Scenario 1: Comparison of Average Pore-Volume Weighted Reservoir Pressure

7.3 Example 3

The reservoir description used in Scenario *2* (Example 3) is the same as that in Scenario 1 (Example 2). The problem is changed by varying the injection and production schedules. In Scenario 2, the minimum bhfp at the production well is increased to 3,000 psia. WAG injection begins at the start of the simulation on a quarter-year cycle and both the water and gas injection rates are increased. This production/injection schedule maintains the average reservoir pressure above the miscibility pressure for the entire simulation. The simulation is terminated at 20 years or when the maximum gas-oil or water-oil ratio is exceeded.

Figures 11 through 13 compare the results predicted by MASTER to ARCO's four-component model and ARCO's compositional model for cumulative oil production, gas-oil ratio, and average reservoir pressure versus time. Although the cumulative oil production predicted by MASTER is greater than that predicted by ARCO's four-component model, the predicted production agrees well (within 5 percent) with ARCO's compositional simulator. The gas-oil ratio agrees well with both ARCO models up to 16 years. At this time, the ratio predicted by MASTER increases rapidly until the maximum of 10 Mscf/STB is exceeded at 17.5 years. The ARCO compositional model reaches a gas-oil ratio of 9 Mscf/STB at 20 years whereas the ARCO four-component model only reaches a gas-oil ratio of 5 Mscf/STB at 20 years. However, three of the other participants' compositional simulators exceeded the maximum gas-oil ratio between 14 and 15 years while two others exceeded the maximum ratio between 17 and 18 years, as did MASTER. The average reservoir pressure predicted by the three models are in good agreement (Figure 13). Figure 14 shows a plot of oil saturation in node 4,4,1 (as discussed by Killough and Kossack [1987]) versus time for all the compositional models, ARCO's four-component model, and MASTER. Although there is great diversity among the predictions, the oil saturation predicted by MASTER agrees well with a few of the compositional models. The agreement between MASTER and the

compositional models for this scenario increases confidence in using MASTER when one considers the complex phase behavior calculations that are performed by a fully compositional model for miscible displacement processes. Samples of the output files for the results at 15 years are given in Section 9.3.

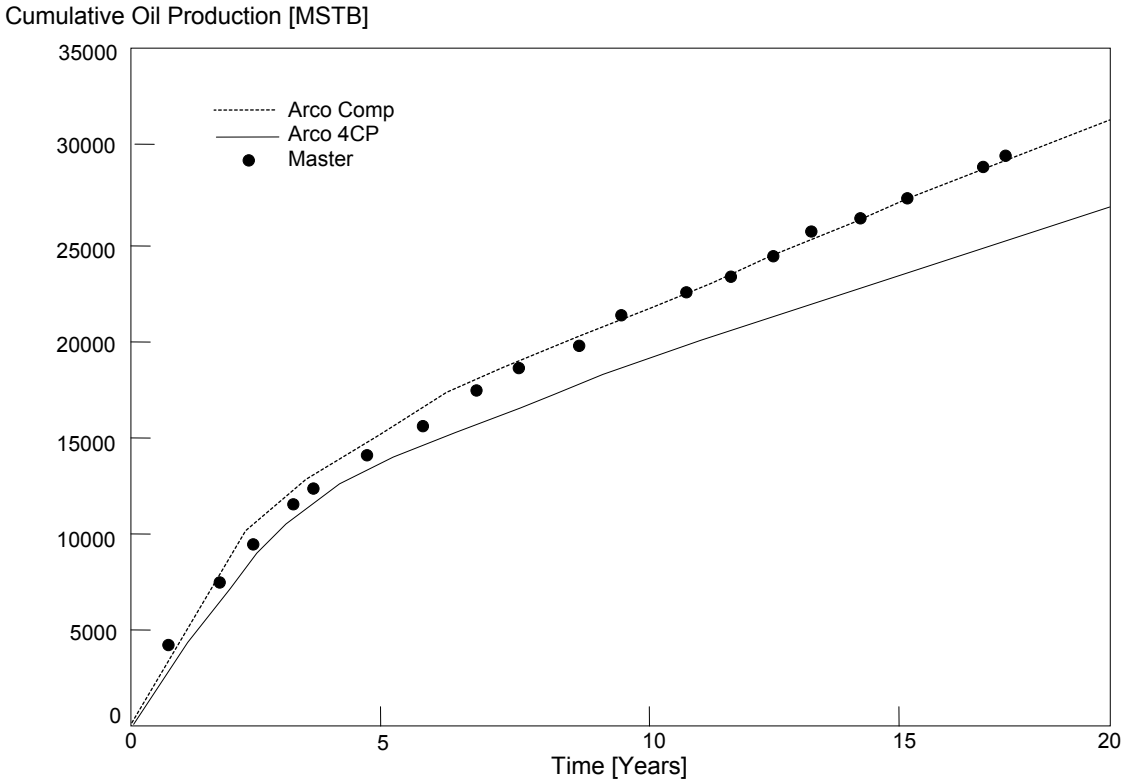


FIGURE 11. Scenario 2: Comparison of Cumulative Oil Production

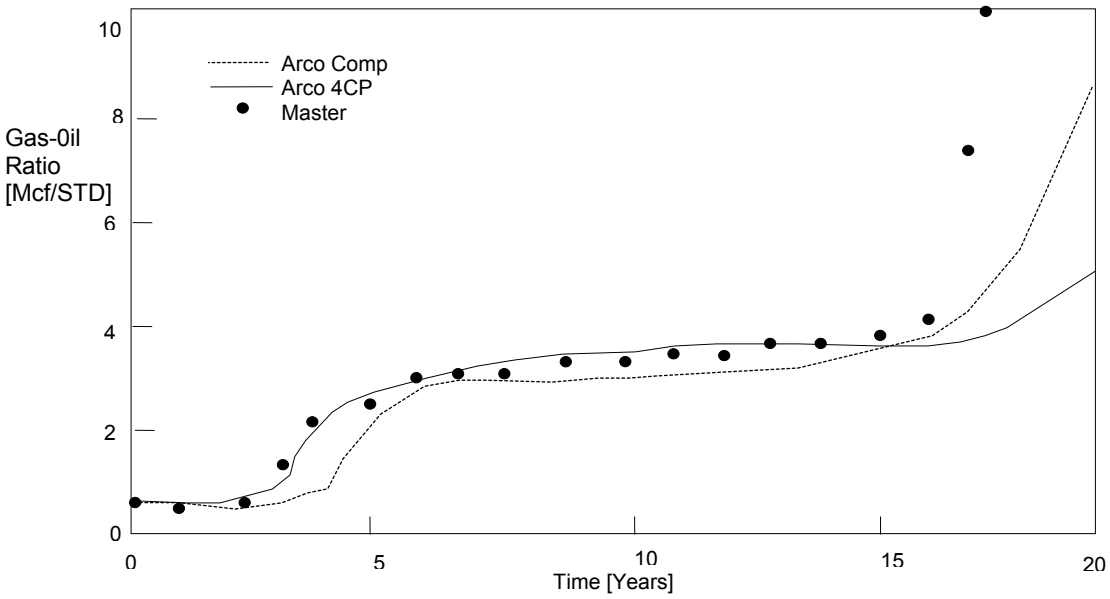


FIGURE 12. Scenario 2: Comparison of Producing Gas-Oil Ratio

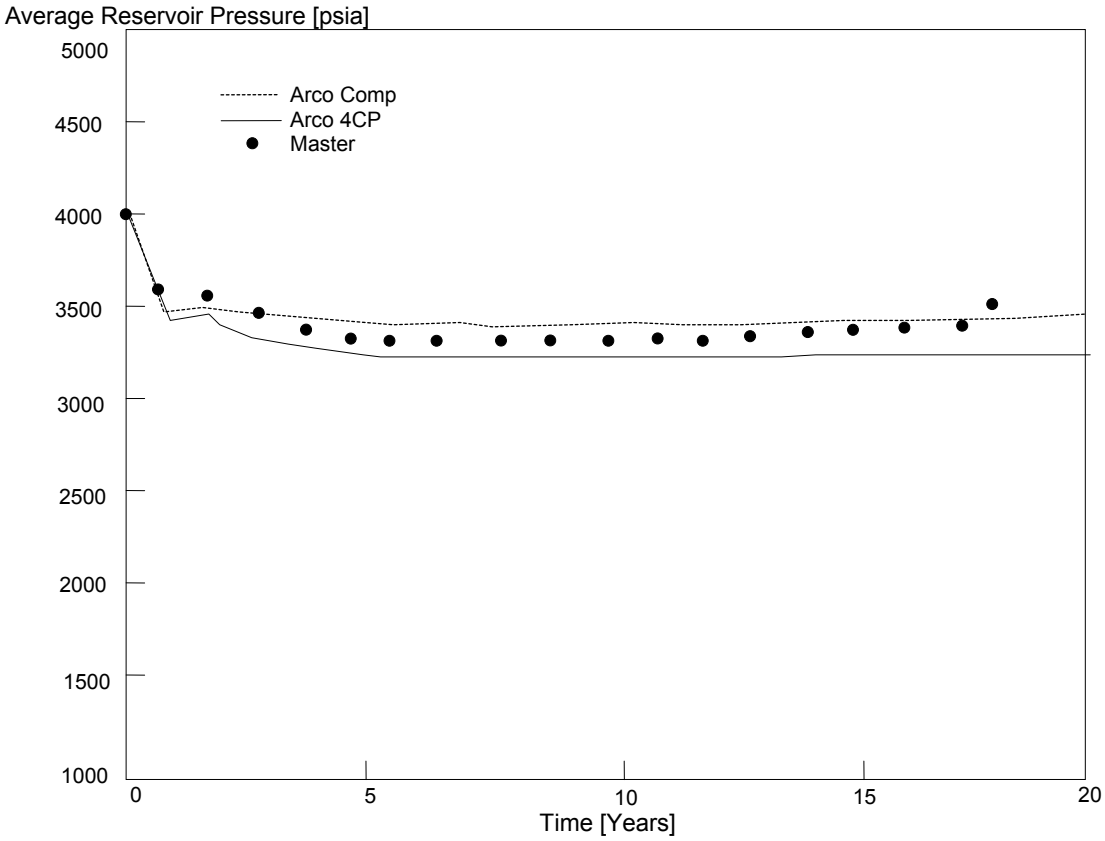


FIGURE 13. Scenario 2: Comparison of Average Pore-Volume Weighted Reservoir Pressure

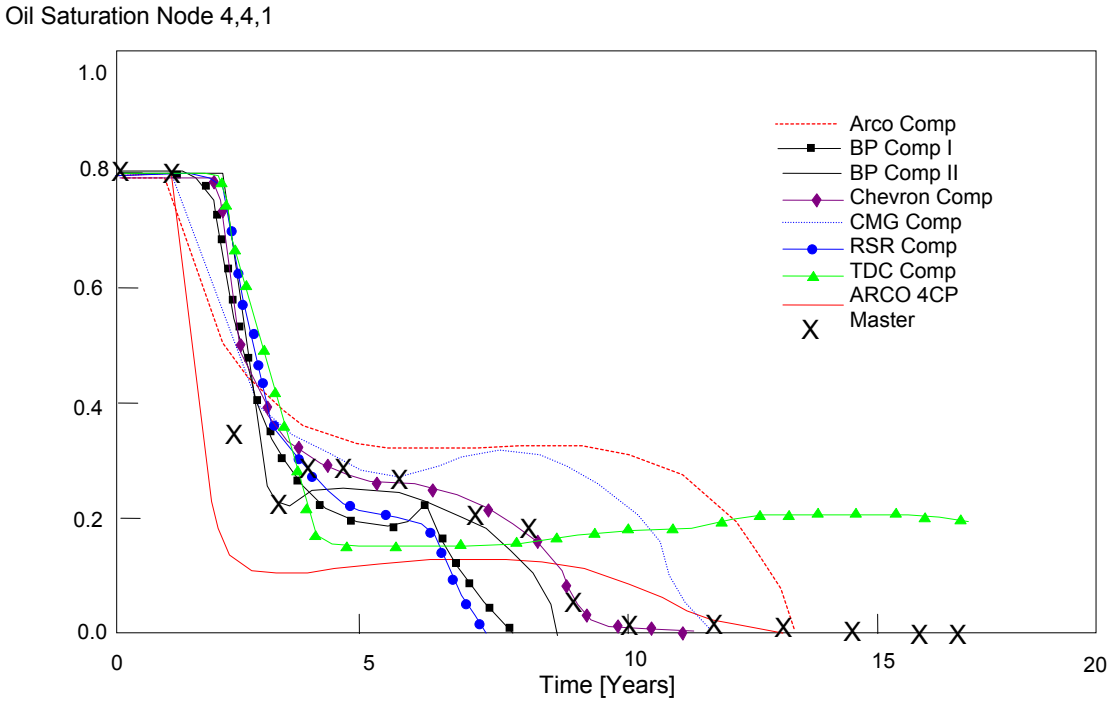


FIGURE 14. Scenario 2: Comparison of Oil Saturation in Node 4,4,1

7.4 Example 4

The reservoir description used in Scenario 3 (Example 4) is the same as that in Scenarios 1 and 2 (Examples 2 and 3). Scenario 3 is similar to Scenario 1 because the average reservoir pressure remains less than the miscibility pressure for almost the entire simulation. After a year of production, during which the average reservoir pressure was reduced below the miscibility and saturation pressures, water injection is started for 1 year, after which a quarter-year WAG cycle is started at rates greater than either Scenario 1 or 2. This rapid injection schedule increases the average reservoir pressure more rapidly than did Scenario 1, causing termination of the run at approximately 11 years.

Figures 15 through 17 compare the results predicted by MASTER and ARCO's four-component and compositional models for cumulative oil production, gas-oil ratio, and average reservoir pressure versus time. The cumulative oil production predicted by MASTER agrees well with the predicted production of ARCO's four-component model. The predicted gas-oil ratio for both models is in good agreement through year 9, whereas a lower gas-oil ratio is predicted by MASTER during year 10.

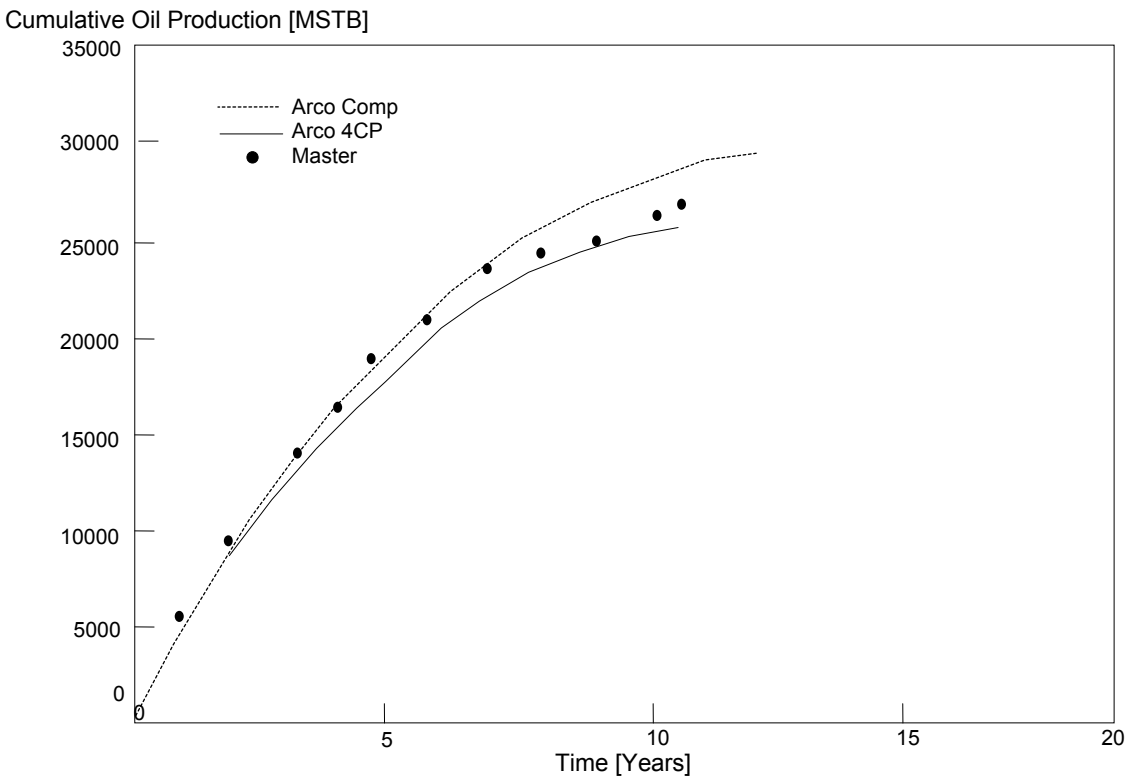


FIGURE 15. Scenario 3: Comparison of Cumulative Oil Production

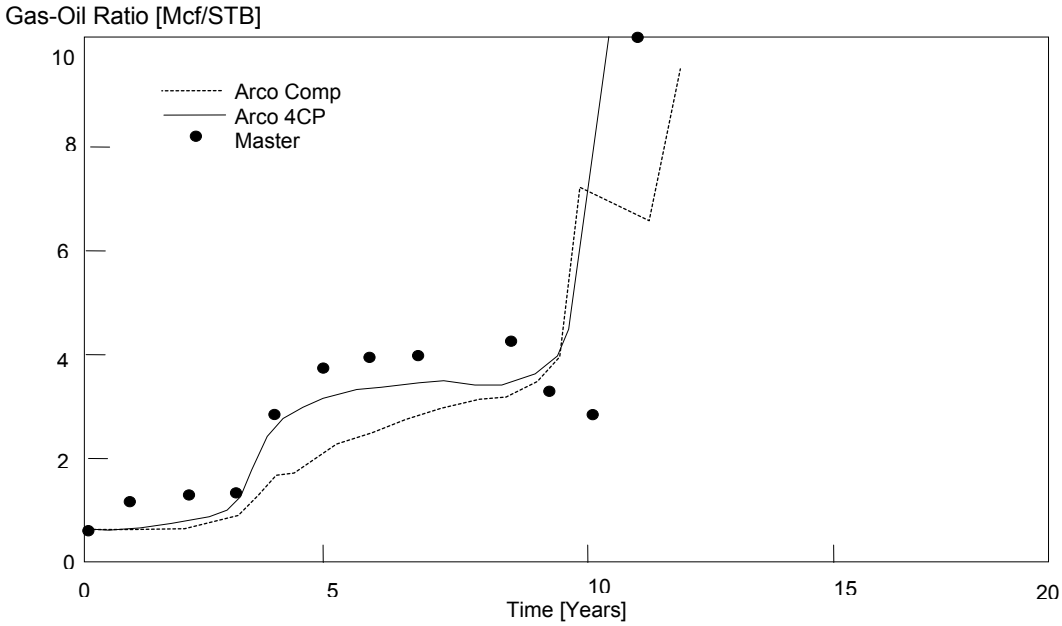


FIGURE 16. Scenario 3: Comparison of Producing Gas-Oil Ratio

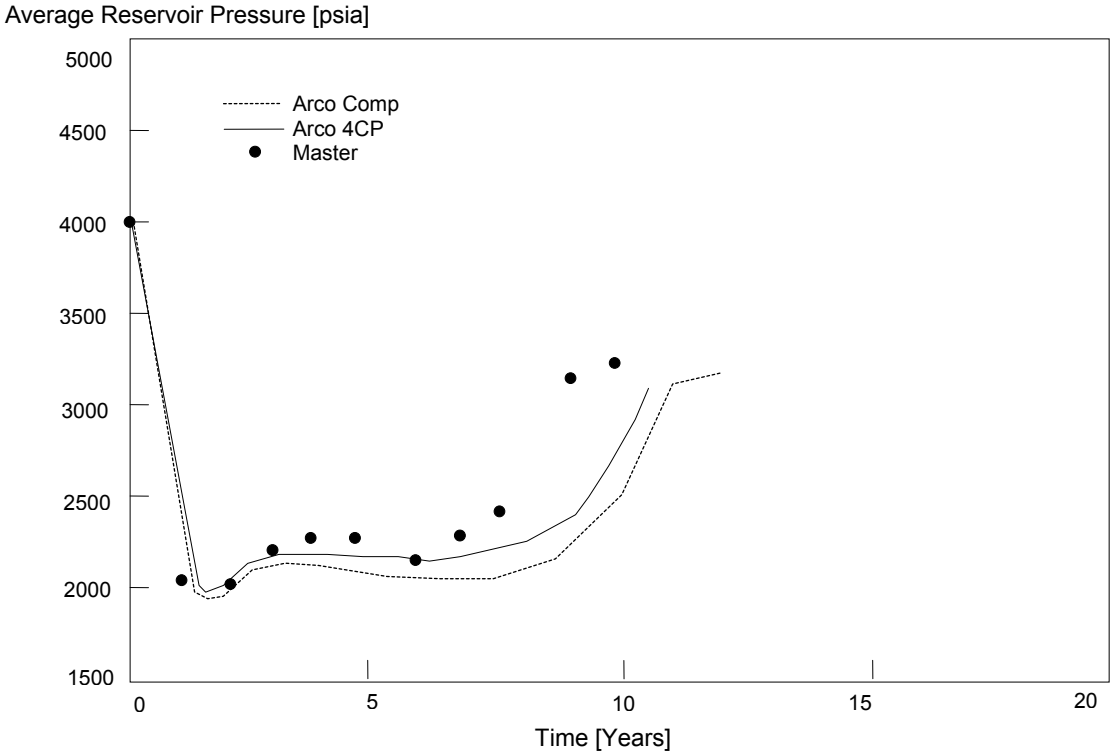


FIGURE 17. Scenario 3: Comparison of Average Pore-Volume Weighted Reservoir Pressure

After this period, the gas-oil ratio agrees well with the two ARCO models. The average reservoir pressure predicted by MASTER compares very well to the ARCO four-component model through year 7, after which MASTER predicts a higher pressure. Table 9 shows a comparison of CPU time for all four-component models for all three scenarios. The required CPU time using MASTER for a given simulation, when accounting for differences in computer hardware efficiency, is favorable when compared to the simulators in the SPE fifth comparison solution project. Samples of the output files for the results at 5 years are given in Section 9.4

Table 9. Comparison of CPU Times (Seconds) for Four-Component Models (After Killough and Kossack [1987])

Company or Program	Computer	Scenario 1	Scenario 2	Scenario 3
ARCO Oil and Gas Company	CRAY X/MP	7.1	20.1	13.2
Chevron Oil Field Research Company	CRAY X/MP	75.0	186.0	102.0
Computer Modeling Group	Honeywell Multics DPS8/7	3,062.0	5,263.0	4,933.0
Energy Research Consultants Ltd.	NORSK DATA ND 570/CX	1,191.0	1,282.0	1,230.0
Todd, Dietrich, and Chase, Inc.	CRAY 15	75.0	221.0	298.0
MASTER	VAX 8650	96.0	317.0	185.0

7.5 Example 5

The reservoir description used in Scenario 4 (Example 5) is the same as that in Scenarios 1 through 3 (Examples 2 through 4). Scenario 4 is similar to Scenario 2, the minimum bhfp at the production well is increased to 3,000 psia. SAG injection (surfactant solution alternating with gas) begins at the start of the third year which was preceded by one year (the second year of the simulation) of surfactant injection. From the start of the third year each half-cycle of surfactant solution and gas (carbon dioxide) is a quarter year injection. This schedule was maintained to approximately the end of the eleventh year and compared to Scenario 2 and 3.

Figures 18 and 19 compare the results predicted by MASTER for the five different cases. Figure 18 compares the cumulative oil production for the five cases with the fifth having the highest production after ten years. Figure 19 compares the oil production rate for the each of the five examples.

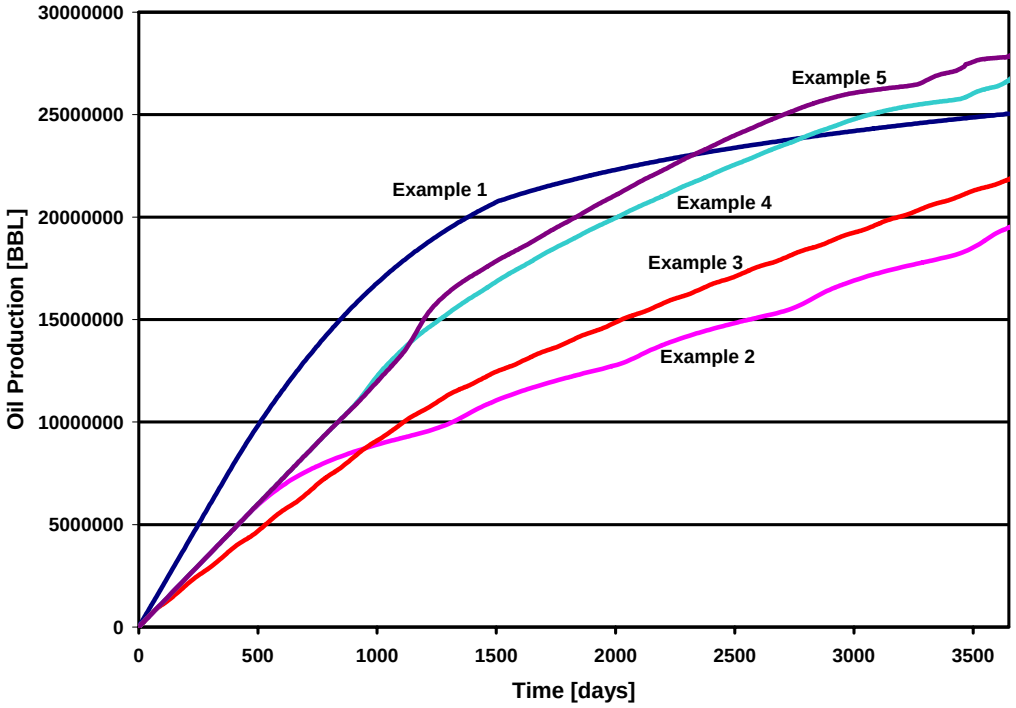


FIGURE 18. Scenario 4: Comparison of Cumulative Oil Production for the Five Examples.

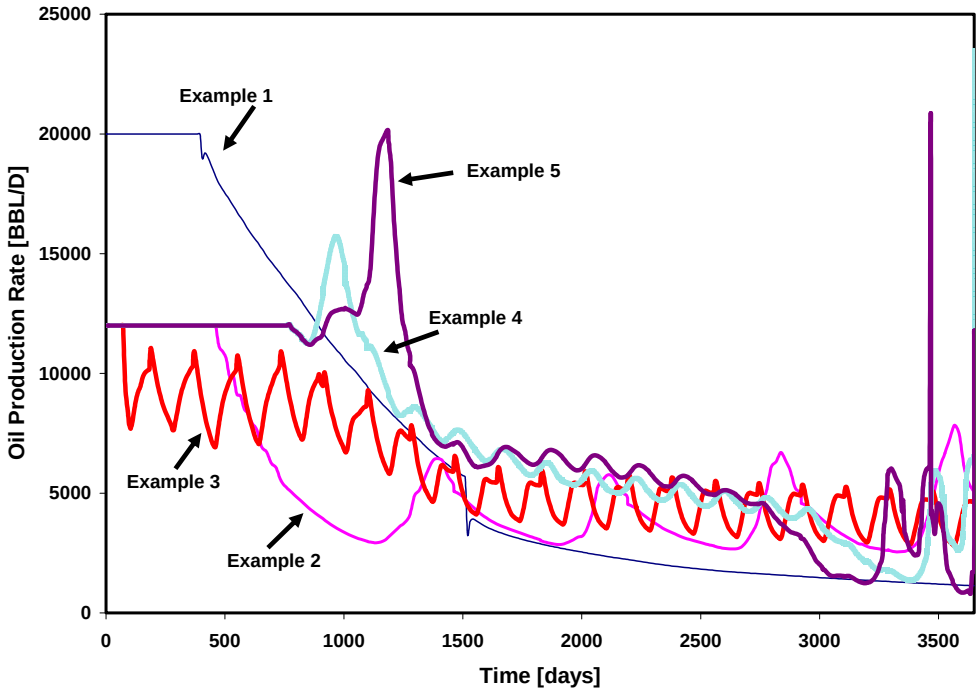


FIGURE 19. Scenario 4: Comparison of Daily Oil Production Rate for the Five Examples.

8.0 CONCLUSION

An extended, black-oil, miscible reservoir simulator, MASTER, has been developed to support DOE's Gas Miscible Displacement EOR Program. MASTER uses a variable switching technique for variable bubble-point problems and an iterative IMPES solution scheme. MASTER, unlike most extended, black-oil, miscible simulators includes the following four features:

1. Fluid property calculations that are functions of both pressure and the amount of soluble components in solution;

2. A transition to miscibility that occurs as a function of both pressure and composition;

3. Multiple solvent component capability; and

4. A mobility control option that reduces gas phase mobility as a function of surfactant concentration.

A material balance error control technique can be used to reduce CPU time without sacrificing accuracy. Validation of the code was conducted by comparing results predicted by MASTER to results presented in two SPE comparative solution projects. The favorable comparison will give public users confidence in applying MASTER.

9.0 SAMPLE INPUT AND OUTPUT FILES

9.1 Example 1

Input Data File for Example 1

```
MASTER VALIDATION Example 1 - IMMISCIBLE GAS INJECTION - ODEH (1981):SPE9723
  10   10    3
GRID BLOCK LENGTHS
  -1   -1    0
1000.
1000.
 20.     30.     50.
GRID BLOCK MODIFICATIONS
   0    0    0    0
CAPROCK BASE DEPTH
   0
8325.
POROSITY AND PERMEABILITY
  -1    0    0    0
.30
 500.    50.        200.
 500.    50.        200.
 100.    37.5       20.83
POROSITY AND PERMEABILITY MODIFICATIONS
   0    0    0    0    0
RELATIVE PERMEABILITY-CAPILLARY PRESSURE DATA
        1
        1
        1
<SWT><KROW><-KRW-><-PCOW->
  0.0      1.0          0.0         0.0
  0.1      1.0           0.0        0.0
  0.12     1.0          0.0         0.0
  0.15     1.0          0.0001      0.0
  0.4      1.0          0.001       0.0
  0.6      1.0          0.01        0.0
  0.8      1.0          0.1         0.0
  1.0      1.0          1.0         0.0
  1.1      1.0          1.0         0.0
<SGT><-KROG-><--KRG-><-PCGO->
 0.0       1.0          0.0         0.0
 0.001     1.0          0.0         0.0
 0.02      1.0          0.0         0.0
 0.05      1.0          0.005       0.0
 0.12      1.0          0.025       0.0
 0.15      0.985        0.040       0.0
 0.20      0.94         0.075       0.0
 0.25      0.66         0.125       0.0
 0.30      0.44         0.190       0.0
 0.40      0.134        0.410       0.0
 0.45      0.0693       0.600       0.0
 0.50      0.0348       0.720       0.0
 0.55      0.0144       0.7950      0.0
 0.60      0.0046       0.870       0.0
```

```
 0.70      0.00028   0.940      0.0
 0.75      0.00007   0.95333    0.0
 0.80      0.00002   0.96666    0.0
 0.85      0.0       0.980      0.0
 1.00      0.0       1.000      0.0
 1.10      0.0       1.000      0.0
<  PBO  >< VSLOPE >< BSLOPE >< BWSLOP ><   PMAX >
 4014.7    0.000046   -0.0000232   -0.000003       9014.7
<   P   >< VISO  >< BO  >< RSO   >
 14.7      1.04      1.062      1.0
 264.7     0.975     1.15       90.5
 514.7     0.910     1.207      180.0
 1014.7    0.830     1.295      371.0
 2014.7    0.695     1.435      636.0
 2514.7    0.641     1.50       775.0
 3014.7    0.594     1.565      930.0
 4014.7    0.51      1.695      1270.0
 5014.7    0.449     1.827      1618.0
 9014.7    0.203     2.357      2984.0
<   P   >< VISW >< BW    >< RSW   >
 14.7      0.31      1.041      0.0
 264.7     0.31      1.0403     0.0
 514.7     0.31      1.0395     0.0
 1014.7    0.31      1.038      0.0
 2014.7    0.31      1.035      0.0
 2514.7    0.31      1.0335     0.0
 3014.7    0.31      1.032      0.0
 4014.7    0.31      1.029      0.0
 5014.7    0.31      1.0258     0.0
 9014.7    0.31      1.013      0.0
<   P   >< VISG  ><     BG    >< CR    >
 14.7      0.0080    0.935830   0.000003
 264.7     0.0096    0.067902   0.000003
 514.7     0.0112    0.035229   0.000003
 1014.7    0.0140    0.017951   0.000003
 2014.7    0.0189    0.009063   0.000003
 2514.7    0.0208    0.007266   0.000003
 3014.7    0.0228    0.006064   0.000003
 4014.7    0.0268    0.004554   0.000003
 5014.7    0.0309    0.003644   0.000003
 9014.7    0.0470    0.002167   0.000003
<  RHOSCO><  RHOSCW><  RHOSCG>
 46.244    62.238   0.0647
<  NSLUGS><  NSREAD>
          0          1
---------- SOLVENT PVT DATA AND MODIFIED OIL & GAS PROPERTIES -----------
<  PBO1  ><VO1OPE  >< BO1OPE >
 14.70      0.000046    -.0000232
<  PBW1  ><VW1OPE  >< BW1OPE >
  14.70        0.0        -.000003
<  MEG1  >< MEG2  >
  0.666      0.666
<  PMISC >< FPMISC >< SOMIN  >< REDK  >< BETA  >< SORM  >< VSMISC >
  8900.0       1.0        -1.00        0.900      -1.000        0.00       0.50
```

```
< RHOSC1 >< RHOSC2 >< RHOSC3 >< RHOSC4 >
  .0647
..... B A S E   S O L V E N T   D A T A .....
<PRES><   VIS   ><      FVF  ><  RSOS1 >< RSWS1><  BO1  >< MUO1 >< BW1  >< MUW1 >
14.7       0.0080     0.935830       1.0          0.0        1.062        1.04     1.0410      0.31
264.7      0.0096     0.067902       90.5         0.0        1.15         0.975    1.0403      0.31
514.7      0.0112     0.035229       180.0        0.0        1.207        0.91     1.0395      0.31
1014.7     0.0140     0.017951       371.0        0.0        1.295        0.83     1.0380      0.31
2014.7     0.0189     0.009063       636.0        0.0        1.435        0.695    1.0350      0.31
2514.7     0.0208     0.007226       775.0        0.0        1.50         0.641    1.0335      0.31
3014.7     0.0228     0.006064       930.0        0.0        1.565        0.594    1.0320      0.31
4014.7     0.0268     0.004554       1270.        0.0        1.695        0.51     1.0290      0.31
5014.7     0.0309     0.003644       1618.        0.0        1.827        0.449    1.0258      0.31
9014.7     0.0470     0.002167       2984.        0.0        2.357        0.203    1.0130      0.31
    [NOMOB, MOBCTL, CSN]
   11    0  0.500
< NSC >< FRCO2 >
   0.00      0.00
   0.10      0.22
   0.20      0.35
   0.30      0.47
   0.40      0.57
   0.50      0.65
   0.60      0.72
   0.70      0.78
   0.80      0.82
   0.90      0.845
   1.00      0.850
EQUILIBRIUM PRESSURE INITIALIZATION/CONSTANT SATURATIONS
    1    0
   4784.   4784.   4784.   4784.   4784.   4784.   4784.   4784.   4784.   4784.
   4784.   4784.   4784.   4784.   4784.   4784.   4784.   4784.   4784.   4784.
   4784.   4784.   4784.   4784.   4784.   4784.   4784.   4784.   4784.   4784.
   4784.   4784.   4784.   4784.   4784.   4784.   4784.   4784.   4784.   4784.
   4784.   4784.   4784.   4784.   4784.   4784.   4784.   4784.   4784.   4784.
   4784.   4784.   4784.   4784.   4784.   4784.   4784.   4784.   4784.   4784.
   4784.   4784.   4784.   4784.   4784.   4784.   4784.   4784.   4784.   4784.
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   4790.   4790.   4790.   4790.   4790.   4790.   4790.   4790.   4790.   4790.
   4790.   4790.   4790.   4790.   4790.   4790.   4790.   4790.   4790.   4790.
   4790.   4790.   4790.   4790.   4790.   4790.   4790.   4790.   4790.   4790.
   4790.   4790.   4790.   4790.   4790.   4790.   4790.   4790.   4790.   4790.
   4790.   4790.   4790.   4790.   4790.   4790.   4790.   4790.   4790.   4790.
   4790.   4790.   4790.   4790.   4790.   4790.   4790.   4790.   4790.   4790.
   4790.   4790.   4790.   4790.   4790.   4790.   4790.   4790.   4790.   4790.
   4790.   4790.   4790.   4790.   4790.   4790.   4790.   4790.   4790.   4790.
   4790.   4790.   4790.   4790.   4790.   4790.   4790.   4790.   4790.   4790.
   4800.   4800.   4800.   4800.   4800.   4800.   4800.   4800.   4800.   4800.
   4800.   4800.   4800.   4800.   4800.   4800.   4800.   4800.   4800.   4800.
   4800.   4800.   4800.   4800.   4800.   4800.   4800.   4800.   4800.   4800.
   4800.   4800.   4800.   4800.   4800.   4800.   4800.   4800.   4800.   4800.
```

```
  4800.  4800.  4800.  4800.  4800.  4800.  4800.  4800.  4800.  4800.
  4800.  4800.  4800.  4800.  4800.  4800.  4800.  4800.  4800.  4800.
  4800.  4800.  4800.  4800.  4800.  4800.  4800.  4800.  4800.  4800.
  4800.  4800.  4800.  4800.  4800.  4800.  4800.  4800.  4800.  4800.
  4800.  4800.  4800.  4800.  4800.  4800.  4800.  4800.  4800.  4800.
  4800.  4800.  4800.  4800.  4800.  4800.  4800.  4800.  4800.  4800.
   0.88   0.120   0.000   0.000
KSW1 KSW2 KSW3
   1    0    0
NMAX <FACT1>< FACT2  ><TMAX><WORMAX>< GORMAX ><  PAMIN ><  PAMAX >
5000      1.00         1.00            3650.    100.               20000.           150.0           20000.
KSOL MITR <OMEGA><TOL>NCYCL<DSMAX><DPMAX>ITMAX< RTOL > NERR
   3      250       1.30       0.001     12             0.05     100.00      5         0.001         1
WEIGHT
 1.0
TRANSMISSIBILITY MODIFICATION CARDS
   0    0    0    0    0
IFOAM Code
0
RECURRENT DATA
   1    1    0    0    0    0    0    0    0    0    0    0    0    0
  1.0     0.10      1.0
NVQN KSIS
   2    0
INJ
1     1     1     1     3     0.     0.     -100000.     0.     0.     3     0     1
0.26     0.
PROD
10     10     3     1     1     20000.     0.     0.     0.     0.     3     0     1
0.26       0.
     0    8    0    0    0    0    0    0    0    0    0    0    0    0
  1.0       0.10      1.0
   0    1    1    1    1    1    1    1    1    0    0    0    0    0
  1.0       0.10      1.0
   0    9    0    0    0    0    0    0    0    0    0    0    0    0
  2.0       0.10      2.0
   0    1    1    1    1    1    1    1    1    0    0    0    0    0
  2.0       0.10      2.0
   0    8    0    0    0    0    0    0    0    0    0    0    0    0
  4.0       0.10      4.0
   0    4    0    0    0    0    0    0    0    0    0    0    0    0
  6.0       0.1       6.0
   0    1    1    1    1    1    1    1    1    0    0    0    0    0
  6.0       0.10      6.0
   0    8    0    0    0    0    0    0    0    0    0    0    0    0
  10.0       0.10      10.0
   0    1    0    0    0    0    0    0    0    0    0    0    0    0
  11.0       0.10      11.0
   0    8    0    0    0    0    0    0    0    0    0    0    0    0
  10.0       0.10      10.0
   0    1    0    0    0    0    0    0    0    0    0    0    0    0
  11.0       0.10      11.0
   0    8    0    0    0    0    0    0    0    0    0    0    0    0
  10.0       0.10      10.0
```

```
 0   1   1   1   1   1   1   1   1   0   0   0   0   0
11.0      0.10      11.0    END YR 1
 0   8   0   0   0   0   0   0   0   0   0   0   0   0
10.0      0.10      10.0
 0   1   0   0   0   0   0   0   0   0   0   0   0   0
11.0      0.10      11.0
 0   8   0   0   0   0   0   0   0   0   0   0   0   0
10.0      0.10      10.0
 0   1   0   0   0   0   0   0   0   0   0   0   0   0
11.0      0.10      11.0
 0   8   0   0   0   0   0   0   0   0   0   0   0   0
10.0      0.10      10.0
 0   1   0   0   0   0   0   0   0   0   0   0   0   0
11.0      0.10      11.0
 0   8   0   0   0   0   0   0   0   0   0   0   0   0
10.0      0.10      10.0
 0   1   1   1   1   1   1   1   1   0   0   0   0   0
12.0      0.10      12.0     END YR 2
 0   8   0   0   0   0   0   0   0   0   0   0   0   0
10.0      0.10      10.0
 0   1   0   0   0   0   0   0   0   0   0   0   0   0
11.0      0.10      11.0
 0   8   0   0   0   0   0   0   0   0   0   0   0   0
10.0      0.10      10.0
 0   1   0   0   0   0   0   0   0   0   0   0   0   0
11.0      0.10      11.0
 0   8   0   0   0   0   0   0   0   0   0   0   0   0
10.0      0.10      10.0
 0   1   0   0   0   0   0   0   0   0   0   0   0   0
11.0      0.10      11.0
 0   8   0   0   0   0   0   0   0   0   0   0   0   0
10.0      0.10      10.0
 0   1   1   1   1   1   1   1   1   0   0   0   0   0
12.0      0.10      12.0     END YR 3
 0   8   0   0   0   0   0   0   0   0   0   0   0   0
10.0      0.10      10.0
 0   1   0   0   0   0   0   0   0   0   0   0   0   0
11.0      0.10      11.0
 0   8   0   0   0   0   0   0   0   0   0   0   0   0
10.0      0.10      10.0
 0   1   0   0   0   0   0   0   0   0   0   0   0   0
11.0      0.10      11.0
 0   8   0   0   0   0   0   0   0   0   0   0   0   0
10.0      0.10      10.0
 0   1   0   0   0   0   0   0   0   0   0   0   0   0
11.0      0.10      11.0
 0   8   0   0   0   0   0   0   0   0   0   0   0   0
10.0      0.10      10.0
 0   1   1   1   1   1   1   1   1   0   0   0   0   0
12.0      0.10      12.0     END YR 4
 0   5   0   0   0   0   0   0   0   0   0   0   0   0
10.0      0.10      10.0
 1   1   0   0   0   0   0   0   0   0   0   0   0   0
10.0      0.1       10.0
```

```
NVQN    KSIS
   2    0
INJT1
1    1    1    1    3    0.    0.    -100000.    0.    0.    3    0    1
0.26    0.
PROD1
10    10    3    1    -11    0.    0.    0.    0.    0.    3    0    1
0.26    1000.
   0    2    0    0    0    0    0    0    0    0    0    0    0    0
  10.0       0.10       10.0
   0    1    0    0    0    0    0    0    0    0    0    0    0    0
  11.0       0.10       11.0
   0    8    0    0    0    0    0    0    0    0    0    0    0    0
  10.0       0.10       10.0
   0    1    0    0    0    0    0    0    0    0    0    0    0    0
  11.0       0.10       11.0
   0    8    0    0    0    0    0    0    0    0    0    0    0    0
  10.0       0.10       10.0
   0    1    0    0    0    0    0    0    0    0    0    0    0    0
  11.0       0.10       11.0
   0    8    0    0    0    0    0    0    0    0    0    0    0    0
  10.0       0.10       10.0
   0    1    1    1    1    1    1    1    1    0    0    0    0    0
  12.0       0.10       12.0      END YR 5
   0    8    0    0    0    0    0    0    0    0    0    0    0    0
  10.0       0.10       10.0
   0    1    0    0    0    0    0    0    0    0    0    0    0    0
  11.0       0.10       11.0
   0    8    0    0    0    0    0    0    0    0    0    0    0    0
  10.0       0.10       10.0
   0    1    0    0    0    0    0    0    0    0    0    0    0    0
  11.0       0.10       11.0
   0    8    0    0    0    0    0    0    0    0    0    0    0    0
  10.0       0.10       10.0
   0    1    0    0    0    0    0    0    0    0    0    0    0    0
  11.0       0.10       11.0
   0    8    0    0    0    0    0    0    0    0    0    0    0    0
  10.0       0.10       10.0
   0    1    1    1    1    1    1    1    1    0    0    0    0    0
  12.0       0.10       12.0      END YR 6
```

[The Recurrent Data Section repeats the sixth year (shaded area) four times for 10 years total]

Sample Well and Summary Reports at 5 Years for Example 1

WELL REPORT FOR ALL ACTIVE WELLS

ELAPSED TIME = 1825.000 DAYS FROM BEGINNING OF SIMULATION

WELL ID	LOCATION I	J	K	BHFP PSIA CALC	BHFP PSIA SPEC	RATE PI BBLS/PSI	RATE OIL STB/D	RATE GAS MCF/D	WATER STB/D	GOR SCF/STB	WOR STB/STB
INJT1	1	1	1	6216.	.0	10.69	0.0	-100000.	0.	0.	0.000
PROD1	10	10	3	-1.	1000.	10.69	14701.4	142178.	0.	9671.	0.000
TOTALS							14701.4	42178.	0.		

	CUMULATIVE OIL MSTB	CUMULATIVE GAS MMCF	CUMULATIVE WATER MSTB
	0.0	-182500.0	0.0
	35532.3	112877.2	0.1
TOTALS	35532.3	-69622.8	0.1

SUMMARY REPORT: MASTER (VERSION 2.00)

Elapsed Time (Days) = 1825.00 Time Step Number = 204 Time Step Size (Days) = 12.0000

Current Avg Pressure(psia) = 5504.5 Previous Avg Pressure (psia) = 5535.2 Pressure DPMAX(1, 1, 3) = -34.1

Oil DSMAX (4, 1, 2) = -0.01169 Gas DSMAX (4, 1, 2) = 0.01167 Water DSMAX(1, 1, 2) = 0.00002

Oil Material Balance (%) = 0.000143 Gas Material Balance (%) = 0.000107 Water Material Balance (%) = 0.000000

Oil Production Rate (STB/D)	= 14701.4	Cum. Oil Production (STB)	= 35532320.
Gas Production Rate (MSCF/D)	= 142177.5	Cum. Gas Production (MSCF)	= 112877232.
Water Production Rate(STB/D)	= 0.1	Cum. Water Production (STB)	= 64.
Gas Injection Rate (MSCF/D)	= 100000.0	Cum. Gas Injection (MSCF)	= 182500016.
Water Injection Rate (STB/D)	= 0.0	Cum. Water Injection (STB)	= 0.
Producing WOR (STB/STB)	= 0.000	Cum. WOR (STB/STB)	= 0.000
Producing GOR (SCF/STB)	= 9671.	Cum. GOR (SCF/STB)	= 3177.

Cumulative Material Balances (oil, gas, water) = 0.00078678% 0.00060797% 0.00007153%

Executive Summary Report for Example 1

TIME STEP	TIME DAYS	OPR STB/D	CUMOIL STB	WPR STB/D	CUM-WAT STB	WOR STB/STB	GPR MCF/D	CUMGAS MCF	GOR SCF/STB	S1PR MCF/D	CUMS1 MCF STB	S1OR SCF/
1	1.0	20000.0	20000.	0.0	0.	0.00	25399.	25399.	1270.	0.0	0.	0.
2	2.0	20000.0	40000.	0.0	0.	0.00	25399.	50799.	1270.	0.0	0.	0.
3	3.0	20000.0	60000.	0.0	0.	0.00	25399.	76198.	1270.	0.0	0.	0.
4	4.0	20000.0	80000.	0.1	0.	0.00	25399.	101598.	1270.	0.0	0.	0.
5	5.0	20000.0	100000.	0.1	0.	0.00	25399.	126997.	1270.	0.0	0.	0.
6	6.0	20000.0	120000.	0.1	0.	0.00	25399.	152396.	1270.	0.0	0.	0.
7	7.0	20000.0	140000.	0.1	0.	0.00	25399.	177796.	1270.	0.0	0.	0.
8	8.0	20000.0	160000.	0.1	0.	0.00	25399.	203195.	1270.	0.0	0.	0.
9	9.0	20000.0	180000.	0.1	1.	0.00	25399.	228594.	1270.	0.0	0.	0.
10	10.0	20000.0	200000.	0.1	1.	0.00	25399.	253994.	1270.	0.0	0.	0.
11	12.0	20000.0	240000.	0.1	1.	0.00	25399.	304793.	1270.	0.0	0.	0.
12	14.0	20000.0	280000.	0.1	1.	0.00	25370.	355532.	1268.	0.0	0.	0.
13	16.0	20000.0	320000.	0.1	1.	0.00	25275.	406081.	1264.	0.0	0.	0.
14	18.0	20000.0	360000.	0.1	1.	0.00	25170.	456422.	1259.	0.0	0.	0.
15	20.0	20000.0	400000.	0.1	2.	0.00	25064.	506549.	1253.	0.0	0.	0.
16	22.0	20000.0	440000.	0.1	2.	0.00	24960.	556470.	1248.	0.0	0.	0.
17	24.0	20000.0	480000.	0.1	2.	0.00	24862.	606193.	1243.	0.0	0.	0.
18	26.0	20000.0	520000.	0.1	2.	0.00	24769.	655732.	1238.	0.0	0.	0.
19	28.0	20000.0	560000.	0.1	3.	0.00	24684.	705099.	1234.	0.0	0.	0.
20	30.0	20000.0	600000.	0.1	3.	0.00	24604.	754307.	1230.	0.0	0.	0.
21	34.0	20000.0	680000.	0.1	3.	0.00	24533.	852440.	1227.	0.0	0.	0.
22	38.0	20000.0	760000.	0.1	4.	0.00	24847.	951827.	1242.	0.0	0.	0.
23	42.0	20000.0	840000.	0.1	4.	0.00	25090.	1052188.	1255.	0.0	0.	0.
24	46.0	20000.0	920000.	0.1	5.	0.00	25273.	1153280.	1264.	0.0	0.	0.
25	50.0	20000.0	1000000.	0.1	5.	0.00	25400.	1254878.	1270.	0.0	0.	0.
26	54.0	20000.0	1080000.	0.1	6.	0.00	25476.	1356781.	1274.	0.0	0.	0.
27	58.0	20000.0	1160000.	0.1	6.	0.00	25508.	1458812.	1275.	0.0	0.	0.
28	62.0	20000.0	1240000.	0.1	7.	0.00	25502.	1560821.	1275.	0.0	0.	0.
29	68.0	20000.0	1360000.	0.1	8.	0.00	25466.	1713615.	1273.	0.0	0.	0.
30	74.0	20000.0	1480000.	0.1	9.	0.00	25359.	1865771.	1268.	0.0	0.	0.
31	80.0	20000.0	1600000.	0.1	9.	0.00	25220.	2017090.	1261.	0.0	0.	0.
32	86.0	20000.0	1720000.	0.1	10.	0.00	25064.	2167472.	1253.	0.0	0.	0.
33	92.0	20000.0	1840000.	0.1	11.	0.00	24901.	2316877.	1245.	0.0	0.	0.
34	102.0	20000.0	2040000.	0.1	12.	0.00	24740.	2564279.	1237.	0.0	0.	0.
35	112.0	20000.0	2240000.	0.1	13.	0.00	24479.	2809072.	1224.	0.0	0.	0.

Reservoir Pressure and Fluid Saturation Distributions at 5 Years for Example 1

***** RESERVOIR PRESSURE DISTRIBUTION - PSIA *****

K=1

5952.	5885.	5835.	5789.	5737.	5682.	5637.	5604.	5585.	5579.
5885.	5854.	5815.	5769.	5717.	5664.	5619.	5587.	5567.	5561.
5835.	5815.	5780.	5735.	5682.	5630.	5586.	5552.	5531.	5523.
5789.	5769.	5735.	5688.	5636.	5585.	5538.	5500.	5475.	5466.
5737.	5717.	5682.	5636.	5584.	5530.	5478.	5432.	5400.	5386.
5682.	5664.	5630.	5585.	5530.	5469.	5407.	5348.	5303.	5280.
5637.	5619.	5586.	5538.	5478.	5407.	5329.	5249.	5179.	5139.
5604.	5587.	5552.	5500.	5432.	5348.	5249.	5137.	5025.	4944.
5585.	5567.	5531.	5475.	5400.	5303.	5179.	5025.	4840.	4655.
5579.	5561.	5523.	5466.	5386.	5280.	5139.	4944.	4655.	4204.

K=2

5955.	5889.	5838.	5793.	5743.	5688.	5643.	5610.	5591.	5585.
5889.	5857.	5819.	5774.	5723.	5670.	5626.	5593.	5573.	5567.
5838.	5819.	5784.	5741.	5688.	5636.	5592.	5558.	5537.	5530.
5793.	5774.	5741.	5694.	5642.	5591.	5544.	5507.	5482.	5472.
5743.	5723.	5688.	5642.	5590.	5536.	5484.	5439.	5406.	5392.
5688.	5670.	5636.	5591.	5536.	5475.	5413.	5355.	5309.	5286.
5643.	5626.	5592.	5544.	5484.	5413.	5335.	5255.	5185.	5145.

5610.	5593.	5558.	5507.	5439.	5355.	5255.	5143.	5031.	4950.
5591.	5573.	5537.	5482.	5406.	5309.	5185.	5031.	4846.	4660.
5585.	5567.	5530.	5472.	5392.	5286.	5145.	4950.	4660.	4203.

K=3

5959.	5895.	5845.	5802.	5753.	5698.	5653.	5621.	5601.	5595.
5895.	5863.	5827.	5784.	5733.	5680.	5636.	5603.	5583.	5577.
5845.	5827.	5794.	5751.	5698.	5647.	5602.	5568.	5547.	5540.
5802.	5784.	5751.	5704.	5652.	5601.	5555.	5517.	5492.	5482.
5753.	5733.	5698.	5652.	5600.	5546.	5494.	5449.	5417.	5402.
5698.	5680.	5647.	5601.	5546.	5486.	5423.	5365.	5319.	5296.
5653.	5636.	5602.	5555.	5494.	5423.	5345.	5265.	5196.	5155.
5621.	5603.	5568.	5517.	5449.	5365.	5265.	5154.	5041.	4959.
5601.	5583.	5547.	5492.	5417.	5319.	5196.	5041.	4856.	4670.
5595.	5577.	5540.	5482.	5402.	5296.	5155.	4959.	4670.	4185.

********* OIL SATURATION - FRACTION *********

K=1

0.307	0.333	0.355	0.447	0.495	0.514	0.522	0.531	0.546	0.694
0.333	0.347	0.418	0.466	0.503	0.516	0.524	0.531	0.546	0.697
0.355	0.418	0.456	0.495	0.512	0.519	0.525	0.531	0.545	0.693
0.447	0.466	0.495	0.510	0.517	0.521	0.526	0.531	0.544	0.682
0.495	0.503	0.512	0.517	0.520	0.523	0.526	0.530	0.541	0.664
0.514	0.516	0.519	0.521	0.523	0.525	0.527	0.530	0.538	0.641
0.522	0.524	0.525	0.526	0.526	0.527	0.528	0.529	0.535	0.615
0.531	0.531	0.531	0.531	0.530	0.530	0.529	0.529	0.532	0.585
0.546	0.546	0.545	0.544	0.541	0.538	0.535	0.532	0.528	0.552
0.694	0.697	0.693	0.682	0.664	0.641	0.615	0.585	0.552	0.519

K=2

0.385	0.434	0.508	0.795	0.881	0.881	0.881	0.881	0.881	0.881
0.434	0.486	0.704	0.881	0.881	0.881	0.881	0.881	0.881	0.881
0.508	0.704	0.881	0.881	0.881	0.881	0.881	0.881	0.881	0.881
0.795	0.881	0.881	0.881	0.881	0.881	0.881	0.881	0.880	0.880
0.881	0.881	0.881	0.881	0.881	0.881	0.880	0.880	0.880	0.880
0.881	0.881	0.881	0.881	0.881	0.880	0.880	0.880	0.880	0.880
0.881	0.881	0.881	0.881	0.880	0.880	0.880	0.880	0.880	0.880
0.881	0.881	0.881	0.881	0.880	0.880	0.880	0.880	0.880	0.880
0.881	0.881	0.881	0.880	0.880	0.880	0.880	0.880	0.880	0.880
0.881	0.881	0.881	0.880	0.880	0.880	0.880	0.880	0.880	0.590

K=3

0.466	0.541	0.639	0.782	0.881	0.881	0.881	0.881	0.881	0.881
0.541	0.614	0.751	0.881	0.881	0.881	0.881	0.881	0.881	0.881
0.639	0.751	0.881	0.881	0.881	0.881	0.881	0.881	0.881	0.881
0.782	0.881	0.881	0.881	0.881	0.881	0.881	0.881	0.880	0.880
0.881	0.881	0.881	0.881	0.881	0.881	0.880	0.880	0.880	0.880
0.881	0.881	0.881	0.881	0.881	0.880	0.880	0.880	0.880	0.880
0.881	0.881	0.881	0.881	0.880	0.880	0.880	0.880	0.880	0.880
0.881	0.881	0.881	0.881	0.880	0.880	0.880	0.880	0.880	0.880
0.881	0.881	0.881	0.880	0.880	0.880	0.880	0.880	0.880	0.880
0.881	0.881	0.881	0.880	0.880	0.880	0.880	0.880	0.880	0.677

******** WATER SATURATION - FRACTION *********

K=1

0.119	0.119	0.119	0.119	0.119	0.119	0.119	0.119	0.119	0.119
0.119	0.119	0.119	0.119	0.119	0.119	0.119	0.119	0.119	0.119
0.119	0.119	0.119	0.119	0.119	0.119	0.119	0.119	0.119	0.119
0.119	0.119	0.119	0.119	0.119	0.119	0.119	0.119	0.120	0.120
0.119	0.119	0.119	0.119	0.119	0.119	0.120	0.120	0.120	0.120
0.119	0.119	0.119	0.119	0.119	0.120	0.120	0.120	0.120	0.120
0.119	0.119	0.119	0.119	0.120	0.120	0.120	0.120	0.120	0.120
0.119	0.119	0.119	0.119	0.120	0.120	0.120	0.120	0.120	0.120
0.119	0.119	0.119	0.120	0.120	0.120	0.120	0.120	0.120	0.120
0.119	0.119	0.119	0.120	0.120	0.120	0.120	0.120	0.120	0.120

K=2

0.119	0.119	0.119	0.119	0.119	0.119	0.119	0.119	0.119	0.119
0.119	0.119	0.119	0.119	0.119	0.119	0.119	0.119	0.119	0.119
0.119	0.119	0.119	0.119	0.119	0.119	0.119	0.119	0.119	0.119
0.119	0.119	0.119	0.119	0.119	0.119	0.119	0.119	0.120	0.120
0.119	0.119	0.119	0.119	0.119	0.119	0.120	0.120	0.120	0.120
0.119	0.119	0.119	0.119	0.119	0.120	0.120	0.120	0.120	0.120
0.119	0.119	0.119	0.119	0.120	0.120	0.120	0.120	0.120	0.120
0.119	0.119	0.119	0.119	0.120	0.120	0.120	0.120	0.120	0.120
0.119	0.119	0.119	0.120	0.120	0.120	0.120	0.120	0.120	0.120
0.119	0.119	0.119	0.120	0.120	0.120	0.120	0.120	0.120	0.120

K=3

0.119	0.119	0.119	0.119	0.119	0.119	0.119	0.119	0.119	0.119
0.119	0.119	0.119	0.119	0.119	0.119	0.119	0.119	0.119	0.119
0.119	0.119	0.119	0.119	0.119	0.119	0.119	0.119	0.119	0.119
0.119	0.119	0.119	0.119	0.119	0.119	0.119	0.119	0.120	0.120
0.119	0.119	0.119	0.119	0.119	0.119	0.120	0.120	0.120	0.120
0.119	0.119	0.119	0.119	0.119	0.120	0.120	0.120	0.120	0.120
0.119	0.119	0.119	0.119	0.120	0.120	0.120	0.120	0.120	0.120
0.119	0.119	0.119	0.119	0.120	0.120	0.120	0.120	0.120	0.120
0.119	0.119	0.119	0.120	0.120	0.120	0.120	0.120	0.120	0.120
0.119	0.119	0.119	0.120	0.120	0.120	0.120	0.120	0.120	0.120

GAS SATURATION - FRACTION

K=1

0.574	0.548	0.526	0.434	0.386	0.366	0.358	0.350	0.335	0.187
0.548	0.534	0.462	0.415	0.377	0.365	0.357	0.350	0.335	0.184
0.526	0.462	0.425	0.386	0.369	0.362	0.356	0.349	0.335	0.187
0.434	0.415	0.386	0.371	0.364	0.359	0.355	0.350	0.337	0.199
0.386	0.377	0.369	0.364	0.361	0.358	0.354	0.350	0.339	0.217
0.366	0.365	0.362	0.359	0.358	0.356	0.354	0.351	0.342	0.239
0.358	0.357	0.356	0.355	0.354	0.354	0.353	0.351	0.345	0.265
0.350	0.350	0.349	0.350	0.350	0.351	0.351	0.352	0.349	0.295
0.335	0.335	0.335	0.337	0.339	0.342	0.345	0.349	0.352	0.328
0.187	0.184	0.187	0.199	0.217	0.239	0.265	0.295	0.328	0.361

K=2

0.496	0.447	0.373	0.086	0.000	0.000	0.000	0.000	0.000	0.000
0.447	0.395	0.176	0.000	0.000	0.000	0.000	0.000	0.000	0.000
0.373	0.176	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
0.085	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	0.000	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	0.000
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	0.000	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	0.000	0.000	0.000
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.289

K=3

0.415	0.340	0.241	0.098	0.000	0.000	0.000	0.000	0.000	0.000
0.340	0.267	0.130	0.000	0.000	0.000	0.000	0.000	0.000	0.000
0.241	0.130	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
0.098	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	0.000	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	0.000
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	0.000	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	0.000	0.000	0.000
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.203

********** END OF REPORT **********

9.2 Example 2

Input Data File for Example 2

```
MASTER VALIDATION Example 2 - WAG INJECTION - KILLOUGH &KOSSACK (1987):SPE16000
   7   7   3
GRID BLOCK LENGTHS
   -1   -1    0
500.
500.
20.  30.  50.
GRID BLOCK MODIFICATIONS
    0    0    0    0
CAPROCK BASE DEPTH
    0
8325.
POROSITY AND PERMEABILITY
   -1    0    0   0
.30
500.  50.  200.
500.  50.  200.
50.  50.  25.
POROSITY AND PERMEABILITY MODIFICATIONS
    0    0    0    0    0
RELATIVE PERMEABILITY-CAPILLARY PRESSURE DATA
         2    [KR3P]
         1    [ITABS]
         1    [NTABS]
<--SWT--->--KROW--><--KRW--->--PCOW-->
   0.20      1.00     0.0000     45.0
   0.2899    0.67690  0.0022     19.03
   0.3778    0.4153   0.0180     10.07
   0.4667    0.2178   0.0607      4.90
   0.5556    0.0835   0.1438      1.8
   0.6444    0.0123   0.2809      0.50
   0.70      0.000    0.4089      0.05
   0.7333    0.000    0.4855      0.01
   0.8222    0.0      0.7709      0.0
   0.9111    0.0      1.0         0.0
   1.00      0.0      1.0         0.0
   1.10      0.0      1.0         0.0
<--SGT--->--KROG--><--KRG--->--PCGO-->
   0.00      1.00     0.0000     0.0
   0.05      0.88     0.0        0.0
   0.0889    0.7023   0.001      0.0
   0.1778    0.4705   0.01       0.0
   0.2667    0.2963   0.03       0.001
   0.3556    0.1715   0.050      0.001
   0.4444    0.0878   0.10       0.03
   0.5333    0.037    0.20       0.8
   0.6222    0.011    0.350      3.0
   0.650     0.000    0.39       4.0
   0.7111    0.000    0.56       8.0
   0.80      0.0      1.0       30.0
   1.00      0.0      1.000     30.0
   1.10      0.0      1.000      0.0
<  PBO   >< VSLOPE  ><   BOSLP   ><  BWSLP  ><  PMAX >
  2302.3  0.00002524  -0.00002185 -0.0000033   4800.0
<   P    ><  VISO  ><  BO    ><  RSO   >
    14.7    .3100     1.0348    0.0
   500.0    .2950     1.1017   117.6
  1000.0    .2740     1.1478   222.6
  1200.0    .2640     1.1677   267.7
  1500.0    .2490     1.1997   341.4
  1800.0    .2340     1.2350   421.5
  2000.0    .2240     1.2600   479.0
  2302.3    .2080     1.3010   572.8
  2500.0    .2000     1.3278   634.1
```

```
  3000.0    .1870     1.3956   789.3
  3500.0    .1750     1.4634   944.4
  4000.0    .1670     1.5312  1099.5
  4500.0    .1590     1.5991  1254.7
  4800.0    .1550     1.6398  1347.8
<   P    ><  VISW  ><  BW    ><  RSW   >
    14.7    0.70       1.000     0.0
   500.0    0.70       0.9984    0.0
  1000.0    0.70       0.9968    0.0
  1500.0    0.70       0.9951    0.0
  2000.0    0.70       0.9935    0.0
  2302.3    0.70       0.9925    0.0
  3000.0    0.70       0.9902    0.0
  4000.0    0.70       0.9869    0.0
  4800.0    0.70       0.9843    0.0
<   P    ><  VISG  ><  BG    ><    CR    >
    14.7    0.0107   1.187015   0.000005
   500.0    0.0127   0.033262   0.000005
  1000.0    0.0134   0.016005   0.000005
  1200.0    0.0138   0.013161   0.000005
  1500.0    0.0145   0.010363   0.000005
  1800.0    0.0153   0.008535   0.000005
  2000.0    0.0159   0.007637   0.000005
  2302.3    0.0170   0.006598   0.000005
  2500.0    0.0177   0.006190   0.000005
  3000.0    0.0195   0.005532   0.000005
  3500.0    0.0214   0.005118   0.000005
  4000.0    0.0232   0.004840   0.000005
  4500.0    0.0250   0.004617   0.000005
  4800.0    0.0261   0.004510   0.000005
<  RHOSCO><  RHOSCW><  RHOSCG>
  38.53      62.4     0.06864
  NSLUGS  NSREAD
    1    2  [No. of solvents for simulation;  No. of solvent datasets]
---------- SOLVENT PVT DATA AND MODIFIED OIL & GAS PROPERTIES -----------
<  PBO1  >< VO1OPE  >< BO1OPE >  (Base solvent only)
    14.7  0.00002524 -0.00002185
<  PBW1  ><VW1OPE  >< BW1OPE >  (Base solvent only)
    14.7   0.0       0.0
<  MEG1  ><  MEG2  >  [MEG1  = "omega" for gas-solvent miscibility]
   1.00      1.00     [MEG2  = "omega" for oil-gas-solvent miscibility]
<  PMISC >< FPMISC >< SOMIN  ><  REDK  ><  BETA  ><  SORM  >< VSMISC >
  3000.0     1.00     0.000      0.50      -1.0       0.0        0.01
< RHOSC1 >< RHOSC2 >< RHOSC3 >< RHOSC4 >
  0.06269    0.06269  0.06269   0.06269
....... B A S E   S O L V E N T   D A T A .........
<PRES>< VIS  ><  FVF  >< RSOS1><  RSWS1><  BO1  >< MUO1 >< BW1  ><MUW1 >
  14.7  0.011  1.125325  0.0     0.0    1.0348   0.31   1.0     0.70
 500.0  0.012   0.03145  117.6   0.0    1.1017   0.295  0.9984  0.70
1000.0  0.013   0.01421  222.6   0.0    1.1478   0.274  0.9968  0.70
1200.0  0.014   0.01143  267.7   0.0    1.1677   0.264  0.9961  0.70
1500.0  0.016   0.00875  341.4   0.0    1.1997   0.249  0.9951  0.70
1800.0  0.018   0.00711  421.5   0.0    1.2350   0.234  0.9941  0.70
2000.0  0.019   0.00634  479.0   0.0    1.2600   0.224  0.9935  0.70
2302.3  0.022   0.00550  572.8   0.0    1.3010   0.208  0.9925  0.70
2500.0  0.023   0.00510  634.1   0.0    1.3278   0.200  0.9918  0.70
3000.0  0.027   0.00438  789.3   0.0    1.3956   0.187  0.9902  0.70
3500.0  0.031   0.00393  944.4   0.0    1.4634   0.175  0.9885  0.70
4000.0  0.034   0.00361 1099.5   0.0    1.5312   0.167  0.9869  0.70
4500.0  0.037   0.00338 1254.7   0.0    1.5991   0.159  0.9852  0.70
4800.0  0.038   0.00327 1347.8   0.0    1.6398   0.155  0.9843  0.70
.......... S O L V E N T   N O.  2   D A T A ........................
<  PRES  ><  VIS   ><  FVF   >< RSOS2  >    [Solvent 2 data]
14.7       0.0200    0.0150    0.0
100.0      0.0200    0.0150    75.0
500.0      0.0200    0.0150    150.0
4800.0     0.0200    0.0150    800.0
```

```
.......... M O B I L I T Y   C O N T R O L   T A B L E ..........
   11    0  0.500     [NOMOB, MOBCTL, CSN]
<  NSC   ><  FRCO2 >
   0.00      0.00
   0.10      0.22
   0.20      0.35
   0.30      0.47
   0.40      0.57
   0.50      0.65
   0.60      0.72
   0.70      0.78
   0.80      0.82
   0.90      0.845
   1.00      0.850
EQUILIBRIUM PRESSURE INITIALIZATION/CONSTANT SATURATIONS
    1    0
3984.3 3984.3 3984.3 3984.3 3984.3 3984.3 3984.3
3984.3 3984.3 3984.3 3984.3 3984.3 3984.3 3984.3
3984.3 3984.3 3984.3 3984.3 3984.3 3984.3 3984.3
3984.3 3984.3 3984.3 3984.3 3984.3 3984.3 3984.3
3984.3 3984.3 3984.3 3984.3 3984.3 3984.3 3984.3
3984.3 3984.3 3984.3 3984.3 3984.3 3984.3 3984.3
3984.3 3984.3 3984.3 3984.3 3984.3 3984.3 3984.3
3990.3 3990.3 3990.3 3990.3 3990.3 3990.3 3990.3
3990.3 3990.3 3990.3 3990.3 3990.3 3990.3 3990.3
3990.3 3990.3 3990.3 3990.3 3990.3 3990.3 3990.3
3990.3 3990.3 3990.3 3990.3 3990.3 3990.3 3990.3
3990.3 3990.3 3990.3 3990.3 3990.3 3990.3 3990.3
3990.3 3990.3 3990.3 3990.3 3990.3 3990.3 3990.3
3990.3 3990.3 3990.3 3990.3 3990.3 3990.3 3990.3
4000.0 4000.0 4000.0 4000.0 4000.0 4000.0 4000.0
4000.0 4000.0 4000.0 4000.0 4000.0 4000.0 4000.0
4000.0 4000.0 4000.0 4000.0 4000.0 4000.0 4000.0
4000.0 4000.0 4000.0 4000.0 4000.0 4000.0 4000.0
4000.0 4000.0 4000.0 4000.0 4000.0 4000.0 4000.0
4000.0 4000.0 4000.0 4000.0 4000.0 4000.0 4000.0
4000.0 4000.0 4000.0 4000.0 4000.0 4000.0 4000.0
     0.80     0.20     0.0     0.0     0.0     0.0     0.0
 KSW1 KSW2 KSW3
    1    0    0
 NMAX<  FACT1 ><  FACT2 ><  TMAX  >< WORMAX >< GORMAX ><  PAMIN ><  PAMAX >
 8000   1.00      1.00      7300.      5.0     10000.      15.0      5000.
 KSOL MITR< OMEGA  ><  TOL   >NCYCL< DSMAX  >< DPMAX  >ITMAX < RTOL  > NERR
    3  450   1.70     0.001    12    0.05     100.00     5    .001       1
 WEIGHT
   1.0
TRANSMISSIBILITY MODIFICATION CARDS
    0    0    0    0    0
IFOAM CODE
0
RECURRENT DATA
    1    2    0    0    0    0    0    0    0    0    0    0    0    0
   5.0     1.0      40.
 NVQN KSIS
    1    0
OILPD
7   7   3   1   1   12000.   0.0   0.0   0.0   0.0   3   O2
 0.258   1000.
  0   1   0   0   0   0   0   0   0   0   0   0   0   0
 10.0   .50   40.
  0   7   0   0   0   0   0   0   0   0   0   0   0   0
 20.0   .50   40.
  0   1   1   1   1   1   1   1   0   0   1   0   0   0
 22.0   .50   40.
  0   8   0   0   0   0   0   0   0   0   0   0   0   0
 20.0   .50   40.
```

```
   0   1   1   1   1   1   1   1   0   0   1   0   0   0
 23.0     .50     40.      END YEAR 1
   0   4   0   0   0   0   0   0   0   0   0   0   0   0
 20.0     .50     40.
   0   1   0   0   0   0   0   0   0   0   0   0   0   0
 15.0     .50     40.
   1   1   1   1   1   1   1   1   0   0   1   0   0   0
 15.0     .50     40.
 NVQN KSIS
   1   0
OILPD
7    7    3    1    -11    0.0    0.0    0.0    0.0    0.0    3    0    2
0.258    1000.
   0   8   0   0   0   0   0   0   0   0   0   0   0   0
 15.0     .50     40.
   0   6   0   0   0   0   0   0   0   0   0   0   0   0
 20.0     .50     40.
   0   1   1   1   1   1   1   1   0   0   1   0   0   0
 15.0     .50     40.      END YEAR 2
   1   2   0   0   0   0   0   0   0   0   0   0   0   0
  5.0     .50     40.
 NVQN KSIS
   2   0
OILPD
7    7    3    1    -11    0.0    0.0    0.0    0.0    0.0    3    0    2
0.258          1000.
WAGIN
1    1    1    1    2    0.0    -12000.    0.0    0.0    0.0    3    0    2
0.258    10000.
   0   1   0   0   0   0   0   0   0   0   0   0   0   0
 10.0     .50     40.
   0   7   0   0   0   0   0   0   0   0   0   0   0   0
 20.0     .50     40.
   0   1   1   1   1   1   1   1   0   0   1   0   0   0
 22.0     .50     40.
   0   8   0   0   0   0   0   0   0   0   0   0   0   0
 20.0     .50     40.
   0   1   1   1   1   1   1   1   0   0   1   0   0   0
 23.0     .50     40.      END YEAR 3
   1   2   0   0   0   0   0   0   0   0   0   0   0   0
  2.5     .50     40.
 NVQN KSIS
   2   0
OILPD
7    7    3    1    -11    0.0    0.0    0.0    0.0    0.0    3    0    2
0.258    1000.
WAGIN
1    1    1    1    100    0.0    0.0    0.0    0.0    -12000.    3    0    2
0.258    10000.
   0   1   0   0   0   0   0   0   0   0   0   0   0   0
  5.0     .50     40.
   0   1   0   0   0   0   0   0   0   0   0   0   0   0
 10.0     .50     40.
   0   7   0   0   0   0   0   0   0   0   0   0   0   0
 20.0     .50     40.
   0   1   1   1   1   1   1   1   0   0   1   0   0   0
 22.0     .50     40.
   0   8   0   0   0   0   0   0   0   0   0   0   0   0
 20.0     .50     40.
   0   1   1   1   1   1   1   1   0   0   1   0   0   0
 23.0     .50     40.      END YEAR 4
```

[The Recurrent Data Section repeats years 3 and 4 (shaded area) for the remaining simulation.]

Sample Well and Summary Reports at 10 Years for Example 2

********* WELL REPORT FOR ALL ACTIVE WELLS *********

ELAPSED TIME = 3650.000 DAYS FROM BEGINNING OF SIMULATION

WELL ID	LOCATION I	J	K	BHFP PSIA CALC	BHFP PSIA SPEC	RATE PI BBLS/PSI	RATE OIL STB/D	RATE GAS MCF/D	WATER STB/D	GOR SCF/STB	WOR STB/STB
OILPD	7	7	3	-1.	1000.	11.89	5026.0	3227.	1.	642.	0.000
TOTALS							5026.0	3227.	1.		

	CUMULATIVE OIL MSTB	CUMULATIVE GAS MMCF	CUMULATIVE WATER MSTB
	19490.1	16990.8	2.8
TOTALS	19490.1	16990.8	2.8

********** SOLVENT REPORT FOR ALL ACTIVE WELLS **********

ELAPSED TIME = 3650.000 DAYS FROM BEGINNING OF SIMULATION

WELL ID	LOCATION I	J	K	BHFP PSIA CALC	BHFP PSIA SPEC	PI BBLS/PSI	RATE SOLVENT1 MCF/D	RATE SOLVENT2 MCF/D	RATE SOLVENT3 MCF/D	RATE SOLVENT4 MCF/D
OILPD	7	7	3	-1	1000.	11.890	6479.	0.	0.	0.
WAGIN	1	1	1	2251.	10000.	11.890	-12000.	0.	0.	0.
TOTALS							-5521.	0.	0.	0.

	CUMULATIVE SOLVENT1 MCF/D	CUMULATIVE SOLVENT2 MCF/D	CUMULATIVE SOLVENT3 MCF/D	CUMULATIVE SOLVENT4 MCF/D
OILPD	10308.1	0.	0.	0.
WAGIN	-17520.0	0.	0.	0.
TOTALS	-7211.9	0.	0.	0.

SUMMARY REPORT: MASTER

Elapsed Time (Days) = 3650.00 Time Step Number = 208 Time Step Size (Days) = 23.0000

Current Avg Pressure (psia)	= 1736.1	Previous Avg Pressure (psia)	= 1738.0	Pressure DPMAX (1, 1, 3)	= -8.9
Oil DSMAX (5, 7, 1)	= -0.01540	Gas DSMAX (5, 7, 1)	= 0.01534	Water DSMAX (6, 5, 3)	= 0.01057
Oil Material Balance (%)	= -0.000018	Gas Material Balance (%)	= 0.000024	Water Material Balance (%)	= 0.000024

Oil Production Rate (STB/D)	= 5026.0	Cum. Oil Production (STB)	= 19490048.
Gas Prod. Rate (MSCF/D)	= 3226.8	Cum. Gas Production (MSCF)	= 16990794.
Water Prod. Rate(STB/D)	= 0.9	Cum. Water Production (STB)	= 2800.
Gas Injection Rate (MSCF/D)	= 0.0	Cum. Gas Injection (MSCF)	= 0.
Water Injection Rate (STB/D)	= 0.0	Cum. Water Injection (STB)	= 17520000.
Producing WOR (STB/STB)	= 0.000	Cum. WOR (STB/STB)	= 0.000
Producing GOR (SCF/STB)	= 642.	Cum. GOR (SCF/STB)	= 872.

Cumulative Material Balances (Oil, Gas, Water) = -0.00008345% 0.00002384% 0.00002384%

***** MAXIMUM SOLVENT SATURATION CHANGES *****

SOLVENT 1 DVSMAX(7, 7, 3) = 0.03022

***** SOLVENT MATERIAL BALANCES -- TIME-STEP & CUMULATIVE ****

SOLVENT 1 MAT. BAL. (%) = 0.238419E-04 0.596046E-04

***** SOLVENT INJECTION/PRODUCTION RATES *****

SOLVENT 1

Injection Rate (MCF/D)	= 12000.0	Cumulative Injection (MCF)	= 17520002.
Production Rate (MCF/D)	= 6479.2	Cumulative Production (MCF)	= 10308089.
SOL 1/Oil Producing Ratio (SCF/STB)	= 1289.		

9.3 Example 3

Input Data File for Example 3

The data set is the same as that in Scenario 1 (Example 2). The changes are in the Recurrent Data, see Section 7.3.

```
RECURRENT DATA
   1   1   0   0   0   0   0   0   0   0   0   0   0   0
  1.250     .50    40.
 NVQN KSIS
   2   0
OILPD
   7   7   3   1   1  12000.    0.0      0.0      0.0      0.0                    3          0          2
0.258   3000.
WAGIN
   1   1   1   1  -12   0.0      0.0      0.0      0.0      0.0                    3          0          2
0.258   4500.
   0   2   0   0   0   0   0   0   0   0   0   0   0   0
  2.5    .50     40.
   0   1   0   0   0   0   0   0   0   0   0   0   0   0
  5.0    .50     40.
   0   2   0   0   0   0   0   0   0   0   0   0   0   0
 10.0    .50     40.
   0   4   0   0   0   0   0   0   0   0   0   0   0   0
 10.0    .50     40.
   1   1   0   0   0   0   0   0   0   0   0   0   0   0
 10.0    .50     40.
 NVQN KSIS
   2   0
OILPD
   7   7   3   1  -11   000.     0.0      0.0      0.0      0.0                    3          0          2
0.258   3000.
WAGIN
   1   1   1   1  -12   0.0      0.0      0.0      0.0      0.0                    3          0          2
0.258   4500.
   0   1   1   1   1   1   1   1   0   0   1   0   0   0
 10.0    .50     40.      END Q1 YR1
   1   1   0   0   0   0   0   0   0   0   0   0   0   0
  1.25    .50     40.
 NVQN KSIS
   2   0
OILPD
   7   7   3   1  -11   0.0      0.0      0.0      0.0      0.0                    3          0          2
0.258   3000.
WAGIN
   1   1   1   1  -14   0.0      0.0      0.0      0.0    -20000.                  3          0          2
0.258   4500.
   0   2   0   0   0   0   0   0   0   0   0   0   0   0
  2.5    .50     40.
   0   1   0   0   0   0   0   0   0   0   0   0   0   0
  5.0    .50     40.
   1   1   1   1   1   1   1   1   1   1   1   1   1   1
  1.25    .50     40.
 NVQN KSIS
   2   0
OILPD
   7   7   3   1  -11   0.0      0.0      0.0      0.0      0.0                    3          0          2
0.258   3000.
WAGIN
   1   1   1   1  100   0.0      0.0      0.0      0.0    -20000.                  3          0          2
```

```
0.258    4500.
   0   2   0   0   0   0   0   0   0   0   0   0   0   0
  2.5     .50      40.
   0   1   0   0   0   0   0   0   0   0   0   0   0   0
  5.0     .50      40.
   0   6   0   0   0   0   0   0   0   0   0   0   0   0
 10.0     .50      40.
   0   1   1   1   1   1   1   1   0   0   1   0   0   0
  8.75     .50      40.      END Q2 YR1
   1   1   0   0   0   0   0   0   0   0   0   0   0   0
  1.250      .50     40.
 NVQN KSIS
   2   0
OILPD
   7   7   3   1  -11   0.0       0.0       0.0       0.0       0.0                    3          0          2
0.258    3000.
WAGIN
   1   1   1   1  -12   0.0       0.0       0.0       0.0       0.0                    3          0          2
0.258    4500.
   0   2   0   0   0   0   0   0   0   0   0   0   0   0
  2.5     .50      40.
   0   1   0   0   0   0   0   0   0   0   0   0   0   0
  5.0     .50      40.
   0   7   0   0   0   0   0   0   0   0   0   0   0   0
 10.0     .50      40.
   0   1   1   1   1   1   1   1   0   0   1   0   0   0
 10.0     .50      40.      END Q3 YR1
   1   1   0   0   0   0   0   0   0   0   0   0   0   0
  1.25    .50      40.
 NVQN KSIS
   2   0
OILPD
   7   7   3   1  -11   0.0       0.0       0.0       0.0       0.0                    3          0          2
0.258    3000.
WAGIN
   1   1   1   1  -14   0.0       0.0       0.0       0.0     -20000.                  3          0          2
0.258    4500.
   0   2   0   0   0   0   0   0   0   0   0   0   0   0
  2.5     .50      40.
   0   1   0   0   0   0   0   0   0   0   0   0   0   0
  5.0     .50      40.
   1   1   0   0   0   0   0   0   0   0   0   0   0   0
  1.25    .50      40.
 NVQN KSIS
   2   0
OILPD
   7   7   3   1  -11   0.0       0.0       0.0       0.0       0.0                    3          0          2
0.258    3000.
WAGIN
   1   1   1   1  100   0.0       0.0       0.0       0.0     -20000.                  3          0          2
0.258    4500.
   0   2   0   0   0   0   0   0   0   0   0   0   0   0
  2.5     .50      40.
   0   1   0   0   0   0   0   0   0   0   0   0   0   0
  5.0     .50      40.
   0   6   0   0   0   0   0   0   0   0   0   0   0   0
 10.0     .50      40.
   0   1   1   1   1   1   1   1   0   0   1   0   0   0
  8.75     .50      40.      END Q4 YR1
   1   1   0   0   0   0   0   0   0   0   0   0   0   0
  1.250      .50     40.
 NVQN KSIS
```

```
   2    0
OILPD
   7    7    3    1  -11   0.0       0.0       0.0       0.0       0.0                    3          0          2
0.258    3000.
WAGIN
   1    1    1    1  -12   0.0       0.0       0.0       0.0       0.0                    3          0          2
0.258    4500.
   0    2    0    0    0    0    0    0    0    0    0    0    0    0
  2.5     .50      40.
   0    1    0    0    0    0    0    0    0    0    0    0    0    0
  5.0     .50      40.
   0    7    0    0    0    0    0    0    0    0    0    0    0    0
 10.0     .50      40.
   0    1    1    1    1    1    1    1    0    0    1    0    0    0
 10.0     .50      40.       END Q1 YR2
   1    1    0    0    0    0    0    0    0    0    0    0    0    0
  1.25    .50      40.
 NVQN KSIS
   2    0
OILPD
   7    7    3    1  -11   0.0       0.0       0.0       0.0       0.0                    3          0          2
0.258    3000.
WAGIN
   1    1    1    1  100   0.0       0.0       0.0       0.0    -20000.                   3          0          2
0.258    4500.
   0    2    0    0    0    0    0    0    0    0    0    0    0    0
  2.5     .50      40.
   0    1    0    0    0    0    0    0    0    0    0    0    0    0
  5.0     .50      40.
   0    7    0    0    0    0    0    0    0    0    0    0    0    0
 10.0     .50      40.
   0    1    1    1    1    1    1    1    0    0    1    0    0    0
 10.0     .50      40.       END Q2 YR2
   1    1    0    0    0    0    0    0    0    0    0    0    0    0
  1.250      .50      40.
 NVQN KSIS
   2    0
OILPD
   7    7    3    1  -11   0.0       0.0       0.0       0.0       0.0                    3          0          2
0.258    3000.
WAGIN
   1    1    1    1  -12   0.0       0.0       0.0       0.0       0.0                    3          0          2
0.258    4500.
   0    2    0    0    0    0    0    0    0    0    0    0    0    0
  2.5     .50      40.
   0    1    0    0    0    0    0    0    0    0    0    0    0    0
  5.0     .50      40.
   0    7    0    0    0    0    0    0    0    0    0    0    0    0
 10.0     .50      40.
   0    1    1    1    1    1    1    1    0    0    1    0    0    0
 10.0     .50      40.       END Q3 YR2
   1    1    0    0    0    0    0    0    0    0    0    0    0    0
  1.25    .50      40.
 NVQN KSIS
   2    0
OILPD
   7    7    3    1  -11   0.0       0.0       0.0       0.0       0.0                    3          0          2
0.258    3000.
WAGIN
   1    1    1    1  100   0.0       0.0       0.0       0.0    -20000.                   3          0          2
0.258    4500.
   0    2    0    0    0    0    0    0    0    0    0    0    0    0
```

```
  2.5     .50      40.
   0    1    0    0    0    0    0    0    0    0    0    0    0    0
  5.0     .50      40.
   0    7    0    0    0    0    0    0    0    0    0    0    0    0
 10.0     .50      40.
   0    1    1    1    1    1    1    1    0    0    1    0    0    0
 10.0     .50      40.       END Q4 YR2
   1    1    0    0    0    0    0    0    0    0    0    0    0    0
  1.250      .50     40.
 NVQN KSIS
   2    0
OILPD
   7    7    3    1  -11   0.0       0.0       0.0       0.0       0.0                    3          0          2
0.258    3000.
WAGIN
   1    1    1    1  -12   0.0       0.0       0.0       0.0       0.0                    3          0          2
0.258    4500.
   0    2    0    0    0    0    0    0    0    0    0    0    0    0
  2.5     .50      40.
   0    1    0    0    0    0    0    0    0    0    0    0    0    0
  5.0     .50      40.
   0   10    0    0    0    0    0    0    0    0    0    0    0    0
  7.0     .50      40.
   0    1    1    1    1    1    1    1    0    0    1    0    0    0
 10.0     .50      40.       END Q1 YR3
   1    1    0    0    0    0    0    0    0    0    0    0    0    0
  1.25    .50      40.
 NVQN KSIS
   2    0
OILPD
   7    7    3    1  -11   0.0       0.0       0.0       0.0       0.0                    3          0          2
0.258    3000.
WAGIN
   1    1    1    1  100   0.0       0.0       0.0       0.0    -20000.                   3          0          2
0.258    4500.
   0    2    0    0    0    0    0    0    0    0    0    0    0    0
  2.5     .50      40.
   0    1    0    0    0    0    0    0    0    0    0    0    0    0
  5.0     .50      40.
   0   10    0    0    0    0    0    0    0    0    0    0    0    0
  7.0     .50      40.
   0    1    1    1    1    1    1    1    0    0    1    0    0    0
 10.0     .50      40.       END Q2 YR3
   1    1    0    0    0    0    0    0    0    0    0    0    0    0
  1.25      .50     40.
 NVQN KSIS
   2    0
OILPD
   7    7    3    1  -11   0.0       0.0       0.0       0.0       0.0                    3          0          2
0.258    3000.
WAGIN
   1    1    1    1  -12   0.0       0.0       0.0       0.0       0.0                    3          0          2
0.258    4500.
   0    2    0    0    0    0    0    0    0    0    0    0    0    0
  2.5     .50      40.
   0    1    0    0    0    0    0    0    0    0    0    0    0    0
  5.0     .50      40.
   0   10    0    0    0    0    0    0    0    0    0    0    0    0
  7.0     .50      40.
   0    1    1    1    1    1    1    1    0    0    1    0    0    0
 10.0     .50      40.       END Q3 YR3
   1    1    0    0    0    0    0    0    0    0    0    0    0    0
```

```
  1.25    .50     40.
 NVQN KSIS
   2   0
OILPD
   7   7   3   1  -11   0.0      0.0      0.0      0.0      0.0                    3          0          2
0.258    3000.
WAGIN
   1   1   1   1  100   0.0      0.0      0.0      0.0    -20000.                  3          0          2
0.258    4500.
   0   2   0   0   0   0   0   0   0   0   0   0   0   0
  2.5    .50     40.
   0   1   0   0   0   0   0   0   0   0   0   0   0   0
  5.0    .50     40.
   0  10   0   0   0   0   0   0   0   0   0   0   0   0
  7.0    .50     40.
   0   1   1   1   1   1   1   1   0   0   1   0   0   0
 10.0    .50     40.      END Q4 YR3
```

[The Recurrent Data Section repeats quarters three and four of the third year (shaded area) until 20 years.]

Sample Well and Summary Reports at 15 Years for Example 3

********** WELL REPORT FOR ALL ACTIVE WELLS **********

ELAPSED TIME = 5475.000 DAYS FROM BEGINNING OF SIMULATION

WELL ID	LOCATION I J K	BHFP PSIA CALC	BHFP PSIA SPEC	RATE PI BBLS/PSI	RATE OIL STB/D	RATE GAS MCF/D	WATER STB/D	GOR SCF/STB	WOR STB/STB
OILPD	7 7 3	-1.	3000.	11.89	3664.4	3254.	0.	888.	0.000
TOTALS					3664.4	3257.	0.		

	CUMULATIVE OIL MSTB	CUMULATIVE GAS MMCF	CUMULATIVE WATER MSTB
	28285.5	16989.2	0.4
TOTALS	28285.5	16989.2	0.4

********** SOLVENT REPORT FOR ALL ACTIVE WELLS **********

ELAPSED TIME = 5475.000 DAYS FROM BEGINNING OF SIMULATION

WELL ID	LOCATION I J K	BHFP PSIA CALC	BHFP PSIA SPEC	PI BBLS/PSI	RATE SOLVENT1 MCF/D	RATE SOLVENT2 MCF/D	RATE SOLVENT3 MCF/D	RATE SOLVENT4 MCF/D
OILPD	7 7 3	-1	3000.	11.890	11689.	0.	0.	0.
WAGIN	1 1 1	3692.	4500.	11.890	-20000.	0.	0.	0.

TOTALS	-8311.	0.	0.	0.

	CUMULATIVE			
	SOLVENT1 MCF/D	SOLVENT2 MCF/D	SOLVENT3 MCF/D	SOLVENT4 MCF/D
OILPD	42227.0	0.	0.	O.
WAGIN	-54581.0	0.	0.	0.
TOTALS	-12354.0	0.	0.	0.

SUMMARY REPORT: MASTER

Elapsed Time (Days) = 5475.00 Time Step Number = 882 Time Step Size (Days) = 10.0000

Current Avg Pressure (psia)	=	3301.6	Previous Avg Pressure (psia)	=	3300.0	Pressure DPMAX (11 1, 3)	=	-11.1
Oil DSMAX (7, 4, 2)	=	-0.00706	Gas DSMAX (6, 5, 1)	=	-0.01316	Water DSMAX (6, 5, 1)	=	0.01609
Oil Material Balance (%)	=	0.000000	Gas Material Balance (%)	=	0.000024	Water Material Balance (%)	=	0.000000

Oil Production Rate (STB/D)	=	3664.4	Cum. Oil Production (STB)	=	28285496.
Gas Prod. Rate (MSCF/D)	=	3254.4	Cum. Gas Production (MSCF)	=	16989212.
Water Prod. Rate(STB/D)	=	0.1	Cum. Water Production (STB)	=	401.
Gas Injection Rate (MSCF/D)	=	0.0	Cum. Gas Injection (MSCF)	=	0.
Water Injection Rate (STB/D)	=	0.0	Cum. Water Injection (STB)	=	27162730.
Producing WOR (STB/STB)	=	0.000	Cum. WOR (STB/STB)	=	0.000
Producing GOR (SCF/STB)	=	888.	Cum. GOR (SCF/STB)	=	601.

Cumulative Material Balances (Oil, Gas, Water) = -0.00000596% 0.00016689% 0.00002384%

***** MAXIMUM SOLVENT SATURATION CHANGES *****

SOLVENT 1 DVSMAX(7, 7, 2) 0.02690

***** SOLVENT MATERIAL BALANCES - TIME-STEP & CUMULATIVE *****

SOLVENT 1 MAT. PAL. (%) -0.274181E-03 -0.649691E-03

***** SOLVENT INJECTION/PRODUCTION RATES *****

SOLVENT 1

Injection Rate (MCF/D)	=	20000.0	Cumulative Injection (MCF)	=	54581008.
Production Rate (MCF/D)	=	11689.4	Cumulative Production (MCF)	=	42227044.
SOL 1/Oil Producing Ratio (SCF/STB)	=	3190.			

9.4 Example 4

Input Data File for Example 4

The data set is the same as that in Scenarios 1 and 2 (Examples 2 and 3). The changes are in the Recurrent Data, see Section 7.4.

```
RECURRENT DATA
   1   1   0   0   0   0   0   0   0   0   0   0   0   0
  5.00     .50    40.
 NVQN KSIS
   1   0
OILPD
   7   7   3   1   1  12000.    0.0      0.0      0.0      0.0                    3          0          2
0.258    1000.
   0   1   0   0   0   0   0   0   0   0   0   0   0   0
  5.0    .50     40.
   0   3   0   0   0   0   0   0   0   0   0   0   0   0
 10.0    .50     40.
   0   4   0   0   0   0   0   0   0   0   0   0   0   0
 15.0    .50     40.
   0  12   0   0   0   0   0   0   0   0   0   0   0   0
 20.0    .50     40.
   0   1   1   1   1   1   1   1   0   0   1   0   0   0
 25.0    .50     40.      END YR1
   1   1   0   0   0   0   0   0   0   0   0   0   0   0
  1.50   .50     40.
 NVQN KSIS
   2   1
OILPD
   7   7   3   1   1  12000.    0.0      0.0      0.0      0.0                    3          0          2
0.258    3000.
WAGIN
   1   1   1   1  -12   0.0      0.0      0.0      0.0      0.0                    3          0          2
0.258    4500.
   0   2   0   0   0   0   0   0   0   0   0   0   0   0
  2.5    .50     40.
   0   1   0   0   0   0   0   0   0   0   0   0   0   0
  5.5    .50     40.
   0  34   0   0   0   0   0   0   0   0   0   0   0   0
 10.0    .50     40.
   0   1   1   1   1   1   1   1   0   0   1   0   0   0
 13.0    .50     40.      END YR2
   0   1   0   0   0   0   0   0   0   0   0   0   0   0
 11.25    .50     40.
   0   2   0   0   0   0   0   0   0   0   0   0   0   0
 10.0    .50     40.
   1   1   0   0   0   0   0   0   0   0   0   0   0   0
 10.0   .50     40.
 NVQN KSIS
   2   0
OILPD
   7   7   3   1  -11   0.0      0.0      0.0      0.0      0.0                    3          0          2
0.258    1000.
WAGIN
   1   1   1   1  -12   0.0      0.0      0.0      0.0      0.0                    3          0          2
0.258    4500.
   0   4   0   0   0   0   0   0   0   0   0   0   0   0
 10.0    .50     40.
   0   1   1   1   1   1   1   1   0   0   1   0   0   0
 10.0    .50     40.      END Q1 YR3
```

```
   1   1   0   0   0   0   0   0   0   0   0   0   0   0
  1.25    .50     40.
 NVQN KSIS
   2   0
OILPD
   7   7   3   1  -11   0.0      0.0      0.0      0.0      0.0                    3          0          2
0.258    1000.
WAGIN
   1   1   1   1  -14   0.0      0.0      0.0      0.0    -30000.                  3          0          2
0.258    4500.
   0   2   0   0   0   0   0   0   0   0   0   0   0   0
  2.5     .50     40.
   0   1   0   0   0   0   0   0   0   0   0   0   0   0
  5.0     .50     40.
   1   6   0   0   0   0   0   0   0   0   0   0   0   0
  5.0     .50     40.
 NVQN KSIS
   2   0
OILPD
   7   7   3   1  -11   0.0      0.0      0.0      0.0      0.0                    3          0          2
0.258    1000.
WAGIN
   1   1   1   1  100   0.0      0.0      0.0      0.0    -30000.                  3          0          2
0.258    4500.
   0   4   0   0   0   0   0   0   0   0   0   0   0   0
  5.0     .50     40.
   0   2   0   0   0   0   0   0   0   0   0   0   0   0
 10.0     .50     40.
   0   1   1   1   1   1   1   1   0   0   1   0   0   0
 10.0     .50     40.      END Q2 YR3
   1   1   0   0   0   0   0   0   0   0   0   0   0   0
 0.625    .50     40.
 NVQN KSIS
   2   0
OILPD
   7   7   3   1  -11   0.0      0.0      0.0      0.0      0.0                    3          0          2
0.258    1000.
WAGIN
   1   1   1   1  -12   0.0      0.0      0.0      0.0      0.0                    3          0          2
0.258    4500.
   0   1   0   0   0   0   0   0   0   0   0   0   0   0
  1.375   .50     40.
   0   2   0   0   0   0   0   0   0   0   0   0   0   0
  2.125   .50     40.
   0   1   0   0   0   0   0   0   0   0   0   0   0   0
  5.0     .50     40.
   0  10   0   0   0   0   0   0   0   0   0   0   0   0
  7.0     .50     40.
   0   1   1   1   1   1   1   1   0   0   1   0   0   0
 10.0     .50     40.      END Q3 YR3
   1   1   0   0   0   0   0   0   0   0   0   0   0   0
  1.25    .50     40.
 NVQN KSIS
   2   0
OILPD
   7   7   3   1  -11   0.0      0.0      0.0      0.0      0.0                    3          0          2
0.258    1000.
WAGIN
   1   1   1   1  -14   0.0      0.0      0.0      0.0    -30000.                  3          0          2
0.258    4500.
   0   2   0   0   0   0   0   0   0   0   0   0   0   0
  2.5     .50     40.
```

```
   0   1   0   0   0   0   0   0   0   0   0   0   0   0
  5.0    .50     40.
   1   6   0   0   0   0   0   0   0   0   0   0   0   0
  5.0    .50     40.
 NVQN KSIS
   2   0
OILPD
   7   7   3   1 -11   0.0      0.0      0.0      0.0      0.0                    3         0         2
0.258    1000.
WAGIN
   1   1   1   1 100   0.0      0.0      0.0      0.0    -30000.                  3         0         2
0.258    4500.
   0   4   0   0   0   0   0   0   0   0   0   0   0   0
  5.0    .50     40.
   0   2   0   0   0   0   0   0   0   0   0   0   0   0
 10.0    .50     40.
   0   1   1   1   1   1   1   1   0   0   1   0   0   0
 10.0    .50     40.      END Q4 YR3
```

```
[The Recurrent Data Section repeats two quarters (shaded area) over and over –
alternating water and gas injection for the remaining simulation. There are some
minor changes in some years to account for leap years]
```

Sample Well and Summary Reports at 5 Years for Example 4

********** WELL REPORT FOR ALL ACTIVE WELLS **********

ELAPSED TIME = 1825.000 DAYS FROM BEGINNING OF SIMULATION

WELL ID	LOCATION I	J	K	BHFP PSIA CALC	BHFP PSIA SPEC	RATE PI BBLS/PSI	OIL STB/D	GAS MCF/D	WATER STB/D	GOR SCF/STB	WOR STB/STB
OILPD	7	7	3	-1	1000.	11.89	6225.3	4236.	1.	680.	0.000
TOTALS							6225.3	4236.	1.		

	CUMULATIVE OIL MSTB	GAS MMCF	WATER MSTB
	19124.7	13254.1	1.8
TOTALS	19124.7	13254.1	1.8

********** SOLVENT REPORT FOR ALL ACTIVE WELLS **********

ELAPSED TIME = 1825.000 DAYS FROM BEGINNING OF SIMULATION

WELL ID	LOCATION I	J	K	BHFP PSIA CALC	BHFP PSIA SPEC	PI BBLS/PSI	RATE SOLVENT1 MCF/D	SOLVENT2 MCF/D	SOLVENT3 MCF/D	SOLVENT4 MCF/D
OILPD	7	7	3	-1	1000.	11.890	14198.	0.	0.	0.
WAGIN	1	1	1	3104.	4500.	11.890	-30000.	0.	0.	0.

TOTALS	-15802	0.	0.	0.

	CUMULATIVE			
	SOLVENT1 MCF/D	SOLVENT2 MCF/D	SOLVENT3 MCF/D	SOLVENT4 MCF/D
OILPD	7709.1	0.	0.	0.
WAGIN	-16392.5	0.	0.	0.
TOTALS	-8683.4	0.	0.	0.

SUMMARY REPORT: MASTER

Elapsed Time (Days) = 1825.00 Time Step Number = 252 Time Step Size (Days) = 10.0000

Current Avg Pressure (psia)	= 2217.7	Previous Avg Pressure (psia)	= 2215.8	Pressure DPMAX(2, 2, 1)	= -25.6
Oil DSMAX (5, 5, 3)	= -0.00968	Gas DSMAX (3, 3, 1)	= 0.01756	Water DSMAX (5, 5, 3)	= 0.01386
Oil Material Balance (%)	= 0.000012	Gas Material Balance (%)	= -0.000030	Water Material Balance (%)	= -0.000024

Oil Production Rate (STB/D)	= 6225.3	Cum. Oil Production (STB)	= 19124720.
Gas Prod. Rate (MSCF/D)	= 4235.7	Cum. Gas Production (MSCF)	= 13254063.
Water Prod. Rate(STB/D)	= 1.2	Cum. Water Production (STB)	= 1844.
Gas Injection Rate (MSCF/D)	= 0.0	Cum. Gas injection (MSCF)	= 0.
Water Injection Rate (STB/D)	= 0.0	Cum. Water Injection (STB)	= 14957062.
Producing WOR (STB/STB)	= 0.000	Cum. WOR (STB/STB)	= 0.000
Producing GOR (SCF/STB)	= 680.	Cum. GOR (SCF/STB)	= 693.

Cumulative Material Balances (Oil, Gas, Water) = -0.00002980% -0.00001788% -0.00003576%

****** MAXIMUM SOLVENT SATURATION CHANGES *****

SOLVENT 1 DVSMAX(5, 4, 1) = 0.01322

***** SOLVENT MATERIAL BALANCES -- TIME-STEP & CUMULATIVE *****

SOLVENT 1 MAT. BAL. (%) 0.000000 E+00 0.476837E-04

***** SOLVENT INJECTION/PRODUCTION RATES *****

SOLVENT 1

Injection Rate (MCF/D)	= 30000.0	Cumulative Injection (MCF)	= 16392518.
Production Rate (MCF/D)	= 14198.1	Cumulative Production (MCF)	= 7709125.
SOL 1/Oil Producing Ratio (SCF/STB)	= 2281.		

9.5 Example 5

Input Data File for Example 5

The data set is the same as that in Scenarios 1 through 3 (Examples 2 through 4). The changes are that IFOAM is I (foam system) in the Recurrent Data, see Section 7.5. This is MASTER validation Example 5 – surfactant solution alternating with gas (SAG) – SCENARIO 4.

```
IFOAM
 1
 JCHFM
 1
 FOAM RUN CODE: MAXITR, EPSC, EPSN
 700, 0.001, 2.0E06
 INITIAL SURFACTANT CONCENTRATION: CS00-g/g
 0.01
 ADSORPTION CONSTANTS:ROR-G/CM3,DELTA-CM2/G,CKS-G/G,AS-G/CM2
 2.66,3000.,793,2.52E-07
 LIMITS:CSLIM-PPM,SOLIM,SWLIM,SGLIM,VGLIM,RMOBMI,QUALIM,FSCAL
 LIMITS for FOAMING
100,0.6,0.25,0.001,1.0,0.005,1,1.0
NUMBER OF NPER, NQUA, NCON, NVEL
NPER, NQUA, NCON, NVEL
4,4,2,3
PERM DATA, MD
PERM1>>>>>>>>>>>>>>>>>>>>>>>
50.0
FOAM QUALITY DATA
FOAM QUALITY1
20
CONCENTRATION DATA, PPM
CONCENTRATION
1000,2500
VELOCITY DATA, FT/DAY
VELOCITY
0.5,39.619,57.619
2.0,37.846,55.846
5.0,34.3,52.3
FOAM QUALITY DATA
FOAM QUALITY2
40.0
CONCENTRATION DATA, PPM
CONCENTRATION
1000.0,2500.0
VELOCITY DATA, FT/DAY
VELOCITY
0.5,48.719,66.719
2.0,46.946,64.946
5.0,43.4,61.4
FOAM QUALITY DATA
FOAM QUALITY3
60.0
CONCENTRATION DATA, PPM
```

CONCENTRATION
1000.0,2500.0
VELOCITY DATA, FT/DAY
VELOCITY
0.5,57.819,75.819
2.0,56.046,74.046
5.0,52.5,70.5
FOAM QUALITY DATA
FOAM QUALITY3
80.0
CONCENTRATION DATA, PPM
CONCENTRATION
1000.0,2500.0
VELOCITY DATA, FT/DAY
VELOCITY
0.5,66.919,84.919
2.0,65.146,83.146
5.0,61.6,79.6
PERM DATA, MD
PERM1>>>>>>>>>>>>>>>>>>>>>>>
200.0
FOAM QUALITY DATA
FOAM QUALITY1
20
CONCENTRATION DATA, PPM
CONCENTRATION
1000,2500
VELOCITY DATA, FT/DAY
VELOCITY
0.5,28.519,46.519
2.0,26.746,44.746
5.0,23.2,41.2
FOAM QUALITY DATA
FOAM QUALITY2
40.0
CONCENTRATION DATA, PPM
CONCENTRATION
1000.0,2500.0
VELOCITY DATA, FT/DAY
VELOCITY
0.5,37.619,55.619
2.0,35.846,53.846
5.0,32.3,50.3
FOAM QUALITY DATA
FOAM QUALITY3
60.0
CONCENTRATION DATA, PPM
CONCENTRATION
1000.0,2500.0
VELOCITY DATA, FT/DAY
VELOCITY
0.5,46.719,64.719
2.0,44.946,62.946
5.0,41.4,59.4

FOAM QUALITY DATA
FOAM QUALITY3
80.0
CONCENTRATION DATA, PPM
CONCENTRATION
1000.0,2500.0
VELOCITY DATA, FT/DAY
VELOCITY
0.5,55.819,73.819
2.0,54.046,72.046
5.0,50.5,68.5
PERM DATA, MD
PERM1>>>>>>>>>>>>>>>>>>>>>>>
350.0
FOAM QUALITY DATA
FOAM QUALITY1
20
CONCENTRATION DATA, PPM
CONCENTRATION
1000,2500
VELOCITY DATA, FT/DAY
VELOCITY
0.5,17.419,35.419
2.0,15.646,33.646
5.0,12.1,30.1
FOAM QUALITY DATA
FOAM QUALITY2
40.0
CONCENTRATION DATA, PPM
CONCENTRATION
1000.0,2500.0
VELOCITY DATA, FT/DAY
VELOCITY
0.5,26.519,44.519
2.0,24.746,42.746
5.0,21.2,39.2
FOAM QUALITY DATA
FOAM QUALITY3
60.0
CONCENTRATION DATA, PPM
CONCENTRATION
1000.0,2500.0
VELOCITY DATA, FT/DAY
VELOCITY
0.5,35.619,53.619
2.0,33.846,51.846
5.0,30.3,48.3
FOAM QUALITY DATA
FOAM QUALITY3
80.0
CONCENTRATION DATA, PPM
CONCENTRATION
1000.0,2500.0
VELOCITY DATA, FT/DAY

VELOCITY
0.5,44.719,62.719
2.0,42.946,60.946
5.0,39.4,57.4
PERM DATA, MD
PERM1>>>>>>>>>>>>>>>>>>>>>>>
500.0
FOAM QUALITY DATA
FOAM QUALITY1
20
CONCENTRATION DATA, PPM
CONCENTRATION
1000,2500
VELOCITY DATA, FT/DAY
VELOCITY
0.5,6.319,24.319
2.0,4.546,22.546
5.0,1,19
FOAM QUALITY DATA
FOAM QUALITY2
40.0
CONCENTRATION DATA, PPM
CONCENTRATION
1000.0,2500.0
VELOCITY DATA, FT/DAY
VELOCITY
0.5,15.419,33.419
2.0,13.646,31.646
5.0,10.1,28.1
FOAM QUALITY DATA
FOAM QUALITY3
60.0
CONCENTRATION DATA, PPM
CONCENTRATION
1000.0,2500.0
VELOCITY DATA, FT/DAY
VELOCITY
0.5,24.519,42.519
2.0,22.746,40.746
5.0,19.2,37.2
FOAM QUALITY DATA
FOAM QUALITY3
80.0
CONCENTRATION DATA, PPM
CONCENTRATION
1000.0,2500.0
VELOCITY DATA, FT/DAY
VELOCITY
0.5,33.619,51.619
2.0,31.846,49.846
5.0,28.3,46.3
----------RECURRENT DATA----------
1 1 0 0 0 0 0 0 0 0 0 0 0 0
5.00 .50 40.

```
 NVQN KSIS
   1    0
OILPD
7    7    3    1    1    12000.    0.0    0.0    0.0    0.0                    3    0    2
0.258    1000.
   0    1    0    0    0    0    0    0    0    0    0    0    0    0
  5.0    .50    40.
   0    3    0    0    0    0    0    0    0    0    0    0    0    0
 10.0    .50    40.
   0    4    0    0    0    0    0    0    0    0    0    0    0    0
 15.0    .50    40.
   0   12    0    0    0    0    0    0    0    0    0    0    0    0
 20.0    .50    40.
   0    1    1    1    1    1    1    1    0    0    1    0    0    0
 25.0    .50    40.      END YR1
   1    1    0    0    0    0    0    0    0    0    0    0    0    0
  1.50    .50    40.
 NVQN KSIS
   2    1
OILPD
7    7    3    1    1    12000.    0.0    0.0    0.0    0.0                    3    0    2
0.258    3000.
WAGIN
1    1    1    1    -12    0.0    0.0    0.0    0.0    0.0                    3    0    2
0.258    4500.
2500.0
   0    2    0    0    0    0    0    0    0    0    0    0    0    0
  2.5    .50    40.
   0    1    0    0    0    0    0    0    0    0    0    0    0    0
  5.5    .50    40.
   0   34    0    0    0    0    0    0    0    0    0    0    0    0
 10.0    .50    40.
   0    1    1    1    1    1    1    1    0    0    1    0    0    0
 13.0    .50    40.      END YR2
   0    1    0    0    0    0    0    0    0    0    0    0    0    0
 11.25    .50    40.
   0    2    0    0    0    0    0    0    0    0    0    0    0    0
 10.0    .50    40.
   1    1    0    0    0    0    0    0    0    0    0    0    0    0
 10.0    .50    40.
 NVQN KSIS
   2    1
OILPD
7    7    3    1    -11    0.0    0.0    0.0    0.0    0.0                    3    0    2
0.258    1000.
WAGIN
1    1    1    1    -12    0.0    0.0    0.0    0.0    0.0                    3    0    2
0.258    4500.
2500.0
   0    4    0    0    0    0    0    0    0    0    0    0    0    0
 10.0    .50    40.
   0    1    1    1    1    1    1    1    0    0    1    0    0    0
 10.0    .50    40.      END Q1 YR3
   1    1    0    0    0    0    0    0    0    0    0    0    0    0
```

```
  1.25    .50      40.
 NVQN KSIS
   2    0
OILPD
7     7     3     1     -11     0.0     0.0     0.0     0.0     0.0                          3     0     2
0.258    1000.
WAGIN
11    1     1     -14     0.0     0.0     0.0     0.0     -30000.                          3     0     2
0.258    4500.
0.0
   0    2    0    0    0    0    0    0    0    0    0    0    0    0
  2.5     .50      40.
   0    1    0    0    0    0    0    0    0    0    0    0    0    0
  5.0     .50      40.
   1    6    0    0    0    0    0    0    0    0    0    0    0    0
  5.0     .50      40.
 NVQN KSIS
   2    0
OILPD
7     7     3     1     -11     0.0     0.0     0.0     0.0     0.0     3     0     2
0.258    1000.
WAGIN
1     1     1     1     100     0.0     0.0     0.0     0.0     -30000.     3     0     2
0.258    4500.
0.0
   0    4    0    0    0    0    0    0    0    0    0    0    0    0
  5.0     .50      40.
   0    2    0    0    0    0    0    0    0    0    0    0    0    0
 10.0     .50      40.
   0    1    1    1    1    1    1    1    0    0    1    0    0    0
 10.0     .50      40.       END Q2 YR3
   1    1    0    0    0    0    0    0    0    0    0    0    0    0
 0.625    .50      40.
 NVQN KSIS
   2    1
OILPD
7     7     3     1     -11     0.0     0.0     0.0     0.0     0.0                          3     0     2
0.258    1000.
WAGIN
1     1     1     1     -12     0.0     0.0     0.0     0.0     0.0                          3     0     2
0.258    4500.
2500.0
   0    1    0    0    0    0    0    0    0    0    0    0    0    0
  1.375   .50      40.
   0    2    0    0    0    0    0    0    0    0    0    0    0    0
  2.125   .50      40.
   0    1    0    0    0    0    0    0    0    0    0    0    0    0
  5.0     .50      40.
   0   10    0    0    0    0    0    0    0    0    0    0    0    0
  7.0     .50      40.
   0    1    1    1    1    1    1    1    0    0    1    0    0    0
 10.0     .50      40.       END Q3 YR3
   1    1    0    0    0    0    0    0    0    0    0    0    0    0
  1.25    .50      40.
```

```
 NVQN KSIS
   2   0
OILPD
7    7    3    1    -11    0.0    0.0    0.0    0.0    0.0                    3    0    2
0.258    1000.
WAGIN
1    1    1    1    -14    0.0    0.0    0.0    0.0    -30000.                3    0    2
0.258    4500.
0.0
   0   2   0   0   0   0   0   0   0   0   0   0   0   0
  2.5    .50     40.
   0   1   0   0   0   0   0   0   0   0   0   0   0   0
  5.0    .50     40.
   1   6   0   0   0   0   0   0   0   0   0   0   0   0
  5.0    .50     40.
 NVQN KSIS
   2   0
OILPD
7    7    3   1   -11   0.0   0.0   0.0   0.0   0.0                          3   0   2
0.258    1000.
WAGIN
1   1   1   1   100   0.0   0.0   0.0   0.0   -30000.                         3   0   2
0.258    4500.
0.0
   0   4   0   0   0   0   0   0   0   0   0   0   0   0
  5.0    .50     40.
   0   2   0   0   0   0   0   0   0   0   0   0   0   0
 10.0    .50     40.
   0   1   1   1   1   1   1   1   0   0   1   0   0   0
 10.0    .50     40.      END Q4 YR3
```

[The Recurrent Data Section repeats two quarters (shaded area) over and over – alternating surfactant solution and gas injection (SAG) for the remaining simulation. There are some minor changes in some years to account for leap years]

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11.0 NOMENCLATURE

A_i	=	Transmissibility for component i, md-ft • $^{cp-1}$ **1**
C_i	=	Compressibility of component j, psi^{-1}
g	=	Acceleration due to gravity, ft/sec^2
h	=	Grid-block thickness, ft
k	=	Absolute permeability, md
k_{ri}	=	Relative permeability to component i, fraction
k_{rog}	=	Oil relative permeability for an oil-gas system
k_{rom}	=	Oil relative permeability at zero gas saturation and irreducible water saturation
k_{row}	=	Oil relative permeability for an oil-water system
M_i	=	Volume of component i in a grid block, ft^3
N_s	=	Number of solvent species, dimensionless
p	=	Oil phase pressure, psia
p_{cg}	=	Gas-oil capillary pressure, psi
P_{cw}	=	Water-oil capillary pressure, psi
q_i	=	Production or injection rate of component i, ft^3/d
r_{eq}	=	Equivalent wellbore radius, ft
r_w	=	Wellbore radius, ft
R_i	=	Residual error for component i, dimensionless
s	=	Skin factor, dimensionless
S_c	=	Surfactant water saturations, fraction
S_{gr}	=	Residual gas saturation, fraction
S_{org}	=	Residual oil saturation to gas, fraction
S_{orw}	=	Residual oil saturation to water, fraction
S_p	=	Saturation of phase p, fraction
S_{twb}	=	Water-blocked oil saturation, fraction
S_{wr}	=	Irreducible water saturation, fraction
Δt	=	Time-step size, d
v_i	=	Volume fraction of soluble component i, fraction
x_s	=	Ratio of the volume of water that contains surfactant to the total volume of water, fraction
$\Delta x,y,z$	=	Dimension of grid-block in the x-, y-, or z-direction, ft
α	=	Pressure dependent weight factor for transition to miscible condition, dimensionless
β	=	Water blocking parameter, dimensionless
γ_i	=	Specific weight of component i, psi/ft
ε	=	Convergence tolerance, dimensionless

μ = Viscosity of component i, cp

ρ = Density of component i, lbm/ft^3

ϕ_i = Flow potential for component i

ω = Mixing rule parameter, dimensionless

Superscripts

e = Effective property of component using mixing parameter

ℓ = Iteration number

n = Time step number

1,2 = Effective properties for pressure conditions

Subscripts

g = Gas phase or natural gas component

i = Component (oil, water, natural gas, or solvent 1, 2, 3, or 4)

m = Perfectly mixed nonwetting phase property

mgs = Perfectly mixed gas phase (natural gas and solvents) property

mos = Perfectly mixed oil and solvent phase property

n = Nonwetting phase

o = Oil phase or oil component

p = Phase (oil, water, or gas)

s = Surfactant

w = Water phase or component or wetting phase

II. TECHNICAL MANUAL

For

"MASTER"

Miscible Applied Simulation Techniques for Energy Recovery

Version 2.0

By

J. R. Ammer
A. C. Brummert
W. N. Sams

1.0 INTRODUCTION

In the discussion that follows, the finite difference equations (Aziz and Settari 1979; Peaceman 1977) for a multicomponent pseudomiscible simulator are developed. Such simulators are also referred to as extended black-oil simulators since they take the concepts of solubility (solution gas-oil ratio) and formation volume factors from black-oil simulators and extend them to the case where there are multiple soluble species. The discussion is divided into six sections. The first section discusses the relation of pseudomiscible simulators to black-oil simulators. The second presents the partial differential equations solved by MASTER and explains the discretization technique. The third section discusses the implicit-in-pressure, explicit-in-saturation (IMPES) solution technique in general terms, and the fourth and fifth sections discuss the IMPES technique as it is applied to saturated and undersaturated blocks, respectively. The sixth section contains closing comments about the simulator. Appendix A discusses calculation of fluid properties and Appendix B discusses the operation of well models in MASTER.

This technical manual is written to provide the technical detail to the equations used in MASTER in case more information is required about the specifics of MASTER than is discussed in the accompanying user's guide. It is suggested that prior to any additions or modifications to the code (for whatever reason), that this technical manual be read to obtain a thorough understanding of the formulation of the simulator.

2.0 RELATION OF PSEUDOMISCIBLE AND BLACK OIL SIMULATORS

Black-oil simulators use a simplified but intuitively appealing model for the reservoir fluid properties. This model is based on many years of successful application in the petroleum industry where it has been used to make accurate predictions of reservoir performance without the necessity of complex phase behavior computations (Odeh, 1969). The fundamental assumption embodied in the model is that at reservoir conditions the liquid hydrocarbon (oleic) phase, often called reservoir oil, is a mixture of two chemical species, stock tank oil and separator gas, these being the product streams from the surface separation equipment. Both the stock tank oil and the separator gas are actually complex mixtures of many hydrocarbon species, although they are treated as single components. The experimental basis for this approximation is that during differential liberation measurements the composition of the produced gas is observed to vary only slightly over a wide range of pressures.

Based on this model the reservoir oil is said to be composed of stock tank oil with dissolved (separator) gas or solution gas. The solution gas-oil ratio is the amount of dissolved gas in one barrel of stock tank oil, and the oil formation volume factor is the volume occupied at reservoir temperature and pressure by the mixture made from one barrel of stock tank oil and its associated solution gas. Oil that contains as much solution gas as possible at a given temperature and pressure is said to be saturated or at its bubble point. If oil contains less than the maximum possible amount of solution gas, it is said to be undersaturated or at a pressure above its bubble point. At this point, it should be noted that the terms oil and gas, when used in the context of black-oil simulators, have two distinct meanings. They may refer to the chemical species, stock tank oil and separator gas, or they may refer to the fluid phases within the reservoir: The oil phase, which contains both stock tank oil and separator gas, and the gas phase, which is composed of separator gas alone.

In a black-oil simulator, the oil phase fluid property data are usually presented as a table of oil formation volume factor, oil viscosity, and solution gas-oil ratio versus pressure. The data may either represent an actual reservoir fluid, in which case there will be data above and below the original bubble point, or it may represent a fluid sample formed by recombining stock tank oil and separator gas that is saturated at the highest pressure in the table. In the former case, the table contains data for both saturated and undersaturated oil, and in the latter case, it contains data for saturated oil only. The undersaturated portion of the table describes a fluid of constant mass and composition (constant solution gas-oil ratio) and hence reflects the true pressure dependence of a liquid, i.e., decreasing volume and increasing viscosity with increasing pressure. The saturated portion of the table, on the other hand, includes the effects of mass transfer (increasing solution gas-oil ratio), as well as the effects of pressure. Since the effects of mass transfer are generally much larger than those of pressure, they tend to mask the true pressure effects with the result that the oil formation volume factor increases and the oil phase viscosity decreases with increasing pressure.

One extension that can be made to a black-oil simulator is the addition of a capability for treating a solvent such as CO_2 or N_2. Such simulators are frequently referred to as four-component simulators since they are based on material balance equations for four chemical species: (stock tank) oil, (separator) gas, solvent, and water. Here additional possibilities exist for the meaning of gas. First, it can refer to the chemical species of a conventional black-oil simulator, separator gas, which is a mixture of light hydrocarbons. Second, it can refer to the vapor stream from an oil and gas separator which can now contain solvent, as well as light hydrocarbons. (It is used in this context when speaking of the producing gas-oil ratio.) And third, it can refer to the gas phase in the reservoir regardless of its composition. In order to avoid confusion in this work, the term hydrocarbon gas or natural gas will be used when the chemical species is intended, and the term gas without any modifier will be used to designate a vapor phase of any composition either in the reservoir or at the surface.

The data for a four-component simulator consist of the conventional black-oil data set describing the properties of a mixture of stock tank oil and natural gas as a function of pressure and an analogous data set describing a mixture of stock tank oil and solvent. The additional data are a tabulation of the amount of solvent that will dissolve in one barrel of stock tank oil as a function of pressure and the corresponding formation volume factor and viscosity of the mixture. The fluid properties section of a four-component simulator uses a mathematical model to calculate the properties of a mixture of stock tank oil, natural gas, and solvent. The model is based on two data sets that describe the fluids two components at a time (i.e., stock tank oil and natural gas, or stock tank oil and solvent). Such a description is an approximation since the rigorous treatment of a three-component mixture requires that the properties be a function of both pressure and overall composition. The advantage of the method is that it retains the conceptual ideas of the black-oil model with its relatively modest data requirements, and yet allows the incorporation of enhanced recovery mechanisms such as oil swelling and viscosity reduction directly in the fluid property calculation. Experience has shown that simulators of this type can yield performance predictions that may be quantitatively similar to those from fully compositional simulators at a fraction of the computer time (Killough and Kossack 1987).

Black-oil simulators also require fluid property data for the aqueous and gas phases. Usually the aqueous phase is treated simply as a slightly compressible fluid of constant viscosity, but some black-oil simulators allow for the solution of natural gas in the aqueous phase with the attendant effects on volume and viscosity. Solvents such as CO_2 are also soluble in the aqueous phase with the result that extended black-oil simulators must treat the aqueous phase like the oil phase. Black-oil simulators handle the gas phase by means of pressure-dependent formation volume factors and viscosities. The extension of these simulators to more components necessitates additional data sets for the solvent species. The properties of the gas phase are then computed by means of mixing rules implemented in the simulator.

Extended black-oil simulators are usually intended for the study of miscible flooding and have special features added for this purpose. Of particular interest is their treatment of miscibility. Because a simplified fluid model is adopted in this type of simulator, true miscibility (the development of a single hydrocarbon-containing phase) is not achieved as it is in an equation-of-state based compositional simulator. Instead, the transition from immiscible to miscible conditions is simulated by switching from real oil and gas relative permeabilities to effective oil and gas relative permeabilities that are proportional to the oil and gas saturations. After the transition, oil and gas saturations no longer have their usual meanings but simply represent the volume fractions occupied by these fluids in the single pseudo-miscible phase. The transition to miscible conditions occurs as a smooth function of the reservoir pressure and composition. The pressure dependence of the transition is related to the minimum miscibility pressure, which is measured in the laboratory by means of slim tube experiments. The details of the miscibility treatment in MASTER are given in Appendix A. Because of the way that they handle miscibility, simulators of this type are also called pseudomiscible simulators.

The methods used to calculate the effective density and viscosity of the fluids in the pseudomiscible phase differ in details for the various pseudo-miscible simulators, but they are generally extensions and modifications of ideas introduced by Todd and Longstaff (Todd and Longstaff, 1972; Watkins, 1982). The methods are meant to account for the fact that the flooding process is unstable and that oil is bypassed as a result of viscous fingering. The details of the calculation of the effective viscosities and densities in MASTER are also given in Appendix A. In the section of this report describing the IMPES technique, it will be shown that these properties appear in terms that are treated explicitly; hence, no derivatives of them are required. For this reason their exact form has no bearing on the mathematical development which follows.

3.0 EQUATIONS OF FLOW

MASTER is a multicomponent pseudomiscible simulator that simultaneously tracks stock tank oil, natural gas, water, up to N_s solvent species where $N_s \leq 4$, and a surfactant. Natural gas and solvent one are allowed to partition between the gas, oil, and aqueous phases; while solvents two, three, and four partition between the gas and oil phases only. The surfactant exists in the aqueous phase only. The partial differential equations describing the multicomponent, multiphase flow (Aziz and Settari, 1979; Peaceman, 1977) are as follows:

Stock tank oil:

$$\frac{\partial}{\partial t}\left(\phi S_o / \beta_o\right) = \nabla \bullet \frac{k\, k_{ro}^e}{\mu_o^e \beta_o} \nabla \phi_o \,. \qquad 1$$

Water plus surfactant:

$$\frac{\partial}{\partial t}\left(\phi S_w / \beta_w\right) = \nabla \bullet \frac{k\, k_{rw}}{\mu_w \beta_w} \nabla \phi_w \,. \qquad 2$$

Soluble species:

$$\frac{\partial}{\partial t}\left[v_i \phi\left(s_g/\beta_i + R_{io}\, S_o/\beta_o + R_{iw}\, S_w/\beta_w\right)\right] = \nabla \bullet \frac{k\, k_{rg}^e v_i}{\mu_i^e \beta_i}$$
$$+\nabla \bullet \frac{k\, k_{ro}^e v_i R_{io}}{\mu_o^e \beta_o} \nabla \phi_o + \nabla \bullet \frac{k\, k_{rw} v_i R_{iw}}{\mu_w \beta_w} \nabla \phi_w \,, \quad i = g, 1, \ldots, Ns \,, \qquad 3$$

where the R_{iw}. are zero for i > 1.

Surfactant:

$$\frac{\partial}{\partial t}\left(\phi\, x_s S_w/\beta_w\right) = \nabla \bullet \frac{k\, k_{rw} x_s}{\mu_w \beta_w} \nabla \phi_w \,. \qquad 4$$

Equations 1, 2, 3, and 4 are discretized using volume integration (Pruess and Bodvarsson 1983; Nghiem 1988) and standard finite difference techniques (Aziz and Settari 1979; Peaceman 1977). Let the reservoir be divided into a number of contiguous rectangular parallelepipeds or blocks. Integrating Equation 1 over block in yields

$$\int_{V_m} \frac{\partial}{\partial t}\left(\phi\, S_o/\beta_o\right) dV = \int_{V_m} \nabla \bullet \left(\frac{k\, k_{ro}^e}{\mu_o^e \beta_o} \nabla \phi_o\right) dV \qquad 5$$

Reversing the order of integration and differentiation on the left-hand side and applying Green's theorem to the right-hand side gives

$$\frac{d}{dt}\int_{Vm} \phi\, S_o/\beta_o\, dV = \int_{S_{em}} \frac{k\, k_{ro}^e}{\mu_o^e \beta_o} \nabla \phi_o \bullet \hat{n}\, dA + \int_{S_{im}} \frac{k\, k_{ro}^e}{\mu_o^e \beta_o} \nabla \phi_o \bullet \hat{n}\, dA \,, \qquad 6$$

where S_{em} are the external surfaces of the block and S_{im} are internal surfaces which are present if the block is penetrated by a well. If the following definitions are made:

$$M_o = \int_{V_m} \phi\, S_o/\beta_o\, dV = V_p\, S_o/\beta_o \quad , \tag{7}$$

$$Q_o = -\int_{S_{im}} \frac{k\, k_{ro}^e}{\mu_o^e \beta_o} \nabla\phi_o \bullet \hat{n}\, dA = \int_{S_{im}} \frac{1}{\beta_o} \vec{V}_o \bullet \hat{n}\, dA \text{ , and} \tag{8}$$

$$\Delta A_o \Delta\phi_o = \int_{S_{em}} \frac{k\, k_{ro}^e}{\mu_o^e \beta_o} \nabla\phi_o \bullet \hat{n}\, dA \quad , \tag{9}$$

where

$$\Delta\phi_o = \Delta p - \Delta\gamma_o D \quad , \tag{10}$$

then the spatially discretized material balance for oil becomes

$$\frac{dM_o}{dt} + Q_o = \Delta A_o \Delta\phi_o \tag{11}$$

When the backward finite difference is used to approximate the time derivative in Equation 11, the standard implicit equation for the oil material balance is obtained:

$$\frac{1}{\Delta t}\left(M_o^{(n+1)} - M_o^{(n)}\right) + Q_o^{(n+1)} = \Delta A_o^{(n+1)} \Delta\phi_o^{(n+1)} \tag{12}$$

where the superscript indicates the time level at which a quantity is to be evaluated. The parentheses around the superscript are included in anticipation of the later use of superscripts without parentheses to indicate iteration level. There is one equation of the form of Equation 12 for each block in the reservoir. The subscript m, which indicates the block to which the equation applies, has been suppressed for notational simplicity. It should also be noted that the equation for block m is coupled to the equations for adjoining blocks through the terms on the right-hand side of the equation (see difference notation in the nomenclature section for details). In a similar manner the other balances are discretized as follows:

Water plus surfactant:

$$\frac{1}{\Delta t}\left(M_w^{(n+1)} - M_w^{(n)}\right) + Q_w^{(n+1)} = \Delta A_w^{(n+1)} \Delta\phi_w^{(n+1)} \quad , \tag{13}$$

where

$$M_w = V_p\ S_w/\beta_w \quad \text{and} \tag{14}$$

$$\Delta\phi_w = \Delta p - \Delta p_{cw} - \Delta\gamma_w D \quad . \tag{15}$$

Soluble species:

$$\frac{1}{\Delta t}\left(M_i^{(n+1)} - M_i^{(n)}\right) + Q_i^{(n+1)} = \Delta A_i^{(n+1)}\Delta\phi_i^{(n+1)} + \Delta v_i^{(n+1)}R_{io}^{(n+1)}A_o^{(n+1)}\Delta\phi_o^{(n+1)} + \Delta v_i^{(n+1)}R_{iw}^{(n+1)}A_w^{(n+1)}\Delta\phi_w^{(n+1)} \quad , \tag{16}$$

with Equation 16 holding for i = g, 1, ..., N_s,

where

$$M_i = v_i(M_{if} + R_{io}M_o + R_{iw}M_w) \quad , \tag{17}$$

$$M_{if} = V_p\, S_g/\beta_i \quad , \tag{18}$$

$$Q_i = -\int_{S_{em}} k\, v_i\left(\frac{k_{rg}^e}{\mu_i^e\beta_i}\nabla\phi_i + \frac{R_{io}\, k_{ro}^e}{\mu_o^e\beta_o}\nabla\phi_o + \frac{R_{iw}\, k_{rw}}{\mu_w\beta_w}\nabla\phi_w\right)\bullet\hat{n}\, dA \, , \tag{19}$$

and

$$\Delta\phi_i = \Delta p + \Delta p_{cg}^e - \Delta\gamma_i D \, . \tag{20}$$

Surfactant:

$$\frac{1}{\Delta t}\left(M_s^{(n+1)} - M_s^{(n)}\right) + Q_s^{(n+1)} = \Delta A_s^{(n+1)}\Delta\phi_w^{(n+1)} \quad , \tag{21}$$

where

$$M_s = x_s\, M_w \quad . \tag{22}$$

Equations 12, 13, 16, and 21 constitute a set of nonlinear algebraic equations to be solved for the reservoir variables at time level n+1. If there are N_s solvent species and N_B grid blocks, then there are $N_B(4 + N_s)$ equations and a corresponding number of unknowns. The appropriate set of variables required to completely specify the state of a block depends on whether the block is saturated or undersaturated. If the block is saturated, its state is specified by the (oil) pressure, two saturations (e.g., water and gas saturations), N_s solvent fractions, and the surfactant fraction. If the block is undersaturated, the gas saturation is zero and bubble-point pressure replaces gas saturation as a primary variable. If no approximations are made, then all $N_B(4 + N_s)$ equations are coupled and must be solved simultaneously.

4.0 THE IMPLICIT PRESSURE EXPLICIT SATURATION TECHNIQUE

The IMPES technique is an approximation that has been developed to partially decouple the equations and reduce the number of simultaneous equations to N_B. The essential feature of the IMPES method is the approximation of the transmissibilities, capillary pressures, and densities at time level n+1 by their values at time level n. The resulting balance equations are:

Stock tank oil:

$$\frac{1}{\Delta t}\left(M_o^{(n+1)} - M_o^{(n)}\right) + Q_o^{(n+1)} = \Delta A_o^{(n+1)} \Delta\phi_o^{(n+1)} \quad , \qquad 23$$

where

$$\Delta\phi_o^{(n+1)} = \Delta p^{(n+1)} - \Delta\gamma_o^{(n)} D \quad . \qquad 24$$

Water plus surfactant:

$$\frac{1}{\Delta t}\left(M_w^{(n+1)} - M_w^{(n)}\right) + Q_w^{(n+1)} = \Delta A_w^{(n+1)} \Delta\phi_w^{(n+1)} \quad , \qquad 25$$

where

$$\Delta\phi_w^{(n+1)} = \Delta p^{(n+1)} - \Delta p_{cw}^{(n)} - \Delta\gamma_w^{(n)} D \quad . \qquad 26$$

Soluble species:

$$\frac{1}{\Delta t}\left(M_i^{(n+1)} - M_i^{(n)}\right) + Q_i^{(n+1)} = \Delta A_i^{(n)} \Delta\phi_i^{(n+1)} + \Delta v_i^{(n)} R_{io}^{(n)} A_o^{(n)} \Delta\phi_o^{(n+1)} \qquad 27$$

$$9 + \Delta v_i^{(n)} R_{iw}^{(n)} A_w^{(n)} \Delta\phi_w^{(n+1)} \quad , \qquad i = g, 1, \ldots, N_s \quad ,$$

where

$$\Delta\phi_i^{(n+1)} = \Delta p^{(n+1)} + \Delta p_{cg}^{e,(n)} - \Delta\gamma_i^{(n)} D \quad , \qquad i = g, 1, \ldots N_s \, . \qquad 28$$

Surfactant:

$$\frac{1}{\Delta t}\left(M_s^{(n+1)} - M_s^{(n)}\right) + Q_s^{(n+1)} = \Delta A_s^{(n)} \Delta\phi_s^{(n+1)} \quad . \qquad 29$$

If the further approximation is made that the surfactant concentration is small enough that the water formation volume factor is independent of surfactant fraction, then Equation 29 decouples from the remaining equations. Only after all the other variables have been updated are the $x_s^{(n+1)}$ computed using Equation 29. For this reason the surfactant equation is not referenced in the following development.

Since the IMPES technique was first developed in the 1960's, numerous variations on the algorithm have been presented. This is primarily because even after the approximations leading

to Equations 23, 25, and 27 have been made, the balances still contain nonlinearities in the accumulation terms, and the various algorithms represent differing approaches for handling the nonlinearities. The approaches that have been taken to this problem may be broadly classified as one of three types. The first is to form N_B simultaneous equations for $p^{(n+1)}$ by linearization and other manipulations. This set of equations for $p^{(n+1)}$ is called the pressure equation. Certain coefficients appearing in the pressure equation are themselves functions of $p^{(n+1)}$. These coefficients are approximated by their value at time n, and the resulting equations are solved for $p^{(n+1)}$. Once $p^{(n+1)}$ is known for all blocks, the remaining variables at time n+1 are obtained from the various balance equations one block at a time. The values so obtained are accepted as the solution for time n+1 and the solution proceeds to the next time step. Techniques of this type will be referred to as noniterative IMPES methods. The BOAST simulator (Fanchi, Harpole, Bujnowski, 1982) is an example of this method.

Since the coefficients appearing in the pressure equation are themselves obtained for $p^{(n+1)}$ functions of pressure, the values by the noniterative IMPES method are only approximate solutions to the balance equations. Iterative procedures overcome this problem by updating the coefficients and resolving for $p^{(n+1)}$ until some convergence criterion is satisfied. Techniques that solve the basic IMPES pressure equation by repeated or successive substitution constitute a second type of IMPES methods which, for the sake of clarity, are referred to as successive substitution IMPES methods.

The third class of IMPES techniques are based on the fact that the IMPES balances are just a set of nonlinear equations and are amendable to solution by the standard techniques for solving such equations. The multi-variable Newton Raphson technique (or simply Newton's method) is one of these techniques. It is simple but powerful and it is used as the basis for the third class of IMPES methods. Of particular significance is the fact that Newton's method possesses quadratic convergence and provides a cookbook method for the linearization. This method is used for the MASTER simulator and will be the method that is meant when IMPES is used without qualification in the remainder of this discussion. When a distinction needs to be made, this type formulation will be referred to as a Newtonian IMPES. The Newtonian and successive substitution IMPES methods may be lumped into the category of iterated IMPES methods. Since IMPES is such a frequently used technique and so many variations have developed over the years, there are, no doubt, variations that do not precisely fit into the classification given here; nevertheless, the nomenclature established here serves to permit a clear discussion of the features possessed by the formulation used in MASTER.

Since the solution method is an iterative method, it is convenient to write the equations in residual form:

$$R_o^\ell = \frac{1}{\Delta t}\left(M_o^\ell - M_o^{(n)}\right) + Q_o^\ell - \Delta A_o^{(n)} \Delta\phi_o^\ell \ . \qquad 30$$

$$R_w^\ell = \frac{1}{\Delta t}\left(M_w^\ell - M_w^{(n)}\right) + Q_w^\ell - \Delta A_w^{(n)} \Delta\phi_w^\ell \ . \qquad 31$$

$$R_o^\ell = \frac{1}{\Delta t}\left(M_i^\ell - M_i^{(n)}\right) + Q_i^\ell - \Delta A_i^{(n)} \Delta\phi_i^\ell - \Delta v_i^{(n)} R_{io}^{(n)} A_o^{(n)} \Delta\phi_o^\ell - \Delta v_i^{(n)} R_{iw}^{(n)} A_w^{(n)} \Delta\phi_w^\ell \ , \qquad 32$$
$$i = g, i, \ldots N_s \ ,$$

where the superscript ℓ indicates the iteration level for the variables at time level n+1. The solution process consists of finding those values of the primary variables for which the residuals are zero in all blocks, i.e.,

$$R_i^\ell = 0 \ , \qquad i = o, w, g, 1, \ldots, N_s; \text{ all blocks} \ . \qquad 33$$

In practice, the R_i^ℓ are never zero, but they can be made very small. The limitations on their smallness are the amount of computation one is willing to do (number of iterations) and the roundoff errors arising from the computer arithmetic. Equation 33 is just a restatement of the original material balance equations, and so the values of the R_i^ℓ are a measure of material balance errors. In particular,

$$\text{local material balance error} = \Delta t \; R_i^\ell \qquad 34$$

In the solution process, the equations will be considered solved when

$$|\Delta t \; R_i^\ell \; | / M_i < \varepsilon , \quad i = o, w, g, 1, \ldots, N_s; \text{ all blocks} , \qquad 35$$

where ε is a user-specified convergence tolerance. Generally, the local material balance errors will vary in sign from block to block with the result that the global material balance errors, which are obtained by summing the local material balance errors over all blocks, can be orders of magnitude smaller than the largest of the local material balance errors. This demonstrates that although small global material balance errors are necessary for a good solution, they are not sufficient (Odeh, 1969). In the past, global material balance errors have been used as the sole criterion for the goodness of a solution, particularly with noniterative IMPES simulators. The method outlined here avoids this danger, since any method that satisfies Equation 35 is guaranteed to solve Equations 23, 25, and 27. Stated in other words for emphasis, since the equations that are being solved are themselves material balance equations, their solution (in the sense of Equation 35) guarantees a small material balance error. This assertion has been borne out in practice with MASTER where both time step and cumulative global material balance errors are typically of the order of .001 percent.

For computational purposes it is useful to develop a recursive expression for the residuals. Consider the oil residual written for iteration ℓ+1:

$$R_o^{\ell+1} = \frac{1}{\Delta t}\left(M_o^{\ell+1} - M_o^\ell + M_o^{(n)}\right) + Q_o^{\ell+1} - Q_o^\ell + Q_o^\ell - \Delta A_o^{(n)} \Delta\phi_o^{\ell+1} + \Delta A_o^{(n)} \Delta\phi_o^\ell - \Delta A_o^{(n)} \Delta\phi_o^\ell , \qquad 36$$

where certain terms evaluated at iteration ℓ have been both added and subtracted. Equation 36 can be written as

$$R_o^{\ell+1} = \frac{1}{\Delta t}\left(M_o^{\ell+1} - M_o^\ell\right) + J_o^{(n)} \delta p^{\ell+1} - \Delta A_o^{(n)} \Delta\delta p^{\ell+1} + R_o^\ell , \qquad 37$$

where

$$J_o^{(n)} = I_w \left(\frac{k_{ro}^e}{\mu_o^e \beta_o} \right) \quad \text{for implicit pressure wells,} \qquad 38$$

$$0 \quad \text{otherwise,}$$

$$\delta p^{\ell+1} = Q_o^{(n)} - \Delta A_o^{(n)} \Delta\phi_o^{(n)} \qquad 39$$

and

$$R_o^o = Q_o^{(n)} - \Delta A_o^{(n)} \Delta\phi_o^{(n)} \quad . \qquad 40$$

The details of the well models used in MASTER are found in Appendix B. Note that the index on I_w, which is used in Appendix B to denote layer, has been omitted in Equation 38 for notational simplicity.

In a similar manner, the water and soluble species residuals can be written as

$$R_w^{\ell+1} = \frac{1}{\Delta t}\left(M_w^{\ell+1} - M_w^{\ell}\right) + J_w^{(n)}\delta p^{\ell+1} + R_w^{\ell} \quad \text{and} \tag{41}$$

$$R_w^{\ell+1} = \frac{1}{\Delta t}\left(M_w^{\ell+1} - M_w^{\ell}\right) + J_{iT}^{(n)}\delta p^{\ell+1} - A_{iT}^{(n)}\Delta\delta p^{\ell+1} + R_w^{\ell} \tag{42}$$

with Equation 42 holding for i = g, 1, ..., N_s,

where

$$J_{iT}^{(n)} = v_i^{(n)}\left[I_w\left(\frac{k_{rg}^e}{\mu_i^e \beta_i}\right)(n) + R_{io}^{(n)}J_o^{(n)} + R_{iw}^{(n)}J_w^{(n)}\right] \qquad \text{for implicit pressure wells,} \tag{43}$$

$$0 \qquad \text{otherwise,}$$

and

$$A_{iT}^{(n)} = A_i^{(n)} + V_i^{(n)}\left(R_{io}^{(n)}A_o^{(n)} + R_{iw}^{(n)}A_w^{(n)}\right). \tag{44}$$

4.1 The IMPES Equations for Saturated Blocks

Newton's method is now applied to a saturated block:

$$\left[\left(\frac{\partial \hat{M}_o}{\partial p}\right)\ell + J_0^{(n)}\right]\delta p^{\ell+1} + \left(\frac{\partial \hat{M}_o}{\partial S_w}\right)\ell\delta S_w^{\ell+1} + \left(\frac{\partial \hat{M}_o}{\partial S_g}\right)\ell\delta S_g^{\ell+1} + \sum_{j=1}^{N_s}\left(\frac{\partial \hat{M}_o}{\partial v_j}\right)\ell\delta v_j^{\ell+1} - \Delta A_o^{(n)}\Delta\delta p^{\ell+1} = R_o^{\ell}, \tag{45}$$

$$\left[\left(\frac{\partial \hat{M}_w}{\partial p}\right)\ell + J_w^{(n)}\right]\delta p^{\ell+1} + \left(\frac{\partial \hat{M}_w}{\partial S_w}\right)\ell\delta S_w^{\ell+1} + \left(\frac{\partial \hat{M}_w}{\partial S_g}\right)\ell\delta S_g^{\ell+1} + \sum_{j=1}^{N_s}\left(\frac{\partial \hat{M}_w}{\partial v_j}\right)\ell\delta v_j^{\ell+1} - \Delta A_w^{(n)}\Delta\delta p^{\ell+1} = -R_w^{\ell}, \tag{46}$$

and

$$\left[\left(\frac{\partial \hat{M}_i}{\partial p}\right)\ell + J_{iT}^{(n)}\right]\delta p^{\ell+1} + \left(\frac{\partial \hat{M}_i}{\partial S_w}\right)\ell\delta S_w^{\ell+1} + \left(\frac{\partial \hat{M}_i}{\partial S_g}\right)\ell\delta S_g^{\ell+1} + \sum_{j=1}^{N_s}\left(\frac{\partial \hat{M}_i}{\partial v_j}\right)\ell\delta v_j^{\ell+1} - \Delta A_{iT}^{(n)}\Delta\delta p^{\ell+1} = -R_w^{\ell}, i = g, 1, \ldots, N_s, \tag{47}$$

where

$$\hat{M}_i = M_i / \Delta t, \qquad I = 0, w, g\ 1, \ldots, N_s \tag{48}$$

Equations 45, 46, and 47 are a set of simultaneous linear equations in the variables $\delta p^{\ell+1}, \delta S_w^{\ell+1}, \delta S_g^{\ell+1}$, and $\delta v_j^{\ell+1}$'s. Since the only linking between blocks involves $\delta p^{\ell+1}$, it is possible to eliminate the dependence on $\delta S_w^{\ell+1}, \delta S_g^{\ell+1}$, and $\delta v_j^{\ell+1}$'s by taking a linear combination of Equations 45, 46, and 47. In other words, with the proper choice for $a_o^\ell, a_w^\ell, a_g^\ell$, and a_i^ℓ's it is possible to write the equation satisfied by the $\delta p^{\ell+1}$, as

$$\left(\hat{V}_p^\ell C_T^\ell + J_T^\ell\right)\ \delta p^{\ell+1} - \Delta A_T^\ell \Delta\delta p^{\ell+1} = R_T^\ell\ , \qquad 49$$

where

$$\hat{V}_p^\ell C_T^\ell = a_o^\ell\left(\frac{\partial \hat{M}_o}{\partial p}\right)\ell + a_w^\ell\left(\frac{\partial \hat{M}_w}{\partial p}\right)\ell + a_g^\ell\left(\frac{\partial \hat{M}}{\partial p}\right)\ell + \sum_{i=1}^{N_s} a_i^\ell\left(\frac{\partial \hat{M}_i}{\partial p}\right)\ell\ , \qquad 50$$

$$J_T^\ell = a_o^\ell J_o^{(n)} + a_w^\ell J_w^{(n)} + a_g^\ell J_{gT}^{(n)} + \sum_{i=1}^{N_s} a_i^\ell J_{iT}^{(n)}\ , \qquad 51$$

$$A_T^\ell = a_o^\ell A_o^{(n)} + a_w^\ell A_w^{(n)} + a_g^\ell A_{gT}^{(n)} + \sum_{i=1}^{N_s} a_i^\ell A_{iT}^{(n)}\ , \qquad 52$$

$$\hat{V}_p = V_p / \Delta t\ , \text{ and} \qquad 53$$

$$R_T^\ell = a_o^\ell R_o^\ell + a_w^\ell R_w^\ell + a_g^\ell R_g^\ell + \sum_{i=1}^{N_s} a_i^\ell R_i^\ell\ , \qquad 54$$

The form of the a_i's can be derived by performing elementary row operations on Equations 45, 46, and 47. In order to simplify the notation, the superscripts denoting iteration level will be dropped during the derivation. First the form of the derivatives appearing in Equation 47 is noted:

$$\frac{\partial \hat{M}_i}{\partial p} = v_i\left(R_{io}\frac{\partial \hat{M}_o}{\partial p} + R_{iw}\frac{\partial \hat{M}_w}{\partial p}\right) + v_i\left[\left(c_r + c_i\right)\hat{M}_{if} + R'_{io}\hat{M}_o + R'_{iw}\hat{M}_w\right], \qquad 55$$

$$\frac{\partial \hat{M}_i}{\partial s_w} = v_i\left(R_{io}\frac{\partial \hat{M}_o}{\partial s_w} + R_{iw}\frac{\partial \hat{M}_w}{\partial s_w}\right)\ \text{, and} \qquad 56$$

$$\frac{\partial \hat{M}_i}{\partial s_g} = v_i\left(R_{io}\frac{\partial \hat{M}_o}{\partial s_g} + R_{iw}\frac{\partial \hat{M}_w}{\partial s_g}\right) + \hat{V}_p v_i / \beta_i\ , \qquad 57$$

where

$$c_r = \frac{1}{\phi}\frac{\partial \phi}{\partial p} \text{ and} \qquad 58$$

$$c_i = \frac{1}{\beta_i}\frac{\partial \beta_i}{\partial p} \quad , \qquad i = g, 1, \ldots, N_s \, , \tag{59}$$

and where R'_{io} and R'_{iw} denote differentiation of the solubilities with respect to pressure, with Equations 55, 56, and 57 holding for i = g, 1, ..., N_s and in addition

$$\frac{\partial \hat{M}_g}{\partial v_j} = v_g\left(R_{so}\frac{\partial \hat{M}_o}{\partial v_j} + R_{sw}\frac{\partial \hat{M}_w}{\partial v_j}\right) - \left(\hat{M}_{gf} + R_{so}\hat{M}_w + R_{sw}\hat{M}_w\right) \quad , \tag{60}$$

while

$$\frac{\partial \hat{M}_i}{\partial v_j} = v_i\left(R_{io}\frac{\partial \hat{M}_o}{\partial v_j} + R_{iw}\frac{\partial \hat{M}_w}{\partial v_j}\right) + \delta_{if}\left(\hat{M}_{if} + R_{io}\hat{M}_o + R_{iw}\hat{M}_w\right) \quad , \tag{61}$$

holds for i = 1, ..., N_s.

The derivative of $\hat{M}_i$ with respect to v_j has a different form for i = g because v_g is not a primary variable but is defined in terms of the primary variables v_i, i = 1, ..., N_s, by

$$v_g = 1 - \sum_{i=1}^{N_s} v_i \, . \tag{62}$$

If c_i^* and ρ_i^* are defined as

$$c_i^* = v_i\left[\left(c_r + c_i\right)S_g/\beta_i + R'_{io}\ S_o/\beta_o + R'_{iw}\ S_w/\beta_w\right] \text{ and} \tag{63}$$

$$\rho_i^* = S_g/\beta_i + R'_{io}\ S_o/\beta_o + R'_{iw}\ S_w/\beta_w \, . \tag{64}$$

Then Equations 55, 60, and 61 may be rewritten as

$$\frac{\partial \hat{M}_i}{\partial p} = v_i\left(R_{io}\frac{\partial \hat{M}_o}{\partial p} + R_{iw}\frac{\partial \hat{M}_w}{\partial p}\right) + \hat{v}_p c_i^* \, , \quad i = g, 1, \ldots, N_s \, , \tag{65}$$

and

$$\frac{\partial \hat{M}_i}{\partial v_j} = v_g\left(R_{so}\frac{\partial \hat{M}_o}{\partial v_j} + R_{sw}\frac{\partial \hat{M}_w}{\partial v_j}\right) - \hat{v}_p \rho_g^* \text{ , and} \tag{66}$$

$$\frac{\partial \hat{M}_i}{\partial v_j} = v_i\left(R_{io}\frac{\partial \hat{M}_o}{\partial v_j} + R_{iw}\frac{\partial \hat{M}_w}{\partial v_j}\right) + \delta_{ij}\hat{v}_p \rho_i^* \, , \quad i = 1, \ldots, N_s \, . \tag{67}$$

If Equation 45 is multiplied by $v_i R_{io}$ and Equation 46 by $v_i R_{iw}$ and then both are subtracted from Equation 47, the result for i = g is

$$\left(\hat{V}_p c_g^* + J_g^*\right)\delta p + \hat{V}_p v_g / \beta_g \, \delta s_g - \hat{V}_p \rho_g^* \sum_{j=1}^{N_s} \delta v_j - \Delta A_g^* \Delta \delta p = -R_g^* \, , \tag{68}$$

and for i = 1, ..., N_s is

$$\left(\hat{V}_p c_g^* + J_i^*\right)\delta p + \hat{V}_p v_i / \beta_i\, \delta s_g - \hat{V}_p \rho_i^* \delta v_i - \Delta A_i^* \Delta \delta p = -R_i^* \ , \qquad 69$$

where

$$J_i^* = J_{iT}^{(n)} - v_i\left(R_{io} J_o^{(n)} + R_{iw} J_w^{(n)}\right) \ , \qquad i = g, 1, \ldots N_s \ , \qquad 70$$

$$A_i^* = A_{iT}^{(n)} - v_i\left(R_{io} A_o^{(n)} + R_{iw} A_w^{(n)}\right) \ , \qquad I = g, 1, \ldots, N_s \ , \text{ and} \qquad 71$$

$$R_i^* = R_{iT}^{(n)} - v_i\left(R_{io} R_o + R_{iw} R_w\right) \ , \qquad i = g, 1, \ldots, N_s \ . \qquad 72$$

Note that since Equation 69 contains only δv_i rather than the sum over all δv_j's, Equation 69 can be used to eliminate the δv_j's from Equations 45, 46, and 68. Prior to eliminating the δv_j's from Equations 45 and 46, it is convenient to multiply Equation 45 by β_o and Equation 46 by β_w yielding

$$\left(\beta_o \frac{\partial \hat{M}_o}{\partial p} + \beta_o J_o^{(n)}\right)\delta p - \hat{V}_p \delta S_w - \hat{V}_p \delta S_g + \sum_{j=1}^{N_s} \beta_o \frac{\partial \hat{M}_o}{\partial v_j} \delta v_j - \Delta\beta_o A_o^{(n)} \Delta\delta p = -\beta_o R_o \ , \qquad 73$$

$$\left(\beta_w \frac{\partial \hat{M}_w}{\partial p} + \beta_w J_w^{(n)}\right)\delta p + \hat{V}_p \delta S_w + \sum_{j=1}^{N_s} \beta_w \frac{\partial \hat{M}_w}{\partial v_j} \delta v_j - \Delta\beta_w A_w^{(n)} \Delta\delta p = -\beta_w R_w \ , \qquad 74$$

where use has been made of the fact that

$$\frac{\partial \hat{M}_o}{\partial s_w} = -\hat{V}_p / \beta_o \ , \qquad 75$$

$$\frac{\partial \hat{M}_o}{\partial s_g} = -\hat{V}_p / \beta_o \ , \qquad 76$$

$$\frac{\partial \hat{M}_w}{\partial S_w} = \hat{V}_p / \beta_w \ , \text{ and} \qquad 77$$

$$\frac{\partial \hat{M}_w}{\partial s_g} = 0 \ . \qquad 78$$

If ξ_i, η_i, and λ_i are defined as

$$\xi_i = -\beta_o \frac{\partial \hat{M}_o}{\partial v_i} \Big/ \hat{V}_p \rho_i^* = \frac{S_o}{\beta_o} \frac{\partial \beta_o}{\partial v_i} \Big/ \rho_i^* \ , \qquad i = 1, \ldots, N_s \ , \qquad 79$$

$$\eta_i = -\beta_w \frac{\partial \hat{M}_w}{\partial v_i} \Big/ \hat{V}_p \rho_i^* = \frac{S_w}{\beta_w} \frac{\partial \beta_w}{\partial v_i} \Big/ \rho_i^* \ , \qquad i = 1, \ldots, N_s \ , \text{ and} \qquad 80$$

$$\lambda_i = \rho_g^* / \rho_i^* \ , \qquad i = 1, \ldots, N_s \ , \qquad 81$$

then if Equation 69 is multiplied by ξ_i, and added to Equation 73 with i = 1, ..., N_s in turn, the result is

$$\left[\beta_o \frac{\partial \hat{M}_o}{\partial p} + \hat{V}_p \sum_{j=1}^{N_s} \xi_j c_j^* + \beta_o J_o^{(n)} + \sum_{j=1}^{N_s} \xi_j J_j^*\right] \delta p - \hat{V}_p \delta S_w$$
$$+ \hat{V}_p \left(-1 + \sum_{j=1}^{N_s} \xi_j v_j / \beta_j\right) \delta S_g - \Delta \left(\beta_o A_o^{(n)} + \sum_{j=1}^{N_s} \xi_j A_j^*\right) \Delta \delta p = -\left(\beta_o R_o + \sum_{j=1}^{N_s} \xi_j R_j^*\right) \qquad 82$$

In a similar manner, if Equation 69 is multiplied by η_i, and added to Equation 74 with i = 1, …, N_s in turn, and Equation 64 is multiplied by λ_i and added to Equation 68 with i = 1, ..., N_s, the resulting equations are

$$\left[\beta_w \frac{\partial \hat{M}_w}{\partial p} + \hat{V}_p \sum_{j=1}^{N_s} \eta_j c_j^* + \beta_w J_w^{(n)} + \sum_{j=1}^{N_s} \eta_j J_j^*\right] \delta p - \hat{V}_p \delta S_w$$
$$+ \hat{V}_p \sum_{j=1}^{N_s} \eta_j v_j / \beta_j \delta S_g - \Delta \left(\beta_w A_w^{(n)} + \sum_{j=1}^{N_s} \eta_j A_j^*\right) \Delta \delta p = -\left(\beta_w R_w + \sum_{j=1}^{N_s} \eta_j R_j^*\right) \qquad 83$$

and

$$\left[\hat{V}_p \left(c_g^* + \sum_{j=1}^{N_s} \lambda_j c_j^*\right) + J_g^* + \sum_{j=1}^{N_s} \lambda_j J_j^*\right] \delta p + \hat{V}_p \left(v_g \Big/ \beta_g + \sum_{j=1}^{N_s} \lambda_j v_j / \beta_j\right) \delta S_g$$
$$- \Delta \left(A_g^* + \sum_{j=1}^{N_s} \lambda_j A_j^*\right) \Delta \delta p = -\left(R_g^* + \sum_{j=1}^{N_s} \lambda_j R_j^*\right) \quad . \qquad 84$$

Finally, note that the coefficient of δS_w is - $\hat{V}_p$ in Equation 82, $\hat{V}_p$ in Equation 83, and 0 in Equation 84; therefore, the equation formed by summing Equations 82 and 83 and a_g times 84 is independent of δS_w for any a_g and can be made independent of δS_g by letting

$$a_g = \left[1 - \sum_{j=1}^{N_s} \left(\xi_j + \eta_j\right) v_j / \beta_j\right] \Big/ \left[v_g / \beta_g + \sum_{j=1}^{N_s} \lambda_j v_j / \beta_j\right] \quad . \qquad 85$$

Thus, the desired result has been obtained where a_g is given by Equation 85, and the remaining constants are obtained by examining the sequence of operations required to obtain Equation 49. The results for the coefficients are

$$a_o = \beta_o - \sum_{j=1}^{N_s} a_j v_j R_{jo} - a_g v_g R_{so} \quad , \qquad 86$$

$$a_w = \beta_w - \sum_{j=1}^{N_s} a_j v_j R_{jw} - a_g v_g R_{sw} \quad \text{, and} \qquad 87$$

$$a_i = \xi_I + \eta_i + a_g \lambda_i \ , \qquad i = 1, ..., Ns \ . \qquad 88$$

The coefficient c_T, which appears in Equation 49, may be computed from Equation 50 or perhaps a little more conveniently from the summation of terms appearing in Equations 82, 83, and 84 as

$$c_T = S_o\left(c_r - \frac{1}{\beta_o}\frac{\partial\beta_o}{\partial p}\right) + S_w\left(c_r - \frac{1}{\beta_w}\frac{\partial\beta_w}{\partial p}\right) + a_g c_g^* + \sum_{j=1}^{N_s}\left(\xi_j + \eta_j + a_g\lambda_j\right)c_j^* \quad , \qquad 89$$

where use has been made of

$$\beta_o\frac{\partial\hat{M}_o}{\partial p} = \hat{V}_p S_o\left(c_r - \frac{1}{\beta_o}\frac{\partial\beta_o}{\partial p}\right) \text{ and} \qquad 90$$

$$\beta_w\frac{\partial\hat{M}_w}{\partial p} = \hat{V}_p S_w\left(c_r - \frac{1}{\beta_w}\frac{\partial\beta_w}{\partial p}\right) \quad . \qquad 91$$

Here it is noted that for $N_s = 0$, the results reduce to the usual expressions found in black oil simulators, i.e.,

$$a_g = \beta_g \ , \qquad 85bo$$

$$a_o = \beta_o - \beta_g R_{so} \qquad 86bo$$

$$a_w = \beta_w - \beta_g R_{sw} \ , \text{ and} \qquad 87bo$$

$$c_T = S_o\left(-\frac{1}{\beta_o}\frac{\partial\beta_o}{\partial p} + \frac{\beta_g}{\beta_o}R'_{so}\right) + S_w\left(-\frac{1}{\beta_w}\frac{\partial\beta_w}{\partial p} + \frac{\beta_g}{\beta_w}R'_{sw}\right) + s_g c_g + c_r \quad , \qquad 89bo$$

In Equation 89bo, the term multiplying S_o is the compressibility of saturated oil, the term multiplying S_w is the compressibility of saturated water, c_g is the (natural) gas compressibility, and C_r is the formation compressibility; hence, c_T is called total or system compressibility. Remember that the superscripts denoting iteration level were dropped earlier in the derivation and that these coefficients depend on the iteration and must be recomputed each iteration.

With some slight rearrangement, Equation 49 can be put into exactly the same form as used in noniterative IMPES simulators such as BOAST. Recalling that such simulators use Equation 49 only once per time step, it can be rewritten as

$$\hat{V}_p^{(n)} c_T^{(n)}\left(p^{(n+1)} - p^{(n)}\right) + J_T^{(n)}\left(p^{(n+1)} - p^{(n)}\right) - \Delta A_T^{(n)}\Delta\left(p^{(n+1)} - p^{(n)}\right) = -R_T^o \quad . \qquad 92$$

Then all the terms involving $p^{(n)}$ are collected on the right hand side of the equation

$$-\left(\hat{V}_p c_T^{(n)} + J_T^{(n)}\right)p^{(n+1)} + \Delta A_T^{(n)}\Delta p^{(n+1)} = R_t^o - \left(\hat{V}_p^{(n)} c_p^{(n)} + J_T^{(n)}\right)p^{(n)} + \Delta A_T^{(n)}\Delta p^{(n)} \quad . \qquad 93$$

The result for $p^{(n+1)}$ that is obtained from solving Equation 93 is exactly the same as the one that is obtained from one iteration of Equation 49. Thus, if MASTER is run with a limit of one iteration per time step, the results will be the same as those for noniterative simulators.

Once the pressure equation has been solved for the $\delta p^{\ell+1}$ and $p^{\ell+1}$ has been computed for the entire reservoir, the remaining variables can be computed block by block without solving simultaneous equations. First, Equation 84 is solved for δS_g then δS_w is obtained from Equation 83 and the δv_j's from Equation 69. Alternately, the saturations and solvent fractions may be obtained from the material balance equations (Equations 23, 25, and 27); however, the procedure outlined here is easier to use in the undersaturated case, which will be discussed next; thus, it will be adopted as the preferred technique.

A close examination of the derivation that has just been presented reveals that IMPES is just a special combination of the multivariable Newton's method and Gauss elimination applied to the solution of a certain set of nonlinear algebraic equations, e.g., the discrete material balance equations for multiphase flow. The steps are summarized by the following. First, a set of nonlinear equations with desirable structural features is created by approximating certain terms in the material balance equations by their value at the last time level. Next, a set of linear equations is generated by applying Newton's method to those equations. Third, a partial elimination is performed by using a sequence of elementary row operations. This generates the pressure equation. Fourth, the pressure equation is solved using any available technique. Fifth, back substitution is performed to obtain the remaining variables. The Newtonian iterations are repeated until Equation 35 is satisfied.

4.2 The IMPES Equations for Undersaturated Blocks

Up to this point, the problem has been treated as though all blocks in the reservoir were in a saturated state. As has been pointed out earlier, when a block is undersaturated the bubble-point pressure replaces gas saturation as a primary variable. This results in a modification of the equations obtained from the application of Newton's method to an undersaturated block, but there is no change in principle. The problem is just described by one set of variables for saturated blocks and another set for undersaturated blocks. The method is referred to as variable switching and an application to reservoir simulation has been given by Thomas, Lumpkin, and Reheis (1976). When Newton's method is applied to an undersaturated block it yields

$$\left(\frac{\partial \hat{M}_o}{\partial p} + J_o^{(n)}\right)\delta p + \left(\frac{\partial \hat{M}_o}{\partial s_w}\right)\delta s_w + \left(\frac{\partial \hat{M}_o}{\partial p_b}\right)\delta p_b + \sum_{j=1}^{N_s}\left(\frac{\partial \hat{M}_o}{\partial v_j}\right)\delta v_j - \Delta A_o^{(n)}\Delta\delta p = -R_o \quad , \qquad 94$$

$$\left(\frac{\partial \hat{M}_w}{\partial p} + J_w^{(n)}\right)\delta p + \left(\frac{\partial \hat{M}_w}{\partial s_w}\right)\delta s_w + \left(\frac{\partial \hat{M}_w}{\partial p_b}\right)\delta p_b + \sum_{j=1}^{N_s}\left(\frac{\partial \hat{M}_w}{\partial v_j}\right)\delta v_j - \Delta A_w^{(n)}\Delta\delta p = -R_w \text{ , and} \qquad 95$$

$$\left(\frac{\partial \hat{M}_i}{\partial p} + J_{iT}^{(n)}\right)\delta p + \left(\frac{\partial \hat{M}_i}{\partial s_w}\right)\delta s_w + \left(\frac{\partial \hat{M}_i}{\partial p_b}\right)\delta p_b + \sum_{j=1}^{N_s}\left(\frac{\partial \hat{M}_i}{\partial v_j}\right)\delta v_j - \Delta A_{iT}^{(n)}\Delta\delta p = -R_i \text{ ,}$$

$$I = g, 1, \ldots, N_s \quad , \qquad 96$$

The sequence of row operations that will reduce Equations 94, 95, and 96 to the form of Equation 49 needs to be determined. Since for undersaturated blocks $S_g = 0$ and the solubilities are a function of p_b rather than p, the derivatives of $\hat{M}_i$ with respect to p and p_b are given by

$$\frac{\partial \hat{M}_i}{\partial p} = v_i\left(R_{io}\frac{\partial \hat{M}_o}{\partial p} + R_{iw}\frac{\partial \hat{M}_w}{\partial p}\right) \quad \text{and} \qquad 97$$

$$\frac{\partial \hat{M}_i}{\partial p} = v_i\left(R_{io}\frac{\partial \hat{M}_o}{\partial p_b} + R_{iw}\frac{\partial \hat{M}_w}{\partial p_b}\right) + \hat{V}_p c_i^* \quad , \qquad 98$$

where, for the undersaturated case, c_i^* is given by

$$c_i^* = v_i\left(R'_{io}\, S_o/\beta_o + R'_{io}\, S_w/\beta_w\right) , \qquad I = g, 1, \ldots, N_s \quad , \qquad 99$$

where R'_{io} and R'_{iw} denote differentiation of the solubilities with respect to the bubble-point pressure. If Equation 94 is multiplied by v_iR_{io} and Equation 95 by v_iR_{iw} and both are subtracted from Equation 96, the result for i = g is

$$J_g^*\delta p + \hat{V}_p c_g^*\delta p_b - \hat{V}_p\rho_g^*\sum_{j=1}^{N_s}\delta v_j - \Delta A_g^*\Delta\delta p = -R_g^* \quad , \tag{100}$$

and for i = 1, ..., N_s is

$$J_i^*\delta p + \hat{V}_p c_i^*\delta p_b - \hat{V}_p\rho_i^*\delta v_i - \Delta A_i^*\Delta\delta p = -R_i^* \quad , \tag{101}$$

where use has been made of Equations 56, 66, and 67. In analogy with the saturated case, Equation 101 will be used to eliminate the δvj's from Equations 94, 95, and 100. If ξ_j times Equation 101 for j = 1, …, N_s is added to β_o times Equation 94, the result is

$$\begin{aligned}&\left(\beta_o\frac{\partial\hat{M}_o}{\partial p} + \beta_o J_o^{(n)} + \sum_{j=1}^{N_s}\xi_j J_j^*\right)\delta p - \hat{V}_p\delta S_w + \left(\beta_o\frac{\partial\hat{M}_o}{\partial p_b} + \hat{V}_p\sum_{j=1}^{N_s}\xi_j c_j^*\right)\delta p_b \\ &-\Delta\left(\beta_o A_o^{(n)} + \sum_{j=1}^{N_s}\xi_j A_j^*\right)\Delta\delta p = -\left(\beta_o R_o + \sum_{j=1}^{N_s}\xi_j R_j^*\right).\end{aligned} \tag{102}$$

In a similar manner, η_j times Equation 101 for j = 1, ..., N_s is added to β_w times Equation 95 to obtain

$$\begin{aligned}&\left(\beta_w\frac{\partial\hat{M}_w}{\partial p} + \beta_w J_w^{(n)} + \sum_{j=1}^{N_s}\eta_j J_j^*\right)\delta p + \hat{V}_p\delta S_w + \left(\beta_w\frac{\partial\hat{M}_w}{\partial p_b} + \hat{V}_p\sum_{j=1}^{N_s}\eta_j c_j^*\right)\delta p_b \\ &-\Delta\left(\beta_w A_w^{(n)} + \sum_{j=1}^{N_s}\eta_j A_j^*\right)\Delta\delta p = -\left(\beta_w R_w + \sum_{j=1}^{N_s}\eta_j R_j^*\right),\end{aligned} \tag{103}$$

and λ_j times Equation 101 for j = 1, ..., N_s added to Equation 100 yields

$$\begin{aligned}&\left(J_g^* + \sum_{j=1}^{N_s}\lambda_j J_j^*\right)\delta p + \hat{V}_p\left(c_g^* + \sum_{j=1}^{N_s}\lambda_j c_j^*\right)\delta p_b - \Delta\left(A_g^* + \sum_{j=1}^{N_s}\lambda_j A_j^*\right)\Delta\delta p \\ &= -\left(R_g^* + \sum_{j=1}^{N_s}\lambda_j R_j^*\right) \quad .\end{aligned} \tag{104}$$

The ξ_i, η_i, and λ_i for the undersaturated case are defined the same way as for the saturated case except that S_g = 0. Finally, Equations 102, 103, and a_g times Equation 104 are summed to obtain Equation 49. The required form for a_g is

$$a_g = \left[\frac{S_o}{\beta_o}\frac{\partial\beta_o}{\partial p_b} + \frac{S_w}{\beta_w}\frac{\partial\beta_w}{\partial p_b} - \sum_{i=1}^{N_s}(\xi_i + \eta_i)c_i^*\right]\Bigg/\left(c_g^* + \sum_{i=1}^{N_s}\lambda_i c_i^*\right) \quad , \tag{105}$$

and the expression for c_T takes the simple form

$$c_T = S_o\left(c_r - \frac{1}{\beta_o}\frac{\partial\beta_o}{\partial p}\right) + S_w\left(c_r - \frac{1}{\beta_w}\frac{\partial\beta_w}{\partial p}\right) \quad . \qquad 106$$

Although Equation 106 is a convenient form for computation, it can be rearranged for the purpose of physical interpretation:

$$c_T = S_o c_o + S_w c_w + c_r \ , \qquad 107$$

where c_o and c_w, the compressibilities of the undersaturated oil and water, are given by

$$c_o = -\frac{1}{\beta_o}\frac{\partial\beta_o}{\partial p} \text{ and} \qquad 108$$

$$c_w = -\frac{1}{\beta_w}\frac{\partial\beta_w}{\partial p} \quad . \qquad 109$$

After the solution of Equation 49, δp_b is obtained from Equation 104. Then δS_w is obtained from Equation 103 and the δv_i's from Equation 101. Solving for p_b and the v_i's from the material balances is a considerably harder task.

The state of a grid block is determined at the beginning of each iteration based on the relative values of the oil pressure and the bubble-point pressure. If the oil pressure is greater than the bubble-point pressure, the block is undersaturated; otherwise the block is saturated. At the end of each iteration, the saturated blocks are tested for a change of state. If the gas saturation has gone negative, the gas saturation is set to zero and the bubble-point pressure is set slightly (.01 psi) below the oil pressure. If no switch is indicated by the gas saturation, the bubble-point pressure is set equal to the oil pressure. Blocks that begin an iteration as undersaturated require no special switching logic.

5.0 CONCLUDING REMARKS

The inclusion of undersaturated blocks in a simulator has an effect in two areas. First, the coefficients in the pressure equation are different for blocks that are undersaturated. And second, a different set of equations is used to calculate the explicit variables for these blocks. The significance of the first effect has not always been appreciated. Some simulators have treated undersaturated blocks by solving a pressure equation in which all coefficients correspond to those for saturated blocks (Fanchi, Harpole, and Bujnowski 1982; Fong 1986). Then, after all variables have been updated, the bubble-point pressure is modified in an ad hoc manner to account for the change in solution gas in the undersaturated blocks. These simulators fail to take into account the fact that the pressures obtained from the pressure equation determine the distribution of fluids in the reservoir. If one solves only an approximate pressure equation, the fluid distribution calculated from those pressures will only be approximately correct and one cannot completely remedy the situation by adjusting the bubble-point pressure in the undersaturated blocks. The use of an approximate pressure equation will not lead to errors in an iterative IMPES simulator if the material balance equations are iterated to convergence; however, the material balance equations will, in general, require more iterations in order to converge. When this technique is applied to a noniterative simulator, it can lead to serious material balance errors.

When differential equations are integrated over many time steps, the small errors that occur at each time step may accumulate to produce a significant overall error. In the field of reservoir simulation, Nolen and Berry (1972) and Spillete, Hillestad, and Stone (1973) have proposed techniques for controlling the accumulation of material balance errors. MASTER employs such a technique as a user option. The idea underlying the technique used in MASTER is summarized as follows. When Newton's method for the solution of the material balance equations has met the convergence criterion given by Equation 35, there are still small component material balance errors, which may approach ε in magnitude. If ε is not kept very small, these errors may, over the period of many time steps, accumulate to non-negligible magnitudes. In order to control the accumulation of such errors without using values of ε that lead to large numbers of iterations, MASTER implements a scheme employing fictitious production and injection terms. For example, if at the end of a time step a component material balance error is positive, it means that the solution results in an excess of that component in place. This can be corrected on the next time step by a fictitious production term of the right size to remove exactly the amount of the component that is in excess. In a similar manner, a negative material balance is corrected by a fictitious injection term. The production or injection rate is simply the amount of material in excess or deficit divided by the time step length.

According to Nolen and Berry (1972), this technique effectively limits the cumulative error to that being made on the current time step. The claims for this technique have, in fact, been verified by tests made using MASTER. It has been found that with this option turned on, MASTER can produce essentially the same answers as with the option turned off but with an ε two orders of magnitude larger. It should be emphasized that this method is meant to control errors resulting from the solution of the nonlinear algebraic equations and has no effect on the time truncation error that is characteristic of the finite difference method and whose size depends on the time step length.

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7.0 NOMENCLATURE

A = flow area appearing in transmissibilities

A_i = gas-phase transmissibility for soluble species i

i = g, 1, ..., N_s $\quad \dfrac{v_i k_{rg}^e kA}{\mu_i^e \beta_i L}$ (vector)

A_0 = oil-phase transmissibility, $\dfrac{k_{ro}^e kA}{\mu_o^e \beta_o L}$ (vector)

A_s = surfactant transmissibility, $x_s A_w$ (vector)

A_w = water-phase transmissibility, $\dfrac{k_{rw} kA}{\mu_w \beta_w L}$ (vector)

c_i = gas-phase compressibility for soluble species i, i = g, 1, ..., N_s

c_o = oil-phase compressibility

C_o^u = undersaturated oil-phase compressibility (parameter in fluid model)

c_r = formation compressibility

c_w = water-phase compressibility

C_w^u = undersaturated water-phase compressibility (parameter in fluid model)

D = depth to grid-block center

g = acceleration of gravity

h = perforated interval in a well block

I_w = well block factor, $\dfrac{2\pi k_w h}{\ln(r_e/r_w) + s}$

J_i = well flow coefficient for component i, i = 0, w, g, 1, ..., N_s

k = absolute permeability (vector)

k_w = effective absolute permeability for well

k_{rg} = relative permeability to gas

k_{rg}^e = effective relative permeability to gas computed using pseudo-miscibility model

k_{ro} = relative permeability to oil

k_{ro}^{e} = effective relative permeability to oil computed using pseudo-miscibility model

k_{row} = relative permeability to oil in an oil-water system

k_{rw} = relative permeability to water

L = flow length appearing in transmissibilities

M_i = amount of component i in a grid block, i =0, w, g, s, 1, ..., N_s

N_B = number of grid blocks

N_s = number of solvent species

p = oil phase pressure

p_b = bubble-point pressure

p_{cg} = gas-oil capillary pressure

p_{cg}^{e} = effective gas-oil capillary pressure computed using pseudomiscibility model

p_{cw} = water-oil capillary pressure

p_{sc} = pressure at stock tank conditions

p_{wb} = wellbore pressure

Q_i = production rate of component i, i = o, w, g, s, l, , ..., N_s

r_e = equivalence radius of wellbore block

R_i = residual for component i, i = o, w, g, l, ..., N_s, S

R_{io} = solubility of component i in oil, i = g, l, ..., N_s

R_{iw} = solubility of component i in water, i = g, l, ..., N_s

R_{so} = solution gas/oil ratio, same as R_{go}

R_{sw} = solution gas/water ratio, same as R_{gw}

r_w= = well radius

s = skin

S_p = saturation of phase p, p = o, w, g

S_{em} = total external area of grid block m

S_{im} = internal area of grid block m, $2\pi r_w h$

Δt = time step length

v_i = volume fraction of component i, i = g, l, , N_s

V_m = volume of grid block m, $\Delta x \Delta y \Delta z$

V_p = pore volume of a grid block, $\Delta x \Delta y \Delta z \Phi$

$\vec{V}_p$ = Darcy velocity of phase p, p = o, w, g

$\Delta x \Delta y \Delta z$ = grid block dimensions

x_s = surfactant fraction

α = parameter controlling the transition of effective fluid properties from immiscible to miscible conditions

β_i = formation volume factor for component i in gas phase, i = g, 1, ., N_s

β_o = formation volume factor for oil

β_w = formation volume factor for water

γ_I = specific weight of pure component i in the gas phase, $\rho_i g$, i = g, 1l, .., N_s

γ_i^e = effective specific weight of component i computed using mixing parameter model, i = g, 1, ..., N_s

γ_o = specific weight of oil phase, $\rho_0 g$

γ_o^e = effective specific weight of oil computed using mixing parameter model

γ_w = specific weight of aqueous phase, $\rho_w g$

δ_{ij} = Kronecker delta

μ_I = viscosity of pure component i in the gas phase, i = g, 1, ..., N_5

μ_i^e = effective viscosity of component i computed using mixing parameter model, i = g, 1, .., N_s

μ_o = viscosity of oil phase

μ_o^e = effective viscosity of oil computed using mixing parameter model

μ_w = viscosity of aqueous phase

ρ_i = density of pure component i in the gas phase, i = g, 1, , N_s

ρ_{iSTC} = density of pure component i in the gas phase at stock tank conditions, i = g, 1, ... N_s

ρ_o = density of oil phase

ρ_{oSTC} = density of oil phase at stock tank conditions

ρ_w = density of aqueous phase

ρ_{wSTC} = density of aqueous phase at stock tank conditions

Φ_i = flow potential for component i in the gas phase, i = g, 1, ..., N_s

Φ_o = oil phase flow potential

Φ_w = aqueous phase flow potential

ϕ = porosity

Superscripts

e = effective property

ℓ = iteration number

(n) = time step number

Subscripts

g = gas phase or natural gas species

i = component

i,j,k = grid block indices in x, y, and z directions

o = oil phase or species

p = phase

s = surfactant

T = total, i.e., free and dissolved

w = water phase or species

1,2,3,4 = solvent number

Difference Notation

If T is any vector quantity or arithmetic expression and X is any scalar quantity or arithmetic expression, then

$$\Delta T \Delta X = \Delta_x T_x \Delta_x X + \Delta_y T_y \Delta_y X + \Delta_z T_z \Delta_z X$$

and

$$\Delta_x T_x \Delta_x X = T_{x,i+1/2} (X_{i+1} - X_i) - T_{x,i-1/2} (X_i - X_{i-1}),$$

where $T_{x,i+1/2}$ is any x direction transmissibility for flow between blocks i,j,k and i+1,j,k, and X_i, is the value of X at the grid block i,j,k. Subscripts j and k have been suppressed for clarity since the differences are taken in the x direction. Analogous definitions hold in the y and z directions.

APPENDIX A.
THE EXTENDED BLACK OIL MODEL CONTAINED IN MASTER

This appendix presents the details of the extension of the black-oil model to include N_s solvent species in addition to stock tank oil, natural gas, and water of the conventional black-oil model. The natural gas and solvents are collectively referred to as soluble species. It is the presence of more than one soluble species that distinguishes this model from the conventional one. The treatment of the soluble species is based on the empirical relation known as Amagat's law of partial volumes. (The partial volumes are not the same as partial molar volumes defined in thermodynamics.) The law states that the volume occupied by a gaseous mixture at a specified temperature and pressure is equal to the sum of the volumes that the gases would occupy if each of the gases were alone in the container at the specified temperature and pressure. Amagat's law is probably the most widely used approximation for gaseous mixtures (Sandier, 1977).

If v_i is defined as the volume fraction of soluble species i, then Amagat's partial volume of species i is $v_i V_p S_g$ and the amount of species i in the gas phase is given by $v_i V_p S_g / \beta_i$. The result is that, for a gaseous mixture, the amount of species i present in a grid block is the amount of species i that would be present if the gas phase were pure species i multiplied by the volume fraction of species i. The above idea is taken and applied as a model for the dissolved material also. Thus, if $R_{io} M_o$ is the amount of species i that would be dissolved in the oil if species i were the only soluble species present, then it is assumed that the amount of dissolved species i present in a mixture is $v_i R_{io} M_o$. It is emphasized that the above model is chosen in analogy with the gas phase behavior and because it has the proper behavior in the limit as v_i goes both to one and to zero. A similar result holds for the soluble species dissolved in the aqueous phase. Thus, the total amount of species i in a grid block is given by $v_i\left(V_p S_g / \beta_i + R_{iw} M_w\right)$.

The model for the volumetric behavior of the oleic and aqueous phases is chosen to reproduce the observed behavior of swelling due to mass transfer and compression due to increasing pressure. The expressions chosen for the formation volume factors of the liquid phases are

$$\beta_o = \left[\beta_o^o\left(v_g R_{so}(p_b)\right) + \Delta\beta_o\left(\sum_{i=1}^{N_s} v_i R_{io}(p_b)\right)\right] e^{-c_o^u(p-p_{sc})} \text{ and} \qquad \text{A-1}$$

$$\beta_w = \left[\beta_w^o\left(v_g R_{sw}(p_b)\right) + \Delta\beta_w\left(v_l R_{lw} p_b\right)\right] e^{-c_o^u(p-p_{sc})}, \qquad \text{A-2}$$

where the terms in the square brackets represent the compositional dependence and the exponential factors represent the pressure dependence. The β_o^o and β_w^o are computed from the standard saturated black-oil data set so that

$$\beta_o(p) \text{ black oil} = \beta_o^o\left(R_{so}(p)\right) e^{-c_o^u(p-p_{sc})} \text{ and} \qquad \text{A-3}$$

$$\beta_w(p) \text{ black oil} = \beta_w^o\left(R_{sw}(p)\right) e^{-c_w^u(p-p_{sc})}, \qquad \text{A-4}$$

and the terms $\Delta\beta_i$ and $\Delta\beta_w$ are computed from the solvent one data set so that they satisfy

$$\beta_o(p)_1 = \left(\beta_o(p_{sc})_1 + \Delta\beta_o\left(R_{lo}(p)\right)\right) e^{-c_o^u(p-p_{sc})} \text{ and} \qquad \text{A-5}$$

$$\beta_w(p)_1 = \left(\beta_w(p_{sc})_1 + \Delta\beta_w\left(R_{lw}(p)\right)\right) e^{-c_w^u(p-p_{sc})} . \qquad \text{A-6}$$

The consistency of the data requires that

$$\beta_o(p_{sc})\text{black oil} = \beta_o(p_{sc})_1 \text{ and} \qquad \text{A-7}$$

$$\beta_w(p_{sc})\text{black oil} = \beta_w(p_{sc})_1 . \qquad \text{A-8}$$

The pressure dependence chosen for the model is that of a fluid of constant compressibility.

The densities are related to the formation volume factors by

$$\rho_o = \left(\rho_{oSTC} + v_g R_{so}\rho_{gSTC} + \sum_{j=1}^{N_s} v_j R_{jo}\rho_{jSTC}\right) / \beta_o , \qquad \text{A-9}$$

$$\rho_w = \left(\rho_{wSTC} + v_g R_{sw}\rho_{gSTC} + v_l R_{lw}\rho_{lSTC}\right) / \beta_w \text{ and} \qquad \text{A-10}$$

$$\rho_i = \rho_{iSTC} / \beta_i , \qquad i = g, 1, \ldots, N_s . \qquad \text{A-11}$$

The viscosity of the oleic phase is computed in a similar manner to the formation volume factor:

$$\mu_o = F_s\left(\sum_{i=1}^{N_s} v_i R_{io}(p_b)\right)\mu_o^o\left(v_g R_{so}(p_b)\left(1 + c_{ov}(p_b - p_{sc})\right) + \mu_o'(p - p_b)\right), \qquad \text{A-12}$$

where μ_o^o is computed from the saturated black-oil data so that

$$\mu_o(p)\text{black oil} = \mu_o^o\left(R_{so}(p)\right)\left(1 + c_{ov}(p - p_{sc})\right), \qquad \text{A-13}$$

where

$$c_{ov} = \mu_o' / \mu_o^o\left(p_b^o\right), \qquad \text{A-14}$$

and p_b^o is the initial bubble-point pressure and μ_o' is the slope of the oil viscosity with respect to pressure above the bubble point. And F_s is computed from the solvent one data so that

$$\mu_o(p)_1 = F_s\left(R_{10}(p)\right)\mu_o^o\left(p_{so}(p)\right)\left(1 + c_{ov}(p - p_{sc})\right). \qquad \text{A-15}$$

Data consistency requires that

$$\mu_o(p_{sc})\text{black oil} = \mu_o(p_{sc})_1 . \qquad \text{A-16}$$

The viscosity of the aqueous phase is a function of the dissolved natural gas only.

The effective viscosities and densities in the gas and oleic phases are computed using a mixing parameter model in conjunction with a model for pseudo-miscibility. Two pressures, p_1 and p_2 control the transition from immiscible to miscible conditions. Below p_1 conditions are entirely immiscible and above p_2 conditions are entirely miscible. For pressures between p_1 and p_2 the properties are a weighted average of the immiscible and miscible properties. The method is summarized by

$$\mu_o^e = (1-\alpha)\mu_o + \alpha\mu_o^2 \quad , \qquad \text{A-17}$$

$$\mu_i^e = (1-\alpha)\mu_i^1 + \alpha\mu_i^2 \quad , \qquad i = g, 1 \ldots, N_s \ , \qquad \text{A-18}$$

$$\rho_o^e = (1-\alpha)\rho_o + \alpha\rho_o^2 \quad , \quad \text{and} \qquad \text{A-19}$$

$$\rho_i^e = (1-\alpha)\rho_i^1 + \alpha\rho_i^2 \quad , \qquad i = g, 1 \ldots, N_s \ , \qquad \text{A-20}$$

where the superscripts 1 and 2 refer to the effective fluid properties at immiscible and miscible conditions, respectively, and the weighting factor α is defined by

$$\alpha = \begin{cases} 0 & p \le p_1 \\ (p-p_1)/p_2-p_1) & p_1 < p < p_2 \\ 1 & p \ge p_2 \ . \end{cases} \qquad \text{A-21}$$

Even for $p < p_1$ the soluble species in the gas phase are miscible with one another and the properties of a perfectly mixed gas phase are computed from the pure component properties by simple but commonly used mixing rules:

$$\mu_{mgs}^{-1/4} = v_g\mu_g^{-1/4} + \sum_{j=1}^{N_s} v_j\mu_j^{-1/4} \ \text{and} \qquad \text{A-22}$$

$$\rho_{mgs} = v_g\rho_g + \sum_{j=1}^{N_s} v_j\rho_j \ . \qquad \text{A-23}$$

The possibility of incomplete mixing is accounted for by use of a mixing parameter, ω_1, which relates the effective properties to the pure component properties and perfectly mixed properties by

$$\mu_i^1 = \mu_i^{(1-\omega_1)}\mu_{mgs}^{\omega^1} \quad , \qquad i = g, 1, \ldots, N_s \ , \text{and} \qquad \text{A-24}$$

$$\rho_i^1 = (1-\omega_1)\rho_i + \omega_1\rho_{mgs} \quad , \qquad i = g, 1, \ldots, N_s \ . \qquad \text{A-25}$$

A value of one for the mixing parameter corresponds to complete mixing and a value of zero corresponds to complete segregation.

For $p > p_2$ the soluble species are miscible with one another and with the oil phase. The following mixture properties are defined:

$$\mu_{mos}^{-1/4} = \frac{1}{S_o + \left(1 - v_g\right)S_g}\left(S_o\mu_o^{-1/4} + S_g\sum_{j=1}^{N_s} v_j\mu_j^{-1/4}\right) \quad , \qquad \text{A-26}$$

$$\mu_m^{-1/4} = \frac{1}{1 - S_w}\left(S_o\mu_o^{-1/4} + S_g\mu_{mgs}^{-1/4}\right) \quad , \qquad \text{A-27}$$

$$\rho_{mos} = \frac{1}{S_o + \left(1 - v_g\right)S_g}\left(S_o\rho_o + S_g\sum_{j=1}^{N_s} v_j\rho_j\right) \quad \text{, and} \qquad \text{A-28}$$

$$\rho_m = \frac{1}{1 - S_w}\left(S_o\rho_o + S_g\rho_{mgs}\right) \quad . \qquad \text{A-29}$$

Then, the effective properties are computed using a second mixing parameter, w_2:

$$\mu_o^2 = \mu_o^{\left(1-\omega_2\right)}\mu_{mos}^{\omega_2} \quad , \qquad \text{A-30}$$

$$\mu_g^2 = \mu_g^{\left(1-\omega_2\right)}\mu_{mos}^{\omega_2} \quad , \qquad \text{A-31}$$

$$\mu_i^2 = \mu_i^{\left(1-\omega_2\right)}\mu_{mos}^{\omega_2} \quad , \qquad i = 1, \ldots, N_s \ , \qquad \text{A-32}$$

$$\rho_o^2 = \left(1 - \omega_2\right)\rho_o + \omega_2\rho_{mos} \quad , \qquad \text{A-33}$$

$$\rho_g^2 = \left(1 - \omega_2\right)\rho_g + \omega_2\rho_{mgs} \quad \text{, and} \qquad \text{A-34}$$

$$\rho_i^2 = \left(1 - \omega_2\right)\rho_i + \omega_2\rho_m \quad , \qquad i = 1, \ldots, N_s \ . \qquad \text{A-35}$$

The effective relative permeabilities and capillary pressure for the gas and oleic phases are given by

$$k_{ro}^e = \left(1 - \alpha_s\right)k_{ro} + \left(\frac{\alpha_s S_o}{1 - S_w}\right)k_{row} \quad , \qquad \text{A-36}$$

$$k_{rg}^e = \left(1 - \alpha_s\right)k_{rg} + \left(\frac{\alpha_s S_g}{1 - S_w}\right)k_{row} \quad , \qquad \text{A-37}$$

$$p_{cg}^e = \left(1 - \alpha_s\right)p_{cg} \text{ and} \quad , \qquad \text{A-38}$$

$$\alpha_s = \alpha\min\left(\left(1 - v_g\right)/v_{smis}, 1\right) \quad . \qquad \text{A-39}$$

The parameters P_1, P_2, and v_{smis} are specified by the user to control the transition from immiscible to miscible conditions.

APPENDIX B.
THE OPERATION OF WELL MODELS IN MASTER

The purpose of well models within a reservoir simulator is to compute the source/sink terms in the material balance equations from the specified control variables. Source terms are referred to as injection wells and sink terms as production wells. The sign convention adopted in Equation 8 is consistent with the industry practice of regarding production as being positive and injection as negative. Thus the source terms are algebraically negative and sink terms are algebraically positive. MASTER contains three basic types of well models: rate specified wells, explicit pressure specified wells, and implicit pressure specified wells. The latter two types are only different mathematical formulations for performing the same function.

There are three subtypes of rate specified wells: oil rate specified wells, reservoir voidage rate specified wells, and injection rate specified wells. The first two subtypes need to compute the rates for all chemical species, while the third subtype only needs to compute the rates for the injected species.

Oil rate specified wells are controlled by specifying the surface oil production rate for the well. If a well is completed in more than one block (layer), the model must allocate the production to the various layers so that the total production from the well sums to the specified amount. Allocation of production to the various layers as well as the computation of the relative amounts of each chemical species produced is determined by mobilities alone. This is equivalent to assuming that each phase in every layer flows according to the same Δp_{wk} where Δp_{wk} is given by

$$\Delta p_{wk} = Q_o \Bigg/ \left\{ \sum_{k'} I_{wk'} \left(\frac{k_{ro}^e}{\mu_o^e \beta_o} \right)_k^{(n)} \right\} \qquad \text{B-1}$$

where the sum on k' is understood to be over all perforated layers. The production terms for each block penetrated by the well are then given by

$$Q_{ok} = I_{wk} \left(\frac{k_{ro}^e}{\mu_o^e \beta_o} \right)_k^{(n)} \Delta p_{wk} \qquad \text{B-2}$$

$$Q_{wk} = I_{wk} \left(\frac{k_{rw}}{\mu_w \beta_w} \right)_k^{(n)} \Delta p_{wk} \qquad \text{B-3}$$

$$Q_{ik} = I_{wk} \left(\frac{k_{rg}^e}{\mu_i^e \beta_i} \right)_k^{(n)} \Delta p_{wk} + \left(v_i^{(n)} R_{io}^{(n)} \right)_k Q_{ok} + \left(v_i^{(n)} R_{iw}^{(n)} \right)_k Q_{wk} \qquad \text{B-4}$$

where $I = g, 1, \ldots, N_s$.

Reservoir Voidage Rate Specified Wells

Reservoir voidage rate specified wells operate in a fashion similar to the oil rate specified wells except that Δp_{wk} is computed from the specified voidage rate rather than the oil rate. The expression for Δp_{wk} is

$$\Delta p_{wk} = Q_T \Bigg/ \left\{ \sum_{k'} I_{wk'} \left[\left(\frac{k_{ro}^e}{\mu_o^e} \right)^{(n)}_{k'} + \left(\frac{k_{rw}}{\mu_w} \right)^{(n)}_{k'} + \left(\frac{k_{rg}^e}{\mu_g^e} \right)^{(n)}_{k'} + \sum_{i=1}^{N_s} \left(\frac{k_{rg}^e}{\mu_i^e} \right)^{(n)}_{k'} \right] \right\} \quad . \qquad \text{B-5}$$

The rates for the individual layers and species are then computed using Equations B-2, B-3, and B-4.

Injection Rate Specified Wells

For injection rate specified wells, the allocation of the injected fluid to individual layers is made on the basis of total fluid mobility. This is equivalent to using a Δp_{wk} given by

$$\Delta p_{wk} = Q_i \Bigg/ \left\{ \sum_{k'} I_{wk'} \left[\left(\frac{k_{ro}^e}{\mu_o^e} \right)^{(n)}_{k'} + \left(\frac{k_{rw}}{\mu_w} \right)^{(n)}_{k'} + \left(\frac{k_{rg}^e}{\mu_g^e} \right)^{(n)}_{k'} + \sum_{j=1}^{N_s} \left(\frac{k_{rg}^e}{\mu_j^e} \right)^{(n)}_{k'} \right] / \beta^{(n)}_{ik'} \right\} \quad , \qquad \text{B-6}$$

then

$$Q_{ik} = I_{wk} \Bigg/ \left[\left(\frac{k_{ro}^e}{\mu_o^e} \right)^{(n)}_{k'} + \left(\frac{k_{rw}}{\mu_w} \right)^{(n)}_{k'} + \left(\frac{k_{rg}^e}{\mu_g^e} \right)^{(n)}_{k'} + \sum_{j=1}^{N_s} \left(\frac{k_{rg}^e}{\mu_j^e} \right)^{(n)}_{k'} \right] \Delta p_{wk} \Big/ \beta^{(n)}_{ik} \quad , \qquad \text{B-7}$$

where $I = w, g, 1, \ldots N_s$.

Explicit Pressure Specified Wells

For explicit pressure specified wells, Δp_{wk} is computed from

$$\Delta p_{wk} = \left(p^{(n)} - p_{wb} \right)_k \quad , \qquad \text{B-8}$$

where $\Delta p_{wk} \geq 0$ for producers and $\Delta p_{wk} \leq 0$ for injectors. The rates for production wells are then computed from Equations B-2, B-3, and B-4, and rates for injection wells are computed from Equation B-7.

Implicit Pressure Specified Wells

For implicit pressure specified wells, Δp_{wk} is computed from

$$\Delta p_{wk} = \left(p^{(n+1)} - p_{wb} \right)_k \quad , \qquad \text{B-9}$$

where $\Delta p_{wk} \geq 0$ for producers and$\Delta p_{wk} \leq 0$ for injectors. The rates for production wells are computed from Equations B-2, B-3, and B-4, and rates for injection wells are computed from Equation B-7. Since Δp_{wk} is computed from $p^{(n+1)}$, it is necessary to include the rate in the iteration procedure. This is in contrast to rate specified and explicit pressure specified wells where the rates are held constant during the iteration process.