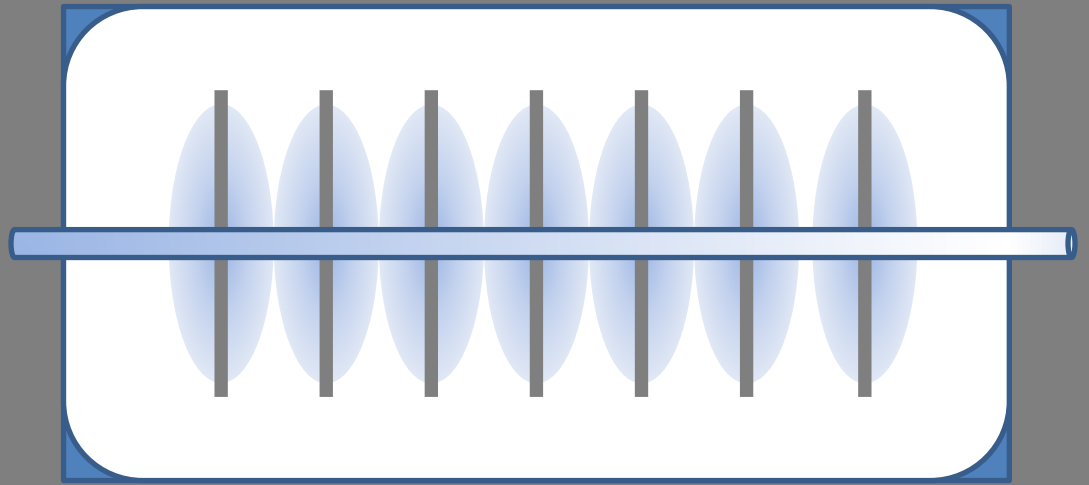


# Petroleum Engineering & Economics Essentials

**Tools and Techniques to Evaluate Unconventional  
(and Conventional) Wells and Reservoirs**



*epci*

Don LeBlanc, PEng  
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Don LeBlanc, PEng  
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## About the Author



**Don LeBlanc, PEng** has an in-depth background in petroleum engineering that includes reservoir engineering, production engineering, hydraulic fracturing, field development, reservoir management, formation evaluation, reservoir modelling, production modelling and reserves certification resulting from extensive independent and operating company experience in Canada, US and Internationally.

During his 43+ year career he has lived in Indonesia, Denmark and the US and worked with super-majors, national oil companies, small independents, and consulting firms all over the world. He has worked on projects in the US, SE Asia, Australia, Croatia, North Sea (Denmark/Norway/UK), Russia, Egypt, East Coast Canada, Beaufort Sea, and Alberta ranging from green (new) fields to brown (old) fields, from offshore to onshore fields and from conventional to unconventional and shale reservoirs.

Don has extensive experience with reservoir and production engineering and simulation of conventional and unconventional reservoirs. He has been working with unconventional and shale reservoirs (Monterey, Diatomite, Utica, Marcellus, Eagle Ford, Montney, Fredericks Brook, Barnett, Haynesville) for over 25 years which led to the development of PE Essentials which includes tools to evaluate conventional and unconventional wells and reservoirs. Don developed the LeBlanc-Okouma Power Law (LOPL) decline curve model which was published in the March 2018 issue of World Oil. He also published the Artificial Neural Network Oil Recovery Factor model in the March 2019 issue of World Oil.

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## Introduction

“Petroleum Engineering Essentials, Tools and Techniques to Evaluate Unconventional (and Conventional) Wells and Reservoirs” is a how-to manual for evaluation of oil and gas wells and reservoirs. It includes tools, theories and techniques covering Reservoir Engineering, Production Engineering and Petroleum Economics. It was originally conceived to be a handbook for evaluation of unconventional reservoirs but quickly evolved to include conventional and some IOR/EOR evaluation techniques as well. This book is a companion to the PE<sup>2</sup> Essentials software.

PE<sup>2</sup> Essentials is a comprehensive suite of software tools comprised of Reservoir/Production Engineering routines and programs that have been built and used during the 35+ year history of Eastex Petroleum Consultants Inc. The PE<sup>2</sup> Essentials suite of tools can be used for all types of wells/reservoirs: unconventional as well as conventional, onshore as well as offshore.

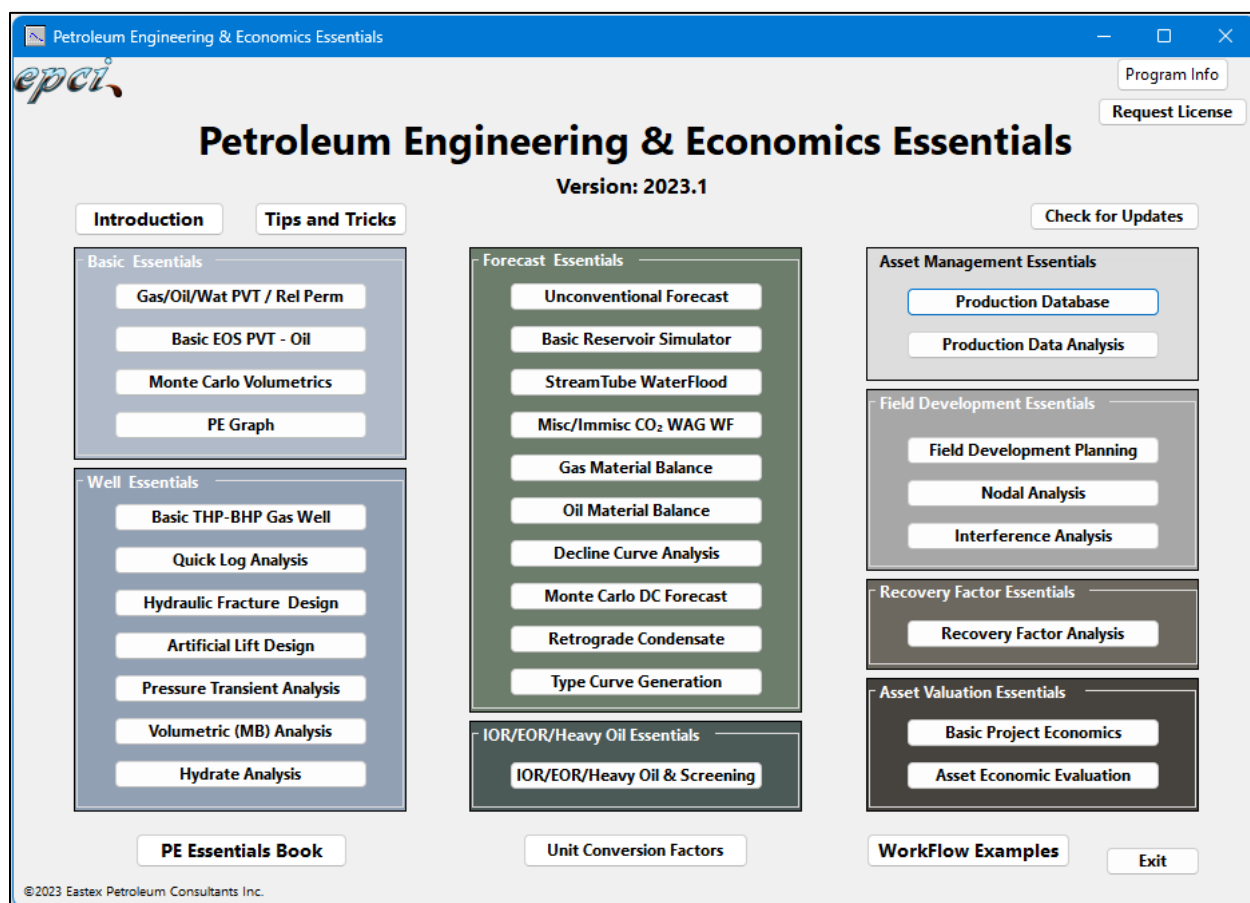


Figure 1: PE<sup>2</sup> Essentials

The tools included in the current version of the program are:

### Basic Essentials

- Gas/Oil/Water PVT and Relative Permeability Curve Generation
- Basic Equation of State Model for Oil
- Monte Carlo Simulation for Oil and Gas In-Place and Recoverable Volumes
- PE Graph (plots output from PE<sup>2</sup> Essentials tools)

### Well Essentials

- THP-BHP Tubing Pressure Drop Calculations for a Gas Well
- Quick Log Analysis – Includes GIIP/OOIP Estimate
- Hydraulic Fracture Design for Horizontal Wells
- Artificial Lift Design
- Pressure Transient Analysis including Analytical Test Simulator
- Volumetric (Material Balance) Surveillance and Analysis
- Hydrate Analysis

### Forecast Essentials

- Hydraulically Fractured Well Forecasting (includes a History Matching tool)
- Basic Reservoir Simulator – General Purpose Reservoir Simulator
- Streamline WaterFlood Simulator (Leighton and Higgins streamline simulator)
- Miscible/Immiscible CO<sub>2</sub> WAG and Waterflood Streamline Simulator
- Multi-Tank Gas Material Balance Forecast – Multi Tank and Aquifer Options
- Oil Material Balance Forecast – Aquifer Options
- Decline Curve Analysis and Production Forecast – Normalized DCA
- Monte Carlo Decline Curve Production Forecasting (Probabilistic Forecast)
- Retrograde Condensate Forecasting
- Type Curve Generation

### IOR/EOR/Heavy Oil Essentials

- IOR/EOR/Heavy Oil Tool (screens 18 different processes, MMP, Thermal, pumps)

### Asset Management Essentials

- Production Database
- Production Data Analysis

### Field Development Essentials

- Field Development Planning (Multi-well Project Planning and Forecasting)
- Nodal Analysis (Includes Wellbore, Pipeline, Artificial Lift and Compressors)
- Interference Analysis

### Recovery Essentials

- Recovery Factor Analysis – Monte Carlo, Unconventional, Reservoir Complexity, ANN

### Asset Valuation Essentials

- Basic Project Economics including Corporate Economics
- Asset Economic Evaluation including Three Tax/Contract Models



Overall, there are more than 30 Petroleum Engineering modules and each module can include multiple tools. A Graphing tool and a book are also included with PE<sup>2</sup> Essentials. In total, there are more than 50 unique tools included in the PE<sup>2</sup> Essentials suite of tools.

The book can be used as a stand-alone resource for some of the techniques but for others, the software is required to generate the results.

The “Petroleum Engineering & Economics Essentials, Tools and Techniques to Evaluate Unconventional (and Conventional) Wells and Reservoirs” book describes the equations and theories incorporated into the tools and, where appropriate, the file formats for input data files. Examples for the use of each tool are included with the software and an example PE Tools database containing input files for all tools is included in the “PE Essentials\Example Input Files” directory. The input/output files for the solved examples in the book are included in the “PE Essentials\Book Examples” directory.

WorkFlow examples are included throughout the book and comprehensive, integrated examples are included in the ‘WorkFlow Examples’ document.

All PE<sup>2</sup> Essential tools are capable of handling metric or oilfield units. It should be noted that unless otherwise specified, the metric routines use kPa rather than bars for pressure (1 bar = 100 kPa). For simplicity, this book presents oilfield units for all equations. An example of a metric problem is included in the workflow examples. All tools include an example metric input file in the example PE Tools database.

The software requires 64bit Microsoft Windows and can include a free trial period, by request. A license is required to unlock the program (click ‘Program Info’ on the main screen). The PVT tool is always available.

Extract and run ‘PE Essentials Setup.exe’ and store the files to a hard drive and directory of your choice then run the program ‘PE Essentials.exe’. It should be noted that the programs are not stand-alone routines and require the main PE Essentials.exe program to execute them. A pre-installed setup is available on request.

In terms of importing production data, data is imported and stored in the Production Database from an Excel spreadsheet. All production data should be imported into the ‘PE Essentials Database’ tool. The ‘PE Essentials Production Data Analysis’ tool is then used to extract the data for the specific well or wells and is used to generate the data input files for the other tools.

The ‘Gas/Oil/Water PVT / Rel Perm’ tool is always available for use. To use the other tools, a demo license can be requested by sending the program’s s/n file (PE Essentials Serial Number.snv) located in the ‘PE Essentials License’ directory to [PEEssentials@eastexpetroleum.com](mailto:PEEssentials@eastexpetroleum.com) and requesting a demo license.

Once a license file has been obtained, copy it to the ‘PE Essentials License’ directory.

After the free trial period, only the ‘Gas/Oil/Water PVT / Rel Perm’ tool will be available for use.



It should be noted that although there is a rudimentary numerical reservoir simulator included with PE<sup>2</sup> Essentials, the tool can export files that can be used with industry standard simulators. The author tends to use an open-source simulator called OPM-Flow (<https://opm-project.org/>) along with an open-source visualization program called ResInsight (<https://resinsight.org/>).

OPM Flow is a reservoir simulator for three-phase black-oil problems and uses a fully-implicit formulation. There are also options to run solvent and polymer problems. OPM Flow can read and write standard industry formats.

ResInsight is the professional quality, open-source 3D visualization, curve plotting and post-processing tool for reservoir models and simulations. The program can read industry standard simulator input and output files.

## PE Essentials File Information

PE Essentials uses SQL databases to store production data as well as tool models and results. The following is a description of the main databases created and used by PE Essentials.

### Production Database (.dvxDB)

The PE Production database (.dvxDB) is the repository of the raw production data. This database is created by the PE Essentials Production Database tool and is not used by any other tool except to import the well data into the PDA tool. The reason for this is so that the raw, unedited production data is always available in a secure location. The intent (someday) is to expand this database to store all raw field data. This database is expanded as new tools are added that require different data – for example, the 2021 version of PE Essentials added injection well data to the database.

The Production Database tool can also edit the production data. Editing is limited to deleting the well; changing the well name; appending data; or reloading the entire well data set. Only limited editing is possible in order to retain the integrity of the raw data. Once the data is loaded into the database, it can be exported to a CSV file.

The Production Database tool can smooth the raw data through averaging and can sum different wells. The results of these operations are stored as new wells in the production database so the raw data is not altered.

### PE Tools Database (.PEEdb)

The PE Tools database (.PEEdb) is the repository of the tool models/data/results. This database is created by the PE Essentials Production Data Analysis (PDA) tool and is used by all other tools except the 'Production Database' tool. This is the database that is used on a continuous basis by all the tools.

The Tools database contains raw and edited data, model data, model results, forecasts, PVT tables, MBal tables, probabilistic tables and other miscellaneous data. All data contained in this database can be exported to CSV files for use in other programs.

It should be noted that the base “edited” data in this database is the raw data with all zero rates from the main well production stream removed – this is termed “Analyzable Data” in the PDA tool. The base edited data is generated as the raw data is imported from the production database.

The PDA tool can be used to copy and backup the PE Tools database. It is also used for management of the PE Tools database. 'Database Management' is used to view the contents of the PE Tools database (Figure Intro-1 and Figure Intro-2).





Data in PEE Tools Database

List Forecasts				Delete Data				List Models							
#	ID	Well Name	Fluid	Units	#Data	#Edit	#Sim	#MBal	PVT	Type	n/a	n/a	n/a	n/a	dbVersion
1	1	Eagle Ford Example	Oil	Oilfield	304	282	304	238	Tab	Prod	0	0	0	0	1
2	2	Tutorial-1	Gas	Oilfield	439	439	439	238	Tab	Prod	0	0	0	0	1
3	4	NO 15/9-F-1 C	Oil	Metric	2892	429	2892	436	Tab	Prod	0	0	0	0	1
4	5	NO 15/9-F-11 H	Oil	Metric	3056	1122	3056	436	Tab	Prod	0	0	0	0	1
5	6	NO 15/9-F-12 H	Oil	Metric	3020	2835	0	2	Tab	Prod	0	0	0	0	1
6	7	NO 15/9-F-14 H	Oil	Metric	2990	2722	0	2	Tab	Prod	0	0	0	0	1
7	8	NO 15/9-F-15 D	Oil	Metric	2983	766	0	2	Tab	Prod	0	0	0	0	1
8	9	NO 15/9-F-5 AH	Oil	Metric	3119	128	0	2	Tab	Prod	0	0	0	0	1
9	10	NO 15/9-F-4 AH WI	Oil	Metric	3140	2843	0	2	Cor	WInj	0	0	0	0	1
10	11	NO 15/9-F-5 AH WI	Oil	Metric	2977	2557	0	2	Cor	WInj	0	0	0	0	1
11	12	NO 15/9-F-1 C Oilfield	Oil	Oilfield	2892	429	2892	436	Tab	Prod	0	0	0	0	1
12	13	NO 15/9-F-11 H Oilfield	Oil	Oilfield	3056	1122	3056	436	Tab	Prod	0	0	0	0	1
13	14	NO 15/9-F-12 H Oilfield	Oil	Oilfield	3020	2835	0	2	Tab	Prod	0	0	0	0	1
14	15	NO 15/9-F-14 H Oilfield	Oil	Oilfield	2990	2722	0	2	Tab	Prod	0	0	0	0	1
15	16	NO 15/9-F-15 D Oilfield	Oil	Oilfield	2983	766	0	2	Tab	Prod	0	0	0	0	1
16	17	NO 15/9-F-5 AH Oilfield	Oil	Oilfield	3119	128	0	2	Tab	Prod	0	0	0	0	1
17	18	NO 15/9-F-4 AH Oilfield WI	Oil	Oilfield	3140	2843	0	2	Cor	WInj	0	0	0	0	1
18	19	NO 15/9-F-5 AH Oilfield WI	Oil	Oilfield	2977	2557	0	2	Cor	WInj	0	0	0	0	1
19	20	WI_RX	Oil	Metric	410	306	0	2	Cor	WInj	0	0	0	0	1
20	21	WI_RX Oilfield	Oil	Oilfield	410	307	0	2	Tab	WInj	0	0	0	0	1

PEE Tools Examples Database.PEEdb

Close

Figure Intro-1: PE<sup>2</sup> Essentials – PEEdb Database Content

Forecasts in the PE Tools database		Forecasts in the PE Tools database	
#	Select Well Name	#	Select Well Name
1	CAPE_PSC Model - Cum Based PSC Esc 100WI	1	Artificial Lift
2	WAGForecast_CO2 Waterflood	2	Artificial Lift Metric
3	DCAForecast_DCA Bakken Shale Oil Well Oilfield	3	Cap Costs: PSC Model - Cum Based PSC Esc 100WI
4	DCAForecast_DCA Marcellus 5Bcfe	4	Currency: PSC Model - Cum Based PSC Esc 100WI
5	DCAHistForecast_DCA Marcellus 5Bcfe	5	Escalation: PSC Model - Cum Based PSC Esc 100WI
6	DailyOil_FDP Example	6	Fiscal Terms: PSC Model - Cum Based PSC Esc 100WI
7	MonthlyOil_FDP Example	7	Op Costs: PSC Model - Cum Based PSC Esc 100WI
8	GMBForecast 2-Tank Volumetric Gas Reservoir	8	Prices: PSC Model - Cum Based PSC Esc 100WI
9	GMBForecast MB Volumetric Gas Reservoir	9	Purchase: PSC Model - Cum Based PSC Esc 100WI
10	HistEV_MCDCA_Marcellus 7Bcfe 2	10	CO2 Waterflood
11	HistP10_MCDCA_Marcellus 7Bcfe 2	11	CO2 Waterflood _ Metric
12	HistP50_MCDCA_Marcellus 7Bcfe 2	12	PSC Model - Cum Based PSC Esc 100WI
13	HistP90_MCDCA_Marcellus 7Bcfe 2	13	PSC Model - Cum Based PSC Esc 100WI
14	P10_MCDCA_Marcellus 7Bcfe 2	14	DCA Database - Norm Well
15	P50_MCDCA_Marcellus 7Bcfe 2	15	DCA Example Database - Interp
16	P90_MCDCA_Marcellus 7Bcfe 2	16	DCA Example Database - Raw
17	EV_MCDCA_Marcellus 7Bcfe 2	17	Economics DCA Bakken Oil Metric
18	SIMGasForecast_Gas Horizontal	18	Economics DCA- Bakken Shale Oil Well Oilfield
19	10Fracs_AnalyticalGasUnconventional Gas	19	Gas Example Metric
20	15Fracs_NumericalOilEagle Ford Example	20	Unconventional Gas Well
21	2Fracs_AnalyticalGasUnconventional Gas	21	Unconventional Gas Well - 6 fracs
22	2Fracs_AnalyticalOilUnconventional Oil	22	IOR_EOR Screening _ Metric
23	2Fracs_NumericalGasUnconventional Gas	23	IOR _ EOR Screening
24	2Fracs_NumericalOilUnconventional Oil	24	EOS Well Tuned McCain
25	3Fracs_AnalyticalGasUnconventional Gas	25	EOS Well Tuned McCain _ Metric
26	3Fracs_AnalyticalOilUnconventional Oil	26	FDP Example Metric
27	3Fracs_NumericalOilUnconventional Oil	27	FDP Example Oil
28	4Fracs_AnalyticalGasUnconventional Gas	28	2-Tank Volumetric Gas Reservoir
29	4Fracs_AnalyticalOilUnconventional Oil	29	MB Volumetric Gas Reservoir
30	5Fracs_AnalyticalGasUnconventional Gas	30	Water Drive Gas Reservoir
31	5Fracs_NumericalGasHistory Match Model	31	Hydraulic Fracture Gas Well
32	6Fracs_AnalyticalGasUnconventional Gas	32	Hydraulic Fracture Gas Well _ Metric
33	7Fracs_AnalyticalGasUnconventional Gas	33	Hydraulic Fracture Oil Well
34	8Fracs_AnalyticalGasUnconventional Gas	34	Hydraulic Fracture Oil Well _ Metric
35	9Fracs_AnalyticalGasUnconventional Gas	35	Complete Hydrate Example
36	WFForecast_Waterflood	36	Complete Hydrate Example - Metric

Figure Intro-2: PE<sup>2</sup> Essentials – PEEdb List Forecasts and Models

Database management is also used to delete data from the PEEdb database (Figure Intro-3).

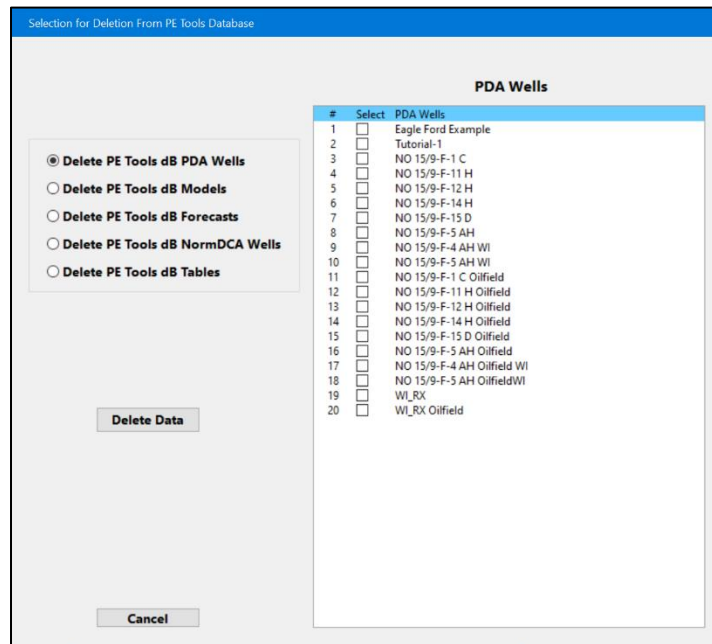


Figure Intro-3: PE<sup>2</sup> Essentials – PEEdb Delete Data

Delete can be performed by category (wells, models, forecast) or by specific files in the database. Extreme caution should be used when deleting specific database files – backup the database before deleting files. Deleting the wrong file can make the database unusable. If specific files are to be deleted, contact [PEEssentials@eastexpetroleum.com](mailto:PEEssentials@eastexpetroleum.com) for assistance.

One trick that can be useful is the capability of loading a model from one database, then opening a different database and saving the model. This will copy the model from one database to another.

### Decline Curve Analysis Database (.dvx)

The DCA tool has its own database that can be stored within the PE Tools database or as a standalone database (.dvx). This was done for reserves purposes so that a separate auditable file is available and can be stored separately from the working database.

The option to load/store a standalone database is accessed from the 'Decline Curve Analysis' tool (Figure Intro-4).

Load DCA Database	Save DCA Database
<input checked="" type="radio"/> PE Tools Database <input type="radio"/> DVX File (DCA dB)	<input type="radio"/> PE Tools Database <input checked="" type="radio"/> DVX File (DCA dB)
<input type="button" value="Continue"/> <input type="button" value="Cancel"/>	<input type="button" value="Continue"/> <input type="button" value="Cancel"/>

Figure Intro-4: PE<sup>2</sup> Essentials – DCA Database Options

It should be noted that when storage to the 'PE Tools Database' is chosen, the DCA standalone database is stored in the PEEdb.

#### Asset Economic Analysis Database (.DVXcdb)

The 'Asset Economic Analysis' tool also has the capability to store its database (.DVXcdb) separately from the PEEdb database. This was done for confidentiality and reserves auditing purposes, if required. If the Asset tool data is stored in the PE Tools database, an option to "Lock Asset db" is available to ensure the data is not modified except by the person who locked it.

#### Volumetric Analysis Database (.DVXv)

The Volumetric Analysis' tool database (.DVXv) is used solely by the 'Volumetric (MB) Analysis' tool and can only be accessed by that tool. The database stores production volume and reservoir pressures. It is a separate database because the availability of reservoir pressures is not normally at the same frequency as production data so it is difficult to store with the main production data.

#### Example Directories

There are two Examples directories in the PE Essentials directory: 'Book Examples' which contain the examples for the Workflow examples; and 'Example Input Files' which contains the example databases, Excel files and workspace files for the PE Graph and PE Interference Analysis examples.

## Basic Fluid Descriptions

There are five basic fluid types that exist in oil/gas reservoirs (Figure Intro-5): Black Oil; Volatile Oil; Retrograde Condensate; Wet Gas; and Dry Gas.

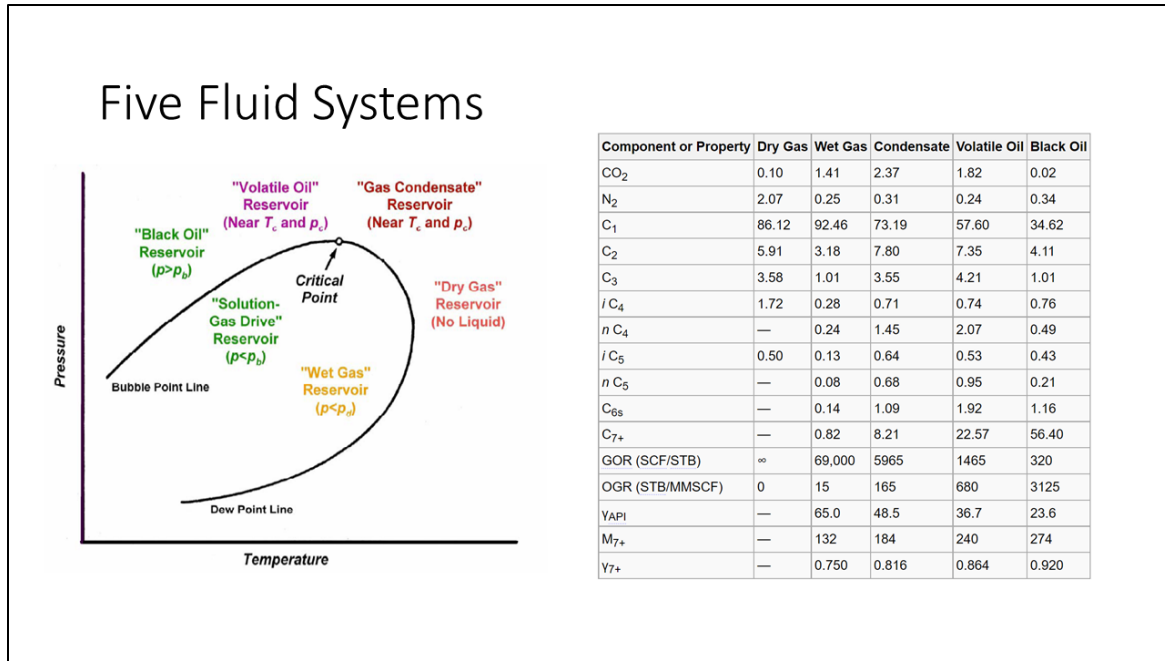


Figure Intro-5: Five Fluid Systems

The fluid types can be characterized by their Pressure-Temperature (P-T) phase envelope and fluid properties. In general, the five fluids can be identified as follows Figures Intro-6 to Intro-10:

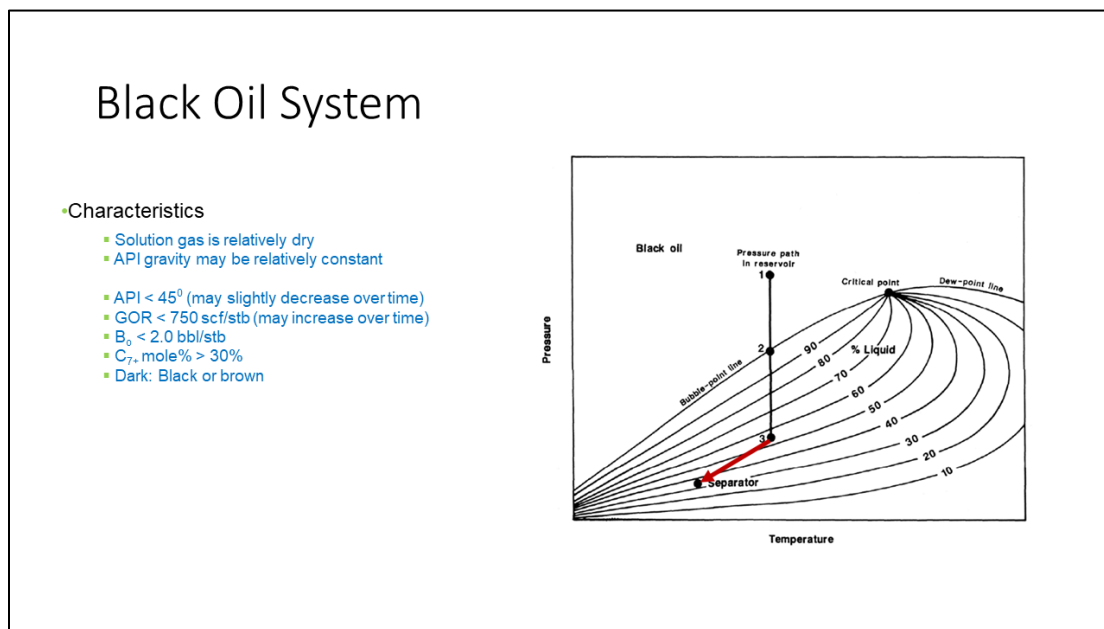


Figure Intro-6: Black Oil

The preferred technique to determine fluid type is to obtain an initial representative sample from the reservoir and evaluate the phase diagram of the fluid. Since this type of sample may be difficult to obtain, the characteristics of the fluid can be used to determine the fluid category.

## Volatile Oil System

### Characteristics

- Critical temperature near res temperature
- Solution gas contains significant condensate
- GOR and  $B_o$  are a function of separator conditions
- Contain more  $C_2-C_6$  than black oils
- Small reduction in P below bubble point releases large amount of gas in the reservoir
- Requires multi-stage separation to minimize shrinkage
- API > 40° (increases over time)
- 750 < GOR < 2,500 scf/stb (increases over time)
- $B_o$  > 2.0 bbl/stb
- $C_{7+}$  mole% 12.5% to 30%
- Brown, orange or green

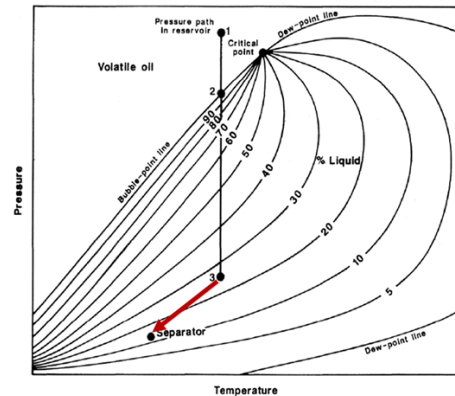


Figure Intro-7: Volatile Oil

## Retrograde Gas

### Characteristics

- Dew point behavior at res temperature
- Critical temperature is less than res temperature
- Liquid condenses in the reservoir below dew point
- Liquid normally does not flow
- P-T diagram shows liquid vaporization as pressure reduces but this is not likely to occur in the reservoir because of compositional changes to the reservoir fluid
- 40 < API < 60° (increases over time)
- 2,500 < GOR ~< 50,000 scf/stb (increases over time)
- 20 < CGR < 400 stb/mmscf (decreases over time)
- $C_{7+}$  mole% < 12.5%
- Light colored (brown, orange, greenish, clear)
- Gas cycling projects have been designed to avoid liquid loss from retrograde condensation. These projects can usually be justified for fluids with liquid content higher than about 50 to 100 STB/MMSCF

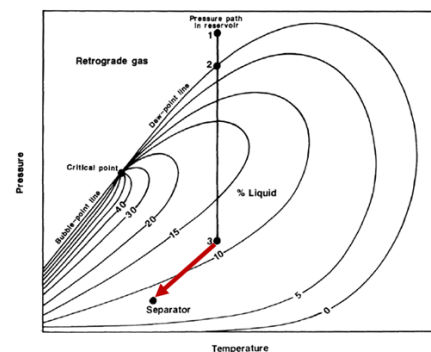


Figure Intro-8: Retrograde Condensate

## Wet Gas

### •Characteristics

- Entire phase diagram lies below the res temperature
- No dew point behavior at res temperature
- Only produces liquids/condensate at the surface
- Reservoir gas is saturated with water
- $40 < \text{API} < 60^\circ$  (does not change over time)
- $\text{GOR} > 50,000 \text{ scf/stb}$  (does not change over time)
- $\text{CGR} < 20 \text{ stb/mmscf}$  (does not change over time)
- $\text{C}_{7+} \text{ mole\%} < \sim 1\text{-}2\%$
- Clear liquid

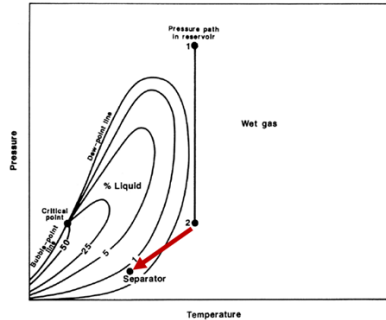


Figure Intro-9: Wet Gas

## Dry Gas

### •Characteristics

- Remains in the gas phase at all operating temperatures and pressures
- No condensate at the surface
- Reservoir gas is saturated with water
- High mole% of methane
- $\text{C}_{7+} \text{ mole\%}$  negligible

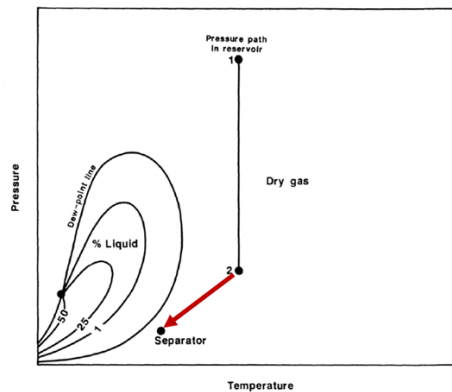


Figure Intro-10: Dry Gas

As an example, for a gas reservoir, the value of the mole% of the  $\text{C}_{7+}$  fraction can be used to determine if it is a retrograde condensate or a wet gas. If the mole% of the  $\text{C}_{7+}$  fraction of the gas sample is between 2% and 12.5%, the fluid would be a retrograde gas/condensate.

## PE Asset Management Essentials

The Asset Management Essentials section contains the following:

- Production Database
- Production Data Analysis

## Production Database Tool

The PE<sup>2</sup> Essentials 'Database' tool (Figure PDB-1) enables input of production, injection and other data into an SQL database for use in the PE<sup>2</sup> Essentials Production Data Analysis tool (PDA). The data in the database is imported into the PDA tool for editing and storing in the PE Tools database for use in the other PE<sup>2</sup> Essentials tools. The Production Database tool can also be used to perform general comparisons (Figure PDB-2) of multi-well performance characteristics.

Figure PDB-1: PE<sup>2</sup> Essentials Database Tool

Note that prior versions of the production database will be automatically updated to the current database format. Following the database upgrade, the database cannot be read by previous versions of the PE Essentials Database Tool.



Make sure a copy of the old database is saved prior to loading it into the new database tool.

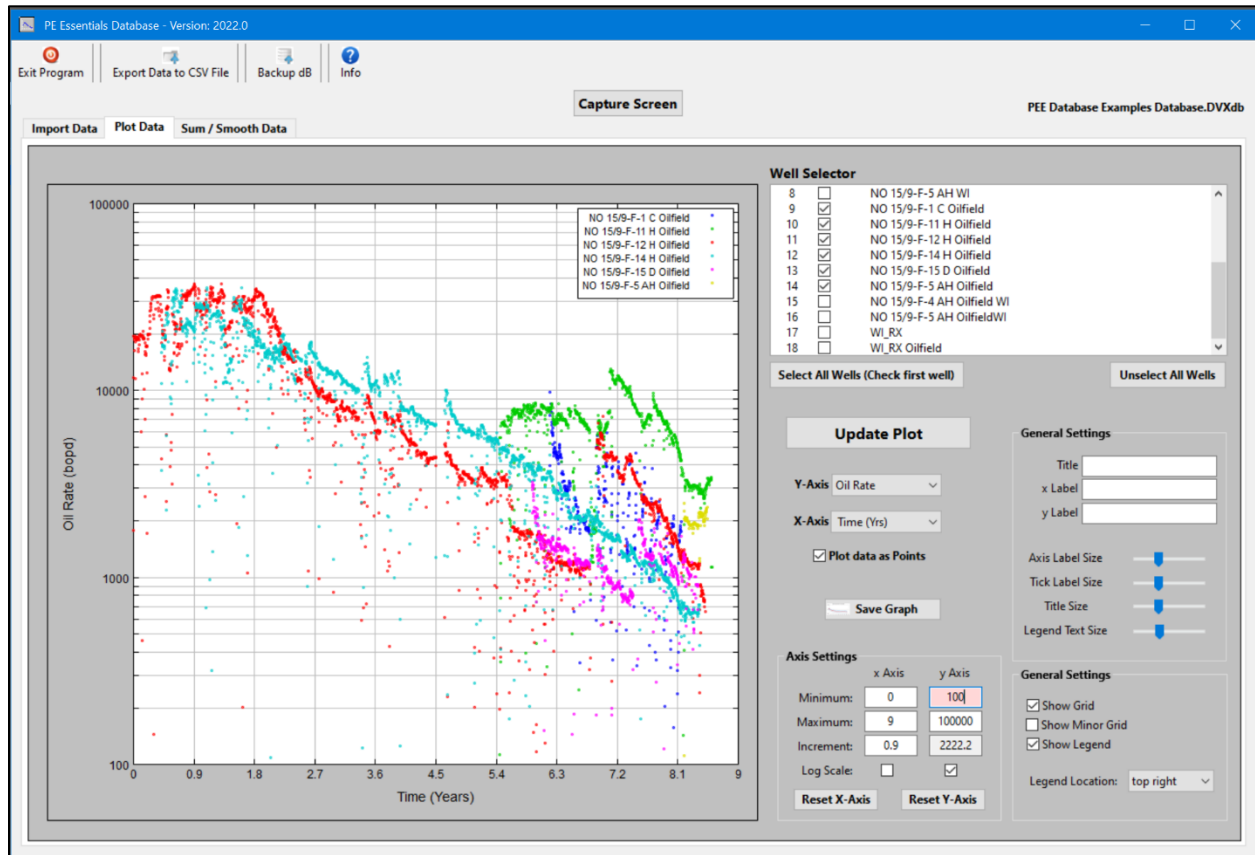


Figure PDB-2: Plotting of Database Data – Multi-Well Plot

The summation of wells can also be performed in the Database tool (Figure PDB-3). In order to sum wells/assets together, the times must be compatible: start time and increment. If this is not true, then a message will be displayed. The 'Import Data' tab can be used to confirm that the time scales are compatible.

After summing the data, the new data set can be saved to the database by selecting/unselecting the appropriate wells and clicking "Save Selected Wells to Database".

It is also possible to average the complete well data based on a 3-day, 7-day or 11-day moving average. These averaged wells are automatically saved in the database. The difference between this averaging and the PDA averaging is that this calculation averages the entire data set, not just the production as done in PDA. The averaged well can be plotted on the 'PlotData' tab.

All plots can be saved to a png file by clicking "Save Graph" on the appropriate tab.



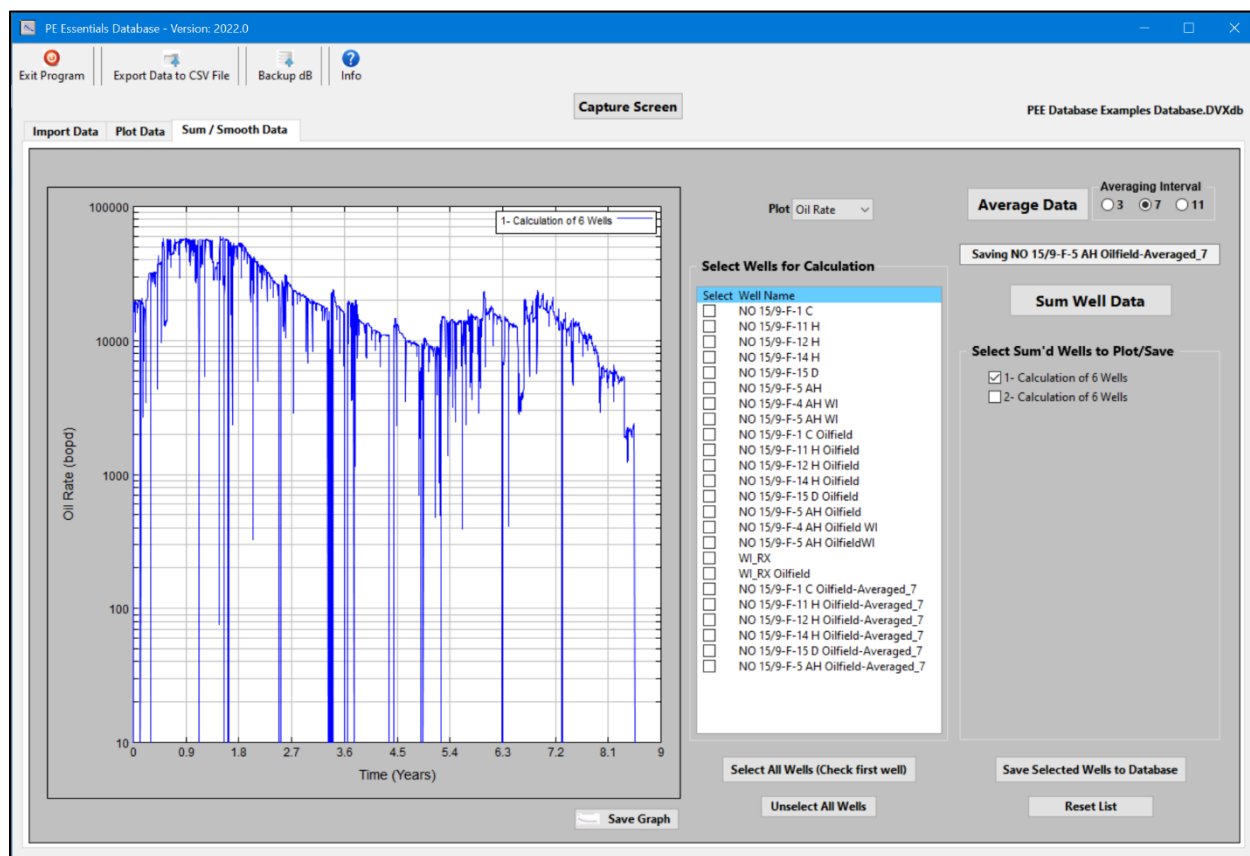


Figure PDB-3: Summing Wells in Production Database

### PDB.1 Data Import

To import data (Figure PDB-4), a new database has to be created (“New Database”) or an existing database must be opened (“Open Database”).

After linking an Excel file to the tool (“Link Excel”), data is imported into the database from the spreadsheet. All data is imported in basic volumetric units - bbls or m<sup>3</sup> for oil and water and mscf or 10<sup>3</sup>sm<sup>3</sup> for gas. The data interval along with the specified input time parameter (Daily Data / Monthly Data / Yearly Data) is used to calculate rates. By specifying the input time parameter, it is possible to have missing data but still calculate the proper rate.

Prior to importing data, ensure that the “Units” and “Fluid Type” and “Well Type” are specified. Although it is possible to include oil wells, gas wells, injection wells, oilfield and metric units in the same database, it is better to load wells with consistent parameters at one time.

If only a limited subset of the data is to be imported, the “End Row” box should be used to specify the end of the data import.

Figure PDB-4: PE<sup>2</sup> Essentials Database - Importing Data

If the Excel file contains multiple wells sequentially, it is possible to enter all well data into the database at once by ensuring there is a “Well Name” column included in the input stream. The Database tool will import data by examining the well name and the time to determine when a new well is to be imported. If only one well is being imported, leave the “Well Name” column box blank. Import of a well is complete either when the well name changes or when the next time step is blank or reduces.

Up to 5 user specified parameters as well as time-based comments can be imported for each well. The 5 user parameters can be plotted in the Database tool for each well (Figure PDA.2) but they cannot be imported into the other PE<sup>2</sup> Essentials tools.

Once the data is imported into the database, or a database is opened, there are a couple options available to view the data. Plots of the data can be generated (Figure PDA-2) or the data itself can be presented in table format (Figure PDB-5). Note: ‘Primary Data - 2’ lists the injection data.

<input checked="" type="radio"/> Primary Data - 1 <input type="radio"/> Primary Data - 2 <input type="radio"/> Calc'd Data					<input checked="" type="radio"/> Show Prod <input type="radio"/> Show Cum		
Date	Days	Oil Prod	Gas Prod	Water Prod	THP	CHP	BHP
11-Feb-08	0	0	0	0	0	0	0
12-Feb-08	1	1.790448	1.37334	2.421713	1753.34	238.8283	4395.128
13-Feb-08	2	11.76041	10.07337	0.0448477	1753.34	238.8283	4395.128
14-Feb-08	3	19.65053	18.00889	0.0072964	1649.342	183.6117	4287.112
15-Feb-08	4	16.40608	13.54059	0.0061013	1694.485	76.34859	4317.231
16-Feb-08	5	19.19582	14.77827	0.0307581	1674.235	179.6239	4292.18
17-Feb-08	6	18.76074	14.92973	0.0116365	1670.919	208.6304	4286.613
18-Feb-08	7	18.74747	14.6143	0.0407592	1643.013	231.7767	4267.169
19-Feb-08	8	19.16054	15.15769	0.0045917	1650.081	272.8341	4261.631
20-Feb-08	9	19.22966	15.64379	0.0028934	1644.723	286.3154	4250.496
21-Feb-08	10	19.06078	14.96668	0.0028305	1640.468	281.8325	4242.936
22-Feb-08	11	18.28855	14.04846	0.0027676	1640.076	15.06351	4240.344
23-Feb-08	12	11.64732	8.902051	0.0017612	1633.164	159.6987	4236.383
24-Feb-08	13	19.66694	15.63762	0.0029563	1612.629	124.4817	4213.948
25-Feb-08	14	19.15645	15.50942	0.0028934	1616.441	178.4597	4209.112
26-Feb-08	15	19.16274	15.7823	0.0028934	1608.954	181.39	4199.366
27-Feb-08	16	19.09355	15.73678	0.0028934	1600.136	179.4945	4190.621
28-Feb-08	17	18.69105	14.99722	0.0028305	1604.533	147.206	4189.388
29-Feb-08	18	19.3137	15.90389	0.0028934	1587.393	165.6903	4170.041
01-Mar-08	19	19.30074	15.80628	0.0028934	1578.399	161.7972	4161.009
02-Mar-08	20	19.28854	15.75543	0.0028934	1571.063	162.7705	4151.916
03-Mar-08	21	19.14387	15.67004	0.0028934	1567.266	157.605	4144.131
04-Mar-08	22	18.76427	15.19402	0.0028305	1567.496	142.5567	4139.114
05-Mar-08	23	18.66274	15.45681	0.0028305	1564.511	135.2153	4131.092
06-Mar-08	24	18.56104	15.28161	0.0109446	1556.405	132.1817	4123.345
07-Mar-08	25	16.71014	13.81738	0.0098753	1562.835	91.02382	4125.215
08-Mar-08	26	16.21864	12.91701	0.0095608	1566.863	66.58511	4125.062
09-Mar-08	27	18.85006	15.1073	0.0111333	1536.377	124.4675	4095.662
10-Mar-08	28	19.00461	15.56243	0.003774	1527.097	130.7047	4083.134
11-Mar-08	29	18.93542	15.92593	0.003774	1520.151	129.5643	4074.028
12-Mar-08	30	17.57703	14.79285	0.0035224	1523.662	97.10792	4076.79
13-Mar-08	31	19.24042	16.19262	0.0038369	1500.289	125.3234	4053.632
14-Mar-08	32	18.64865	15.11521	0.0037111	1497.071	113.4838	4048.173
15-Mar-08	33	19.69632	16.0377	0.0039627	1481.415	127.899	4031.338
16-Mar-08	34	19.72148	16.06104	0.0039627	1475.6	121.9838	4021.786
17-Mar-08	35	19.7718	16.60637	0.0039627	1469.218	116.1214	4011.226
18-Mar-08	36	19.70261	15.01878	0.0039627	1463.587	112.4508	4002.79
19-Mar-08	37	19.74821	16.03615	0.0039627	1457.046	108.4287	3993.799
20-Mar-08	38	19.85545	16.5084	0.0039627	1452.179	101.0636	3985.53

Figure PDB-5: PE<sup>2</sup> Essentials Database – Data Table List

To view a specific well, the drop-down menu is used to choose a well from the database. It is possible to view the imported primary data, the imported user-defined date, or the calculated variable generated with the imported data by choosing the appropriate radio button. It is also possible to list the cumulative volumes rather than the production volumes. Note – that rates can be viewed through the plotting options or by importing the well data into the PDA tool.

The units displayed in the data listing is selected by choosing the appropriate radio button in the “Table Display Units” group box.

It should be noted that the data is automatically stored in the SQL as soon as it has been imported. It is possible to modify or delete wells by editing the database.

## PDB.2 Comments/Caveats on Data Entry

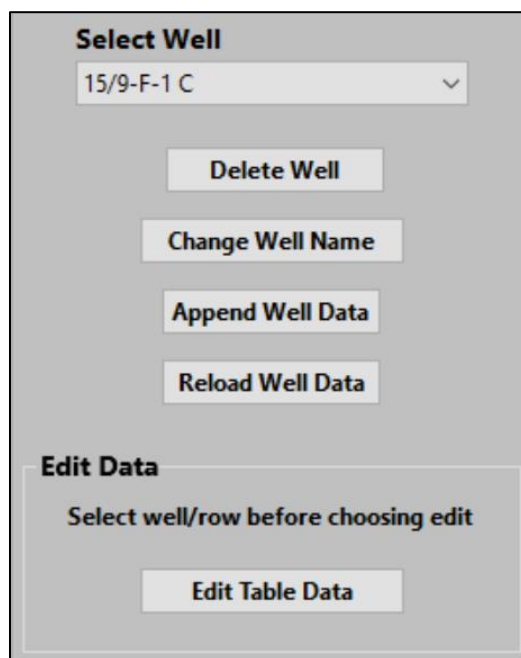
Most issues that arise when importing data are a direct result of the time sequence in the data set. Things to look out for (and correct) include the following;

- Time must always increase. In order to determine the end of data for one well and the start of the next well, the import logic looks for two things – a name change in the name column or a time earlier than the time in the current row. The logic assumes a new well if the next time step is earlier than the current time step. This will cause a new well to be started but it will have the same name as the current well. This will cause issues with storing and loading data into PE Essentials. The time data should be reviewed prior to importing to ensure that the time is continuously increasing for the well.
  - A quick technique to check the time is to set up a column that subtracts the current time from the previous time. All negative results should then be evaluated to confirm they are valid.
- Time gaps can cause erroneous cumulative calculations. Cumulative volumes are calculated by assuming the imported volume is valid for the entire time interval. For example, if a well is shut-in for 1 week, the zero rate may not be entered prior to the well being re-opened. Assume that the rate is 100 and the next day it is 0. These rates are recorded. Seven days later the well is reopened at 200. The import routine will assume that the 200 is valid for the entire 7 days and the cumulative calculations will be too high. To correct this a zero rate needs to be added to the data for the day before the well is opened. This issue becomes important when the data frequency is greater than daily (monthly, quarterly, etc).
  - A quick technique to check this is to set up a column that subtracts the current time from the previous time. All results greater than the data frequency should then be evaluated to confirm that the proper volumes are being imported for the time interval.
- It is also good practice to evaluate the data and correct any erroneous spikes that are evident prior to importing the data. This is especially important for negative data which can be recorded in unedited allocated data – specifically the secondary production streams. The spikes can be edited out in the tools but it is much easier to correct them before importing the data.
  - A quick technique to check this is to filter the data in Excel and evaluate all data that is anomalously high, low or negative.

Performing the above steps will correct 90-95% of data import issues that have been encountered by users of the tools.

### PDB.3 Database Editing

The data contained in the database can be edited as shown in Figure PDB-6.



The screenshot shows a web-based interface for editing database data. At the top, there is a section titled "Select Well" with a dropdown menu currently showing "15/9-F-1 C". Below this, there are four buttons stacked vertically: "Delete Well", "Change Well Name", "Append Well Data", and "Reload Well Data". At the bottom, there is a section titled "Edit Data" which contains the instruction "Select well/row before choosing edit" and a button labeled "Edit Table Data".

Figure PDB-6: PE<sup>2</sup> Essentials Database - Editing Data

The options available for editing are to delete a well, change the well name, append data to a specified well or multiple wells and reload the data. Reloading well data can also be used to add new data to the well – in this case the complete production data is reloaded so any edits of the data will be lost. Both 'Append Well Data' and 'Reload Well Data' can import multiple wells at the same time.

It is possible to edit a specific data entry in a specified well by selecting the well and data row and clicking 'Edit Table Data'.

Prior to deleting a well, the user will have to confirm that the specified well is to be deleted (Figure PDB-7).



The screenshot shows a "Delete Confirmation" dialog box. It has a blue header bar with the text "Delete Confirmation". The main content area is white and contains the text "Confirm Delete Well: NO 15/9-F-1 C". At the bottom, there are two buttons: "Yes" and "No".

Figure PDB-7: PE<sup>2</sup> Essentials Database – Delete Well

To change a well name, a screen will pop-up for entering the new name (Figure PDB-8).

Figure PDB-8: PE<sup>2</sup> Essentials Database – Change Well Name

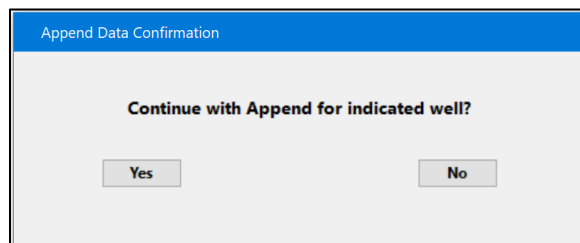
After changing a well name, it is possible to confirm the change by clicking “List Database Wells” (Figure PDB-9). The list will also include other parameters for the wells.

#	Well Name	Type	Fluid	Units	Time	Oil	Gas	Water	dbVersion
1	NO 15/9-F-1 C	Prod	Oil	Metric	Calender	m <sup>3</sup>	10 <sup>3</sup> sm <sup>3</sup>	m <sup>3</sup>	2
2	NO 15/9-F-11 H	Prod	Oil	Metric	Calender	m <sup>3</sup>	10 <sup>3</sup> sm <sup>3</sup>	m <sup>3</sup>	2
3	NO 15/9-F-12 H	Prod	Oil	Metric	Calender	m <sup>3</sup>	10 <sup>3</sup> sm <sup>3</sup>	m <sup>3</sup>	2
4	NO 15/9-F-14 H	Prod	Oil	Metric	Calender	m <sup>3</sup>	10 <sup>3</sup> sm <sup>3</sup>	m <sup>3</sup>	2
5	NO 15/9-F-15 D	Prod	Oil	Metric	Calender	m <sup>3</sup>	10 <sup>3</sup> sm <sup>3</sup>	m <sup>3</sup>	2
6	NO 15/9-F-5 AH	Prod	Oil	Metric	Calender	m <sup>3</sup>	10 <sup>3</sup> sm <sup>3</sup>	m <sup>3</sup>	2
7	NO 15/9-F-4 AH WI	WI	Water	Metric	Calender	m <sup>3</sup>	10 <sup>3</sup> sm <sup>3</sup>	m <sup>3</sup>	2
8	NO 15/9-F-5 AH WI	WI	Water	Metric	Calender	m <sup>3</sup>	10 <sup>3</sup> sm <sup>3</sup>	m <sup>3</sup>	2
9	NO 15/9-F-1 C Oilfield	Prod	Oil	Oilfield	Calender	bbbls	mscf	bbbls	2
10	NO 15/9-F-11 H Oilfield	Prod	Oil	Oilfield	Calender	bbbls	mscf	bbbls	2
11	NO 15/9-F-12 H Oilfield	Prod	Oil	Oilfield	Calender	bbbls	mscf	bbbls	2
12	NO 15/9-F-14 H Oilfield	Prod	Oil	Oilfield	Calender	bbbls	mscf	bbbls	2
13	NO 15/9-F-15 D Oilfield	Prod	Oil	Oilfield	Calender	bbbls	mscf	bbbls	2
14	NO 15/9-F-5 AH Oilfield	Prod	Oil	Oilfield	Calender	bbbls	mscf	bbbls	2
15	NO 15/9-F-4 AH Oilfield WI	WI	Water	Oilfield	Calender	bbbls	mscf	bbbls	2
16	NO 15/9-F-5 AH OilfieldWI	WI	Water	Oilfield	Calender	bbbls	mscf	bbbls	2
17	WL_RX	WI	Water	Metric	Calender	m <sup>3</sup>	10 <sup>3</sup> sm <sup>3</sup>	m <sup>3</sup>	2
18	WL_RX Oilfield	WI	Water	Oilfield	Calender	bbbls	mscf	bbbls	2
19	NO 15/9-F-1 C Oilfield-Averaged_7	Prod	Oil	Oilfield	Calender	bbbls	mscf	bbbls	2
20	NO 15/9-F-11 H Oilfield-Averaged_7	Prod	Oil	Oilfield	Calender	bbbls	mscf	bbbls	2
21	NO 15/9-F-12 H Oilfield-Averaged_7	Prod	Oil	Oilfield	Calender	bbbls	mscf	bbbls	2
22	NO 15/9-F-14 H Oilfield-Averaged_7	Prod	Oil	Oilfield	Calender	bbbls	mscf	bbbls	2
23	NO 15/9-F-15 D Oilfield-Averaged_7	Prod	Oil	Oilfield	Calender	bbbls	mscf	bbbls	2
24	NO 15/9-F-5 AH Oilfield-Averaged_7	Prod	Oil	Oilfield	Calender	bbbls	mscf	bbbls	2

Figure PDB-9: PE<sup>2</sup> Essentials Database – List Wells

To append data to a well in the database, enter the Excel parameters and click “Append Well Data”. Confirmation is required before the import is started (Figure PDB-10).



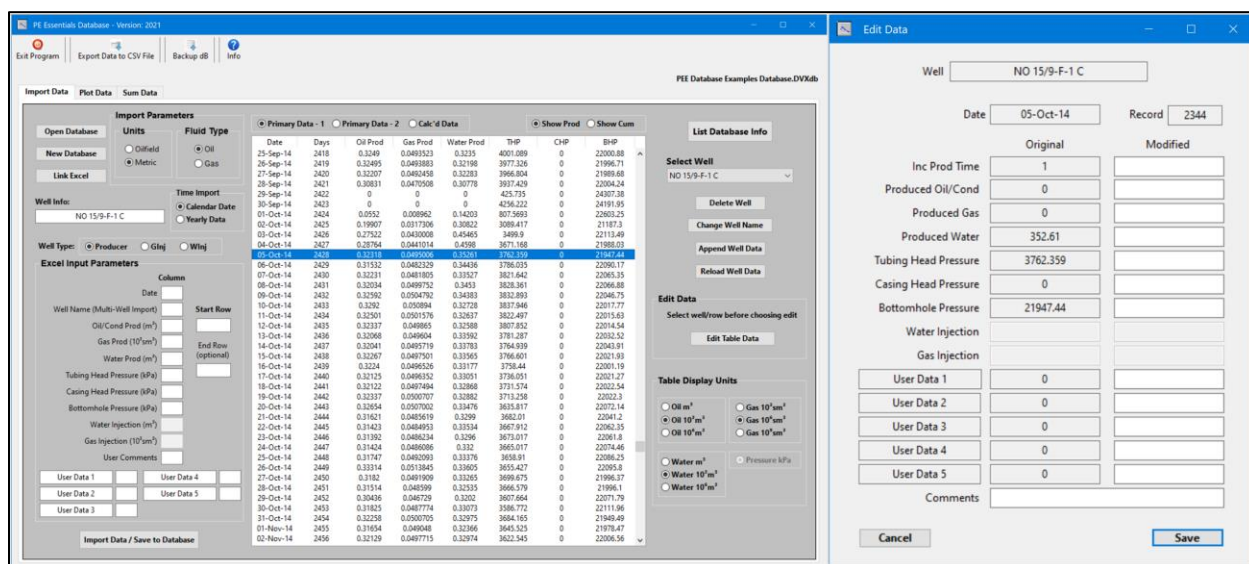
Figure PDB-10: PE<sup>2</sup> Essentials Database – Append Well Data

To reload multiple well's production data and/or append data to multiple wells at the same time, use the 'Reload Well Data' option. This is useful if data was loaded incorrectly, for instance, if fluid type was specified as oil when gas should have been specified. This option can be used to reload the well data with the proper options.

It should be noted that only wells that currently exist in the database will be reloaded. To import a new well, the 'Import Data / Save to Database' option should be used.

To edit data for a specific date, highlight the target row and click "Edit Data". An edit window will pop-up to allow modification of the data for the indicated date

Figure PDB-11 shows a production well and Figure PDB-12 shows an injection well.

Figure PDB-11: PE<sup>2</sup> Essentials Database – Production Well Data Edit

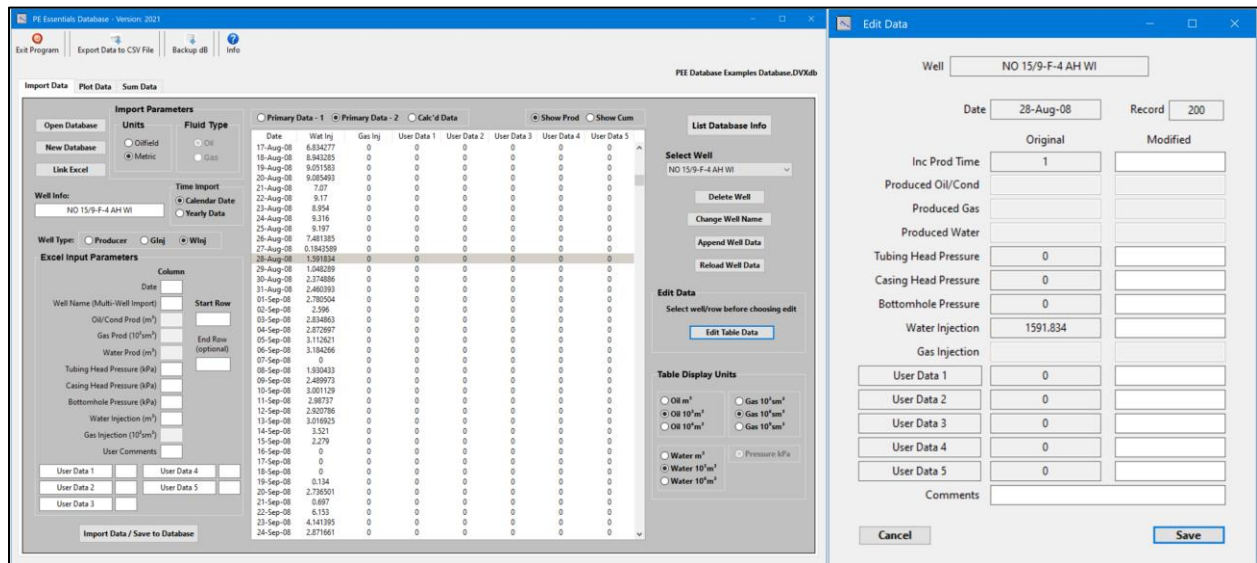


Figure PDB-12: PE<sup>2</sup> Essentials Database – Injection Well Data Edit

Once the appropriate data is entered, clicking “Save” will update the data in the database.

Note – it is strongly recommended that the PE Production Database be backed up on a regular basis. Click ‘Backup dB’ on the main menu and a dated copy of the Production Database will be placed in the “PEE Production Database Backup” directory.



## Production Data Analysis Tool

The PE<sup>2</sup> Essentials Production Data Analysis (PDA) tool is a multi-analysis tool (Figure PDA-1).

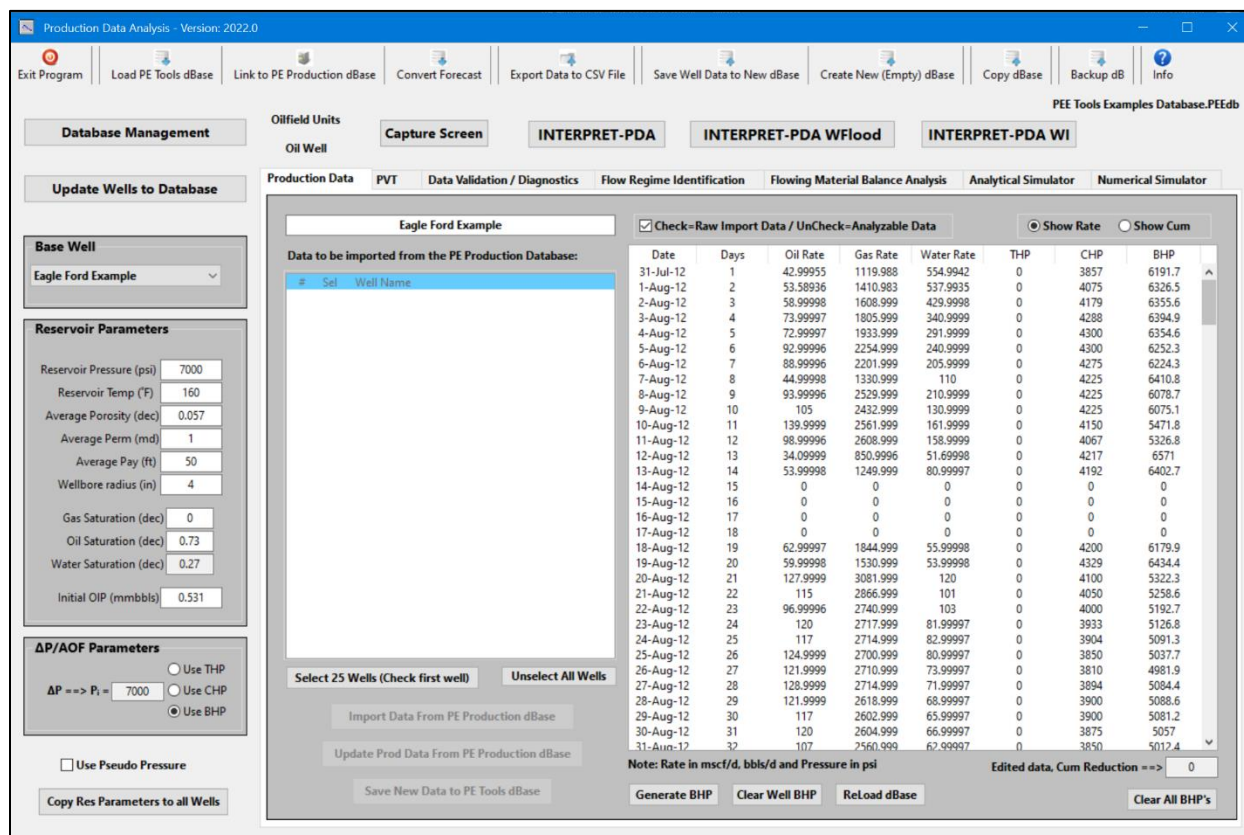


Figure PDA-1: PE<sup>2</sup> Essentials Production Data Analysis Tool

The tool is comprised of a number of different modules:

- Production Data: Data import and editing
- PVT: Input of PVT parameters
- Data Validation/Diagnostics: Multi-well data comparison
- Flow Regime Identification: includes superposition
- Flowing Material Balance Analysis: includes flowing P/Z and PI
- Analytical Simulator: Includes numerous analytical models
- Numerical Simulator: Build models for the PE<sup>2</sup> Essentials Simulators
- PE Tools Database management tools
- INTERPRET-PDA; INTERPRET-PDA WI; and INTERPRET-PDA WFlood tools

The PDA tool is a very versatile multi-well analysis tool that builds and maintains the PE Tools database which is used to integrate all the PE<sup>2</sup> Essentials tools. Refer to Section PDA.13 for information on managing the PE Tools database.

## PDA.1 Reservoir Data Entry

The reservoir data is entered on the main PDA screen (Figure PDA-2).

Reservoir Parameters	
Reservoir Pressure (psi)	443.5
Reservoir Temp (°F)	120
Average Porosity (dec)	0.2
Average Perm (md)	30
Average Pay (ft)	65.6
Wellbore radius (in)	4
Gas Saturation (dec)	0.8
Oil Saturation (dec)	0
Water Saturation (dec)	0.2
Initial GIP (Bscf)	2.442072

Figure PDA-2: PDA – Reservoir Data

It will be necessary to enter the reservoir parameters before any analysis is performed. This is especially true for a gas well since all analysis is performed using pseudo pressures.

An estimate of the initial in place volume needs to be input in order to allow iterations to initialize properly. If a value is not entered, it will be requested when it is needed.

It should be noted that for single well analysis, the well to be analysed is chosen from the drop-down menu (Figure PDA-3).

Base Well	
Tutorial-1	▼

Figure PDA-3: PDA – Choosing a Well

When THP, CHP or BHP is available, the pressure to use for analysis is chosen under “ $\Delta P$ /AOF Parameters” (Figure PDA-4). The initial pressure must be entered if THP or CHP is chosen.

$\Delta P$ /AOF Parameters	
$\Delta P ==> P_i =$	443.5
Use THP	<input type="radio"/>
Use CHP	<input type="radio"/>
Use BHP	<input checked="" type="radio"/>

Figure PDA-4: PDA – Choosing Pressure Source for analysis

All wells can have unique reservoir parameters. If all wells are similar, reservoir parameters can be copied to all wells in the database by clicking the “Copy Res Parameters to all Wells” button.

## PDA.2 Production Data Import

The Production Data tab is used to import data into the PDA tool (Figure PDA-5).

The screenshot shows the 'PDA - Production Data Import' window. On the left, the 'Base Well' section is active, showing a dropdown menu for 'Eagle Ford Example' and a list of wells. Below this, there are input fields for various well parameters: Reservoir Pressure (7000), Reservoir Temp (160), Average Porosity (0.057), Average Perm (1.8), Average Pay (50), Wellbore radius (4), Gas Saturation (0), Oil Saturation (0.73), Water Saturation (0.27), and Initial OIP (0.416). The 'Tutorial: 1' section is also visible. The main area is titled 'List / Delete PE Tools Database Data' and contains a table of wells to be saved to the PE Tools Database. The table has columns for Well Name, Well ID, and Well Type. The table lists several wells, including 'NO 15/9-F-1 C', 'NO 15/9-F-11 H', 'NO 15/9-F-12 H', 'NO 15/9-F-14 H', 'NO 15/9-F-15 D', 'NO 15/9-F-4 AH', and 'NO 15/9-F-5 AH'. At the bottom, there are buttons for 'Import Wells From PE Production dBase', 'Add Data to PE Tools dBase', 'Generate BHP', 'Clear Well BHP', and 'Clear All BHP's'.

Figure PDA-5: PDA – Production Data Import

Production data is imported into the PDA tool by linking to a PE<sup>2</sup> Production Database, 'Link to PE Production dBase', selecting the wells to be imported, then clicking 'Import Wells From PE Production dBase'. Additional wells can be loaded at anytime.

To add wells to an existing PE Tools database, first load the database ('Load PE Tools dBase') then 'Link to PE Production dBase' and import the additional wells. Note that there is a limit of 175 wells that can be imported into the PDA tool.

When well data is imported into PDA, it is not stored in the PE Tools database until the 'Add Data to PE Tools dBase' is clicked.

It should also be noted that if the well being imported does not contain production data (i.e injection well) then that well will not be imported into PDA.

To generate BHP, push the 'Generate BHP' button. This button is visible only if THP or CHP has been imported. To convert surface pressures to bottom hole pressures it is necessary to load a THP-BHP well model from the database by clicking the 'Load Well Model' button.

The BHP calculation sheet will allow use of either THP or CHP if both data sets are available and will default to CHP when both are available. If one set of surface pressure is not available, that column will show "n/a" instead of a check box.

Note – when using CHP for conversion to BHP for an oil well, it is assumed that the annulus is filled with gas.

After BHP is calculated, the option to calculate BHP will be disabled for that well (Figures PDA-6a and PDA-6b). This allows a visual determination of which wells require a BHP calculation.

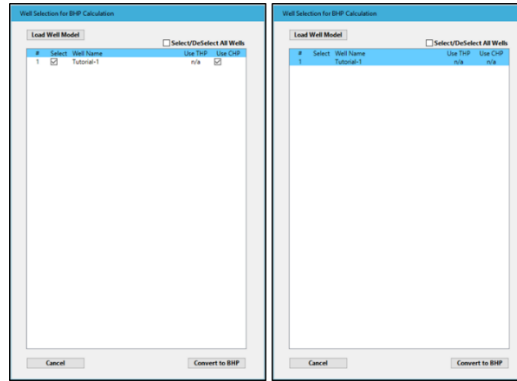


Figure PDA-6a: PDA – BHP Generation      Figure PDA-6b: PDA – BHP Calculation Disabled

To re-calculate BHP, click the reset BHP button on the Production Data page (Figure PDA-5). BHP data will be cleared and the BHP calculation for the specified well or wells will be re-enabled.

The well data in the database can be updated by clicking ‘Update Database’. A screen will open so the specific wells can be selected (Figure PDA-6c). TO discard changes, do not update the well in the database.

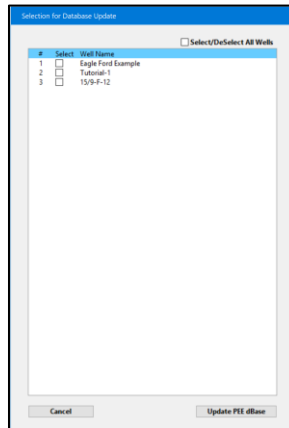


Figure PDA-6c: PDA – Update Well in PE Tools Database

When entering production data, two sets of data are stored in the database: the original data set and an analyzable data set that has all zero production rates removed from the dataset. By checking the “Check=Raw Import Data / UnCheck=Analyzable Data” box, the table will cycle between the raw data and the edited data.

To view the cum data rather than the rate data, choose “Show Cum”.

### PDA.3 PVT Data Entry

The PVT sheet is used to import fluid and rock data for each well (Figure PDA-7).

**Production Data** | **PVT** | Data Validation / Diagnostics | Flow Regime Identification | Flowing Material Balance Analysis | Analytical Simulator | Numerical Simulator

**Import PVT Data From Tools DB**

**Oil PVT Option**  
☒ Use Correlation  
☐ Use Import Data

Gas Properties	Oil Properties	Water/Rock Properties
Gas Gravity: 0.8	Oil/Cond API: 30	Salinity (ppm NaCl): 35000
H <sub>2</sub> S - mol%: 0	Bubble Point Pressure (psi): 3000	Initial Bw (rbbl/sbbl): 1.0149
CO <sub>2</sub> - mol%: 0	Separator Pressure (psi): 114.7	Water Viscosity (cp): 0.434
N <sub>2</sub> - mol%: 0	Separator Temperature (°F): 60	Solution GWR (scf/bbl): 22.39
Cond/Gas Ratio (bbls/mmcf): 0	Corrected Gas G: 0.8	Initial cw (10 <sup>-5</sup> /psi): 0.288
Gas Pc (psi): 665	Initial Bo (rbbl/sbbl): 1.2915	Initial cr (10 <sup>-5</sup> /psi): 0.625
Gas Tc (°R): 420	Oil Viscosity (cp): 1.27	Initial c <sub>g</sub> (10 <sup>-5</sup> /psi): 1.114
Acid Free Gas G: 0.8	Solution GOR (scf/bbl): 638.7	
Gas Viscosity (cp): 0.0436	Initial co (10 <sup>-5</sup> /psi): 0.564	
Gas Z Factor: 1.168		
Initial cg (10 <sup>-5</sup> /psi): 4.655		

**Copy PVT Properties to all Wells** | **View/Export PVT Data**

Figure PDA-7: PDA – PVT

PVT data input is straightforward and is required for use in the analysis routines. There are no defaults for the parameters so all parameters should be entered.

If more than one well has been entered into the database, the entered PVT data can be copied to all wells by clicking the “Copy PVT Properties to all Wells” button.

It should be noted that, for a gas well, the oil properties represent the condensate properties. If Condensate/Gas Ratio is 0, then input of the condensate properties is not required.

The PVT data can be imported from the PE Tools database (Figure PDA-8).

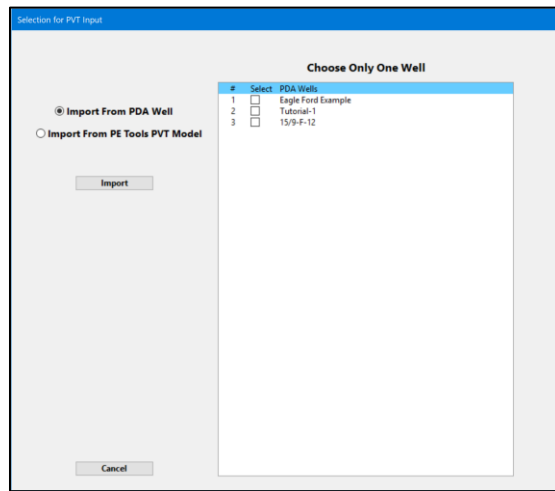


Figure PDA-8: PDA – PVT Import

PVT data from another PDA well or from a PVT Model stored in the database can be imported. To import the data from a PVT model, select the button and a list of the available PVT Models will be listed.

## PDA.4 Oil and Gas Pseudo Pressure

The PE<sup>2</sup> Essentials Production Data Analysis tool performs gas analysis using gas pseudo pressure. For oil analysis, there is an option to use pressure or oil pseudo pressure.

### PDA.4.1 Gas Pseudo Pressure

For gas, most of the PVT properties can vary significantly with pressure. To compensate for changing gas properties, the concept of pseudo-pressure ( $\psi$ ) was developed by Al-Hussainy et al. (1966) and is defined as follows:

$$\Psi_g(p) = 2 \int_{p_0}^p \frac{p}{\mu Z} dp$$

This transformation of pressure to pseudo-pressure is an exact transformation, which accounts for variation of gas density and viscosity. Assuming that changes of total compressibility ( $c_t$ ), porosity, and fluid saturations are insignificant, the gas flow equation can be written in a form that is similar to the liquid equation. Therefore, the liquid-flow solution can be used for gas well analysis provided pressure is replaced by pseudo-pressure.

### PDA.4.2 Oil Pseudo Pressure

The Flowing Material Balance (FMB) equation presented in Section PDA.8 is valid under the assumption that the variation of oil and rock properties ( $c_t$ ,  $B_o$ ,  $\mu_o$ , and  $k$ ) with pressure is negligible. This assumption may be valid for most cases, but sometimes (e.g. for oil with high gas content, or for cases with pressure-dependent rock properties), it is important to accurately account for variations in oil and rock properties (Refer to Stalgorova, E. and Mattar, L. “Analytical Methods for Single-phase Oil Flow: Accounting for Changing Liquid and Rock Properties.” SPE 180139).

Oil pseudo pressure is defined as follows:

$$\Psi_o(p) = \frac{B_{oi}\mu_{oi}}{k_i} \int_{p_0}^p \frac{k(p)}{B_o(p)\mu_o(p)} dp$$

For use in PE<sup>2</sup> Essentials PDA, it is assumed that permeability is constant,  $k(p)/k_i = 1$ , so only fluid properties are used in the oil pseudo pressure formulation.

### PDA.5 Data Validation / Diagnostics

The Data Validation / Diagnostic sheet is used to review and edit the data (Figure PDA-9).

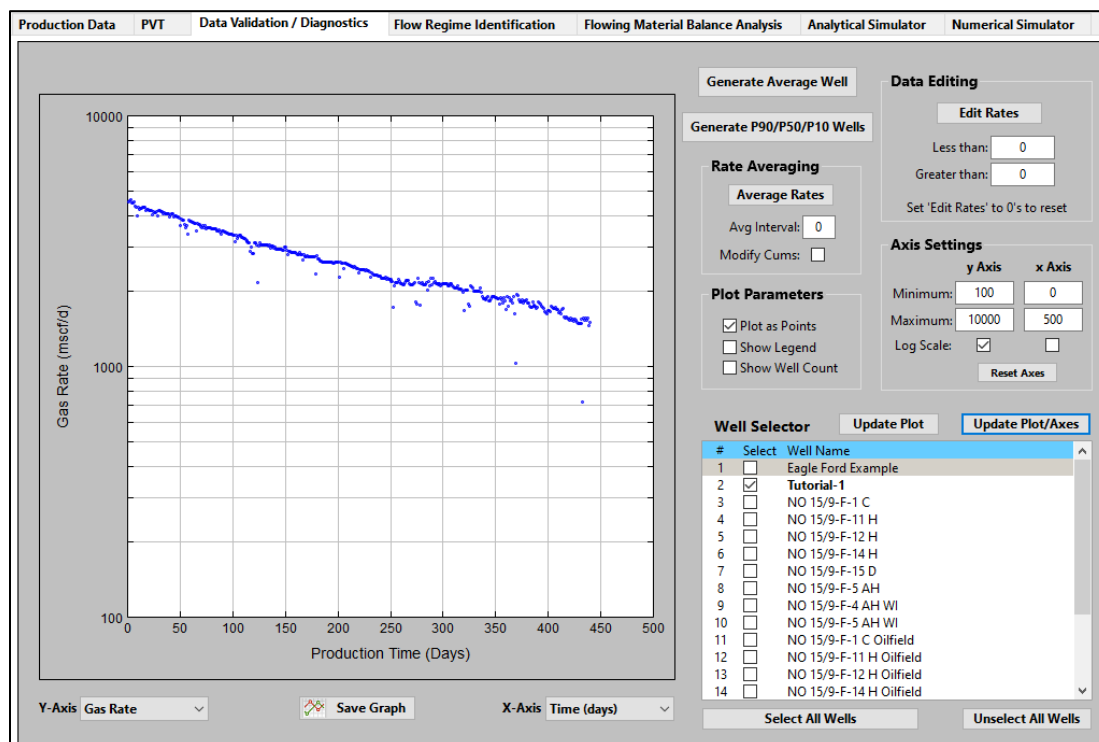


Figure PDA-9: PDA – Data Validation /Diagnostics

Any spikes in the data can be removed using options on this tab. Note that all zero rates are removed when the well data is loaded. Spikes can be removed using the “Data Editing” option or by averaging the rates (Figure PDA-10).

Figure PDA-10: PDA – Data Editing and Rate Averaging

Both low and high rate spikes can be removed from the analyzable data set – the original data set is unchanged. For instance, to remove the two low rates in Figure PDA-9, enter 1100 in the “Less Than” box and click “Edit Rates”. Figure PDA-11 shows the result. To undo the edits, enter 0 for the high/low rates and click “Edit Rates”. The impact on the well’s cum as a result of editing data is shown on the Production Data sheet for that well in the “Edited data, Cum Reduction ==>” box.

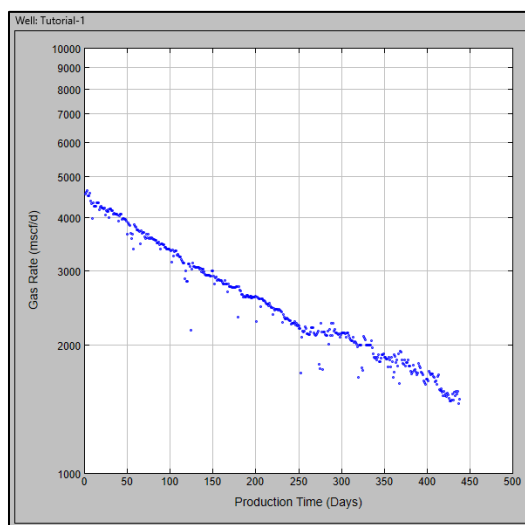


Figure PDA-11: PDA – Data Editing: Removing Spikes

The Data Validation / Diagnostics tab has multi-well capability (Figure PDA-12).

To select well data to plot, check the well and click “Update Plot”. To remove a well from the plot, uncheck the well and click “Update Plot”.

When there are less than 25 wells in the database, all wells can be selected and plotted by clicking “Select All Wells”. When there are more than 25 wells in the database, 25 wells at a time can be selected and viewed by clicking “Select 25 Wells”. Each subsequent click of the button will add 25 wells to the plot until all wells are selected.



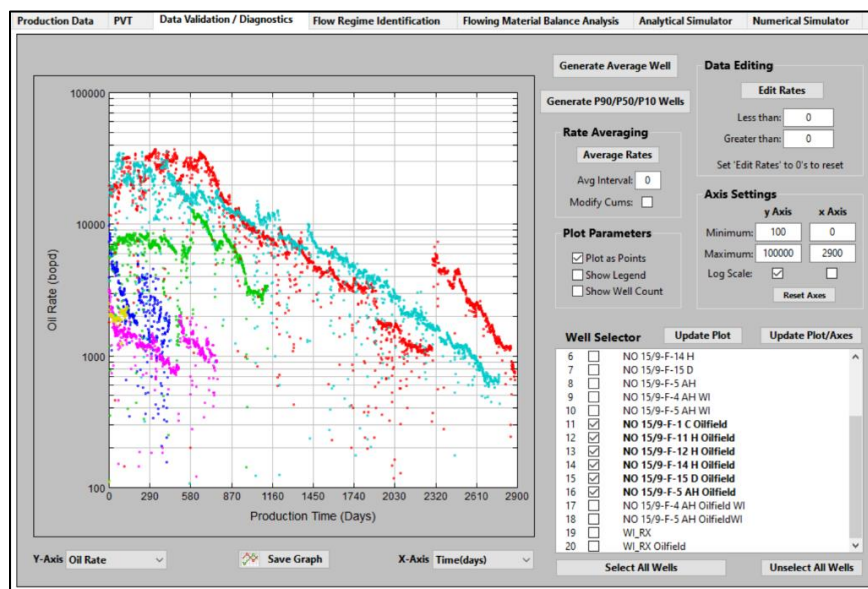


Figure PDA-12: PDA – Multi-Well Plotting

### PDA.5.1 Average Well

When more than one well is selected, it is possible to generate an average for all the rates by clicking “Generate Average Well”.

The average well is generated as a simple calculation of the monthly average rate for the given monthly time period. The average well will be plotted and is available for use as a well in the analysis routines of PDA (Figure PDA-13).

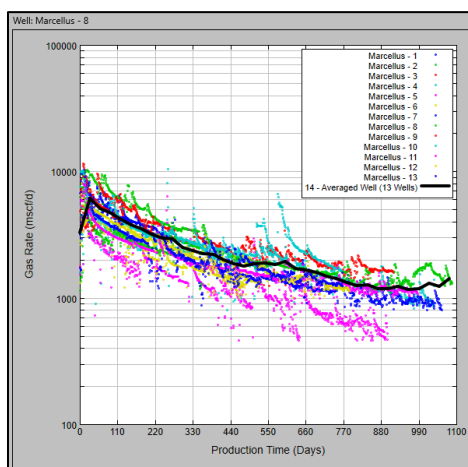


Figure PDA-13: PDA – Average Well

To keep the average well, the database should be saved.

One note of caution, if another average well is generated using the same number of wells, then there will be two wells in the database with the same name. To delete one of the wells, return to the Production Data sheet, select the well to be deleted from the Base Well drop-down menu and click “Delete Well”. To generate new names for average wells, generate the average well using a different well count.

### PDA.5.2 P90, P50 and P10 Wells

When more than one well is selected, it is possible to generate a P90, P50 and P10 well by clicking “Generate P90/P50/P10 Wells”. These wells are not true probabilistic profiles but are based on calculating percentiles for the well data included in the calculation (Figure PDA-14).

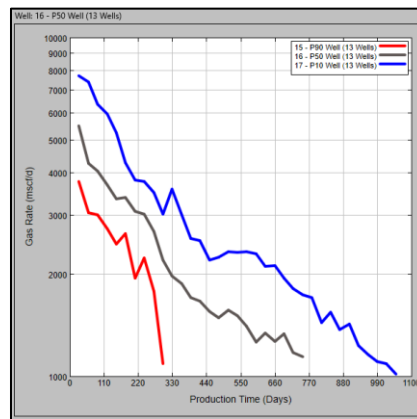


Figure PDA-14: PDA – P90/P50/P10 Wells

The meaning of “percentile” can be state as: the  $P^{th}$  percentile of a data distribution is a number such that approximately P percent (P%) of the values in the distribution are equal to or less than that number. So, if for example 50 is the 90<sup>th</sup> percentile of a larger distribution of numbers, 90% of those numbers are less than or equal to 50, so it can be termed P90.

Mathematically, a percentile can be calculated directly for values that exist in the distribution or interpolated for values that don’t exist. To calculate percentiles, the data is sorted so that  $x_1$  is the smallest value, and  $x_n$  is the largest, with  $n$  = total number of data points. Then  $x_i$  will be the  $P_i$  percentile of the data set where:

$$P_i = 100 * (i - 0.5) / n$$

Conversely, to calculate the value at a specific percentile (P90, P50, P10), the above equation is solved for  $i$  as follows:

$$i = n * P_i / 100 + 0.5$$

If the calculated  $i$  is an integer, then the  $P_i$  value will be  $x_i$ . If  $i$  is not an integer, then a linear interpolation is used to determine the  $x_i$  value for that  $P_i$ .

### PDA.6 Pseudo Steady State vs Boundary Dominated Flow

The difference between pseudo steady state flow and boundary dominated flow is presented in Figure PDA-15 (ref: Figures in Appendix B SPE Well testing book by John Lee).

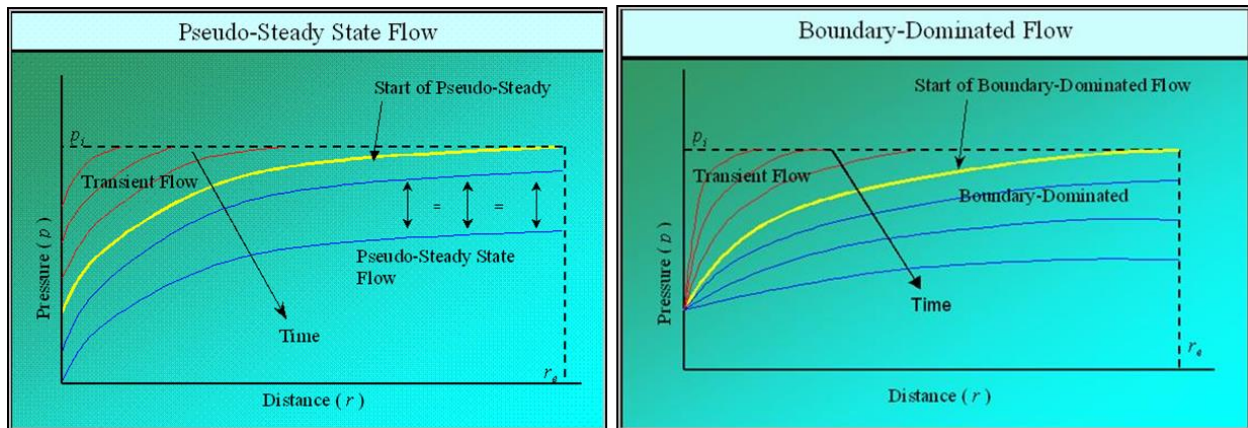


Figure PDA-15: PDA – Pseudo Steady State vs Boundary Dominated Flow

Pseudo steady state is normally associated with well testing or wells operating under a rate constraint. The well flow rate is maintained constant and the flowing pressure is allowed to fall.

Boundary dominated flow is normally associated with long term production where a well is constrained by surface pressures (separators, pipelines, etc). In this case, the bottom hole pressure is approximately constant, and the rate is allowed to decline. Boundary dominated flow is the flow of interest for FMB.

In reality, although well head pressure is constant, the bottom hole pressure may not be constant since tubing pressure drop changes as the flow rate declines. To account for this, the rate is “normalized” in terms of  $\Delta P$  and used instead of  $q$ . For oil, the normalized rate is defined as  $q_N = q/\Delta P$  and for gas it is defined as  $q_N = q/\Delta \Psi$ .

In addition, the concept of “Material Balance Time” ( $t_{mb} = \text{cum}/\text{rate}$ ) was developed to provide the normalization necessary to make constant pressure and constant rate solutions equivalent. Plotting production data using  $t_{mb}$  also allows solutions with both declining rates and pressures to look like the equivalent constant rate solution, similar to the superposition time function in PTA but applied to boundary dominated flow in PDA.

When normalized rate ( $q_N$ ) is plotted against  $t_{mb}$  on log-log scale, boundary dominant flow is evident as negative unit slope.

## PDA.7 Flow Regime Identification

The Flow Regime Identification tab is used to identify flow regimes in the data (Figure PDA-16) to confirm, for example, that boundary dominated flow has been achieved.

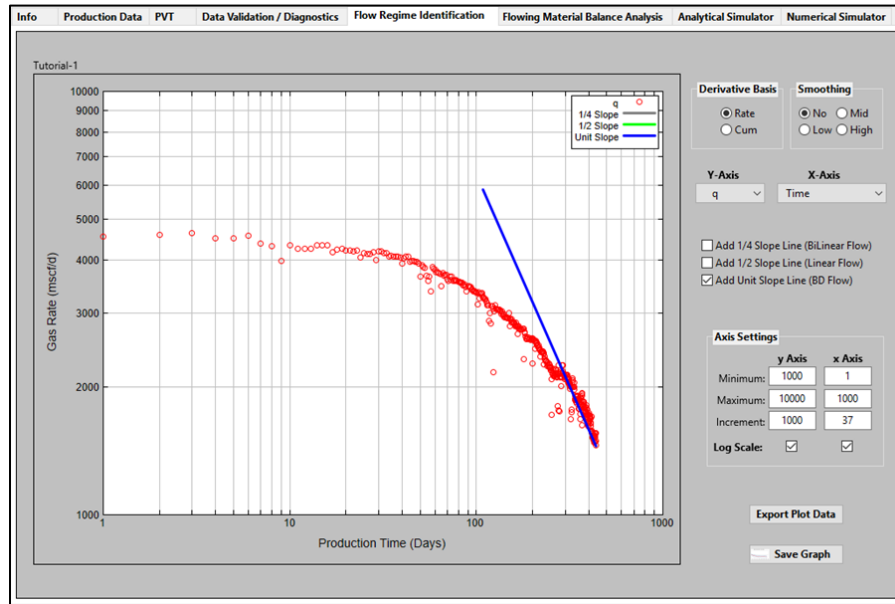


Figure PDA-16: PDA – Flow Regime Identification

To assist in flow regime identification, lines with  $\frac{1}{4}$  slope,  $\frac{1}{2}$  slope and unit slope can be placed on the graph and moved around to the appropriate area of the plot.

As shown in Figure PDA-15, bilinear flow ( $\frac{1}{4}$  slope line) was evident until approximately 110 days. Linear flow ( $\frac{1}{2}$  slope line) occurred until approximately 320 days.

Boundary dominated flow (unit slope) was evident after 320 days of production. For this well, an exponential Arps analysis would be valid for data after 300 days, although the LOPL eDCA model could be used to model the entire flow period.

The DCA “base governing equation” presented in Section DCA.8.7 of the DCA Tool documentation, can be plotted on this sheet. Figure PDA-17 shows a plot of Equation PDA.1 assuming no derivative smoothing.

$$D(t) \equiv -\frac{1}{q(t)} \frac{dq(t)}{dt} \quad (\text{PDA.1})$$

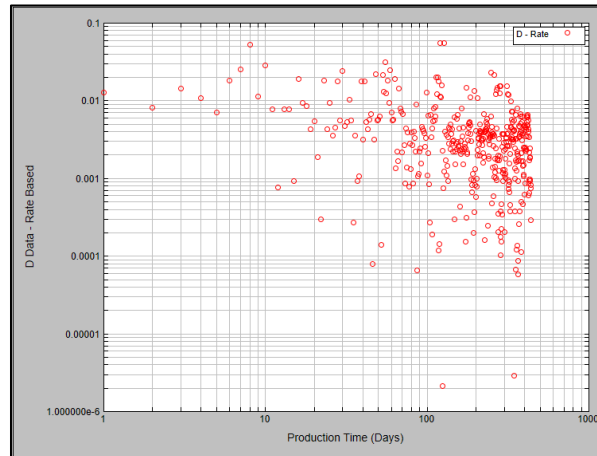


Figure PDA-17: PDA – Plot of D-Parameter, No Smoothing

There is a lot of scatter in the data so trends in the data are not obvious. A “Mid” smoothing was applied to the data (Figure PDA-18) using rate and cum as the derivative basis.

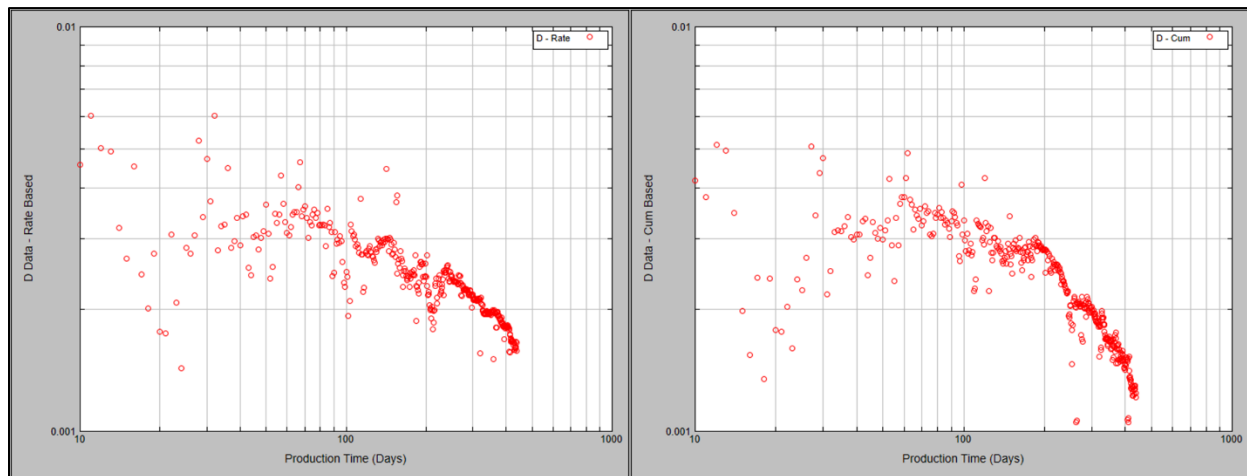


Figure PDA-18: PDA – Plot of D-Parameter, Mid Smoothing (Left-Rate Based, Right-Cum Based)

The plot on the left (rate based) of Figure PDA-18 now appears to exhibit a trend in the data where the right plot (cum based) shows the same trend but it appears to be more obvious.

Note that caution should be used when smoothing derivative data since the amount of smoothing applied can result in an overprint on the derivative resulting in false trends. The minimum amount of smoothing required for analysis should be used.

The “Export Plot Data” button will save all the plot data to a csv file and the “Save Graph” button will save the graph to graphics file.

### PDA.7.1 Example: PDA/eDCA

Figure PDA-19 shows the production data for a gas well with 2100 producing days and the flow regime identification plot showing that boundary dominated flow was achieved after approximately 600 days of production.

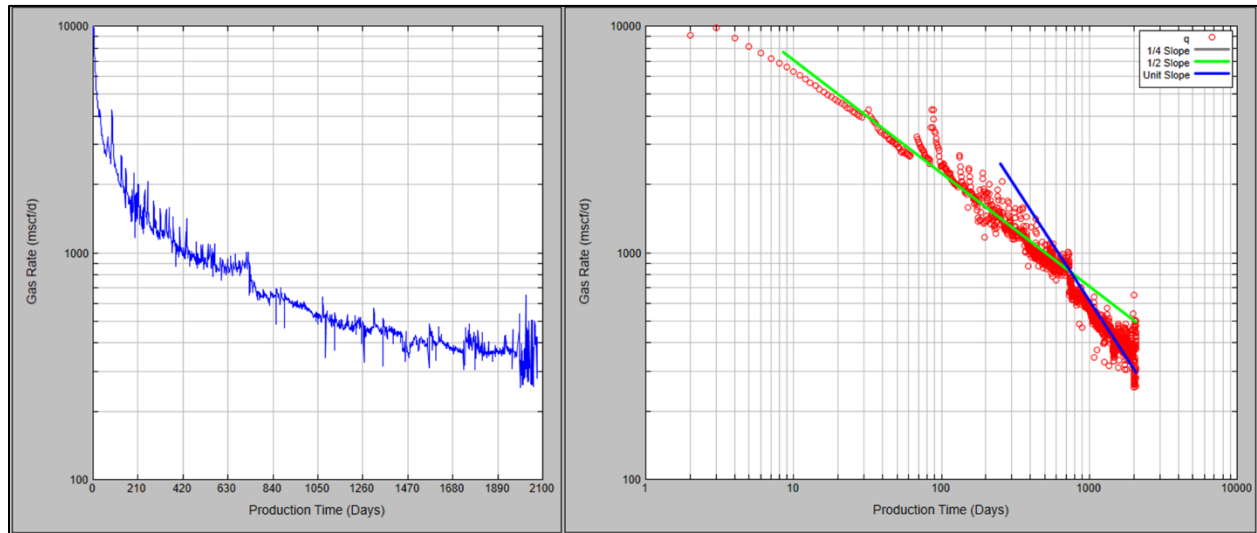


Figure PDA-19: PDA – Example Well: Data and Flow Regime Identification

The data was imported into the DCA tool and analysed with eDCA. The data was matched to the LOPL model and equivalent Arps parameters were generated. A forecast was then generated to a minimum rate of 100 mscf/d (Figure PDA-20).

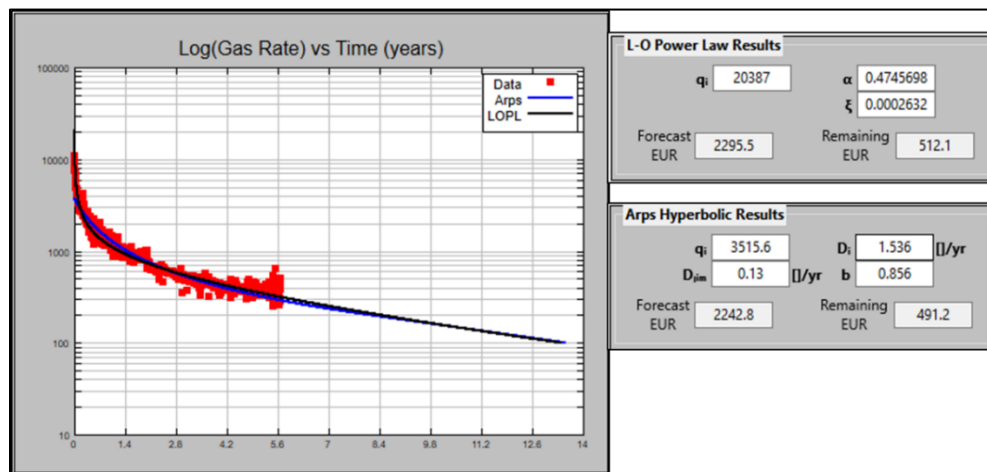


Figure PDA-20: PDA – Example Well: eDCA Results

The final LOPL-Arps matched was achieved with a  $D_{lim}$  of 0.13.

## PDA.8 Flowing Material Balance Analysis

The Flowing Material Balance Analysis tab is used to perform analysis of the data to estimate initial volumes in place (Figure PDA-21). It is only possible to perform this analysis if pressure is included in the imported well data.

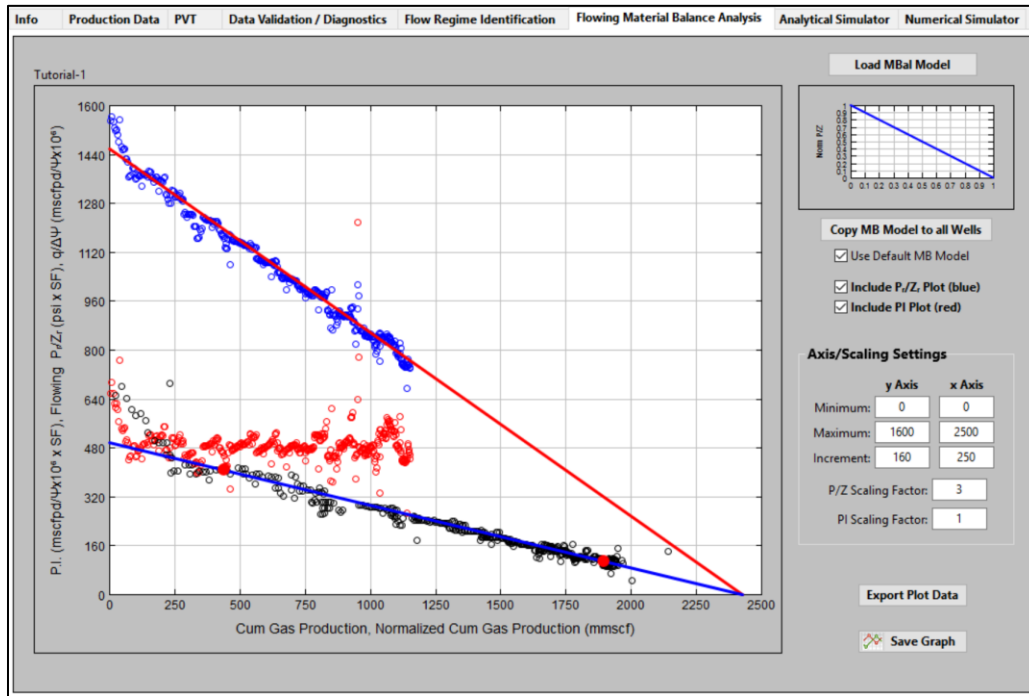


Figure PDA-21: PDA – Flowing Material Balance Analysis

Flowing material balance (FMB) analysis is a practical method for determining original hydrocarbon volumes in-place. It has become popular because it enables performing material balance analysis without having to shut-in wells to obtain estimates of reservoir pressure. Its application is valid for single-phase oil and/or gas during the stabilized, or boundary dominated flow period. For FMB of a gas well, pseudo-pressure is used to account for pressure-dependant gas properties. For an oil well, use of pseud pressure is optional.

The basis of flowing material balance analysis is the Agarwal and Gardner FMB technique augmented by flowing P/Z and flowing PI (for gas wells). To perform FMB, a material balance model is required to estimate declining reservoir pressure. It is very important to load the proper material balance model to estimate reservoir pressure. For a gas reservoir, the default straight-line material balance model should work since the gas recovery process is normally a straight-line P/Z process which extrapolates to initial gas in place.

For oil reservoirs, the material balance is a complex process of depletion, gas and water drives and as a result, the default straight line will not work, and a suitable material balance model should be imported from the PE Tools database (click 'Load MBal Model')



### PDA.8.1 A-G Flowing Material Balance

Figure PDA-22 shows the A-G flowing material balance plot which is a plot of normalized rate versus normalized cum.

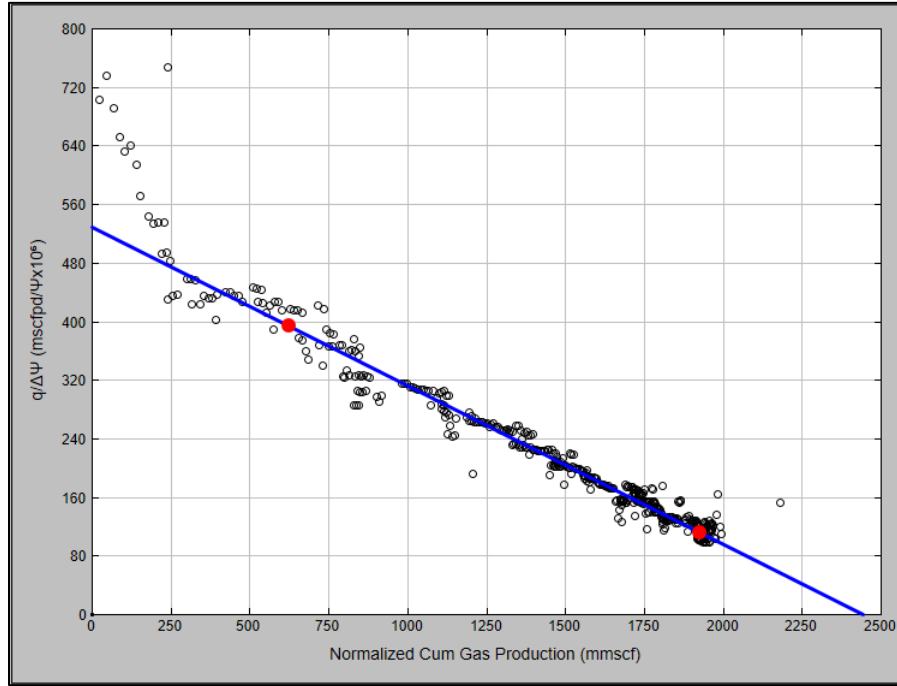


Figure PDA-22: PDA – A-G Flowing Material Balance

Agarwal et al discussed using normalized rate versus cumulative production to determine hydrocarbons in place in “Analyzing Well Production Data Using Combined-Type-Curve and Decline-Curve Analysis Concepts”, SPE 57916.

Flowing material balance analysis is based on common DCA plot of rate vs. cumulative production analysis techniques. The advancement over traditional decline analysis is the pressure normalization of both rate and cumulative production to account for variations in flowing bottom-hole pressure.

The normalized rate versus normalized cum approach applies to both oil and gas reservoirs and works for constant or variable rate systems. The normalized rate for both oil and gas is defined as Equation PDA.2 and the normalized cum is defined as Equation PDA.3.

$$\text{Oil: } q_N = \frac{q_o}{p_i - p_{wf}} \qquad \text{Gas: } q_N = \frac{q_g}{\Psi_i - \Psi_{wf}} \qquad (\text{PDA.2})$$

$$\text{Oil: } Cum_N = \frac{B_o S_o N_P}{c_i B_{oi} (p_i - p_{wf})} \qquad \text{Gas: } Cum_N = \frac{GIIP(\Psi_i - \Psi_R)}{\Psi_i - \Psi_{wf}} \qquad (\text{PDA.3})$$



Where:  $q_N$  is the normalized rate,  $Cum_N$  is the normalized cum,  $P_i$  is the initial pressure,  $P_{wf}$  is the flowing pressure,  $c_t$  is the total compressibility,  $\Psi_i$  is the initial pseudo pressure,  $\Psi_{wf}$  is the flowing pseudo pressure,  $\Psi_R$  is the average reservoir pressure at time  $t$ .

If using oil pseudo pressure, the oil  $Cum_N$  equation is the same as the gas  $Cum_N$  equation except for OOIP. Since the OOIP/GIIP term is part of the normalized cum, it is necessary to initialize the procedure with an initial guess of in-place volume in the reservoir section.

A straight-line section on the A-G FMB cartesian plot indicates boundary dominated flow and can be extrapolated to the initial volume in place. To modify the straight line for analysis, move the red dots until the analysis is completed. The Gas/Oil in Place value will be updated as the analysis progresses.

Since  $\Psi_R$  is include in the normalized gas cum calculation, there needs to be a way to calculate the average reservoir pressure over time. This is done through the use of a normalized material balance model. The normalized MB model is used along with the extrapolated A-G FMB GIIP to estimate  $P_R$  as the reservoir is depleted.

The default gas MB model is a straight-line P/Z plot where, since the MB model is normalized, the initial P/Z point is 1 and the final cum gas point is 1 (Figure PDA.23).

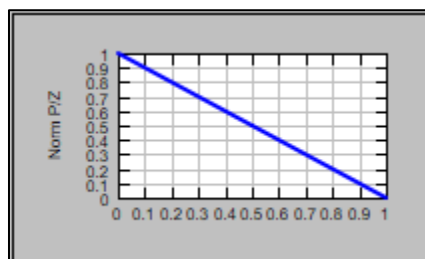


Figure PDA-23: PDA - Default Normalized Material Balance Model

If the default MB model is not acceptable, a material balance model can be imported from the PE Tools database. The MB model is imported by clicking the “Load MBal Model” button. The MB model is normalized based on the pressure and in-place volumes in the MB model. The normalized curve is then used to calculate  $\Psi_R$  at each time step. A normalized MB model for each well can be entered or the same model can be copied to all wells by clicking the “Save MB Model to all Wells” button. The MB model is also used in the Analytical Simulator (Section PDA.9).

## PDA.8.2 Flowing Productivity Index

To assist with the A-G FMB analysis, a flowing PI curve can be included on the plot. Figure PDA-24 shows the flowing material balance plot with A-G FMB and flowing PI curves.

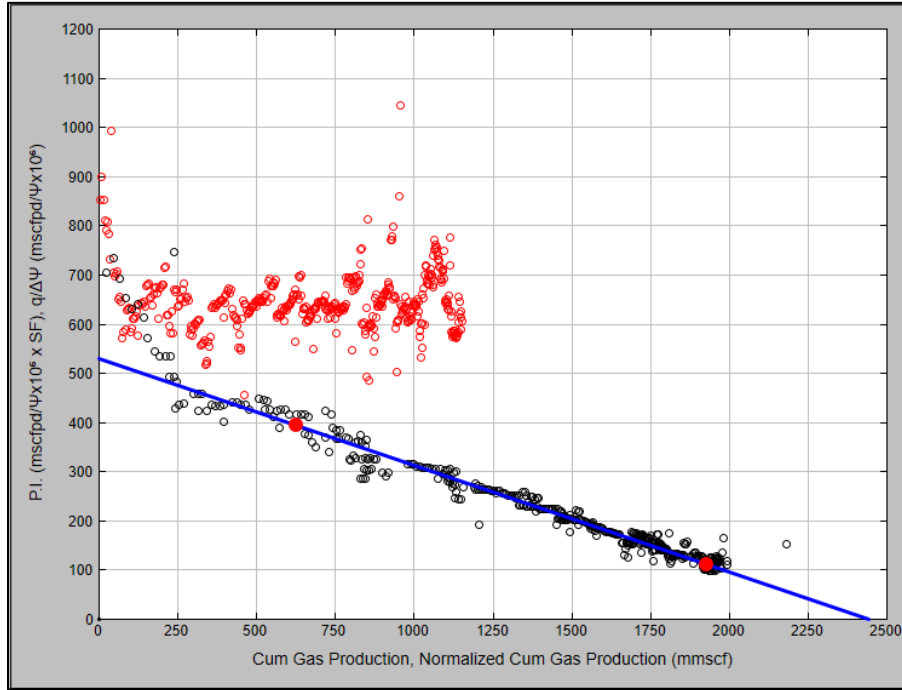


Figure PDA-24: PDA – A-G FMB and Flowing PI Curves

The flowing PI plot is used as a qualitative indicator for the A-G FMB analysis. The flowing PI is calculated with Equation PDA.4 and is dependant on the reservoir pressure at each timestep.

$$\text{Oil : } PI_o = \frac{q_o}{p_R - p_{wf}} \qquad \text{Gas : } PI_g = \frac{q_g}{\Psi_R - \Psi_{wf}} \qquad (\text{PDA.4})$$

During boundary dominated flow, both rate and  $p_R$  or  $\Psi_R$  will decline proportionally and the resulting PI will be a constant, or steady-state PI. When changing the slope and location of the straight line on the A-G FMB curve, the PI will be updated with the new  $p_R$  or  $\Psi_R$  forecast based on the extrapolated in-place volume. When the PI plot stabilizes, the A-G FMB results can be considered to be valid.

### PDA.8.3 Flowing $P_R/Z_R$ and Flowing $P_R$

One additional plot is available, the flowing  $P_R/Z_R$  (for gas) or  $P_R$  (for oil) plot (Figure PDA-25).

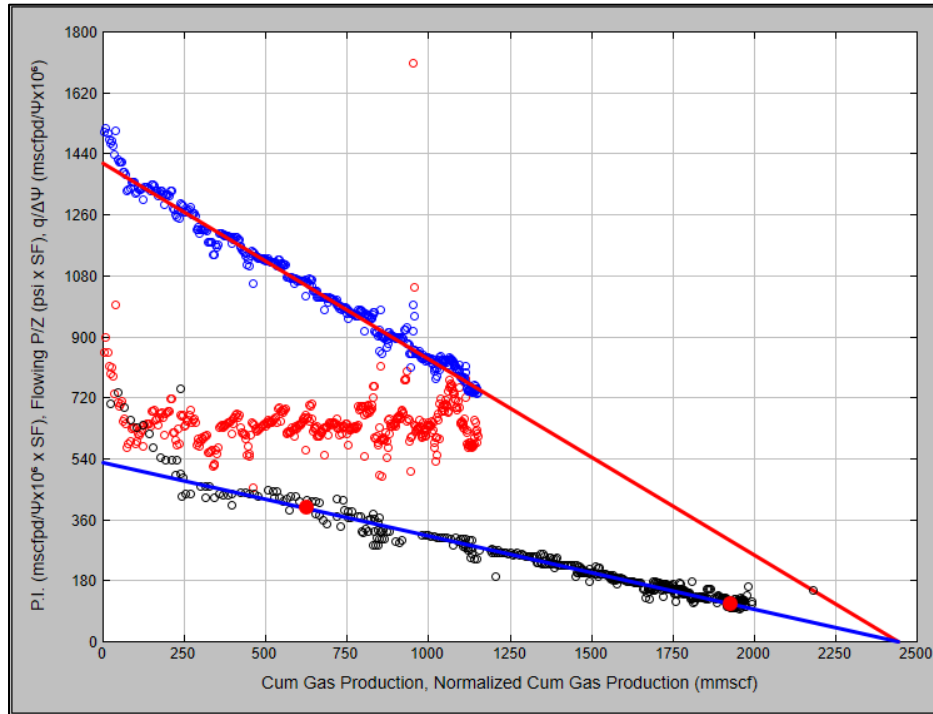


Figure PDA-25: PDA – A-G FMB, Flowing PI and Flowing  $P_R/Z_R$  Curves

Flowing  $P_R/Z_R$  was introduced by Mattar et al in 1998 (Mattar-McNeil “The flowing Gas MB”, JCPT, Vol37 no.2 1998). The flowing  $P_R/Z_R$  assumes that boundary dominated flow has been achieved so that the declining  $P_{wf}$  or  $\Psi_{wf}$  is directly proportional to declining  $P_R$  or  $\Psi_R$  (Figure PDA-26). Equation PDA.5 and PDA.6 present the stabilized flow equation for a gas well with a circular boundary.

$$\Psi_R = \Psi_{wf} + \frac{1422T}{kh} \left[ \ln \left( \frac{r_e}{r_{wa}} \right) - \frac{3}{4} \right] q \quad (\text{PDA.5})$$

$$\Psi_R = \Psi_{wf} + b q \quad (\text{PDA.6})$$

Where  $b$  is a constant for the specific well.

The oil equations are similar where  $P_R = P_{wf} + bq$ .

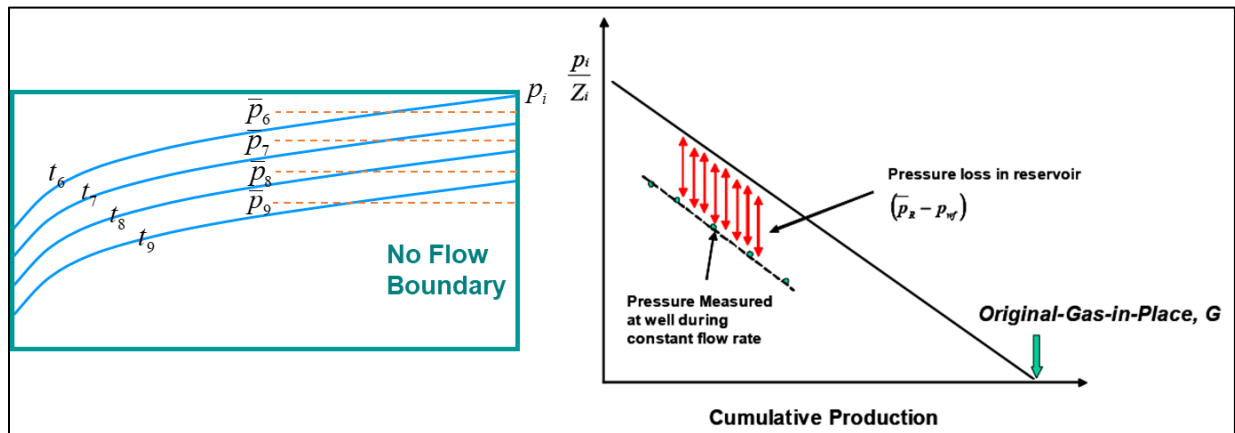


Figure PDA-26: PDA – Flowing P/Z

When the flow rate is constant, the  $bq$  term in Equation PDA.6 is constant and based on  $P_R/Z_R$  material balance:

$$\frac{P_R}{Z_R} = \frac{P_i}{Z_i} \left( 1 - \frac{G_p}{G} \right) = \frac{P_{wf}}{Z_{wf}} + bq \quad (\text{PDA.7})$$

When rate is constant the difference between static  $P_R/Z_R$  and flowing  $P_{wf}/Z_{wf}$  is  $bq$ . For variable rates, the flowing PI is substituted for the  $b$  term as shown in Equation PDA.8.

$$\frac{P_R}{Z_R} = \frac{P_i}{Z_i} \left( 1 - \frac{G_p}{G} \right) = \frac{P_{wf}}{Z_{wf}} + \frac{q}{PI} \quad (\text{PDA.8})$$

The PI in Equation PDA.8 is obtained from the y-intercept of the A-G FMB plot and is used to update the flowing  $P_R/Z_R$  curve.

During flowing material balance analysis, the reservoir pressure can be modified to adjust the  $P_R/Z_R$  line to finalize the analysis.

The flowing material balance is complete when the flowing PI is approximately constant and the flowing P/Z points fall along the P/Z straight line as shown in Figure PDA-25.

It should be noted that only the A-G FMB line can be directly modified.

## PDA.9 Analytical Simulator

The PE<sup>2</sup> Essentials Production Data Analysis tool includes an analytical simulator that can be used to confirm the FMB results and estimate reservoir properties by history matching the production data (Figure PDA-27).

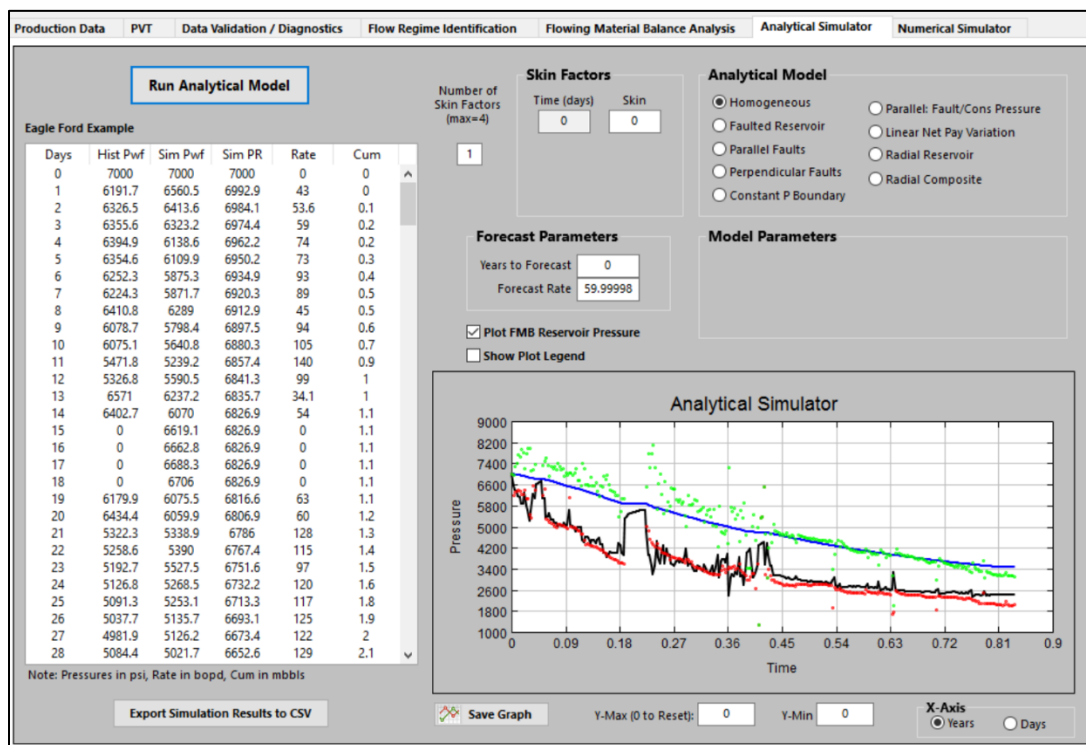


Figure PDA-27: PDA – Analytical Simulator

The analytical simulator included in the PE<sup>2</sup> Essentials Production Data Analysis tool simulates well pressures based on the “Method of Images”. Imaginary wells, referred to as image wells, are used to generate the pressure effect of the reservoir discontinuity.

There are nine different reservoir models included in the PDA analytical simulator (Figure PDA-28). After choosing a model, the required input will be requested. All wells have unique reservoir models.

The screenshot shows the 'Analytical Model' dialog box. The 'Radial Composite' model is selected. The 'Model Parameters' section includes fields for 'Radius of Inner Zone (ft)' (0), 'k/u of Outer Zone (md/cp)' (0), and ' $\Phi_{ci}$  of Outer Zone ( $10^{-3}$ )' (0). The 'Radial Composite Outer Zone Parameters' section includes fields for 'Radial Distance to Outer Zone (ft)' (0), 'Permeability in Outer Zone' (0), 'Viscosity in Outer Zone (cp)' (0), 'Porosity in Outer Zone (dec)' (0), and 'Compressibility in Outer Zone ( $10^{-5}$ /psi)' (0). A 'Continue' button is at the bottom right.

Figure PDA-28: PDA – Analytical Simulator Models

Up to four skin factors can be entered to for matching the production history (Figure PDA-29).

Skin Factors	
Time (days)	Skin
0	0
0	0
0	0
0	0

Figure PDA-29: PDA – Analytical Simulator Skin Factors

Checking the “Plot FMB Reservoir Pressure” will plot the  $P_R$  calculated from the flowing P/Z analysis. To modify these values, the flowing material balance analysis would have to be performed again with the new  $P_i$  or GIIP values.

If historical pressure is not available in the data set, the analytical simulator can be used to predict the pressure.

Following simulation, the results can be saved to a csv file by clicking on the “Save Simulation Results” button.

### PDA.10 Numerical Simulator

The PE<sup>2</sup> Essentials Production Data Analysis tool includes the option to build a data file for the PE<sup>2</sup> Essentials Unconventional Forecast tool and the PE<sup>2</sup> Essentials Basic Reservoir Simulator tool (Figure PDA-30).

The simulation models are built based on the reservoir parameters entered into the PDA tool. As a quality check, the initial volumes in place will be reported on the Numerical Analysis page so the dimensions of the simulation model can be confirmed to yield the in-place volumes calculated with PDA. The area of the simulation model will also be reported.

The option is included to build a horizontal fractured well or a vertical well simulator model.

If building a PE<sup>2</sup> Essentials Unconventional Forecast model, there is an option to include the production history data so that this tool can be used to refine the history match generated with the PDA – analytical simulator.

It is possible to build a vertical, horizontal, or a single frac stage single-well model for the PE<sup>2</sup> Essentials Basic Reservoir Simulator. The single frac stage model can be used as the basis to build a forecast for a well with multiple hydraulic fractures.

Production Data   PVT   Data Validation / Diagnostics   Flow Regime Identification   Flowing Material Balance Analysis   Analytical Simulator   Numerical Simulator

### Eagle Ford Example

**Numerical Model**

Depth to Top Reservoir (ft)

Reservoir Length (ft)

Reservoir Width/Well Spacing (ft)

Tubing ID (in)

Number of Hydraulic Fractures

Fracture Half Length (ft)

**Estimated Numerical Model Parameters**

Area of Simulation Model (Acres)

Initial Oil in Place (mmbbls)

Free+Sol'n Gas in Place (Bscf)

Initial Water in Place (mmbbls)

**Basic Reservoir Simulator**

☐ Vertical Well   ☒ Horizontal Well

☐ Build Single Fracture Stage Model

**Unconventional Forecast**

☒ Horizontal Well

**Industry Simulator - Single Vertical Well Model**

☒ Rate Control   ☐ BHP Control   ☐ THP Control

Figure PDA-30: PDA – Numerical Simulator

Building models for the 'Industry Simulator' will generate a file that can be read by Eclipse-compatible simulators like OPM Flow.

The 'Export Schedule File' can generate a simulator schedule "include" file for multiple wells. Note – that the well production times must be compatible, this option will not synchronize well times.

## PDA.11 INTERPRET-PDA

‘INTERPRET-PDA’ enables straight-line analysis of any plot to be performed (Figure PDA-31). It is possible to include up to three straight lines on any plot. The straight-line data can be saved to the PE Tools database. Individual lines can be removed by selecting the line and clicking the ‘Clear’ button. It should be noted That the straight-line info is stored on a plot basis not a well basis. This is so multi-wells can be evaluated with a straight line based on the plotted parameter.

The straight-line data for all plots can be exported to a CSV file (Table PDA-1).

PE Essentials INTERPRET-PDA Data Export							
Oil	Oilfield						
Database:	PEE Tools Examples Database.PEEdb						
Info:	INTERPRET-PDA Eagle Ford						
# Wells analyzed:	1						
First analyzed well:	Eagle Ford Example						
X-Parameter	Y-Parameter	Line 1	Line 1	Line 2	Line 2	Line 3	Line 3
		Slope	Intercept	Slope	Intercept	Slope	Intercept
Time (yrs)	q-Oil/l <sup>1/2</sup> P	-0.90209	0.05906	0	0	0	0
Time (yrs)	1/D (yr)	1.028719	0.055823	0	0	0	0

Table PDA-1: INTERPRET-PDA – Exporting Straight Line Data

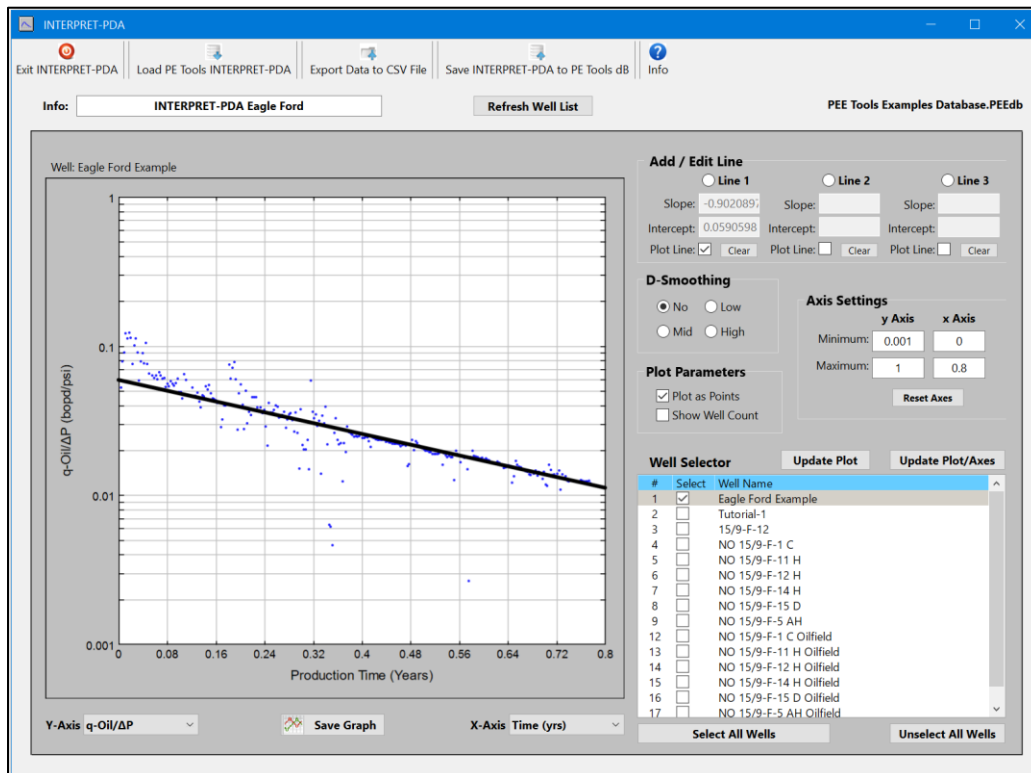


Figure PDA-31: INTERPRET-PDA – Straight Line Analysis

It should be noted that no analysis is performed with this tool. It can be used to observe and plot trends between wells.



## PDA.12 INTERPRET-PDA WI

The 'INTERPRET-PDA WI' tool (Figure PDA-32) enables a Hall Plot analysis of water injection well data. A Hall Plot evaluated steady-state flow at an injection well. In general, the slope of a Hall plot is an indicator of the average well injectivity. Under normal conditions, the plot is a straight line.

Hall (Ref: Hall, H.N.: How to Analyze Waterflood Injection Well Performance, World Oil, Oct. 1963) presented a technique to interpret injection well rate and pressure data to estimate near wellbore skin effects and average injectivity performance. The data required for Hall Plot analysis includes the following:

- Bottom-hole injection pressures
- Average reservoir pressure
- Water injection rate/volumes

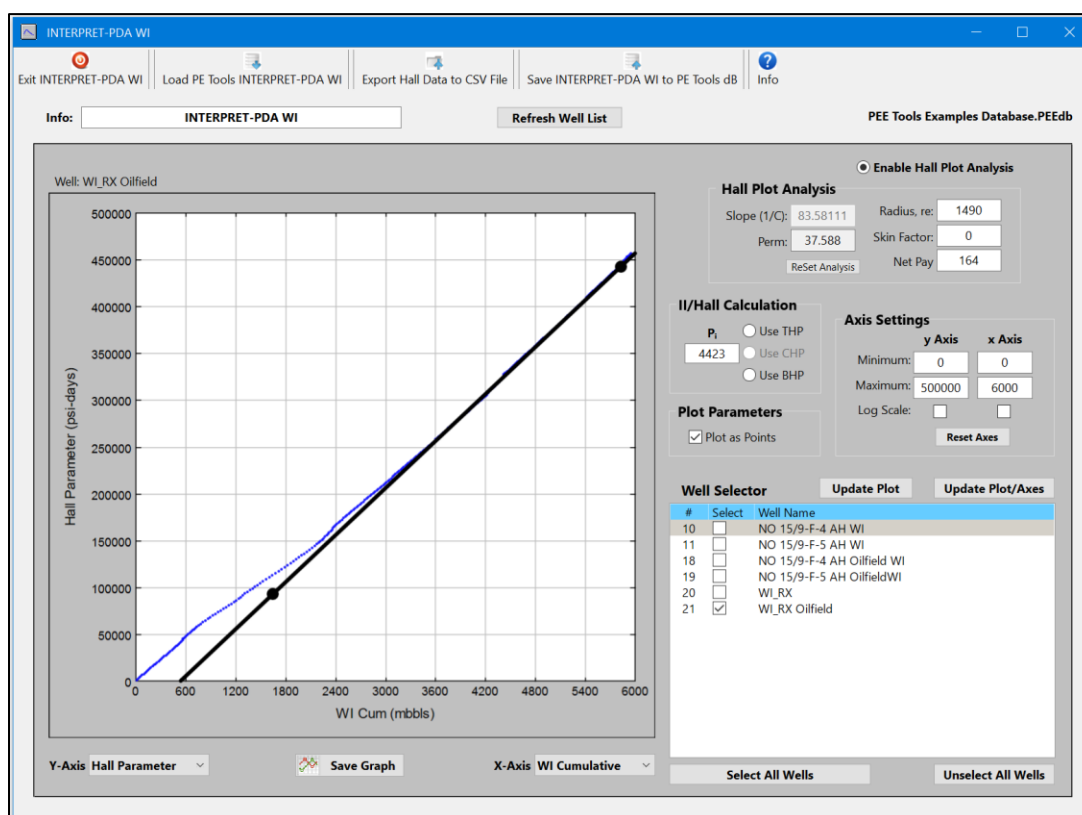


Figure PDA-32: INTERPRET-PDA – Straight Line Analysis

The Hall method assumes steady-state injection such that the injection rate can be expressed as:

$$i_w = \frac{0.00707kh(p_{wi}-p_{avg})}{\mu \left[ \ln \frac{r_e}{r_w} + S \right]} \quad (\text{PDA.9})$$

Where:  $k$  = permeability,  $h$  = reservoir thickness,  $p_{wi}$  = flowing pressure,  $p_{avg}$  = average reservoir pressure,  $\mu$  = fluid viscosity,  $r_e$  = reservoir effective radius,  $r_w$  = wellbore radius and  $S$  = skin

Equation PDA.8 is based on the following assumptions:

- The fluid is homogenous and incompressible
- The reservoir is uniform, both in terms of permeability and thickness
- The reservoir is horizontal, and the flow is radial
- Flow is under steady-state flow conditions
- Mobility ratio is equal to 1
- The pressure at a distance equal to  $r_e$  is constant

If it is assumed that  $k$ ,  $h$ ,  $\mu$ ,  $r_e$ ,  $r_w$  and  $S$  are constant, Equation PDA.8 can be rewritten as PDA.10

$$i_w = C(p_{wi} - p_{avg}) \quad (\text{PDA.10})$$

$$C = \frac{0.00707kh}{\mu \left[ \ln \frac{r_e}{r_w} + S \right]} \quad (\text{PDA.11})$$

Rearranging Equation PDA.10 yields the following:

$$(p_{wi} - p_{avg}) = \frac{i_w}{C} \quad (\text{PDA.12})$$

Integrating both sides of Equation PDA.12 with respect to time yields Equation PDA.13.

$$\int_0^t (p_{wi} - p_{avg}) dt = \frac{1}{C} \int_0^t i_w dt \quad (\text{PDA.13})$$

The integral on the right-hand side of Equation PDA.13 is cumulative water injected so Equation PDA.13 can be rewritten as Equation PDA.14

$$\int_0^t (p_{wi} - p_{avg}) dt = \frac{W_i}{C} \quad (\text{PDA.14})$$

where:  $W_i$  is the cumulative volume of water injected at time  $t$ .

A plot Equation PDA.14 should yield a straight line with a slope of  $1/C$ . This type of plot is called the Hall Plot. If the parameters  $h$ ,  $\mu$ ,  $r_e$ ,  $r_w$ , and  $S$  are constant, then from Equation PDA.11, the value of  $C$  is a constant and the slope is a constant. If the parameters change,  $C$  and the slope of the Hall Plot will change, which is the diagnostic value of the plot.

Changes in injection conditions can be observed from the Hall Plot. For example, if wellbore plugging or other restrictions are gradually occurring, the net effect is a gradual increase in the skin factor,  $S$ . As  $S$  increases,  $C$  decreases and the slope of the Hall Plot increases. Conversely, if  $S$  decreases (for example, if injection pressure exceeds fracture pressure), then  $C$  increases and

the slope of the Hall Plot decreases. Figure PDA.33 presents generic Hall Plot signatures for different injection conditions.

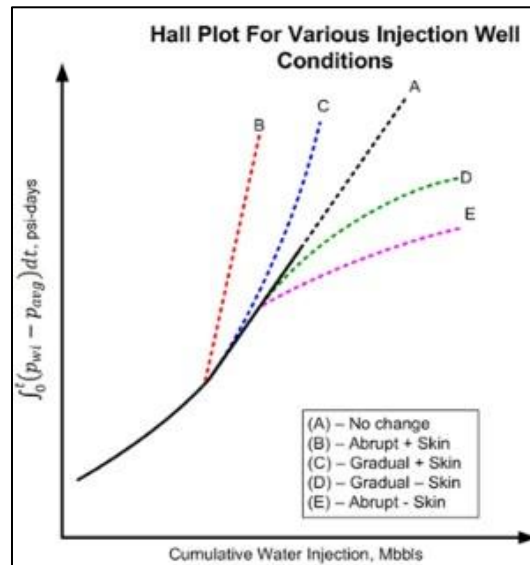


Figure PDA-33: Hall Plot Example

For practical purposes, the integral in Equation PDA.14 can be represented by Equation PDA.15 simplifying the generation of the Hall Plot.

$$\int_0^t (p_{wi} - p_{avg}) dt = \sum \Delta p * \Delta t \quad (\text{PDA.15})$$

Where:  $\Delta p = p_{wi} - p_{avg}$ ,  $p_{wi}$  is injection pressure,  $p_{avg}$  is the average reservoir pressure (assumed to be constant) and  $\Delta t$  = number of injection days.

Changes in the slope of a Hall Plot tend to occur gradually, so several months of injection history may be needed to reach reliable conclusions about injection behaviour. It is important to note that changes in the slope of the Hall Plot can be the result of other factors.

Typically, during the early life of an injection well, the radius of the water injection zone increases with cumulative injection (for example from gas fill-up) and causes the value of  $C$  to increase, resulting in a concave upward trend in the Hall Plot. Also, the Hall Plot technique assumes a mobility ratio of 1.0. If the mobility ratio is greater than 1, then the Hall Plot gradually trends concave downwards (as shown in curve D in Figure PDA.33); if mobility ratio is less than 1.0, it will gradually trend concave upwards (see curve C in Figure PDA.33). Also, as the average water saturation in the reservoir increases with time,  $k_w$  may increase, which can also affect the slope of the plot.

The overall purpose of the Hall Plot is to detect changes in the injection well skin factor. If the skin factor is known or can be assumed, then the permeability can be estimated using Equation PDA.11, after the slope is determined.

### PDA.13 INTERPRET-PDA WaterFlood

The 'INTERPRET-PDA Wflood' tool (Figure PDA-34) enables a straight line analysis of oil-water performance in order to estimate the EUR for a given cutoff.

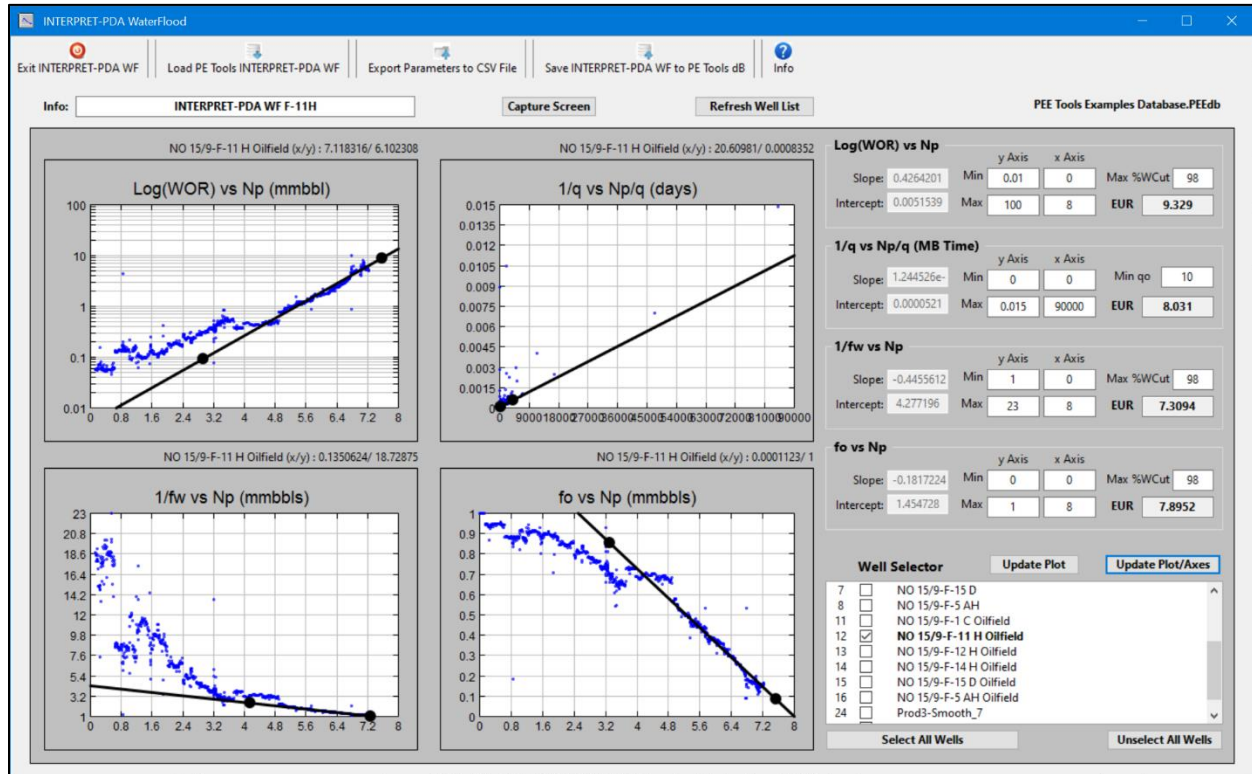


Figure PDA-34: INTERPRET-PDA Wflood – WaterFlood EUR Analysis

An excellent reference that summarizes the available techniques was published by Elmabrouk, Mahmud and Shiga (Ref: Elmabrouk, S.K., Mahmud, W.M., Shiga, H.M. Calculation of EUR from Oil and Water Production Data, IEOM Society International, March 2018). The data required for analysis is water and oil production. The techniques, which are valid when water cut is greater than 50%, include the following:

- Log(WOR) versus Cum Oil
- $1/q_o$  versus Cum Oil/ $q_o$
- $1/f_w$  versus Cum Oil
- $1/f_o$  versus Cum Oil

Where: WOR is water-oil ratio,  $q_o$  is oil rate,  $f_w$  is fraction of water, and  $f_o$  is fraction of oil.

The purpose of the analyses is to obtain consistent EUR results for the given cutoff. Multiple wells can be plotted for comparative purposes and the results of the straight lines can be exported to a CSV file (Figure PDA-35).

Plot	Slope	Intercept	Cutoff	EUR
LogWOR-Np	0.4264201	0.0051539	98	9.329
1/q-Np/q	1.24E-07	0.0000521	10	8.031
1/fw-Np	-0.4455612	4.277196	98	7.3094
fo-Np	-0.1817224	1.454728	98	7.8952

Figure PDA-35: INTERPRET-PDA WFlood – CSV File

It should be noted that no forecasts are generated from these plots except the estimate of EUR. The plots are only intended for analytical/interpretation purposes.

The value for EUR is calculated from the equation of the straight line added to the plot.

$$x\text{-value} = \text{slope } y\text{-value} + \text{intercept}$$

Where: x-value is  $N_p$  or  $N_p/q_o$ , slope and intercepts are calculated and presented and y-value is  $\text{Log}(\text{WOR})$ ,  $1/q_o$ ,  $1/f_w$  or  $f_o$ , as appropriate.

## PDA.14 Exporting Data from the PE Tools Database

The PE<sup>2</sup> Essentials Production Data Analysis tool has an option to export the well data to a CSV file (Figure PDA-36) by clicking 'Export Data to CSV File'.

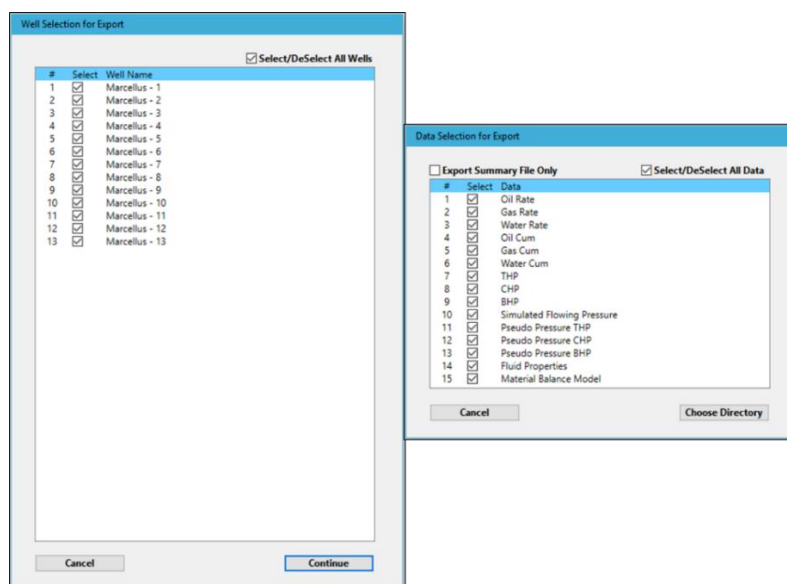


Figure PDA-36: PDA – General Export Options

For the data export, any number of wells can be chosen and the type of data to export is checked. The data is exported to a csv file that can be plotted using the PE Chart tool or imported into Excel.

A summary file will be exported along with the data for the specified well. It is possible to export just the summary file. The summary file is saved in a csv file format so the results can be imported into Excel. Table PDA-2 is an example of the summary output.

Well Name	OOIP	PI	Tr	Porosity	k	h	Rw	Sg	So	GasG	H2S	CO2	N2	API	Pb	NaCl	Depth	Length	Width	TubID	#fracs	xf
Eagle Ford Example	0.578376	7000	160	0.057	1.8	50	4	0	0.73	0.8	0	0	0	30	3000	35000	8700	5037	400	1.992	15	150

Table PDA-2: PDA – Well Summary Table

## PDA.15 Converting Forecast Data to Production Data

It is possible to convert a production forecast stored in the PE Tools database into an equivalent production data by clicking 'Convert Forecast' on the main menu (Figure PDA-37). This will copy the chosen forecast into a production well and store it in the PE Tools database. Note the original forecast is not impacted.

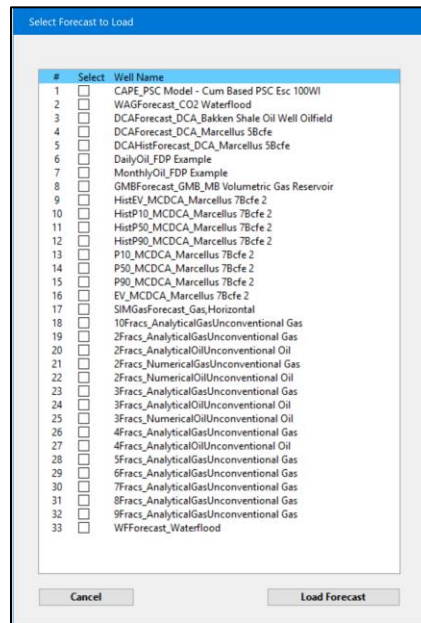


Figure PDA-37: PDA – Convert Forecast to Production

Once converted, the forecast can be analyzed as if it were a production well.

## PDA.16 PE Tools Database Management

The PDA tool creates the PE Tools database which is the repository of all the input/output files for the PE<sup>2</sup> Essentials tools. It is separate from the PE<sup>2</sup> Essentials Production Database to ensure that the integrity of the raw production data is maintained.

The PDA tool is used to modify the contents of the PE Tools database. This is done by clicking the 'Database Management' button (Figure PDA-38).

Data in PE Tools Database

List Forecasts

Delete Data

List Models

#	ID	Well Name	Fluid	Units	#Data	#Edit	#Sim	#MBal	PVT	Type	n/a	n/a	n/a	n/a	dbVersion
1	1	Eagle Ford Example	Oil	Oilfield	304	282	304	238	Tab	Prod	0	0	0	0	1
2	2	Tutorial-1	Gas	Oilfield	439	439	439	238	Tab	Prod	0	0	0	0	1
3	4	NO 15/9-F-11 C	Oil	Metric	2892	429	2892	436	Tab	Prod	0	0	0	0	1
4	5	NO 15/9-F-11 H	Oil	Metric	3056	1122	3056	436	Tab	Prod	0	0	0	0	1
5	6	NO 15/9-F-12 H	Oil	Metric	3020	2835	0	2	Tab	Prod	0	0	0	0	1
6	7	NO 15/9-F-14 H	Oil	Metric	2990	2722	0	2	Tab	Prod	0	0	0	0	1
7	8	NO 15/9-F-15 D	Oil	Metric	2983	766	0	2	Tab	Prod	0	0	0	0	1
8	9	NO 15/9-F-5 AH	Oil	Metric	3119	128	0	2	Tab	Prod	0	0	0	0	1
9	10	NO 15/9-F-5 AH WI	Oil	Metric	3140	2843	0	2	Cor	Winj	0	0	0	0	1
10	11	NO 15/9-F-5 AH WI	Oil	Metric	2977	2557	0	2	Cor	Winj	0	0	0	0	1
11	12	NO 15/9-F-11 C Oilfield	Oil	Oilfield	2892	429	2892	436	Tab	Prod	0	0	0	0	1
12	13	NO 15/9-F-11 H Oilfield	Oil	Oilfield	3056	1122	3056	436	Tab	Prod	0	0	0	0	1
13	14	NO 15/9-F-12 H Oilfield	Oil	Oilfield	3020	2835	0	2	Tab	Prod	0	0	0	0	1
14	15	NO 15/9-F-14 H Oilfield	Oil	Oilfield	2990	2722	0	2	Tab	Prod	0	0	0	0	1
15	16	NO 15/9-F-15 D Oilfield	Oil	Oilfield	2983	766	0	2	Tab	Prod	0	0	0	0	1
16	17	NO 15/9-F-5 AH Oilfield	Oil	Oilfield	3119	128	0	2	Tab	Prod	0	0	0	0	1
17	18	NO 15/9-F-5 AH Oilfield WI	Oil	Oilfield	3140	2843	0	2	Cor	Winj	0	0	0	0	1
18	19	NO 15/9-F-5 AH Oilfield WI	Oil	Oilfield	2977	2557	0	2	Cor	Winj	0	0	0	0	1
19	20	WI_RX	Oil	Metric	410	306	0	2	Cor	Winj	0	0	0	0	1
20	21	WI_RX Oilfield	Oil	Oilfield	410	307	0	2	Tab	Winj	0	0	0	0	1

PEE Tools Examples Database.PEEdb

Close

Figure PDA-38: PE Tools Database

The 'List Forecast' button lists all the forecasts stored in the PE Tools database (Figure PDA-39a) and the 'List Models' button lists the tool models (Figure PDA-39b).

Forecasts in the PE Tools Database

#

Select

Well Name

1	CAPE_PSC Model - Cum Based PSC Esc 100WI
2	WAGForecast_CO2 Waterflood
3	DCAForecast_DCA Bakken Shale Oil Well Oilfield
4	DCAForecast_DCA Marcellus 5Bcfe
5	DCAHistForecast_DCA Marcellus 5Bcfe
6	DailyOil_FDP Example
7	MonthlyOil_FDP Example
8	GMBForecast_GMB_MB Volumetric Gas Reservoir
9	HistEV_MCDCA_Marcellus 7Bcfe 2
10	HistP10_MCDCA_Marcellus 7Bcfe 2
11	HistP50_MCDCA_Marcellus 7Bcfe 2
12	HistP90_MCDCA_Marcellus 7Bcfe 2
13	P10_MCDCA_Marcellus 7Bcfe 2
14	P50_MCDCA_Marcellus 7Bcfe 2
15	P90_MCDCA_Marcellus 7Bcfe 2
16	EV_MCDCA_Marcellus 7Bcfe 2
17	SHOGasForecast_Gas Horizontal
18	10Fracs_AnalyticalGasUnconventional Gas
19	2Fracs_AnalyticalGasUnconventional Gas
20	2Fracs_NumericalOilUnconventional Oil
21	2Fracs_NumericalGasUnconventional Gas
22	3Fracs_AnalyticalGasUnconventional Gas
23	3Fracs_AnalyticalOilUnconventional Oil
24	3Fracs_NumericalOilUnconventional Oil
25	4Fracs_AnalyticalGasUnconventional Gas
26	4Fracs_AnalyticalOilUnconventional Oil
27	5Fracs_AnalyticalGasUnconventional Gas
28	6Fracs_AnalyticalGasUnconventional Gas
29	7Fracs_AnalyticalGasUnconventional Gas
30	8Fracs_AnalyticalGasUnconventional Gas
31	9Fracs_AnalyticalGasUnconventional Gas
32	WFForecast_Waterflood
33	

Cancel

Forecasts in the PE Tools database

#

Select

Well Name

1	Artificial Lift
2	Artificial Lift Metric
3	Cap Costs: PSC Model - Cum Based PSC Esc 100WI
4	Currency: PSC Model - Cum Based PSC Esc 100WI
5	Escalation: PSC Model - Cum Based PSC Esc 100WI
6	Fiscal Terms: PSC Model - Cum Based PSC Esc 100WI
7	Op Costs: PSC Model - Cum Based PSC Esc 100WI
8	Prices: PSC Model - Cum Based PSC Esc 100WI
9	Purchase: PSC Model - Cum Based PSC Esc 100WI
10	CO2 Waterflood
11	CO2 Waterflood - Metric
12	PSC Model - Cum Based PSC Esc 100WI
13	PSC Model - Cum Based PSC Esc 100WI
14	Economics DCA Bakken Shale Oil Metric
15	Economics DCA Bakken Shale Oil Well Oilfield
16	Gas Example Metric
17	Unconventional Gas Well
18	Unconventional Gas Well - 6 fracs
19	IOR_EOR Screening - Metric
20	IOR_EOR Screening
21	EOS Well Tuned McCain
22	EOS Well Tuned McCain - Metric
23	FDP Example Metric
24	FDP Example Oil
25	2-Tank Volumetric Gas Reservoir
26	MB Volumetric Gas Reservoir
27	Multi-Tank Volumetric Gas Reservoir
28	Water Drive Gas Reservoir
29	Hydraulic Fracture Gas Well
30	Hydraulic Fracture Gas Well - Metric
31	Hydraulic Fracture Oil Well
32	Hydraulic Fracture Oil Well - Metric
33	EOR Tools
34	EOR Tools - Metric
35	Gas Model
36	Gas Model Barnett

Cancel

Figure PDA-39a: PE Tools db Forecasts      Figure PDA-39b: PE Tools db Models  
Clicking 'Delete Data' enables data to be deleted from the database (Figure PDA-40).



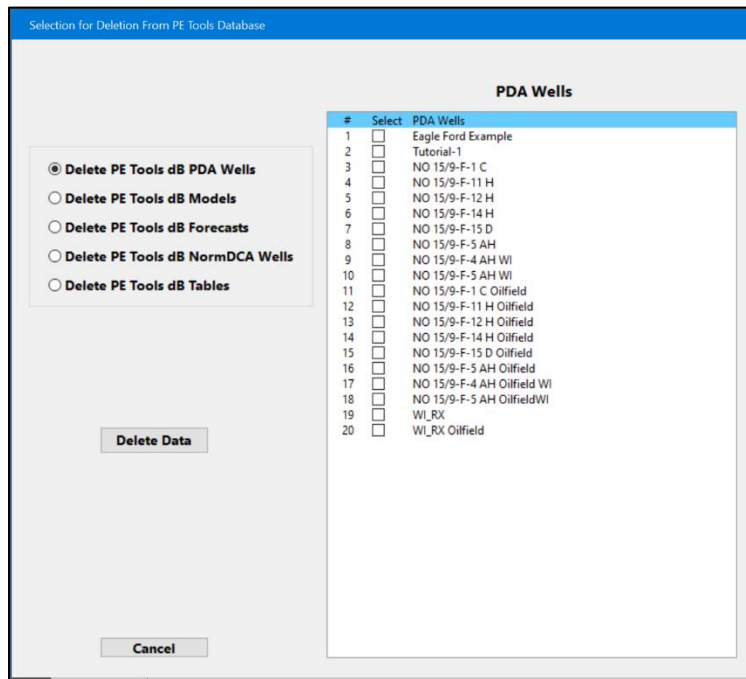


Figure PDA-40: PE Tools Delete

Figure PDA-40 shows that 'Delete PE Tools dB PDA Wells' option has been selected. To delete a well, check the well, or wells, and click 'Delete Data'. This will immediately delete the well from the database. This cannot be undone so caution should be exercised when deleting data.

Similar to deleting wells, the tool models, forecasts and NormDCA wells can be deleted. This allows the database to be 'cleaned up of old or erroneous data.

Note – it is strongly recommended that the PE Tools be backed up before performing deletes. Click 'Backup dB' on the main menu and a dated copy of the PE Tools database will be placed in the "PEE Tools Database Backup" directory.

The fifth deletion option, 'Delete PE Tools dB Tables', allows the user to delete individual tables in the database (Figure PDA-41). Caution should be exercised with this option since the integrity of the database can be compromised if the wrong table is deleted.

This option is useful if a well with the same name is accidentally added to the database. The redundant data can be found and deleted with this option.

The database table naming convention is that the first three letters indicate the tool from which the table came from. The term 'Model' indicates that it is a tool model, for instance, EORModel indicates that this table is a model input for the EOR tool.



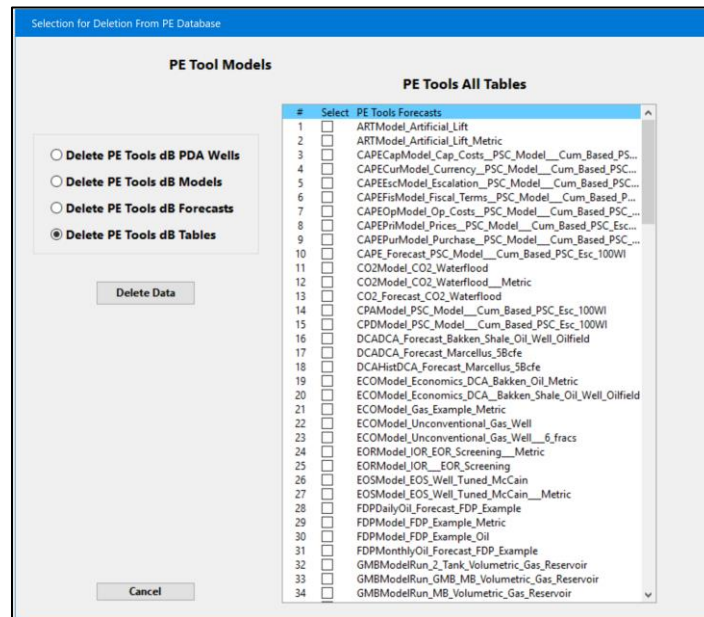


Figure PDA-41: PE Tools Database – General File Delete

If the name includes ‘\_Forecast\_’ then the table contains a production forecast. For instance, FDPDailyOil\_Forecast indicates that this is a daily oil forecast from the FDP tool.

If the name contains ‘Well’, then this is the actual well data tables. There are a number of ‘Well’ tables that comprise a well so it should only be deleted with the ‘Delete PE Tools dB PDA Wells’ option. If manual deletion is required, delete all tables associated with the particular well number.

The main menu item, ‘Save to New PE Tools dBase’, will save the current well data to a new PE Tools database. All the wells will be saved to the new database but none of the tool models or forecasts.

The main menu item, ‘Create New PE Tools dBase’, will create a blank PE Tools database. Once created, the wells to be stored in the database need to be selected. Clicking ‘Add Data to PE Tools dBase’ will open a screen showing the available wells. Choose the wells to be stored in the database and save the data. This is useful when a subset of the wells is to be separated from the main database.

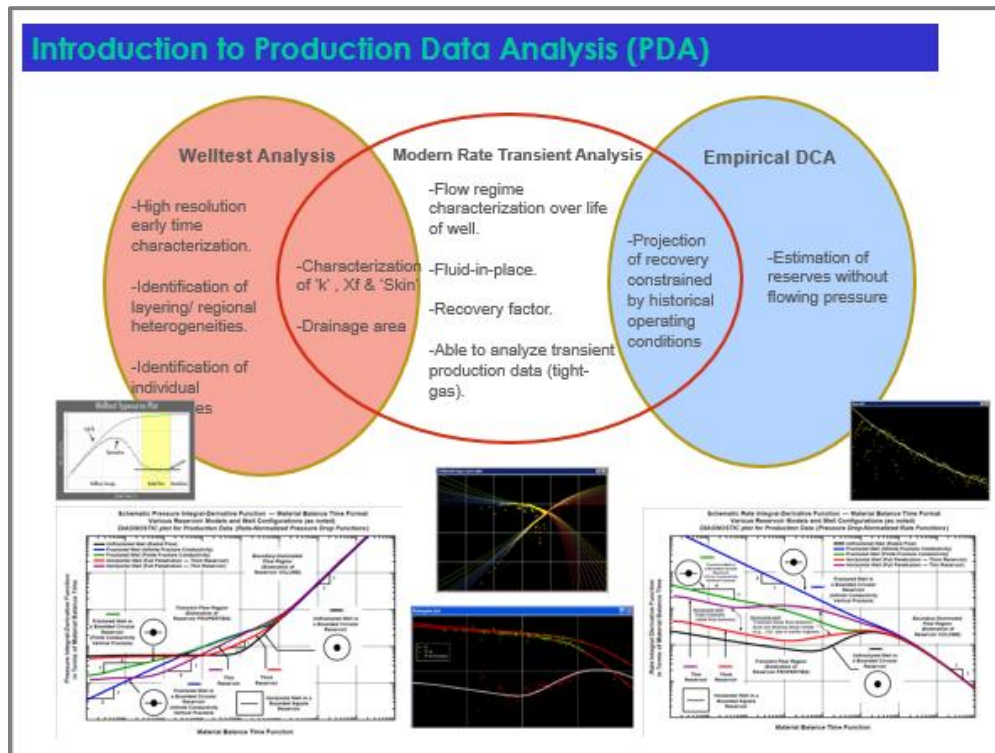
‘Update Wells to Database’ will replace the data in the database with the current PDA information. This button will not add a well to the database – this is performed by loading the data from the Production database and then clicking the ‘Add Data to PE Tools dBase’ button.

‘Copy Database’ will make a copy of the current database and is a quick way to save the database before making significant changes to the database.

## PDA Appendix – Concepts of Production Data Analysis

This appendix provides basic introductory concepts and an inventory of the time-pressure-rate relations used in the book and available in PE<sup>2</sup> Essentials software, as well as formulations for the various diagnostic functions. The Appendix begins with basic definitions and finishes off with the various diagnostic plots that are necessary for Production Data Analysis.

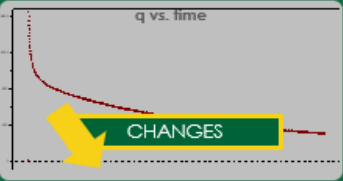
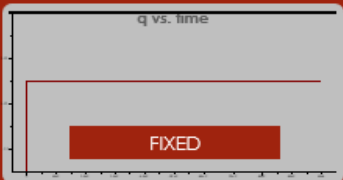
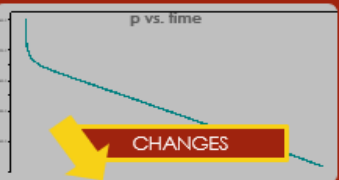
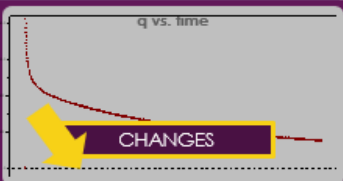
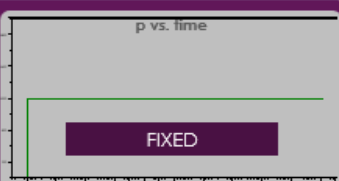
### A.1 General Concepts



### Theoretical Background in Production Data Analysis

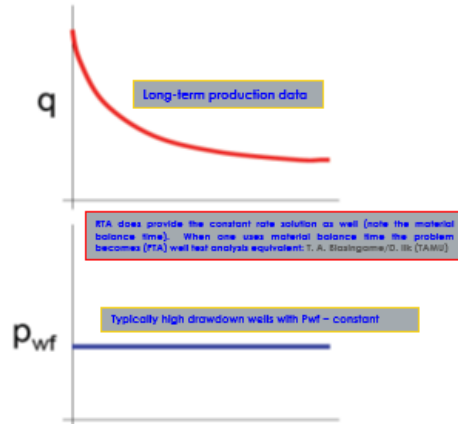
- Advanced methods in PDA means they incorporate ' $P_{wf}$ ' (PDHG data)
- They employ concepts of normalized rate/pressure, material balance time (MBT) and pseudo-time for gas.
- Applicable to variable rate/pressure history because of following features:
  - Rate or pressure normalization:
    - Rate normalized pressure drop ( $\Delta p/q$ ) – NPI format
    - Pressure drop normalized rate ( $q/\Delta p$ ) caters the effect of back pressure changes – Blasingame format
  - Use of MBT function:  $t_{eq} = N_p/q_0$
  - Handling the changing compressibility of gas with pressure, using pseudo-time (or material balance time) enables gas material balance rigorous with decreasing pressure.
    - Material-balance-pseudo-time 
$$t_{eq} = \frac{(\mu c_i)}{q} \int_0^t q dt / \bar{\mu} c_i$$
- Depletion analysis is analytical and valid for single-phase volumetric reservoirs.
- Diagnostic plots are biased toward PSS and tends to give conservative estimates of HCIP.

### Production Data Analysis (PDA) Techniques

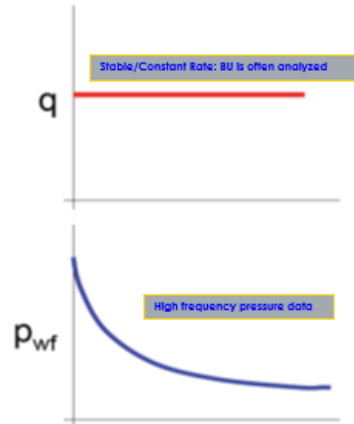
	RATE	PRESSURE
<b>DCA</b> Decline Curve Analysis		NOT OBSERVED/NOT USED
<b>PTA</b> Pressure Transient Analysis		
<b>RTA</b> Rate Transient Analysis		

## Operating Conditions – Simplified for PTA/RTA

### Constant Pressure = Production



### Constant Rate = Welltest



## Transient (Linear) vs. Boundary Flow

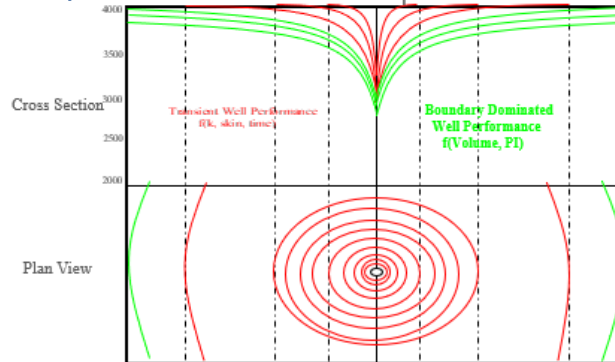
### Transient Flow

- Early time or low permeability.
- Flow that occurs when the pressure “pulse” is moving into an infinite or semi infinite acting reservoir.
- The “fingerprint” of the reservoir. Contains information about reservoir properties i.e.  $k$  & hydraulic fracture ( $X_f$ ,  $C_D$ )

### Boundary Flow

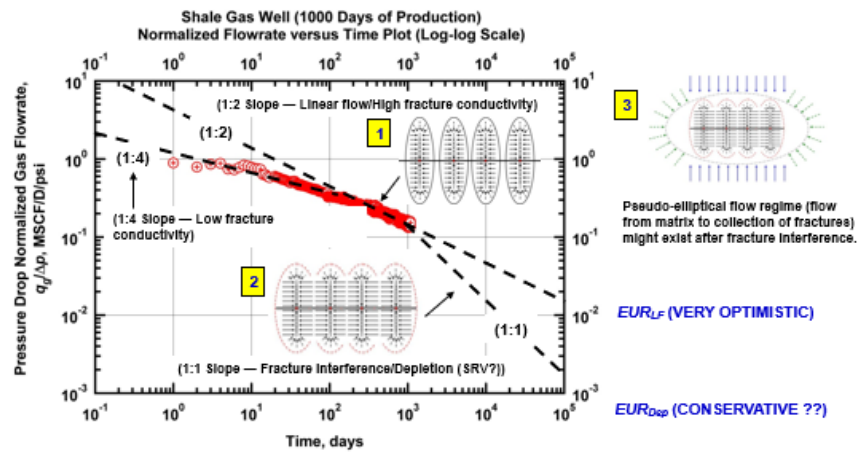
- Late time flow behavior. (pseudo radial)
- Typically dominates long term production data.
- Reservoir is in a state of pseudo-equilibrium – mass balance.
- Contains information about reservoir pore volume (OGIP).

Constant Rate Example



$$E_{\infty} = \left( \frac{h^2}{948 \mu C_v} \right)^{1/2} \text{ in Oil Fields Units}$$

### Orientation: Flow Regimes in Unconventional Reservoirs



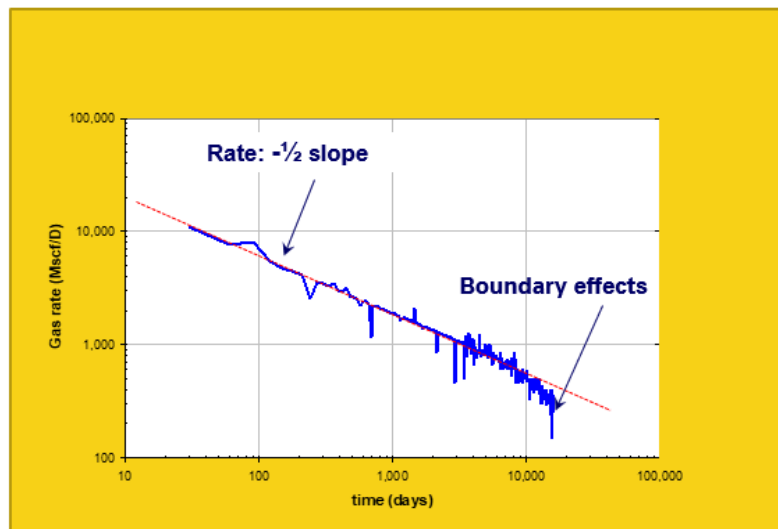
#### Flow Regimes: (Time-Pressure-Rate Data)

- Production data of a multi-fracture horizontal well from the Barnett Shale.
- Schematic illustrates possible flow regimes exhibited by production data.
- Duration/existence of flow regimes is DIFFERENT for each play.

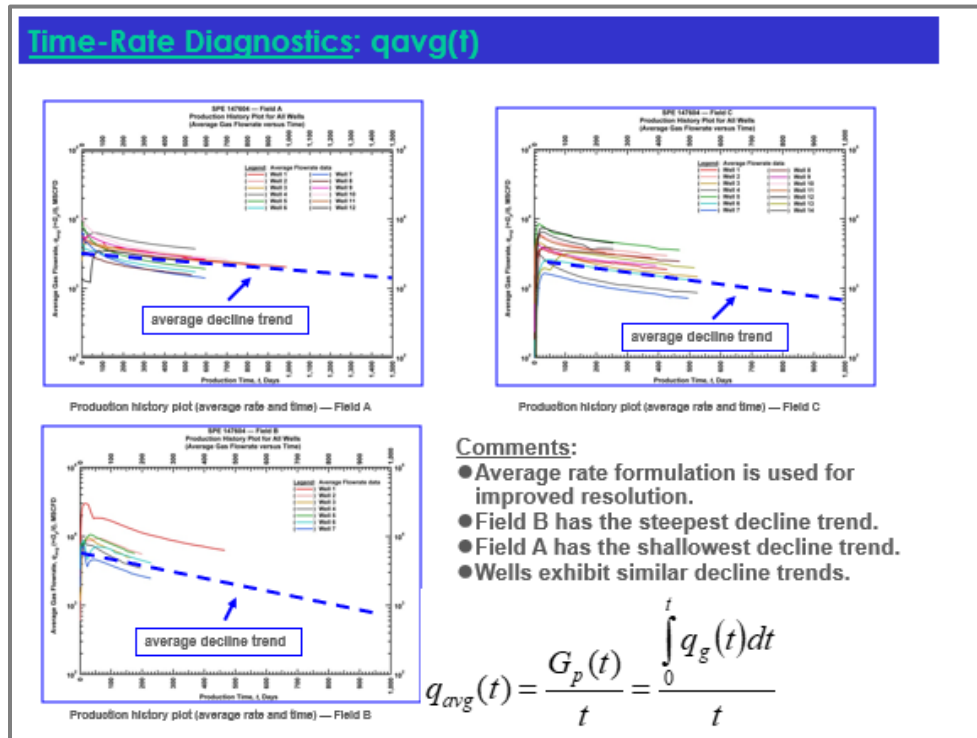
## A.2 Basic Diagnostics Definitions

### A.2.1 $q(t)$

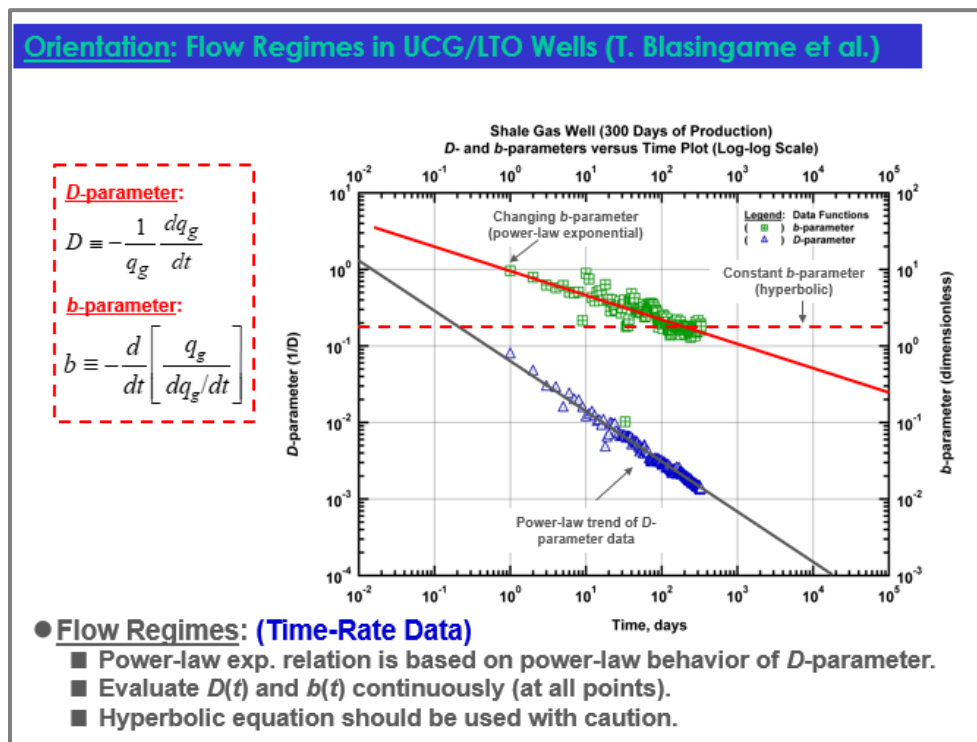
#### Orientation: Typical linear flow behavior (Bob Wattenbarger, Texas A&M)

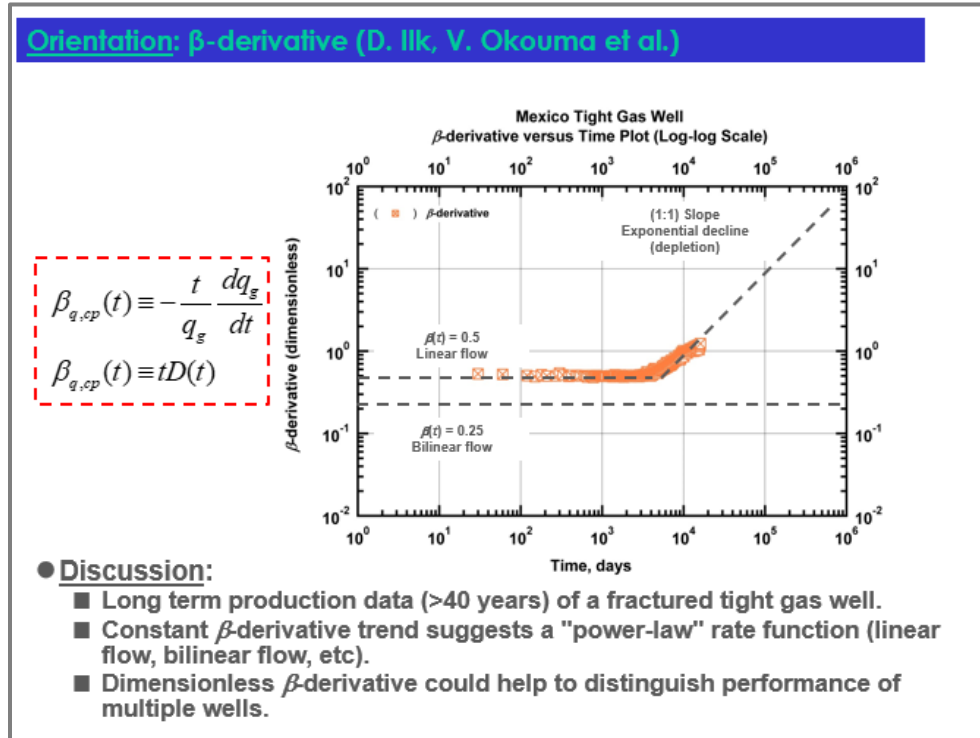


### A.2.2 $q_{avg}(t)$

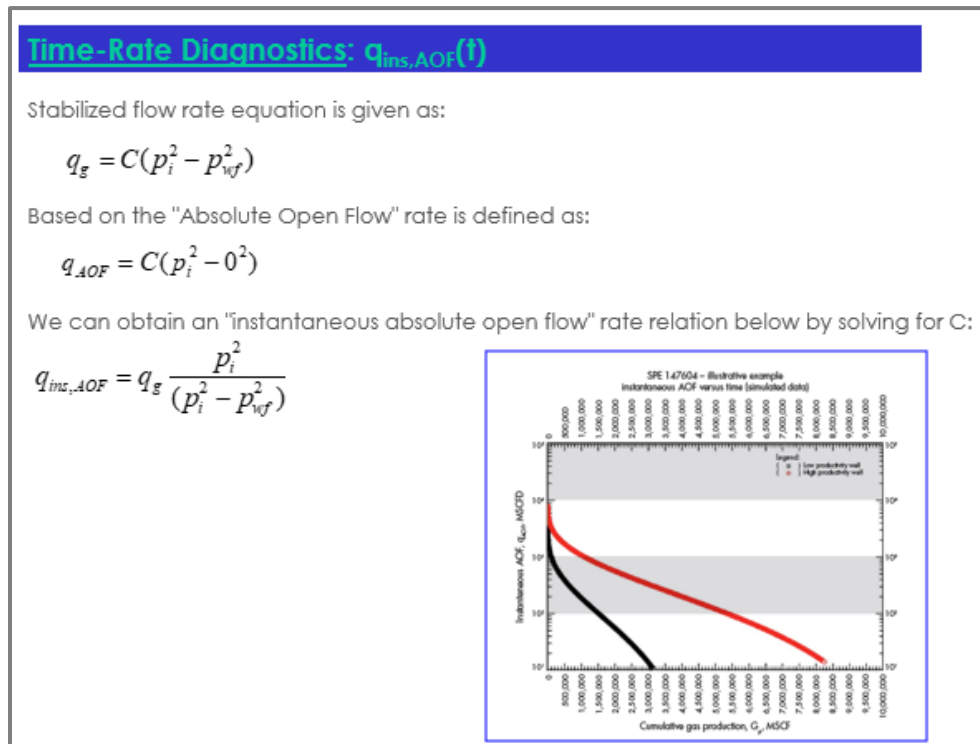


### A.2.3 $D(t)$ and $b(t)$



A.2.4  $\beta_{avg}(t)$ 

## A.2.5 AOF (Absolute Open Flow Potential)

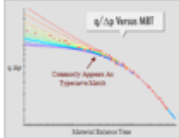


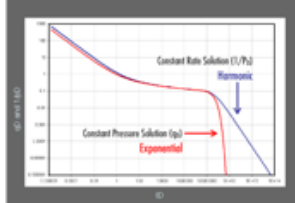


### A.2.6 Material Balance Time


**Concept of Material Balance Time (MBT)**

- The concept of MBT provides the normalization necessary to make constant pressure and constant rate solutions equivalent.
- Plotting using MBT also allows solutions with both declining rates and pressures to look like the equivalent constant rate solution and is helpful in TCM analogous to PTA
- Like a superposition time function in PTA but applied to boundary dominated flow in PDA.
- When normalized rate (PI) plotted against 't<sub>cr</sub>' on log-log scale the BDF exhibits -ve unit slope line.


$$PI = \frac{q(t)}{p_i - p(t)} \quad \text{Vs.} \quad t_{cr} = \frac{N_p}{q_o}$$




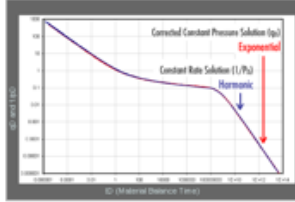
**Material Balance Time**



Actual Rate Decline  
Actual Time (t)



Equivalent Constant Rate  
Material Balance Time (t<sub>cr</sub>)



### A.3 Time Functions

Superposition time is a time function which will create a common straight line when data from different rates are plotted on the same plot. The formulation of superposition time depends on the flow regime being analyzed. For example, superposition radial time is found by performing the superposition in time of the radial flow equation for each rate specified. The following formulae are the generalized forms of superposition time for each flow regime. They can handle any number of step changes in rate.

Flow Regimes	Superposition Time Functions
Radial Flow Superposition	$t(f) \equiv \sum_{j=1}^n \frac{q_j - q_{j-1}}{q_n} \log(t_n - t_{j-1})$
Linear Flow Superposition	$t(f) \equiv \sum_{j=1}^n \frac{q_j - q_{j-1}}{q_n} \sqrt{t_n - t_{j-1}}$
Bilinear Flow Superposition	$t(f) \equiv \sum_{j=1}^n \frac{q_j - q_{j-1}}{q_n} \sqrt[4]{t_n - t_{j-1}}$
Spherical Flow Superposition	$t(f) \equiv \sum_{j=1}^n \frac{q_j - q_{j-1}}{q_n} \frac{1}{\sqrt{t_n - t_{j-1}}}$
Pseudo-Steady State (PSS)-BDF Superposition	$t(f) \equiv \sum_{j=1}^n \frac{q_j - q_{j-1}}{q_n} (t_n - t_{j-1})$



### A.3.1 Pseudo-Time/Pseudo-Pressure

Pseudo-time is a mathematical time function that accounts for the variable compressibility ( $c_g$ ) and viscosity ( $\mu_g$ ) of gas as well as the variable total porosity ( $\phi$ ) with respect to time and pressure. It is often confused with pseudo-pressure ( $\Psi(p)$ ). To deal with the changing gas and formation properties the concept of pseudo-time ( $t_a$ ) was developed by Agarwal (1980). It should be noted that the concept of pseudo-time is not amenable to a completely rigorous solution, as is the case for pseudo-pressure that will make the flow equation solvable.

The mathematical definition of pseudo-time is reminiscent of the definition of pseudo-pressure. Agarwal was focussed on pressures in the wellbore, and he defined pseudo-time in terms of the viscosity ( $\mu_g$ ) and compressibility ( $c_g$ ) at the wellbore. This definition accounted for the large change in gas compressibility ( $c_g$ ) that occurs at low pressures. It had little effect on late time data, and was generally used for pressure buildups only.

In the 90's, when the gas flow equations were being used for analyzing or forecasting data affected by reservoir depletion, it was realized that the Agarwal definition of pseudo-time for buildups, while adequate for transient flow, was inappropriate for boundary dominated flow (depleting systems). Moreover, the Agarwal pseudo-time definition did not solve the problem, because it was using a simplified version of the total system compressibility ( $c_t$ ).

Blasingame et al. introduced a new definition of pseudo-time to account for these depletion effects. Instead of defining the pseudo-time transformation in terms of wellbore conditions like Agarwal did, they defined it in terms of the average reservoir pressure. This pseudo-time is best described as material balance pseudo-time, which is appropriate for rate transient analysis.

With the introduction of pseudo-time, the gas flow equation can be written in a manner similar to the liquid equation. Therefore, the liquid flow solution can be used for gas well test analysis and forecasting provided pressure is replaced by pseudo-pressure, and time is replaced by pseudo-time as presented below.

$$t_a(t) \equiv \mu_{gi} C_{gi} \int_0^t \frac{dt}{\mu_g(p) C_g(p)} \text{ and } m(p) \equiv 2 \int_{p_{base}}^p \frac{p}{\mu z} dp$$

*Litterature also defines Material Balance Equivalent time as :  $t_e \equiv \frac{Q(t)}{q(t)}$*

### A.3.2 PDA Straight Line and Derivative Analysis

Straight line analysis for incompressible / slightly compressible fluids are represented by the following equations.

Flow Regime	Equation	Time Function	Specialized Plots	Results
Wellbore Storage	$\Delta p = \frac{qB_o \Delta t}{24C}$	$\Delta t$	$\left(\frac{\Delta p}{q}\right)$ vs. $\Delta t$	$C$
Linear Flow	$\Delta p = 4.064 \frac{qB_o \mu \sqrt{\Delta t}}{h \cdot X_f \cdot \sqrt{k\phi\mu C_t}}$	$\sqrt{\Delta t}$	$\left(\frac{\Delta p}{q}\right)$ vs. $\sqrt{\Delta t}$	$X_f \sqrt{k}$
Bilinear Flow	$\Delta p = 44.13 \frac{qB_o \mu^2 \sqrt{\Delta t}}{h \sqrt{k_f w_f} \cdot \sqrt[4]{k\phi\mu C_t}}$	$\sqrt[4]{\Delta t}$	$\left(\frac{\Delta p}{q}\right)$ vs. $\sqrt[4]{\Delta t}$	$\sqrt[4]{k} \sqrt{k_f w_f}$
Spherical Flow	$\Delta p = 70.6 \frac{qB_o \mu}{k_z r_z} - 2452.87 \frac{qB_o \mu \sqrt{\phi\mu C_t}}{k_z^{\frac{3}{2}} \sqrt{\Delta t}}$	$\frac{1}{\sqrt{\Delta t}}$	$\left(\frac{\Delta p}{q}\right)$ vs. $\frac{1}{\sqrt{\Delta t}}$	$\sqrt[3]{k_x k_z}$
Radial Flow	$\Delta p = 162.2 \frac{qB_o \mu}{kh} \left[ \log \frac{k\Delta t}{\phi\mu C_t r_w^2} - 3.23 + 0.87 s' \right]$	$\text{Log}(\Delta t)$	$\left(\frac{\Delta p}{q}\right)$ vs. $\text{Log}(\Delta t)$	$kh$
BDF	$\Delta p = 0.2342 \frac{qB_o}{\phi C_t h A} \Delta t - 70.65 \frac{qB_o \mu}{kh} \left[ \ln \left( \frac{2.2458 A}{C_t r_w^2} \right) + 2s \right]$	$\Delta t$	$\left(\frac{\Delta p}{q}\right)$ vs. $\Delta t$	$V_p$

Derivative analysis for incompressible / slightly compressible fluids are represented by the following equations.

Flow Regime	Bourdet Derivative Equation	Derivative Slope on log-log plot	$\beta(t)$ -Derivative Value
Wellbore Storage	$\Delta p' = \frac{qB_o}{24C} \Delta t$	1	1
Linear Flow	$\Delta p' = \frac{1}{2} \times 4.064 \frac{qB_o \mu \sqrt{\Delta t}}{h \cdot X_f \cdot \sqrt{k\phi\mu C_t}}$	$\frac{1}{2}$	$\frac{1}{2}$
Bilinear Flow	$\Delta p' = \frac{1}{4} \times 44.13 \frac{qB_o \mu^2 \sqrt{\Delta t}}{h \sqrt{k_f w_f} \cdot \sqrt[4]{k\phi\mu C_t}}$	$\frac{1}{4}$	$\frac{1}{4}$
Spherical Flow	$\Delta p' = \frac{1}{2} \times 2452.87 \frac{qB_o \mu \sqrt{\phi\mu C_t}}{k_z^{\frac{3}{2}} \sqrt{\Delta t}}$	$-\frac{1}{2}$	$-\frac{1}{2}$
Radial Flow	$\Delta p' = 70.65 \times \frac{qB_o \mu}{kh}$	0	-
Elliptical Flow	$\Delta p' = 0.7241 \times C_{EF} \left( \sqrt{\frac{k_x}{k_y}} \Delta t \right)^{0.35}$	$\frac{1}{3}$	$\frac{1}{3}$
BDF	$\Delta p' = 0.234 \times \frac{qB_o}{h\phi C_t A} \Delta t$	1	1

For gas (compressible fluids), replace pressure (p) with pseudo-pressure  $\Psi(p)$  and time (t) by pseudo-time  $t_a$ .

## A.4 Flowing Material Balance (FMB)

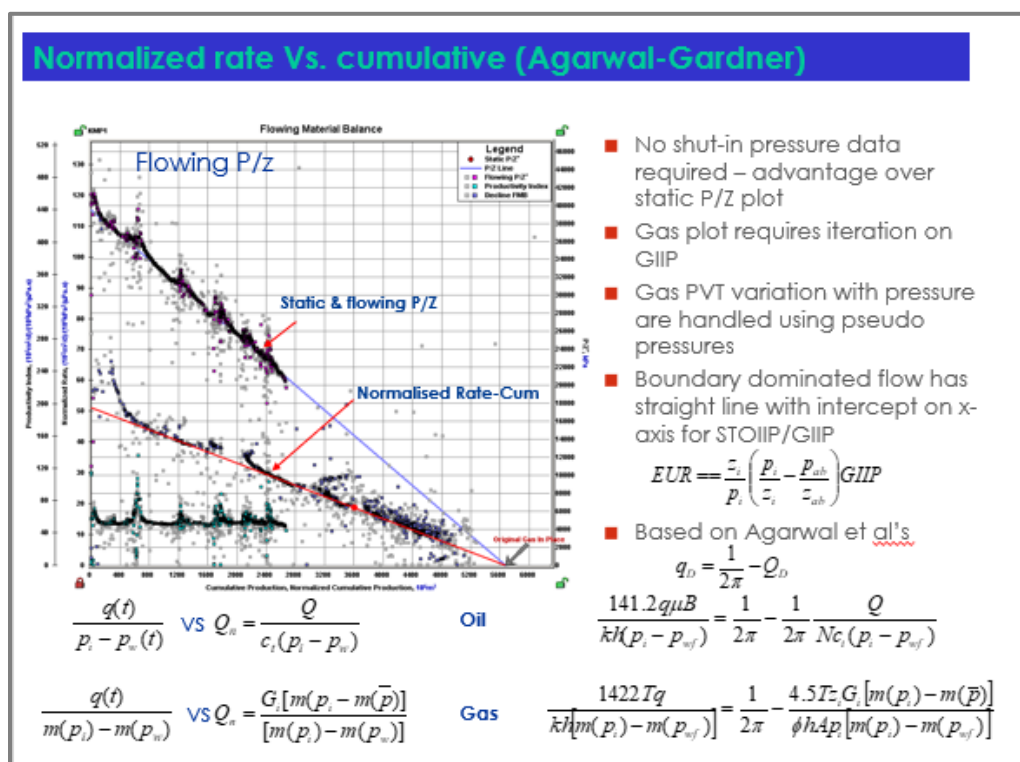
The "flowing material balance" formulation has been cited numerous times in one form or another (Palacio and Blasingame 1993; Mattar and McNeil 1998; and Agarwal et al. 1999).

Flowing material balance formulation is derived using the solution for the diffusivity equation during boundary-dominated flow (or pseudo steady state flow) regime. A significant advantage of flowing material balance type models is that they do not require static or shut-in pressures.

Contacted volume is determined from an extrapolation of a straight line drawn through the data exhibiting boundary-dominated flow regime. The major disadvantage of material balance type methods is that they are strictly limited to boundary-dominated flow regime. For tight gas and shale gas wells exhibiting very long periods of transient flow regime, material balance type methods would not be applicable.

The flowing material balance addresses this by using stabilized flowing pressures. Once flowing pressure stabilizes, the FMB produces a trend that, when extrapolated, provides an estimate of GIIP/OIIP without the requirement of shutting in the well.

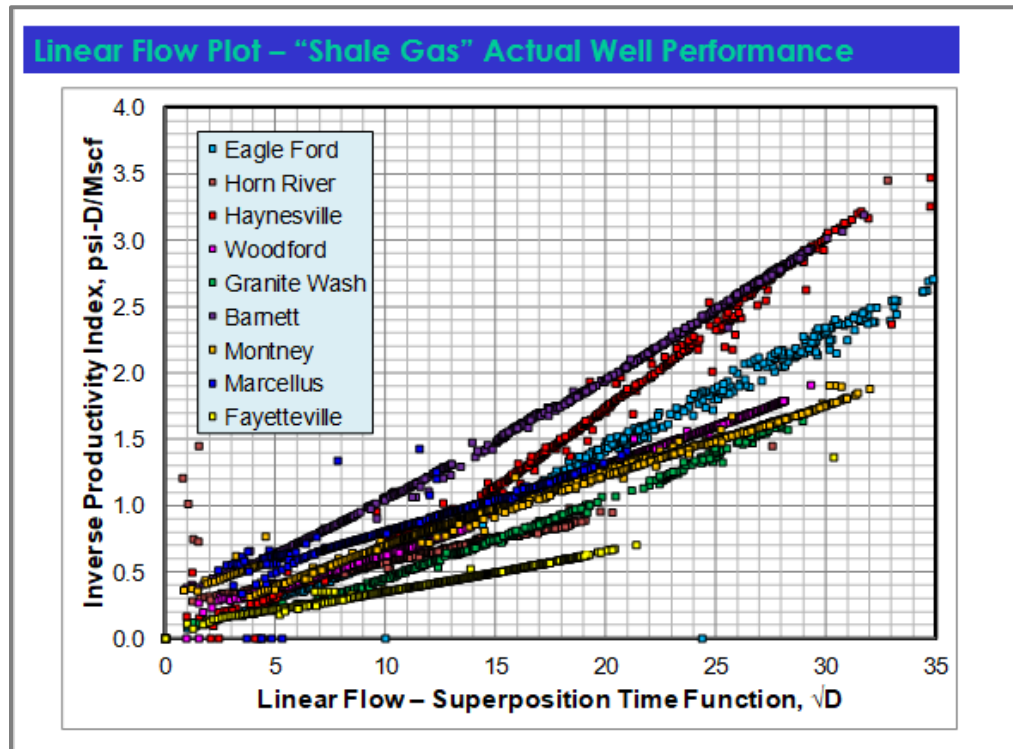
FMB assumes the late time data is in the boundary dominated flow and therefore points towards a GIIP/OIIP. Conversely, for data that is transient or linear, it provides an estimate of contacted / connected GIIP/OIIP.



## A.5 Specialized Analysis

Specialized analysis is functionality similar to that of FMB. The x-axis of the plot is a time function calculated based on the model that the user chooses (either constant pressure solution or superposition time) while the y-axis is normalized pressure. Choosing the superposition option will account for changes in operating conditions (i.e., accounting for variable pressures).

Specialized analysis should be used in conjunction with other plots to confirm the presence of linear flow. A non-zero, positive y-axis intercept indicates the presence of skin.



The specialized plots can be accessed in the Data Validation/Diagnostic section of the PE<sup>2</sup> Essentials Production Data Analysis tool as the  $\Delta P/q$  or  $\Delta \Psi/q$  plot.

## A.6 Production Diagnostics Plots

### Orientation: Time-Rate Diagnostics Plots

#### Diagnostic Plots:

- $q$  vs.  $t$
- $\log(q)$  vs.  $t$
- $\log(q)$  vs.  $\log(t)$
- $\log(q)$  vs.  $G_p$
- $\log(q)$  vs.  $\log(G_p/q)$
- $\log(q_{avg})$  vs.  $t$
- $\log(q_{avg})$  vs.  $\log(t)$
- $\log(q_{avg})$  vs.  $\log(G_p/q)$
- $\log(q_{ins,AOF})$  vs.  $t$
- $\log(q_{ins,AOF})$  vs.  $\log(t)$
- $\log(q_{ins,AOF})$  vs.  $\log(G_p/q)$
- $\log(D)$  vs.  $\log(t)$
- $\log(D_{avg})$  vs.  $\log(t)$
- $\log(b)$  vs.  $\log(t)$
- $\log(b_{avg})$  vs.  $\log(t)$
- $\log(\beta)$  vs.  $\log(t)$
- $\log(\beta_{avg})$  vs.  $\log(t)$
- $\log(\beta_{avg})$  vs.  $\log(t)$
- $q/G_p$  vs.  $t$
- $\log(q/G_p)$  vs.  $\log(t)$
- $\log(\zeta)$  vs.  $\log(t)$

#### ● Rationale for Plots:

- Single well Plots: Comparison of data functions on a per-well basis.
- Multi-well Plots: Comparison of data functions across several wells.
- Used average rate (cumulative production at a specific time divided by time) formulation for better resolution.

#### Frequently Asked Questions: $\beta_{avg}$

##### Q. Required Data for Diagnostics?

A. Essential rate (gas, oil, and water) and pressure (casing, tubing, and bottomhole (if possible)) measurements.

##### Q. Data Quality/Frequency?

A. Very low resolution (monthly data). Must have DAILY DATA, significant improvement in resolution with higher frequency data (hourly, etc.). Proper diagnostics require good data.

##### Q. Theory Behind Plots?

A. Some plots have, some do not. The main objective is to compare the performance of the wells *qualitatively*.

##### Q. What about Flowback?

A. Understanding of flowback behavior can lead the way for modeling "water unloading" phase.

### Orientation: Time-Pressure-Rate Diagnostics Plots

#### Diagnostic Plots:

- $\log(q_{ins,AOF}/\Delta p)$  vs.  $t$
- $\log(q_{ins,AOF}/\Delta p)$  vs.  $\log(t)$
- $\log(q_{ins,AOF}/\Delta p)$  vs.  $\log(G_p/q)$
- $\log(q_{ins,AOF}/\Delta p)$  vs.  $\log(G_p)$
- $\log(q/\Delta p)$  vs.  $\log(t)$
- $\log(q/\Delta p)$  vs.  $\log(t)$
- $\log(q/\Delta p)$  vs.  $\log(G_p/q)$
- $\log(q/\Delta p)$  vs.  $\log(G_p)$
- $\log(\Delta p/q)$  vs.  $t$
- $\log(\Delta p/q)$  vs.  $\log(t)$
- $\log(\Delta p/q)$  vs.  $\log(G_p/q)$
- $\log(\Delta p/q)$  vs.  $\log(G_p)$
- $(\Delta p/q)$  vs.  $t^{0.5}$  (Linear Flow)
- $(\Delta p/q)$  vs.  $t^{0.25}$  (Bilinear Flow)
- $G_p$  vs.  $t$
- $\log(G_p)$  vs.  $\log(t)$
- $\log(G_p/\Delta p)$  vs.  $\log(t)$
- $\log(G_p/\Delta p)$  vs.  $\log(G_p/q)$

#### ● Rationale for Plots:

- Single well Plots: Comparison of data functions on a per-well basis.
- Multi-well Plots: Comparison of data functions across several wells.
- Used average rate (cumulative production at a specific time divided by time) formulation for better resolution.

#### Frequently Asked Questions:

##### Q. Required Data for Diagnostics?

A. Essential rate (gas, oil, and water) and pressure (casing, tubing, and bottomhole (if possible)) measurements.

##### Q. Data Quality/Frequency?

A. Very low resolution (monthly data). Must have DAILY DATA, significant improvement in resolution with higher frequency data (hourly, etc.). Proper diagnostics require good data.

##### Q. Theory Behind Plots?

A. Some plots have, some do not. The main objective is to compare the performance of the wells *qualitatively*.

##### Q. What about Flowback?

A. Understanding of flowback behavior can lead the way for modeling "water unloading" phase.

## PE Basic Essentials

Basic Essentials includes tools (equations and routines) that can be used in the analysis of all conventional and unconventional reservoirs and are comprised of the following:

- Reservoir Fluid PVT Properties
- Relative Permeability Curve Generation
- Basic EOS PVT Simulator
- Monte Carlo Simulation: Volumetrics
- PE Graph - plots output from PE<sup>2</sup> Essentials tools

The reservoir fluid properties tool is always authorized for use in PE<sup>2</sup> Essentials.

## PVT and Relative Permeability Tool

Reservoir fluids are comprised of gas, oil, and water. Without exception, the properties of these fluids at reservoir conditions or at flowing conditions are required to perform an analysis. Reservoir conditions would be defined as the temperature and pressure of the reservoir. Flowing conditions are dynamic but represent a flowing temperature and pressure at a defined point in time and location – bottom hole or wellhead.

In most cases, fluid properties are generated by the use of published empirical correlations that have been developed over time. This allows the determination of fluid properties with a minimum of input requirements.

All the PVT data and relative permeability data can be saved to a text file with the option of saving the data in a format that can be read by standard (Eclipse, OPM Flow, etc) reservoir simulators.

To generate fluid properties, the 'Gas/Oil/Water PVT & Rel Perm' tool is run as shown in Figure PVT-1.

This tool generates gas (Section PVT.1), oil (Section PVT.3) and water/rock (Section PVT.4) properties based on industry standard correlations as well as fluid properties based on gas components (Section PVT.2). Tables of calculated properties can be generated and saved for use in other programs such as reservoir simulators.

The tool can also be used to generate relative permeability tables for use in reservoir simulators (Section PVT.6).

Fluid PVT Properties / Relative Permeability Tool - Version 2023.1

Exit Program | Load PE Tools PVT Model | Relative Permeability | Production Rel Perm | Export CSV | Save to PE Tools dBase | Info

Capture Screen

Oilfield  PEE Tools Examples Database.PEEdb

Update PVT Properties

Info: PVT Well Oil

**Reservoir Parameters**

Reservoir Pressure (psia)	2965
Reservoir Temperature (°F)	220
Water Saturation (dec)	0.2
Oil Saturation (dec)	0.5
Gas Saturation (dec)	0.3

**Gas Parameters**

Gas Gravity	0.855	
%H <sub>2</sub> S	0	bbls/mmstd
%CO <sub>2</sub>	0	CGR 0
%N <sub>2</sub>	0	CGR Info

**Oil Parameters**

Oil API	40.7
Solution GOR	768
Bubble Point Pressure	2741.7

**Rock/Water Parameters**

Salinity (ppm NaCl)	30000
Porosity (dec)	0.2

**Generate Oil PVT Tables**

**Generate Gas PVT Tables**

**Generate Water/Rock PVT Tables**

**Generate Pseudo Gas Composition**

**Generate Pseudo Oil Composition**

Gas Properties	Value	Units
Gas Pc	662.4	psia
Gas Tc	436.7	°R
Z	0.817	<>
Gas Compressibility	28.991	x10 <sup>-5</sup> /psi
Gas Viscosity	0.0236	cp
Gas Expansion (1/Bg)	188.7	scf/ft <sup>3</sup>
Initial CGR (Rv)	0	bbls/mmstd

Oil Properties	Value	Units
Reservoir Pressure	2965	psia
Bubble Point Pressure	2741.7	psia
Solution GOR @ PR	768	scf/bbl
Oil Compressibility	1.921	x10 <sup>-5</sup> /psi
Oil Viscosity	0.235	cp
Bo	1.444	bbl/sbbl

Water Properties	Value	Units
Water Density	1.0213	g/cc
Solution RSW	13.8	scf/bbl
Water Compressibility	0.334	x10 <sup>-5</sup> /psi
Water Viscosity	0.289	cp
Bw	1.0421	bbl/sbbl
G/W Interfacial Tension	45.4	Dynes/cm
O/W Interfacial Tension	2.32	Dynes/cm

Rock Properties	Value	Units
Reservoir Pressure	2965	psia
Rock Compressibility	0.361	x10 <sup>-5</sup> /psi
Total Compressibility	10.013	x10 <sup>-5</sup> /psi
Estimated Oil Perm	100	md
Estimated Gas Perm	31.6	md

Figure PVT-1: PE<sup>2</sup> Essentials - Gas/Oil/Water PVT & Relative Permeability Tool

Either US Oilfield or Metric units can be specified (Figure PVT-2).

Gas Properties			Gas Properties		
Gas G - no acid gas	0.7859	<>	Gas G - no acid gas	0.7859	<>
Gas Pc	667.2	psia	Gas Pc	4600.5	kPaa
Gas Tc	414.1	°R	Gas Tc	230.1	°K
Z	0.758	<>	Z	0.758	<>
Gas Compressibility	38.046e-5	1/psi	Gas Compressibility	5.518e-5	1/kPa
Gas Viscosity	0.0218	cp	Gas Viscosity	21.8335	μPa-s
Gas Expansion (1/Bg)	191.1	scf/ft <sup>3</sup>	Gas Expansion (1/Bg)	191.1	sm <sup>3</sup> /m <sup>3</sup>

Figure PVT-2: US Oilfield/Metric Output Properties

Selecting the 'Export Tables' button brings up a screen with options for saving calculated PVT property tables (Figure PVT-3). These tables are useful for input into other programs, for example, PE<sup>2</sup> Essentials Chart. The data is saved in a comma delimited file format (CSV). The tool can also save the relative permeability data in a csv file.



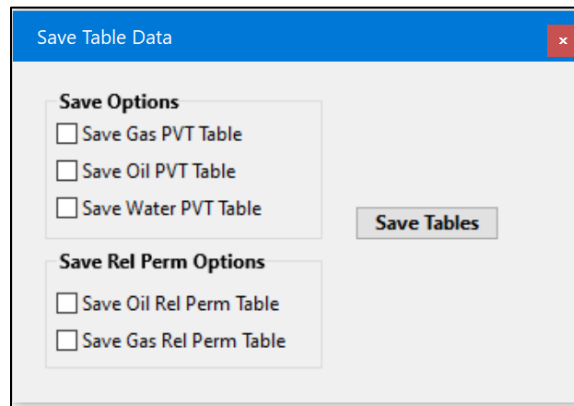


Figure PVT-3: PVT Table Output Properties Options

Include tables for reservoir simulation can also be exported by the tools from the relevant screens using through the 'Save Simulator Deck' button.

The PE<sup>2</sup> Essentials 'Gas/Oil/Water PVT & Rel Perm' tool includes empirical correlations for gas, oil and water and also includes component generation routines for gas and oil to determine gas shrinkage, use in EOS modeling, etc.

The tool also includes routines to calculate oil, gas and water relative permeability data (Section PVT.6). An example of the relative permeability output table in simulator format is shown in Figure PVT-4

```
-- RELATIVE PERMEABILITY FOR OIL AND WATER AS ACTIVE PHASES
-- NSSFUN = 22
SWOF
-- SW      KRW      KROW      PCWO
0.2000    0.000000    0.850000    0.0
0.2275    0.001500    0.710316    0.0
0.2550    0.006000    0.587852    0.0
0.2825    0.013500    0.481266    0.0
0.3100    0.024000    0.389255    0.0
0.3375    0.037500    0.310551    0.0
0.3650    0.054000    0.243928    0.0
0.3925    0.073500    0.188198    0.0
0.4200    0.096000    0.142216    0.0
0.4475    0.121500    0.104879    0.0
0.4750    0.150000    0.075130    0.0
0.5025    0.181500    0.051959    0.0
0.5300    0.216000    0.034406    0.0
0.5575    0.253500    0.021560    0.0
0.5850    0.294000    0.012570    0.0
0.6125    0.337500    0.006641    0.0
0.6400    0.384000    0.003041    0.0
0.6675    0.433500    0.001111    0.0
0.6950    0.486000    0.000269    0.0
0.7225    0.541500    0.000024    0.0
0.7500    0.600000    0.000000    0.0
1.0000    1.000000    0.000000    0.0 /
```

Figure PVT-4: Simulator Table of Relative Permeability



The main screen (Figure PVT-1) is used to calculate single values for the oil, gas and water PVT parameters. To calculate ranges of parameters, the 'Generate Oil PVT Tables'; 'Generate Gas PVT Tables'; and 'Generate Water/Rock PVT Tables' buttons are clicked.

For a gas well, entering a CGR value of '-1' will use the internal correlation to estimate CGR. If '0' is entered, a dry gas is assumed and if a positive value for CGR is entered, then the CGR calculations will be calibrated to the entered value at the given temperature and pressure.

## PVT.1 Gas Properties

There are several standard correlations that can be used to generate gas properties. All correlations require gas gravity, reservoir pressure and reservoir temperature as input. PE<sup>2</sup> Essentials will also apply corrections based on the acid gas (N<sub>2</sub>, CO<sub>2</sub>, H<sub>2</sub>S) concentrations.

The gas correlations incorporated into PE<sup>2</sup> Essentials, as well as their range of validity, are presented in the following sections.

Clicking the 'Generate Gas PVT Tables' button on the main screen will bring up the screen to calculate a table of gas PVT values (Figure PVT-5).

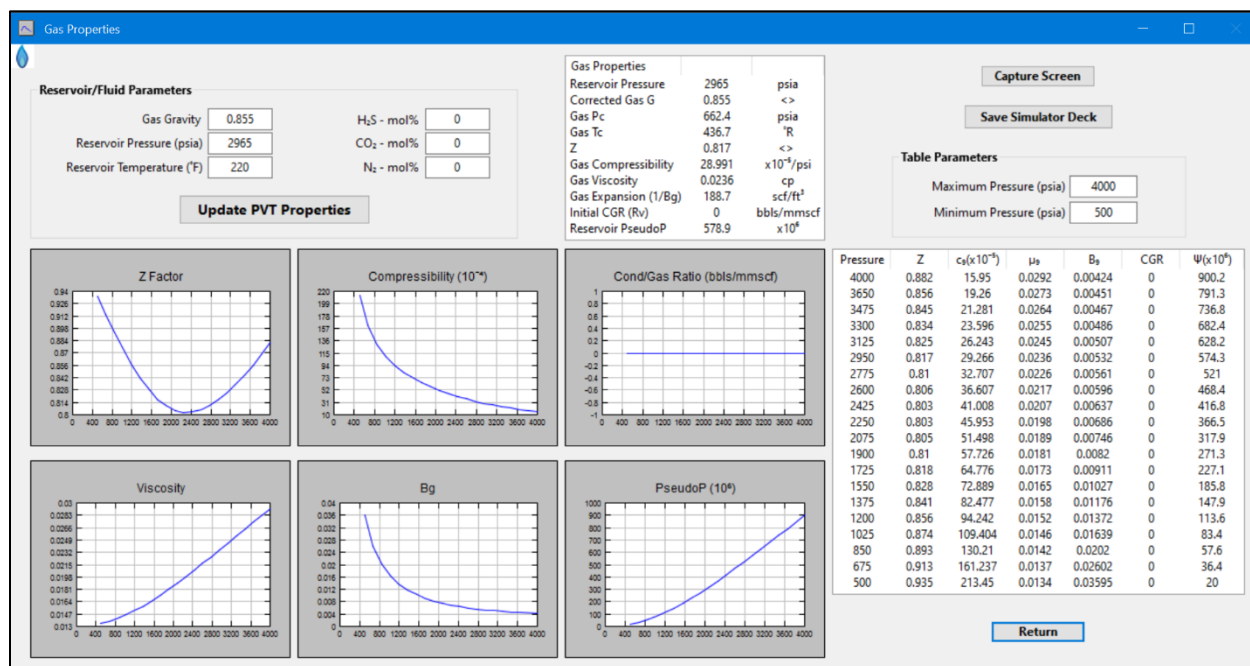


Figure PVT-5: Gas PVT Parameters

Once the PVT table has been generated, the data can be saved to an industry-standard reservoir simulator file format by clicking the "Save Simulator Deck" button.

### PVT.1.1 Gas Tc and Pc

The correlations for pseudocritical temperature, Tc in °R; pseudocritical pressure, Pc in psia; and for miscellaneous gases, is from Standing, M. B., Volumetric and Phase Behavior of Oil Field Hydrocarbon Systems, 1977, and includes the Wichert-Aziz correction for acid gas (Wichert, E., Aziz, K., "Calculate Z's for Sour Gases", Hydrocarbon Proceedings, May 1972).

$$\begin{aligned}
 y_{N_2} &= \text{Input\_}\%N_2/100 \\
 y_{CO_2} &= \text{Input\_}\%CO_2/100 \\
 y_{H_2S} &= \text{Input\_}\%H_2S/100 \\
 \text{Corr\_SG} &= \frac{(SG - 0.9672y_{N_2} - 1.5195y_{CO_2} - 1.1765y_{H_2S})}{(1 - y_{N_2} - y_{CO_2} - y_{H_2S})} \quad (\text{PVT-1}) \\
 T_c' &= 168 + 325\text{Corr\_SG} - 12.5\text{Corr\_SG}^2 \\
 P_c' &= 677 + 15\text{Corr\_SG} - 37.5\text{Corr\_SG}^2 \\
 T_c'' &= (1 - y_{N_2} - y_{CO_2} - y_{H_2S})T_c' + 227.3y_{N_2} + 547.6y_{CO_2} + 672.4y_{H_2S} \\
 P_c'' &= (1 - y_{N_2} - y_{CO_2} - y_{H_2S})P_c' + 493y_{N_2} + 1071y_{CO_2} + 1306y_{H_2S} \\
 \text{Corr\_wa} &= 120((y_{CO_2} + y_{H_2S})^{0.9} - (y_{CO_2} + y_{H_2S})^{1.6}) + 15(y_{H_2S}^{0.5} - y_{H_2S}^4) \\
 T_c &= T_c'' - \text{Corr\_wa} \quad (\text{PVT-2}) \\
 P_c &= \frac{P_c'' T_c}{(T_c'' + y_{H_2S} (1 - y_{H_2S}) \text{Corr\_wa})} \quad (\text{PVT-3})
 \end{aligned}$$

Range of validity:

$$\begin{aligned}
 0 &\leq \%N_2 < 100 \\
 0 &\leq \%CO_2 < 100 \\
 0 &\leq \%H_2S < 100 \\
 0 &\leq \%N_2 + \%CO_2 + \%H_2S < 100 \\
 0 &\leq \%CO_2 + \%H_2S < 80
 \end{aligned}$$

Gas correlations use pseudocritical pressure and temperature in a form termed pseudoreduced pressure and temperature as follows:

$$\begin{aligned}
 P_{pr} &= \frac{P}{P_c} \quad (\text{PVT-4}) \\
 T_{pr} &= \frac{T + 460}{T_c} \quad (\text{PVT-5})
 \end{aligned}$$

Where: P and T are the pressure (psia) and temperature (°F) of interest and SG is gas specific gravity.

### PVT.1.2 Gas Z Factor

The correlation for gas Z factor is from Dranchuk, P. M., Purvis, R. A., and Robinson, D. B., "Computer Calculations of Natural Gas Compressibility Factors Using the Standing and Katz Correlation", Institute of Petroleum Technical Series, No. IP 74-008, 1974.

$$\begin{aligned}
 a &= 0.064225 \\
 b &= 0.535308T_{pr} - 0.612320 \\
 c &= 0.315062T_{pr} - 1.04671 - 0.578327/T_{pr}^2 \\
 d &= T_{pr} \\
 e &= 0.681570/T_{pr}^2 \\
 f &= 0.684465 \\
 g &= 0.27P_{pr} \\
 \rho &= \frac{0.27P_{pr}}{T_{pr}} \quad \text{'Initial guess} \\
 \rho_{old} &= \rho \\
 \text{Iterate on } \rho \text{ until } \text{Abs}((\rho - \rho_{old})/\rho) &< 0.00001 \\
 f_p &= a\rho^6 + b\rho^3 + c\rho^2 + d\rho + e\rho^3(1 + f\rho^2)\exp(-f\rho^2) - g \\
 df_p &= 6a\rho^5 + 3b\rho^2 + 2c\rho + d + e\rho^2(3 + f\rho^2(3 - 2f\rho^2))\exp(-f\rho^2) \\
 \rho &= \frac{\rho - f_p}{df_p} \\
 Z &= \frac{0.27P_{pr}}{\rho T_{pr}} \quad \text{(PVT-6)} \\
 \text{Range of validity: } 1.05 < T_{pr} < 3.0 \\
 0 < P_{pr} < 30
 \end{aligned}$$

### PVT.1.3 Gas Viscosity

The correlation for gas viscosity is from Lee, A. L., Gonzalez, M. H., and Eakin, B. E., "The Viscosity of Natural Gases", Journal of Petroleum Technology, August, 1966.

$$\begin{aligned}
 MW &= 28.97SG \quad \text{(PVT-7)} \\
 a &= \frac{10000 (9.379 + 0.01607MW)(T + 460)^{1.5}}{(209.2 + 19.26MW + (T + 460))} \\
 b &= 3.448 + 986.4 / (T + 460) + 0.01009MW
 \end{aligned}$$

$$c = 2.447 - 0.2224b$$

$$\rho = \frac{P \text{ MW}}{669.8 Z (T + 460)} \quad (\text{PVT-8})$$

$$\mu_g = a \exp(bp^c) \quad (\text{PVT-9})$$

$$\begin{aligned} \text{Range of validity: } & 40 < T < 460 \text{ }^\circ\text{F} \\ & 14.7 < P < 10,000 \text{ psi} \end{aligned}$$

Where:  $\mu_g$  is in centipoise (cp) and P and T are the pressure (psia) and temperature ( $^\circ\text{F}$ ) of interest and SG is gas specific gravity.

### PVT.1.4 Gas Isothermal Compressibility

The correlation for gas isothermal compressibility is from Meehan, D. N., and Lyons, W. K., "Programmable Calculations for Gas Compressibility", Oil and Gas Journal, Oct. 8, 1979.

$$T' = 1 / T_{pr}$$

$$\alpha = 0.06125T' \exp(-1.2(1 - T')^2)$$

$$y = \frac{\alpha P_{pr}}{Z}$$

$$dfdy1 = \frac{1 + 4y + 4y^2 - 4y^3 + y^4}{(1 - y)^4}$$

$$dfdy2 = y(29.52T' - 19.52T'^2 + 9.16T'^3)$$

$$dfdy3 = (2.18 + 2.82T')(90.7T' - 242.2T'^2 + 42.4T'^3)y^{(1.18 + 2.82T')}$$

$$dfdy = dfdy1 - dfdy1 + dfdy1$$

$$dzdp = \frac{\alpha}{P_{pr}} \left( \frac{1}{y} - \frac{\alpha P_{pr}}{y^2 dfdy} \right)$$

$$c_g = \frac{1}{P} - \frac{dzdp}{Z} \quad (\text{PVT-10})$$

$$\begin{aligned} \text{Range of validity: } & 1.05 < T_{pr} < 3.0 \\ & 0 < P_{pr} < 30 \end{aligned}$$

Where:  $c_g$  is in  $\text{psi}^{-1}$  and P is the pressure (psia) of interest.

### PVT.1.5 Gas Formation Volume Factor

When dealing with oil reservoirs the gas formation volume factor is more commonly denoted as  $B_g$  and has the units of rbbl/scf. For gas reservoirs the gas formation volume factor is presented as a gas expansion factor  $E_g$ , or  $1/B_g$ , and has the units scf/rcf ( $5.615/B_g$ ).

$$B_g = \frac{0.15879Z(T + 460)}{P} \quad (\text{PVT-11})$$

Where:  $B_g$  is in rbbl/scf and  $P$  and  $T$  are the pressure (psia) and temperature ( $^{\circ}\text{F}$ ) of interest.

### PVT.1.6 Condensate-Gas Ratio

The following is an empirical technique present by Meehan and Vogel for calculating the CGR behaviour of volumetric gas-condensate reservoirs (Meehan, D. N., and Vogel, E. L, HP-41 Reservoir Engineering Manual, PennWell Books, 1982).

The technique requires the %mole of  $C_{4+}$  and  $C_{5+}$  in the reservoir fluid. If these values are not available, they can be estimated from the surface CGR as follows.

$$R_d = 1000/\text{CGR}$$

$$C_{4+} = 6.547 + 25.52\text{SG}_{\text{res}} + 30.38/R_d + 0.02633R_d - 30.3\text{OilSG} - 0.00417T \quad (\text{PVT-12})$$

$$C_{5+} = -8.53 + 7.83\text{SG}_{\text{res}} + 56.26/R_d + 0.0109R_d + 0.07286\text{API} - 0.00424T \quad (\text{PVT-13})$$

Where: CGR is the surface condensate-gas-ratio (bbls/mmscf) for pressure greater than or equal to the dew point pressure, OilSG is the surface specific gravity of oil ( $141.5/[131.5 + ^{\circ}\text{API}]$ ),  $\text{SG}_{\text{res}}$  is the surface specific gravity of the reservoir gas, and  $T$  is the reservoir temperature in  $^{\circ}\text{F}$ .

If dew point pressure of the gas is unknown, the initial reservoir pressure can be used as an estimate. If a gas composition analysis was performed to estimate dew point pressure, the  $C_{4+}$  and  $C_{5+}$  and dew point pressure from that analysis should be used for the CGR forecast.  $\text{CGR}_p$ , for a given pressure, is forecast as follows.

$$R_d = 1000/\text{CGR}$$

$$\text{R50\%} = \exp[31.49 - 0.0001085P_d - 92.03C_{4+}/T + 110.8C_{5+}/T + 0.0215T + 6.833\text{SG}_{\text{res}} - 26.98/R_d - 6.632\ln(T)]$$

$$\text{Log}(R) = 2(1 - P/P_d) \log(\text{R50\%}/R_d) + \log(R_d)$$

$$\text{CGR}_p = 1000/R \quad (\text{PVT-14})$$

Where: CGR is the surface condensate-gas-ratio (bbls/mmscf) for pressure greater than or equal to the dew point pressure,  $\text{CGR}_p$  is the condensate-gas-ratio in bbls/mmscf at pressure  $P$  (psi),  $P_d$  is dew point pressure in psia,  $\text{SG}_{\text{res}}$  is gas specific gravity and  $T$  is the reservoir temperature in  $^{\circ}\text{F}$ .

When using this technique, a number of points need to be considered:

- For  $P < 0.3P_d$ ,  $R$  should be set to the value at  $P = 0.3P_d$
- For  $P \geq P_d$ ,  $R = R_d$
- If  $R_{50\%} > R_d$ , no retrograde behaviour,  $R = R_d$

When the initial CGR is unknown, a method to predict CGR for any pressure was presented in 2007 (Ovalle, A.P., Lenn, C.P., and McCain Jr, W.D.; "Tools to Manage Gas/Condensate Reservoirs; Novel Fluid-Property Correlations on the Basis of Commonly Available Field Data", SPE112977, SPE Reservoir Evaluation & Engineering, December, 2007).

This method is used in the PVT tool to predict  $CGR_p$ , at, and below, the dew point pressure.

$$CGR_p = 3.684 + 0.61967 Z_t + 0.015359 Z_t^2 \quad (PVT-15)$$

$$Z_1 = 20.809 - 6.7095 \ln(P) + 0.5136 (\ln(P))^2$$

$$Z_2 = 11.175 - 1.2965 API + 0.042311 API^2 - 0.0005438 API^3 + 2.4889e-6 API^4$$

$$Z_3 = -13.365 + 27.652 SG_{res} - 18.598 SG_{res}^2 + 4.3658 SG_{res}^3$$

$$Z_4 = -1.5309 + 0.0058453 T + 1.4035e-6 T^2$$

$$Z_t = Z_1 + Z_2 + Z_3 + Z_4$$

Where:  $CGR_p$  is the condensate-gas-ratio in bbls/mmscf at pressure  $P$  (psi),  $Z$  are the correlation parameter equations,  $SG_{res}$  is gas specific gravity and  $T$  is the reservoir temperature in °F.

### PVT.1.7 Hydrate Formation Temperature

Gas hydrates are a recurring problem in the gas industry since they can plug tubing, production, and transmission lines. Numerous empirical correlations are available to predict the hydrate forming temperature at various pressures. The most accurate correlation appears to be Omole et al correlation published in 2009 (Omole, O., Falode, O.A., and Arinkoola, A.O.; Development of empirical correlations for predicting formation of gas hydrate, International Journal Oil, Gas and Coal Technology, Vol. 2, No. 1, 2009). This correlation is like other correlations but includes the water vapour pressure which appears to enhance the accuracy of the correlation.

The first component of the correlation is the generation of the water vapour pressure for the given reservoir temperature. The Buck correlation (Bokmal.; "New equations for computing vapor pressure and enhancement factor", Journal of Applied Meteorology, 20: 1527–1532) appears to generate accurate values over the highest range of temperatures. It is presented as Equation PVT-16.

$$P_w = 0.088648 [\exp(18.678 - 0.004264 T_c) (T_c / (257.14 + T_c))] \quad (PVT-16)$$

Where:  $P_w$  is the water vapour pressure in psi and  $T_c$  is the reservoir temperature in °C.

The hydrate temperature,  $T_h$  in °F, at pressure  $P$  (psi) is estimated from Equation PVT-17.

$$T_h = C1 + C2 \log(P) + C3 (\log(SG))^2 + C4 SG \log(P_w) + C5 SG P_{vw}^2 + C6 SG^2 (\log(P))^2$$

$$+ C7 SG^3 \log(P) + C8 SG^4 \log(P) + C9 (\log(P))^3 P_{vw}^3 \quad (PVT-17)$$

$$C1 = 37.42042$$

$$C2 = 8.920842$$

$$C3 = -43.1429$$

$$C4 = 22.62722$$

$$C5 = 143.7678$$

$$C6 = -1.90037$$

$$C7 = 12.98294$$

$$C8 = -2.86029$$

$$C9 = -0.07458$$

### PVT.1.8 Converting SG to Recombined Reservoir Specific Gravity

In most circumstances, only wellhead/separator gas SG is available. If condensate volume is also available, the surface SG can be converted to reservoir condition (recombined) SG using the following equation (Craft, B. C., and Hawkins, M.F., Applied Petroleum Reservoir Engineering, Prentice Hall, Inc. 1959).

$$Mo = 5954/({}^\circ\text{API} - 8.8) \quad (PVT-18)$$

$$\text{OilSG} = 141.5/(131.5 + {}^\circ\text{API}) \quad (PVT-19)$$

$$Rs = 1000000/\text{CGR} \quad (PVT-20)$$

$$\text{SG}_{\text{res}} = \frac{Rs \text{ SG} + 4600 \text{ OilSG}}{Rs + 133300(\text{OilSG}/Mo)} \quad (PVT-21)$$

Where: CGR is condensate-gas-ratio in bbls/mmcsf, API is stock tank condensate gravity, SG is surface gas gravity and  $\text{SG}_{\text{res}}$  is reservoir gas gravity.

## PVT.2 Gas Component Generation and Analysis

The PE<sup>2</sup> Essentials PVT tool includes the capability of generating pseudo components for oil and gas fluids. The gas components are used to generate raw versus sales gas properties and the pseudo oil components can be input to the EOS tool for further analysis. Components can be manually entered or generated by the tool.

After completion of the component analysis, the final components can be saved to the PE Tools Database for use in other tools.

### PVT.2.1 Gas Pseudo Component Generation

When analysing gas fields, it may be necessary to predict shrinkage in order to determine sales gas volumes. Shrinkage of the raw gas occurs as the heavier components of the gas become liquid. The gas specific gravity (SG) measured at surface will always be lower than the value of



specific gravity in the reservoir. Since gas properties are a function of SG, without a bottomhole sample it will be necessary to estimate reservoir gas SG based on the value measured at surface. To do this, the PVT tool includes an option to work with gas components (Figure PVT-6).

The gas component generation tool is accessed through the 'Generate Pseudo Gas Composition' button. When the button is clicked, the input gas SG is converted to a pseudo composition and the gas components table is populate. Entering '0' for the seed allows manual entry of the components. The raw gas component values can then be changed until the desired sales gas SG is obtained. Calculations will not be performed until the sum of the components equals 100%.

**Pseudo Gas Components**

**Parameters**  
 Gas Gravity: 0.7    Seed: 0    **Seed Info**

**Dew Pt Calculation**  
☒ Model 1    ☐ Model 2  
☐ Model 3

**Generate Composition**

H2S - mol%	0
CO2 - mol%	0.1
N2 - mol%	0
C1 - mol%	95.22
C2 - mol%	1.68
C3 - mol%	0.91
iC4 - mol%	0.26
nC4 - mol%	0.33
iC5 - mol%	0.16
nC5 - mol%	0.11
C6 - mol%	0.25
C7Plus - mol%	0.98
Σ Comps	100
C7Plus MW	122.6
C7Plus SG	0.772
Calc'd SG	0.772

**Sales Streams**

	Gas	Liquid
	0	0
	0.1	0
	96.75	0
	1.71	0
	0.92	0
	0.2	4.12
	0.25	5.23
	0.04	7.6
	0.03	5.23
	0	15.76
	0	62.07
	100	100

**Calculated Properties**

Gas MW	18.16
Raw Gas G	0.6271
Gas Pc (psi)	663.2
Gas Tc (°R)	362.1
Sales Gas G	0.5793
GHV (btu/scf)	1048
Shrinkage (%)	1.4
Propane-C3 (bbls/mmcsf)	0
Butane-C4 (bbls/mmcsf)	1.12
CGR-C5+ (bbls/mmcsf)	15.9
Liquid Density (°API)	61.6
Dew Point Pressure (psi)	3167.5

**Buttons:** Calculate Properties, Transfer Gas Parameters, Capture Screen, Save to PE Tools dB, Return

Figure PVT-6: Gas Composition Analysis

The technique used to generate the pseudo gas components is an EPCI-developed technique and is based on the assumption that the gas gravity predominately determines the  $C_1$  value which in turn determines the  $C_2$  to  $C_{7+}$  values as follows:

$$C_1 = (1.6254 - \text{GasG}) / 0.010783 \quad (\text{PVT-22})$$

$$C_2 \text{ to } C_{7+} = (96.7271 - C_1) + (3.27299 - (\text{H}_2\text{S} + \text{N}_2 + \text{CO}_2)) \quad (\text{PVT-23})$$



The individual  $C_2$  through  $C_6$  values are determined through random sampling and the  $C_{7+}$  value is modified to ensure the sum equals 100%. The  $C_{7+}$  molecular weight is defaulted to 150.

If the Seed is set to -1, new components will be generated every time the 'Generate Gas Composition' button is clicked. It is possible to click the button until a desired sample is generated. To fix the composition, copy the 'Equiv Seed' to the Seed box. To manually enter component values, enter 0 in the Seed box.

The equations in the following sections use the relevant property values from Table PVT-1 (GPA Midstream Standard 2145-16, Table of Physical Properties for Hydrocarbons and Other Compounds of Interest to the Natural Gas and Natural Gas Liquids Industries, 2017) to generate the gas properties based on the generated pseudo components.

Comp	Mol Wt	Tc (°R)	Pc (psia)	SG (liquid)	SG (gas)	GHV BTU/scf	GHV MJ/m <sup>3</sup>
H <sub>2</sub> S	34.08	671.58	1305.3	0.7989	1.1767	637.1	23.9
N <sub>2</sub>	44.01	227.14	492.5	0.8069	0.9672	-	-
CO <sub>2</sub>	28.01	547.43	1070.0	0.8172	1.5195	-	-
CH <sub>4</sub>	16.04	343.01	667.1	0.3000	0.5539	1010.0	38.0
C <sub>2</sub> H <sub>6</sub>	30.07	549.58	706.7	0.3563	1.0382	1769.7	66.0
C <sub>3</sub> H <sub>8</sub>	44.10	665.80	616.6	0.5072	1.5225	2516.1	94.0
iC <sub>4</sub> H <sub>10</sub>	58.12	734.06	526.3	0.5628	2.0068	3251.9	121.8
nC <sub>4</sub> H <sub>10</sub>	58.12	765.23	550.6	0.5842	2.0068	3262.3	121.4
iC <sub>5</sub> H <sub>12</sub>	72.15	828.63	489.9	0.6251	2.4911	4000.9	149.7
nC <sub>5</sub> H <sub>12</sub>	72.15	845.46	488.8	0.6307	2.4911	4008.7	149.3
C <sub>6</sub> H <sub>14</sub>	86.18	913.47	436.9	0.6641	2.9754	4755.9	177.6
C <sub>7</sub> H <sub>16</sub>	100.20	972.23	396.8	0.6882	3.4597	5502.6	205.4

Table PVT-1: Gas Physical Constants (GPA 2017)

A missing value in the table is the SG for the  $C_{7+}$  component. This value can be estimated from the input  $C_{7+}$  molecular weight based on a derived MW-SG correlation. The MW-SG correlation was derived from a plot of molecular weight versus SG for components  $C_3$  to  $C_{30}$ .

A plot of the MW-SG data is shown in Figure PVT-7. The data was fitted to a 6<sup>th</sup> order polynomial with a resulting  $R^2$  of 0.9985. The plot includes additional laboratory examples to validate the correlation. To implement this calculation, enter 0 for 'C7Plus SG'.

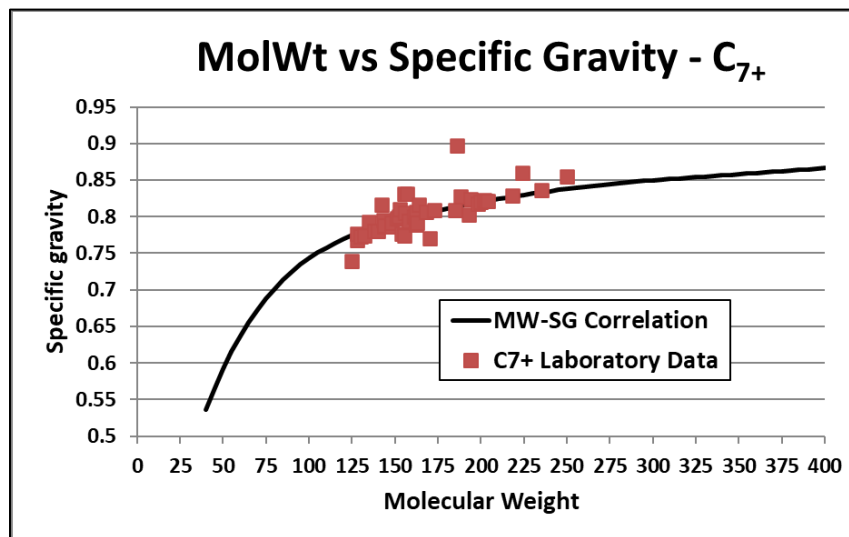


Figure PVT-7: Molecular Weight versus Specific Gravity

The resulting correlation (Equation PVT-12) can be used to estimate SG for the  $C_{7+}$  MW.

$$SG_{C_{7+}} = aMW^6 + bMW^5 + cMW^4 + dMW^3 + eMW^2 + fMW + g \quad (\text{PVT-24})$$

$$a = -1.6884 \times 10^{-15}$$

$$b = 2.7757 \times 10^{-12}$$

$$c = -1.8574 \times 10^{-9}$$

$$d = 6.4967 \times 10^{-7}$$

$$e = -0.00012678$$

$$f = 0.013644$$

$$g = 0.15658$$

The specific gravity for the combined  $C_5$ ,  $C_6$  and  $C_{7+}$  components are used to calculate the API value for the condensate.

For analysis of real fluids, components higher than  $C_7$  are “lumped” together and reported as  $C_{7+}$ . To use the  $C_{7+}$  component in analysis, it is necessary to determine the equivalent properties of  $T_c$ ,  $P_c$ , true boiling point ( $T_b$ ), and acentric factor ( $\omega$ ) for the lumped component. The  $T_c$ ,  $P_c$  and  $T_b$  parameters are calculated using the correlations developed by Riazi and Daubert and  $\omega$  is calculated using the Edmister correlation. The development of these correlations is presented in the book “Characterization and Properties of Petroleum Fractions”, M.R.Riazi, ASTM International, 2005; Pages 48-49 and 65.

The general equation for calculating  $T_c$ ,  $P_c$  and  $T_b$  is as follows:

$$\text{Parameter} = a * MW^b * SG^c * \exp(d * M + e * SG + f * M * SG) \quad (\text{PVT-25})$$

Where Parameter is  $T_c$  ( $^{\circ}\text{R}$ ),  $P_c$  (psi), or  $T_b$  ( $^{\circ}\text{R}$ ); MW is the molecular weight of the  $C_{7+}$  component; SG is the specific gravity of the  $C_{7+}$  component; and a, b, c, d, e, f are constants that are dependent on the chosen parameter and are presented in Figure PVT-8.

Parameter	a	b	c	d	e	f
Tc	554.4	0.2998	1.055	-0.00013478	-0.61641	0
Pc	45203.01	-0.8063	1.6015	-0.0018078	-0.3084	0
Tb	6.77857	0.40167	-1.58262	0.00377409	2.984036	-0.00425288

Figure PVT-8: Riazi and Daubert Correlation Coefficients

The following equation is used to calculate  $\omega$  for the  $C_{7+}$  component.

$$\omega = 0.42857 * Tb/Tc / (1-Tb/Tc) * \log_{10}(P_c / 14.696) - 1 \quad (\text{PVT-26})$$

Where Tc (°R), Pc (psi), and Tb (°R) are the parameters for the  $C_{7+}$  component

## PVT.2.2 Gas Shrinkage Factor

The gas component generation tool performs a Joule-Thompson (J-T) separation of the raw gas stream to calculate the shrinkage factor. For the J-T process, it is assumed that 25% of  $C_3$ , 50% of  $C_4$  and 99.5% of  $C_{5+}$  will be recovered as liquid. The  $C_{5+}$  is termed condensate. It should be noted that if a “deep cut” process is being used, then the  $C_3$  and  $C_4$  recovery factors used in this calculation will be too low.

The raw-to-sales gas shrinkage factor is calculated as follows.

$$C3Rec=0.25$$

$$C4Rec=0.5$$

$$C5Rec=0.995$$

$$\text{Shrinkage} = 100 - [C_1 + C_2 + (1 - C3Rec)C_3 + (1 - C4Rec)(iC_4 + nC_4) + (1 - C5Rec)(iC_5 + nC_5 + C_6 + C_{7+})]$$

Where: all component values ( $C_1$ ,  $C_2$ , etc) are in mole percent.

## PVT.2.3 Gas Liquids

Once the raw gas stream has been processed, the sales gas parameters are calculated, and the liquid content of the gas stream is calculated. Note that all component values are in %mole.

The following equations use the data in Table PVT-1 and the calculated SG for the  $C_{7+}$  component to derive the liquid recovery (in gallons per mscf) from the gas stream.

$$C3Liq = 0.003151C_3(C3\_MW/C3\_SG)$$

$$C4Liq = 0.003151[iC_4(iC4\_MW/iC4\_SG) + nC_4(nC4\_MW/nC4\_SG)]$$

$$C5Liq = 0.003151[iC_5(iC5\_MW/iC5\_SG) + nC_5(nC5\_MW/nC5\_SG)]$$

$$C6Liq = 0.003151C_6(C6\_MW/C6\_SG)$$

$$C7plusLiq = 0.003151C_{7+}(C7plus\_MW/SG_{C7+})$$

The liquid recovery (gals/mscf) is then converted to bbls per mmscf.

$$C3Liq(bbls/mmscf) = 1000 C3Rec C3Liq /42 \quad (PVT-27)$$

$$C4Liq(bbls/mmscf) = 1000 C4Rec C4Liq /42 \quad (PVT-28)$$

$$C5+Liq(bbls/mmscf) = 1000 C5Rec(C5Liq + C6Liq + C7plusLiq)/42 \quad (PVT-29)$$

Where: all component values ( $C_3$ ,  $iC_4$ , etc) are in mole percent.

### PVT.2.4 Gas GHV

The Gross Heating Value (GHV) for the sales gas is a direct summation of the %mole of the component multiplied by the corresponding component heating value from Table PVT-1.

$$GHV = \sum_{i=0}^n \frac{(\%mole(i) * GHV(i))}{100} \quad (PVT-30)$$

Where: i represents  $C_1$  to  $C_7$  of the sales gas. The GHV for  $C_{7+}$  is irrelevant since the %mole of the  $C_{7+}$  component in the sales gas is zero.

### PVT.2.5 Gas Dew Point Pressure

Some gas reservoirs have initial temperature and pressure conditions that result in what is termed as retrograde condensate reservoirs, sometimes called dew point reservoirs. Initially the fluid in the reservoir is a single-phase gas but as the pressure reduces, the pressure falls below the dew point and liquid condenses in the reservoir. The initial condensate that forms is comprised of the denser components of the gas and the result is that the producing condensate-gas-ratio (CGR) decreases. This will also have an effect on the production characteristics of the well as the relative permeability to gas in the area of the wellbore is reduced because of the liquid in the pores. A condensate “bank” may also form, further impacting gas rate.

When obtaining bottomhole samples of gas for analysis, the pressure should be above the dew point pressure to ensure that a representative sample is obtained. To confirm that the sample is representative of the reservoir fluid, the dew point pressure of the sample is determined. If estimated dew point pressure is above or similar to the sampling pressure, the sample may not be representative.

Dew point pressure can be calculated using one of three models or the average of all three models.

Model 1 was developed by Ahmadi and Elsharkway (Ahmadi,A.A; Elsharkway, A., “Robust correlation to predict dew point pressure of gas condensate reservoirs”, Southwest Petroleum University, KeAi Communications Co Ltd, 2016).

$$P_d = -888.278 - 3.60639 x_{C1} T + 0.00785623 T^2 + 1467.87 x_{C1} + 0.989073 c \quad (\text{PVT-31a})$$

$$a = 29014 - 52127.9 x_{C1} + 79848.3 x_{C1} SG_{C7+}^3 + 12633.6 x_{C1} x_{C7}^{1/3} + 11116.5 x_{C1}^2 \\ - 58526.6 SG_{C7+}^3 + 58263.6 x_{C7}^{1/3} SG_{C7+}^3 - 43792.7 x_{C7}^{2/3}$$

$$b = -6991.4 + 0.00165952 MW_{C7+}^3 - 0.00122815 x_{C7}^{1/3} MW_{C7+}^3 - 5.7182 \times 10^{-11} MW_{C7+}^6 \\ - 79241 x_{C4}^{1/3} x_{C7}^{1/3} + 31517.4 x_{C4}^{2/3} + 50917.8 x_{C7}^{1/3} - 31614.2 x_{C7}^{2/3}$$

$$c = 140.909 - 0.484983 b x_{N2}^{1/3} + 0.576219 a x_{N2}^{1/3} + 1746.2 x_{N2}^{2/3} + 0.290811 b \\ + 3.33869 \times 10^{-5} b^2 + 0.484502 a$$

Where:  $P_d$  is the dew point pressure in psia,  $T$  is temperature in °F,  $SG_{C7+}$  is the specific gravity of the  $C_{7+}$  component,  $MW_{C7+}$  is the molecular weight of  $C_{7+}$  component and all component values ( $x_{C1}$ ,  $x_{C2}$ , etc) are in decimal mole.

Model 2 was presented by Aghamiri, Tamtaji and Ghafoori (Aghamiri,S.; Tamtaji,M.; and Ghafoori,M.J., “Developing a K-value equation for predict [sic] dew point pressure of gas condensate reservoirs at high pressure”, KeAi Communications Co Ltd, 2018).

$$P_d = P_k^{((1+2*\beta)/(1+3*\beta))} / \text{Denom}^{(1/(1+3*\beta))} \quad (\text{PVT-31b})$$

$$P_k = -2381.8542 + 46.341487 * M_{SG} + 6124.3049 * M_{SG}/T - 2753.2538 * (M_{SG}/T)^2 + \\ 415.42049 * (M_{SG}/T)^3$$

$$M_{SG} = MW_{C7+} SG_{C7+}$$

$$\beta = (T_{b\_mix}/T)^{(T/T_{c\_mix})}$$

$$T_{b\_mix} = \sum_i [T_{b_i}]$$

$$T_{c\_mix} = \sum_i [T_{c_i}]$$

$$\text{Denom} = \sum_i [ (0.01 * X_i) / (P_{c_i}^{\beta} * \exp(5.37 * \beta * (1 + \omega_i)) * (1 - T_{c_i}/T)) ]$$

Where the subscript  $i$  denotes the different components,  $X_i$  is in mole%;  $T$ ,  $T_c$  and  $T_b$  are in °R; and  $P_c$  and  $P_d$  are in psi

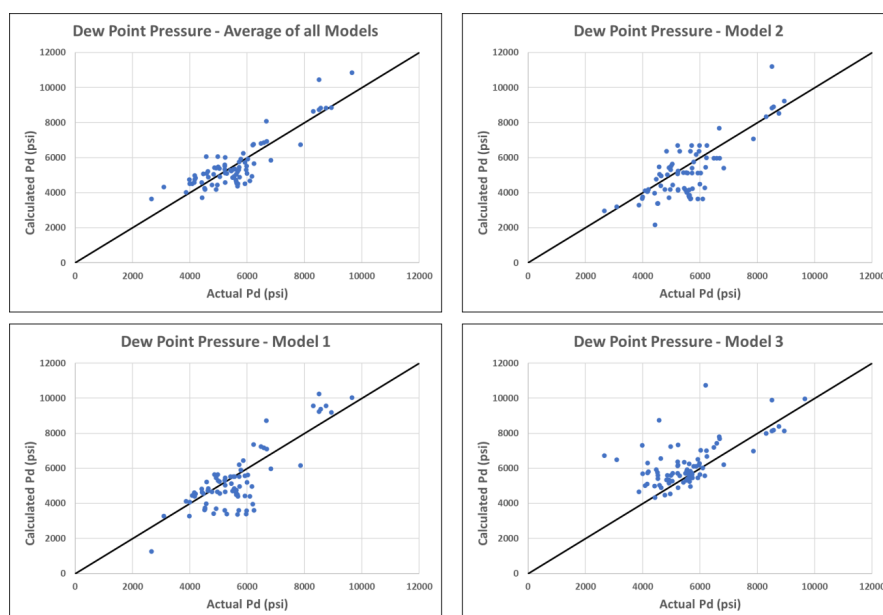
Model 3 was developed by Elsharkway (Elsharkway, A.M., “Predicting the dew point pressure for gas condensate reservoirs: empirical models and equations of state”, Kuwait University, 2001).

$$P_d = a_0 + a_1 + a_2 + a_3 + a_4 + a_5 + a_6 + a_7 + a_8 + a_9 + a_{10} + a_{11} \\ + a_{12} + a_{13} + a_{14} + a_{15} + a_{16} + a_{17} + a_{18} \quad (\text{PVT-31c})$$

$$\begin{aligned}
 a_0 &= 4268.85 \\
 a_1 &= 0.094056 T \\
 a_2 &= -7157.87 x_{H_2S} \\
 a_3 &= -4540.58 x_{CO_2} \\
 a_4 &= -4663.55 x_{N_2} \\
 a_5 &= -1357.56 x_{C_1} \\
 a_6 &= -7776.10 x_{C_2} \\
 a_7 &= -9967.99 x_{C_3} \\
 a_8 &= -4257.10 x_{C_4} \\
 a_9 &= -1417.10 x_{C_5} \\
 a_{10} &= 691.5298 x_{C_6} \\
 a_{11} &= 40660.36 x_{C_7} \\
 a_{12} &= 205.26 MW_{C_7+} \\
 a_{13} &= -7260.32 SG_{C_7+} \\
 a_{14} &= -352.413 x_{C_7} MW_{C_7+} \\
 a_{15} &= -114.519 MW_{C_7+}/SG_{C_7+} \\
 a_{16} &= 8.133 x_{C_7} MW_{C_7+}/SG_{C_7+} \\
 a_{17} &= 94.916 x_{C_7}/(x_{C_1}+x_{C_2}) \\
 a_{18} &= 238.252 x_{C_7}/(x_{C_2}+x_{C_3}+x_{C_4}+x_{C_5}+x_{C_6})
 \end{aligned}$$

Where: Pd is the dew point pressure in psia, T is temperature in °F,  $SG_{C_7+}$  is the specific gravity of the  $C_{7+}$  component,  $MW_{C_7+}$  is the molecular weight of  $C_{7+}$  component and all component values ( $x_{C_1}$ ,  $x_{C_2}$ , etc) are in decimal mole.

The following graphs show the comparison of each model to 81 actual dew point pressures presented in the Aghamiri, Tamtaji and Ghafoori reference as well as the results from averaging the correlations.



## PVT.3 Oil Properties

A number of standard correlations are available for generating oil properties (Figure PVT-9). All correlations require oil density, gas gravity, reservoir pressure and reservoir temperature and either gas-oil-ratio or bubble point pressure as input.

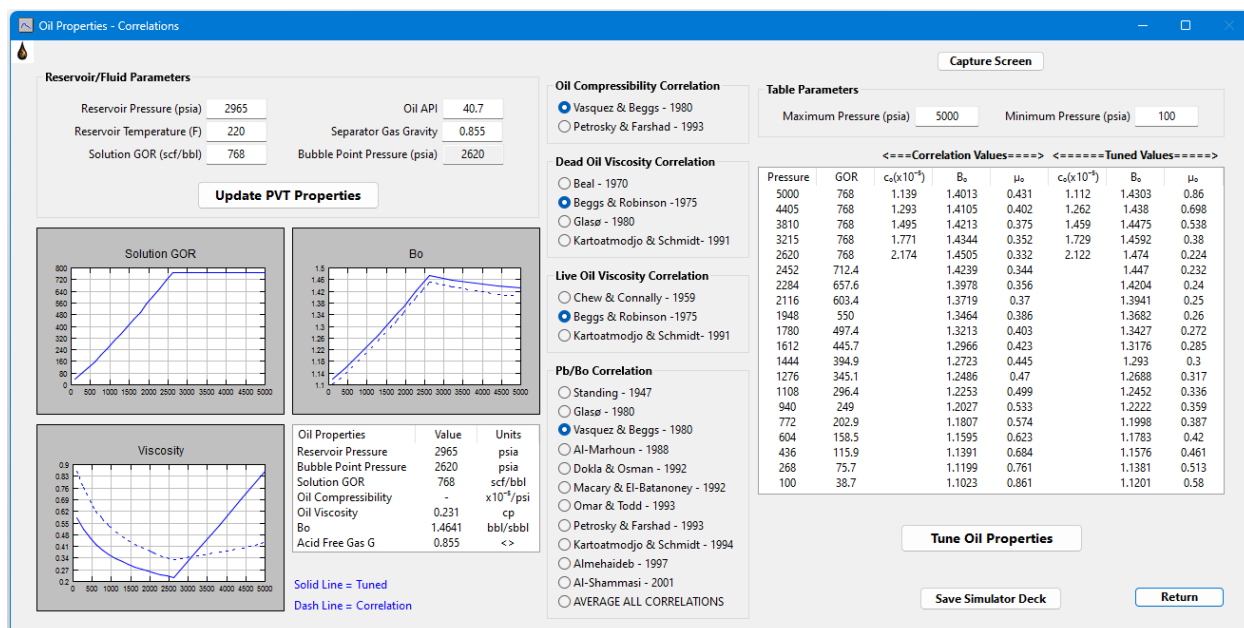


Figure PVT-9: Oil PVT Properties

Once the PVT properties are generated, a simulator input file can be saved by clicking the 'Save Simulator Deck' button.

### PVT.3.1 Oil $B_o$ and $P_b$ Correlations

The bubble point pressure ( $P_b$ ) and oil formation volume factor correlations ( $B_o$ ), as well as their validity ranges, available in the PVT tool are listed in Table PVT-2.

$B_{ob}$ and $P_b$ Correlation	$B_{ob}$ Range		$P_b$ Range		Temp Range		$R_s$ Range		API Range		GasG Range	
	Low	High	Low	High	Low	High	Low	High	Low	High	Low	High
Standing (1947)	1.024	2.150	130	7000	100	258	20	1425	16.5	63.8	0.590	0.950
Vasquez and Beggs (1980)	1.028	2.226	15	6055	75	294	0	2199	15.3	59.3	0.511	1.350
Glasø (1980)	1.032	2.588	165	7142	80	280	90	2637	22.3	48.1	0.650	1.280
Al-Marhoun (1988)	1.032	1.997	20	3573	74	240	26	1602	19.4	44.6	0.750	1.370
Abdul-Majeed and Salman (1988)	1.028	2.042			75	290	0	1664	9.5	59.5	0.510	1.350
Dokla and Osman (1992)	1.216	2.493	590	4640	190	275	181	2266	28.2	40.3	0.800	1.290
Lasater (1992)			48	5780	82	272	3	2905	17.9	51.1	0.570	1.200
Macary and El-Batanoney (1992)	1.200	2.000	1200	4600	130	290	200	1200	25.0	40.0	0.700	1.000
Petrosky and Farshad (1993)	1.118	1.623	1574	6523	114	288	217	1406	16.3	45.0	0.580	0.850
Omar and Todd (1993)	1.085	1.954	790	3851	125	280	142	1440	26.6	53.2	0.612	1.320
Kartoatmodjo and Schmidt (1994)	1.007	2.144	15	6055	75	320	0	2890	14.4	58.9	0.380	1.710
Almehaideb (1997)	1.142	3.562	501	4822	190	306	128	3871	30.9	48.6	0.750	1.120
Al-Shammasi (2001)	1.020	2.916	32	7127	74	342	6	3299	6.0	63.7	0.510	3.440

Table PVT-2: Available  $B_{ob}$  and  $P_b$  Correlations and Validity Ranges

Table PVT-3 presents the  $B_o$  equation for each correlation and Table PVT-4 presents the corresponding coefficients for the equations.

$B_o$ Correlation	$B_o$ Correlation Equation
Standing	$a_1 + a_2 * (RS * (GasG / SGoil) ^ a_3 + a_4 * t) ^ a_5$
Vasquez and Beggs	$1 + a_1 * RS + a_2 * (t - 60) * (OilAPI / GasG) + a_3 * RS * (t - 60) * (OilAPI / GasG)$
Glasø	$1 + 10 ^ {(a_1 + a_2 * LOG(RS * (GasG / SGoil) ^ a_3 + a_5 * t) / LOG(10)) - a_3 * (LOG(RS * (GasG / SGoil) ^ a_4 + a_5 * t) / LOG(10)) ^ 2}$
Al-Marhoun	$a_1 + a_2 * (t + 460) + a_3 * (RS ^ a_5 * GasG ^ a_6 * SGoil ^ a_7) + a_4 * (RS ^ a_5 * GasG ^ a_6 * SGoil ^ a_7) ^ 2$
Dokla and Osman	$a_1 + a_2 * (t + 460) + a_3 * (RS ^ a_5 * GasG ^ a_6 * SGoil ^ a_7) + a_4 * (RS ^ a_5 * GasG ^ a_6 * SGoil ^ a_7) ^ 2$
Petrosky and Farshad	$a_1 + a_2 * (RS ^ a_3 * (GasG ^ a_4 / SGoil ^ a_5) + a_6 * t ^ a_7) ^ a_8$
Omar and Todd	$a_1 + a_2 * (RS * (GasG / SGoil) ^ a_3 + a_4 * t) ^ {(a_6 + a_7 * (OilAPI / GasG) + a_8 * GasG)}$
Almehaideb	$a_1 + a_2 * RS * t / SGoil ^ 2$
Macary and El-Batanoney	$(a_1 + a_2 * t) * EXP(a_3 * RS + a_4 * (SGoil / GasG))$
Kartoatmodjo and Schmidt	$a_1 + a_2 * (RS ^ a_3 * GasG ^ a_4 / SGoil ^ a_5 + a_6 * t) ^ a_7$
Al-Shammasi	$1 + a_1 * (RS * (t - 60)) + a_2 * (RS / SGoil) + a_3 * ((t - 60) / SGoil) + a_4 * (RS * GasG / SGoil)$

Table PVT-3:  $B_o$  Correlation Equations

$B_o$ Correlation	$a_1$	$a_2$	$a_3$	$a_4$	$a_5$	$a_6$	$a_7$	$a_8$
Standing	0.972	0.0001472	0.5	1.25	1.175			
Vasquez and Beggs (<30 API)	0.0004677	0.00001751	-1.8106E-08					
Vasquez and Beggs (>30 API)	0.000467	0.000011	1.337E-09					
Glasø	-6.58511	2.91329	0.27683	0.526	0.968			
Al-Marhoun 1	0.497069	0.00086296	0.00182594	3.181E-06	0.74239	0.323294	-1.20204	
Dokla and Osman	0.0431935	0.00156667	0.00139775	3.8053E-06	0.773572	0.40402	-0.882605	
Petrosky and Farshad	1.0113	7.2046E-05	0.3738	0.2914	0.6265	0.24626	0.5371	3.0936
Omar and Todd	0.972	0.0001472	0.5	1.25	1.175	1.1663	0.000762	-0.0399
Almehaideb	1.122018	0.00000141						
Macary and El-Batanoney	1.0031	0.0008	0.0004	0.0006				
Kartoatmodjo and Schmidt	0.98496	0.0001	0.755	0.25	1.5	0.45	1.5	
Al-Shammasi	5.53E-07	0.000181	0.000449	0.000206				

Table PVT-4:  $B_o$  Correlation Equation Parameters

Table PVT-5 presents the  $P_b$  equation for each correlation and Table PVT-6 presents the corresponding coefficients for the equations.

$P_b$ Correlation	$P_b$ Correlation Equation
Standing	$a_1 * ((RS / GasG) ^ a_2 * 10 ^ {(t * a_3 - OilAPI * a_4) - a_5})$
Vasquez and Beggs	$((a_1 * RS / GasG) * 10 ^ {(a_3 * OilAPI / (460 + t)) ^ a_2})$
Glasø	$10 ^ {(a_1 + a_2 * LOG((RS / GasG) ^ a_4 * t ^ a_5 * OilAPI ^ a_6) / LOG(10)) - a_3 * ((LOG((RS / GasG) ^ a_4 * t ^ a_5 * OilAPI ^ a_6) / LOG(10)) ^ 2)}$
Al-Marhoun	$a_1 * RS ^ a_2 * GasG ^ a_3 * SGoil ^ a_4 * (t + 460) ^ a_5$
Dokla and Osman	$a_1 * RS ^ a_2 * GasG ^ a_3 * SGoil ^ a_4 * (t + 460) ^ a_5$
Petrosky and Farshad	$a_1 * ((RS ^ a_2 / GasG ^ a_3) * 10 ^ {(a_5 * t ^ a_6 - a_7 * OilAPI ^ a_8) - a_4})$
Omar and Todd	$a_{10} * ((RS / GasG) ^ {(a_1 + a_2 * Bo + a_3 * GasG + a_4 * Bo ^ 2 + a_5 * GasG ^ 2 + a_6 / (Bo * GasG))} * 10 ^ {(t * a_7 - OilAPI * a_8) - a_9})$
Almehaideb	$a_1 + a_2 * RS * SGoil / (GasG * Bo ^ a_3) + a_4 * t$
Macary and El-Batanoney	$a_1 * (EXP(a_4 * t - a_5 * OilAPI - a_6 * GasG)) * (RS ^ a_2 - a_3)$
Kartoatmodjo and Schmidt	$(RS / (a_1 * GasG ^ a_2 * 10 ^ {(a_3 * OilAPI / (460 + t))}) ^ a_4$
Al-Shammasi	$SGoil ^ a_1 * EXP(a_2 * SGoil * GasG) * (RS * (460 + t) * GasG) ^ a_3$

Table PVT-5:  $P_b$  Correlation Equations



P <sub>b</sub> Correlation	a <sub>1</sub>	a <sub>2</sub>	a <sub>3</sub>	a <sub>4</sub>	a <sub>5</sub>	a <sub>6</sub>	a <sub>7</sub>	a <sub>8</sub>	a <sub>9</sub>	a <sub>10</sub>
Standing	18.2	0.83	0.00091	0.0125	1.4					
Vasquez and Beggs (<30 API)	27.64	0.914328	11.172							
Vasquez and Beggs (>30 API)	56.18	0.84246	10.393							
Glasø	1.7669	1.7447	0.30218	0.816	0.172	-0.989				
Al-Marhoun	0.0053809	0.715082	-1.87784	3.14437	1.32657					
Dokla and Osman	8363.86	0.724047	-1.01049	0.107991	-0.952584					
Petrosky and Farshad	112.727	0.5774	0.8439	12.34	0.00004561	1.3911	0.0007916	1.541		
Omar and Todd	1.4256	-0.2608	-0.4596	0.04481	0.236	-0.1077	0.00091	0.0125	1.4	18.2
Almehaideb	-620.592	6.23087	1.38559	2.89868						
Macary and El-Batanoney	204.257	0.51	4.7927	0.00077	0.0097	0.4003				
Kartoatmodjo and Schmidt (<30 API)	0.05958	0.7972	13.1405	0.9986						
Kartoatmodjo and Schmidt (>30 API)	0.0315	0.7587	11.2895	0.9143						
Al-Shammasi	5.527215	-1.841408	0.783716							

Table PVT-6: P<sub>b</sub> Correlation Equation Parameters

Where: P<sub>b</sub> is bubble point pressure (psi), RS is the solution gas-oil ratio (scf/bbl), GasG is gas specific gravity, OilAPI is oil gravity (°API), t is temperature (°F), SGOil is specific gravity of oil, B<sub>o</sub> is oil formation volume factor at the bubble point.

### PVT.3.2 Oil Viscosity Correlations

The viscosity ( $\mu_{obp}$ ) correlations for oil at the bubble point, as well as their validity ranges, which are available in the PVT tool are listed in Table PVT-7.

$\mu_{obp}$ Correlation	$\mu_{o-dead}$ Range		Temp Range		R <sub>s</sub> Range		P <sub>b</sub> Range		API Range	
	Low	High	Low	High	Low	High	Low	High	Low	High
Chew & Connally (1959)	0.377	50	72	292	51	3544	132	5645		
Beggs & Robinson (1975)			70	295	20	2070	132	5265	16.0	58.0
Kartoatmodjo & Schmidt (1991)	0.506	682	80	320	0	2890	24.7	4765	14.4	59.0

Table PVT-7: Available  $\mu_{obp}$  Correlations and Validity Ranges

Table PVT-8 presents the  $\mu_{obp}$  equation for each correlation and Table PVT-9 presents the corresponding coefficients for the equations.

$\mu_{obp}$ Correlation	$\mu_{obp}$ Correlation Equation
Chew & Connally	$(10^{(RS * (a_1 * RS - a_2))} * uod^{(a_6 / (10^{(a_3 * RS)} + a_7 / (10^{(a_4 * RS)} + a_8 / (10^{(a_5 * RS)})))))$
Beggs & Robinson	$a_1 * (RS + a_5)^{a_2} * uod^{(a_3 * (RS + a_6)^{a_4})}$
Kartoatmodjo & Schmidt	$a_1 + a_2 * f + a_3 * f^2 / f = (0.2001 + a_6 * 10^{(a_4 * RS)}) * uod^{(0.43 + a_7 * 10^{(a_5 * RS)})}$

Table PVT-8:  $\mu_{obp}$  Correlation Equations

$\mu_{obp}$ Correlation	a <sub>1</sub>	a <sub>2</sub>	a <sub>3</sub>	a <sub>4</sub>	a <sub>5</sub>	a <sub>6</sub>	a <sub>7</sub>	a <sub>8</sub>
Chew & Connally	2.2E-07	0.00074	8.62E-05	0.0011	0.00374	0.68	0.25	0.062
Beggs & Robinson	10.715	-0.515	5.44	-0.338	100	150		
Kartoatmodjo & Schmidt	-0.0682	0.9824	0.0004043	-0.000845	-0.00081	0.8428	0.51656	

Table PVT-9:  $\mu_{obp}$  Correlation Equation Parameters

Table PVT-10 presents the dead oil viscosity,  $\mu_{od}$ , equation for the correlations which are available in the PVT tool and Table PVT-11 presents the corresponding coefficients for the equations.

$\mu_{od}$ Correlation	$\mu_{od}$ Correlation Equation
Beal	$(a_1 + a_2 / \text{OilAPI}^{a_3}) * (a_4 / (t + a_5))^{(10^{a_6 + a_7 / \text{OilAPI}})}$
Beggs & Robinson	$10^{((10^{a_1 + a_2 * \text{OilAPI}}) * t^{a_3}) - 1}$
Glasø / Kartoatmodjo & Schmidt	$a_1 * t^{a_2} * (\text{LOG}(\text{OilAPI}) / \text{LOG}(10))^{(a_3 * \text{LOG}(t) / \text{LOG}(10) + a_4)}$

 Table PVT-10:  $\mu_{od}$  Correlation Equations

$\mu_{od}$ Correlation	$a_1$	$a_2$	$a_3$	$a_4$	$a_5$	$a_6$	$a_7$
Beal	0.32	18000000	4.53	360	200	0.43	8.33
Beggs & Robinson	3.0324	-0.02023	-1.163				
Glasø	3.14E+10	-3.444	10.313	-36.447			
Kartoatmodjo & Schmidt	1.6E+09	-2.8177	5.7526	-26.9718			

 Table PVT-11:  $\mu_{od}$  Correlation Equation Parameters

Table PVT-12 presents the live oil viscosity,  $\mu_{oi}$ , equation – for  $P > P_b$  – for the correlation which is included in the PVT tool and Table PVT-13 presents the corresponding coefficients for the equations.

$\mu_{oi}$ Correlation	$\mu_{oi}$ Correlation Equation ( $P > P_b$ )
Vasquez and Beggs	$u_{obp} * (P / P_b)^{(a_1 * (P^{a_2}) * (10^{(a_3 * P) + a_4}))}$
Kartoatmodjo & Schmidt	$a_1 * u_{obp} + a_2 * (P - P_b) * (a_3 * u_{obp}^{a_4} + a_5 * u_{obp}^{a_6})$

 Table PVT-12:  $\mu_{oi}$  Correlation Equations

$\mu_{oi}$ Correlation ( $P > P_b$ )	$a_1$	$a_2$	$a_3$	$a_4$	$a_5$	$a_6$
Vasquez and Beggs	2.6	1.187	-9E-05	-11.513		
Kartoatmodjo & Schmidt	1.00081	0.001127	-0.00652	1.8148	0.038	1.59

 Table PVT-13:  $\mu_{oi}$  Correlation Equation Parameters

Where:  $P$  is the pressure (psi),  $P_b$  is bubble point pressure (psi),  $RS$  is the solution gas-oil ratio (scf/bbl),  $\text{OilAPI}$  is oil gravity ( $^\circ\text{API}$ ),  $t$  is temperature ( $^\circ\text{F}$ ).

### PVT.3.3 Gas Gravity Correction for Separator Conditions

Oil property correlations assume that the surface gas specific gravity value is referenced to a separator pressure of 114.7 psia and temperature of 60°F. If actual separator conditions are different, the gas specific gravity can be corrected using the following equation.

$$SG = SG_{sep} [1 + 5.912 \times 10^{-5} \text{API SepT Log}(\text{SepP}/114.7)] \quad (\text{PVT-32})$$

$$\begin{aligned} \text{Range of validity: } & 76 < \text{SepT} < 150 \text{ } ^\circ\text{F} \\ & 30 < \text{SepP} < 535 \text{ psia} \end{aligned}$$

Where:  $\text{SepP}$  is separator pressure in psi,  $\text{SepT}$  is separator temperature in  $^\circ\text{F}$ ,  $SG_{sep}$  is gas specific gravity measured at separator conditions,  $\text{API}$  is the density of the stock tank oil and  $SG$  is the corrected specific gravity.

### PVT.3.4 Solution Gas-Oil-Ratio

Knowing the bubble point pressure, the correlation for solution gas-oil-ratio, RS, of the oil as presented by Vasquez, M., and Beggs, H. D., "Correlations for Fluid Physical Property Predictions", Journal of Petroleum Technology, June 1980, can be estimated. The constants to use in the correlation are dependent on the oil density. Note if the gas-oil-ratio is calculated at initial reservoir conditions, it is normally labeled RSI.

$$RS1 = \exp[c \text{ API} / (460 + T)]$$

$$RS = RS1(a \text{ SG } P_b^b) \quad (\text{PVT-33})$$

If the oil density is greater than 30°API, then the constants are as follows:

$$a = 0.0178$$

$$b = 1.187$$

$$c = 23.931$$

For other values of API, the constants are:

$$a = 0.0362$$

$$b = 1.0937$$

$$c = 25.724$$

Range of validity:

For  $15 < ^\circ\text{API} \leq 30$ :

$$0.511 < \text{SG} < 1.351$$

$$14.7 < P_b < 4,542 \text{ psia}$$

For  $30 < ^\circ\text{API} \leq 59.5$ :

$$0.530 < \text{SG} < 1.259$$

$$14.7 < P_b < 6,025 \text{ psia}$$

Where:  $P_b$  is bubble point pressure in psia, RS is the solution gas-oil-ratio in scf/bbl, SG is the corrected gas specific gravity, and T is temperature in °F.

### PVT.3.5 Oil Isothermal Compressibility

When considering oil compressibility, there are separate correlations available to calculate compressibility above the bubble point and below the bubble point. The different correlations result in a discontinuity at the bubble point (Figure PVT-10).

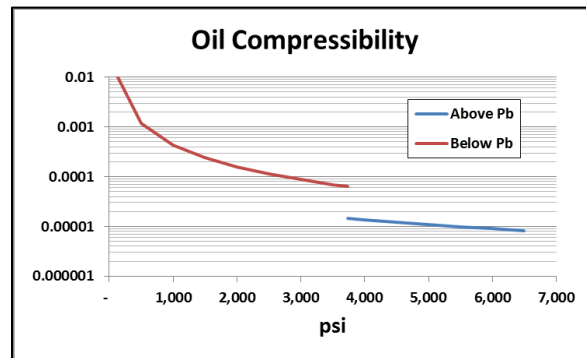


Figure PVT-10: Oil Compressibility

The reason for the discontinuity is that the definition of oil compressibility below the bubble point contains a  $\delta RS/\delta P$  term representing the change in the amount of dissolved gas in the oil. As a result, the change in volume below the bubble point includes a liquid and a gas component which has a significant impact on compressibility. In addition, the RS increases up to the bubble point then becomes constant at, and above, the bubble point causing a discontinuity.

Table PVT-14 presents the isothermal compressibility,  $c_o$ , equations for undersaturated oil ( $P > P_b$ ) for the correlations which are available in the PVT tool and Table PVT-15 presents the corresponding coefficients for the equations.

$c_o$ Correlation	$c_o$ Correlation Equation
Vasquez and Beggs	$(a_1 + a_2 * RS + a_3 * t + a_4 * GasG + a_5 * OilAPI) / (a_6 * P)$
Petrosky and Farshad	$a_1 * RS^{a_2} * GasG^{a_3} * OilAPI^{a_4} * t^{a_5} * P^{a_6}$

Table PVT-14:  $c_o$  Correlation Equations

$c_o$ Correlation	$a_1$	$a_2$	$a_3$	$a_4$	$a_5$	$a_6$
Vasquez and Beggs	-1433	5	17.2	-1180	12.61	100000
Petrosky and Farshad	1.705E-07	0.69357	0.1885	0.3272	0.6729	-0.5906

Table PVT-15:  $c_o$  Correlation Equation Parameters

Where:  $C_o$  is in  $psi^{-1}$ ,  $P$  is the pressure in psia,  $P_b$  is the bubble point pressure in psia, RS is the solution gas-oil-ratio in scf/bbl, GasG is the gas specific gravity, OilAPI is the oil gravity in °API and  $T$  is the temperature in °F.

The PVT Tool estimate for oil isothermal compressibility below the bubble point uses the correlation presented by McCain, Rollens and Villena (McCain, W. D., Rollens, J. B. and Villena, A.

J., “The coefficient of Isothermal Compressibility of Black Oils at Pressures Below the Bubble point”, SPE Formation Evaluation, September 1988), shown below.

$$C_{ob} = \exp[a + b \ln(P) + c \ln(P_b) + d \ln(T + 460) + e \ln(API) + f \ln(RS)] \quad (\text{PVT-34})$$

$$a = -7.573$$

$$b = -1.450$$

$$c = -0.383$$

$$d = 1.402$$

$$e = 0.256$$

$$f = 0.449$$

Where:  $C_{ob}$  is in  $\text{psi}^{-1}$ ,  $P$  is the pressure in psia,  $P_b$  is the bubble point pressure in psia,  $RS$  is the solution gas-oil-ratio in scf/bbl at the bubble point pressure,  $SG$  is the corrected gas specific gravity,  $API$  is the oil gravity in  $^\circ API$  and  $T$  is temperature in  $^\circ F$ .

The range of validity for all the compressibility correlations are as follows:

$$111 < P < 9,485 \text{ psia}$$

$$76 < \text{Sep}T < 150^\circ F$$

$$30 < \text{Sep}P < 535 \text{ psia}$$

$$15.3 < ^\circ API \leq 59.5$$

$$0.511 < SG < 1.351$$

### PVT.3.6 Pseudo Oil Components

The PE<sup>2</sup> Essentials PVT tool includes the capability of generating pseudo components for oil fluids. The pseudo oil components can be input to the EOS tool for further analysis. Components can be manually entered or generated by the tool.

After completion of the component analysis, the final components can be saved to the PE Tools Database for use in other tools.

The oil component generation tool is accessed through the ‘Generate Pseudo Oil Composition’ button. When the button is clicked, the input oil API and solution GOR are converted to a pseudo composition and the oil components table is populate (Figure PVT-11). Entering ‘0’ for the seed allows manual entry of the components. The oil component values can then be changed until the desired oil properties are obtained. Calculations will not be performed until the sum of the components equals 100%.

The technique used to generate the pseudo oil components is based on the assumption that most conventional oil components fall within a limited range of mole concentration values:  $C_1$  – 0.4 to 0.5;  $C_2$  – 0.05 to 0.06;  $C_3$  – 0.045 to 0.055 ;  $iC_4$  – 0.007 to 0.015;  $nC_4$  – 0.02 to 0.03;  $iC_5$  – 0.007 to 0.015;  $nC_5$  – 0.01 to 0.02;  $C_6$  – 0.015 to 0.025;  $C_7$  – 0.3 to 0.4;  $C_2$  – 0.05 to 0.06.

The ranges are randomly sampled. The generated random distribution is then normalized to take the impurities into account and the properties are then modified to match API and solution GOR.

Figure PVT-11: Gas Composition Analysis

To correct to the solution GOR (RSI) in mscf/bbl, the actual C7/C1 ratio is modified until the expected C7/C1 ratio is obtained, where:

$$\text{Expected C7/C1 Ratio} = 2.4525 * (\text{RSI}/1000)^2 - 4.5405 * \text{RSI}/1000 + 2.6265$$

The C7Plus MW and C7Plus SG are then calculated as follows:

$$\text{C7Plus MW} = 237 * \text{EXP}(0.137 * a)$$

$$\text{C7Plus SG} = (0.0366 * \text{API}^2 - 8.369 * \text{API} + 1115.7) / 1000$$

Where:

$$a = a1 + a2 + a3$$

$$a1 = -1.47 * (\text{Log}(\text{RSI}))^6 + 52.16 * (\text{Log}(\text{RSI}))^5 - 768.34 * (\text{Log}(\text{RSI}))^4 + 6017.87 * (\text{Log}(\text{RSI}))^3 - 26431.59 * (\text{Log}(\text{RSI}))^2 + 61730.18 * \text{Log}(\text{RSI}) - 59893.7$$

$$a2 = 0.0000047 * \text{API}^5 - 0.0008 * \text{API}^4 + 0.0535 * \text{API}^3 - 1.76318 * \text{API}^2 + 28.78 * \text{API} - 186.6162$$

$$a3 = -325.12 * \text{GasSG}^6 + 2142.8 * \text{GasSG}^5 - 5777.4 * \text{GasSG}^4 + 8144.1 * \text{GasSG}^3 - 6323.3 * \text{GasSG}^2 + 2562.9 * \text{GasSG} - 423.9504$$

## PVT.4 Water and Rock Properties

The correlations used to generate water properties require water salinity, reservoir pressure and reservoir temperature as input (Figure PVT-12). The correlations incorporated into PE<sup>2</sup> Essentials are presented in the following sections.

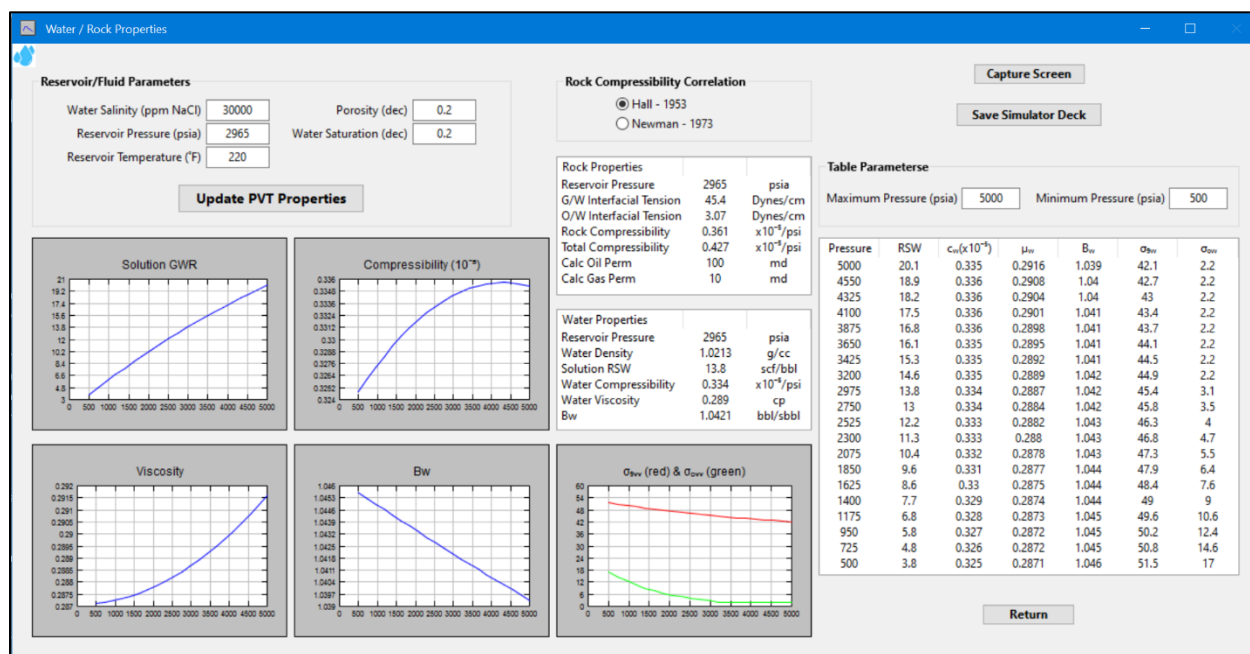


Figure PVT-12: Water PVT Properties

Once the PVT properties are generated, a simulator input file can be saved by clicking the 'Save Simulator Deck' button.

### PVT.4.1 Water Density

The density of water is a function of the salinity of the water. The CRC Handbook of Chemistry and Physics (56th ed.), CRC Press, Ohio, 1975-1976 published properties of NaCl-water (14.7 psia and 60°F) which has been plotted as shown in Figure PVT-13.

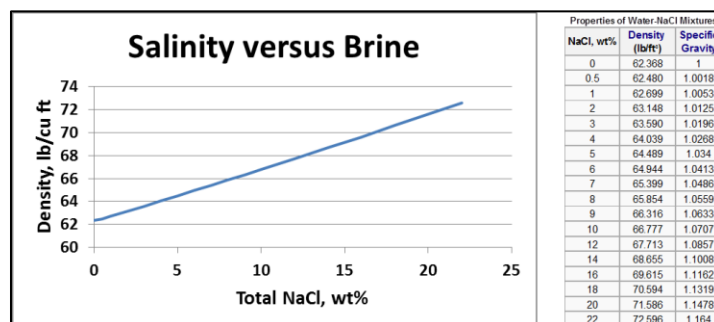


Figure PVT-13: Water Properties

The following correlation (Equation PVT-35) is a representation of Figure PVT-12 plot ( $R^2=0.9998$ ).

$$\begin{aligned}\rho_w &= a\text{Salt}^2 + b\text{Salt} + c \\ SG_w &= \rho_w/62.368\end{aligned}\quad (\text{PVT-35})$$

$$\begin{aligned}\text{Salt} &= \text{ppmNACL}/10000 \\ a &= 0.00224483 \\ b &= 0.41643 \\ c &= 62.368\end{aligned}$$

Where:  $\rho_w$  is the density of water in lb/ft<sup>3</sup> at 14.7 psia and 60°F, ppmNACL is the salinity of the water in ppm, and  $SG_w$  is specific gravity of the water.

To correct to reservoir conditions, divide  $\rho_w$  by  $B_w$  (Section PVT.4.5).

### PVT.4.2 Solution Gas-Water Ratio

Correlations for solution gas-water ratio only consider the solubility of methane in water. The effect of solubility of the heavier components are two to three times less than the solubility of methane and are considered to be outside the accuracy limits of the correlation and are normally disregarded. The correlation included in PE<sup>2</sup> Essentials was published by McCain (McCain, W. D., The Properties of Petroleum Fluids, Second Edition, PennWell Books, 1990), as shown in the following equation:

$$\begin{aligned}RS_w &= RS_w' \log^{-1}(-0.0840655 \text{ Salt } T^{-0.285854}) \\ RS_w' &= a + bP + cP^2 \\ \text{Salt} &= \text{ppmNACL}/10000 \\ a &= a_0 + a_1T + a_2T^2 + a_3T^3 \\ b &= b_0 + b_1T + b_2T^2 + b_3T^3 \\ c &= (c_0 + c_1T + c_2T^2 + c_3T^3 + c_4T^4) \times 10^{-7}\end{aligned}\quad (\text{PVT-36})$$

$$\begin{aligned}\text{Where: } a_0 &= 8.1539; a_1 = -6.12265 \times 10^{-2}; a_2 = 1.91663 \times 10^{-4}; a_3 = -2.1654 \times 10^{-7} \\ b_0 &= 1.01021 \times 10^{-2}; b_1 = -7.44241 \times 10^{-5}; b_2 = 3.05553 \times 10^{-7}; b_3 = -2.94883 \times 10^{-10} \\ c_0 &= -9.02505; c_1 = 0.130237; c_2 = -8.53425 \times 10^{-4}; c_3 = 2.34122 \times 10^{-6}; c_4 = -2.37049 \times 10^{-9}\end{aligned}$$

$$\begin{aligned}\text{Range of validity: } & 70 < T < 340^\circ\text{F} \\ & 1,000 < P < 10,000 \text{ psia} \\ & 0 \leq \text{Salt} < 30\% \text{ by weight}\end{aligned}$$

Where:  $RS_w'$  is the solution gas-water ratio for fresh water in scf/bbl,  $RS_w$  is the solution gas-water ratio for saltwater in scf/bbl, ppmNACL is the salinity of the water in ppm,  $P$  is pressure in psia and  $T$  is temperature in °F.



### PVT.4.3 Water Isothermal Compressibility (Gas Saturated)

The correlation for water isothermal compressibility only calculates values for undersaturated water (no free gas in the water). Two correlations are available, one for temperature up to 250°F with pressures up to 6000 psia and one for higher temperatures and pressures. The correlations for the lower temperature can be found in a number of references: Craft, B. C. and Hawkins, M. F., Applied Petroleum Reservoir Engineering, Prentice-Hall, 1959; Meehan, D. N., "A Correlation for Water Compressibility", Petroleum Engineer, November, 1980; and Numbere, D., Brigham, W. E., and Standing, M. B., Correlations for Physical Properties of Petroleum Reservoir Brines, Petroleum Research Institute, Stanford University, November, 1977. The equation is:

$$C_w' = (a + bT + cT^2) \times 10^{-6}$$

$$\text{Dissolved gas correction: } C_w'' = C_w'(1 + 0.0089RS_w)$$

$$C_w = C_w'' [(-0.052 + 2.7 \times 10^{-4}T - 1.14 \times 10^{-6}T^2 + 1.121 \times 10^{-9}T^3) \text{Salt}^{0.7} + 1] \quad (\text{PVT-37})$$

$$\text{Salt} = \text{ppmNACL} / 10000$$

$$a = 3.8546 - 1.34 \times 10^{-4}P$$

$$b = -0.01052 + 4.77 \times 10^{-7}P$$

$$c = 3.9267 \times 10^{-5} - 8.8 \times 10^{-10}P$$

$$\text{Range of validity: } 80 < T < 250^\circ\text{F}$$

$$1,000 < P < 6,000 \text{ psia}$$

$$0 \leq \text{Salt} < 25\% \text{ by weight}$$

Where:  $C_w$  is the isothermal compressibility of saturated salt water in  $\text{psia}^{-1}$ ,  $C_w'$  is the isothermal compressibility of fresh, gas-free water in  $\text{psia}^{-1}$ ,  $RS_w$  is the solution gas-water ratio in scf/bbl, ppmNACL is the salinity of the water in ppm,  $P$  is pressure in psia and  $T$  is temperature in °F.

The correlation equation for high temperatures and high pressures was presented by Osif (Osif, T. L., "The Effects of Salt, Gas, Temperature and Pressure on the Compressibility of Water", SPE Reservoir Engineering, February 1988), as shown below:

$$C_w = 1 / (aP + b\text{ppmNACL} + cT + d) \quad (\text{PVT-38})$$

$$a = 7.033$$

$$b = 0.5415$$

$$c = -537.0$$

$$d = 403300$$

$$\text{Range of validity: } 200 < T < 270^\circ\text{F}$$

$$1,000 < P < 20,000 \text{ psia}$$

$$0 \leq \text{ppm} < 250,000 \text{ ppm}$$

Where:  $C_w$  is the isothermal compressibility of saturated saltwater in  $\text{psia}^{-1}$ , ppmNACL is the salinity of the water in ppm,  $P$  is pressure in psia and  $T$  is temperature in °F.

#### PVT.4.4 Water Viscosity

The correlation for water viscosity was presented by Meehan (Meehan, D. N., "Estimating Water Viscosity at Reservoir Conditions", Petroleum Engineer, July 1980), where:

$$\mu_w = 0.02414 a b 10^c \quad (\text{PVT-39})$$

$$\text{Salt} = \text{ppmNACL}/10000$$

$$a = 1 - 0.00187\text{Salt}^{0.5} + 0.00021\text{Salt}^{2.5} + (T^{0.5} - 0.0135T)(0.00276\text{Salt} - 0.000344\text{Salt}^{1.5})$$

$$b = 1 + 3.5 \times 10^{-12} P^2 (T - 40)$$

$$c = 247.8 / [133.15 + 0.5556(T - 32)]$$

$$\begin{aligned} \text{Range of validity: } & 32 < T < 572^\circ\text{F} \\ & 0 \leq \text{Salt} < 25\% \text{ by weight} \end{aligned}$$

Where:  $\mu_w$  is the water viscosity in cp at pressure P in psia and temperature T in °F, and ppmNACL is water salinity in ppm.

#### PVT.4.5 Water Formation Volume Factor

The correlation for water formation volume factor for gas saturated water was presented by Numbere, Brigham and Standing (Numbere, D., Brigham, W. E., and Standing, M. B., Correlations for Physical Properties of Petroleum Reservoir Brines, Petroleum Research Institute, Stanford University, November 1977), as presented below:

$$B_w = d(a + bP + cP^2) \quad (\text{PVT-40})$$

$$\text{Salt} = \text{ppmNACL}/10000 \quad (\text{PVT-41})$$

$$a = 0.9911 + 6.35 \times 10^{-5} T + 8.5 \times 10^{-7} T^2$$

$$b = -1.093 \times 10^{-6} - 3.497 \times 10^{-9} T + 4.57 \times 10^{-12} T^2$$

$$c = -5 \times 10^{-11} + 6.429 \times 10^{-13} T - 1.43 \times 10^{-15} T^2$$

$$d = 1 + \text{Salt}[5.1 \times 10^{-8} P + (5.47 \times 10^{-6} - 1.95 \times 10^{-10} P)(T - 60) - (3.23 \times 10^{-8} - 8.5 \times 10^{-13} P)(T - 60)^2]$$

$$\begin{aligned} \text{Range of validity: } & 100 < T < 250^\circ\text{F} \\ & 1,000 < P < 5,000 \text{ psia} \\ & 0 \leq \text{Salt} < 25\% \text{ by weight} \end{aligned}$$

Where:  $B_w$  is the water formation volume factor in rbbl/sbbl, P is pressure in psia, T is temperature in °F and ppmNACL is the water salinity in ppm.

#### PVT.4.6 Formation Isothermal Compressibility

There are two correlations available for formation isothermal compressibility. One was generated from the correlation developed by Hall (Equation PVT-38) (Hall, H. N., "Compressibility of reservoir Rocks", Transactions of AIME, Vol. 198, 1953) and the other was published by

Newman (Equation PVT-39) (Newman, G.H., 1973, Pore-Volume Compressibility of Consolidated, Friable, and Unconsolidated Reservoir Rocks under Hydrostatic Loading: Journal of Petroleum Technology, Feb, 1973), where:

$$C_r = 1.782 \times 10^{-6} (\text{Porosity})^{-0.438} \quad (\text{PVT-42})$$

$$C_r = 9.732 \times 10^{-5} (1 + 55.8721 * \text{Porosity}) \quad (\text{PVT-43})$$

Where:  $C_r$  is the formation isothermal compressibility in  $\text{psi}^{-1}$ , and Porosity is the formation porosity in decimal format.

### PVT.5 Interfacial Tension

Interfacial tension between gas and liquid phases has minimal effect on two phase pressure calculations but when using some of the pressure gradient prediction techniques, interfacial tension is required to calculate certain dimensionless numbers used in the technique. Original work was performed by Baker and Swerdloff to estimate gas-oil interfacial tension (Baker, O., and Swerdloff, W., "Finding Surface Tension of Hydrocarbon Liquids", Oil and Gas Journal, (January 2, 1956), and gas-water graphs were published by Hough ("Interfacial Tensions at Reservoir Pressures and Temperatures", Transactions of AIME, 1951).

In 2000 Abdul-Majeed and Al-Soof updated the Baker and Swerdloff correlation (Abdul-Majeed and Abu Al-Soof, "Estimation of Gas-Oil Surface Tension", Journal of Petroleum Science and Engineering, Vol. 27).

#### Gas-Oil Interfacial Tension – 1 (Abdul-Majeed and Al-Soof)

Note- This gas-oil correlation is the one that has been incorporated into PE<sup>2</sup> Essentials.

For gas-oil interfacial tension, the calculation is a two-step process. The dead oil-gas interfacial tension is calculated, and this value is corrected based on the value of RS. Abdul-Majeed and Al-Soof presented two equations for the ratio of live oil surface tension to dead oil surface tension based on whether RS was less than 280 scf/bbl or greater than or equal to 280 scf/bbl. The graph they presented can be better represented by a single exponential curve as shown at [http://petrowiki.org/Interfacial\\_tension](http://petrowiki.org/Interfacial_tension).

$$\sigma_{og} = \sigma_{od} \sigma_{og}/\sigma_{od} \quad (\text{PVT-44})$$

$$\sigma_{od} = (1.17013 - 0.001694T) (38.085 - 0.259\text{API})$$

$$\sigma_{og}/\sigma_{od} = 0.056379 + 0.94365 \exp^{(-0.0038491\text{RS})}$$

Where:  $\sigma_{og}$  is the saturated gas-oil interfacial tension in dynes/cm,  $\sigma_{od}$  is the dead oil gas-oil interfacial tension in dynes/cm at temperature T in °F, RS is the solution gas-oil ratio in scf/bbl and API is oil gravity in °API.

It should be noted that  $\sigma_{og}$  will be zero at miscibility pressure. A value of 1 is normally used for  $\sigma_{og}$  above miscibility pressure in the appropriate dimensionless equations.

### **Gas-Oil Interfacial Tension – 2 (Baker and Swerdloff)**

For gas-oil interfacial tension, Baker and Swerdloff presented graphs relating dead oil surface tension with temperature and API gravity. Only 68°F and 100°F were considered for the correlation. To correct for the effect of solution gas, Baker and Swerdloff related the ratio of live to dead oil surface tension with saturation pressure. These graphs can be represented by the following equations which were presented by Beggs (Beggs, H. D., Production Optimization Using Nodal Analysis, OGCI, 1991).

$$\sigma_{og} = \sigma_{od} \exp(-0.00086306P) \quad (\text{PVT-45})$$

$$\sigma_{od} = \sigma_{68} - (T - 68)(\sigma_{68} - \sigma_{100})/32$$

$$\sigma_{68} = 39 - 0.2571\text{API}$$

$$\sigma_{100} = 37.5 - 0.2571\text{API}$$

Where:  $\sigma_{og}$  is the saturated gas-oil interfacial tension in dynes/cm,  $\sigma_{od}$  is the dead oil gas-oil interfacial tension in dynes/cm at temperature T in °F, and P is pressure in psia.

The  $\sigma_{og}$  equation will be zero at a pressure of 3977 psia. A value of 1 should be used for  $\sigma_{og}$  above 3977 psia in the appropriate dimensionless equations. For temperatures below 68°F, assume  $\sigma_{og} = \sigma_{68}$  and for temperatures above 100°F, assume  $\sigma_{og} = \sigma_{100}$ .

### **Gas-Water Interfacial Tension – 1 (Jennings, H. Y. and Newman. G. H)**

Note- This gas-water correlation is the one that has been incorporated into PE<sup>2</sup> Essentials.

Published data for gas-water systems do not agree. According to McCain, the most consistent data was published by Jennings and Newman (Jennings, H. Y. and Newman. G. H. "The Effect of Temperature and Pressure on the Interfacial Tension of Water Against Methane-Normal Decani Mixtures", Transactions of AIME, 1971). The correlations can be represented as follows.

$$w_{ow} = A + BP + CP^2$$

(PVT-46)

$$A = 79.1618 - 0.118978T$$

$$B = -5.28473 \times 10^{-3} + 9.87913 \times 10^{-6}T$$

$$C = (2.33814 - 4.57194 \times 10^{-4}T - 7.52678 \times 10^{-6}T^2) \times 10^{-7}$$

Where:  $\sigma_{gw}$  is the gas-water interfacial tension in dynes/cm at temperature T in °F

**Gas-Water Interfacial Tension – 2 (Baker and Swerdloff)**

For gas-water interfacial tension, Baker and Swerdloff presented graphs for 74°F and 280°F. These graphs can be represented by the following equations which were presented by Beggs (Beggs, H. D., Production Optimization Using Nodal Analysis, OGCI, 1991)

$$\sigma_{gw} = \sigma_{74} - (T - 74)(\sigma_{74} - \sigma_{280})/206 \quad (\text{PVT-47})$$

$$\sigma_{74} = 75 - 1.108P^{0.349}$$

$$\sigma_{280} = 53 - 0.1048P^{0.637}$$

Where:  $\sigma_{gw}$  is the gas-water interfacial tension in dynes/cm at temperature T in °F, and pressure P in psia. For temperatures below 74°F, assume  $\sigma_{gw} = \sigma_{74}$  and for temperatures above 280°F, assume  $\sigma_{gw} = \sigma_{280}$ .

**PVT.6 Relative Permeability Curve Generation**

The letter k represents the absolute permeability of the reservoir (in md) and  $k_o$ ,  $k_g$  and  $k_w$  represent the effective permeability to oil, gas and water. The fluid saturations,  $S_o$ ,  $S_g$  and  $S_w$  must also be specified to fully define the conditions for the value of effective permeability. Studies have shown that a reservoir's effective permeability in terms of the reservoir fluid is a function of the saturation of that fluid and the wetting characteristics of the reservoir.

Since there are many possible values for saturation, effective permeability is normally reported as relative permeability:  $k_{ro}$ ,  $k_{rg}$  and  $k_{rw}$ .

$$k_{ro} = k_o/k$$

$$k_{rg} = k_g/k$$

$$k_{rw} = k_w/k$$

Effective permeability ranges from zero to k so relative permeabilities range from zero to one.

$$0 \leq k_{ro}, k_{rg}, k_{rw} \leq 1.0$$

When all three phases are present in the reservoir, the sum of the relative permeabilities is variable and less than or equal to one:  $k_{ro} + k_{rg} + k_{rw} \leq 1.0$

There are two techniques available to generate relative permeabilities: correlations and production data.

The PE<sup>2</sup> Essentials PVT tool (Figure PVT-14) can be used to generate oil/gas/water relative permeability curves and tables. The figure shows the curves that result after selecting the 'Default' option. This tool is executed by clicking the 'Relative Permeability' button on the main PVT screen.

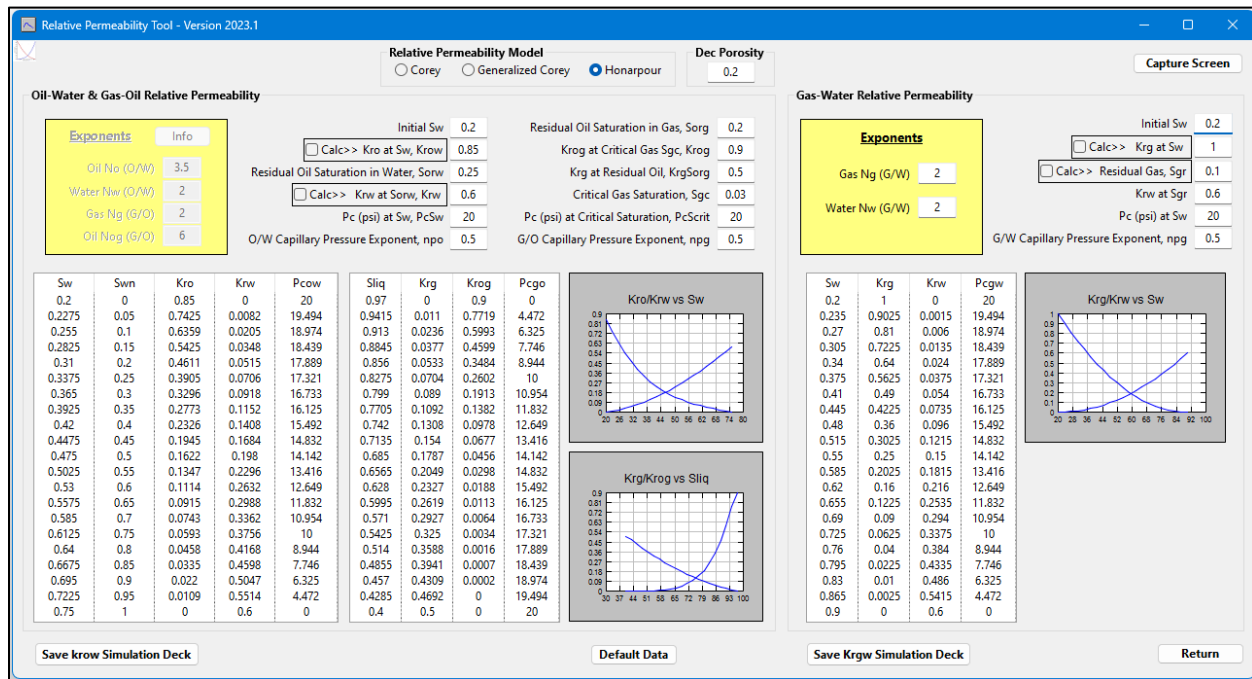


Figure PVT-14: Oil/Gas/Water Relative Permeability: Correlations

The relative permeability data generated by the tool can be saved to a simulator input file by clicking 'Save Simulator Deck'.

The following can be used (with caution) to determine input parameters:

Oil Wet:

$$\begin{aligned} n_o &\geq 6 \\ n_w &< 3 \\ k_{row} &\geq 0.5 \end{aligned}$$

Intermediate Wet:

$$\begin{aligned} 6 &< n_o \leq 3 \\ 5 &< n_w \leq 3 \end{aligned}$$

Water Wet:

$$\begin{aligned} n_o &< 3 \\ n_w &\geq 5 \\ k_{row} &< 0.5 \end{aligned}$$

Note that normalized water saturation,  $S_{wn}$ , is calculated as follows:

$$S_{wn} = (S_w - S_{iw}) / (1 - S_{iw} - S_{orw})$$

Where  $S_w$  is the desired water saturation,  $S_{iw}$  is the initial water saturation and  $S_{orw}$  is the residual oil saturation in the oil zone.

There are a number of internal correlations that can be used for some of the parameters. These options will be enabled when it is possible to use them.

$$k_{row} = 1.31 - 2.62 S_w - 1.1 S_w^2$$

$$k_{rgw} = 1.08 - 1.11 S_w - 0.73 S_w^2$$

$$S_{grw} = 0.151956 S_g^2 - 0.374026 S_g + 1.4476 S_w^{1.2861} + 0.25611$$

$K_{rw}$  @  $S_{orw}$  is calculated using the Honarpour correlation when enabled

### PVT.6.1 Corey Model

The Corey model assumes that the wetting and non-wetting phase-relative permeabilities are independent of the saturations of the other phases and requires only a single suite of gas and oil relative permeability data. This model requires minimal inputs.

$$k_{rw} = (S_w^*)^{\frac{2+3\lambda}{\lambda}} \quad (\text{PVT-48})$$

$$k_{rn} = k_r^o \left( \frac{S_m - S_w}{S_m - S_{iw}} \right)^2 \left( 1 - (S_w^*)^{\frac{2+\lambda}{\lambda}} \right) \quad (\text{PVT-49})$$

$$S_w^* = \left( \frac{S_w - S_{iw}}{1 - S_{iw}} \right) \quad (\text{PVT-50})$$

$$k_r^o = 1.31 - 2.62 S_{iw} - 1.1 (S_{iw})^2 \quad (\text{PVT-51})$$

Where  $k_{rw}$  is the water relative permeability,  $k_{rn}$  is the non-wetting phase (oil/gas) relative permeability,  $k_r^o$  is the oil relative permeability at irreducible water saturation,  $S_w^*$  is the normalized water saturation,  $\lambda$  is a pore size distribution index,  $S_m$  is  $1 - S_{or}$  ( $1 -$  residual oil saturation),  $S_w$  is water saturation and  $S_{iw}$  is initial water saturation.

Equation PVT-51 can be used to estimate the  $k_r^o$  value when core information is not available. To estimate the  $k_r^o$  value, enter the value for  $S_{iw}$  in the PVT tool and the  $k_r^o$  value will be calculated.

The  $\lambda$  value (pore size distribution index) is critical in calculating relative permeability. The actual number represents how uniform the pore size is in the sample/reservoir. A low value of  $\lambda$  (i.e. 2) indicates a wide range of pore sizes, while a high value represents a rock with a more uniform pore size distribution.

Using a  $\lambda$  value of 2 results in the well-known Corey equations. In general,  $\lambda$  can be as follows:

- $\lambda = 2$  (cemented sandstones, oolitic and small-vug limestones)
- $\lambda = 4$  (poorly sorted unconsolidated sandstones)
- $\lambda = \text{infinity}$  (well sorted unconsolidated sandstones)

## PVT.6.2 Generalized Corey Model

The Generalized Corey model was developed for a wider range of rock and wettability characteristics. This model can be used to change the endpoints of water-oil and gas-liquid relative permeability curves while still retaining the shape of the curves.

### Oil-Water System ( $k_{ro}/k_{rw}$ )

For an oil-water sytem the generalized Corey equations are as follows:

$$k_{ro} = k_{rocw} \left[ \frac{1 - S_w - S_{orw}}{1 - S_{iw} - S_{orw}} \right]^{n_{ow}} \quad (\text{PVT-52})$$

$$k_{rw} = k_{rwrw} \left[ \frac{S_w - S_{iw}}{1 - S_{iw} - S_{orw}} \right]^{n_w} \quad (\text{PVT-53})$$

Where  $n_{ow}$  is the Corey exponent for oil,  $n_w$  is the Corey exponent for water,  $k_{rocw}$  is the  $k_{ro}$  at  $S_{iw}$ ,  $S_{iw}$  is the initial water saturation,  $S_{orw}$  is the residual oil saturation,  $k_{rwrw}$  is the  $k_{rw}$  at  $S_{orw}$ ,  $S_{orw}$  is the residual oil saturation and  $S_w$  is the desired water saturation.

### Gas-Oil System ( $k_{ro}/k_{rg}$ )

For a gas-oil sytem the generalized Corey equations are as follows:

$$k_{rog} = k_{rocw} \left[ \frac{S_o - S_{iw} - S_{org}}{1 - S_{iw} - S_{org}} \right]^{n_{og}} \quad (\text{PVT-54})$$

$$k_{rgo} = k_{rgro} \left[ \frac{S_g - S_{go}}{1 - S_{gc} - S_{iw} - S_{org}} \right]^{n_g} \quad (\text{PVT-55})$$

Where  $n_{og}$  is the Corey exponent for oil,  $n_g$  is the Corey exponent for gas,  $k_{rocw}$  is the  $k_{ro}$  at  $S_{org}$ ,  $S_{iw}$  is the initial water saturation,  $S_{org}$  is the residual gas saturation,  $k_{rgro}$  is the  $k_{rgo}$  at  $S_{org}$ ,  $S_{gc}$  is the critical gas saturation,  $S_g$  is the desired gas saturation and  $S_o$  is the desired oil saturation.

### Gas-Water System ( $k_{rg}/k_{rw}$ )

For a gas-water sytem the generalized Corey equations are as follows:

$$k_{rg} = k_{rgcw} \left[ \frac{S_g - S_{gc}}{1 - S_{gc} - S_{iw}} \right]^{n_g} \quad (\text{PVT-56})$$

$$k_{rw} = k_{rwcg} \left[ \frac{S_w - S_{iw}}{1 - S_{iw}} \right]^{n_w} \quad (\text{PVT-57})$$

Where  $n_g$  is the Corey exponent for gas,  $n_w$  is the Corey exponent for water,  $k_{rgcw}$  is the  $k_{rg}$  at  $S_{iw}$ ,  $S_{iw}$  is the initial water saturation,  $S_{gc}$  is the trapped/residual gas saturation,  $k_{rwcg}$  is the  $k_{rw}$  at  $S_{gc}$ ,  $S_g$  is the desired water saturation, and  $S_w$  is the desired water saturation.



### PVT.6.3 Honarpour Model

The Honarpour model was developed using data from oil & gas fields in the US, Canada, Libya, Iran, Argentina, and the United Arab Republic. The model includes correlations for sandstone and limestone reservoirs. The PVT tool incorporates the model for sandstone reservoirs.

Note that the Honarpour model requires input of porosity,  $\phi$ . For a sandstone reservoir, the equations are as follows:

$$k_{row} = 0.76067 \left[ \frac{\left( \frac{S_o}{1 - S_{iw}} \right) - S_{or}}{1 - S_{orw}} \right]^{1.8} \left[ \frac{S_o - S_{orw}}{1 - S_{iw} - S_{orw}} \right]^{2.0} + 2.6318 \phi \left( 1 - S_{orw} \right) \left( S_o - S_{orw} \right) \quad (\text{PVT-58})$$

$$k_{rog} = 0.98372 \left[ \frac{S_o}{1 - S_{iw}} \right]^4 \left[ \frac{S_o - S_{org}}{1 - S_{iw} - S_{org}} \right]^2 \quad (\text{PVT-59})$$

$$k_{rw} = 1.5814 \left[ \frac{S_w - S_{iw}}{1 - S_{iw}} \right]^{1.91} - 0.58617 \left[ \frac{S_w - S_{orw}}{1 - S_{iw} - S_{orw}} \right] \left( S_w - S_{iw} \right) + 1.2484 \phi \left( 1 - S_{iw} \right) \left( S_w - S_{iw} \right) \quad (\text{PVT-60})$$

$$k_{rg} = 1.1072 \left[ \frac{S_g - S_{gc}}{1 - S_{iw}} \right]^2 k_{rgo} + 2.7794 S_{org} \left[ \frac{S_g - S_{gc}}{1 - S_{iw}} \right] k_{rgro} \quad (\text{PVT-61})$$

Refer to the previous sections for explanation of the terms.

### PVT.6.4 Capillary Pressure

For all models, capillary pressure is calculated as follows.

$$P_{cow} = P_{c(S_{iw})} \left( (1 - S_w - S_{orw}) / (1 - S_{iw} - S_{orw}) \right)^{N_{po}} \quad (\text{PVT-64})$$

$$P_{cog} = P_{c(S_{gc})} \left( (S_g - S_{gc}) / (1 - S_{iw} - S_{org} - S_{gc}) \right)^{N_{pg}} \quad (\text{PVT-65})$$

Where  $N_{po}$  is the oil capillary pressure exponent,  $N_{pg}$  is the gas capillary pressure exponent,  $P_{cow}$  is the oil-water capillary pressure and  $P_{c(S_{iw})}$  is the capillary pressure at  $S_{iw}$  and  $P_{cog}$  is the gas-oil capillary pressure and  $P_{cog(S_{gc})}$  is the capillary pressure at  $S_{gc}$ .

### PVT.6.5 Three Phase Relative Permeability

Three phase relative permeability is not generated by the tool but is included here for completeness.

Three-phase relative permeability can be generated from the two-phase relative permeability curves for an oil-water system and gas-oil system. The two-phase curves represent the end curves when either the gas saturation or water saturation equals zero.

The most common three phase relative permeability model was developed by Stone (Stone I and Stone II). The model estimates the three-phase relative permeability to oil in the presence of water and gas flow using two-phase data. The model assumes that water-relative permeability and water-oil capillary pressure in three-phase systems are functions of water saturation alone. Similarly, the gas-phase relative permeability and gas-oil capillary pressure are the same functions for gas saturation in the three-phase system as in the two-phase gas-oil system.

Stone I is widely used in the industry for reservoir simulation. It is a better predictor than Stone II in low oil saturation regions and is more appropriate for water-wet systems. It is not well-suited for intermediate wet systems. The Stone I equations are as follows:

$$S_o^* = \frac{S_o - S_{orw}}{1 - S_{iw} - S_{orw}} \quad (\text{PVT-62})$$

$$S_w^* = \frac{S_w - S_{iw}}{1 - S_{iw} - S_{orw}} \quad (\text{PVT-63})$$

$$S_g^* = \frac{S_g}{1 - S_{iw} - S_{orw}} \quad (\text{PVT-64})$$

$$k_{ro} = k_{rocw} S_o^* \left[ \frac{k_{row}(@S_w)}{k_{rocw}(1 - S_w^*)} \right] \left[ \frac{k_{rog}(@S_g)}{k_{rocw}(1 - S_g^*)} \right] \quad (\text{PVT-65})$$

Stone's Model II is a modified version of Stone I and is preferred in high-oil saturation regions. It is more appropriate for water-wet systems and is not well-suited for intermediate wet systems. The Stone II equation is as follows:

$$k_{ro} = k_{rocw} \left[ \left( \frac{k_{row}}{k_{rocw}} + k_{rw} \right) \left( \frac{k_{rog}}{k_{rocw}} + k_{rg} \right) - \left( k_{rw} + k_{rg} \right) \right] \quad (\text{PVT-66})$$

For intermediate-wet or oil-wet systems, the Baker model is the most relevant. Baker's three-phase model is based on saturation-weighted interpolation between the two-phase relative permeability values. The Baker equation is as follows:

$$k_{ro} = \frac{(S_w - S_{iw})(k_{rocw}) + (S_g - S_{gc})(k_{rog})}{(S_w - S_{iw}) + (S_g - S_{gc})} \quad (\text{PVT-67})$$

Refer to the previous sections for explanation of the terms.

## PVT.6.6 Production Based Relative Permeability

Production based permeability curve generation yields pseudo relative permeability curves from historical production data that could be used for history matching with reservoir simulators (Figure PVT-15).

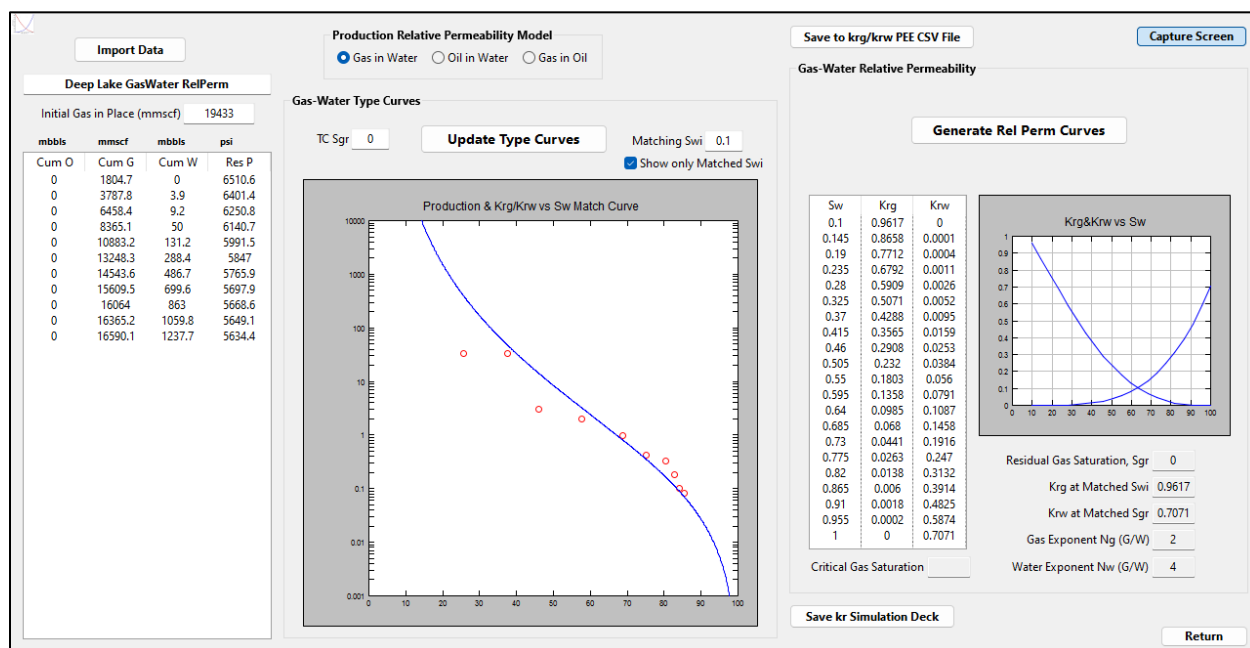


Figure PVT-15: Production-Based Relative Permeability

It should be noted that production data is inherently noisy so attempting to generate relative permeability curves from this type of data is not always successful. When the process does not appear to work, the 'Save to krg/krw PEE CSV File' will save the parameters used for the calculations to a CSV file. This file can be used for debugging.

The PE Essentials production-based relative permeability generation techniques are based on information presented in three main references: Meads,R., and Bassiouni,Z. "Combining Production History and Petrophysical Correlations To Obtain Representative Relative Permeability Data", SPE 12113, 1983; Fetkovich,M.D.; Guerrero,E.T.; Fetkovich,M.J.; and Thomas,L.K. "Oil and Gas Relative Permeabilities Determined From Rate-Time Performance Data", SPE 15431, 1986; and Al-Khalifa,A-J.A. "In-Situ Determination of Oil/Water Relative Permeability Curves Using Well Performance Data", SPE 25670, 1993.

There are three options (Figure PVT-16) available for relative permeability generation in the PE Essentials PVT tool: gas/water (G/W), oil/water (O/W) and gas/oil (G/O). The G/W and O/W assume the existence of an aquifer, or in the case of O/W, this includes water injection. The G/O option assumes either a depletion drive. The O/W option also includes a wettability option.

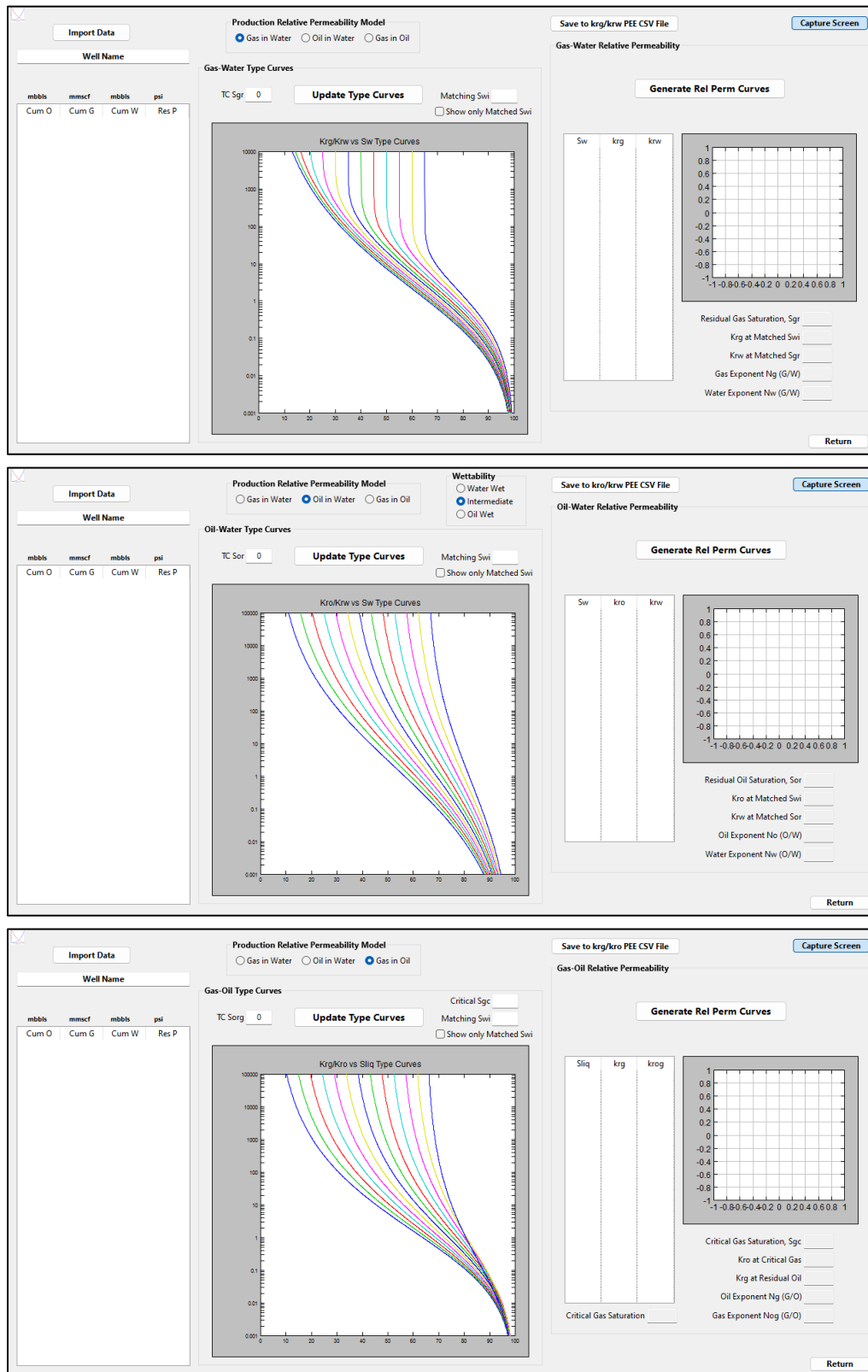


Figure PVT-16: Production-Based Relative Permeability Type Curve Options

The tool generates type curves for relative permeability ratios on which the production based relative permeability ratios are matched. Matching requires a fluid in place value as well as values for saturation parameters.

The basis of using production data to determine relative permeability is the generation of a relative permeability ratio based on production ratios and PVT parameters and a varying reservoir  $S_w$  calculation based on cumulative production.

The following equations present the ratio calculations from production ratios.

$$\frac{k_{rg}}{k_{rw}} = GWR \frac{\mu_g B_g}{\mu_w B_w} \quad (\text{PVT-68})$$

$$\frac{k_{ro}}{k_{rw}} = OWR \frac{\mu_o B_o}{\mu_w B_w} \quad (\text{PVT-69})$$

$$\frac{k_{rg}}{k_{ro}} = (GOR - RS) \frac{\mu_g B_g}{\mu_o B_o} \quad (\text{PVT-70})$$

Where  $k_{rg}$  is gas relative permeability;  $k_{ro}$  is oil relative permeability;  $k_{rw}$  is water relative permeability; GWR is producing gas-water ratio; OWR is producing oil-water ratio; GOR is producing gas-oil ratio; RS is solution gas-oil ratio;  $\mu_g, \mu_o, \mu_w$  are the fluid viscosities and  $B_g, B_o, B_w$  are the fluid formation volume factors.

The water saturation at any given time is calculated based on material balance equations (refer to the material balance tool documentations for information on the material balance equations). The  $S_w$  calculation for a gas-water system is as follows.

$$S_w = 1 - \frac{\left(1 - \frac{G_p}{G}\right) B_g}{B_{gi}} (1 - S_{wi}) \quad (\text{PVT-71})$$

Where  $S_w$  and  $S_g$  are the water and gas saturations at time  $t$ , respectively;  $S_{wi}$  is the initial water saturation;  $G$  is the initial gas in place;  $G_p$  is the cumulative gas produced to time  $t$ ; and  $B_{gi}$  and  $B_g$  are the gas formation volume factors initially and at time  $t$ .

For an oil-water system, the  $S_w$  calculation is a little more involved because the water injection has to be taken into account. The tool assumes a steady state flow exists, the result of either a strong aquifer or water injection at a voidage replacement ratio of 1. For this case, the solution GOR should be constant since the reservoir pressure should be maintained approximately constant.

The tool uses a normalization based on effective, or movable, pore volume,  $PV_e$ , calculated using PVT-72 to determine  $S_w$  at any given time.

$$PV_e = OOIP \frac{B_{oi}}{(1 - S_{wi} - S_{or})} \quad (\text{PVT-72})$$

Where  $PV_e$  is the effective, or movable, pore volume; OOIP is the original oil in place;  $B_{oi}$  is the initial oil formation volume factor;  $S_{wi}$  is the initial water saturation; and  $S_{or}$  is the residual oil saturation.

Water saturation is calculated from the production data using the Buckley-Leverett solution for linear flow at steady-state flow conditions (ref: Prakasa,B,;Muradov,K; Davies,D; “Linear and radial flow modelling of a waterflooded, stratified, non-communicating reservoir deveolped with downhole, flow control completions”, Journal of Petroleum Science and Engineering, November 2019) as follows:

$$S_w = Q_{winj-pv} (1 - WaterCut) + Q_{o-pv} + S_{wi} \quad (PVT-73)$$

$$Q_{winj-pv} = Q_{o-pv} + Q_{w-pv} \quad (PVT-74)$$

$$Q_{o-pv} = \frac{N_p B_o}{PV_e} \quad (PVT-75)$$

$$Q_{w-pv} = \frac{W_p B_w}{PV_e} \quad (PVT-76)$$

Where  $S_w$  is the current water saturation;  $Q_{winj-pv}$  is the cumulative water injected in pore volumes;  $Q_{o-pv}$  is the cummulative oil production in pore volumes;  $Q_{w-pv}$  is the cummulative water production in pore volumes;  $N_p$  is the cummulative oil produced;  $W_p$  is the cummulative water produced; and  $PV_e$  is the effective pore volume.

For a gas-oil system, the liquid saturation,  $S_l$ , is calculated by asssuming that the reservoir is a solution gas drive reservoir with a constant water saturation. The saturation calculation is as follows:

$$S_l = S_{wi} + \frac{\left(1 - \frac{N_p}{N}\right) B_o}{B_{oi}} (1 - S_{wi}) \quad (PVT-76)$$

### PVT.6.6.1 Production Based Relative Permeability: Oil/Water Example

In order to generate relative permeability from production data, the fluid PVT properties, the initial hydrocarbon in place, and the reservoir pressure over time are required. If there is reservoir pressure measurements available, then the PE Essentials Material Balance tool can be used to generate the reservoir pressure for the field.

When reservoir pressures are not available, the PE Essentials PDA tool can be used to estimate the required parameters (Figure PVT-17).

The INTERPRET-PDA WF tool can be used to determine EUR for a water drive / waterflooded reservoir. The EUR value can be used to estimate OOIP, for example EUR/0.3.

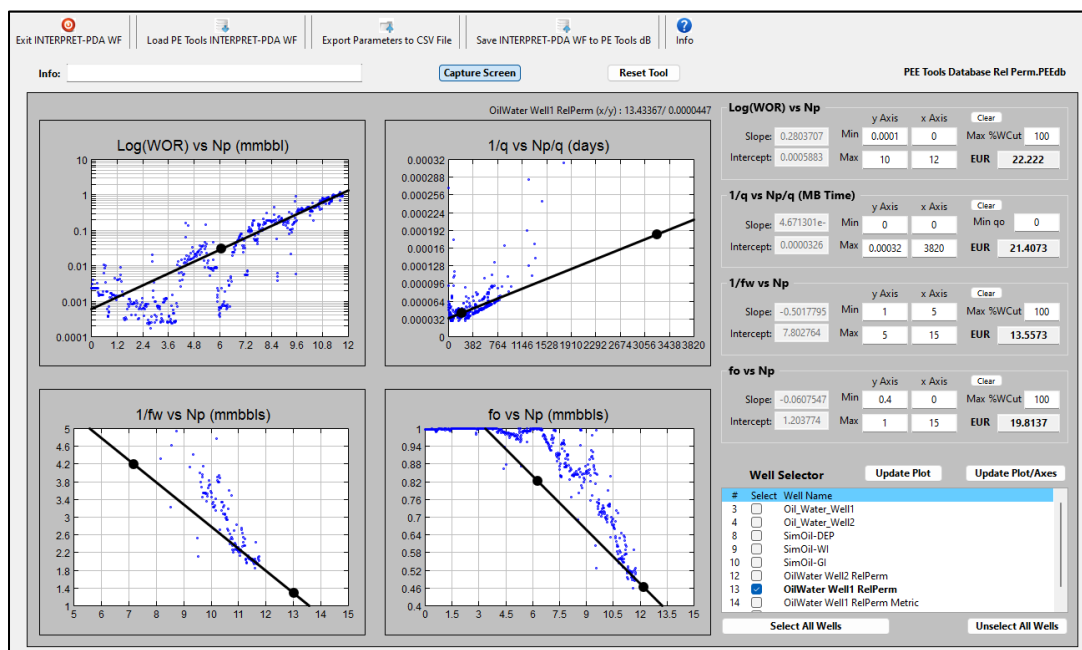


Figure PVT-17: Production-Based Relative Permeability Type Curve Options

For the 'OilWater Well1 RelPerm' well located in the PDA database, the average EUR is around 20 mmbbls (Figure PVT-17) so OOIP could be around 65 mmbbls. This is not obvious from flowing material balance so the Analytical Simulator in the PDA tool was used to estimate OOIP.

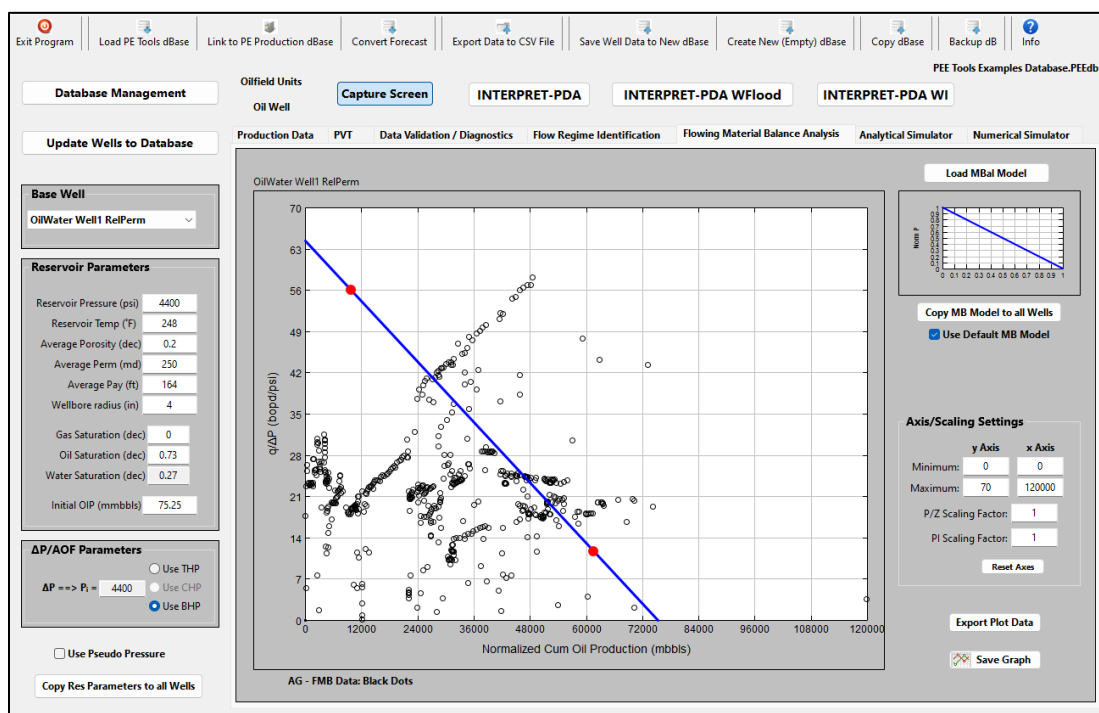


Figure PVT-18: Flowing Material Balance – 'Oil Water Well2 REL Perm' Well

The analytical simulator was used to match the flowing BHP's in the 'Oil Water Well2 REL Perm' Well and a good match was obtained with an OOIP of 50.25 mmbbls (Figure PVT-19).

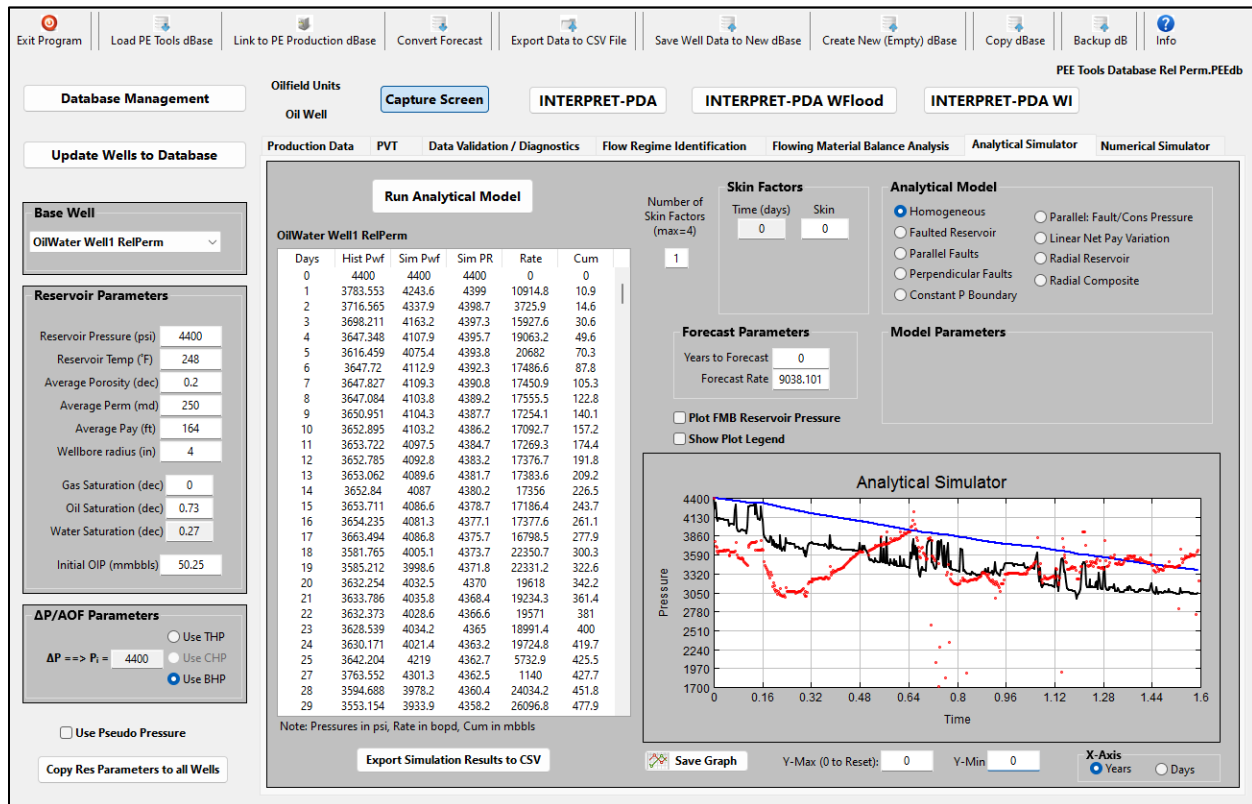


Figure PVT-19: Analytical Simulator History Match – 'Oil Water Well2 REL Perm' Well

The reason that this is required is because PVT parameters are required for each production data point and to generate the PVT data, a reservoir pressure is required. This data is used to calculate the production relative permeability ratios and the water saturation in the reservoir.

Once the PVT model is loaded into the PVT tool, the production-based relative permeability tool is accessed by clicking the 'Production Rel Perm' button.

For this example, the 'Oil in Water option should be chosen (Figure PVT-20).

Importing production data is performed by clicking the 'Import Data' button (Figure PVT-21).

There are three options for importing reservoir pressure; import data from the PE Essentials PDP tool (as indicated in Figures 17 – 19); from the PE Essentials MatBal tool; or by entering a minimum pressure and recovered volume (internal linear interpolation).



**Import Data**

**Well Name**

mbbls	mmscf	mbbls	psi
Cum O	Cum G	Cum W	Res P

**Production Relative Permeability Model**

☐ Gas in Water ☒ Oil in Water ☐ Gas in Oil

**Wettability**

☒ Water Wet ☐ Intermediate ☐ Oil Wet

**Oil-Water Type Curves**

TC Sor: 0 **Generate Type Curves** Matching Swi: ☐ Show only Matched Swi

**Oil-Water Relative Permeability**

**Generate Rel Perm Curves**

Sw kro krw

Residual Oil Saturation, Sor:   
 Kro at Matched Swi:   
 Krw at Matched Sor:   
 Oil Exponent No (O/W):   
 Water Exponent Nw (O/W):

**Capture Screen** **Return**

Figure PVT-20: Production-Based Relative Permeability Tool

**Select Data to Load**

**PEE Tools Examples Database.PEEdb**

- ☐ 9 NO 15/9-F-4 AH WI
- ☐ 10 NO 15/9-F-5 AH WI
- ☐ 11 NO 15/9-F-1 C Oilfield
- ☐ 12 NO 15/9-F-11 H Oilfield
- ☐ 13 NO 15/9-F-12 H Oilfield
- ☐ 14 NO 15/9-F-14 H Oilfield
- ☐ 15 NO 15/9-F-15 D Oilfield
- ☐ 16 NO 15/9-F-5 AH Oilfield
- ☐ 17 NO 15/9-F-4 AH Oilfield WI
- ☐ 18 NO 15/9-F-5 AH OilfieldWI
- ☐ 19 WL\_RX
- ☐ 20 WL\_RX Oilfield
- ☐ 21 Retrograde Oilfield
- ☐ 22 Retrograde Metric
- ☐ 23 Winj4-Smooth\_7
- ☐ 24 Prod3-Smooth\_7
- ☐ 25 Winj4-Metric
- ☐ 26 Prod3-Metric
- ☐ 27 Deep Lake Gas/Water RelPerm
- ☒ 28 OilWater Well1 RelPerm
- ☐ 29 OilWater Well1 RelPerm Metric
- ☐ 30 OilWater Well2 RelPerm

**Reservoir Pressure Data**

☐ Import Reservoir Pressure and Volumes from PDA  
☐ Import Material Balance Model for Reservoir Pressure Calculation  
☒ Enter Minimum Reservoir Pressure and Volume Produced

Minimum Pressure:  psi  
 Volume Produced:  mbbls

**Cancel** **Import Data**

Figure PVT-21: Production-Based Relative Permeability Tool – Data Import

Selecting the 'Import Material BalanceModel for Reservoir Pressure Calaculation' option will open another screen (Figure PVT-22) to choose the location of the MBal model that is to be used.

Selection for Material Balance Input

☐ Import From PDA Well  
☒ Import From PE Tools MBal Model

Import

Cancel

#	Select	PE Tools MBal Models
1	<input type="checkbox"/>	Depletion Drive Ahmed pg 759
2	<input type="checkbox"/>	MB Oil Reservoir Schilthuis
3	<input type="checkbox"/>	Oil Reservoir Depletion Drive
4	<input type="checkbox"/>	Oil Reservoir - Depletion Drive Metric
5	<input type="checkbox"/>	Oil Reservoir - Smith et al page 12-71

Figure PVT-22: Production-Based Relative Permeability Tool – MBal Model Import

When the PDA option is chosen, all available data will be displayed so the desired value can be chosen (Figure PVT-23).

In-Place Volume Input

PDA INTERPRET-PDA WFlood Data

☐ 22222    ☐ 21407  
☐ 13557    ☐ 19814  
 Average EUR: ☐ 19250

PDA In-Place: ☐ 75250  
 MBal In-Place: ☒ OOIP

Rel Perm OOIP

OOIP

Return

Figure PVT-23: Production-Based Relative Permeability Tool – OOIP Import

The imported data can now be plotted (Figure PVT-24) and the OOIP and saturations can be modified until a match is obtained (Figure PVT-25).

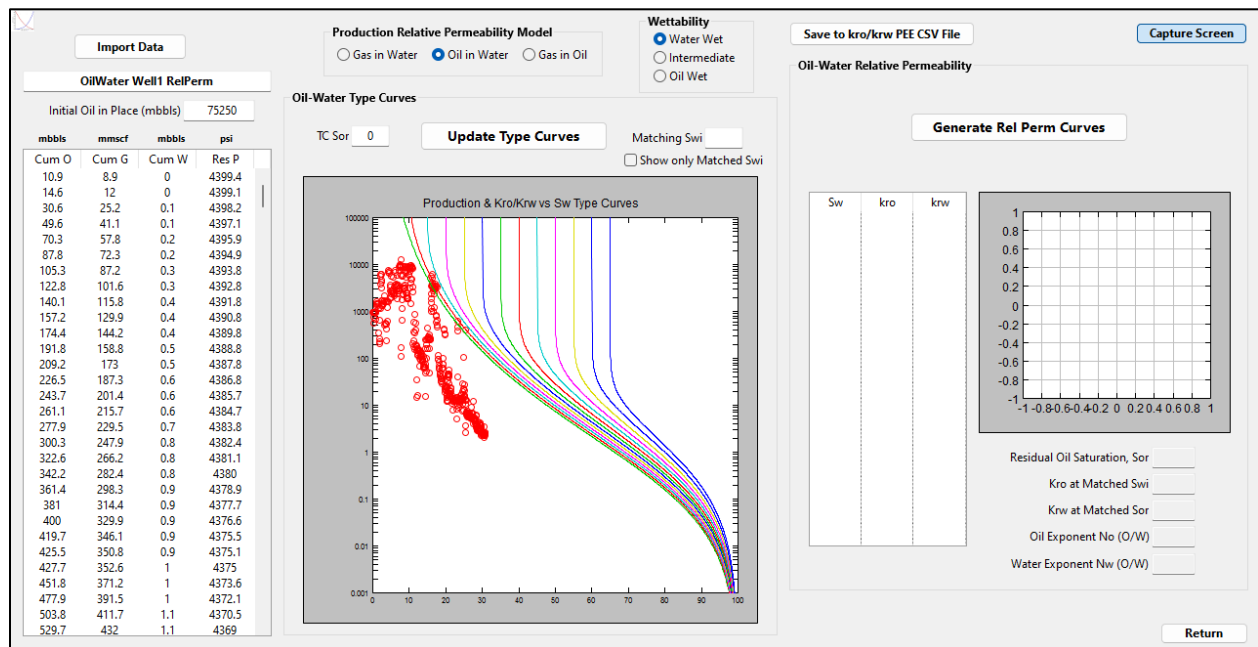


Figure PVT-24: Production-Based Relative Permeability Tool – Production Data

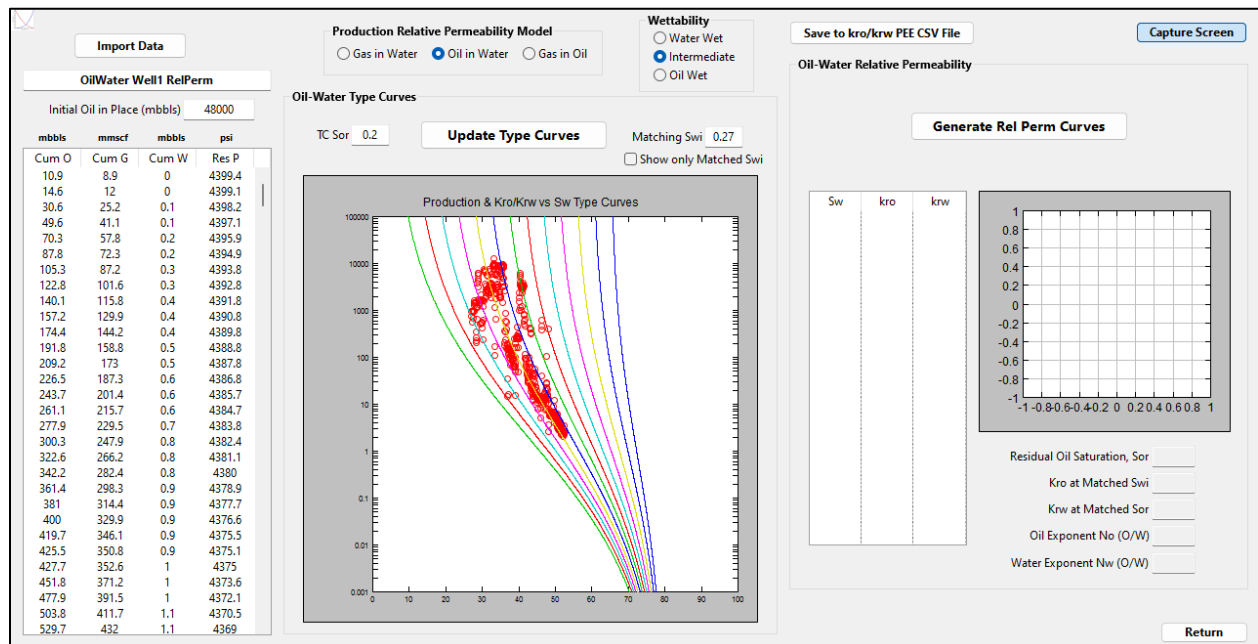


Figure PVT-25: Production-Based Relative Permeability Tool – Production Data Match

For this example, the initial  $S_w$  was known to be 0.27, so OOIP and  $S_{or}$  were used for matching. To make the final refinement on the match, check the box 'Show only Matched  $S_{wi}$ '. Click the "Generate Rel Perm Curves to generate the pseudo relative permeability data for the well (Figure PVT-26).

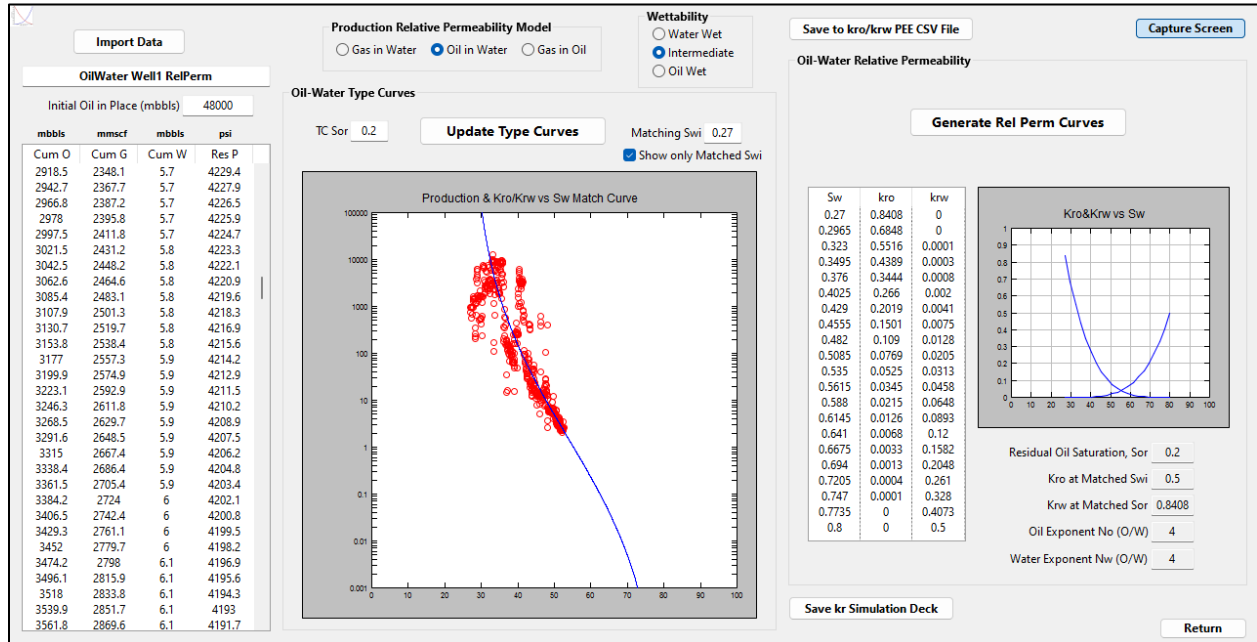


Figure PVT-26: Production-Based Relative Permeability Tool – Rel Permeability Generation

To see the results and for debugging purposes, a CSV file can be generated (Figure PVT-27).

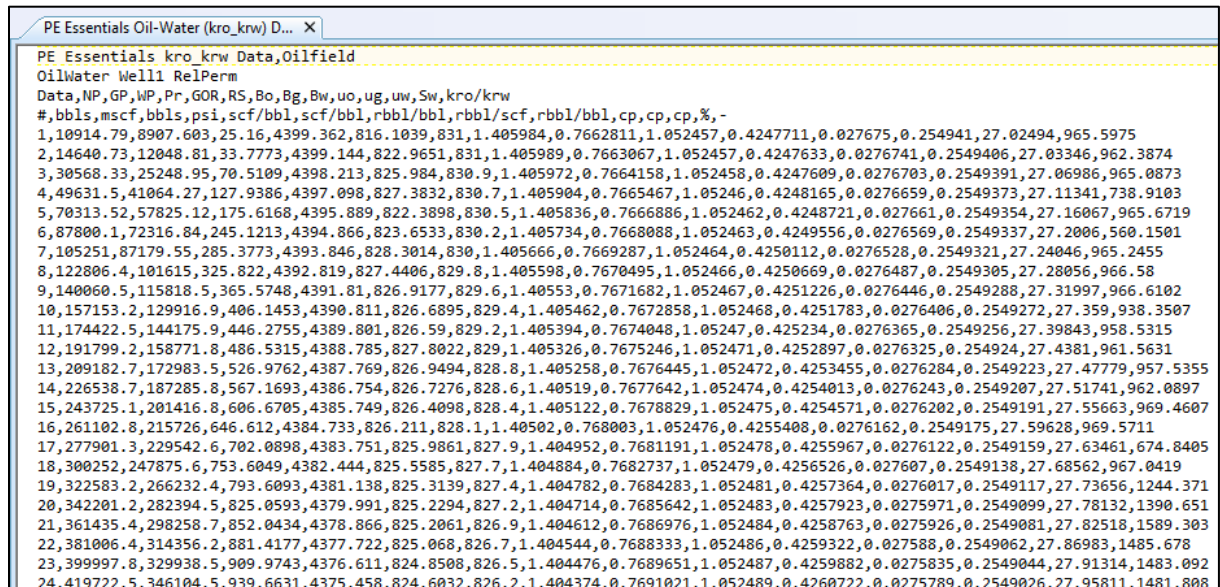


Figure PVT-27: Production-Based Relative Permeability Tool – Calculation Output

## Basic Equation of State (EOS) PVT Tool

If fluid component data is available, then the PE<sup>2</sup> Essentials 'Basic EOS PVT – Oil' tool (Figure EOS-1) can be used to generate oil PVT and separator properties.

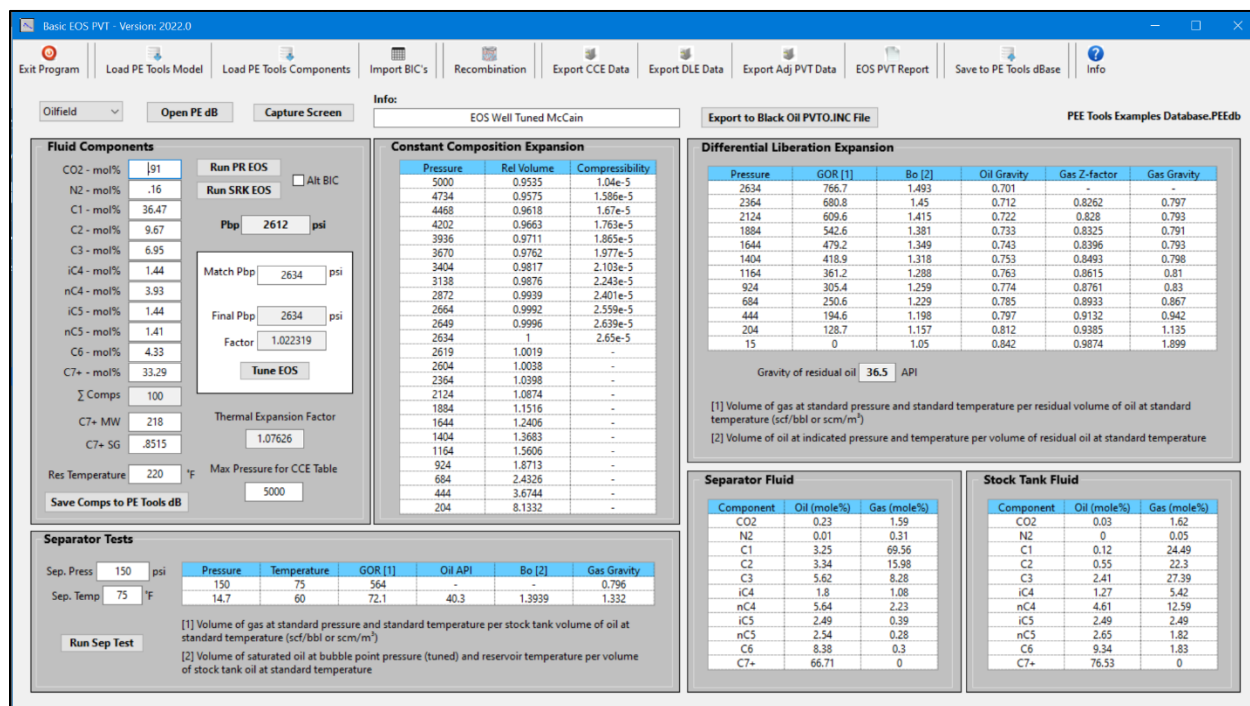


Figure EOS-1: PE<sup>2</sup> Essentials Basic EOS PVT – Oil Tool

For a complete description on solving equations of state, refer to Chapter 15 in McCain, W. D., The Properties of Petroleum Fluids, Second Edition, PennWell Books, 1990 and Chapter 15 in Ahmed, T., Reservoir Engineering Handbook, Second Edition, Gulf Professional Publishing, 2001.

### EOS.1 Equations of State

The PE<sup>2</sup> Essentials Basic EOS tool generates PVT properties by performing EOS analysis of the recombined reservoir fluid. The current EOS implementation is restricted to 11 components: N<sub>2</sub>, CO<sub>2</sub>, C<sub>1</sub> to C<sub>6</sub> and a C<sub>7+</sub> pseudo component – hence the tool's title of "Basic EOS". Only the Soave-Redlich-Kwong and Peng-Robinson EOS formulations are available in this version of the tool.

An EOS is a PVT relationship comprising an empirical cubic equation relating pressure to the volume and temperature of the petroleum fluid. Although there are correlations available to generate PVT properties, an EOS equation is normally required to accurately model the volumetric and phase behaviour of petroleum fluids and to predict the performance of surface separation facilities.

For input to EOS calculations the following component properties (Table EOS-1) are used (GPA Midstream Standard 2145-16, Table of Physical Properties for Hydrocarbons and Other Compounds of Interest to the Natural Gas and Natural Gas Liquids Industries, 2017).

Comp	Mol Wt	Tc (°R)	Pc (psia)	SG (liquid)	SG (gas)	Acentric Factor
H <sub>2</sub> S	34.08	671.58	1305.3	0.7989	1.1767	0.1005
N <sub>2</sub>	44.01	227.14	492.5	0.8069	0.9672	0.0372
CO <sub>2</sub>	28.01	547.43	1070.0	0.8172	1.5195	0.2239
CH <sub>4</sub>	16.04	343.01	667.1	0.3000	0.5539	0.0114
C <sub>2</sub> H <sub>6</sub>	30.07	549.58	706.7	0.3563	1.0382	0.0995
C <sub>3</sub> H <sub>8</sub>	44.10	665.80	616.6	0.5072	1.5225	0.1521
iC <sub>4</sub> H <sub>10</sub>	58.12	734.06	526.3	0.5628	2.0068	0.1835
nC <sub>4</sub> H <sub>10</sub>	58.12	765.23	550.6	0.5842	2.0068	0.2008
iC <sub>5</sub> H <sub>12</sub>	72.15	828.63	489.9	0.6251	2.4911	0.2274
nC <sub>5</sub> H <sub>12</sub>	72.15	845.46	488.8	0.6307	2.4911	0.2515
C <sub>6</sub> H <sub>14</sub>	86.18	913.47	436.9	0.6641	2.9754	0.2986
C <sub>7</sub> H <sub>16</sub>	100.20	972.23	396.8	0.6882	3.4597	0.3494
C <sub>8</sub> H <sub>18</sub>	114.23	1023.89	360.7	0.7066	3.9440	0.3971
C <sub>9</sub> H <sub>20</sub>	128.26	1070.19	330.8	0.7222	4.4283	0.4433
C <sub>10</sub> H <sub>22</sub>	142.28	1111.86	305.0	0.7346	4.9126	0.4884

Table EOS-1: EOS Component Properties (GPA Data Tables - 2017)

For analysis of real fluids, components higher than C<sub>7</sub> are “lumped” together and reported as C<sub>7+</sub>. To use the C<sub>7+</sub> component in analysis, it is necessary to determine the equivalent properties of Tc, Pc, true boiling point (Tb), and acentric factor ( $\omega$ ) for the lumped component. The Tc, Pc and Tb parameters are calculated using the correlations developed by Riazi and Daubert and  $\omega$  is calculated using the Edmister correlation. The development of these correlations is presented in the book “Characterization and Properties of Petroleum Fractions”, M.R.Riazi, ASTM International, 2005; Pages 48-49 and 65.

The general equation for calculating Tc, Pc and Tb is as follows:

$$\text{Parameter} = a * MW^b * SG^c * \exp(d * M + e * SG + f * M * SG) \quad (\text{EOS-1a})$$

Where Parameter is Tc (°R), Pc (psi), or Tb (°R); MW is the molecular weight of the C<sub>7+</sub> component; SG is the specific gravity of the C<sub>7+</sub> component; and a, b, c, d, e, f are constants that are dependent on the chosen parameter and are presented in Figure EOS-2.

Parameter	a	b	c	d	e	f
<b>Tc</b>	554.4	0.2998	1.055	-0.00013478	-0.61641	0
<b>Pc</b>	45203.01	-0.8063	1.6015	-0.0018078	-0.3084	0
<b>Tb</b>	6.77857	0.40167	-1.58262	0.00377409	2.984036	-0.00425288

Figure EOS-2: Riazi and Daubert Correlation Coefficients

The following equation is used to calculate  $\omega$  for the  $C_{7+}$  component.

$$\omega = 0.42857 * T_b/T_c / (1-T_b/T_c) * \log_{10}(P_c / 14.696) - 1 \quad (\text{EOS-1b})$$

Where  $T_c$  ( $^{\circ}\text{R}$ ),  $P_c$  (psi), and  $T_b$  ( $^{\circ}\text{R}$ ) are the parameters for the  $C_{7+}$  component

The simplest and commonly known equation of state is the ideal gas law.

$$PV = RT \quad (\text{EOS-2})$$

Where  $V$  is the gas volume in  $\text{ft}^3/\text{mole}$ ,  $P$  is pressure in psia,  $T$  is temperature in  $^{\circ}\text{R}$  and  $R$  is the universal gas constant =  $10.73 \text{ psi}\cdot\text{ft}^3/\text{lb}\cdot\text{mol}\cdot^{\circ}\text{R}$ .

The ideal gas law was experimentally derived and is only valid for hydrocarbon gases near atmospheric pressure. For pressures and temperatures found in petroleum reservoirs, physical properties calculated with the ideal gas law can lead to errors in excess of 500%. This is because real gases (natural gases) do not behavior as an ideal gas. Basically, the magnitude of deviations of real gases from the conditions of the ideal gas law increases with increasing pressure and temperature and varies widely with the composition of the gas. The reason for this is that the ideal gas law was derived under the assumption that the volume of molecules is insignificant and molecular neither attraction nor repulsion takes place. This is not the case for real gases.

In order to express a more exact relationship between the variables  $P$ ,  $V$ , and  $T$ , a correction factor called the gas compressibility factor (the gas deviation factor, or simply the  $Z$ -factor) is introduced, that is equation (EOS-2) becomes  $PV = ZRT$ . This equation is valid for real gases, gases at in situ conditions, but has limitations for condensate and oil fluids. The limitations of the real gas law have led to a number of attempts to develop an equation of state that was valid for describing real fluids at extended ranges of pressure and temperature. The Soave-Redlich-Kwong (SRK) and Peng-Robinson (PR) versions of the EOS are implemented in PE<sup>2</sup> Essentials.

There are a number of components that go into an EOS formulation, one is the development of the cubic equation itself (SRK and PR) describing properties of pure fluids, and the second is the mixing rule used to calculate mixture parameters that are equivalent to pure substances.

All EOS equations are extensions of the Van der Waals equation of state. In 1872 Van der Waals PhD dissertation presented an equation that attempted to remove the pressure and temperature limitations of the ideal gas law. Van der Waals proposed equation was as follows.



$$P = \frac{RT}{(V - b)} - \frac{a}{V^2} \quad (\text{EOS-3})$$

Where  $V$  is the gas volume in  $\text{ft}^3/\text{mole}$ ,  $P$  is pressure in psia,  $T$  is temperature in  $^\circ\text{R}$ ,  $R$  is the universal gas constant =  $10.73 \text{ psi}\cdot\text{ft}^3/\text{lb}\cdot\text{mol}\cdot^\circ\text{R}$ , and  $a$  and  $b$  are constants that characterize the molecular properties of the components.

The  $a/V^2$  term represents a correction for the forces of attraction between the molecules which results in a reduced pressure exerted by the real gas when compared to an ideal gas. The  $RT/(V - b)$  term represents the force of repulsion caused by the molecules which will increase the pressure of a real gas when compared to an ideal gas.

Expansion of Van der Waals EOS equation yields the following cubic equation.

$$V^3 - (b + RT/P)V^2 + (a/P)V - ab/P = 0$$

This equation has two empirical constants ' $a$ ' and ' $b$ ', and is termed a cubic equation of state. Since Van de Waals equation was accurate only at low pressures, all subsequent EOS equation formulations included extensions/modifications to Van de Waals equation to correct for the pressure limitation.

The Van de Waal equation (and all EOS equations) must satisfy the following conditions at the critical temperature and critical pressure points.

$$\partial P/\partial V = 0 \text{ and } \partial^2 P/\partial V^2 = 0$$

Differentiating Van der Waals EOS equation with respect to volume at the critical point results in the following values for  $a$  and  $b$  for a pure component.

$$a = \text{cons}_1 R^2 T_c^2 / P_c \quad (\text{EOS-4})$$

$$b = \text{cons}_2 R T_c / P_c \quad (\text{EOS-5})$$

Where  $\text{cons}_1$  and  $\text{cons}_2$  are dimensionless pure component parameters and have values that are dependent on the actual EOS formulation. For a multi-component system, a mixing rule must be applied (Section EOS.4) to determine the ' $a$ ' and ' $b$ ' terms.

The two most common EOS equations used in the industry were developed by Redlich and Kwong with a modification by Soave (Redlich, O. and Kwong, J. N. S., "On the Thermodynamics of Solutions. V-An Equation of State. Fugacities of Gaseous Solutions", Chemical Reviews, 1949; and Soave, G., "Equilibrium Constants from a Modified Redlich-Kwong Equation of State", Chemical Engineering Science, 1972), and Peng and Robinson (Peng, D. and Robinson, D. B., "A New Two-Constant Equation of State", Industrial & Engineering Chemistry Fundamentals, 1976).



## EOS.2 Soave-Redlich-Kwong (SRK) EOS

Redlich and Kwong showed that adjustment of the attractive force term would considerably improve the prediction capabilities of Van der Waals EOS equation. The resulting Redlich-Kwong EOS is as follows.

$$P = \frac{RT}{(V - b)} - \frac{a}{V(V + b)T^{0.5}}$$

In 1972, Soave replaced the term  $a/T^{0.5}$  in the Redlich-Kwong equation to a more generalized temperature dependent term,  $a_T$ . The Soave-Redlich-Kwong EOS was the first modification of the simple Redlich-Kwong EOS where the parameter 'a' was made temperature dependent in such a way that the vapour pressure curve was more accurately reproduced.

$$P = \frac{RT}{(V - b)} - \frac{a_T}{V(V + b)} \quad (\text{EOS-6})$$

$$a_T = a_c \alpha$$

Where  $a_c$  is the value of  $a_T$  at the critical temperature and  $\alpha$  is a dimensionless temperature-dependent term that becomes 1 at the critical temperature ( $\alpha = 1$  when  $T = T_c$ ). The term  $\alpha$  is defined as follows.

$$\alpha = [1 + m(1 - T_{pr}^{0.5})]^2 \quad (\text{EOS-7})$$

Where  $T_{pr}$  is the reduced temperature and the parameter  $m$  is defined as follows (Grabowski M. S. and Daubert, T. E., "A Modified Soave Equation of State for Phase Equilibria Calculations 1. Hydrocarbon Systems", Industrial & Engineering Chemistry Process Design and Development, 1978, Volume 17).

$$m = 0.48508 + 1.5517\omega - 0.15613\omega^2 \quad (\text{EOS-8})$$

Where  $\omega$  is the acentric factor and is obtained from the GPSA tables.

Expanding the SRK equation and differentiating with respect to volume at the critical point results in the following values for  $a_c$  and  $b$  for any pure component.

$$a_c = 0.42747 R^2 T_c^2 / P_c \quad (\text{EOS-9})$$

$$b = 0.08664 R T_c / P_c \quad (\text{EOS-10})$$

Where  $b$  modifies the actual molar volume,  $V$ , to account for high pressure effects, and  $a_c$  is a measure of the intermolecular attractive forces.

The EOS requires three input parameters per pure compound:  $T_c$ ,  $P_c$  and  $\omega$ . For a multi-component system, a mixing rule must be applied (Section EOS.4) to determine the  $a_c$  and  $b$  terms.

### EOS.3 Peng-Robinson (PR) EOS

In 1976 Peng and Robinson performed an in-depth study of the capability of the SRK EOS to predict the behaviour of hydrocarbon systems and published an improved model as follows.

$$P = \frac{RT}{(V - b)} - \frac{a_T}{V(V + b) + b(V - b)} \quad (\text{EOS-11})$$

$$a_T = a_c \alpha$$

Where  $a_c$  is the value of  $a_T$  at the critical temperature and  $\alpha$ , which is equivalent to the SRK term, is a dimensionless temperature-dependent term that becomes 1 at the critical temperature ( $\alpha = 1$  when  $T = T_c$ ). The term  $\alpha$  was defined as Equation EOS-8.

$$\alpha = [1 + m(1 - T_{pr}^{0.5})]^2 \quad (\text{EOS-12})$$

Where  $T_{pr}$  is the reduced temperature and the parameter  $m$  is defined as follows.

$$m = 0.37464 + 1.54226\omega - 0.26992\omega^2 \quad (\text{EOS-13})$$

Where  $\omega$  is the acentric factor and is obtained from the GPSA tables.

Peng and Robinson recommended a modified equation for the parameter  $m$  when  $\omega > 0.49$  (heavier components) as follows.

$$m = 0.379642 + 1.48503\omega - 0.1644\omega^2 + 0.016667\omega^3 \quad (\text{EOS-14})$$

Expanding the PR equation and differentiating with respect to volume at the critical point results in the following values for  $a_c$  and  $b$  for any pure.

$$a_c = 0.45724 R^2 T_c^2 / P_c \quad (\text{EOS-15})$$

$$b = 0.07780 R T_c / P_c \quad (\text{EOS-16})$$

Where  $b$  modifies the actual molar volume,  $V$ , to account for high pressure effects, and  $a_c$  is a measure of the intermolecular attractive forces.

The EOS requires three input parameters per pure compound:  $T_c$ ,  $P_c$  and  $\omega$ . For a multi-component system, a mixing rule must be applied (Section EOS.4) to determine the  $a_c$  and  $b$  terms.

## EOS.4 Mixing Rule and Binary Interaction Coefficients

The SRK and PR equations of state were developed for pure fluids. To extend their use to mixtures it is necessary to apply a mixing rule. The mixing rule is simply a technique that calculates parameters for the mixture that results in the equivalent of a pure fluid. The mixing rule applies corrections to the  $a_T$  and  $b$  terms used in the EOS formulation.

There are a number of mixing rules that have been published and they all yield slightly different results. PE<sup>2</sup> Essentials uses the mixing rules suggested by McCain (McCain, W. D., The Properties of Petroleum Fluids, Second Edition, PennWell Books, 1990). These mixing rules are as follows.

$$a_T = \sum_i \sum_j y_i y_j (a_{Ti} a_{Tj})^{0.5} (1 - \delta_{ij}) \quad (\text{EOS-17})$$

$$b = \sum_j y_j b_j \quad (\text{EOS-18})$$

Where  $\delta_{ij}$  are the binary interaction coefficients (BIC's) and are the result of interaction between unlike molecules ( $i$  and  $j$  represent the component).

Values for the BIC's are empirically derived from PVT data of binary mixtures of the compounds of interest. BIC's are dependent on the difference in molecular sizes of the two components. The BIC's have different values for each binary pair and are normally different for the different equations of state.

The PE<sup>2</sup> Essentials EOS model includes options for three different set of BIC's. The BIC's and derivation techniques were presented by Ahmed (Ahmed, T. H., Equations of State and PVT Analysis: Applications for Improving Reservoir Modeling, Gulf Publishing Company, 2007 and in Ahmed, T., Reservoir Engineering Handbook, Second Edition, Gulf Professional Publishing, 2001).

The PE<sup>2</sup> Essentials PR EOS includes the following set of BIC values.

PR_BIC	CO2	N2	C1	C2	C3	iC4	nC4	iC5	nC5	C6	C7+
CO2	0	0	0.105	0.13	0.125	0.12	0.115	0.115	0.115	0.115	0.115
N2	0	0	0.025	0.01	0.09	0.095	0.095	0.1	0.1	0.1	0.1
C1	0.105	0.025	0	0.005	0.01	0.035	0.025	0.05	0.03	0.03	0.118141
C2	0.13	0.01	0.005	0	0.005	0.005	0.01	0.02	0.02	0.02	0.094513
C3	0.125	0.09	0.01	0.005	0	0	0	0.015	0.015	0.01	0.07561
iC4	0.12	0.095	0.035	0.005	0	0	0.005	0.005	0.005	0.005	0.060488
nC4	0.115	0.095	0.025	0.01	0	0.005	0	0.005	0.005	0.005	0.048391
iC5	0.115	0.1	0.05	0.02	0.015	0.005	0.005	0	0	0	0.038712
nC5	0.115	0.1	0.03	0.02	0.015	0.005	0.005	0	0	0	0.03097
C6	0.115	0.1	0.03	0.02	0.01	0.005	0.005	0	0	0	0.024776
C7+	0.115	0.1	0.118141	0.094513	0.07561	0.060488	0.048391	0.038712	0.03097	0.024776	0

Table EOS-2: Binary Interaction Coefficients for PR EOS

Note that the values for C<sub>7+</sub> BIC's in all PE<sup>2</sup> Essentials EOS equations are calculated using Equation EOS-24 as described for the ALT\_BIC calculations presented below.

The PE<sup>2</sup> Essentials SRK EOS includes the following set of BIC values.

SRK_BIC	CO2	N2	C1	C2	C3	iC4	nC4	iC5	nC5	C6	C7+
CO2	0	0	0.1107	0.1363	0.1	0.1	0.1	0.1	0.1	0.1	0.1
N2	0	0	0.0278	0.0407	0.0763	0.0944	0.07	0.0867	0.0878	0.1496	0.12
C1	0.1107	0.0278	0	0	0.009	0.0241	0.0056	0	0.0019	0.0374	0.118141
C2	0.1363	0.0407	0	0	0	0	0.0067	0.005	0.0056	0	0.094513
C3	0.1	0.0763	0.009	0	0	0	0	0.0078	0.0233	0	0.07561
iC4	0.1	0.0944	0.0241	0	0	0	0.0011	0	0	0	0.060488
nC4	0.1	0.07	0.0056	0.0067	0	0.0011	0	0	0.0204	0	0.048391
iC5	0.1	0.0867	0	0.005	0.0078	0	0	0	0	0	0.038712
nC5	0.1	0.0878	0.0019	0.0056	0.0233	0	0.0204	0	0	0	0.03097
C6	0.1	0.1496	0.0374	0	0	0	0	0	0	0	0.024776
C7+	0.1	0.12	0.118141	0.094513	0.07561	0.060488	0.048391	0.038712	0.03097	0.024776	0

Table EOS-3: Binary Interaction Coefficients for SRK EOS

There is a third option for BIC's called 'Alt BIC' that allows the user to enter alternate BIC's for use in either EOS formulation. The Alt BIC's are used by checking the appropriate box on the main screen (Figure EOS-1). The Alt BIC's are entered through the 'ALT\_BICs.Blib' file located in the "PE Essentials\Bin\PE Essentials Basic EOS PVT Libs" directory. To use internally calculated alternate BIC's, delete the Blib file.

The internal alternate BIC calculation is based on molecular weights as described by Ahmed (Ahmed, T. H., Equations of State and PVT Analysis: Applications for Improving Reservoir Modeling, Gulf Publishing Company, 2007).

$$\delta_{C1-C7+} = 0.00189T - 1.167059 \quad (\text{EOS-19})$$

$$\delta_{CO_2 - N_2} = 0.12 \quad (\text{EOS-20})$$

$$\delta_{CO_2\text{-hydrocarbon}} = 0.12 \quad (\text{EOS-21})$$

$$\delta_{N_2\text{-hydrocarbon}} = 0.10 \quad (\text{EOS-22})$$

$$\delta_{Ci-C7+} = 0.8\delta_{C(i-1) - C7+} \quad (\text{EOS-23})$$

$$\delta_{Ci-Cj} = \delta_{Ci-C7+} (M_j^5 - M_i^5) / (M_{C7+}^5 - M_i^5) \quad (\text{EOS-24})$$

Where T is temperature in °R, C<sub>i</sub> and C<sub>j</sub> represents a component (C<sub>2</sub>, C<sub>3</sub>, C<sub>4</sub>, etc), and M<sub>i</sub> and M<sub>j</sub> is the molecular weight of component C<sub>i</sub> and C<sub>j</sub>.

The internally calculated alternate BIC's, which are included in the PE<sup>2</sup> Essentials ALT\_BICs.Blib file (assuming 200°F in Eqn. EOS-19), are presented in Table EOS-4.

ALT_BIC	CO2	N2	C1	C2	C3	iC4	nC4	iC5	nC5	C6	C7+
CO2	0	0.12	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
N2	0.12	0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
C1	0.1	0.1	0	0.000054	0.000038	0.000152	0.000152	0.000448	0.000448	0.001089	0.080341
C2	0.1	0.1	0.000054	0	0.000026	0.000117	0.000117	0.000354	0.000354	0.000867	0.064273
C3	0.1	0.1	0.000038	0.000026	0	0.000073	0.000073	0.000262	0.000262	0.000673	0.051418
iC4	0.1	0.1	0.000152	0.000117	0.000073	0	0	0.000152	0.000152	0.000481	0.041134
nC4	0.1	0.1	0.000152	0.000117	0.000073	0	0	0.000121	0.000121	0.000384	0.032908
iC5	0.1	0.1	0.000448	0.000354	0.000262	0.000152	0.000121	0	0	0.000211	0.026326
nC5	0.1	0.1	0.000448	0.000354	0.000262	0.000152	0.000121	0	0	0.000169	0.021061
C6	0.1	0.1	0.001089	0.000867	0.000673	0.000481	0.000384	0.000211	0.000169	0	0.016849
C7+	0.1	0.1	0.080341	0.064273	0.051418	0.041134	0.032908	0.026326	0.021061	0.016849	0

Table EOS-4: Internal Alternate Binary Interaction Coefficients for PR and SRK EOS

It is possible to enter alternate BIC's through the 'Import BIC's' button on the main screen. The BIC values to be imported must be in an Excel file in the format shown in Figure EOS-3.

The file shown in Figure EOS-5 is called ALT\_BICs.xlsx and is included in the "PE Essentials\Example Input Files\Basic EOS" directory.

	ALT_BICs	CO2	N2	C1	C2	C3	iC4	nC4	iC5	nC5	C6	C7+ at 200F
1	ALT_BICs	CO2	N2	C1	C2	C3	iC4	nC4	iC5	nC5	C6	C7+ at 200F
2	CO2	0	0.12	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
3	N2	0.12	0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
4	C1	0.1	0.1	0	0.000054	0.000038	0.000152	0.000152	0.000448	0.001089	0.080341	
5	C2	0.1	0.1	0.000054	0	0.000026	0.000117	0.000117	0.000354	0.000867	0.064273	
6	C3	0.1	0.1	0.000038	0.000026	0	0.000073	0.000073	0.000262	0.000673	0.051418	
7	iC4	0.1	0.1	0.000152	0.000117	0.000073	0	0	0.000152	0.000481	0.041134	
8	nC4	0.1	0.1	0.000152	0.000117	0.000073	0	0	0.000121	0.000384	0.032908	
9	iC5	0.1	0.1	0.000448	0.000354	0.000262	0.000152	0.000121	0	0	0.000211	0.026326
10	nC5	0.1	0.1	0.000448	0.000354	0.000262	0.000152	0.000121	0	0	0.000169	0.021061
11	C6	0.1	0.1	0.001089	0.000867	0.000673	0.000481	0.000384	0.000211	0.000169	0	0.016849
12	C7+	0.1	0.1	0.080341	0.064273	0.051418	0.041134	0.032908	0.026326	0.021061	0.016849	0
13												
14												
15												
16	ALT_BICs	CO2	N2	C1	C2	C3	iC4	nC4	iC5	nC5	C6	C7+
17	CO2	0	0	0	0	0	0	0	0	0	0	0
18	N2	0	0	0	0	0	0	0	0	0	0	0
19	C1	0	0	0	0	0	0	0	0	0	0	0
20	C2	0	0	0	0	0	0	0	0	0	0	0
21	C3	0	0	0	0	0	0	0	0	0	0	0
22	iC4	0	0	0	0	0	0	0	0	0	0	0
23	nC4	0	0	0	0	0	0	0	0	0	0	0
24	iC5	0	0	0	0	0	0	0	0	0	0	0
25	nC5	0	0	0	0	0	0	0	0	0	0	0
26	C6	0	0	0	0	0	0	0	0	0	0	0
27	C7+	0	0	0	0	0	0	0	0	0	0	0

Figure EOS-5: Excel File Containing Alternate BIC's

Figure EOS-6 shows the import of the Alternate BICs from the Excel spreadsheet.

Alt BIC	CO2	N2	C1	C2	C3	iC4	nC4	iC5	nC5	C6	C7+
CO2	0	0.12	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
N2	0.12	0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
C1	0.1	0.1	0	0.000054	0.000038	0.000152	0.000152	0.000448	0.000448	0.001089	0.080341
C2	0.1	0.1	0.000054	0	0.000026	0.000117	0.000117	0.000354	0.000354	0.000867	0.064273
C3	0.1	0.1	0.000038	0.000026	0	0.000073	0.000073	0.000262	0.000262	0.000673	0.051418
iC4	0.1	0.1	0.000152	0.000117	0.000073	0	0	0.000152	0.000152	0.000481	0.041134
nC4	0.1	0.1	0.000152	0.000117	0.000073	0	0	0.000121	0.000121	0.000384	0.032908
iC5	0.1	0.1	0.000448	0.000354	0.000262	0.000152	0.000121	0	0	0.000211	0.026326
nC5	0.1	0.1	0.000448	0.000354	0.000262	0.000152	0.000121	0	0	0.000169	0.021061
C6	0.1	0.1	0.001089	0.000867	0.000673	0.000481	0.000384	0.000211	0.000169	0	0.016849
C7+	0.1	0.1	0.080341	0.064273	0.051418	0.041134	0.032908	0.026326	0.021061	0.016849	0

Figure EOS-6: Import of Alternate BIC's

Importing the BIC's will make them available for use in the EOS equations. To use these BIC's in future runs, they should be saved to Blib library through the 'Save Alt BIC's to BLIB Library' button.

The alternate BIC's are selected through the 'Alt BIC' check box (Figure EOS-1).

## EOS.5 EOS Basic Example and EOS Validation

As a basic example and to validate the PE<sup>2</sup> Essentials implementation of the EOS equations, the fluid study included in the McCain book, The Properties of Petroleum Fluids, was used. The sample analysis included on page 260 in the McCain book was entered into the EOS tool. The actual bubble point pressure for this fluid was reported to be 2620 psi at 220°F. The EOS tool was used to calculate bubble point pressure for the PR and SRK formulations, as well as for the Alt BIC and the results are shown in Figure EOS-7. This EOS model is available in the example PE Tools database.

Figure EOS-7: EOS Bubble Point Pressure Validation – McCain Example

Calculated, untuned bubble point pressures were consistent for all formulations and ranged from 2505 psi to 2564 psi.

## EOS.6 EOS Tuning

When the bubble point pressure is not matched to a satisfactory degree, it is possible to 'tune' the EOS equation to the known bubble point pressure and thereby improve the accuracy of the predictions generated by the EOS.

It has been found that slight changes to the characterization of the  $C_{7+}$  fraction can have a dramatic effect on the EOS-predicted PVT properties of the fluid. As a result, it is possible to 'tune' the EOS equation by modifying just the  $C_{7+}$  properties. The usual technique to tune the EOS equation is to modify the critical properties ( $T_c$  and  $P_c$ ) and the BIC's of the  $C_{7+}$  component until a match is achieved.

Since  $T_c$  and  $P_c$  for the  $C_{7+}$  fraction are calculated from correlations based on molecular weight (Equations PVT-13 and PVT-14), tuning the PE<sup>2</sup> Essentials EOS model is restricted to modification of the  $C_{7+}$  BIC's. It should be noted that binary interaction coefficients are the big 'fudge factors' in EOS analysis since they are not unique and normally determined through empirical means.

Specialty EOS programs incorporate tuning techniques for all laboratory measured data so that the final EOS equation can regenerate the complete lab data set. The PE<sup>2</sup> Essentials EOS model is a basic implementation and tunes on bubble point pressure only. If a more in-depth EOS formulation is required, other programs should be used.

Based on the bubble point pressure results for the PR EOS (Section EOS.5), the PR EOS was tuned to the lab-derived bubble point pressure of 2620 psig (2634.5 psia) with the results presented in Figure EOS-8. The resulting tuned BIC's are presented in Table EOS-5.

Fluid Components	
CO2 - mol%	.91
N2 - mol%	.16
C1 - mol%	36.47
C2 - mol%	9.67
C3 - mol%	6.95
iC4 - mol%	1.44
nC4 - mol%	3.93
iC5 - mol%	1.44
nC5 - mol%	1.41
C6 - mol%	4.33
C7+ - mol%	33.29
Σ Comps	100
C7+ MW	218
C7+ Specific Gravity	.8515
Res Temperature	220 °F

Run PR EOS	<input type="checkbox"/> Alt BIC
Run SRK EOS	
Pbp	2564 psi
Match Pbp	2634.5 psi
Final Pbp	2634 psi
Factor	1.07029
Tune EOS	
Thermal Expansion Factor for Saturated Oil	
1.07377	

Figure EOS-8: Tuned Bubble Point Pressure – McCain Example



PR Tuned	CO2	N2	C1	C2	C3	iC4	nC4	iC5	nC5	C6	C7+
CO2	0	0	0.105	0.13	0.125	0.12	0.115	0.115	0.115	0.115	0.115
N2	0	0	0.025	0.01	0.09	0.095	0.095	0.1	0.1	0.1	0.1
C1	0.105	0.025	0	0.005	0.01	0.035	0.025	0.05	0.03	0.03	0.126445
C2	0.13	0.01	0.005	0	0.005	0.005	0.01	0.02	0.02	0.02	0.101156
C3	0.125	0.09	0.01	0.005	0	0	0	0.015	0.015	0.01	0.080925
iC4	0.12	0.095	0.035	0.005	0	0	0.005	0.005	0.005	0.005	0.06474
nC4	0.115	0.095	0.025	0.01	0	0.005	0	0.005	0.005	0.005	0.051792
iC5	0.115	0.1	0.05	0.02	0.015	0.005	0.005	0	0	0	0.041434
nC5	0.115	0.1	0.03	0.02	0.015	0.005	0.005	0	0	0	0.033147
C6	0.115	0.1	0.03	0.02	0.01	0.005	0.005	0	0	0	0.026518
C7+	0.115	0.1	0.126445	0.101156	0.080925	0.06474	0.051792	0.041434	0.033147	0.026518	0

Table EOS-5: BIC's for Tuned Bubble Point Pressure – McCain Example

As confirmed in Table EOS-5, only the C<sub>7+</sub> BIC's were modified to achieve the bubble point pressure match. The modification was to increase the C<sub>7+</sub> BIC's by a factor of 1.07029 as shown on Figure EOS-8.

## EOS.7 EOS Flash Calculations – CCE, DLE, Separator Test

All parameters generated by equations of state are based on flash calculations. Flash calculations are the basis for reservoir and process engineering calculations. A flash calculation is required to determine the number of moles of gas and liquid coexisting in a reservoir or a vessel (separator) at a given pressure and temperature. A flash calculation is also required to determine the composition existing in the resulting gas and liquid phases.

The calculations required for estimation of moles of gas, moles of liquid, composition of the gas and composition of the liquid require an estimate of the equilibrium ratios, also referred to as K-factors. The correlation published by Wilson is incorporated into the PE<sup>2</sup> Essentials EOS model (Wilson, G., "A Modified Redlich-Kwong Equation of State Applicable to General Physical Data Calculations," Paper No15C, 65th AIChE National meeting, May, 1968).

$$K_i = Pr' \exp[5.371(1 + \omega_i)(1 - Tr')] \quad (\text{EOS-25})$$

$$Pr' = P_{c_i}/P$$

$$Tr' = T_{c_i}/(T + 460)$$

Where K<sub>i</sub> is the equilibrium ratio of component i, P<sub>c<sub>i</sub></sub> is the critical pressure of component i in psia, T<sub>c<sub>i</sub></sub> is the critical temperature of component i in °R, T is the temperature in °F, P is the pressure in psia and ω<sub>i</sub> is the acentric factor of component i.

The three main calculations performed with an EOS are the constant composition expansion (CCE), the differential liberation expansion (DLE) and separator tests.



### EOS.7.1 Constant Composition Expansion

The CCE test is performed to determine bubble point pressure, isothermal compressibility of the single-phase fluid, compressibility factors of the gas phase and total hydrocarbon volume as a function of pressure. In the CCE, the total hydrocarbon volume is determined at a number of different pressures through a flash calculation. For this technique, no hydrocarbon material is removed from the system, which leads to the constant composition for the system. The total volume at the bubble point pressure is termed the reference volume and the final CCE data is reported as a ratio of the total volume at a specified pressure to the reference volume (the volume at the saturation pressure) and is termed the relative volume.

The compressibility of the saturated oil can be calculated from the CCE relative volume using Equation EOS-26.

$$C_o = \frac{-1}{V_{rel}} \frac{\partial V_{rel}}{\partial P} = \frac{-1}{V_{rel_2}} \frac{(V_{rel_2} - V_{rel_1})}{(P_2 - P_1)} \quad (\text{EOS-26})$$

Where  $C_o$  is the compressibility in  $\text{psi}^{-1}$ ,  $V_{rel_1}$  is the relative volume at the higher pressure  $P_1$  and  $V_{rel_2}$  is the relative volume at the lower pressure  $P_2$ .

For the McCain example, using the tuned EOS model, the CCE is presented in Figure EOS-9.

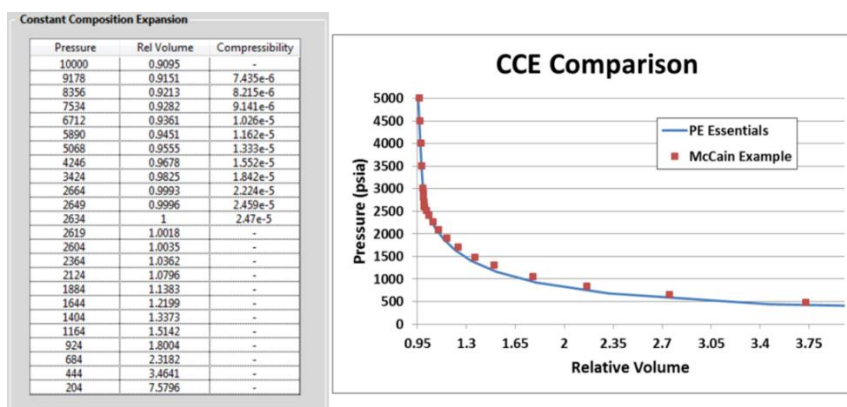


Figure EOS-9: CCE Comparison – McCain Example

The CCE process is indicative of a reservoir's pressure depletion process. As the reservoir pressure is reduced, the gas is liberated but remains in contact/equilibrium with the oil in the reservoir until the gas is produced.

### EOS.7.2 Differential Liberation Expansion

The DLE test yields solution gas oil ratio, oil shrinkage, properties and composition of the liberated gas, specific gravity and density of the remaining oil as function of pressure. During the

DLE test, the liberated gas is removed from the system before establishing a new equilibrium with the remaining liquid. The fluid is maintained as a single phase, gas saturated liquid for each pressure point.

The DLE test is performed to atmospheric pressure and 60°F in order to determine residual, stock tank density of the oil. The results of the DLE test are presented in Figure EOS-10 and a comparison with the lab data is shown in Figure EOS-11.

Overall, the match to the McCain lab data is reasonable for this basic EOS system. To obtain a closer match to the lab data, additional tuning could be attempted by modifying the bubble point pressure.

Pressure	GOR [1]	Bo [2]	Oil Gravity	Gas Z-factor	Gas Gravity
2634	683.8	1.444	0.701	-	-
2364	608.8	1.407	0.712	0.826	0.794
2124	546.2	1.376	0.722	0.8278	0.791
1884	486.8	1.346	0.732	0.8322	0.79
1644	430.2	1.318	0.742	0.8393	0.792
1404	376.2	1.29	0.753	0.849	0.798
1164	324.2	1.263	0.763	0.8612	0.809
924	273.8	1.237	0.774	0.876	0.83
684	224.2	1.21	0.785	0.8933	0.867
444	173.5	1.181	0.797	0.9134	0.94
204	114.1	1.144	0.812	0.9389	1.132
15	0	1.049	0.842	0.9876	1.882

Gravity of residual oil 36.5 API

[1] Volume of gas at standard pressure and standard temperature per residual volume of oil at standard temperature (scf/bbl or scm/m<sup>3</sup>)  
 [2] Volume of oil at indicated pressure and temperature per volume of residual oil at standard temperature

Figure EOS-10: DLE Results – McCain Example

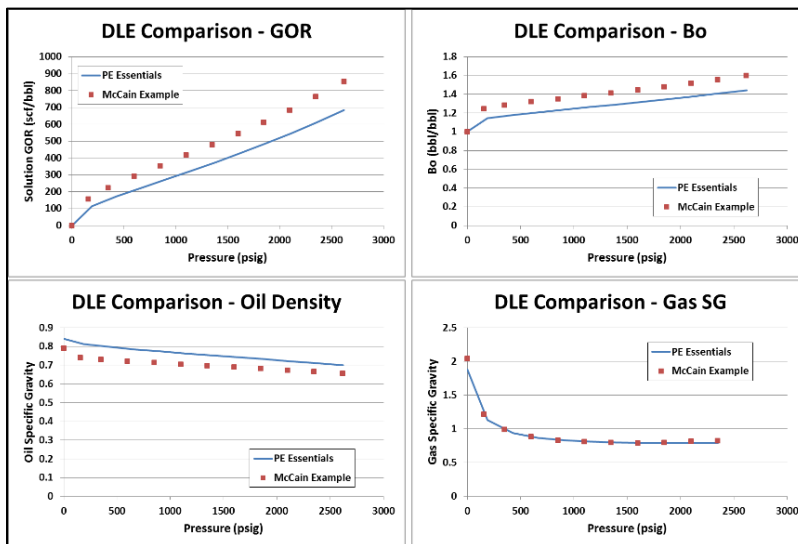


Figure EOS-11: DLE Comparison – McCain Example

The DLE process is indicative of production where reservoir fluid is flashed into the wellbore and produced to the separator. In this process, the gas and oil become independent fluids and the compositions of gas and liquid hydrocarbons in the system will vary. DLE also describes the reservoir process after liberated gas begins to flow, independent of the oil.

### EOS.7.3 Separator Test

Separator tests are run to determine the optimum production conditions that will maximize the volume of stock tank oil. The volumetric behaviour of the stock tank fluid is dependent on the operating conditions of the separator: operating pressure, operating temperature, number of stages. The Basic EOS model will perform a single stage separator test to determine the properties of the stock tank oil at the given separator operating conditions.

The separator test, when combined with the DLE test results, will yield the  $B_o$  and RS data required for petroleum engineering calculations. Separator tests start at the bubble point pressure and reservoir temperature, then proceeds to the separator conditions and finally to stock tank conditions. The separator test is a differential liberation test in that the liberated gas is removed from the system prior to the next step.

The result of the separator test for the McCain example is presented in Figure EOS-12.

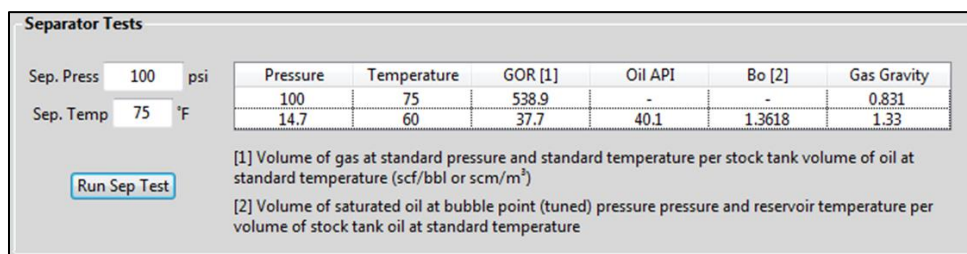


Figure EOS-12: Separator Test Results – McCain Example

By way of comparison, the laboratory data for this separator test yielded a GOR of 768 scf/bbl versus the EOS value of 577 scf/bbl; an oil API of 40.7 versus 40.1, a  $B_o$  of 1.474 versus 1.362. The separator gas composition from the EOS and the McCain laboratory data is shown in Table EOS-6 and indicates that the big difference between the compositions is in the mole% of  $C_1$ .

PR Tuned	PEE EOS Mol%	Lab Mol%
CO2	1.58	1.67
N2	0.3	0.32
C1	66.87	71.08
C2	16.22	15.52
C3	9.34	7.36
iC4	1.35	0.92
nC4	2.96	1.98
iC5	0.55	0.33
nC5	0.41	0.26
C6	0.43	0.27
C7+	0	0.29
Gas SG	0.831	0.786

Table EOS-6: Separator Test Gas Composition Comparison – McCain Example

Following the separator test, the DLE results are adjusted to the separator conditions for use in petroleum engineering calculations (Section EOS.7.5).

### EOS.7.4 Determining Optimum Separator Operating Conditions

Tests are run at a number of separator conditions to determine the optimum separator operating conditions that maximizes recovery of oil. Several separator tests were run using the tuned PR EOS with the McCain example data. The comparative results are presented in Figure EOS-13 for separator operating temperature of 75°F.

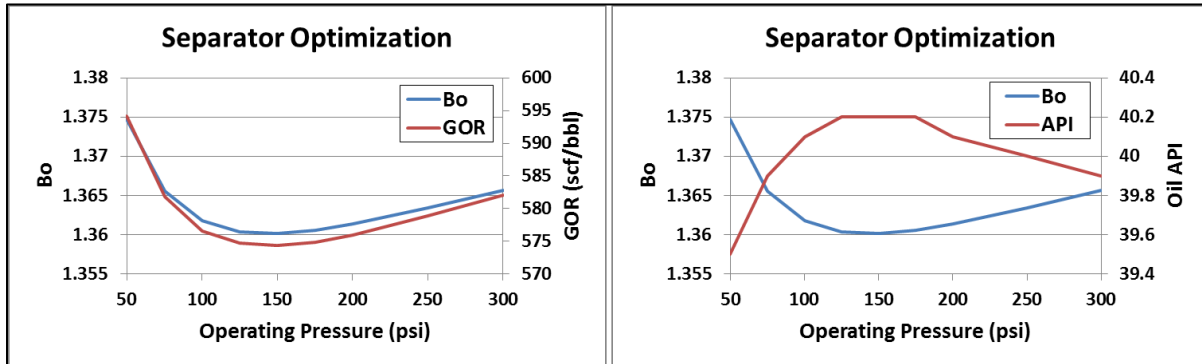


Figure EOS-13: Separator Optimization – McCain Example

From the EOS separator test results, operating the separator at 150 psi and 75°F will maximize oil production. Figure EOS-14 presents the EOS results for the separator test at 150 psi and 75°F.

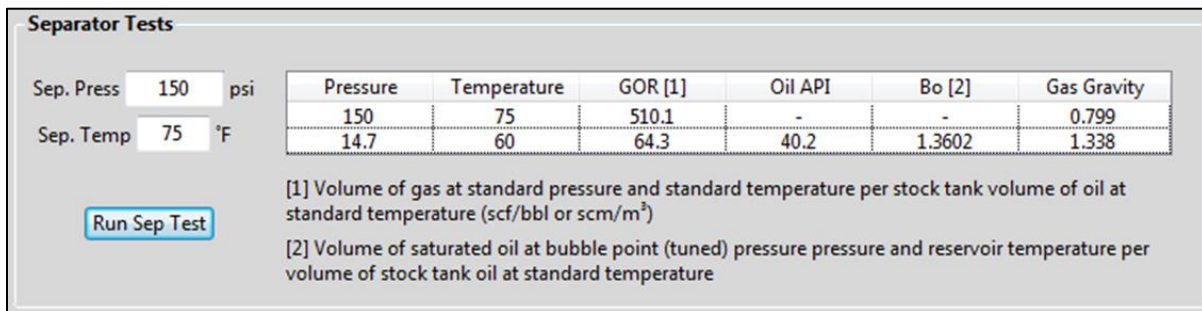


Figure EOS-14: Optimum Separator Test – McCain Example

### EOS.7.5 Adjusting CCE/DLE Data to Optimum Separator Conditions

After determining the optimum separator operating conditions, the CCE and DLE data are adjusted to the separator test results. These adjustments are required in order to use the data in material balance calculations or for input into reservoir simulation models.

First, adjust the formation volume factor,  $B_o$ , above the bubble point pressure (CCE) and below the bubble point pressure (DLE) using the following equations.

$$\text{Above bubble point: } B_o = \text{Sep}B_o \text{ RelVol}$$

$$\text{Below bubble point: } B_o = \text{Sep}B_o \text{ DLE}B_o/\text{DLE}B_{obp}$$

Where  $B_o$  is the value at the relevant pressure,  $SepB_o$  is the value generated by the separator test,  $RelVol$  is the CCE relative volume at the relevant pressure,  $DLEB_o$  is the DLE  $B_o$  at the relevant pressure and  $DLEB_{obp}$  is the DLE  $B_o$  value at the bubble point pressure.

Example: at  $P=5062$  psi,  $SepB_o=1.3602$ ,  $RelVol=0.9555$  then  $B_o=1.2997$

Example: at  $P=1884$  psi,  $SepB_o=1.3602$ ,  $DLEB_o=1.3462$ ,  $DLEB_{obp}=1.4441$  then  $B_o=1.2679$

Next, adjust the solution gas-oil ratio,  $RS$ , using the following equation.

$$RS = SepGOR - (DLEGOR_{bp} - DLEGOR) SepB_o / DLEB_{obp}$$

Where  $RS$  is the value at the relevant pressure,  $SepGOR$  is the value generated by the separator test,  $DLEGOR_{bp}$  is the DLE GOR at the bubble point pressure,  $DLEGOR$  is the DLE GOR at the relevant pressure,  $SepB_o$  is the  $B_o$  value generated by the separator test and  $DLEB_{obp}$  is the DLE  $B_o$  value at the bubble point pressure.

Example  $RS$  for  $P=1884$  psi:

$$SepGOR = 574.4, DLEGOR_{bp} = 683.8, DLEGOR = 486.8$$

$$SepB_o = 1.3602, DLEB_{obp} = 1.4441$$

$$So, RS=388.8 \text{ scf/bbl}$$

These calculations are performed for all the data points. Figure EOS-15 presents the results for the McCain example.

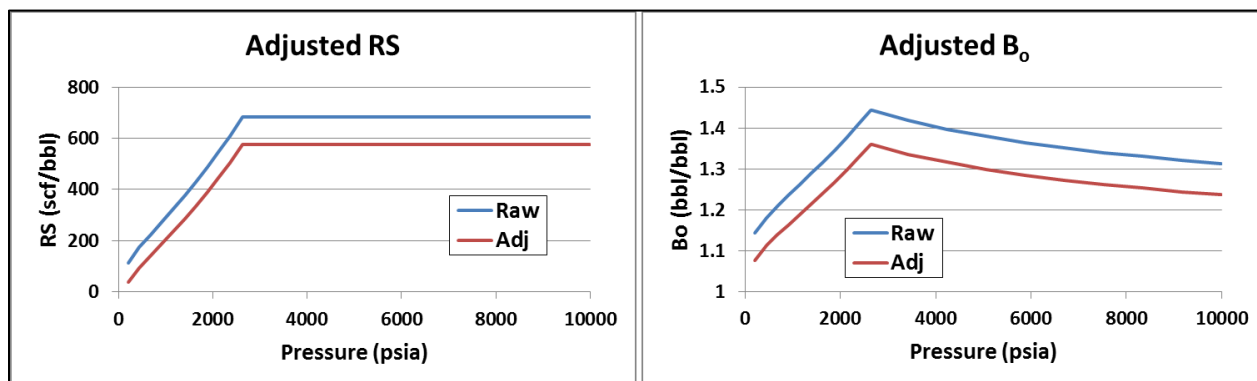


Figure EOS-15: Adjusted Oil Properties – McCain Example

The adjusted oil properties can then be used in material balance calculations or for input into reservoir simulation models. It should be noted that the CCE, DLE and adjusted PVT data can be exported to a CSV file and imported into PE<sup>2</sup> Essentials Chart for basic plotting (Figure EOS-16). Use the 'Export Adj PVT Data' menu button to export the data.

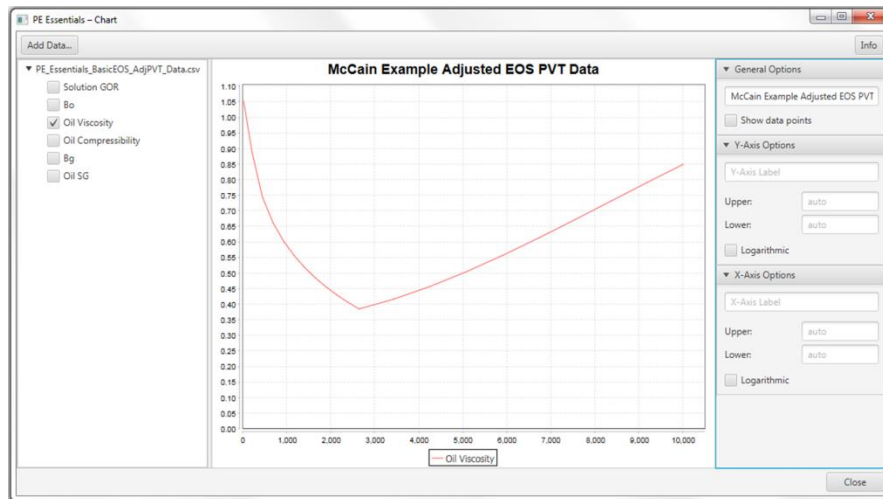


Figure EOS-16: PE<sup>2</sup> Essentials Chart – EOS Data

## EOS.8 Gas-Oil Recombination for EOS

A gas-oil recombination routine is included in the PE<sup>2</sup> Essentials EOS tool and can be used to generate the recombined reservoir fluid from composition analysis of the oil and gas. The recombined fluid compositions can then be transferred to the EOS model for analysis.

Once the liquid and gas compositions are entered, recombination is performed by molar addition of the fluids based on the inputs for gas and oil rates (Figure EOS-17). This allows the regeneration of reservoir fluids for different separator rates.

Separator Fluids		
	Liquid	Gas
CO <sub>2</sub> - mol%	1.65	2.38
N <sub>2</sub> - mol%	.82	1.51
C <sub>1</sub> - mol%	21.14	87.29
C <sub>2</sub> - mol%	5.04	5.77
C <sub>3</sub> - mol%	3.09	1.48
iC <sub>4</sub> - mol%	1.2	.3
nC <sub>4</sub> - mol%	1.91	.39
iC <sub>5</sub> - mol%	1.27	.15
nC <sub>5</sub> - mol%	1.38	.14
C <sub>6</sub> - mol%	3.17	.18
C <sub>7+</sub> - mol%	59.33	.41
Σ Comps	100	100
C <sub>7+</sub> MW	220	218
C <sub>7+</sub> SG	.85	.8

Oil Rate: 500 bopd  
Gas Rate: 275 mscf/d

**Recombined Fluid**

CO <sub>2</sub> - mol%	1.95
N <sub>2</sub> - mol%	1.1
C <sub>1</sub> - mol%	48.44
C <sub>2</sub> - mol%	5.34
C <sub>3</sub> - mol%	2.43
iC <sub>4</sub> - mol%	0.83
nC <sub>4</sub> - mol%	1.28
iC <sub>5</sub> - mol%	0.81
nC <sub>5</sub> - mol%	0.87
C <sub>6</sub> - mol%	1.94
C <sub>7+</sub> - mol%	35.01
C <sub>7+</sub> MW	220
C <sub>7+</sub> SG	0.8497

Figure EOS-17: Gas-Oil Recombination

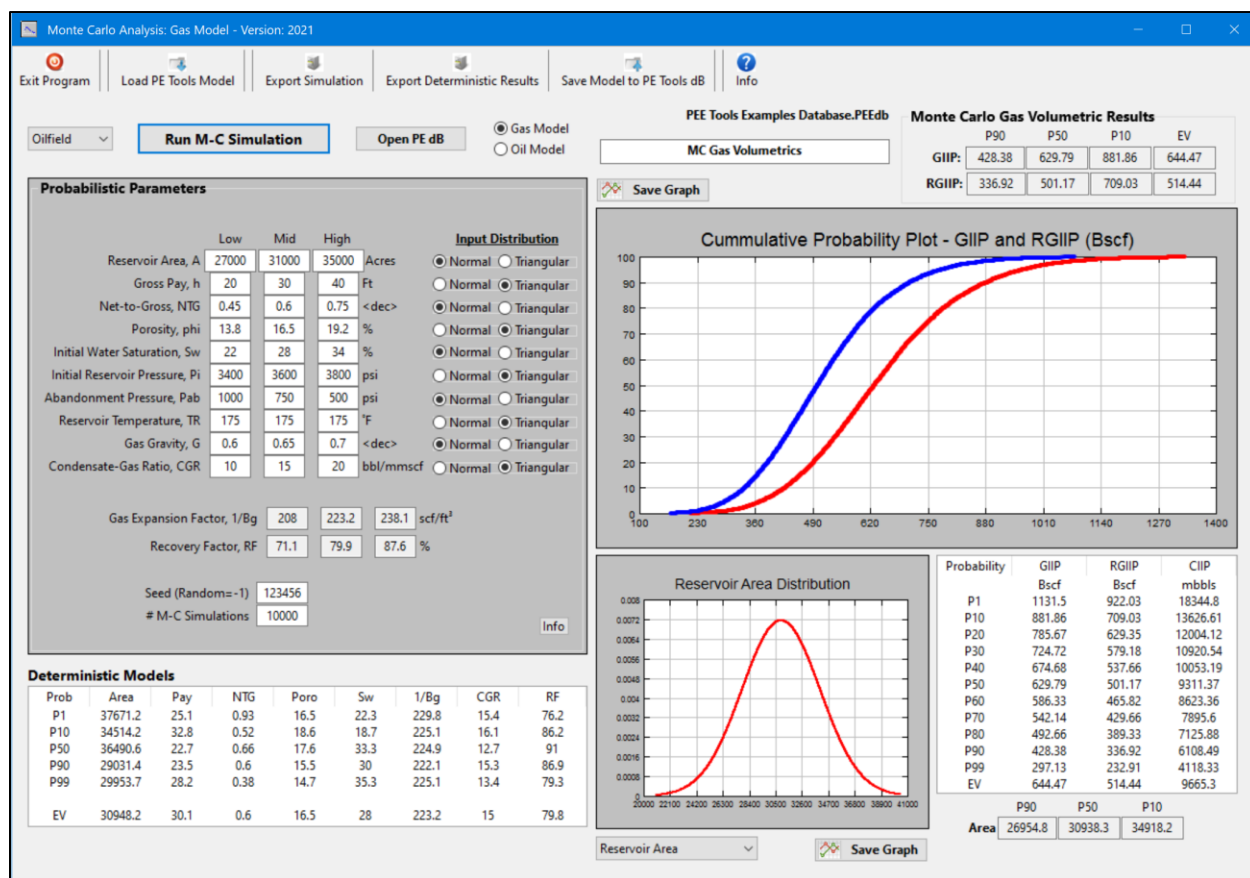
Following recombination, the reservoir fluid can be transferred to the EOS model through the 'Transfer to EOS' button.

## Monte Carlo Simulation: Volumetrics

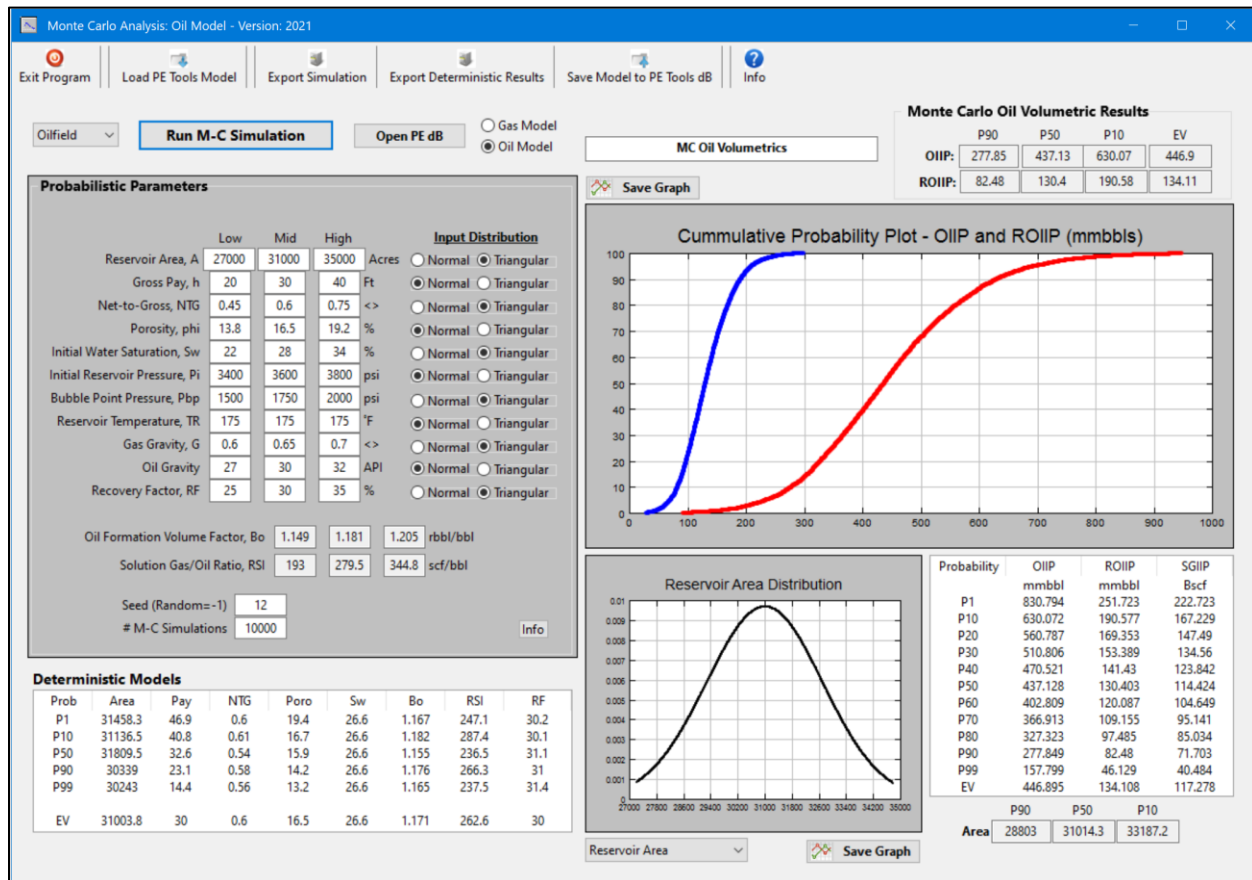
Monte Carlo simulation is a technique that relies on repeated random sampling to obtain numerical results. The purpose is to use randomness to solve problems that might be deterministic in principle. In a Monte Carlo simulation, random values are selected for each of the input variables, within a defined range and distribution of values. The model is calculated based on these random values and the model is recorded. The simulation can be repeated hundreds or thousands of times, each time using different randomly selected values to generate a large number of results, each based on random input values.

When calculating volumetrics, the volume calculation is deterministic, but the input values have a range of possible values. Use of Monte Carlo simulation will generate a range of possible outcomes which can be used in decision analysis. An excellent reference for this subject is the Project Economics book by Mian (Mian, M. A., Project Economics and Decision Analysis Volume II: Probabilistic Models. PennWell, 2011).

PE<sup>2</sup> Essentials includes a ‘Monte Carlo Volumetric’ tool (Figure MCV-1a and 1b) that can be used to generate probabilistic values for oil or gas in-place and recoverable oil/gas volumes.

Figure MCV-1a: PE<sup>2</sup> Essentials Monte Carlo Volumetrics – Gas Reservoir Tool




 Figure MCV-1b: PE<sup>2</sup> Essentials Monte Carlo Volumetrics – Oil Reservoir Tool

The tool includes all the parameters that go into the calculation of in-place and recoverable volumes, not just the reservoir parameters but the fluid parameters as well. Since fluid properties are calculated at each sampling step, the fluid properties are consistent with the reservoir properties at each sample step.

Input parameters to Monte Carlo simulation have a continuous probability distribution. This means that the parameter can have any number within the range of the distribution. The most common distributions used in the oil industry are normal, lognormal, uniform and triangular. For the Monte Carlo Simulation model included in PE<sup>2</sup> Essentials, normal, triangular and uniform can be used. A skewed normal distribution can also be input. Figure MCV-2 shows a normal and a skewed normal probability distribution.

It is possible to use a triangular distribution for the input parameters. The triangular distribution is similar to a skewed normal distribution but does not have the high and low tails that a normal distribution has. This reduces the number of very high and very low samples.



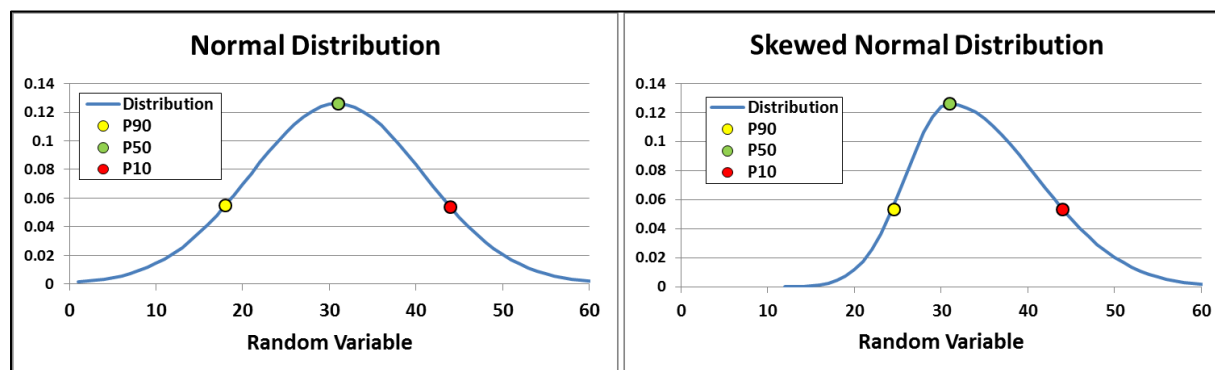


Figure MCV-2: Probability Distributions

For a normal distribution, the absolute difference between the mid value and the low and high values are equal ( $P50 - P90 = P10 - P50$ ) but for the skewed normal distribution the differences are not equal ( $P50 - P90 < > P10 - P50$ ). For a uniform distribution, all values are equal ( $P90 = P50 = P10$ ).

Note that the nomenclature used in the oil industry is that P90 is the lower value and P10 is the higher value. What this means is that for the P90 value, there is a 90% probability that the actual value will be higher (10% probability it will be lower) than that value, for the P50 value there is an equal probability that the actual value will be higher or lower than that value, and for the P10 value there is a 10% probability that the actual value will be higher (90% probability it will be lower) than that value. Occasionally, the P95 or P99 value is used when evaluating disaster scenarios.

Executing a Monte Carlo simulation will result in a cumulative distribution function (CDF) which can be used to extract the value for any given probability (Figure MCV-3).

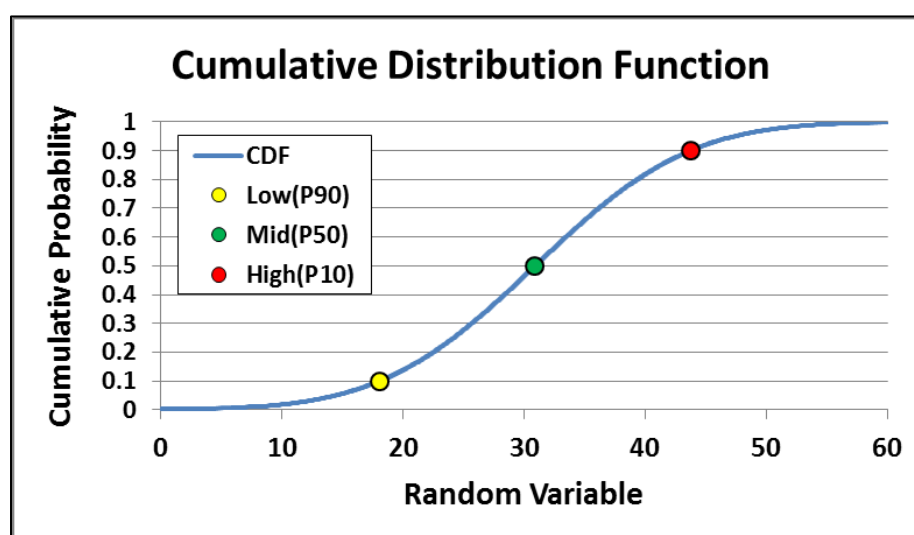


Figure MCV-3: Cumulative Distribution Function

To calculate oil/gas volumetrics, the distribution of the input parameters is entered, the CDF's are calculated and sampled using a random number generator. The fluid properties are calculated based on the randomly sampled reservoir parameters and the volumes are calculated (Figures MCV-4, MCV-5 and MCV-6). If the 'Seed' is entered as '-1', the tool will present an equivalent seed that can be used to regenerate the current results.

Probabilistic Parameters					Input Distribution
	Low	Mid	High		
Reservoir Area, A	27000	31000	35000	Acres	<input type="radio"/> Normal <input checked="" type="radio"/> Triangular
Gross Pay, h	20	30	40	ft	<input checked="" type="radio"/> Normal <input type="radio"/> Triangular
Net-to-Gross, NTG	0.45	0.6	0.75	<>	<input type="radio"/> Normal <input checked="" type="radio"/> Triangular
Porosity, phi	13.8	16.5	19.2	%	<input checked="" type="radio"/> Normal <input type="radio"/> Triangular
Initial Water Saturation, Sw	22	28	34	%	<input type="radio"/> Normal <input checked="" type="radio"/> Triangular
Initial Reservoir Pressure, Pi	3400	3600	3800	psi	<input checked="" type="radio"/> Normal <input type="radio"/> Triangular
Bubble Point Pressure, Pbp	1500	1750	2000	psi	<input type="radio"/> Normal <input checked="" type="radio"/> Triangular
Reservoir Temperature, TR	175	175	175	°F	<input checked="" type="radio"/> Normal <input type="radio"/> Triangular
Gas Gravity, G	0.6	0.65	0.7	<>	<input type="radio"/> Normal <input checked="" type="radio"/> Triangular
Oil Gravity	27	30	32	API	<input checked="" type="radio"/> Normal <input type="radio"/> Triangular
Recovery Factor, RF	25	30	35	%	<input type="radio"/> Normal <input checked="" type="radio"/> Triangular
Oil Formation Volume Factor, Bo				1.149 1.181 1.205	rbbl/bbl
Solution Gas/Oil Ratio, RSI				193 279.5 344.8	scf/bbl
Seed (Random=-1)				-1	~Equiv Seed 47003
# M-C Simulations				10000	

Info

Figure MCV-4: Monte Carlo Simulation – Gas Input Parameters

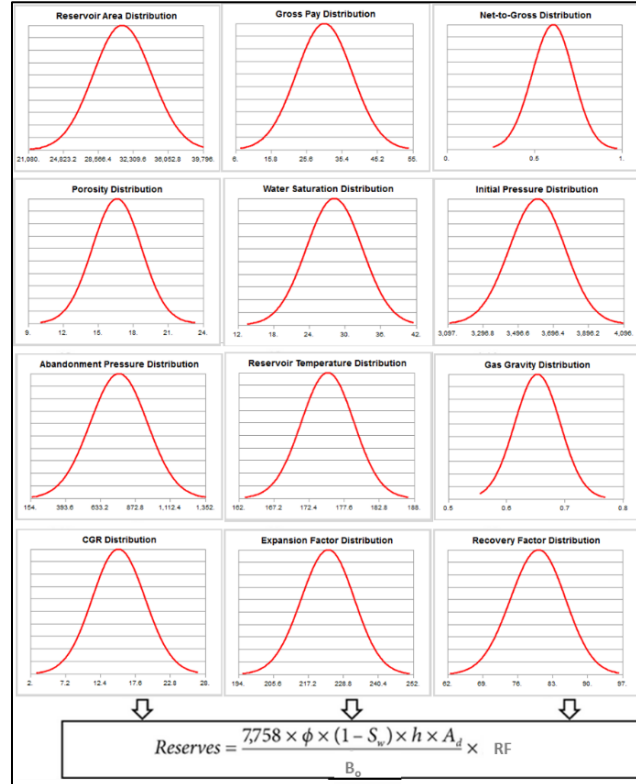


Figure MCV-5: Monte Carlo Simulation – Input Distributions

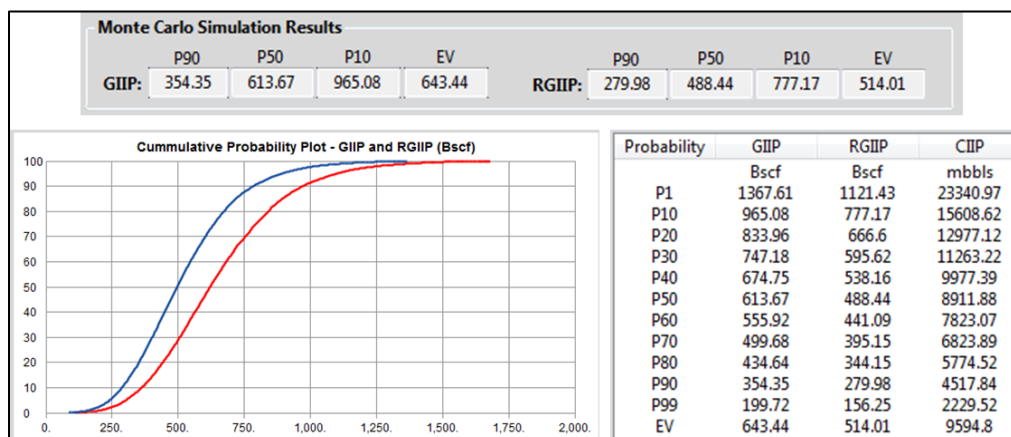


Figure MCV-6: Monte Carlo Simulation – Gas Simulation Results

Once the volumetric calculations are performed, the values are stored as an output CDF. The P90, P50 and P10 values are extracted from this output CDF and the deterministic values for the specific realization are extracted for use in other calculations. PE<sup>2</sup> Essentials also reports deterministic models for P1 and P99 along with the P90, P50, P10 and expected value (EV) deterministic models (Figure MCV-7). It should be noted that these deterministic models are just one realization and if the Monte Carlo simulation is run again, different deterministic models will be generated. Figure MCV-8 presents an example of deterministic oil models.

Deterministic Models								
Prob	Area	Pay	NTG	Poro	Sw	1/Bg	CGR	RF
P1	28040.5	40	0.9	18.7	24.4	221.4	12.5	72.7
P10	29752.5	40.1	0.6	18.2	25.1	226.8	18.5	74.7
P50	31562.6	28.5	0.62	16.7	35.7	236.2	12.7	82.3
P90	28542.3	22.9	0.44	15.6	23	233.7	18.7	81.2
P99	33882.6	9.9	0.51	15.5	24.2	225.8	13	91.9
EV	30961.3	30	0.6	16.5	27.9	222.9	14.9	79.8

Figure MCV-7: Monte Carlo Simulation - Deterministic Gas Models

Deterministic Models								
Prob	Area	Pay	NTG	Poro	Sw	Bo	RSI	RF
P1	30899.4	41.6	0.85	16.6	22	1.202	330.2	37.4
P10	35044.9	33.5	0.62	20.1	29.5	1.202	328	29.7
P50	31896.7	37.5	0.47	15	26.6	1.141	193.7	21.1
P90	29573.9	31	0.39	15	30.8	1.175	264.3	26.3
P99	33936.3	25.8	0.2	16.5	29.9	1.189	285.1	29.1
EV	30948.2	30.1	0.6	16.5	28	1.171	263.4	30

Figure MCV-8: Monte Carlo Simulation - Deterministic Oil Models

Computers do not generate truly random numbers instead they generate pseudo-random numbers based on an initial seed for the random number generator. As a result, to generate the same probabilistic profile, and corresponding deterministic models, a constant 'Seed' value can be entered in the 'Seed (Random=-1)' input box. By entering a specific seed value, the same random number sequence will be generated for the Monte Carlo simulation and the output results will be the same. Entering '-1' for the seed will generate random seed numbers based on an internal timer so the forecast will be different each time a simulation is run.

The Monte Carlo simulation results ('Save Simulation') as well as the deterministic models ('Save Model') and the CDF profiles ('save SDF Results') can be saved as 'csv' files. The CDF data can be imported into PE<sup>2</sup> Essentials Chart but the x and y axis will be reversed as shown in Figure MCV-9. To properly plot the data, it should be imported into Excel.

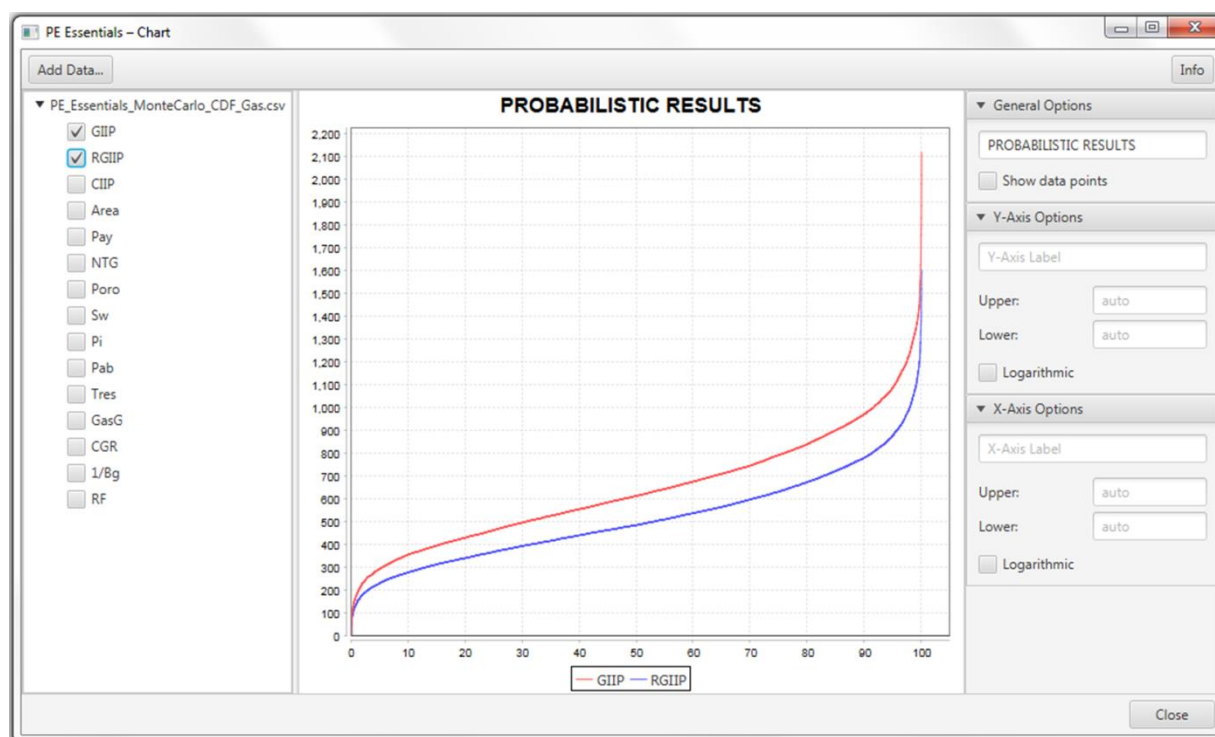


Figure MCV-9: Monte Carlo Simulation – PE<sup>2</sup> Essentials Chart Plot

## PE Graph Tool

The PE<sup>2</sup> Essentials 'PE Graph' Tool imports PE Essentials generated CSV files and can construct plots with user defined x- and y- axes. Multiple data can be plotted on the y-axis.

The tool is made up of three components: the control section (Figure GRP-1); the plotting section (Figure GRP-3); and the data import section (Figure GRP-4).

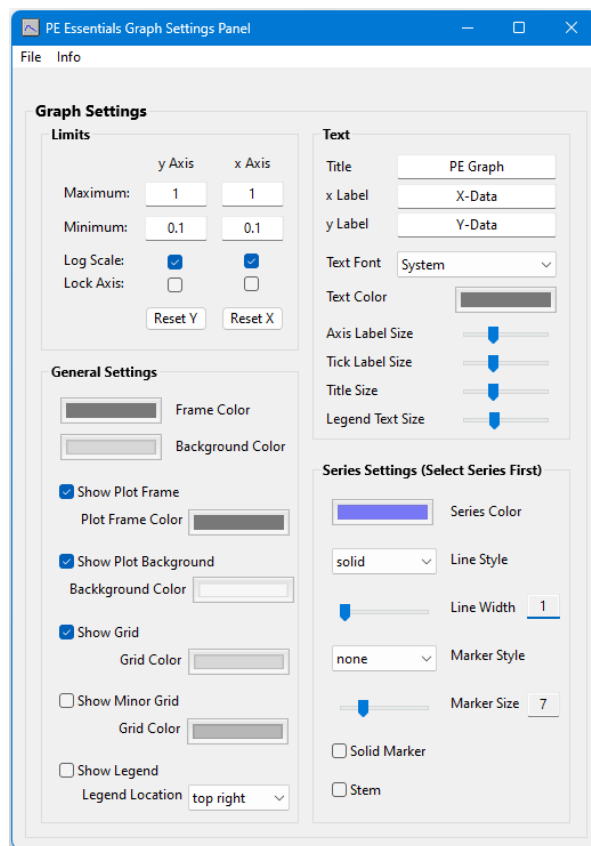


Figure GRP-1: PE Graph Tool – Control Panel

Once data has been imported and plots have been constructed, the PE Graph workspace can be stored and reloaded in the future. This is accessed through the 'File' dropdown menu (Figure GRP-2).

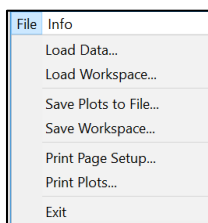


Figure GRP-2: PE Graph Tool – Control Panel

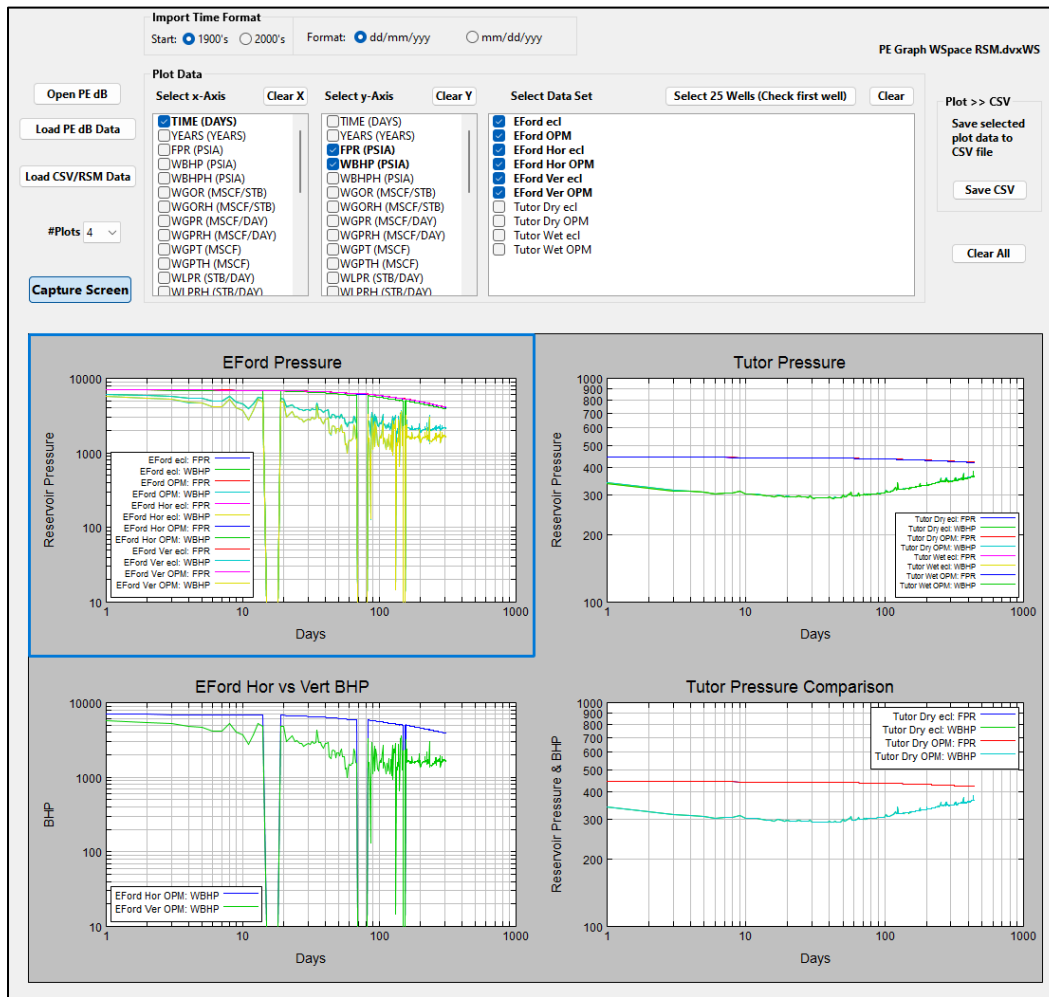


Figure GRP-3: PE Graph Tool - Plotting

CSV/RSM File Viewer and Loader

SIM\_FEE\_EAGLE\_FORD\_EXAMPLE.RSM

SIM\_FEE\_EAGLE\_FORD\_EXAMPLE SIM Oilfield

Eagle

TIME	YEARS	FPR	WBHP	WBHPH	WGOR	WGORH	WGPR	WGPRH
DAYS		PSIA	PSIA	PSIA	MSCF/STB	MSCF/STB	MSCF/DAY	MSCF/DAY
1	0.002738	6995.037	6160.306	6191.700	0.638192	26.04650	27.44750	1119.988
2	0.005476	6988.832	5888.250	6326.500	0.638700	26.32953	34.22752	1410.983
3	0.008214	6981.996	5729.684	6355.600	0.638700	27.27117	37.68328	1608.999
4	0.010951	6973.430	5405.062	6394.899	0.638700	24.40540	47.26378	1805.999
5	0.013689	6964.970	5359.749	6354.600	0.638700	26.49314	46.62508	1931.999
6	0.016427	6954.211	4957.389	6252.299	0.638700	24.24721	59.39907	2254.999
7	0.019165	6943.901	4957.565	6224.299	0.638700	24.74157	56.84427	2201.999
8	0.021903	6938.723	5694.917	6410.799	0.638700	29.57776	28.74148	1330.999
9	0.024641	6927.902	4843.257	6078.700	0.638700	26.91489	60.03777	2529.999
10	0.027379	6915.760	4580.925	6075.100	0.638700	23.17141	67.06349	2432.999
11	0.030116	6899.636	3912.496	5471.799	0.638700	18.30800	89.41793	2561.999
12	0.032854	6886.153	4513.774	5326.799	0.638700	26.35353	63.23127	2608.999
13	0.035592	6884.219	5627.409	6571	0.638700	24.95600	21.77966	850.9995
14	0.038330	6877.958	5338.997	6402.700	0.638700	23.14813	34.488978	1249.999
15	0.041068	6877.905	0	0	0	0	-0	0
16	0.043806	6877.888	0	0	0	0	-0	0
17	0.046543	6877.875	0	0	0	0	-0	0
18	0.049281	6877.864	0	0	0	0	-0	0
19	0.052019	6870.566	5352.125	6179.899	0.638519	29.28571	40.22670	1844.999
20	0.054757	6863.611	5326.209	6434.399	0.638700	25.51665	38.32198	1530.999
21	0.057495	6848.844	4125.767	5322.299	0.638700	24.07813	81.75353	3081.999
22	0.060233	6835.569	4310.743	5360.600	0.638700	24.07813	77.48909	2865.999

Records: 309, Data: 27

☐ CSV File ☒ RSM File

Edit Well Name

Drag and Drop File to View. 'Import Data' to Load into PE Graph

Import Data

Figure GRP-4: PE Graph Tool – Data Import

## GRP.1 Data Import

Data can be imported directly from the PE Tools database or, alternatively, most CSV files generated by the PE Essentials tools can be imported into PE Graph for plotting of the data. RSM (simulator output) files can also be imported but they can only contain one well or group or field. To import multiple wells, multiple RSM files would have to be created.

To import the data from a CSV or RSM file, open the import window either using the 'File' menu or click the 'Load CSV/RSM File' button. After opening the import window, drag and drop the file onto the window. This will open the file allowing it to be reviewed before importing the data into PE Graph, but the data is not yet loaded into PE Graph.

The data is loaded into PE Graph by clicking the 'Import Data' button. This will import the data headings and units into the 'Select x-Axis Data' and 'Select y-Axis Data' tables and the data set name into the 'Select Data Set' table. Before clicking 'Import Data', it is possible to rename the data set by clicking 'Edit Well Name' (Figure GRP-5). Enter the new name and click "Change".

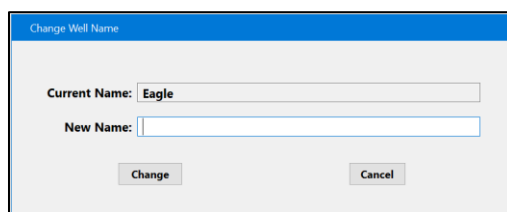


Figure GRP-5: PE Graph Tool – Data Import

Multiple files can be imported into the tool, but they must all have the same format. For example, all the Raw CSV data files generated by the PDA tool can be imported, but an Analyzable CSV data file cannot be imported with a Raw CSV file. The first imported file determines the format for the remaining files. This is because the x-Axis and y-Axis data tables are imported once, and different CSV file types will have different data stored in the files.

To make importing of PDA and Production Database generated CSV files easier, these tools save all exported CSV files to the 'PE Essentials 2021\CSV Output Files' directory.

It is possible to import a user-built CSV file into PE Graph but when generating the file, the format should follow the PE Essentials CSV format of the appropriate tool. Specifically, the first 4 lines of the CSV file are used to confirm that the file can be imported into PE Graph – refer to Section GRP.3.

It is also possible to import single-well simulator RSM files by selecting the 'RSM File' option, as long as the RSM files are generated for only one well or group or field. If more than one well is to be evaluated, a separate RSM file has to be generated for each well. The output data format included in each RSM file must be the same.

## GRP.2 Plotting

Up to nine individual plots can be built with the PE Graph tool. To modify a specific plot, click (select) the plot and a blue border will indicate the selected plot. To modify a specific curve, click on the curve and it will be highlighted. In both cases after the plot/curve has been highlighted, the plot parameters are modified from the control window.

After the plots have been finalized, the plot group can be saved to a png file (File/Save Plots to File...) or sent to the printer (File/Print Plots...).

Figure GRP-6 is an example of multi-data plotting of PDA data. The plot was built with the parameters shown in Figure GRP-7, then the plot was saved to a PNG file.

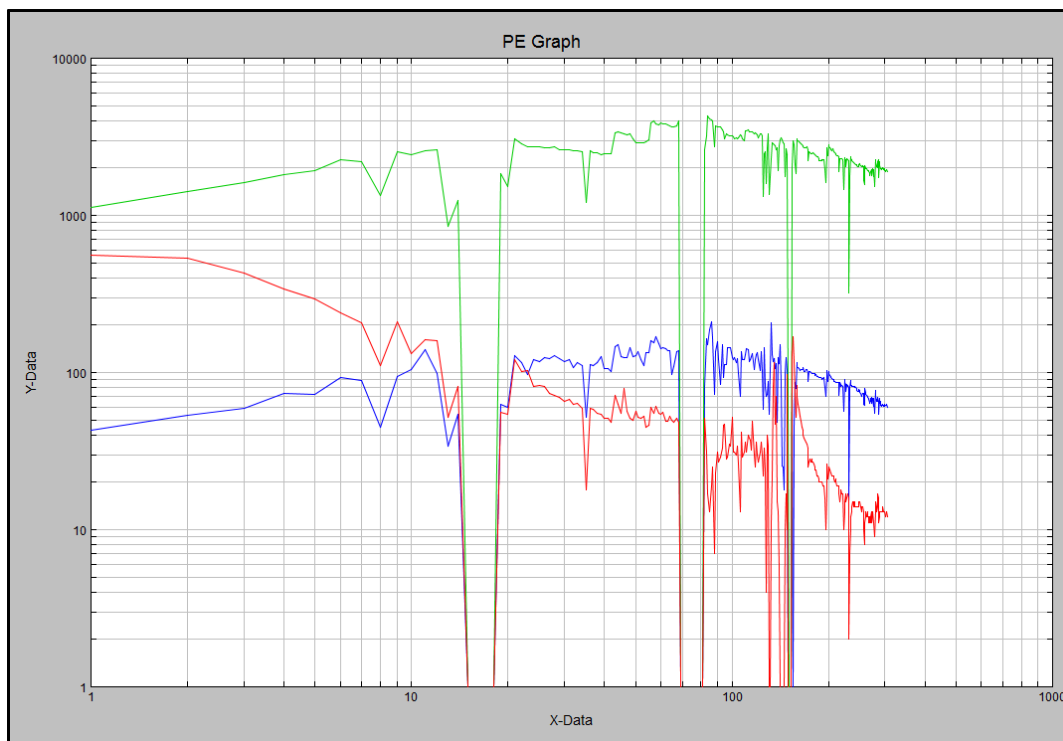


Figure GRP-6: PE Graph – Example Plot of PDA Data

Plot Data		
Select x-Axis Data	Select y-Axis Data	Select Data Set
<input type="checkbox"/> Time (Years) <input checked="" type="checkbox"/> Time (Days) <input type="checkbox"/> Oil Rate ( bopd) <input type="checkbox"/> Gas Rate ( mscf/d) <input type="checkbox"/> Water Rate ( bwpd) <input type="checkbox"/> Liquid Rate ( bwpd) <input type="checkbox"/> Cum Oil ( mbbls) <input type="checkbox"/> Cum Gas ( mmscf) <input type="checkbox"/> Cum Water ( mbbls) <input type="checkbox"/> Cum Liquid ( mbbls) <input type="checkbox"/> THP ( psi) <input type="checkbox"/> CHP ( psi) <input type="checkbox"/> BHP ( psi) <input type="checkbox"/> Sim.Pr. ( psi)	<input type="checkbox"/> Time (Years) <input type="checkbox"/> Time (Days) <input checked="" type="checkbox"/> Oil Rate ( bopd) <input checked="" type="checkbox"/> Gas Rate ( mscf/d) <input checked="" type="checkbox"/> Water Rate ( bwpd) <input type="checkbox"/> Liquid Rate ( bwpd) <input type="checkbox"/> Cum Oil ( mbbls) <input type="checkbox"/> Cum Gas ( mmscf) <input type="checkbox"/> Cum Water ( mbbls) <input type="checkbox"/> Cum Liquid ( mbbls) <input type="checkbox"/> THP ( psi) <input type="checkbox"/> CHP ( psi) <input type="checkbox"/> BHP ( psi) <input type="checkbox"/> Sim.Pr. ( psi)	<input checked="" type="checkbox"/> Eagle Ford Example

Figure GRP-7: PE Graph – Parameters for Plot



Figures GRP-8 and GRP-9 present an example of multi-well, multi-graph plotting of Production Database data.

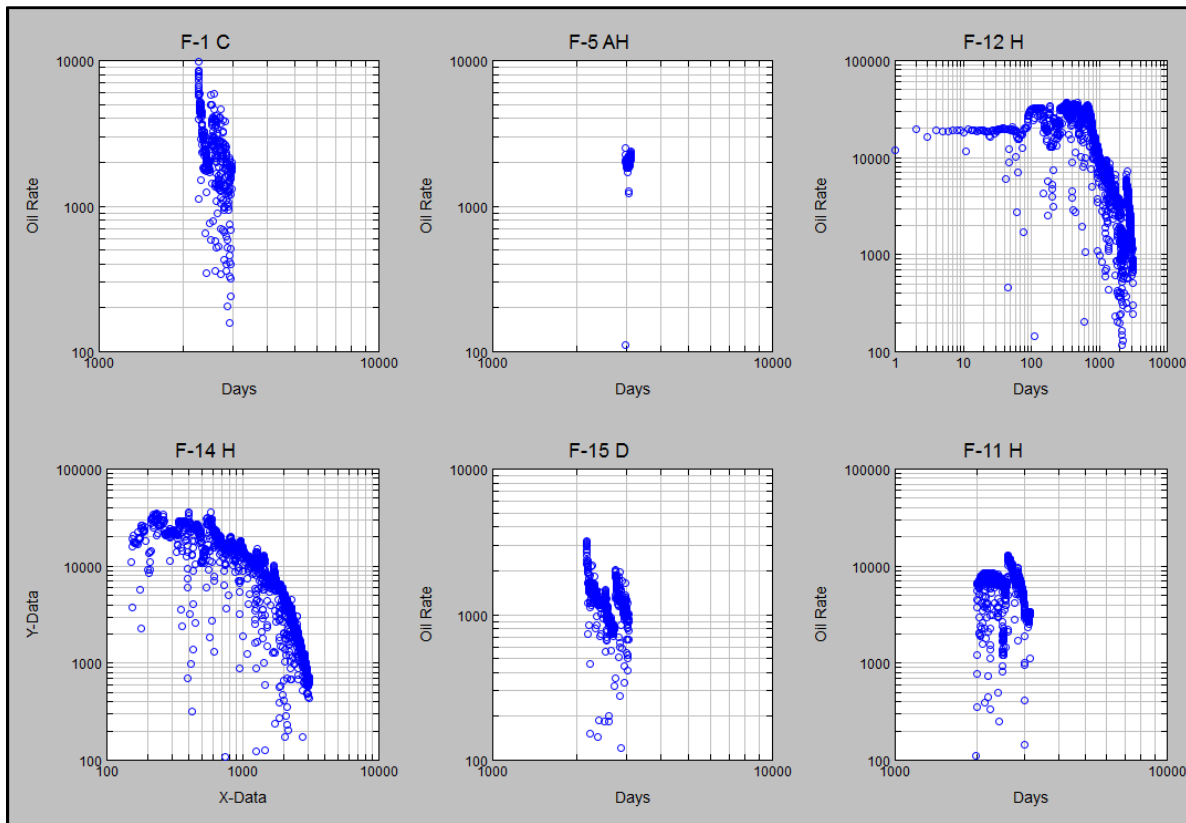


Figure GRP-8: PE Graph – Example Plot of Production Database Data

Plot Data		
Select x-Axis Data	Select y-Axis Data	Select Data Set
<input type="checkbox"/> Time (Years) <input checked="" type="checkbox"/> <b>Time (Days)</b> <input type="checkbox"/> Oil Rate ( m3/d) <input type="checkbox"/> Gas Rate ( 103m3/d) <input type="checkbox"/> Water Rate ( m3/d) <input type="checkbox"/> Liquid Rate ( m3/d) <input type="checkbox"/> Cum Oil ( 103m3) <input type="checkbox"/> Cum Gas ( 106sm3) <input type="checkbox"/> Cum Water ( 103m3) <input type="checkbox"/> Cum Liquid ( 103m3) <input type="checkbox"/> THP ( kPa) <input type="checkbox"/> CHP ( kPa) <input type="checkbox"/> BHP ( kPa) <input type="checkbox"/> CHP/THP ( <> )	<input type="checkbox"/> Time (Years) <input type="checkbox"/> Time (Days) <input checked="" type="checkbox"/> <b>Oil Rate ( m3/d)</b> <input type="checkbox"/> Gas Rate ( 103m3/d) <input type="checkbox"/> Water Rate ( m3/d) <input type="checkbox"/> Liquid Rate ( m3/d) <input type="checkbox"/> Cum Oil ( 103m3) <input type="checkbox"/> Cum Gas ( 106sm3) <input type="checkbox"/> Cum Water ( 103m3) <input type="checkbox"/> Cum Liquid ( 103m3) <input type="checkbox"/> THP ( kPa) <input type="checkbox"/> CHP ( kPa) <input type="checkbox"/> BHP ( kPa) <input type="checkbox"/> CHP/THP ( <> )	<input type="checkbox"/> NO 15/9-F-1 C Oilfield <input type="checkbox"/> NO 15/9-F-5 AH Oilfield <input checked="" type="checkbox"/> <b>NO 15/9-F-12 H Oilfield</b> <input type="checkbox"/> NO 15/9-F-14 H Oilfield <input type="checkbox"/> NO 15/9-F-15 D Oilfield <input type="checkbox"/> NO 15/9-F-11 H Oilfield

Figure GRP-9: PE Graph – Parameters for F-12 H Well Plot

Note – when increasing/decreasing the number of displayed graphs, some of the control parameters may be reset to the default values.

The scales can be locked by clicking the appropriate box on the Settings Panel.

### GRP.3 PE Graph Import File Format

The PE Graph tool can be used to import and plot non-PEE csv files as long as the format of the csv file is set up to the required PE Graph import format.

A normal PE Essentials csv file has the format shown in Figure GRP-10.

```
PE Essentials Gravity-Based Gas Hydrate, Oilfield
Complete Hydrate Example, Gas Gravity = 0.7
Pressure, Salufu, Towler, Makogan, Motiee, Katz, Sun
psi, F, F, F, F, F, F
100,26.66103,21.91354,21.58332,24.23709,22.50268,26.19626
200,35.0628,31.66434,32.06317,33.33264,32.88473,34.96733
300,39.97753,37.36819,37.83808,38.42945,38.97598,40.19892
400,43.46458,41.41514,41.79795,41.94554,43.09954,43.94548
500,46.16935,44.5542,44.79751,44.61558,46.13072,46.865
600,48.3793,47.11899,47.20452,46.76003,48.48042,49.25489
700,50.24779,49.2875,49.21036,48.54708,50.37106,51.27557
800,51.86635,51.16594,50.92707,50.0758,51.93516,53.02367
900,53.29403,52.82285,52.4258,51.40936,53.25738,54.56202
1000,54.57112,54.305,53.75449,52.59046,54.39468,55.93382
1100,55.7264,55.64577,54.94694,53.64929,55.387,57.17006
1200,56.78108,56.86979,56.02786,54.60796,56.26328,58.29375
1300,57.75129,57.99579,57.01586,55.48313,57.04507,59.32246
1400,58.64957,59.0383,57.92526,56.28768,57.74879,60.26991
1500,59.48585,60.00885,58.76737,57.03173,58.38719,61.14701
1600,60.26813,60.91674,59.55121,57.72342,58.97033,61.9626
1700,61.00297,61.76957,60.28413,58.36935,59.50627,62.72394
1800,61.6958,62.57364,60.97219,58.97497,60.00157,63.43706
1900,62.35116,63.33423,61.62043,59.54481,60.4616,64.10703
2000,62.9729,64.0558,62.23309,60.0827,60.8908,64.73816
```

Figure GRP-10: PE Graph – Example Input CSV File Format

The file contains the following:

Line 1: File information and units

Note that 'PE Essentials' must be the first words in the file

Line 2: Well name/model name information

Line 3: Date contained in the columns in the file

Line 4: Units for the data in the file

Line 5+: Data

PE Graph reads the data in the second line, up to the first comma, to assign the name for the imported data.

The third and fourth lines are used to set up the x-data and y-data tables.

The data starting from the fifth line is read into the plotting arrays.

## GRP.4 PE Graph Export Plotted Data

The data included on a specific plot can be exported to a csv file by clicking the ‘Save CSV’ button. Make sure to click (select) the relevant plot before saving the data.

The data will be automatically stored in the ‘PE Essentials 2021\CSV Output Files’ directory. The data can then be imported into Excel (Figure GRP-11) for subsequent use.

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
1	PE Essentials Graph Data																		
2	EFord Pressure																		
3	EFord ecl																		
4	TIME	FPR	WBHP	WLPRH		TIME	FPR	WBHP	WLPRH		TIME	FPR	WBHP	WLPRH		TIME	FPR	WBHP	WLPRH
5	DAYS	PSIA	PSIA	STB/DAY		DAYS	PSIA	PSIA	STB/DAY		DAYS	PSIA	PSIA	STB/DAY		DAYS	PSIA	PSIA	STB/DAY
6	0	7000	6992.493	0		1	6995.037	6160.306	597.9937		0	6991.659	6991.659	0		1	6986.665	6966.029	597.9937
7	1	6995.012	6157.774	597.9938		2	6988.832	5888.25	591.5828		1	6986.67	6966.03	597.9938		2	6980.447	6949.816	591.5828
8	2	6988.794	5888.417	591.5829		3	6981.996	5729.684	488.9997		2	6980.453	6949.813	591.5829		3	6973.601	6935.386	488.9997
9	3	6981.949	5729.524	488.9998		4	6973.43	5405.062	414.9998		3	6973.606	6935.384	488.9998		4	6965.015	6914.666	414.9998
10	4	6973.359	5405.127	414.9999		5	6964.97	5359.749	364.9998		4	6965.019	6914.658	414.9999		5	6956.544	6900.415	364.9998
11	5	6964.886	5359.423	364.9999		6	6954.211	4957.389	333.9998		5	6956.547	6900.419	364.9999		6	6945.751	6874.574	333.9998
12	6	6954.086	4957.29	333.9998		7	6943.901	4957.565	294.9998		6	6945.752	6874.571	333.9998		7	6935.422	6858.631	294.9998
13	7	6943.751	4957.489	294.9998		8	6938.723	5694.917	154.9999		7	6935.42	6858.638	294.9998		8	6930.199	6868.006	154.9999
14	8	6938.526	5694.62	155		9	6927.902	4843.257	304.9998		8	6930.196	6868.021	155		9	6919.288	6832.721	304.9998
15	9	6927.609	4842.72	304.9998		10	6915.76	4580.925	235.9998		9	6919.281	6832.718	304.9998		10	6907.1	6807.74	235.9998
16	10	6915.419	4580.378	235.9999		11	6899.636	3932.496	301.9997		10	6907.088	6807.738	235.9999		11	6890.846	6767.22	301.9997
17	11	6899.185	3931.843	301.9998		12	6888.153	4513.774	257.9998		11	6890.827	6767.217	301.9998		12	6879.35	6764.129	257.9998
18	12	6887.656	4513.253	257.9998		13	6884.219	5627.409	85.79997		12	6879.327	6764.159	257.9998		13	6875.386	6785.779	85.79997
19	13	6883.654	5626.81	85.79997		14	6877.958	5338.997	134.9999		13	6875.365	6785.809	85.79997		14	6869.113	6771.859	134.9999

Figure GRP-11: PE Graph – Export of Plotted Data

## PE Well Essentials

Well Essentials includes the following tools:

- THP-to-BHP for gas wells
- Quick Log Analysis
- Hydraulic Fracture Design
- Artificial Lift Design
- Pressure Transient Analysis (Build-up)
- Volumetric Analysis
- Hydrate Analysis

### THP – BHP Tool: Gas Well

The 'THP-BHP Gas Well' tool will model pressure drop in vertical and horizontal wells as well as gas flow through the tubing-casing annulus (Figure THPG-1). For a horizontal well, pressure drop is calculated to the top of the lateral (assumes constant pressure throughout the lateral).

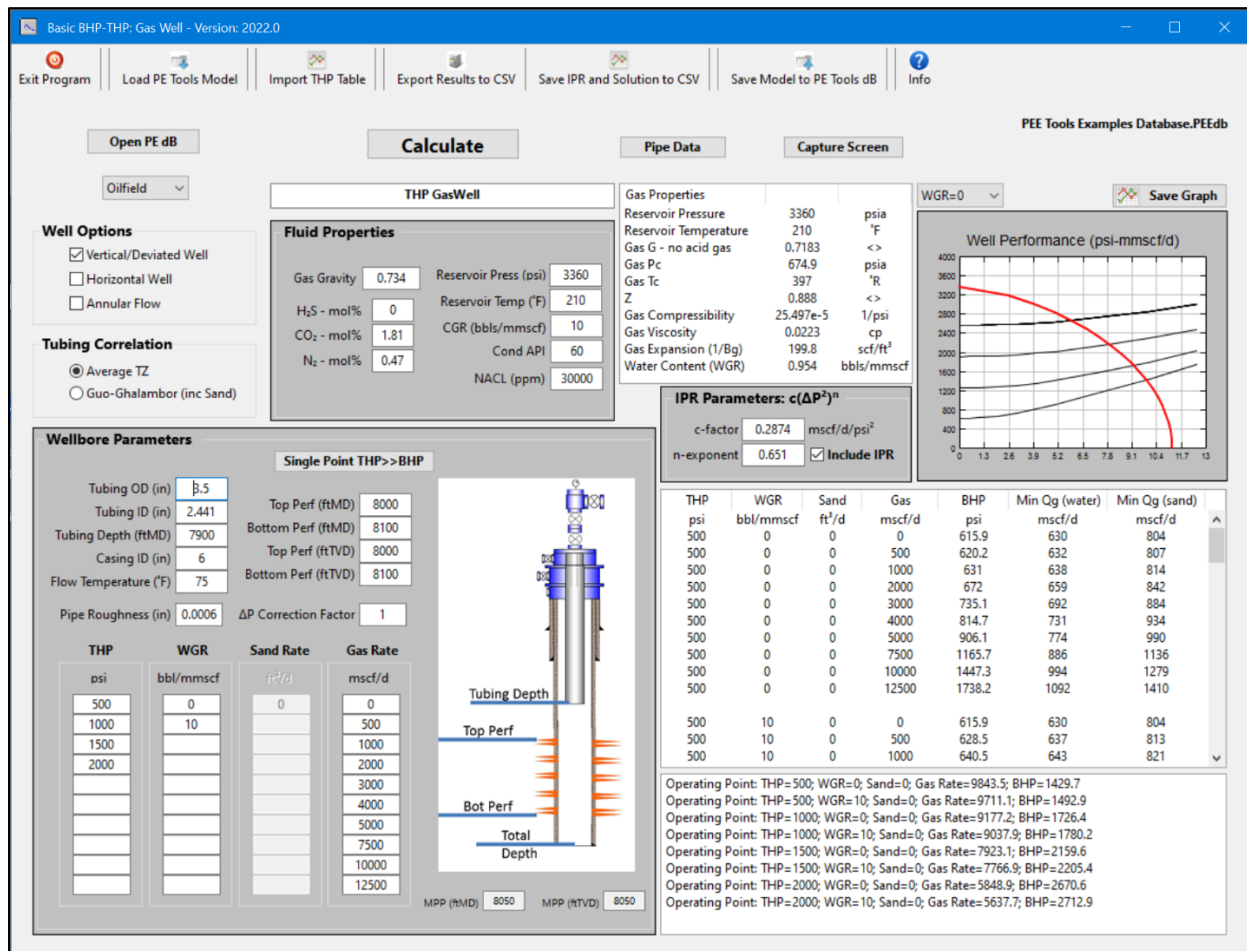


Figure THPG-1: PE<sup>2</sup> Essentials THP-BHP Gas Well Tool

Gas flow in a well is governed by the conservation of energy (first law of thermodynamics) which yields a differential equation for steady state flow in a pipe. For gas wells, the only significant terms are the terms representing the hydrostatic gradient and the friction gradient.

$$\nabla P = \nabla P_{\text{hyd}} + \nabla P_{\text{fric}}$$

There are 2 options for gas well pressure drop correlations included in PE<sup>2</sup> Essentials: Average TZ (for gas and condensate) or Guo-Ghalambor (for gas, condensate, water and sand). It should be noted that only the Guo-Ghalambor correlation includes the option for modeling sand in the flow stream.

### THPG.1 Average Temperature/Z-Factor Technique

The pressure gradient in an angled gas well, where  $\phi$  is the well angle measured from the vertical (calculated from the MD and TVD data), can be simplified to the following differential equation.

$$\frac{dP}{dL} = \frac{\rho g \cos \phi}{g_c} + \frac{f \rho v^2}{2 g_c d}$$

This equation can be directly integrated to a solution as follows.

$$P_1^2 = P_2^2 \exp(S_1) + 0.000667 f_m Q_{ge}^2 Z_a^2 T_a^2 (\exp(S_2) - 1) / ID^5 \quad (\text{THPG-1})$$

$$S_1 = 0.0375 SG_w TVD / (T_a Z_a)$$

$$S_2 = S_1 MD / TVD$$

$$SG_w = (GCR SG_g + 4584 SG_c) / (GCR + GE_c)$$

$$GE_c = 133000 SG_c / MW_c$$

$$MW_c = 6084 / (\text{API} - 5.9)$$

$$SG_c = 141.5 / (\text{API} + 131.5)$$

$$Q_{ge} = Q_g (1 + GE_c / GCR)$$

$$f_m = [1.14 - 2 \log(\delta / ID + 21.25 / Re^{0.9})]^{-2}$$

$$Re = 20011 SG_w Q_{eg} / (ID \mu_g)$$

$$T_a = T_{fa} + 460$$

Where: P is pressure in psia,  $Q_{ge}$  is equivalent gas rate (gas + condensate) in mscf/d,  $Z_a$  is average Z based on  $P_1$  and  $P_2$ ,  $T_a$  is average temperature in °R for the depth increment, ID is pipe ID in inches,  $SG_g$  is gas specific gravity,  $SG_c$  is condensate specific gravity,  $MW_c$  is condensate molecular weight, GCR is producing gas-condensate ratio in scf/bbl, API is the °API of the condensate,  $\delta$  is the absolute roughness of the tubing in inches,  $f_m$  is the Moody friction factor,  $Re$  is the Reynolds number and  $\mu_g$  is the average gas viscosity in cp based on  $P_1$  and  $P_2$  and  $T_{fa}$  is average temperature in °F.

Since Z and gas viscosity are functions of pressure, the pressure calculations are done in steps. The pressures are assumed as  $P_1$  is bottomhole and  $P_2$  is tubing head. If performing the

calculations by hand, two to four depth increments may be sufficient. The PE<sup>2</sup> Essentials routines uses 100 depth increments to calculate the pressure.

## THPG.2 Guo-Ghalambor Technique

In 2005 Guo and Ghalambor developed a four-phase (gas-oil-water-sand) pressure drop model (Guo, B. and Ghalambor, Natural gas Engineering Handbook, Gulf Publishing Company, 2005). The model was an extension of the original formulation by Guo for coal bed methane wells. The solution is a complex equation that requires iteration to solve. This model is included since sand production in hydraulically fractured well may be a common occurrence.

It should be noted that the Guo-Ghalambor model is a no-slip model which limits its validity to mist flow. As a result, it is not valid for gas wells that produce significant water.

$$a(\cos\phi + d^2e)MD = 144b(P_1 - P_2) + X_1 - X_2 \quad (\text{THPG-2})$$

$$X_1 = (0.5 - bM) \ln\{[(144P_1 + M)^2 + N]/[(144P_2 + M)^2 + N]\}$$

$$X_2 = M + bN/c - bM^2N^{-0.5} \{\tan^{-1}[(144P_1 + M)N^{-0.5}] - \tan^{-1}[(144P_2 + M)N^{-0.5}]\}$$

$$a = (0.0765 SG_g Q_g + 350 SG_o Q_o + 350 SG_w Q_w + 62.4 SG_s Q_s) / (4.07 T_a Q_g)$$

$$b = (5.615 Q_o + 5.615 Q_w + Q_s) / (4.07 T_a Q_g)$$

$$c = 1.2431 T_a Q_g / ID^2$$

$$d = 0.30436 (5.615 Q_o + 5.615 Q_w + Q_s) / ID^2$$

$$e = 0.18651 f_m / ID$$

$$f_m = [1.74 - 2 \log(2\delta / ID)]^{-2}$$

$$M = cde / (\cos\phi + d^2e)$$

$$N = c^2 e \cos\phi / (\cos\phi + d^2e)^2$$

$$T_a = T_{fa} = 460$$

Where:  $P_1$  is bottomhole pressure in psia,  $P_2$  is tubing head pressure in psia,  $\phi$  is the well angle measured from the vertical,  $Q_g$  is gas rate in scf/d,  $Q_o$  is oil rate in bbl/d,  $Q_w$  is water rate in bbl/d,  $Q_s$  is sand rate in ft<sup>3</sup>/d,  $SG_g$  is gas specific gravity,  $SG_o$  is oil specific gravity,  $SG_w$  is water specific gravity,  $SG_s$  is sand specific gravity,  $T_a$  is average temperature in °R for the depth increment and ID is pipe ID in inches and  $T_{fa}$  is average temperature in °F.

The Guo-Ghalambor model is solved in one depth increment using an iterative process where an estimate of the unknown pressure is made and then modified until the left-hand side of the Equation THPG-2 equals the right-hand side of the Equation THPG-2.

## THPG.4 Options for THP-BHP Calculations

### THPG.4.1 Well Options

Pressure calculations can be performed for vertical or horizontal wells and for tubing or tubing-casing annulus flow by checking the appropriate boxes in 'Well Options' (Figures THPG-3 and THPG-4).

Well Options	
<input checked="" type="checkbox"/>	Vertical/Deviated Well
<input type="checkbox"/>	Horizontal Well
<input type="checkbox"/>	Annular Flow

Figure THPG-3: Well Type and Flow Path Options

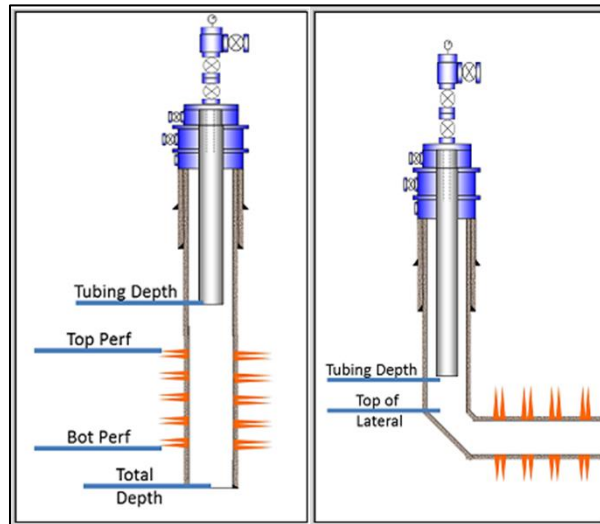


Figure THPG-4: Vertical and Horizontal Well Options

Annular flow is modeled by calculating an equivalent ID for the flow path.

$$ID_{ann} = (CsgID + TubOD)^2 (CsgID - TubOD)^3 \quad (THPG-17)$$

Where:  $ID_{ann}$  is the equivalent ID of the annulus in inches.

### THPG.4.2 Minimum gas Rates to Lift Liquid

The bottomhole pressure calculation routine also includes a calculation of the minimum gas rate required to continuously lift water and sand (Figure THPG-5) for information purposes.

The minimum gas rate calculations are based on the Turner equations.

$$\text{Min}Q_g = 3060 \text{ THP Area } V_{\min} / ((\text{THT} + 460) Z) \quad (\text{THPG-18})$$

$$V_{\min(\text{water})} = 1.3 \sigma_w^{0.25} (62.4 \text{ SG}_w - \text{RhoGas})^{0.25} / \text{RhoGas}^{0.5} \quad (\text{THPG-19})$$

$$V_{\min(\text{sand})} = 1.3 \sigma_w^{0.25} (62.4 \text{ SG}_s - \text{RhoGas})^{0.25} / \text{RhoGas}^{0.5} \quad (\text{THPG-20})$$

$$\text{RhoGas} = 2.699 \text{ SG THP} / (\text{THT} + 460)$$

Where:  $\text{Min}Q_g$  is the minimum gas rate based on the minimum velocity,  $V_{\min}$  to lift water or sand in mscf/d,  $\sigma_w$  is the water-gas interfacial tension, SG is specific gravity of gas,  $\text{SG}_w$  is specific gravity of water,  $\text{SG}_s$  is specific gravity of sand, Area is the cross-sectional area of the tubing in  $\text{ft}^2$ , THP is the flowing wellhead pressure in psi and THT is flowing wellhead temperature in  $^{\circ}\text{F}$ .

THP	WGR	Sand	Gas	BHP	Min Qg (water)	Min Qg (sand)
psi	bbt/mmcsf	ft <sup>3</sup> /d	mscf/d	psi	mscf/d	mscf/d
500	0	0	0	616.6	689	880
500	0	0	250	627.8	696	889
500	0	0	500	630.9	698	892
500	0	0	1000	643.1	706	902
500	0	0	1500	663.1	719	918
500	0	0	2000	689.9	735	940
500	0	0	3000	761.4	779	996
500	0	0	4000	851.5	832	1065
500	0	0	5000	954.2	891	1141
500	0	0	7500	1246.3	1049	1348
500	10	0	0	616.6	689	880
500	10	0	250	635.3	701	896
---	---	---	---	---	---	---

Figure THPG-5: Output Listing of Forecast

### THPG.4.3 Single Point / $\Delta P$ Correction Factor

There is a “ $\Delta P$  Correction Factor” included for gas wells that will assist with matching a known pressure data. Entering a value for this factor will multiply the friction factor ( $f_m$ ) by the entered value. This will modify the friction gradient term in the pressure drop calculations. To change the hydrostatic gradient, modify the gas specific gravity value. The ‘Single Point THP>>BHP’ is selected (Figure THPG-6).

THP to BHP Conversion

**Tubing Correlation**

☒ Average TZ  
☐ Guo-Ghalambor (Sand)

Calculate

THP 677 psi

Gas Rate 1000 mscf/d

Cond Rate 0 bcpd

Water Rate 0 bwpd

Sand Rate 0 ft<sup>3</sup>/d

Calculated BHP 850.6 psi

Exit

Figure THPG-6: Converting a Single TH Pressure to BH Pressure



With this option the best correlation can be chosen and the correction factor can be evaluated. While this option screen is active, the correction factor can be changed and then clicking the 'Calculate' button will re-calculate the BHP.

Note that entering a negative rate will generate a BHP to THP conversion.

#### THPG.4.4 THP/CHP to BHP Conversion

It is possible to import a table of pressure/rate data and convert it to BHP. This is done by clicking the 'Import THP Table' menu button. This will open the 'THP to BHP Conversion' page (Figure THPG-7). The pressure/rate data is imported from the PE Tools database or an Excel spreadsheet by clicking on the 'Load Data' button. Figure THPG-8 shows the import of data from the database.

#	THP	Gas mscf/d	Cond bcpd	Water bwpd	Sand ft³/d	BHP psi
1	698.6	10.02	0	0	0	
2	956	14.78	0	0	0	
3	692.8	15.1	0	0	0	
4	695.6	15.39	0	0	0	
5	811.5	20.38	0	0	0	
6	798.6	20.54	0	0	0	
7	824.7	20.69	0	0	0	
8	821.1	20.83	0	0	0	
9	881	21.13	0	0	0	
10	556	23.95	0	0	0	
11	681.6	24.64	0	0	0	
12	843.5	24.9	0	0	0	
13	907.4	30.45	0	0	0	
14	676.6	30.66	0	0	0	
15	808.6	31.08	0	0	0	
16	892.3	31.42	0	0	0	
17	612.8	39.21	0	0	0	
18	562.1	39.66	0	0	0	
19	588.9	39.88	0	0	0	
20	583	40.09	0	0	0	
21	547.3	51.09	0	0	0	
22	551.3	51.23	0	0	0	
23	552.6	51.37	0	0	0	
24	551.8	51.51	0	0	0	
25	549.3	51.65	0	0	0	
26	647	54.88	0	0	0	
27	717.2	55.13	0	0	0	
28	793.1	55.25	0	0	0	
29	746.5	55.43	0	0	0	
30	715.4	58.4	0	0	0	
31	1424	58.76	0	0	0	
32	1196.8	59.1	0	0	0	
33	787.9	59.44	0	0	0	

Figure THPG-7: Converting a Table of THP/CHP Data to BHP

	Column	Start Row	End Row
Tubing Head Pressure			
Gas Rate			
Condensate Rate			
Water Rate			
Sand Rate			

#	Select	Well Name
1	<input checked="" type="checkbox"/>	THP GasWell
2	<input type="checkbox"/>	THP OilWell

Figure THPG-8: Loading and Converting THP to BHP Data

The data presented in Figure THPG-7 is included in an Excel file called 'THP to BHP Example Data.xlsx' located in the "PE Essentials\Example Input Files\Excel Files" directory.

After the data has been imported and converted to BHP, it is possible to save the data to a CSV file by clicking the 'Export BHP Data to CSV File'. After exporting the BHP data, the results can be imported into PE<sup>2</sup> Essentials Chart for plotting.

The THP data can also be saved to the PE Tools database by clicking 'Save THP Data to PE Tools db'.

It is possible to modify the parameters for the well and recalculate the BHP without re-importing the THP data – for example, 'ΔP Correction Factor' can be modified on the main screen while the conversion page remains opened. Check the 'Convert THP>>BHP' button on the conversion page to update the BHP.

### THPG.5 IPR Well Operating Point

Entering the Jones IPR parameters of c and n (Equation THPG-21 and Figure THPG-9) will enable the generation of the operating point for the well based on the intersection of the IPR curve and the tubing performance curve.

$$Q = (P_i^2 - P_{wf}^2)^n \quad (\text{THPG-21})$$

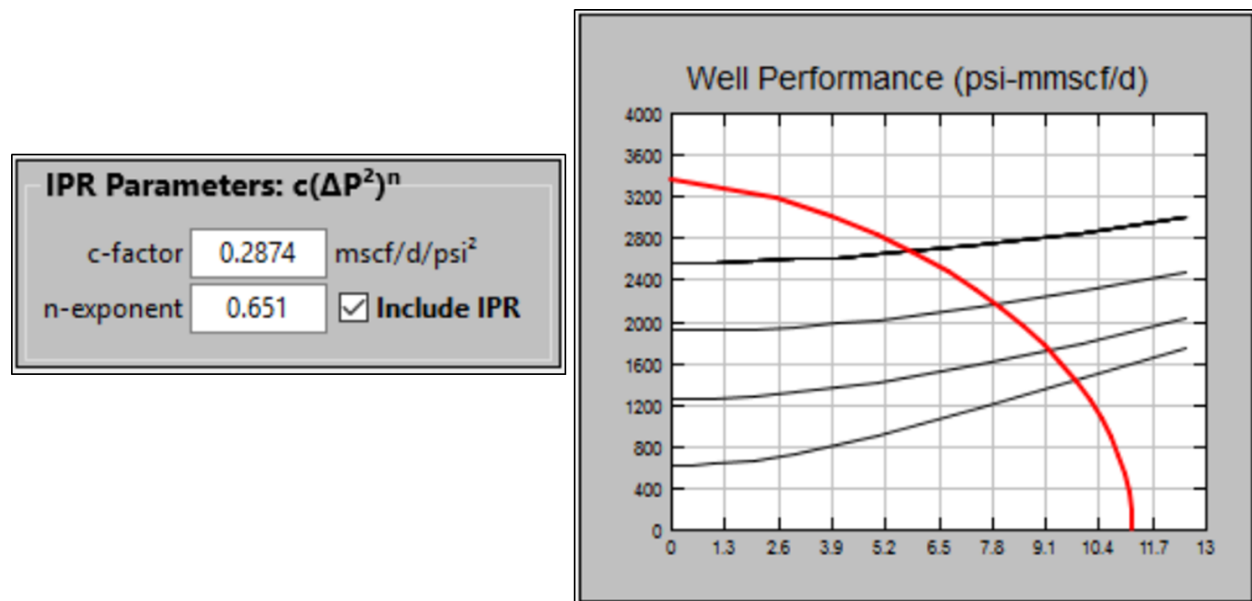


Figure THPG-9: Well IPR and Performance Plot

Operating Point: THP=500; WGR=0; Sand=0; Gas Rate=9841.1; BHP=1430.9
Operating Point: THP=500; WGR=10; Sand=0; Gas Rate=9708.3; BHP=1494.2
Operating Point: THP=1000; WGR=0; Sand=0; Gas Rate=9172.9; BHP=1728.1
Operating Point: THP=1000; WGR=10; Sand=0; Gas Rate=9033; BHP=1782.1
Operating Point: THP=1500; WGR=0; Sand=0; Gas Rate=7914.7; BHP=2162.1
Operating Point: THP=1500; WGR=10; Sand=0; Gas Rate=7758; BHP=2208
Operating Point: THP=2000; WGR=0; Sand=0; Gas Rate=5832.2; BHP=2674
Operating Point: THP=2000; WGR=10; Sand=0; Gas Rate=5619.6; BHP=2716.5

Figure THPG-10: Well Performance Listing

Figure THPG-10 presents the actual well operating points at the different tubing conditions.

Clicking the 'Save IPR and Solution' will save the well performance data to a CSV file.

## Quick Log Analysis Tool

There are numerous log analysis books available. The definitive reference for log analysis techniques is Crain, E. R., The Log Analysis Handbook, Volume 1, Quantitative Log Analysis Methods, PennWell Publishing Company, 1986. In addition, some of the techniques and equations presented here were also published in LeBlanc, D. P., "Enhanced Shaly Sands and Carbonate Analysis on the HP-41c", Canadian Well Logging Society Journal, December, 1983 and LeBlanc, D. P., "Shaly Sands and Carbonate Analysis on the HP-41c", Canadian Well Logging Society Journal, December, 1982.

PE<sup>2</sup> Essentials 'Quick Log Analysis' tool (Figure QLA-1) is a 'quick and dirty' log analysis tool that can be used to evaluate up to six reservoir intervals as well as pressure-depth data.

**Quick Log Analysis - Version: 2021.0**

Exit Program | Load PE Tools Model | Pressure Gradient | Save Model to PE Tools dB | Info

Oilfield | Open PE dB | **Run Quick Log Analysis** | Capture Screen | PEE Tools Examples Database.PEEdb

---

**Well Information**

Well Name: Example QLA Well  
 Location: Anywhere  
 Field: Good Field  
 Zone: Oil gas Zone  
 KB Elev: 150 feet  
 Date: 1/1/2000  
 Comments: Example Well

**Shale Parameters**

Gamma Ray Clean: 30 API  
 Gamma Ray Shale: 145 API  
 SP Clean: -55 mV  
 SP Shale: -50 mV  
 Neutron Porosity Shale: 0.18 dec  
 Density Porosity Shale: -0.03 dec  
 Sonic ΔT Shale: 61 μs/ft  
 Shale Resistivity: 100 ohm-m

**Log Data**

	Interval 1	Interval 2	Interval 3	Interval 4	Interval 5	Interval 6
Interval Top	6740.8	6745.7	6752.3	6758.9	0	0
Interval Bottom	6745.7	6752.3	6758.9	6763.8		
Resistivity, Rt	40	30	30	80		
Neutron Porosity < dec>	0.13	0.185	0.14	0.17		
Density Porosity < dec>	0.08	0.165	0.09	0		
Sonic ΔT	67	76	67	95		
GR	35	30	30	125		
SP	-50	-50	-50	-50		

**Analysis Parameters**

a= 0.62 m= 2.15 n= 2  
 Sonic ΔT Water: 200 μs/ft  
 Sonic ΔT Matrix: 50.3 μs/ft

**Net Pay Cutoffs**

Vsh<= 0.6 Sw<= 0.6 Perm>= 0.01

**Reservoir Parameters**

Reservoir Area: 80 Acres  
 Oil Bo: 1.25 vol/vol  
 Gas Bg: 0.0045 vol/vol

**Water Resistivity**

Rw From Logs  
 Resistivity in Water Zone: 0.9  
 Neutron Porosity in Water Zone: 0.17  
 Density Porosity in Water Zone: 0.15  
 Rw\_Log: 0.028

Rw From Salinity  
 Water Salinity (ppmNaCl): 150000  
 Interval temperature, °F: 180  
 Rw\_Salinity: 0.025  
☒ Use Rw from log  
☐ Use Rw from salinity

**Shale Model**

☐ Gamma Ray  
☐ Clavier  
☐ SP  
☐ N-D CrossPlot  
☒ Minimum

**Porosity Model**

☐ Sonic  
☐ Density  
☐ Neutron  
☐ N-D CrossPlot  
☒ N-D Shaley Sand

**Saturation Model**

☐ Archie  
☒ Simandoux  
☐ Poupon

**Perm Model**

☒ Wyllie  
☐ Timur  
 Calibration= 1

**Analysis Results**

Parameter	Interval 1	Interval 2	Interval 3	Interval 4	Interval 5	Interval 6
Net Pay	4.9	6.6	6.6	0		
Vshale	0.019	0	0	0.675		
Porosity	0.104	0.175	0.115	0.034		
Water Saturation	0.237	0.157	0.247	0.29		
Permeability	2.205	116.086	3.791	0.002		
TOC - Sonic	6.1	6.5	4.4	16.9		
TOC - Density	7.6	10.3	7.2	6.3		
phi-h	0.508	1.155	0.759	0		
phi-h-(1-Sw)	0.387	0.973	0.572	0		
kh	10.8	766.2	25	0		
Gas Indicator?	No	No	No	No		
OOIP (mbbls)	192.4	483.3	283.8	0		
GIIP (mmscf)	300	753.7	442.6	0		

**Summary:**  
 Total Net Pay: 18.1 Average Phi: 0.134 Total OOIP: 959.386 mbbls  
 Average Vsh: 0.005 Average Sw: 0.212 Total GIIP: 1496.335 mmscf

Figure QLA-1: PE<sup>2</sup> Essentials Quick Log Analysis Tool

Commercial log analysis packages can load raw log data into the system and can clean-up the data prior to performing log analysis on a sample basis. The purpose of the Quick Log Analysis tool is to be able to perform a quick analysis of a potential reservoir interval so average log values are entered and used in the calculations.

## QLA.1 Log Analysis Models

A number of petrophysical models make up a log analysis system. PE<sup>2</sup> Essentials Quick Log Analysis tool includes models for shale, porosity, water saturation and permeability (Figure QLA-2).

Figure QLA-2: PE<sup>2</sup> Essentials Quick Log Analysis Tool - Model Options

Although there are many models and techniques available, the following models are some of the most common used models for log analysis.

### QLA.1.1 Shale Models

Shale volume is required to correct porosity and water saturation results for the effects of shale. Shale volume is also an indicator of reservoir quality and is used to indicate net pay.

The most common models used to calculate shale volume are based on the Gamma Ray (GR) log, the Spontaneous Potential (SP) log, and the Neutron-Density logs (Figure QLA-3).

Figure QLA-3: Shale Model Options

The 'Gamma Ray' and 'Clavier' options both use an index ( $I_{SH}$ ) calculated from the GR log.

For the 'Gamma Ray' option, the assumption is that the shale volume,  $V_{sh}$ , follows a linear relationship from the clean GR value,  $GR_0$ , to the 100% shale GR value,  $GR_{100}$ .

$$I_{SH} = (GR_{log} - GR_0) / (GR_0 - GR_{100}) \quad (QLA-1)$$

$$V_{sh} = I_{GR} \quad (QLA-2)$$

Shlumberger and Dresser-Atlas (now Baker-Hughes) published optional equations that changed the  $V_{sh}$  calculation to a non-linear function of  $I_{GR}$ . Shlumberger's equation is included as the "Clavier" option as follows.

$$V_{sh} = 1.7 - (3.38 - (I_{SH} + 0.7)^2)^{0.5} \quad (QLA-3)$$

The Dresser-Atlas equations are as follows.

$$V_{sh} = 0.083 (2^{3.7I_{SH}} - 1) \quad \text{:Tertiary Rocks} \quad (QLA-4)$$

$$V_{sh} = 0.33 (2^{2I_{SH}} - 1) \quad \text{:Older Rocks} \quad (QLA-5)$$

Note that the Dresser-Atlas equations are not included in the PE<sup>2</sup> Essentials Quick Log Analysis model.

The 'SP' option is similar to the Gamma Ray option in that the assumption is that the shale volume,  $V_{sh}$ , follows a linear relationship from the clean SP value,  $SP_0$ , to the 100% shale SP value,  $SP_{100}$ .

$$I_{SH} = (SP_{log} - SP_0) / (SP_0 - SP_{100}) \quad (QLA-6)$$

$$V_{sh} = I_{SH} \quad (QLA-7)$$

The 'N-D CrossPlot' option uses the Neutron ( $\phi_N$ ) and Density ( $\phi_D$ ) logs to determine  $V_{sh}$ .

$$V_{sh} = (\phi_{Nlog} - \phi_{Dlog}) / (\phi_{NSH} - \phi_{DSH}) \quad (QLA-8)$$

The  $V_{sh}$  calculated by N-D crossplot may be impacted by the assumed value of the rock matrix, the existence of gas and the rugosity of the borehole.

Choosing the 'Minimum' option will choose the minimum  $V_{sh}$  calculated using all models.

### QLA.1.2 Porosity Models

There are three basic porosity logging tools – sonic, density and neutron. Each tool can be used as an independent indicator of porosity or the Neutron ( $\phi_N$ ) and Density ( $\phi_D$ ) logs can be used simultaneously (crossplotted) to determine the porosity (Figure QLA-4).

Porosity calculated from logs without applying a shale correction is termed apparent or total porosity. Effective porosity is the resulting porosity after applying a shale correction.

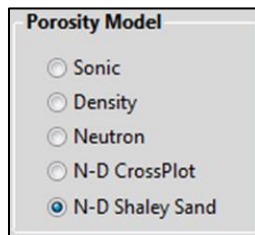


Figure QLA-4: Porosity Model Options

The sonic log records the sonic travel time,  $\Delta t$ , of a small interval of rock. The equation for sonic porosity,  $\phi_s$ , is as follows.

$$\phi_s = (\Delta t_{\log} - \Delta t_{ma}) / (\Delta t_w - \Delta t_{ma}) \quad (\text{QLA-9})$$

The equation for sonic-based porosity, with shale correction is as follows.

$$\phi = (\Delta t_{\log} - ((1 - V_{sh}) \Delta t_{ma}) - (V_{sh} * \Delta t_{sh})) / (\Delta t_w - \Delta t_{ma}) \quad (\text{QLA-10})$$

Where:  $\phi$  is the porosity in decimal,  $\Delta t_{\log}$  is the sonic log reading in the interval of interest,  $V_{sh}$  is the volume of shale,  $\Delta t_{ma}$  is the rock matrix travel time (Table QLA-1),  $\Delta t_{sh}$  is the sonic travel time in 100% shale and  $\Delta t_w$  is the sonic travel time in water.

Lithology	$\Delta t$	
	$\mu\text{sec}/\text{ft}$	$\mu\text{sec}/\text{m}$
Fresh Water	200	656
Salt Water	188	617
Shale	60 - 150	197-492
Granite	50	164
Sandstone	55.5	182
Limy sandstone	52	171
Limestone	47.3	155
Limy Dolomite	46	151
Dolomite	44	144
Anhydrite	50	164
Coal	95+	312+
Salt	66.7	219

Table QLA-1: Sonic  $\Delta t$  Values

One caution to be kept in mind is what is termed as the 'sonic compaction factor',  $C_p$ . This is only an issue if  $\Delta t_{sh}$  is greater than  $100\mu\text{sec}/\text{ft}$  ( $328\mu\text{sec}/\text{m}$ ), which could occur for depths less than 3000ft (1000m).

$$C_p = \Delta t_{sh} / 100 \text{ or } C_p = \Delta t_{sh} / 328 \quad (\text{QLA-11})$$

$$\phi = \phi_s / C_p \quad (\text{QLA-12})$$

The Quick Log Analysis tool assumes that  $C_p$  is one; i.e. no compaction correction applied to  $\phi_s$ .

The density log measures the bulk density,  $\rho_b$ , of the rock and records either the density,  $\rho_b$ , or the density porosity,  $\phi_D$ . The equation for density porosity is as follows.

$$\phi_D = (\rho_{ma} - \rho_b) / (\rho_{ma} - \rho_f) \quad (\text{QLA-13})$$

The equation for density-based porosity, with shale correction is as follows.

$$\phi = \phi_D - V_{sh} \phi_{Dsh} \quad (\text{QLA-14})$$

$$\phi_{Dsh} = (\rho_{ma} - \rho_{sh}) / (\rho_{ma} - \rho_f) \quad (\text{QLA-15})$$

Where:  $\phi$  is the porosity in decimal,  $\phi_D$  is the density porosity,  $V_{sh}$  is the volume of shale,  $\phi_{Dsh}$  is the density porosity of 100% shale,  $\rho_b$  is the recorded log bulk density,  $\rho_{ma}$  is the rock matrix density (Table QLA-2),  $\rho_{sh}$  is the density of 100% shale and  $\rho_f$  is the density of mud filtrate (water).

Lithology	$\rho$	
	g/cc	kg/m <sup>3</sup>
Fresh Water	1	1000
Salt Water	1.1	1100
Shale	2.5 - 2.83	2500-2830
Chlorite	2.6 - 2.96	2600-2960
Kaolinite	2.6 - 2.68	2600-2680
Montmorillonite	2.2 - 2.7	2200-2700
Granite	2.75	2750
Sandstone	2.65	2650
Limy sandstone	2.68	2680
Limestone	2.71	2710
Limy Dolomite	2.83	2830
Dolomite	2.87	2870
Anhydrite	2.95	2950
Coal	1.5 - 2.35	1500-2350
Salt	2.03	2030

Table QLA-2: Density Values

The existence of gas may cause the calculated porosity to be too high because a low bulk density is recorded. This can be corrected by modifying  $\rho_f$  as follows.

$$\rho_f = (1 - S_{xo})\rho_g + S_{xo}\rho_{mf} \quad (\text{QLA-16})$$

Where:  $S_{xo}$  is the water saturation in the invaded zone,  $\rho_g$  is the gas density and  $\rho_{mf}$  is the density of the mud filtrate.

Note that this correction is not incorporated into the Quick Log Analysis model.

The neutron log measures hydrogen index of the rock and presents it as the neutron porosity,  $\phi_N$ , of the rock.

The caveat for the neutron log is the matrix on which the log is recorded. Most analysis and interpretation charts assume that the neutron log is recorded on a limestone matrix. For this situation, the neutron porosity can be corrected to a different lithology. As an example, for Schlumberger CNL logs the following corrections apply.

$$\text{- Limestone to sandstone: } \phi_{Nss} = 0.222\phi_{NLS}^2 + 1.021\phi_{NLS} + 0.039 \quad (\text{QLA-17})$$

$$\text{- Limestone to dolomite: } \phi_{Ndol} = 1.4\phi_{NLS}^2 + 0.389\phi_{NLS} - 0.01259 \quad (\text{QLA-18})$$



In general, if the neutron porosity is presented on a limestone scale, add 0.04 to the log reading to yield neutron porosity for a sandstone matrix, and vice-versa.

The equation for neutron-based porosity, with shale correction is as follows.

$$\phi = \phi_N - V_{sh} \phi_{Nsh} \quad (QLA-19)$$

Where:  $\phi$  is the porosity in decimal,  $\phi_N$  is the neutron porosity,  $V_{sh}$  is the volume of shale and  $\phi_{Nsh}$  is the neutron porosity of 100% shale.

The existence of gas may cause the neutron porosity read too low because of the reduced hydrogen index in the gas. This effect is not a constant and is a function of the density and wetness of the gas. Dry, low-pressure and high temperature gases have larger impact on the neutron porosity. Shale will reduce the gas effect since shale  $\phi_{Nsh}$  tend to be high values.

If the existence of gas is suspected, using the neutron-density crossplot model is preferred to calculate porosity. The 'N-D CrossPlot' model will take an average of the neutron and density log porosities.

$$\phi = (\phi_N + \phi_D) / 2 \quad (QLA-20)$$

If the neutron porosity is more than 0.02 less than the density porosity, a gas effect is assumed to exist and the porosity calculation is as follows.

$$\phi = ((\phi_N^2 + \phi_D^2) / 2)^{0.5} \quad (QLA-21)$$

This weights the porosity towards the density porosity and is valid in a clean sandstone or a carbonate reservoir.

The 'N-D Shaly Sand' model takes an average of the shale-corrected neutron and density porosities.

$$\phi = (\phi_{Nc} + \phi_{Dc}) / 2 \quad (QLA-22)$$

$$\phi_{Nc} = \phi_N - V_{sh} \phi_{Nsh} \quad (QLA-23)$$

$$\phi_{Dc} = \phi_D - V_{sh} \phi_{Dsh} \quad (QLA-24)$$

If the shale-corrected neutron porosity is more than 0.02 less than the shale-corrected density porosity, a gas effect is assumed to exist and the porosity calculation is as follows.

$$\phi = ((\phi_{Nc}^2 + \phi_{Dc}^2) / 2)^{0.5} \quad (QLA-25)$$

This weights the porosity towards the density porosity.

### QLA.1.3 Water Saturation Models

There are two shaly sand water saturation models as well as the Archie water saturation model included in the Quick Log Analysis model (Figure QLA-5).

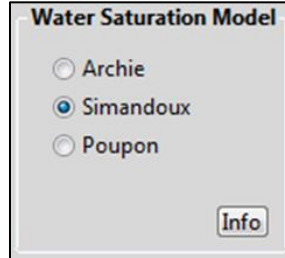


Figure QLA-5: Water Saturation Model Options

The Archie water saturation model is the original standard used by the oil industry but is now only used for clean sandstones or carbonates. The equation is as follows.

$$S_w = (a R_w / \phi^m R_t)^{1/n} \quad (\text{QLA-26})$$

Where:  $a$  is the tortuosity factor (1 for carbonate and 0.62 for sandstone),  $m$  is the cementation exponent (2 for carbonate and 2.15 for sandstone),  $n$  is the saturation exponent (ranges from 1.8 to 2.5, normally set equal to 2),  $R_w$  is the formation water resistivity and  $R_t$  is the true formation resistivity.

For the flushed zone, the Archie equation is as follows.

$$S_{xo} = (a R_{mf} / \phi^m R_{xo})^{1/n} \quad (\text{QLA-27})$$

Where:  $R_{mf}$  is the mud filtrate resistivity and  $R_{xo}$  is the flushed zone resistivity.

If the value for  $S_{xo}$  is greater than the value for  $S_w$ , this may be an indication that movable hydrocarbons exist in the reservoir.

The Archie equation is inaccurate when shale is present in the reservoir. One of the most commonly used shaly sand water saturation model is the Simondoux model.

The Simondoux water saturation equation is as follows.

$$S_w = [(A^2 + B)^{0.5} - C]^{2/n} \quad (\text{QLA-28})$$

$$A = [(1 - V_{sh}) V_{sh} a R_w / 2 \phi^m R_{sh}]$$

$$B = (1 - V_{sh}) a R_w / \phi^m R_t$$

$$C = 0.5(1 - V_{sh}) V_{sh} a R_w / \phi^m R_{sh}$$

Where:  $a$  is the tortuosity factor (1 for carbonate and 0.62 for sandstone),  $m$  is the cementation exponent (2 for carbonate and 2.15 for sandstone),  $n$  is the saturation exponent (ranges from 1.8

to 2.5, normally set equal to 2),  $R_w$  is the formation water,  $R_{sh}$  is the resistivity of the shale, and  $R_t$  is the true formation resistivity.

An alternative shaly sand model is the empirical Poupon-Leveaux model, also referred to as the Indonesian model. The Poupon-Leveaux water saturation equation is as follows.

$$S_w = [(A + B)^2 R_t]^{-1/n} \quad (\text{QLA-29})$$

$$A = [V_{sh}^{(2-V_{sh})} / R_{sh}]^{0.5}$$

$$B = (\phi^m / aR_w)^{0.5}$$

Where:  $a$  is the tortuosity factor (1 for carbonate and 0.62 for sandstone),  $m$  is the cementation exponent (2 for carbonate and 2.15 for sandstone),  $n$  is the saturation exponent (ranges from 1.8 to 2.5, normally set equal to 2),  $R_w$  is the formation water,  $R_{sh}$  is the resistivity of the shale, and  $R_t$  is the true formation resistivity.

### QLA.1.4 Permeability Models

There are two permeability models included in the Quick Log Analysis model (Figure QLA-6).

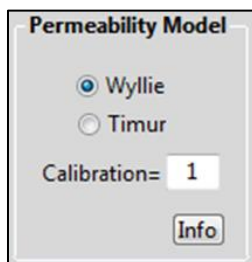


Figure QLA-6: Permeability Model Options

The Wyllie-Rose permeability model is the original method used to calculate permeability from logs. It is accurate when calibrated to core data. The equation is as follows.

$$k = 65000 \text{Cor } \phi^6 / S_w^2 \quad (\text{QLA-30})$$

Where:  $k$  is permeability in md,  $\text{Cor}$  is the correlating parameter equal to 1 for oil and 0.1 for gas.

The Timur permeability model is similar to the Wyllie-Rose formulation but incorporates different constants. The equation is as follows.

$$k = 3400 \text{Cor } \phi^{4.4} / S_w^2 \quad (\text{QLA-31})$$

Where:  $k$  is permeability in md,  $\text{Cor}$  is the correlating parameter equal to 1 for oil and 0.1 for gas.

The  $\text{Cor}$  constant is entered as the 'Calibration' input on the main screen. This factor can also be used to calibrate the log reading to the core data.

## QLA.2 Log Analysis Parameters and Results

A number of parameters are required in order to generate a log analysis. Formation water resistivity,  $R_w$ , is one of the main parameters required for all water saturation models. There are two main techniques to derive  $R_w$ ; calculate directly from a water bearing interval, or estimate the value based on water salinity (Figure QLA-7).

Figure QLA-7: Input Formation Water Resistivity

Estimating  $R_w$  from a water zone is done using the Archie equation with input  $R_t$  and  $\phi$ . For this calculation the  $a$ ,  $m$  and  $n$  parameters need to be entered as well (Figure QLA-8). To estimate  $R_w$  based on salinity, the ppm NACL and the temperature have to be entered. If both calculations are performed, then the  $R_w$  to be used in the water saturation calculations has to be specified.

The net pay cutoffs and the reservoir parameters are optional inputs but are normally entered so that net reservoir and hydrocarbon (oil and/or gas) volumes can be calculated.

Input of shale parameters are required if shaly sand analysis is to be performed (Figure QLA-9).

Figure QLA-8: Input Analysis Parameters

Shale Parameters		
Gamma Ray Clean	30	API
Gamma Ray Shale	145	API
SP Clean	-55	mV
SP Shale	-50	mV
Neutron Porosity Shale	0.18	dec
Density Porosity Shale	-0.03	dec
Sonic ΔT Shale	61	μs/ft
Shale Resistivity	100	ohm-m

Figure QLA-9: Input Shale Parameters

Once the model/analysis parameters are entered, the log data is entered. Note that the Quick Log Analysis routine is not a foot-by-foot analysis of the log data, but instead uses average interval data. Up to six intervals can be entered (Figure QLA-10). There is no option to enter net-to-gross values so, for shaly sands, sands with distributed shale or interbedded sands in laminated sand/shale sequences, averages for the interval should be entered.

It is assumed that the neutron and density porosity values are calibrated to the proper matrix. There is no internal matrix correction applied to these log values.

Raw Log Data						
	Interval 1	Interval 2	Interval 3	Interval 4	Interval 5	Interval 6
Interval Top	6740.8	6745.7	6752.3	6758.9	0	0
Interval Bottom	6745.7	6752.3	6758.9	6763.8		
Resistivity, Rt	40	30	30	80		
Neutron Porosity <dec>	0.13	0.185	0.14	0.17		
Density Porosity <dec>	0.08	0.165	0.09	0		
Sonic ΔT	67	76	67	95		
GR	35	30	30	125		
SP	-50	-50	-50	-50		

Figure QLA-10: Input Log Parameters

After all analysis parameters have been entered, the log analysis models have been chosen and the log data has been entered, log analysis is initiated by clicking the 'Run Log Analysis' button (Figure QLA-11).

Analysis Results						
Parameter	Interval 1	Interval 2	Interval 3	Interval 4	Interval 5	Interval 6
Net Pay	4.9	6.6	6.6	0		
Vshale	0.019	0	0	0.675		
Porosity	0.104	0.175	0.115	0.034		
Water Saturation	0.237	0.157	0.247	0.29		
Permeability	2.205	116.086	3.791	0.002		
TOC - Sonic	6.1	6.5	4.4	16.9		
TOC - Density	7.6	10.3	7.2	6.3		
phi-h	0.508	1.155	0.759	0		
phi-h-(1-Sw)	0.387	0.973	0.572	0		
kh	10.8	766.2	25	0		
Gas Indicator?	No	No	No	No		
OOIP (mbbls)	192.4	483.3	283.8	0		
GIP (mmmscf)	170.9	429.5	252.2	0		

Figure QLA-11: Output Log Analysis Results

Included in the log analysis results (Figure QLA-11) is sonic-based and density-based total organic carbon (TOC). These calculations are included in the analysis results but they are purely qualitative estimates and should be used for comparative purposes only. The TOC's are calculated as follows (ref: <https://spec2000.net/11-vshtoc.htm>).

$$\text{Sonic: TOC} = 0.234 * (\Delta t + 59.433 \log(R)) - 31.86 \quad (\text{QLA-32})$$

$$\text{Density: TOC} = 45.14 - 142.9(p - 1.014)/(\log(R) + 4.122) \quad (\text{QLA-33})$$

Where:  $\Delta t$  sonic travel time in  $\mu\text{sec/ft}$ ,  $R$  is the resistivity and  $p$  is bulk density in  $\text{g/cc}$ .

The analysis results also include a summation of the hydrocarbon volumes contained in the intervals identified as net pay (Figure QLA-12).

Total Net Pay	18.1	Average Phi	0.107	Total OOIP	959.386	mbbls
Average Vsh	0.173	Average Sw	0.233	Total GIIP	852.559	mmscf

Figure QLA-12: Reservoir Volumetrics Based on Log Analysis Results

To disable either the oil volume calculation or the gas volume calculation, enter zero for the 'Oil Bo' or the 'Gas Bg'.

### QLA.3 Pressure-Depth Analysis

The Pressure Gradient Analysis tool is accessed from the main menu (Figure QLA-13). Data is loaded into the tool by clicking 'Load Data'.

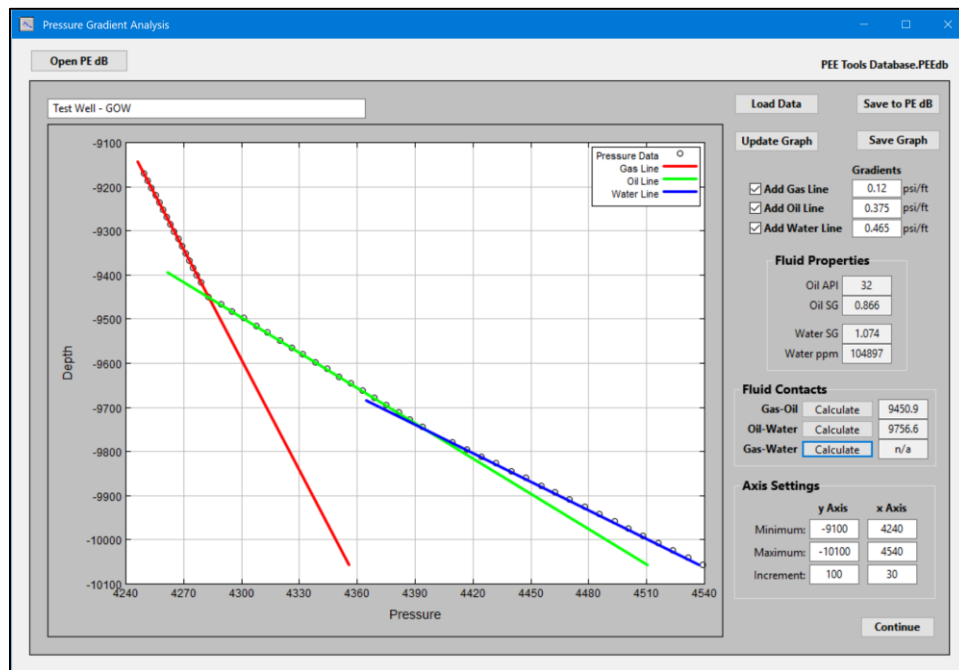


Figure QLA-13: Pressure-Depth Analysis

Data can be entered manually in the Depth/Pressure table; imported from a PE Tools database file ('Load PE db Data'), Figure QLA-14; or imported from an Excel file ('Excel Import'), Figure QLA-15. The data in the figures is from 'Gradient Data.xlsx' included in the 'Example Input Files\Excel Files' directory.

**Pressure-Depth Data Input**

Depth	Pressure
9170	4249.3
9187	4251.34
9203	4253.26
9220	4255.3
9236	4257.22
9252	4259.14
9269	4261.18
9285	4263.1
9302	4265.14
9318	4267.06
9334	4268.98
9351	4271.02
9367	4272.94
9384	4274.98
9400	4276.9
9416	4278.82
9449	4282.78
9466	4289.155
9482	4295.155
9498	4301.155
9515	4307.53
9531	4313.53
9548	4319.905
9564	4325.905
9580	4331.905
9597	4338.28
9613	4344.79

Buttons: Excel Import, Load PE dB Data, Return

Depth in feet; Pressure in psi

**Select P-D Data to Load**

#	Select	Well Name
1	<input checked="" type="checkbox"/>	Test Well - GOW
2	<input type="checkbox"/>	Test Well - GOW 2

Buttons: Cancel, Load P-D Data

Figure QLA-14: Pressure-Depth Analysis, Database Import

**Pressure-Depth Data Input**

Depth	Pressure
9170	4249.3
9187	4251.34
9203	4253.26
9220	4255.3
9236	4257.22
9252	4259.14
9269	4261.18
9285	4263.1
9302	4265.14
9318	4267.06
9334	4268.98
9351	4271.02
9367	4272.94
9384	4274.98
9400	4276.9
9416	4278.82
9449	4282.78
9466	4289.155
9482	4295.155
9498	4301.155
9515	4307.53
9531	4313.53
9548	4319.905
9564	4325.905
9580	4331.905
9597	4338.28
9613	4344.79

Buttons: Excel Import, Load PE dB Data, Return

Depth in feet; Pressure in psi

**Pressure-Depth Data Import**

Link to Excel:  Oilfield:

Info:

**Excel Input Parameters**

Column	Start Row
Depth: b	4
Pressure: c	End Row (optional)

Buttons: Import Data, Continue

Depth	Pressure
9170	4249.3
9187	4251.34
9203	4253.26
9220	4255.3
9236	4257.22
9252	4259.14
9269	4261.18
9285	4263.1
9302	4265.14
9318	4267.06
9334	4268.98
9351	4271.02
9367	4272.94
9384	4274.98
9400	4276.9
9416	4278.82
9449	4282.78
9466	4289.155
9482	4295.155
9498	4301.155
9515	4307.53
9531	4313.53

Figure QLA-15: Pressure-Depth Analysis, Excel Import

After the data is loaded, it can be saved to the PE Tools database with 'Save to PE db' (Figure QLA-13). The database model will also contain the analysis parameters for the well.

This tool can be used to estimate fluid properties and fluid contacts.

Gas/water/oil gradient lines can be added to the plot. The line can be moved by clicking on the upper left end of the line and moving it to the desired location. The gradient is then modified to get the best fit. The equivalent reservoir fluid property, at reservoir conditions, is calculated for the given gradient and presented in the 'Fluid Properties' box (Figure QLA-15).

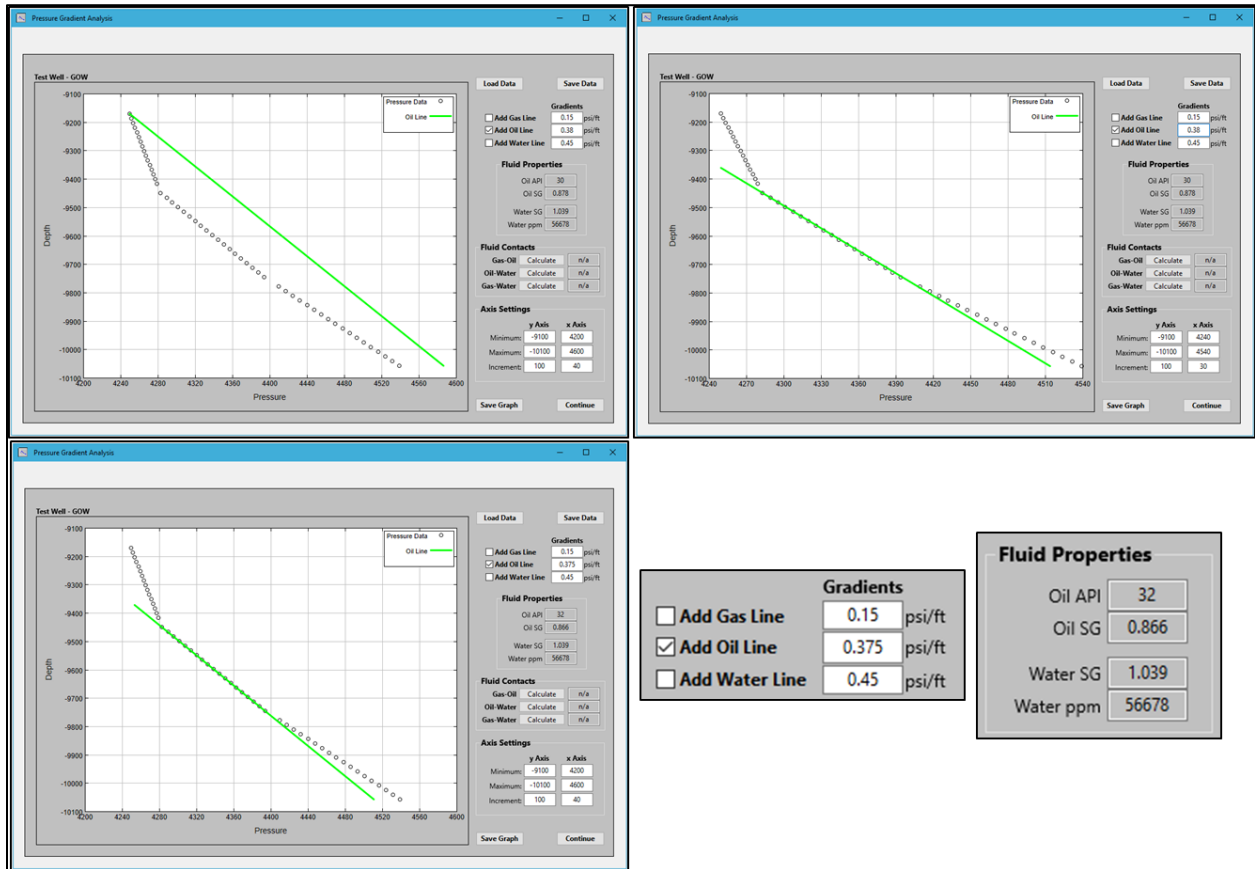


Figure QLA-15: Pressure-Depth Analysis Example

If more than one gradient line is included on the plot, the fluid contact - GOC, OWC or GWC – can be determined by clicking the appropriate 'Calculate' button.



## Hydraulic Fracture Design Tool

The theory in the PE<sup>2</sup> Essentials Hydraulic Fracture Design model are referenced from SPE 98047 (Daal, J. A. and Economides, M. J., Optimization of Hydraulically Fractured Wells in Irregularly Shaped Drainage Areas, SPE98047, 2006), the book Unified Fracture Design (Economides, M. J., Oligney, R. E. and Valko, P. P., Unified Fracture Design, Bridging the Gap Between Theory and Practice, Orsa Press, 2002) and the book Modern Fracturing (Economides, M. J. and Martin, T. Modern Fracturing Enhancing Natural Gas Production Energy Tribune Publishing, 2007).

The 'Hydraulic Fracture Design' tool (Figure HYD-1) is used to generate fracture parameters, for a given hydraulic fracture design, that can be used when forecasting production from a hydraulically fractured horizontal well. The theoretical well PI is presented so that the fracture design parameters can be optimized to maximize the well PI.

Horizontal Well, Hydraulic Fracture Design - Version: 2021

Exit Program | Load PE Tools Model | Save Model to PE Tools dB | Info

Oilfield ▼ Open PE dB

**Hydraulic Fracture Parameters**

Proppant Permeability	1.5	Darcy
Proppant Specific Gravity	2.5	<dec>
Packed Porosity	0.35	<dec>
Total Propped Height	400	ft
Proppant Mass	10000	lbm
Number of Stages	6	<>

**Analysis Results**

Info: Hydraulic Fracture Gas Well

Optimized FCD	1.6	<dec>	Optimized Xf	61.3	ft
Optimized Ix	0.163	<dec>	Optimized Wf	0.016	in
Total Well JD	0.345	<dec>			
Stabilized Well PI	0.117	mmscfpd/psi <sup>2</sup>			
Stabilized Potential @ 500psi	1710.3	mmscf/d			
Equivalent Skin Factor for Well	-4.8	<>			

**Reservoir Parameters**

Well Spacing	750	ft	Reservoir Area	82.6	Acres
Length of Lateral	4800	ft	Fracture Area	495.87	Acres
Frac Pay Thickness	300	ft	Fracture Spacing	800	ft
Reservoir Permeability	0.02	md			
Wellbore Diameter	6	in			

**Deliverability Parameters**

Reservoir Pressure	3850	psi	<input checked="" type="radio"/> Gas Well <input type="radio"/> Oil Well
Viscosity	0.02	cp	
Z Factor	1	<>	
Reservoir Temperature	160	°F	
Flowing Pressure	500	psi	

**Diagram 1: Well Lateral and Stage Spacing**

**Diagram 2: Reservoir Thickness and Well Spacing**

Figure HYD-1: PE<sup>2</sup> Essentials Quick Log Analysis Tool

The resulting fracture parameters ( $x_f$ ,  $w_f$ ,  $k_f$ , and number of frac stages) can be saved and imported into the 'Frac Parameters' sheet of the Unconventional Forecast tool.

The Hydraulic Fracture Design tool enables the fracture parameters to be optimized based on a calculation of the resulting pseudo-steady state productivity index for the well.

If 'Deliverability Parameters' are entered, an estimate of the stabilized well production potential at the bottom hole 'Flowing Pressure' entered into the model will be reported.

The optimization routine is based on using the concept of Proppant Number,  $N_p$ , as a normalizing and descriptive parameter (Valko, P. P., Economides, M. J., "Heavy Crude Production from Shallow Formations: Long Horizontal Wells Versus Horizontal Fractures", SPE50421, 1998) as presented by Daal and Economides.

In general, for any  $N_p$  there exists a maximum dimensionless productivity index ( $J_D$ ) that corresponds to the optimum dimensionless fracture conductivity ( $C_{fD}$ ). With this value of the dimensionless fracture conductivity it is possible to determine the fracture width ( $w_f$ ) and length ( $x_f$ ) depending on the properties of the reservoir and the proppant.

For reference purposes, Figure HYD-2 presents the parameters for hydraulically fractured wells.

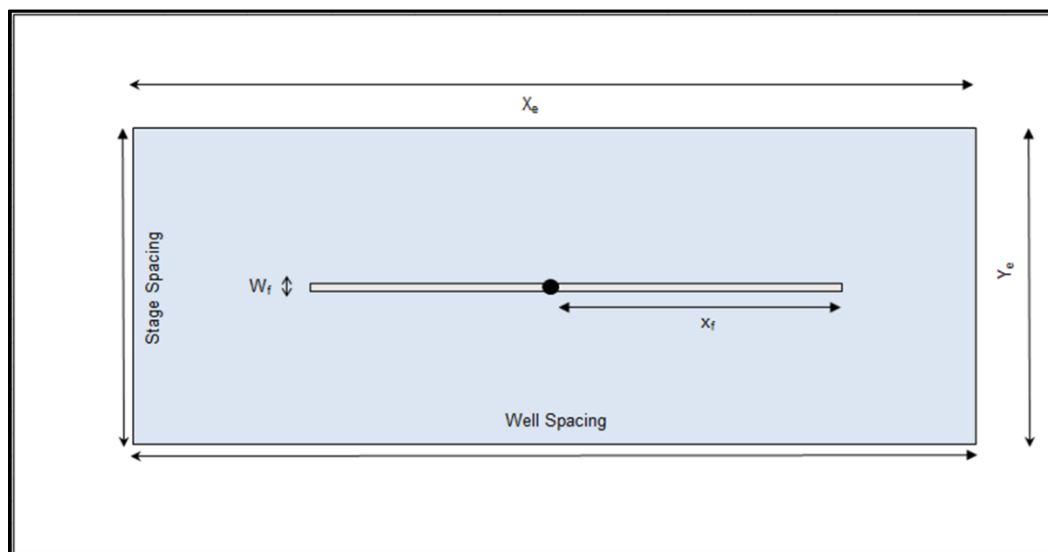


Figure HYD-2: Hydraulic Fracture Parameters – Top View

Since one hydraulic fracture, or stage, in a horizontal well has a non-square, non-radial drainage area, it is necessary to use the rectangular shape factors ( $C_A$ ) to determine the productivity index for each fracture and by extension, for the well. The shape factors for irregular drainage areas were presented by Daal and Economides.

For implementation in the tool, a shape factor correlation was generated from a plot of the  $C_A$  and  $Y_{eD}$  (dimensionless aspect ratio =  $y_e/x_e$ ) data (Figure HYD-3).

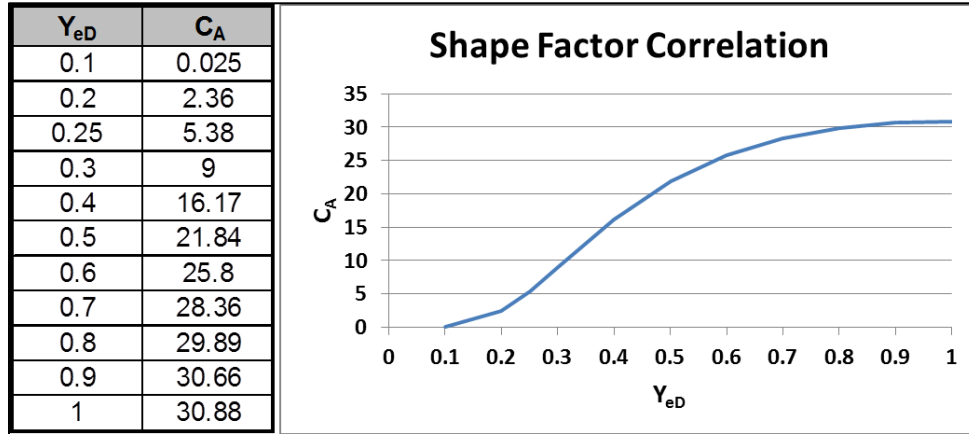


Figure HYD-3: Rectangular Shape Factors

The correlation equation for the shape factor is as follows.

$$Y_{eD} > 0.2: C_A = -367.43Y_{eD}^5 + 1227.3Y_{eD}^4 - 1538.2Y_{eD}^3 + 833.48Y_{eD}^2 - 129.65Y_{eD} + 5.3719 \quad (\text{HYD-1})$$

$$Y_{eD} \leq 0.2: C_A = 23.35Y_{eD} - 2.31 \quad (\text{HYD-2})$$

$$Y_{eD} = y_e/x_e \quad (\text{HYD-3})$$

Where  $y_e$  is the drainage length (fracture spacing) and  $x_e$  is the drainage length (well spacing). Fracture spacing is defined as the length of the lateral divided by the number of fractures. Note that a square drainage has a  $Y_{eD} = 1$  and a  $C_A = 30.88$ .

The proppant number is defined as follows for a square reservoir.

$$N_p = I_x^2 C_{fD} \quad (\text{HYD-4})$$

Where  $I_x$  is the penetration ratio, defined as:

$$I_x = 2x_f/x_e \quad (\text{HYD-5})$$

$C_{fD}$  is the dimensionless fracture conductivity, defined as:

$$C_{fD} = k_f w_f / k x_f \quad (\text{HYD-6})$$

This results in  $N_p$  as follows:

$$N_p = \frac{2V_{\text{frac}}k_f}{V_{\text{res}}k} \quad (\text{HYD-7})$$

$$V_{\text{frac}} = \text{PropM}/(\text{PropSG } 62.4) h/h_f \quad (\text{HYD-8})$$

$$V_{\text{res}} = x_e y_e h \quad (\text{HYD-9})$$

Where  $V_{\text{frac}}$  is the volume of the fracture contained within the pay and  $V_{\text{res}}$  is the reservoir drainage volume,  $k_f$  is the fracture permeability,  $k$  is the reservoir permeability,  $x_f$  is the fracture half-length,  $w_f$  is the fracture width,  $x_e$  is the drainage area length,  $y_e$  is the drainage area width, PropM is the mass of proppant injected in lbm, PropSG is the specific gravity of the proppant,  $h$  is the reservoir thickness and  $h_f$  is the total propped height of the fracture within the pay.

For rectangular, and square, reservoir drainage,  $N_p$  becomes:

$$N_p = l_x^2 C_{fD} / Y_{eD} \quad (\text{HYD-10})$$

Daal and Economides presented a number of plots showing the relationship between  $C_{fD}$ ,  $J_D$  and  $N_p$  for a square drainage area. Figure HYD-4 presents Figures 2 and 9 from Daal and Economides showing the occurrence of the maximum value of  $C_{fD}$  for each  $N_p$  in a square drainage area. Daal and Economides also presented a plot of  $Y_{eD}$  versus  $J_{D\text{max}}$  and  $N_p$  (Figure HYD-5).

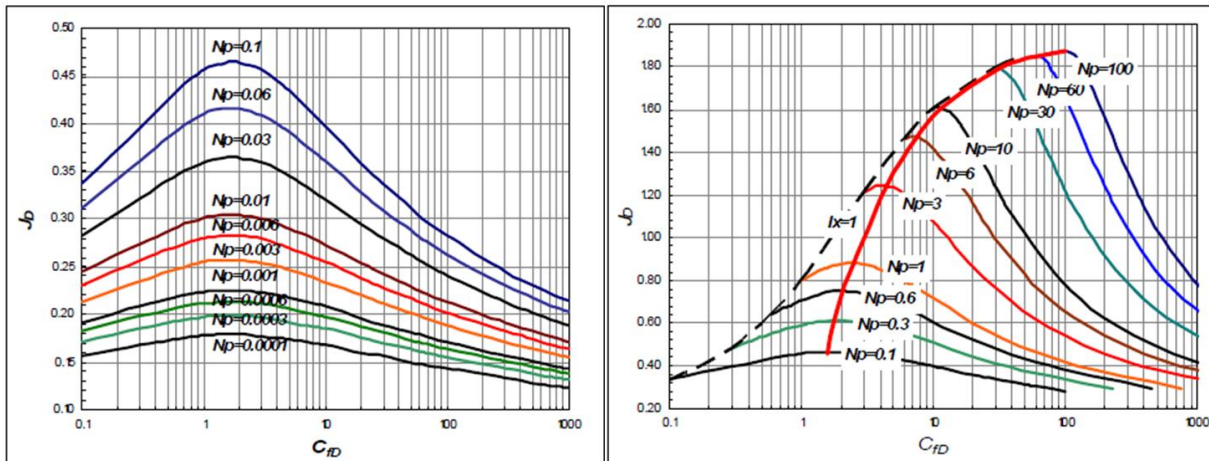


Figure HYD-4: Maximum  $C_{fD}$  (Figure 2 and Figure 9 from Daal and Economides)

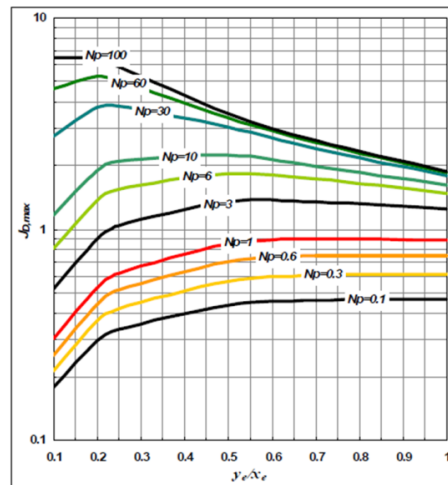


Figure HYD-5: Maximum  $J_D$  (Figure 13 from Daal and Economides)

Daal and Economides extended the analysis for a square drainage area to include non-square reservoirs and presented the correlation for the optimum value of  $C_{fD}$  for  $N_p$  greater than, or equal to, 0.1 as follows:

$$C_{fDopt} = 0.01 (100Y_{ed} - C_{fD,0.1}) (N_p - 0.1) + C_{fD,0.1} \quad (HYD-11)$$

$$\begin{aligned} C_{fD,0.1} &= 1.6 & 1 \geq Y_{ed} > 0.25 \\ C_{fD,0.1} &= 4.5Y_{ed} + 0.25 & 0.1 \leq Y_{ed} \leq 0.25 \end{aligned}$$

Incorporating productivity index ( $J$ ) in its dimensionless form,  $J_D$ . Economides, Oligney and Valko presented the following expression for  $J_D$  in a square reservoir and Daal and Economides presented the expression for maximum  $J_D$  ( $J_{Dmax}$ ) for non-square reservoirs.

$$J_D = [-0.63 - 0.5\ln(N_p) + 0.5\ln(C_{fD}) + f]^{-1} \quad (HYD-12)$$

$$J_{Dmax} = [-0.63 - 0.5\ln(N_p) + F_{opt}]^{-1} \quad (HYD-13)$$

Where  $f$  is the Cinco-Ley and Samaniego pseudo skin function for hydraulic fractures and  $F_{opt}$  is a function to describe the optimum fracture behavior. Daal and Economides defined the function,  $F_{opt}$ , as follows.

$$F_{opt} = (9.33Y_{ed}^2 + 3.9Y_{ed} + 4.7) / 10Y_{ed} \quad N_p < 0.1 \text{ and } 0.25 \geq Y_{ed} \geq 0.1 \quad (HYD-14)$$

$$F_{opt} = (a + bu_{opt} + cu_{opt}^2 + du_{opt}^3) / (a' + b'u_{opt} + c'u_{opt}^2) \quad N_p \geq 0.1 \quad (HYD-15)$$

$$u_{opt} = \ln(C_{fDopt})$$

$$a' = 10$$

$$b' = 36$$

$$c' = 33$$

The constants  $a$ ,  $b$ ,  $c$ , and  $d$  had been presented as a table of values dependent on  $Y_{ed}$ . For ease of use, the constants have been plotted and correlations were generated for each constant as follows.

For  $Y_{ed} < 0.25$ :

$$\begin{aligned} a &= 146.67Y_{ed}^2 + 29.133 \\ b &= 306.67Y_{ed}^2 - 398Y_{ed} + 126.33 \\ c &= -146.27Y_{ed}^2 + 53.72Y_{ed} + 66.054 \\ d &= 13.28Y_{ed} - 0.127 \end{aligned}$$

For  $Y_{ed} \geq 0.25$ :

$$\begin{aligned} a &= -89.481Y_{ed}^3 + 235.53Y_{ed}^2 - 205.1Y_{ed} + 76.252 \\ b &= 55.704Y_{ed}^3 - 141.21Y_{ed}^2 + 114.74Y_{ed} + 25.27 \\ c &= -98.074Y_{ed}^3 + 240.43Y_{ed}^2 - 196.61Y_{ed} + 106.76 \\ d &= 16.9 & Y_{ed} > 0.5 \\ d &= 4.24Y_{ed} + 14.78 & 0.25 \geq Y_{ed} \leq 0.5 \end{aligned}$$

After  $C_{fDopt}$  is calculated based on  $N_p$  and  $Y_{ed}$ , the fracture parameters are calculated as follows.

$$l_{xopt} = (N_p Y_{ed} / C_{fDopt})^{1/2} \quad (HYD-16)$$

$$x_{fopt} = 0.5 l_{xopt} x_e \quad (HYD-17)$$

$$w_{opt} = 12 C_{fDopt} k x_{fopt} / k_f \quad (HYD-18)$$

Where  $x_{fopt}$  is the optimum fracture half-length in ft and  $w_{fopt}$  is the optimum fracture width in inches.

$J_{Dmax}$  is calculated using the values for  $F_{opt}$  and  $N_p$  then converted to a horizontal well,  $J_{Dhmax}$ , for an individual fracture as follows:

$$J_{Dhmax} = [1/J_{Dmax} + S_c]^{-1} \quad (HYD-19)$$

$$S_c = kh/k_f w_f [\ln(h/2r_w) - 1.5708] \quad (HYD-20)$$

Where  $S_c$  is the choked skin in the fracture and  $r_w$  is the wellbore radius in ft.

With the value  $J_{Dhmax}$  and the number of fracture stages, the productivity index is calculated for a gas well and an oil well as follows.

$$PI_{gas} = 1000 \text{ Stages } J_{Dhmax} k h / (1424.0 \mu Z (T + 460)) \quad (HYD-21)$$

$$PI_{oil} = \text{Stages } J_{Dhmax} k h / (141.2 \mu B_o) \quad (HYD-22)$$

Where Stages are the number of hydraulic fracture stages placed in the well,  $PI_{gas}$  is in mmscfpd/psi<sup>2</sup> and  $PI_{oil}$  is in bopd/psi.

## Artificial Lift Design Tool

A survey performed by World Oil and published in February 2012 indicated that 95% of active oil wells in the US were produced by some form of artificial lift. A market research firm (Welling & Company) publishes data on artificial lift in their “Worldwide Survey of the Market of Artificial Lift Equipment”. Figure ALD-1 presents the percentage of artificially lifted oil wells, on land, around the world and Figure ALD-2 presents the percentage of artificially lifted gas wells.

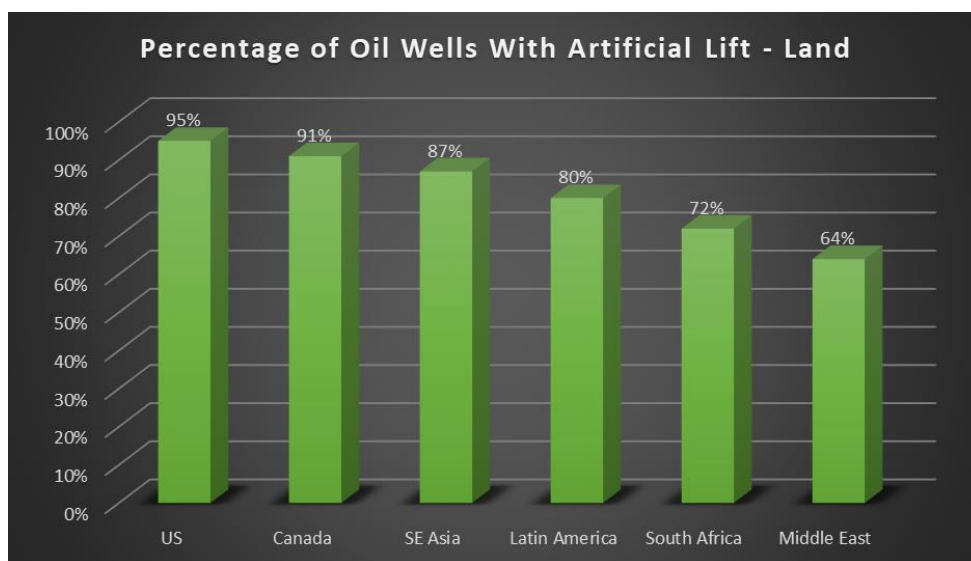


Figure ALD-1: Worldwide Artificial Lift Utilization – Land-Based Oil Wells

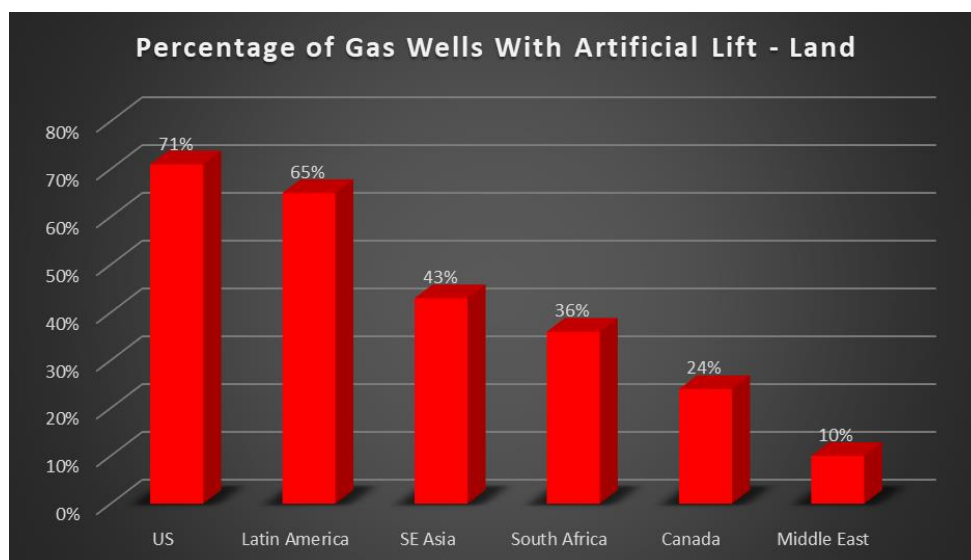


Figure ALD-2: Worldwide Artificial Lift Utilization – Land-Based Gas Wells

The type of artificial lift used on the land-based wells are presented in Figure ALD-3.

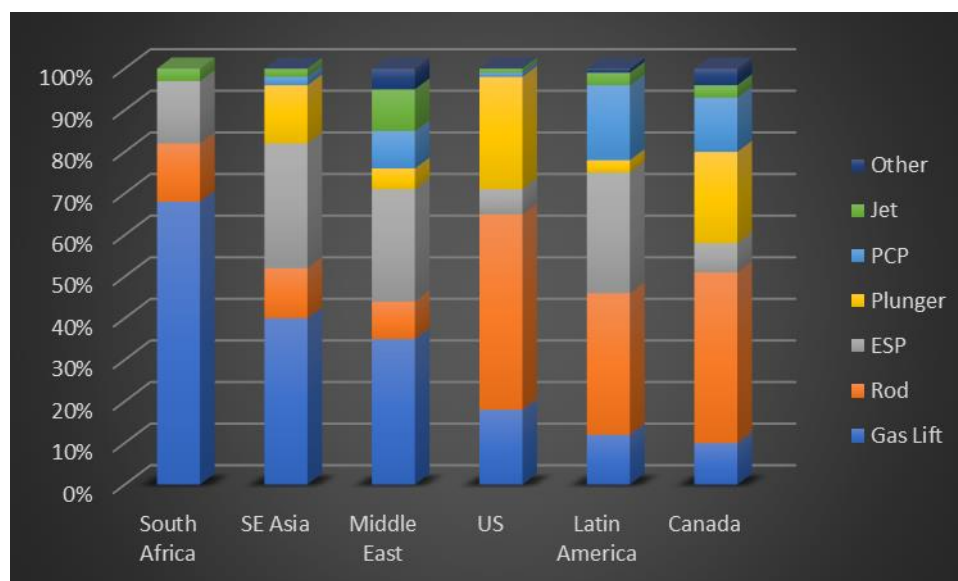


Figure ALD-3: Worldwide Artificial Lift Utilization – Land Wells

(Source for Figures ALD-1 to ALD-3: Welling & Company 2017, Worldwide Survey of the Market of Artificial Lift Equipment)

The preferred type of artificial lift used is a function of many parameters. Table ALD-1 and Figure ALD-4 show the operating parameters for a number of artificial lift systems.

	Plunger	Foam Lift	PCP	Rod Lift	Jet Pump	ESP	Gas Lift
Maximum Volume	200 bpd	500 bpd	5,000 bpd	6,000 bpd	35000 bpd	60,000 bpd	75,000 bpd
	32 m <sup>3</sup> /d	80 m <sup>3</sup> /d	790 m <sup>3</sup> /d	950 m <sup>3</sup> /d	5,560 m <sup>3</sup> /d	9,500 m <sup>3</sup> /d	12,000 m <sup>3</sup> /d
Maximum Depth	19,000 ft	22,000 ft	8,600 ft	16,000 ft	20,000 ft	15,000 ft	18,000 ft
	5,791 m	6,705 m	2,621 m	4,878 m	6,100 m	4,572 m	5,486 m
Maximum Temp	550°F	400°F	250°F	550°F	550°F	482°F	450°F
	288°C	204°C	121°C	288°C	288°C	250°C	232°C
Gas Handling	Excellent	Excellent	Good	Fair to Good	Good	Fair	Excellent
Solids Handling	Fair	Good	Excellent	Fair to Good	Good	Sand<40ppm	Good
Fluid Gravity	>15°API	>8°API	8°<API<40°	>8°API	>8°API	>6°API	>15°API
Prime Mover	Well Energy	Well Energy	Gas/Electric	Gas/Electric	Gas/Electric	Electric	Compressor
System Efficiency	N/A	N/A	50% to 75%	45% to 60%	10% to 30%	35% to 60%	10% to 30%

Table ALD-1: Artificial Lift Selection Criteria



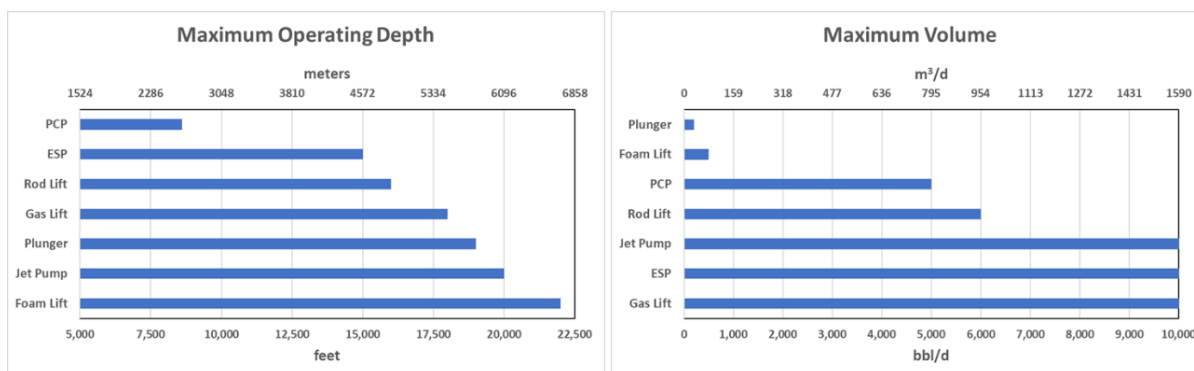
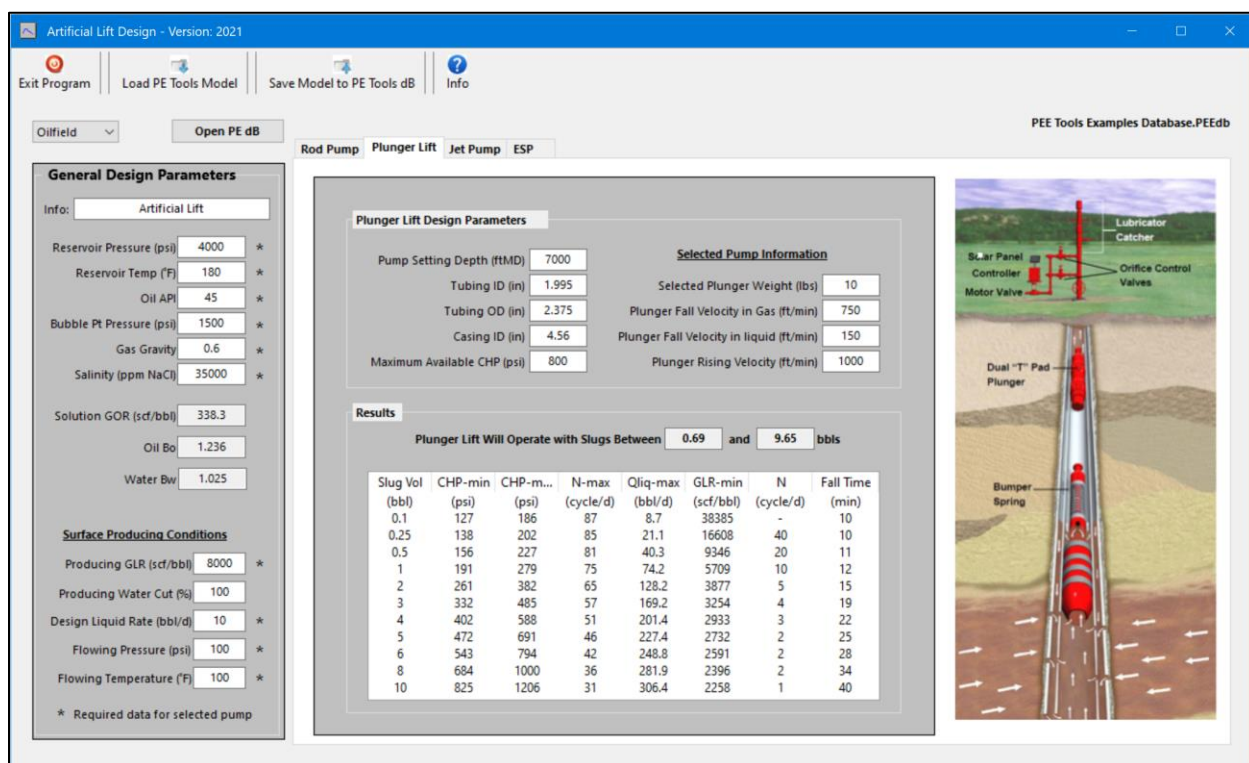


Figure ALD-4: Artificial Lift Operating Parameters

The PE<sup>2</sup> Essentials Artificial Lift Design tool (Figure ALD-5) can be used help determine artificial lift parameters and to compare the benefits of the different artificial lift options.

Figure ALD-5: PE<sup>2</sup> Essentials Artificial Lift Design Tool

The PE<sup>2</sup> Essentials Artificial Lift Design tool includes design parameters for rod pumps, plunger lift, hydraulic jet pumps and electrical submersible pumps (ESP). The definitive reference for artificial lift are the series of books by Brown, K., et al, The Technology of Artificial Lift Methods, Volumes 1, 2a, 2b and 4, PennWell Books, 1980 – 1984.

## ALD.1 Rod Pumps

### ALD.1.1 Overview

Sucker rod pumping is an artificial lift technique that provides mechanical energy to lift oil from bottom hole to surface. Both “Rod Lift” and “PCP” artificial lift systems use sucker rods but only rod lift is included in the PE<sup>2</sup> Essentials Artificial Lift Design tool.

Rod pumps can pump a well down to very low pressure by placing the pump barrel near the perforations and thereby maximize oil production rate. This pump system is applicable to slim holes, multiple completions, high bottom hole temperatures and viscous oils. The pump system is easy to change to other wells with minimal cost.

The major disadvantages of rod pumping include excessive friction in crooked/deviated holes, solids sensitivity, low efficiency in gassy wells, limited depth due to rod capacity, and bulky surface equipment. Figure ALD-6 is a diagram of a sucker rod pumping system (ref: Golan, M. and Whitson, C.H., Well Performance, Prentice Hall, 1991).

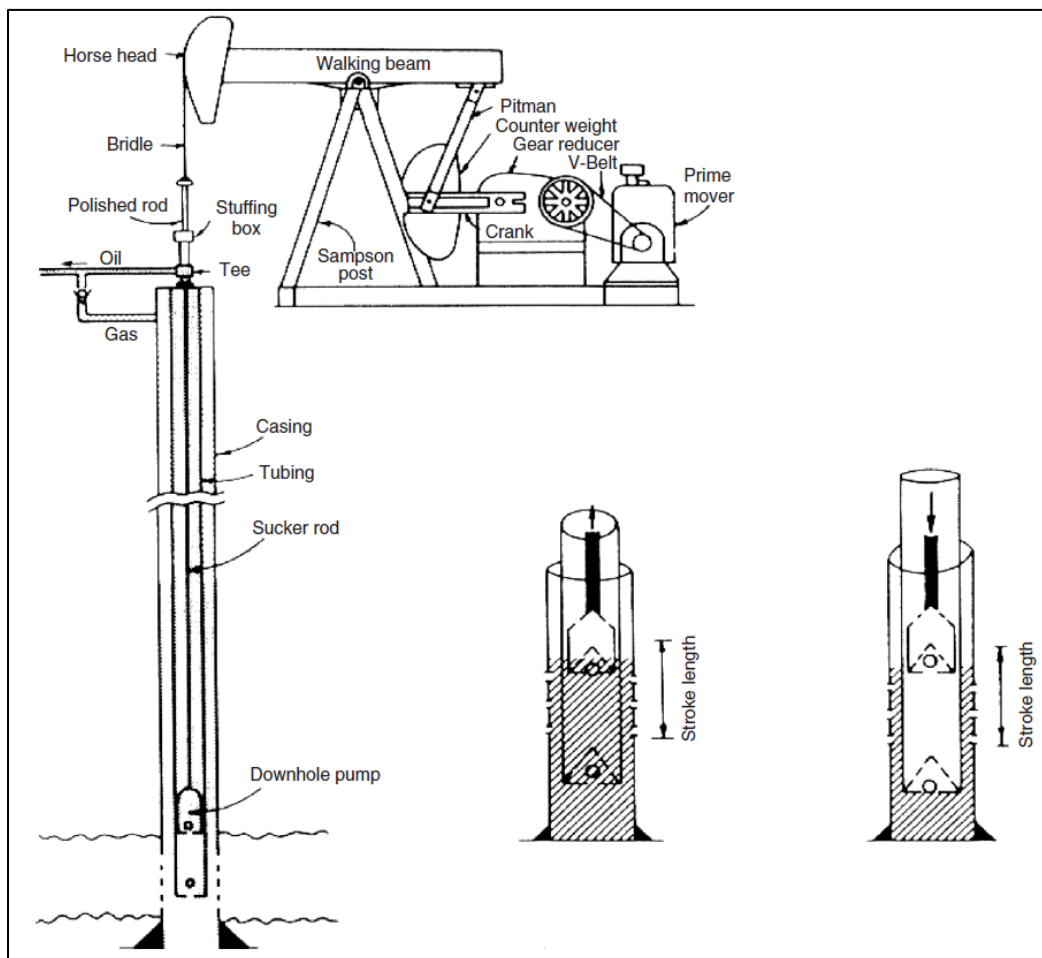


Figure ALD-6: Conventional Sucker Rod Pump

The polished rod and stuffing box combine to maintain a good liquid seal at the surface forcing the fluid to flow into the Tee connection just below the stuffing box. Conventional pumping units are available in a wide range of sizes, with stroke lengths varying from 12in (0.3m) to 200in (5.1m). The stroke lengths are achieved by varying the position of the pitman arm connection on the crank arm.

Walking beam ratings are expressed in allowable polished rod loads (PRL's) and vary from approximately 3,000lb (13,345N) to 35,000lb (155,690N). Counterbalance for conventional pumping units is accomplished by placing counterweights directly on the beam of smaller units or by attaching weights to the rotating crank arm for larger units.

There are two major types of pumping units: Conventional; and Mark II / Air-Balanced Units. (Figure ALD-6 shows a conventional unit and Figure ALD-7 shows an air-balanced unit). Instead of using counterweights, air cylinders are used in the air-balanced units to balance the torque on the crankshaft.

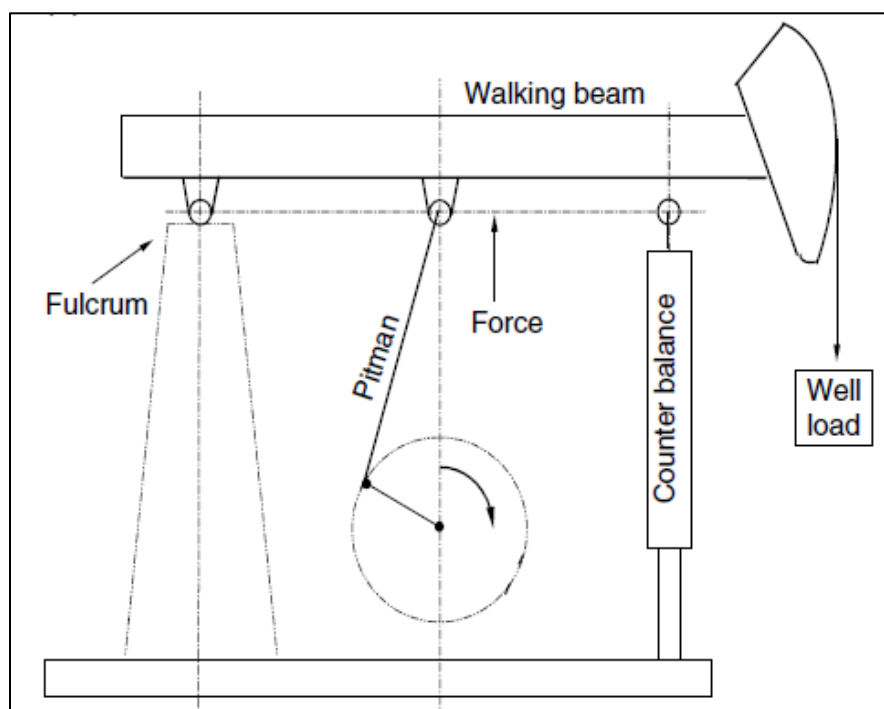


Figure ALD-7: Mark II / Air Balanced Sucker Rod Pump

The American Petroleum Institute (API) has established designations for sucker rod pumping units using a string of characters containing four fields. Table ALD-2 is an excerpt from a table of pump information. A Lufkin pump catalogue is included in the “\Public\Artificial Lift Catalogues” directory for reference purposes.

Conventional Pumping Unit API Geometry Dimensions									
API Unit designation	A (in.)	C (in.)	I (in.)	P (in.)	H (in.)	G (in.)	R1, R2, R3 (in.)	C <sub>s</sub> (lb)	Torque factor
C-912D-365-168	210	120.03	120	148.5	237.88	86.88	47, 41, 35	-1,500	80.32
C-912D-305-168	210	120.03	120	148.5	237.88	86.88	47, 41, 35	-1,500	80.32
C-640D-365-168	210	120.03	120	148.5	237.88	86.88	47, 41, 35	-1,500	80.32
C-456D-305-168	210	120.03	120	148.5	237.88	86.88	47, 41, 35	-1,500	80.32
C-912D-427-144	180	120.03	120	148.5	237.88	86.88	47, 41, 35	-650	68.82
C-912D-365-144	180	120.03	120	148.5	237.88	86.88	47, 41, 35	-650	68.82
C-640D-365-144	180	120.03	120	148.5	238.88	89.88	47, 41, 35	-650	68.82
C-640D-305-144	180	120.08	120	144.5	238.88	89.88	47, 41, 35	-520	68.45
C-456D-305-144	180	120.08	120	144.5	238.88	89.88	47, 41, 35	-520	68.45
C-640D-256-144	180	120.08	120	144.5	238.88	89.88	47, 41, 35	-400	68.45
C-456D-256-144	180	120.08	120	144.5	238.88	89.88	47, 41, 35	-400	68.45
C-320D-256-144	180	120.08	120	144.5	238.88	89.88	47, 41, 35	-400	68.45
C-456D-365-120	152	120.03	120	148.5	238.88	89.88	47, 41, 35	570	58.12
C-640D-305-120	155	111.09	111	133.5	213	75	42, 36, 30	-120	57.02
C-456D-305-120	155	111.09	111	133.5	213	75	42, 36, 30	-120	57.02

Table ALD-2: Pumping Unit API Designations

As an example, the API Unit Designation, C-912D-365-168, represents the following (refer to Figure ALD-8 for labels). The first field is the code for the type of pumping unit: C is for conventional units; A is for air-balanced units; B is for beam counterbalance units; and M is for Mark II units. The second field (912D) is the code for peak torque rating in thousands of inch-pounds and gear reducer information: D stands for double-reduction gear reducer. The third field (365) is the code for PRL rating in hundreds of pounds – 36,500lb in this example. The last field (168) is the code for maximum stroke length in inches.

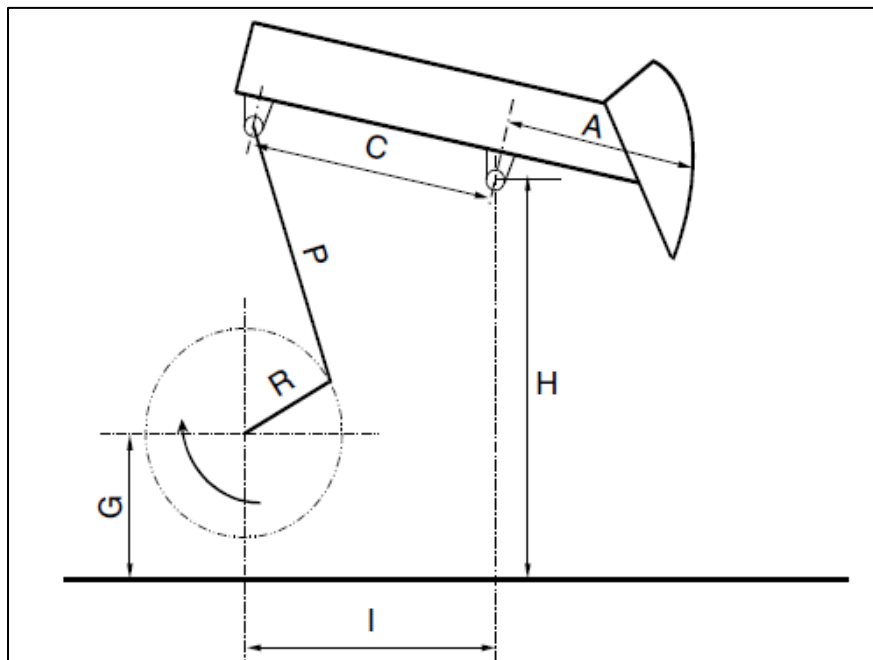


Figure ALD-8: Sucker Rod Pump Labels

The information in the API Geometry table used in PE<sup>2</sup> Essentials Artificial Lift Design are the “A” pump dimension, the “C” pump dimension and the “R” crank dimension. The “Crank-to-Pitman” ratio is also required. This value can be calculated as R/P where “P”, the pitman arm dimension, is obtained from the geometry table. For the example used above the Crank-to-Pitman ratio would be 47/148.5 or 0.3165. This ratio is used to determine maximum pump speed.

One factor in rod pump design is the “Maximum Allowable Acceleration Factor”. There is a limiting relationship between stroke length and cycles per minute. The maximum value of the downward acceleration occurs at the top of the pump stroke. If the maximum acceleration divided by g (gravitational acceleration) exceeds one, then the downward acceleration is greater than the free-fall acceleration of the rods at the top of the stroke. This leads to severe pounding when the polished rod shoulder falls onto the hanger and leads to failure of the rod at the shoulder. As a result, a Maximum Allowable Acceleration Factor (the downward acceleration divided by g) is normally limited to approximately 0.5 or to a value determined by experience in a particular field.

Volumetric efficiency of the plunger is dependent on the rate of oil slippage past the pump plunger and the solution–gas ratio at pump conditions. Metal-to-metal plungers are commonly available with plunger-to-barrel clearance -0.001, -0.002, -0.003, -0.004, and -0.005. For example, the -0.001 means the plunger’s outside diameter is 0.001 inches smaller than the barrel’s inside diameter. For low viscosity oils (<20 cp), a plunger-to-barrel clearance 0.001 inches can be used. For high viscosity oils, the clearance can be increased and if sand/solids are expected a plunger-to-barrel clearance 0.005 inches can be used.

A pump’s volumetric efficiency is mainly affected by the slippage of oil and the free gas volume below the plunger. Both effects are difficult to quantify and pump efficiency can vary over a wide range but are commonly around 70–80%.

The procedure and equations for rod pump design are presented in Section ALD.1.2. The derivations of the equations are not presented here but can be found in the references.

### ALD.1.2 Rod Pump Design

The pump design procedure is as follows:

Step 1 - Calculate the weight of the fluid,  $W_f$ :

$$W_f = S_f (62.4) \frac{DA_p}{144} \quad (\text{ALD-1})$$

$$S_f = (1 - \text{WCut}/100) * 141.5 / (131.5 + \text{OilAPI}) + \text{WCut}/100 * S_{\text{water}}$$

$$A_p = 0.25 \pi \text{OD}_p^2$$

Where:  $W_f$  is the weight of the fluid in lbs,  $S_f$  is the specific gravity of the produced fluid,  $D$  is the pump setting depth in ft,  $A_p$  is the cross-sectional area of the plunger in  $\text{in}^2$ ,  $W_{\text{Cut}}$  is the water cut in %, OilAPI is oil gravity in °API,  $S_{\text{water}}$  is the specific gravity of the produced water, and  $OD_p$  is the diameter of the plunger in inches.

Step 2 - Calculate the weight of the rods,  $W_r$ :

$$W_r = \frac{\gamma_s D A_r}{144} \quad (\text{ALD-2})$$

$$A_r = 0.25 \pi OD_r^2$$

Where:  $W_r$  is the weight of the rods in lbs,  $\gamma_s$  is the specific weight of the steel rod ( $=400\text{lb/ft}^3$ ),  $D$  is the pump setting depth in ft,  $A_r$  is the cross sectional-area of the rods in  $\text{in}^2$ , and  $ID_r$  is the diameter of the rods in inches. Note for a tapered string, the value for  $OD_r$  is calculated as the depth-weighted average of the rod diameters.

Step 3 - Calculate the actual downhole plunger stroke,  $S_p$ :

$$S_p = S - \frac{12D}{E} \left[ W_f \left( \frac{1}{A_r} + \frac{1}{A_t} \right) - \frac{SN^2 M}{70500} \frac{W_r}{A_r} \right] \quad (\text{ALD-3})$$

$$E = 30 \times 10^6 \text{ lb/in}^2$$

$$A_t = 0.25 \pi (OD_t^2 - ID_t^2)$$

$$M = 1 + \text{Unit} * R/P$$

Where:  $S_p$  is the stroke length of the plunger in inches,  $S$  is the stroke length of the polished rod in inches,  $D$  is the pump setting depth in ft,  $E$  is the modulus of elasticity of steel in  $\text{lb/in}^2$ ,  $W_f$  is the weight of the fluid in lbs,  $A_r$  is the cross sectional-area of the rods in  $\text{in}^2$ ,  $A_t$  is the cross sectional-area of the tubing in  $\text{in}^2$  (note: this is set to 0 for an anchored tubing),  $N$  is pump speed in SPM,  $M$  is the pittman ratio,  $W_r$  is the weight of the rods in lbs,  $A_r$  is the cross sectional-area of the rods in  $\text{in}^2$ ,  $OD_t$  is outer diameter of the tubing in inches,  $ID_t$  is inner diameter of the tubing in inches, Unit is +1 for a conventional pump and -1 for a Mark II / air balanced pump,  $R$  is the crank dimension in inches, and  $P$  is pitman arm dimension in inches.

Step 4 - Calculate the production rate,  $q$ :

$$q = 0.1484 \frac{A_p N S_p E_v}{B_o} \quad (\text{ALD-4})$$

Where:  $q$  is the fluid production rate in  $\text{stb/d}$ ,  $A_p$  is the cross-sectional area of the plunger in  $\text{in}^2$ ,  $N$  is the pump speed in SPM,  $S_p$  is the stroke length of the plunger in inches,  $E_v$  is the pump volumetric efficiency, and  $B_o$  is the oil formation factor ( $B_t$  is used for oil/water production).

**Step 5** - Calculate the required prime mover power,  $P_{pm}$ :

$$P_{pm} = F_s (P_h + P_f) \quad (\text{ALD-5})$$

$$P_h = 7.36 \times 10^{-6} q S_f L_N$$

$$L_N = H + \frac{P_{tf}}{0.433 S_f}$$

$$P_f = 6.31 \times 10^{-7} W_r S N$$

Where:  $P_{pm}$  is the required prime mover (surface) power in hp,  $F_s$  is the safety factor (1.25 – 1.5),  $P_h$  is the hydraulic power required to lift the fluid in hp,  $P_f$  is the power required to overcome the friction in the system in hp,  $q$  is the production rate in stb/d,  $S_f$  is the specific gravity of the produced fluid,  $L_N$  is the net lift in ft,  $H$  is the depth to the average fluid level in the annulus,  $P_{tf}$  is the flowing tubing head pressure in psi,  $W_r$  is the weight of the rods in lbs,  $S$  is the stroke length of the polished rod in inches, and  $N$  is the pump speed in SPM

**Step 6** – Calculate the maximum polished rod load,  $PRL_{max}$ :

$$PRL_{max} = W_f - S_f (62.4) \frac{W_r}{\gamma_s} + W_r + W_r F_1 \quad (\text{ALD-6})$$

$$F_1 = \frac{S_m N_m^2 (1 + Unit \frac{R}{P})}{70500}$$

$$S_m = 2R \frac{A}{C}$$

$$N_m = \sqrt{\frac{70500L}{S_m (1 - \frac{R}{P})}}$$

Where:  $PRL_{max}$  is the maximum polished rod load in lbs,  $W_f$  is the fluid weight in lbs,  $S_f$  is the specific gravity of the produced fluid,  $W_r$  is the weight of the rods in lbs,  $\gamma_s$  is the specific weight of the steel rod (=400lb/ft<sup>3</sup>),  $F_1$  is the maximum upward acceleration factor,  $S_m$  is the maximum stroke length of the polished rod in inches,  $N_m$  is the maximum allowable pump speed in SPM, Unit is +1 for a conventional pump and -1 for a Lufkin II / air balanced pump,  $R$  is the crank dimension in inches,  $P$  is pitman arm dimension in inches,  $A$  is the API pump dimension in inches and  $C$  is the API pump dimension in inches and  $L$  is the maximum allowable acceleration factor.

**Step 7** – Calculate the minimum polished rod load,  $PRL_{min}$ :

$$PRL_{min} = -S_f (62.4) \frac{W_r}{\gamma_s} + W_r - W_r F_2 \quad (\text{ALD-7})$$

$$F_2 = \frac{S_m N_m^2 (1 - Unit \frac{R}{P})}{70500}$$



Where:  $PRL_{min}$  is the minimum polished rod load in lbs,  $S_f$  is the specific gravity of the produced fluid,  $W_r$  is the weight of the rods in lbs,  $\gamma_s$  is the specific weight of the steel rod ( $=400\text{lb/ft}^3$ ),  $F_2$  is the minimum upward acceleration factor,  $S_m$  is the maximum stroke length of the polished rod in inches,  $N_m$  is the maximum allowable pump speed in SPM, Unit is +1 for a conventional pump and -1 for a Lufkin / air balanced pump,  $R$  is the crank dimension in inches, and  $P$  is pitman arm dimension in inches.

**Step 8** – Calculate the counterweight requirements, CW:

$$CW = \frac{1}{2} (PRL_{max} + PRL_{min}) \quad (\text{ALD-8})$$

Where: CW is the recommended counterweight in lbs,  $PRL_{max}$  is the maximum polished rod load in lbs,  $PRL_{min}$  is the minimum polished rod load in lbs.

### ALD.1.3 Rod Pump Example

Table ALD-3 and Figure ALD-9 present an example of a rod pump design.

This example uses a C-320D-213-86 pump. The API specs for this pump are as follows:  $A = 111\text{in}$ ,  $C = 96.05\text{in}$ ,  $R = 37\text{in}$  and  $P = 114\text{in}$ . From experience, a maximum acceleration factor of 0.4 was used.

The design input parameters are as follows:

Reservoir Pressure = 4500psi Reservoir Temperature = 200°F Oil Density = 45°API Bubble Point Pressure = 500psi Gas Gravity = 0.6 Water Salinity = 35,000ppm Solution GOR = 87scf/bbl Bo = 1.134 Water Cut = 0% Tubing Head Pressure = 100psi	Tubing OD = 3.5in Tubing ID = 2.992in Pump Setting Depth = 3500ft Annulus Liquid Depth = 3500ft No Tubing Anchor Plunger Diameter = 2.25in Rod Diameter = .875in Rod Length = 3500ft Polish Rod Stroke = 86in Pumping Speed = 18	Conventional Pump Pump Volumetric Efficiency = 0.8 Safety Factor for Prime Mover = 1.35 API Pump Dimension A = 111in API Pump Dimension C = 96.05in API Pump Dimension R = 37in API Pump Dimension P = 114in Maximum Allowable Acceleration = 0.4
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Table ALD-3: Sucker Rod Pump Design – Input Data



Artificial Lift Design - Version: 2021

Exit Program Load PE Tools Model Save Model to PE Tools dB Info

Oilfield Open PE dB PEE Tools Examples Database.PEEdb

Rod Pump Plunger Lift Jet Pump ESP

### General Design Parameters

Info: Artificial Lift

Reservoir Pressure (psi)	4500	*
Reservoir Temp (°F)	200	*
Oil API	45	*
Bubble Pt Pressure (psi)	500	*
Gas Gravity	0.6	*
Salinity (ppm NaCl)	35000	*
Solution GOR (scf/bbl)	87.3	
Oil Bo	1.134	
Water Bw	1.032	

### Surface Producing Conditions

Producing GLR (scf/bbl)	87	
Producing Water Cut (%)	0	
Design Liquid Rate (bbl/d)	10	
Flowing Pressure (psi)	100	*
Flowing Temperature (°F)	100	

\* Required data for selected pump

### Sucker Rod Pump Design Parameters

Tubing OD (in)	3.5	Pump Setting Depth (ftMD)	3500
Tubing ID (in)	2.992	Annulus Liquid Depth (ftMD)	3500
Plunger Diameter (in)	2.25	Tubing Anchored?	<input checked="" type="radio"/> Yes <input type="radio"/> No
Rod Diameter (in)	0.875	Polished Rod Stroke (in)	86
Rod Length (ft)	3500	Pumping Speed (spm)	18
Crank-to-Pitman Ratio	3246	Pump Volumetric Efficiency	0.8
API Pump Dimension A (in)	111	Safety Factor for Prime Power	1.35
API Pump Dimension C (in)	96.05	Type of Pump	<input checked="" type="checkbox"/> Conventional <input type="checkbox"/> Mark II/Balanced
API Pump Dimension R (in)	37		
Max Allowable Accel Factor	.256		

### Results

Pumping Liquid Rate (blpd)	625.5	Maximum Speed (spm)	18
Resulting Hydraulic Power (hp)	15.9	Maximum PRL (lbs)	14861
Resulting Friction Power (hp)	7	Minimum PRL (lbs)	4597
Required Prime Mover Power (hp)	30.8	Counterweights (lbs)	9729

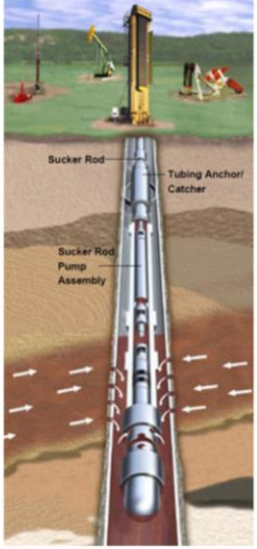


Figure ALD-9: Sucker Rod Pump Design - Example

The design calculations and results are as follows:

Step 1:  $A_p = 3.976$ ,  $S_f = 0.802$ ,  $W_f = 4834.6$

Step 2:  $A_r = 0.601$ ,  $W_r = 7161.6$

Step 3:  $M = 1.3246$ ,  $A_t = 2.59$ ,  $S_p = 80.86$

Step 4:  $q = 605.9$  blpd

Step 5:  $L_N = 3788.1$ ,  $P_f = 6.995$  hp,  $P_h = 15.36$  hp,  $P_{pm} = 30.18$  hp

Step 6:  $S_m = 85.52$ ,  $N_m = 17.7$ ,  $F_1 = 0.502$ ,  $PRL_{max} = 14,860.6$  lbs

Step 7:  $F_2 = 1.35$ ,  $PRL_{min} = 4,597.0$  lbs

Step 8:  $CW = 9,728.8$  lbs

## ALD.2 Plunger Lift

### ALD.2.1 Overview

Plunger lift systems are applicable to high gas–liquid ratio (GLR) wells. As an added benefit, the plunger automatically keeps the tubing clean of paraffin and scale. Plunger lift systems (Figure ALD-10) are good for low-rate liquid wells producing less than 200 bpd and are commonly used to lift water and condensate from gas wells.

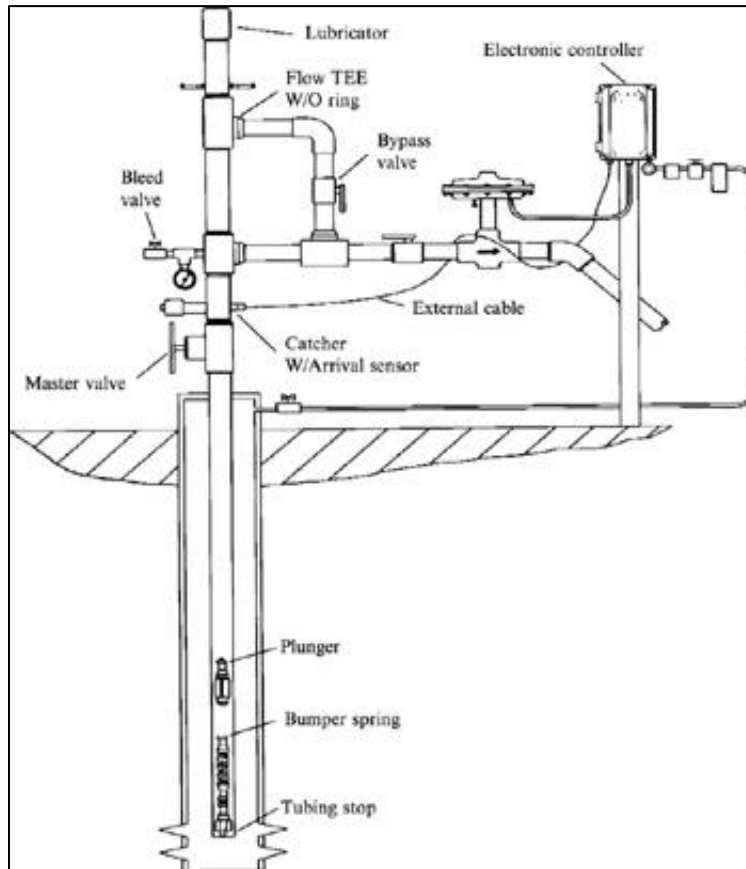


Figure ALD-10: Plunger Lift Pumping System

The main advantages of plunger lift are that it requires no external energy source, a rig is not required for installation, it is low cost, can be used in gas wells, works in deviated wells and can produce wells to depletion. Disadvantages include the required GLR's, it is a low volume pump and it cannot handle solids.

The design techniques for a plunger lift system are referenced from Foss, D. L. and Gaul, R. B.: "Plunger Lift Performance Criteria with Operating Experience - Ventura Field," "Drilling and Production Practice, API (1965), 124-140 and Mower, L.N; Lea, J.F., Beauregard, E., and Ferguson, P.L.: "Defining the Characteristics and Performance of Gas-Lift Plungers", SPE Paper 14344.

Originally, plunger lift was used to produce oil wells. Currently, plunger lift has become more common in gas wells for de-watering purposes. As shown in Figure ALD-11 (Source Khamsehchi, E; Khishvand, K; Abdolhosseini, H: A case study to optimum selection of deliquification method for gas condensate well design: South Pars gas field) high-pressure gas wells may produce gas, water and/or condensate in the form of mist. As the gas flow velocity reduces, the carrying capacity of the gas decreases and the liquid builds up in the bottom of the well.

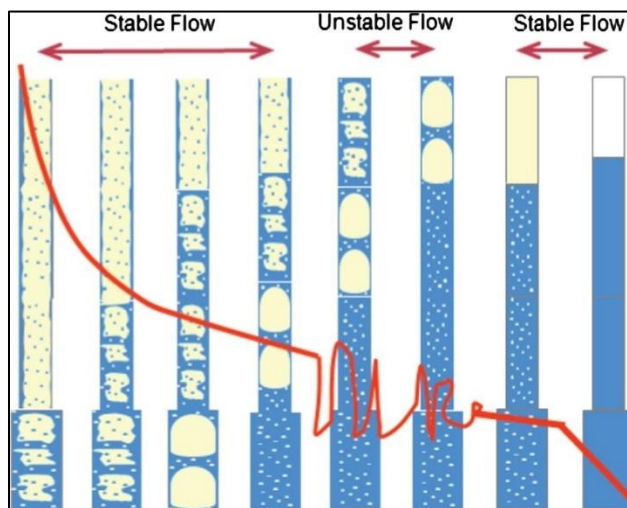


Figure ALD-11: Liquid Loading of a Gas Well

When the gas velocity drops to a critical level, liquid begins to accumulate in the well and the flow will change to a slug flow regime. The accumulation of liquids (liquid loading) increases bottom hole pressure which further reduces gas production rate. Low gas production rate results in lower gas velocity and eventually the well may stop producing as the liquid level rises in the well.

The purpose of plunger lift is to remove liquids from the wellbore allowing the well to be produced at a low bottom hole pressure. The plunger is basically a length of steel and is dropped down the tubing to the bottom of the well and allowed to travel back to the surface. The plunger provides a piston-like interface between liquids and gas in the wellbore. The well's energy is used to lift the plunger and the liquids out of the wellbore.

There are two main requirements for plunger lift operation: a minimum GLR and sufficient well pressure. For the plunger lift to operate, there must be a sufficient quantity of gas per barrel of liquid for a given well depth. The gas in the tubing-casing annulus is used as the source of gas. It is possible to augment the gas supply and increase casing pressure by injecting additional gas into the annulus.

The Foss and Gaul design model was originally designed for oil well operations that assumed the well would be shut-in after plunger arrival. In general, this model overpredicts required casing

pressure. If a well meets the Foss and Gaul criteria, it is almost certainly a candidate for plunger lift.

One of the required input items for the plunger lift design model is the fall times of the plunger in both liquid and gas. Table ALD-4 is an example of a manufacturer's recommended fall times (A PCS Ferguson catalogue is included in the "\Public\Artificial Lift Catalogues" directory).

Fall Times (ft/min)	Plungers, Weatherford
39-150	Pad / Conventional Plungers in Fluid
150-400	Pad / Conventional Plungers in Gas
1500-1800	Continuous Flow In Gas, Shut in
600-1000	Continuous Flow against flow

Table ALD-4: Typical Fall Times for Plungers

### ALD.2.2 Plunger Lift Design

The plunger lift design procedure is as follows:

Step 1 – For a given slug, calculate the minimum pressure required to lift the plunger:

$$P_{Cmin} = [P_p + 14.7 + P_{tf} + (P_{lh} + P_{lf})V_{slug}](1 + \frac{D}{K}) \quad (ALD-9)$$

$$P_p = W_p / A_t$$

$$A_t = 0.25 \pi ID_t^2$$

Where:  $P_{Cmin}$  is minimum casing pressure in psi,  $P_p$  is the plunger weight pressure in psi,  $P_{tf}$  is the flowing tubing head pressure in psi,  $P_{lh}$  is the hydrostatic liquid gradient of the slug in psi/bbl,  $P_{lf}$  is the flowing friction gradient of the slug in psi/bbl,  $V_{slug}$  is the volume of the slug in bbls,  $D$  is the depth to the plunger in ft,  $K$  is a gas friction factor constant in feet,  $W_p$  is the weight of the plunger in lbs,  $A_t$  is the internal cross sectional area of the tubing in  $in^2$ ,  $ID_t$  is the internal diameter of the tubing in inches.

Foss and Gaul suggested an approximation where  $K$  and  $P_{lh} + P_{lf}$  are constant for a given tubing size and a plunger velocity of 1,000 ft/min. Table ALD-5 presents the Foss and Gaul values.

Tubing Size (in)	K (ft)	$P_{lh}+P_{lf}$ (psi/bbl)
2.375	33,500	165
2.875	45,000	102
3.5	57,600	63

Table ALD.4-5: Foss and Gaul Parameters

The PE<sup>2</sup> Essentials plunger lift design tool calculates the value for  $P_{lh}$ ,  $P_{lf}$  and  $K$  as follows:

$$P_{lh} = 0.433 L_s S_f$$

$$S_f = (1 - \text{WCut}/100) * 141.5 / (131.5 + \text{OilAPI}) + \text{WCut}/100 * S_{\text{water}}$$

$$P_{lf} = \frac{\text{fric}_l S_f L_s V_{\text{rise}}^2}{44585 ID_t}$$

$$\text{fric}_l = 0.0056 + 0.5(25.794 S_f ID_t V_{\text{rise}})^{-0.32}$$

$$K = \frac{875292.6 ID_t (T_{\text{avg}} - 460)}{\text{fric}_g S_g V_{\text{rise}}^2}$$

$$\text{fric}_g = 0.0056 + 0.5(135972 S_g ID_t V_{\text{rise}} / (T_{\text{avg}} + 460))^{-0.32}$$

Where:  $P_{lh}$  is the tubing hydrostatic liquid gradient of the slug in psi/bbl,  $L_s$  is the slug length per barrel in the tubing in feet,  $S_f$  is the specific gravity of the produced fluid,  $\text{WCut}$  is the water cut in %,  $S_{\text{water}}$  is specific gravity of the water,  $P_{lf}$  is the flowing friction gradient of the slug in psi/bbl,  $\text{fric}_l$  is the liquid friction factor,  $ID_t$  is the internal diameter of the tubing in inches,  $V_{\text{rise}}$  is the rising velocity of the plunger in ft/min,  $K$  is the gas friction factor constant in feet,  $T_{\text{avg}}$  is the average wellbore temperature in °F,  $\text{fric}_g$  is the gas friction factor and  $S_g$  is the gas gravity.

Step 2 - Calculate the maximum pressure that the casing must reach:

$$P_{C \max} = P_{C \min} \left( \frac{A_a + A_t}{A_a} \right) \quad (\text{ALD-10})$$

$$A_a = 0.25 \pi (OD_t^2 - ID_c^2)$$

Where:  $P_{C \max}$  is maximum pressure must reach to operate the system in psi,  $P_{C \min}$  is minimum casing pressure when the plunger reaches the surface in psi,  $A_a$  is casing-tubing annular cross section in  $\text{in}^2$ ,  $A_t$  is the inner cross section of the tubing in  $\text{in}^2$ ,  $OD_t$  is the outer diameter of the tubing in inches,  $ID_c$  is the internal diameter of the casing in inches, and  $ID_t$  is the internal diameter of the tubing in inches.

Step 3 - Calculate the minimum required GLR to lift the slug and the plunger:

$$\text{GLR}_{\min} = 1000 V_g / V_{\text{slug}} \quad (\text{ALD-11})$$

$$V_g = \frac{37.14 F_{gs} P_{\text{Cavg}} V_t}{Z(T_{\text{avg}} + 460)}$$

$$F_{GS} = 1 + 0.02 D / 1000$$

$$P_{\text{Cavg}} = P_{C \min} \left( 1 + \frac{A_t}{2A_a} \right)$$

$$V_t = A_t (D - V_{\text{slug}} L_t)$$

$$L_t = 808.56 / A_t$$

Where:  $GLR_{min}$  is minimum gas-liquid ratio required to lift the slug and plunger in scf/bbl,  $V_g$  is the gas volume required to lift the slug in mscf,  $V_{slug}$  is the slug volume to be lifted in bbl,  $F_{gs}$  is the gas slippage factor,  $P_{Cavg}$  is average casing annulus pressure in psi,  $V_t$  is the gas volume in the tubing in mcf,  $Z$  is the gas deviation factor,  $T_{avg}$  is the average wellbore temperature in °F,  $D$  is the depth to the plunger in ft,  $P_{Cmin}$  is minimum casing pressure in psi,  $A_t$  is the inner cross section of the tubing in in<sup>2</sup>,  $A_a$  is casing-tubing annular cross section in in<sup>2</sup>, and  $L_t$  is the tubing capacity in ft/bbl.

**Step 4** - Calculate the cycles per day and maximum rate:

$$N_{Cmax} = \frac{1440}{\frac{D}{V_r} + \frac{D - V_{slug} L_t / (1 - F_g)}{V_{fg}} + \frac{V_{slug} L_t}{(1 - F_g) V_{fl}}} \quad (ALD-12)$$

$$q_{max} = N_{Cmac} V_{slug} \quad (ALD-13)$$

Where:  $N_{Cmac}$  is the maximum possible cycles per day,  $D$  is the depth to the plunger in ft,  $V_{slug}$  is the volume of the slug to be lifted in bbl,  $L_t$  is the tubing capacity in ft/bbl,  $F_g$  is the fraction of gas in the slug (commonly set at 0.8),  $V_r$  is the rising velocity of the plunger in ft/min,  $V_{fg}$  is the plunger fall velocity in gas in ft/min,  $V_{fl}$  is the plunger fall velocity in liquid in ft/min and  $q_{max}$  is the maximum liquid rate in bbl/d.

**Step 5** - Calculate plunger fall time for a given slug:

$$L_h = L_t V_{slug} / (1 - F_g) \quad (ALD-14)$$

$$Ft_t = Fact [(D - L_h) / Ft_g + L_h / Ft_l]$$

Where:  $L_h$  is height of the gassy liquid in the tubing in ft,  $L_t$  is the tubing capacity in ft/bbl,  $V_{slug}$  is the slug volume to be lifted in bbl,  $F_g$  is the fraction of gas in the slug (commonly set at 0.8),  $Ft_t$  is the total plunger fall time in minutes,  $Fact$  is a calibration factor,  $Ft_g$  is plunger fall time in gas in minutes, and  $Ft_l$  is the plunger fall time in the gassy liquid in minutes.

### ALD.2.3 Plunger Lift Example

Figure ALD-12 and Table ALD-6 show the input/output for a plunger lift design example. This is a gas well that produces water. A rising velocity for the plunger of 1000 ft/min was assumed for this example. The calculations are presented for a 1-barrel slug.

**Artificial Lift Design - Version: 2021**

Oilfield: [ ] Open PE dB

PEE Tools Examples Database.PEEdb

**General Design Parameters**

Info: Artificial Lift

Reservoir Pressure (psi): 4000 \*

Reservoir Temp (°F): 180 \*

Oil API: 45 \*

Bubble Pt Pressure (psi): 1500 \*

Gas Gravity: 0.7 \*

Salinity (ppm NaCl): 35000 \*

Solution GOR (scf/bbl): 394.7

Oil Bo: 1.247

Water Bw: 1.025

**Surface Producing Conditions**

Producing GLR (scf/bbl): 8000 \*

Producing Water Cut (%): 100 \*

Design Liquid Rate (bbl/d): 10 \*

Flowing Pressure (psi): 100 \*

Flowing Temperature (°F): 100 \*

\* Required data for selected pump

**Plunger Lift Design Parameters**

Pump Setting Depth (ftMD): 7000

Tubing ID (in): 1.995

Tubing OD (in): 2.375

Casing ID (in): 4.56

Maximum Available CHP (psi): 800

**Selected Pump Information**

Selected Plunger Weight (lbs): 10

Plunger Fall Velocity in Gas (ft/min): 750

Plunger Fall Velocity in Liquid (ft/min): 150

Plunger Rising Velocity (ft/min): 1000

**Results**

Plunger Lift Will Operate with Slugs Between 0.7 and 9.6 bbls

Slug Vol (bbl)	CHP-min (psi)	CHP-max (psi)	N-max (cycle/d)	Qliq-max (bbl/d)	GLR-min (scf/bbl)	N (cycle/d)	Fall Time (min)
0.1	128	187	87	8.7	38775	-	10
0.25	139	203	85	21.1	16785	40	10
0.5	156	229	81	40.3	9453	20	11
1	192	280	75	74.2	5783	10	12
2	262	384	65	128.2	3940	5	15
3	333	487	57	169.2	3318	4	19
4	404	591	51	201.4	3001	3	22
5	475	694	46	227.4	2805	2	25
6	545	798	42	248.8	2670	2	28
8	687	1005	36	281.9	2488	2	34
10	828	1211	31	306.4	2362	1	40

Diagram labels: Lubricator Catcher, Solar Panel Controller, Motor Valve, Dual "T" Pad Plunger, Bumper Spring.

Figure ALD-12: Plunger Lift Pump Design - Example

The design input parameters are as follows:

Reservoir Pressure = 4000psi	Producing GLR = 8000scf/bbl	Tubing ID = 1.995in
Reservoir Temperature = 180°F	Water Cut = 100%	Tubing OD = 2.375in
Oil Density = 45°API	Liquid Rate = 10bbl/d	Casing ID = 4.56in
Bubble Point Pressure = 1500psi	Tubing Head Pressure = 100psi	Plunger Weight = 10lb
Gas Gravity = 0.7	Tubing Head Temperature = 100°F	Fall Velocity in Gas = 750ft/min
Gas Z Factor = 0.9519	Pump Setting Depth = 7000ft	Fall Velocity in Liquid = 750ft/min
Water Density = 1.025	Maximum Available CHP = 800psi	Design Rise Velocity = 750ft/min

Table ALD-6: Plunger Lift Design- Input Data

The design calculations and results for a 1 barrel slug are as follows:

Step 1:  $A_t = 3.126$ ,  $P_p = 3.199$ ,  $fric_g = 0.0143$ ,  $fric_l = 0.0210$ ,  $K = 104764$ ,

$P_{lh} = 114.8$ ,  $P_{lf} = 62.6$ ,  $P_{Cmin} = 315.1$  psi

Step 2:  $A_a = 11.901$ ,  $P_{Cmax} = 397.8$  psi

Step 3:  $L_t = 258.6$ ,  $V_t = 0.146$ ,  $P_{Cavg} = 356.4$  psi,  $FGS = 1.14$ ,

$V_g = 3.867$ ,  $GLR = 3866.7$  scf/bbl

Step 4:  $N_{Cmax} = 61.98$  cycles/d,  $q_{max} = 61.98$  bbl/d

Step 5:  $L_h = 1293.3$ ,  $F_{t_t} = 16.2$  min



### ALD.3 Hydraulic Jet Pump

#### ALD.3.1 Overview

A hydraulic jet pump converts the energy in an injected power fluid (water or oil) to pressure that lifts production fluids. The main advantages of a hydraulic jet pump are that it has no moving parts so solids and gassy fluids present no problem to the pump, it can handle high rates, works in deviated wells, multiple wells can be run from the same surface equipment and it is a low maintenance pump. Disadvantages are that it has low efficiency (10–30%), and it requires high pressure surface equipment.

A hydraulic jet pump is a dynamic displacement pump that increases the pressure in the produced fluids through the use of a jet nozzle (Figure ALD-13 – from Volume 4 of Technology of Artificial Lift Methods).

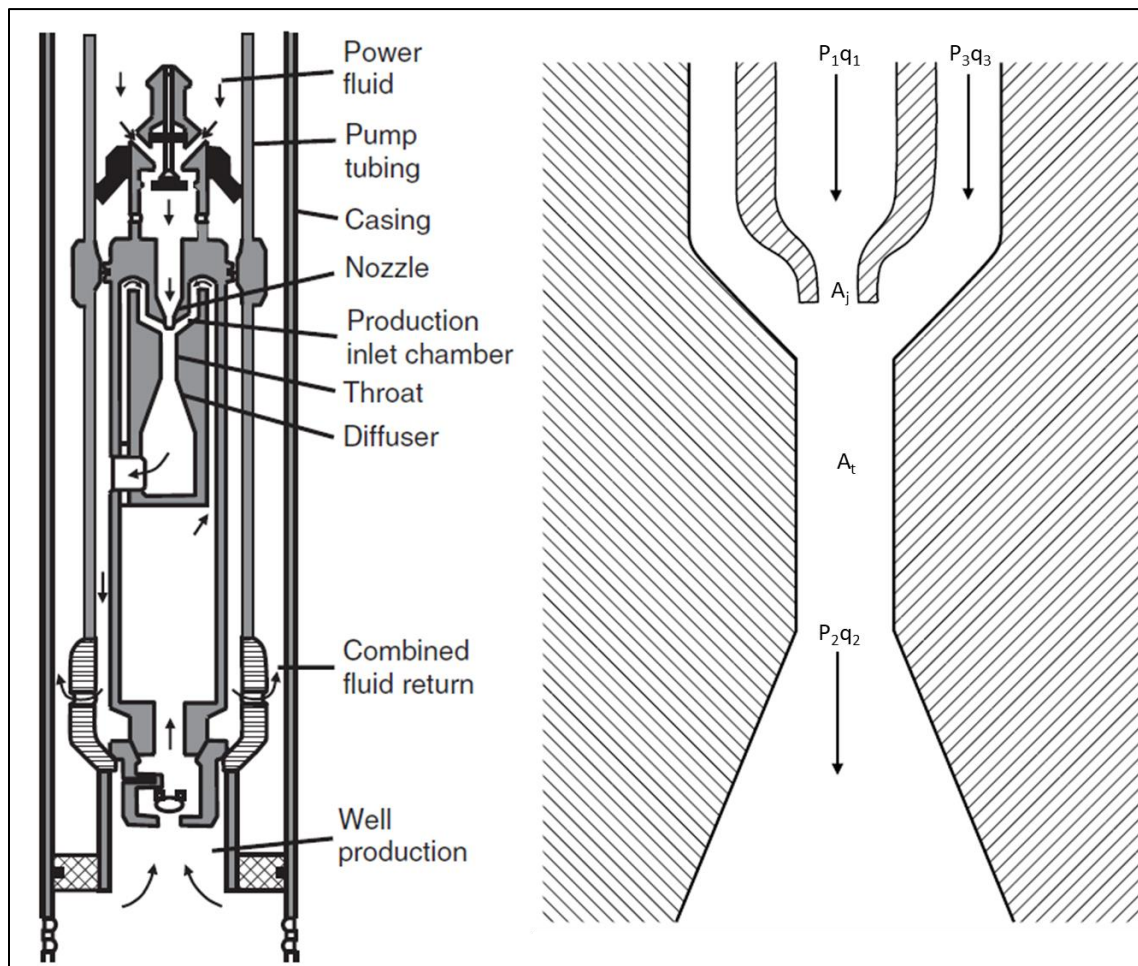


Figure ALD-13: Hydraulic Jet Pump



The power fluid enters the top of the pump through an injection tubing. The power fluid accelerates through the nozzle and is mixed with the well's produced fluid in the throat of the pump. As the fluids mix, some of the momentum of the power fluid is transferred to the produced fluid and thereby increases its kinetic energy (velocity head) resulting in a pressure increase in the produced fluid. The combined fluid stream enters the casing-tubing annulus and is produced to surface.

Selection of a jet pump is made based on a number of dimensionless variables (refer to Figure ALD-13).

$$R = A_j / A_t$$

$$M = q_3 / q_1$$

$$H = (P_2 - P_3) / (P_1 - P_2)$$

$$\eta = M H$$

Where: R is the dimensionless nozzle area, M is the dimensionless flow rate, H is the dimensionless head,  $\eta$  is the pump efficiency,  $A_j$  is the jet pump nozzle area in  $\text{in}^2$ ,  $A_t$  is the jet pump throat area in  $\text{in}^2$ ,  $q_3$  is the well fluid rate in  $\text{bbl/d}$ ,  $q_1$  is the power fluid rate in  $\text{bbl/d}$ ,  $P_2$  is the available discharge pressure from the pump in  $\text{psi}$ ,  $P_3$  is the pressure at the pump inlet in  $\text{psi}$ , and  $P_1$  is the required power fluid pressure in  $\text{psi}$ .

Table ALD-7 presents one manufacture's selection of jet pumps.

TFC Jet Pump Specifications				
Nominal Size	Tubing Sizes	Production Rates	Nozzle Sizes	Throat Sizes
TFC 1.66	1" TO 2" IJ/Coil or 2.375 SSD/Cavity	Up to 1700 BPD	DD-G	000-10
TFC 2.20	1.5" to 2.375" or 2.875 SSD/Cavity	Up to 4000 BPD	AA-J	00-12
TFC 3.10	2" TO 4.5" or 4.5" SSD	Up to 10 000 BPD	AA-J	00-16

Table ALD-7: Jet Pump Specifications

A Weatherford catalogue is included in the "\Public\Artificial Lift Catalogues" directory for reference purposes. Pump selection is based on the pump manufacturer's performance curves, Figure ALD-14. The performance curve in Figure ALD-14 shows the effect of M on H and  $\eta$ .

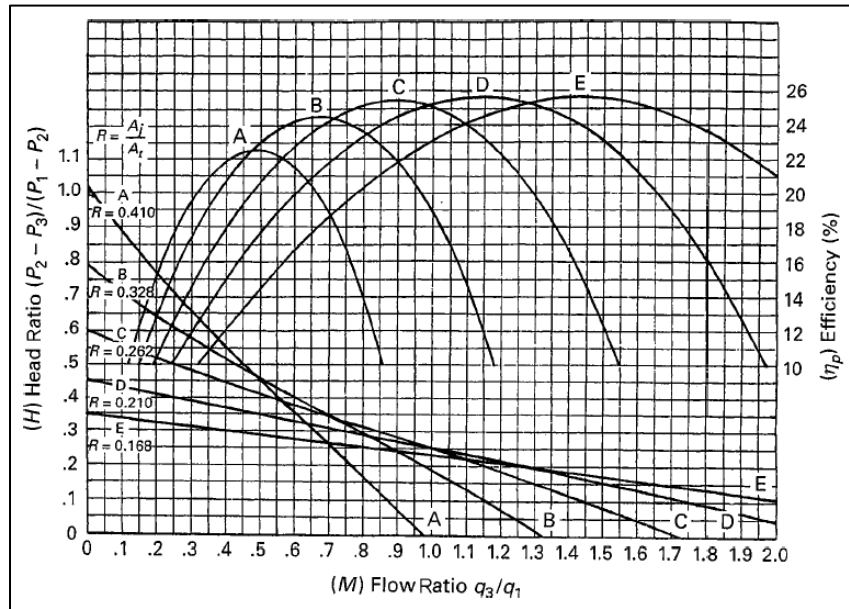


Figure ALD-14: Jet Pump Performance Chart (ref: Vol. 4 of Technology of Artificial Lift Methods)

For a given jet pump specified by an  $R$  value, there exists a peak efficiency  $\eta_p$  at a peak  $H_p$  and  $M_p$ . For example, assuming a pump with an  $R$  value of 0.262, the peak efficiency,  $\eta_p$ , of 0.255 will occur at an  $M_p$  value of 0.9 and  $H_p$  value of 0.28 (from the 'C' curves in Figure ALD-14).

It is good field practice to attempt to operate the pump at its peak efficiency. If  $M_p$  and  $H_p$  are used to denote  $M$  and  $H$  at the peak efficiency, respectively, pump parameters should be designed using these parameters.

### ALD.3.2 Hydraulic Jet Pump Design

Note that the PE<sup>2</sup> Essentials Artificial Lift Design tool uses the Vogel IPR equation to calculate the bottom hole flowing pressure for the hydraulic jet pump as well as for the electrical submersible pump.

The hydraulic jet pump design procedure is as follows:

**Step 1** - Calculate flowing bottom hole pressure and pump intake pressure:

$$P_{wf} = 0.125P_r \left[ \sqrt{81 - 80(q/q_{\max})} - 1 \right] \quad (\text{ALD-15})$$

$$P_3 = P_{wf} - 0.433S_l(TD - D) \quad (\text{ALD-16})$$

Where:  $P_{wf}$  is the bottom hole flowing pressure in psi,  $P_r$  is the reservoir pressure in psi,  $q$  is the flow rate in bbls/d,  $q_{\max}$  is Vogel IPR maximum rate in bbls/d,  $P_3$  is the pressure at the pump inlet in psi,  $TD$  is the depth of the reservoir in feet, and  $D$  is the depth to the jet pump in feet.

**Step 2** - Calculate pump fluid rates:

$$q_1 = q_3 B_o / M_p \quad (\text{ALD-17})$$

$$q_2 = q_3 B_o + q_1 \quad (\text{ALD-18})$$

Where:  $q_1$  is the power fluid rate in bbl/d,  $q_3$  is the well production rate in bbl/d,  $B_o$  is the oil formation factor ( $B_t$  is used for oil/water production),  $M_p$  is dimensionless rate at peak efficiency, and  $q_2$  is the total return flow rate in bbl/d

**Step 3** - Calculate system pressures:

$$P_1 = P_3 + S_f (q_1 / (1214.5 A_j))^2$$

$$P_2 = (P_3 + H_p P_1) / (1 + H_p)$$

$$H_p = M_p \eta_p$$

$$S_f = (1 - \text{WCut}/100) * 141.5 / (131.5 + \text{OilAPI}) + \text{WCut}/100 * S_{\text{water}}$$

Where:  $P_1$  is the required power fluid pressure in psi,  $P_3$  is the pressure at the pump inlet in psi,  $S_f$  is the specific gravity of the produced fluid,  $q_1$  is the power fluid rate in bbl/d,  $A_j$  is the jet pump nozzle area in  $\text{in}^2$ ,  $P_2$  is the available discharge pressure from the pump in psi,  $H_p$  is the dimensionless head at peak efficiency,  $M_p$  is the dimensionless rate at peak efficiency, and  $\eta_p$  is the peak pump efficiency.

**Step 4** - Calculate required pump power:

$$\text{Power} = 1.7\text{e-}5 q_1 P_s \quad (\text{ALD-19})$$

Where: Power is the required pump power in hp,  $q_1$  is the power fluid rate in bbl/d, and  $P_s$  is the required surface pump operating pressure calculated from the pump discharge pressure using tubing pressure drop correlations in psi.

**ALD.3.3 Hydraulic Jet Pump Example**

Table ALD-8 and Figure ALD-15 show the input/output for a hydraulic jet pump design example.

Reservoir Pressure = 4000psi Reservoir Temperature = 200°F Oil Density = 40°API Bubble Point Pressure = 1500psi Gas Gravity = 0.6 Bo = 1.207 Water Density = 1.025 Reservoir Depth = 10000ft	Producing GLR = 268.2scf/bbl Water Cut = 0% Liquid Rate = 758bbl/d Tubing Head Pressure = 100psi Tubing Head Temperature = 100°F Pump Setting Depth = 9700ft Max Rate for Vogel IPR = 8000 stb/d	Tubing ID = 1.992in Tubing OD = 2.375in Casing ID = 5in Pump Area Ratio, R = 0.262 Jet Nozzle Area = 0.16in <sup>2</sup> Pump Peak Efficiency, $\eta_p$ = 0.255 Rate at Peak Efficiency, $M_p$ = 0.9 Power Fluid Specific Gravity = 0.8
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Table ALD-8: Hydraulic Jet Pump Design – Input Data

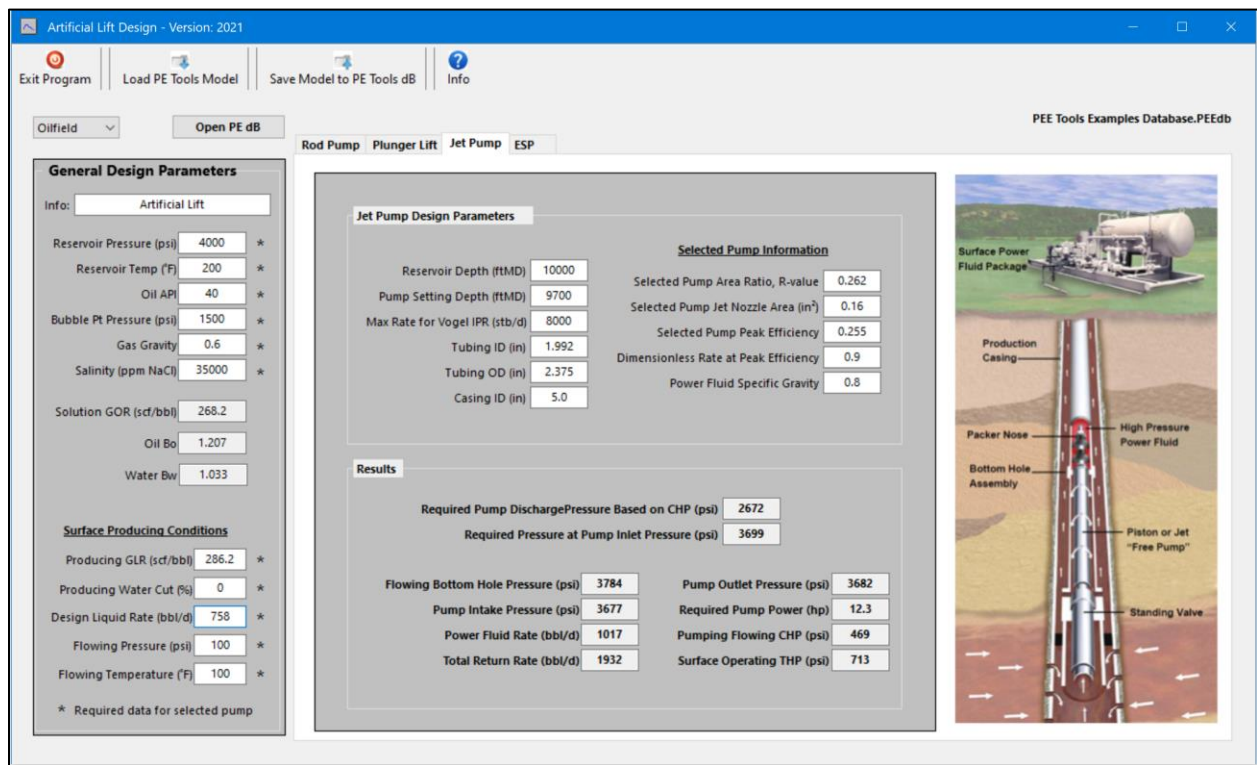


Figure ALD-15: Jet Pump Design - Example

The design calculations and results are as follows:

Step 1:  $P_{wf} = 3784$  psi,  $P_3 = 3677.1$  psi

Step 2:  $q_1 = 1016.8$  bbl/d,  $q_2 = 1931.9$  bbl/d

Step 3:  $H_p = 0.283$ ,  $S_f = 0.825$ ,  $P_1 = 3699.0$  psi,  $P_2 = 3681.9$  psi

Step 4: CHP = 522.0 psi (using Hagedorn-Brown from  $P_2$ ),

$P_s = 805$  psi (using Hagedorn-Brown from  $P_1$ ), Power = 13.9 hp

## ALD.4 Electrical Submersible Pump

### ALD.4.1 Overview

Electrical submersible pumps (ESP's) can lift extremely high volumes of fluid from highly productive oil reservoirs. ESP's tend to be used in offshore operations but are also used onshore. ESP systems can deliver higher horsepower than other lift systems, they can operate in hotter applications, can be installed as a dual pump installation, and may include down-hole oil/water separation. New pump designs tend to be more tolerant of sand and gas production. Automation of the ESP system includes monitoring, analysis, and control.

Limitations to ESP applications include the requirement for high voltage electricity, they are not suitable for deep, high-temperature reservoirs, gas and solids production tend to cause issues, and they are costly to install and repair.

Figure ALD-16 is a schematic of an ESP installation.

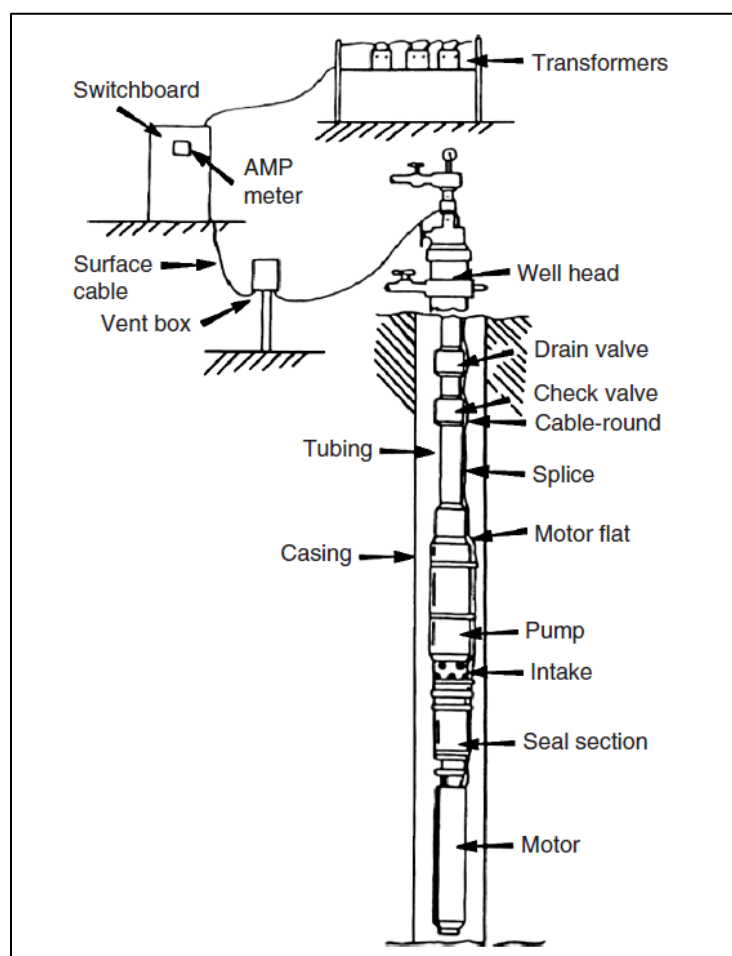


Figure ALD-16: Electrical Submersible Pump (ESP)

The ESP system operates like any electric pump commonly used in other applications. Electrical energy is transported to the down-hole electric motor through electric cables. These electric cables are attached to the side of the production tubing. The downhole electric motor drives the pump and the pump imparts energy to the fluid in the form of hydraulic power, which lifts the fluid to surface.

ESPs are pumps made of centrifugal pump stages. The number of stages required is determined by the volumetric flow rate and the lift (height) required. The length of a pump module can range from 40 to 344 inches in length. Voltage requirements can range from 420 to 4,200 V.

ESPs can operate over a wide range of conditions; at depths over 12,000 ft and volumetric flow rates of up to 45,000 bbl/day. Some operating conditions can limit ESP applications, including: free gas production, downhole temperature, fluid viscosity, and solids content.

ESP design incorporates pump performances curves published by the pump manufacturer (Figure ALD-17). A Haliburton ESP catalogue is included in the “\Public\Artificial Lift Catalogues” directory for reference purposes. Selection of a specific pump involves choosing a pump of the largest possible diameter that can be run in the well. The required pump rate should be within the recommended operating range of the pump and close to its peak efficiency.

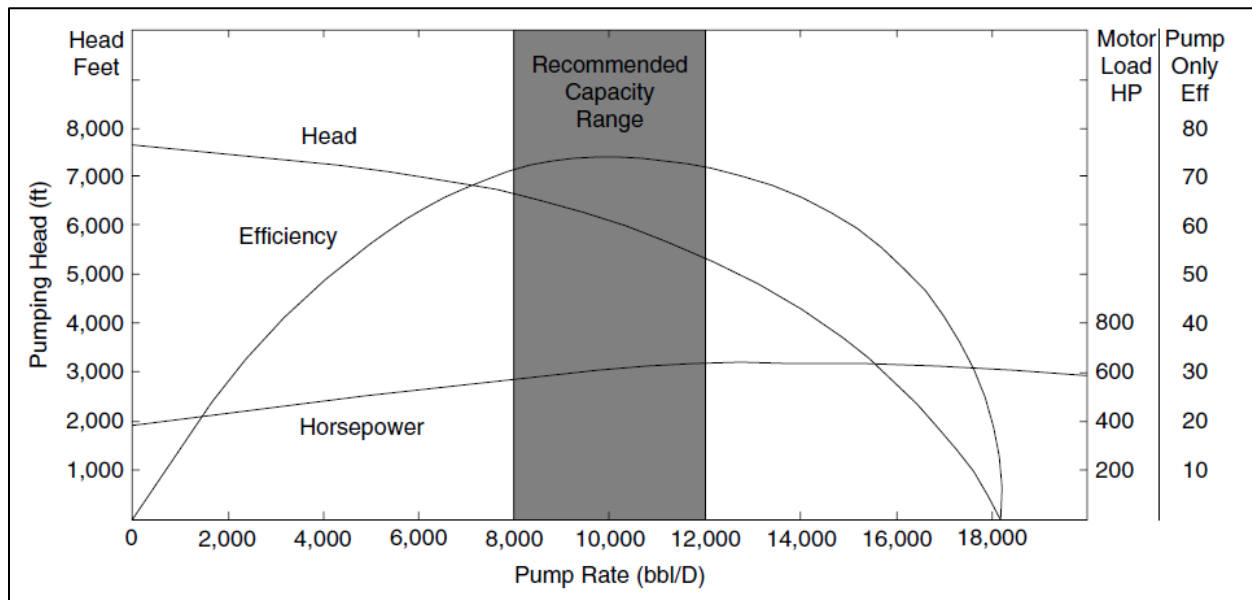


Figure ALD-17: ESP Performance Plot for a 100-Stage Pump

PE<sup>2</sup> Essentials ESP design is based on the head generated per stage and the power required per stage of the selected pump.

### ALD.4.2 Electrical Submersible Pump Design

Note that the PE<sup>2</sup> Essentials Artificial Lift Design tool uses the Vogel IPR equation to calculate the bottom hole flowing pressure for the hydraulic jet pump as well as for the electrical submersible pump.

The ESP design procedure is as follows:

Step 1 - Calculate flowing bottom hole pressure and pump intake pressure:

$$P_{wf} = 0.125P_r \left[ \sqrt{81 - 80(q/q_{max})} - 1 \right] \quad (ALD-20)$$

$$P_{int} = P_{wf} - 0.433S_l(TD - D)$$

Where:  $P_{wf}$  is the bottom hole flowing pressure in psi,  $P_r$  is the reservoir pressure in psi,  $q$  is the flow rate in bbls/d,  $q_{max}$  is Vogel IPR maximum rate in bbls/d,  $P_{int}$  is the pressure at the ESP inlet in psi,  $TD$  is the depth of the reservoir in feet, and  $D$  is the depth to the ESP in feet.

Step 2 - Calculate pump parameters:

$$D_{min} = D - (P_{wf} - P_s) / 0.433S_f \quad (ALD-21)$$

$$S_f = (1 - W_{Cut}/100) * 141.5 / (131.5 + \text{OilAPI}) + W_{Cut}/100 * S_{water}$$

$$\Delta P = P_D - P_{int}$$

$$\text{Head} = \Delta P / 0.433 \quad (ALD-22)$$

$$N_s = \text{Head} / H_s$$

$$\text{Power} = N_s \text{ Power}_s \quad (ALD-23)$$

Where:  $D_{min}$  is the minimum setting depth for the ESP in feet,  $D$  is the depth to the ESP in feet,  $P_{wf}$  is the bottom hole flowing pressure in psi,  $P_s$  is the reservoir pressure in psi,  $S_f$  is the specific gravity of the produced fluid,  $\Delta P$  is the required ESP pressure differential in psi,  $P_D$  is the required discharge pressure at the pump based on THP (calculated by tubing pressure drop correlations) in psi,  $P_{int}$  is the pressure at the ESP inlet in psi,  $\text{Head}$  is the required head to be generated by the pump in feet,  $N_s$  is the required number of stages,  $H_s$  is the head per stage for the selected pump in feet,  $\text{Power}$  is the required pump power in hp, and  $\text{Power}_s$  is power per stage for the selected pump in hp.

### ALD.4.3 Electrical Submersible Pump Example

Table ALD-9 and Figure ALD-18 show the input/output for an ESP design example.



Reservoir Pressure = 4350psi Reservoir Temperature = 200°F Oil Density = 32°API Bubble Point Pressure = 2650psi Gas Gravity = 0.6 Bo = 1.252 Water Density = 1.032	Reservoir Depth = 10000ft Producing GLR = 394.3scf/bbl Water Cut = 25% Liquid Rate = 8000bbl/d Tubing Head Pressure = 100psi Tubing Head Temperature = 100°F Max Rate for Vogel IPR = 15000 stb/d	Tubing ID = 2.992in Pump Setting Depth = 9800ft Minimum Pump Suction = 200psi Capacity of Pump = 10000bbl/d Pump Head per Stage = 60ft Pump Power per Stage = 6hp Pump Efficiency = 0.72
--	---	--

Table ALD-9: ESP Design – Input Data

The screenshot displays the 'Artificial Lift Design - Version: 2021' software interface. The 'ESP' tab is selected under the 'Rod Pump' category. The interface is divided into three main sections: General Design Parameters, ESP Design Parameters, and Results.

**General Design Parameters:**

- Info: Artificial Lift
- Reservoir Pressure (psi): 4350 \*
- Reservoir Temp (°F): 200 \*
- Oil API: 32 \*
- Bubble Pt Pressure (psi): 2650 \*
- Gas Gravity: 0.6 \*
- Salinity (ppm NaCl): 35000 \*
- Solution GOR (scf/bbl): 394.3
- Oil Bo: 1.252
- Water Bw: 1.032
- Surface Producing Conditions:
  - Producing GLR (scf/bbl): 394.3 \*
  - Producing Water Cut (%): 25 \*
  - Design Liquid Rate (bbl/d): 8000 \*
  - Flowing Pressure (psi): 100 \*
  - Flowing Temperature (°F): 100 \*

**ESP Design Parameters:**

- Reservoir Depth (ftMD): 10000
- Pump Setting Depth (ftMD): 9800
- Max Rate for Vogel IPR (stb/d): 15000
- Tubing ID (in): 2.992
- Min Pump Suction Pressure (psi): 200
- Min Capacity of Pump (bbl/d): 10000
- Pumping Head per Stage (ft/stage): 60
- Power per Stage (hp): 6

**Results:**

- Required Pump Discharge Pressure Based on THP (psi): 3526
- Flowing Bottom Hole Pressure (psi): 2823
- Production Rate at Pump (bbl/d): 9577
- Minimum Pump Setting Depth (ft): 3309
- Pump Suction Pressure (psi): 2744
- Required Pump ΔP (psi): 781
- Required Pumping Head (ft): 1804
- Required Number of Stages: 30
- Total Motor Power (hp): 180.4

A 3D schematic diagram on the right shows the wellbore with labels for 'Produced Hydrocarbons Out', 'Vent Box', 'Motor Control', 'Production Tubing', 'Pump', 'Flat Cable Extension', 'Seal Section', and 'Motor'.

Figure ALD-18: ESP Design - Example

The design calculations and results are as follows:

Step 1:  $P_{wf} = 2822.8$  psi,  $P_{int} = 2744.4$  psi

Step 2:  $D_{min} = 3309.2$  ft,  $S_f = 0.905$ ,  $P_D = 3525.6$  psi (using M-HB for BHP)

$\Delta P = 781.1$  psi, Head = 1804.0 ft,  $N_s = 30.1$ , Power = 180.4 hp



## Pressure Transient Analysis Tool

The PE<sup>2</sup> Essentials 'Pressure Transient Analysis' tool is comprised of a basic pressure buildup analysis module (Figure PTA-1) and an analytical test simulator (Figure PTA-2).

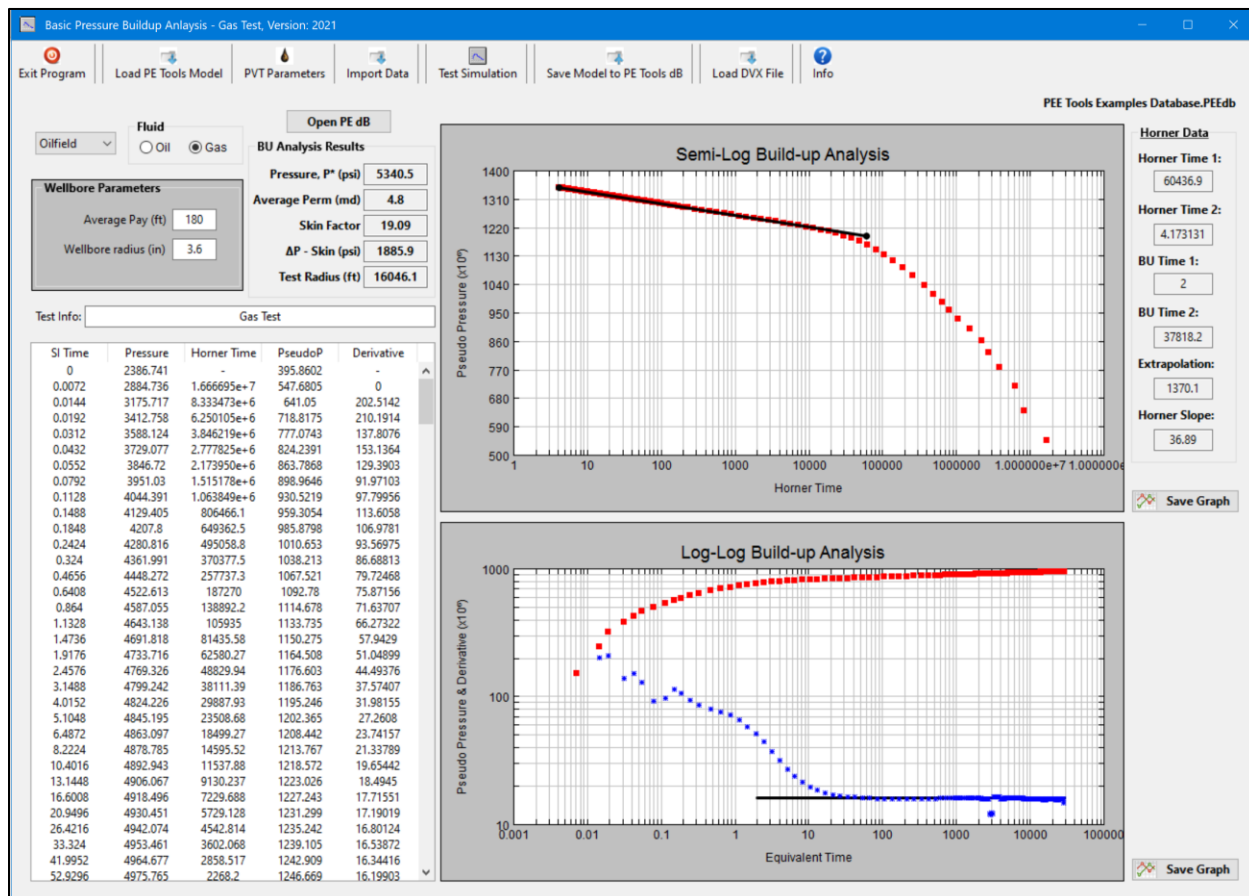
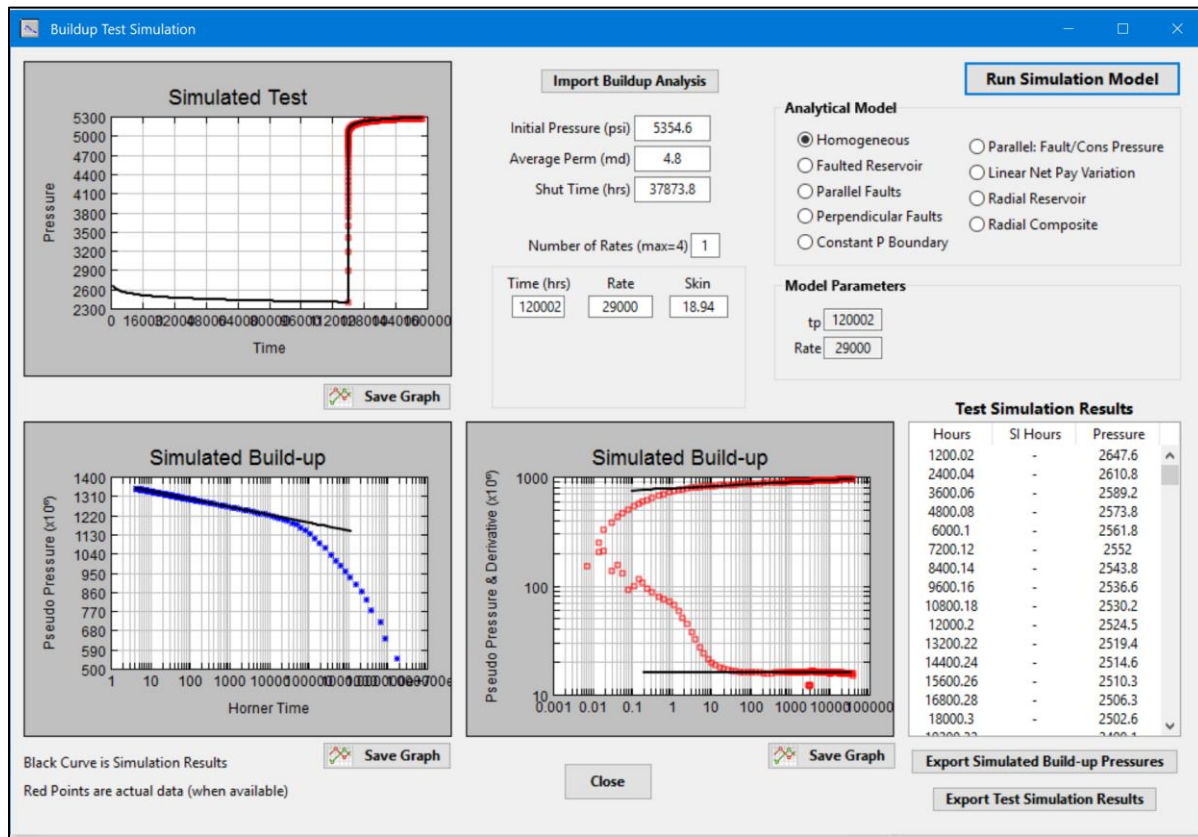


Figure PTA-1: PE<sup>2</sup> Essentials Pressure Transient Analysis Tool

There are numerous reference texts available on the subject of well test analysis. The one reference the author uses the most often is the book by John Lee - Lee, W.J., Well Testing, SPE Textbook Series Vol. 1, 1982, SPE. This reference contains concise information and includes a full list of the metric versions of all the equations presented in the book. This book was update in 2003 (Lee, J.; Rollins, J.; and Spivey, J. Pressure Transient Testing, SPE Textbook Series Vol. 9, 2003, SPE) but the 1982 edition is still the most useful if you have to deal with US oilfield and metric units.

A secondary reference, and the main reference for the Analytical Well Test Simulator, is Streltsova, T.D., Well Testing in Heterogeneous Formations, John Wiley & Sons, 1988.


 Figure PTA-2: PE<sup>2</sup> Essentials Analytical Well Test Simulator

Pressure drawdown and buildup tests provide an opportunity to obtain estimates of the following well and reservoir properties:

- Permeability to the produced phase (oil, gas, or water) - the average value within the radius of investigation achieved during the test
- Skin factor - a dimensionless measurement of the damage or stimulation done to the well
- Current average pressure within the drainage area of the well
- Indication of flow barriers (such as faults) in the reservoir

Flow tests can be useful when the reservoir is at uniform pressure, such as when a new well is completed or when a well has been shut in for a lengthy period. Flow tests are appropriate when a well must continue to produce revenue even though a test is needed. Analysis of flow tests is simplest when the rate is fairly constant.

Buildup tests are appropriate at virtually any time in the life of a well because they simply require that the well be shut in. Buildup tests have the advantage that the zero rate is much more easily controlled than a “constant rate” flow test. For this reason, buildup tests are the preferred type of pressure transient test.

Only build-up test analysis is included in the PE<sup>2</sup> Essentials Pressure Transient Analysis tool.

## PTA.1 Pressure Buildup Analysis

PE<sup>2</sup> Essentials build-up analysis is focused on a semi-logarithmic plot of test data, with the slope of the straight line on the plot used to determine permeability. Figure PTA.3 is a typical semi-log Horner plot of the buildup test data.

To generate an interpretation, the straight line on the semi-log Horner plot is moved by using the mouse to click on and move the end of the line, to generate a best-fit through the points. When the mouse is released, the equivalent of the semi-log straight line is placed on the log-log plot to confirm the interpretation. When the lines are acceptable on both plots, the interpretation is completed.

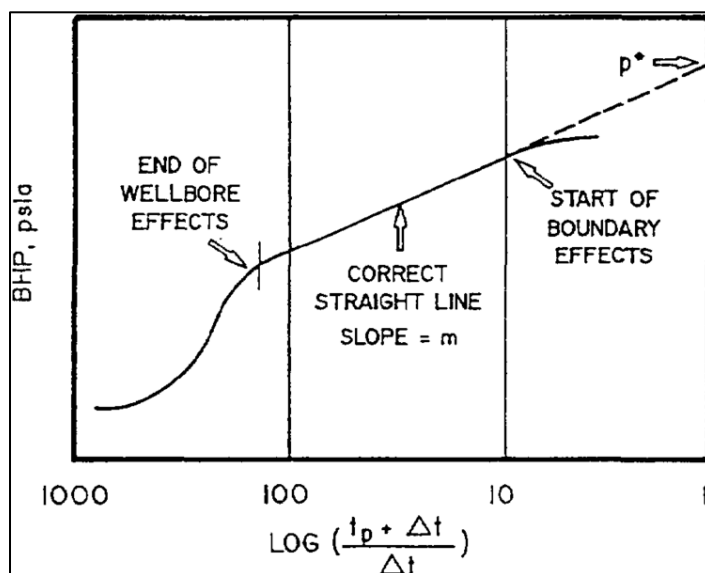


Figure PTA-3: Semi-Log / Horner Buildup Analysis Plot

The “correct” semi-log straight line used for basic analysis is indicated on the figure; the line can be identified with the help of log-log plots (Figure PTA-4).

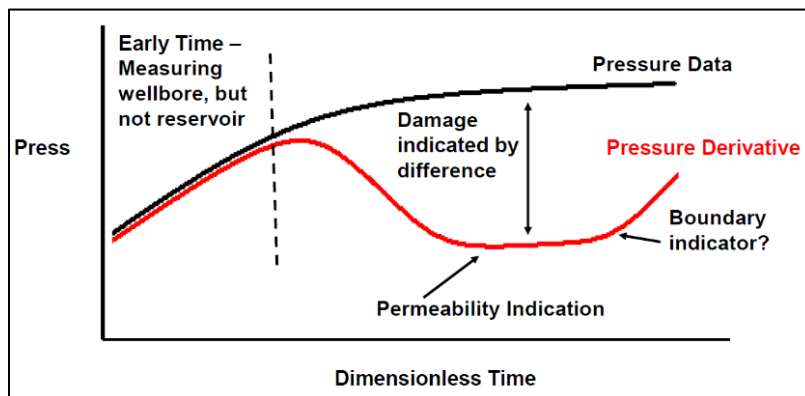


Figure PTA-4: Log-Log Diagnostic Plot

The log-log diagnostic plot includes a “derivative” curve. The numerical derivative at a point is determined by finding a weighted average of the slopes preceding the point and following the point, as illustrated in Figure PTA-5.

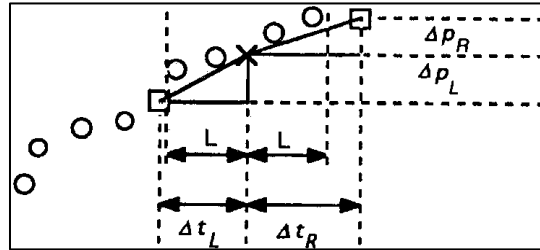


Figure PTA-5: Numerical Derivative at Point X

In Figure PTA-5, the parameter  $L$  defines the minimum range of the preceding and following points. This is incorporated to smooth out "noise" in the neighborhood of the central,  $X$ , point.  $L$  is defined as a  $\Delta(\ln(\Delta t))$  for a well test. Experience suggests that a value of  $L = 0.1$  to  $0.3$  is usually a satisfactory compromise between being so far from the central point that detail is lost and being so near the central point that a great amount of noise is retained in the data. The PE<sup>2</sup> Essentials build-up analysis tool has a default smoothing factor of  $0.1$ .

For a Horner plot, shut-in bottomhole pressure is plotted versus the logarithm of the ratio of producing time,  $t_p$ , plus shut-in time,  $\Delta t$ , to shut-in time (called Horner time). Simple equations are used to estimate permeability and skin factor once the correct semi-log straight line is identified and its slope,  $m$ , is determined. These equations apply to both drawdown and buildup tests. The following build-up analysis equations are used for oil wells:

$$k = \frac{162.6q\mu B}{mh} \quad (\text{PTA.1})$$

$$S = 1.151 \left( \frac{(P_{1hr} - P_{wf})}{m} - \log \left( \frac{k}{\phi \mu c_t r_w^2} \right) + 3.23 \right) \quad (\text{PTA.2})$$

$$\Delta P_s = 0.87mS \quad (\text{PTA.3})$$

$$r_{inv} = \sqrt{\frac{kt}{948\phi\mu c_t}} \quad (\text{PTA.4})$$

Where:  $k$  is effective permeability to the produced phase in md,  $q$  is oil flow rate in stbbl/d,  $B$  is the formation volume factor in rbbl/stbbl,  $m$  is the slope of the semi-log straight line in psi/cycle,  $h$  is the net pay thickness in feet,  $S$  is the skin factor (dimensionless),  $P_{1hr}$  is the theoretical change in pressure after 1 hour of shut-in taken from the straight line fit in psi,  $P_{wf}$  is the final flowing pressure in psi,  $\phi$  is the porosity (fraction),  $\mu$  is the fluid viscosity in cp,  $c_t$  is the total compressibility of the formation and its fluids in 1/psi,  $r_w$  is the wellbore radius in feet,  $\Delta P_s$  is the pressure drop caused by the skin in psi,  $r_{inv}$  is the radius of investigation for time  $t$  in feet, and  $t$  is time in hours.

For gas well test analysis, the equations are similar except for the use of pseudo pressure,  $\psi$ , instead of pressure, as follows:

$$k = \frac{1632qT}{mh} \quad (\text{PTA.5})$$

$$S = 1.151 \left( \frac{(\psi_{1hr} - \psi_{wf})}{m} - \log \left( \frac{k}{\phi \mu c_t r_w^2} \right) + 3.23 \right) \quad (\text{PTA.6})$$

Where:  $q$  is gas flow rate in mscf/d,  $T$  is the formation temperature in °R,  $m$  is the slope of the semi-log straight line in  $\text{psi}^2/\text{cp}/\text{cycle}$ .

Extrapolation of the pressure on a semi-log plot to a Horner time of 1 yields  $P^*$  which provides an estimate of original reservoir pressure in a new well or “false” pressure, which serves as the basis for determining current drainage area pressure,  $P_r$ .

The skin factor is an indicator of the damage, or stimulation, existing in the wellbore. Following calculation of the skin factor, the pressure drop caused by the skin can then be determined.

Finally, a radius of investigation can be determined for a given time. This radius can be used to estimate minimum fluids in place in the reservoir.

For a well test in which rates were not constant prior to the build-up, an effective production time for the Horner plot is calculated as follows:

$$t_p = \frac{24 \sum N_p}{q_{last}} \quad (\text{PTA.7})$$

Where:  $t_p$  is the corrected producing time,  $N_p$  is total production during the flow period in bbls, and  $q_{last}$  is the final flow rate before shut-in in bbls/d.

Consider the following example of a build-up test following a multiple rate flow period. Table PTA-1 presents the flow and pressure build-up data.

Rate (bbls/d)	Period (hours)	$N_p$ (bbls)	Shut-in (hours)	Pressure (psi)	Horner Time
200	36	300	0	1384	-
0	12	0	2	1530	121
100	48	200	3	1535	81
125	144	750	4	1538	61
			5	1540	49
			8	1546	31
			10	1549	25
			12	1551	21
			19	1556	13.6
			24	1559	11
			36	1563	7.67

Table PTA-1: Example Build-up Test

From Equation PTA.7, the equivalent  $t_p$  was 240 hrs. This value was used to calculate the Horner Time in Table PTA-1. Figure PTA-6 is the semi-log plot of the build-up data.

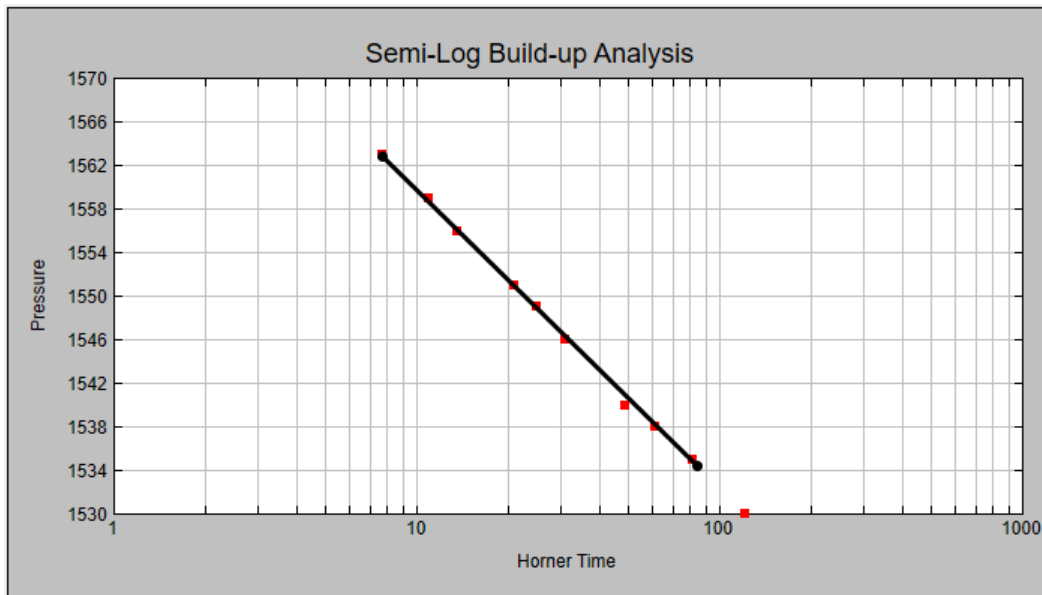


Figure PTA-6: Semi-Log Plot of Data in Table PTA-1

Assuming the following parameters:

Horner Slope,  $m = 27.3$  psi/cycle

$P_{1hr} = 1522$  psi

$\mu = 0.8$  cp

$h = 15$  ft

$c_t = 1.5 \times 10^{-5}$ /psi

$\phi = 0.25$

$r_w = 0.333$  ft

$B = 1.25$  rbbl/stbbl

Analysis yields the following:

$$k = \frac{162.6q\mu B}{mh} = \frac{162.6(125)(0.8)(1.25)}{(27.3)(15)} = 49.6 \text{ md}$$

$$S = 1.151 \left( \frac{(P_{1hr} - P_{wf})}{m} - \log \left( \frac{k}{\phi \mu c_t r_w^2} \right) + 3.23 \right) = 1.151(5.055 - 8.379 + 3.23) = -0.1$$

$$r_{inv} = \sqrt{\frac{kt}{948\phi\mu c_t}} = \sqrt{\frac{(49.6)(36)}{948(0.25)(0.8)0.000015}} = 792 \text{ ft}$$

## PTA.2 Analytical Well Test Simulator

The Analytical Well Test Simulator included in the PE<sup>2</sup> Essentials Pressure Transient Analysis tool simulates well tests based on the “Method of Images”. Imaginary wells, referred to as image wells, are used to generate the pressure effect of the reservoir discontinuity.

For a full description of the Method of Images, refer to the Streltsova book. For purposes of this section, rather than a derivation, only specific results are presented here. The basic solution of the flow equation for pressure drop at any point in the reservoir is given by Equation 8.8.

$$P = P_i + 70.6 \frac{qB\mu}{kh} Ei \left( -\frac{948\phi\mu c_i r^2}{kt} \right) \quad (PTA.8)$$

$$Ei(-x) = -\int_x^\infty \frac{e^{-u}}{u} du$$

Where: Ei is the exponential integral and all other terms are as defined previously.

At the wellbore,  $r$  becomes  $r_w$  and for practical shut-in times,  $\Delta t$ ,  $Ei$  can be approximated by a log function,  $Ei(-x) = \ln(1.781x)$  so the flowing pressure at the wellbore becomes Equation PTA-9:

$$P_{wf} = P_i - 70.6 \frac{qB\mu}{kh} \ln \left( \frac{kt}{1688\phi\mu c_i r_w^2} \right) \quad (PTA.9)$$

For the Method of Images, the image well is represented by Equation 8.8. Consider a linear no-flow boundary (a fault) in the reservoir. The configuration can be represented as shown in Figure PTA-7 with the real well and an image well located at a distance of  $2d$  from the real well,  $d$  being the distance to the fault.

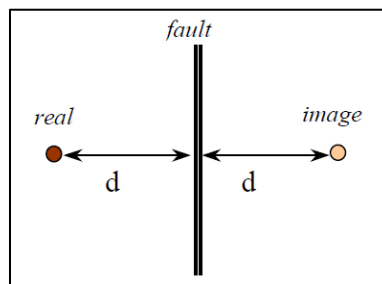


Figure PTA-7: Image Well configuration for a No-Flow Boundary

The image well produces at the same rate as the real well so, over time, there will be a drainage boundary generated at a distance ‘ $d$ ’ from the real well as shown in Figure PTA-8

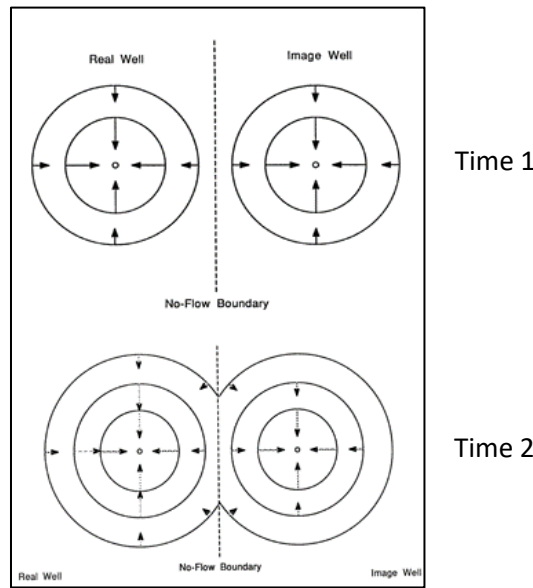


Figure PTA-8: Image Well Generation of No-Flow Boundary

The equation describing the pressure at the wellbore in Figure PTA-8 is presented below:

$$P_{wf} = P_i - 70.6 \frac{qB\mu}{kh} \left[ \ln \left( \frac{kt}{1688\phi\mu c_i r_w^2} \right) - Ei \left( \frac{948\phi\mu c_i (2d)^2}{kt} \right) \right] \quad (\text{PTA.10})$$

The first term in the square brackets is the pressure drop at the real well and the second term is the pressure drop caused by the image well at a distance of  $2d$  from the real well.

The Analytical Well Test Simulator can model the following configurations (Figure PTA-9):

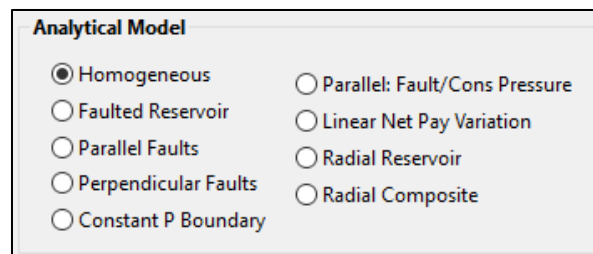


Figure PTA-9: Analytical Model Configurations

Figure PTA-10 presents examples of two image well configurations: perpendicular boundaries and parallel no-flow boundaries. For more complete descriptions and for additional configurations, refer to the Streltsova book.



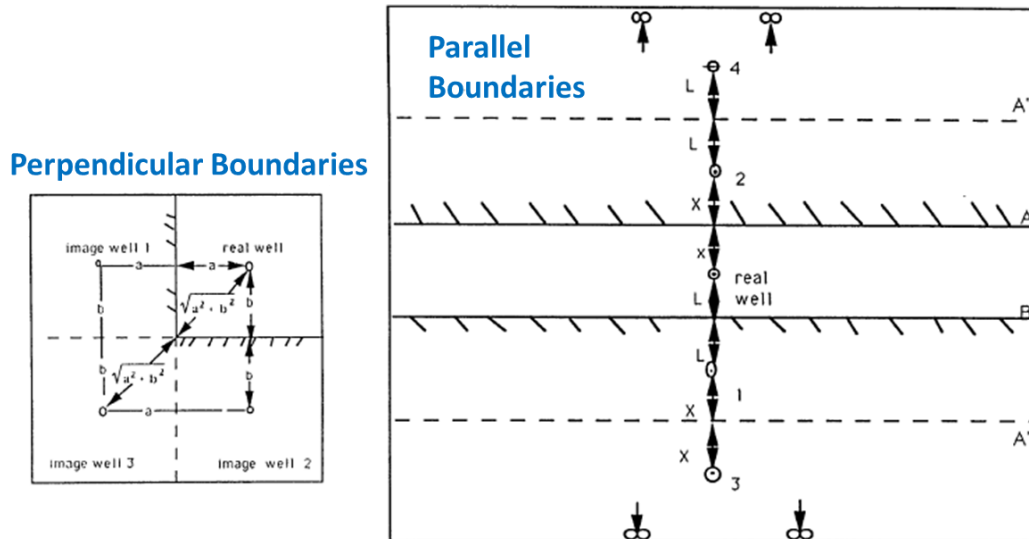


Figure PTA-10: Example Image Well Configurations

To use the Analytical Well Test Simulator, the data from the build-up analysis can be imported into the model or, to simulate a future test, the data can be manually entered.

## PTA.2 Gas Well Example

This example uses the data in the Excel file 'General WellTest Example\_BHP Data.xlsx' in the 'PE Essentials 2022\Example Input Files\Excel Files' directory.

This is a gas well example so choose 'Gas Well' on the main screen and enter the gas PVT parameters (Figure PTA-11).

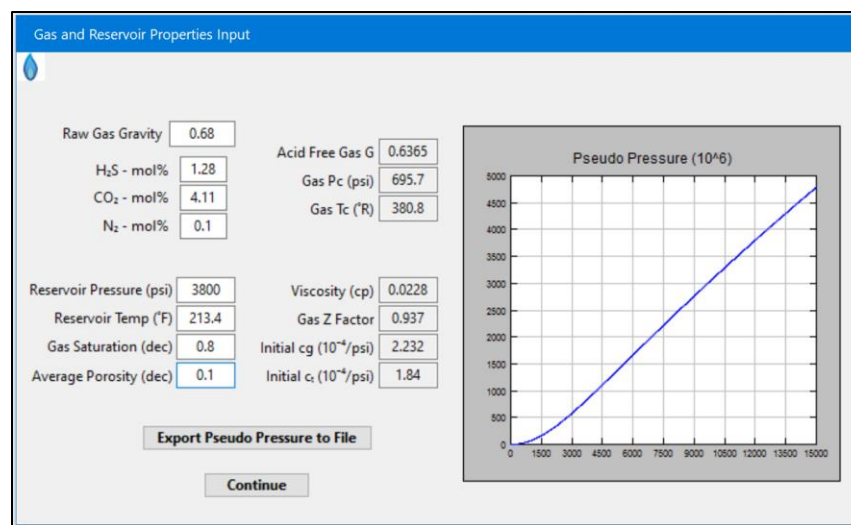


Figure PTA-11: Example Gas Well PVT Data

The Excel file is linked to the tool and the pressure data is entered (Figure PTA-12 and PTA-13).

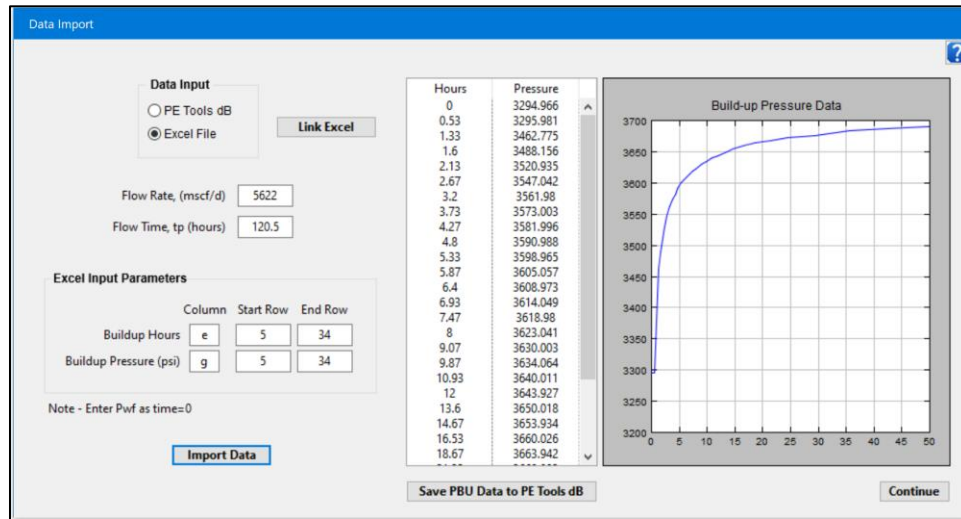


Figure PTA-12: Example Gas Well Pressure Data

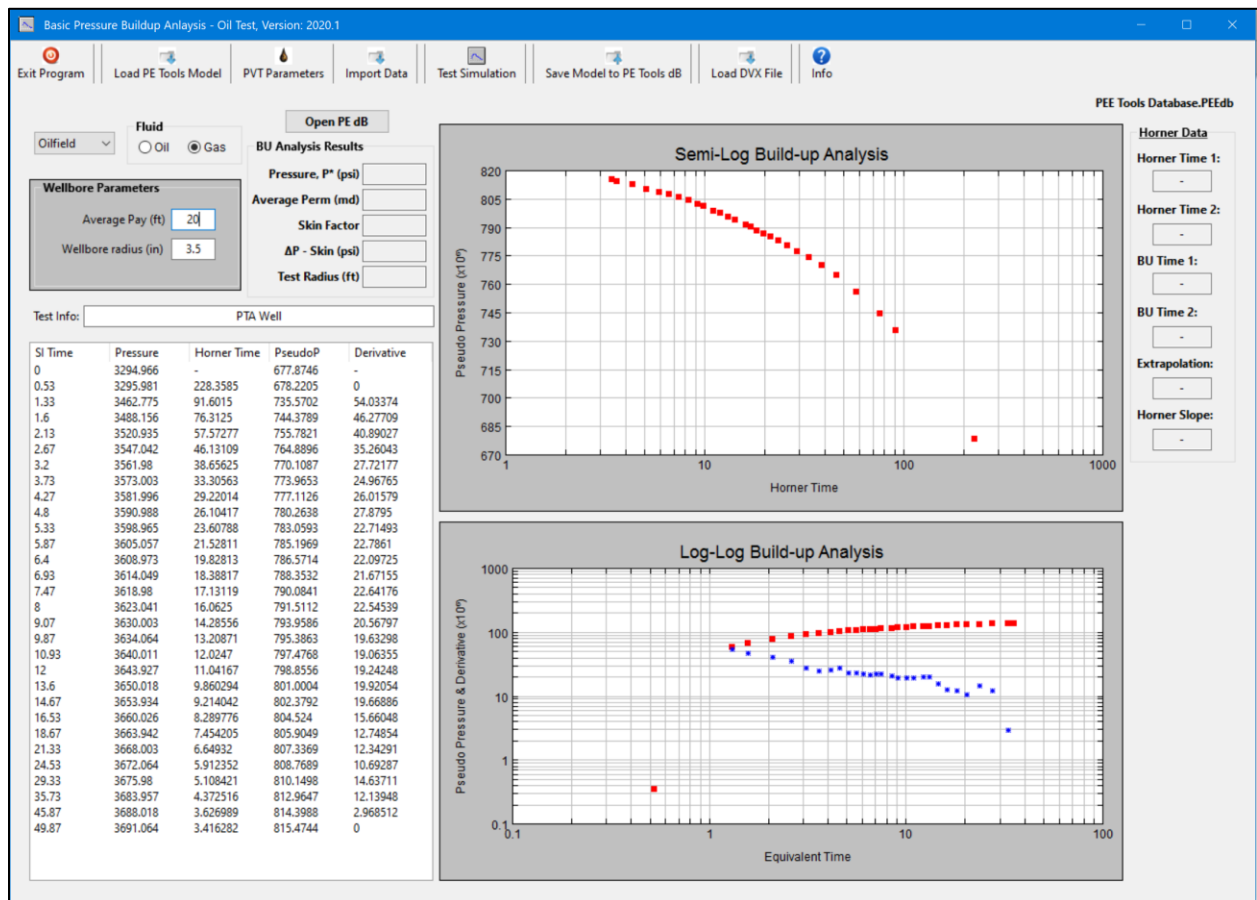


Figure PTA-13: Example Gas Well

Note that the pressure data can be saved to the PE Tools database for import at a later time.

The values for net pay and wellbore radius are then entered before proceeding to analysis.

From the log-log plot, it appears that the derivative had stabilized between 3.5 hours and 12 hours. Two points are entered on the semi-log plot to place a straight line in this time interval (Horner time of 11 and 38) – Figure PTA-14. The straight line can be changed by clicking on one of the end points.

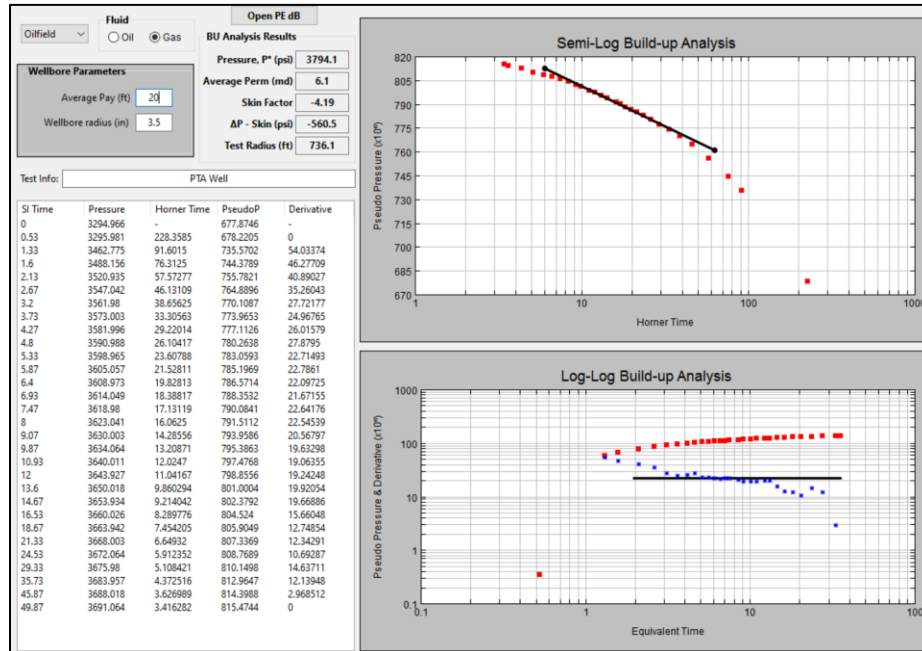


Figure PTA-14: Example Gas Well Analysis

The pressure derivative and the semi-log plot data appears to fall below the straight line at late shut in times. This could be indicative of increasing pay in the reservoir or a constant pressure boundary – the radius of investigation for this test is 736 ft.

## Volumetric Analysis Tool

The PE<sup>2</sup> Essentials 'Volumetric (MB) Analysis' tool is a diagnostic material balance analysis tool (Figure MBA-1).

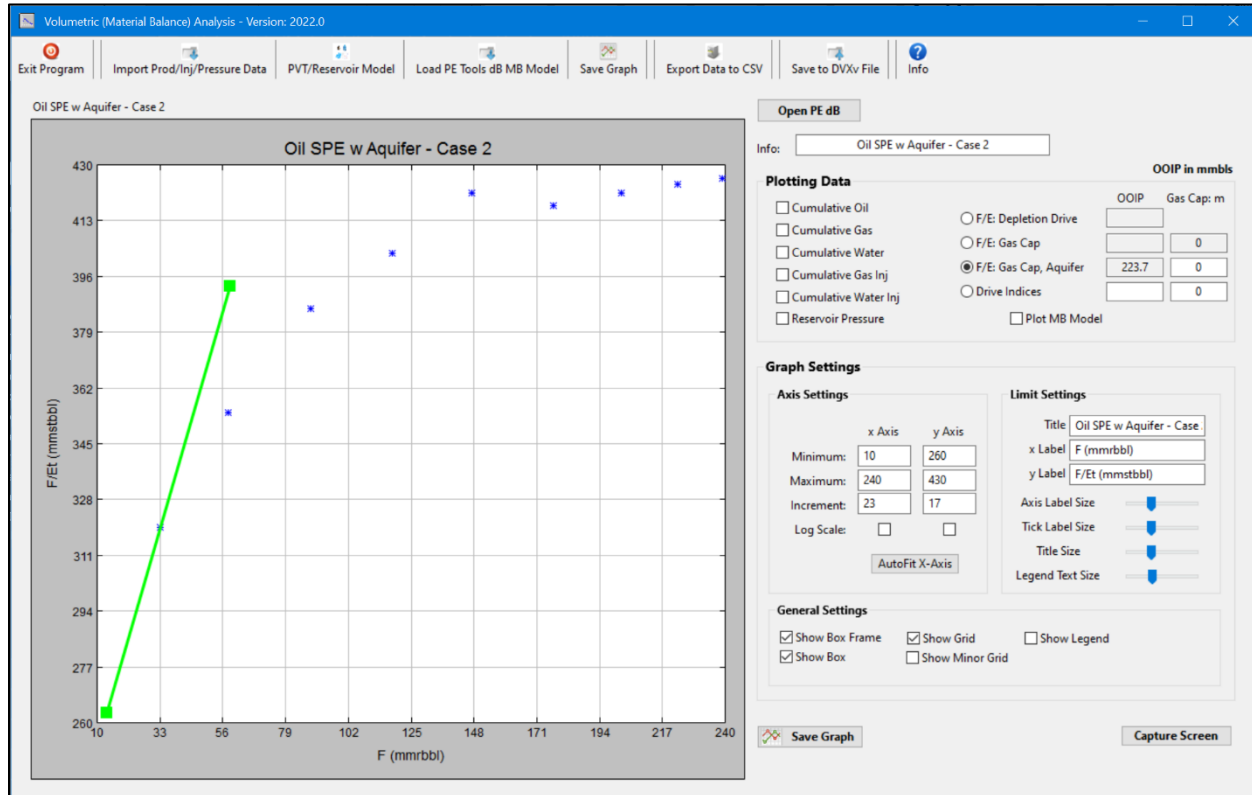


Figure MBA-1: PE<sup>2</sup> Essentials Volumetric (MB) Analysis Tool

### MBA.1 General Material Balance

Material balance analysis (MBA) is an interpretation technique used to determine original oil or original gas in-place (OOIP, GIIP) based on production and injection volumes and static reservoir pressure data. It is based on the law of conservation of mass and makes the following assumptions:

- The reservoir is homogenous and behaves like a tank
- Fluid production/injection occurs at single points
- There is no directional component to the flow

In real life, none of these assumptions are met by oil and gas reservoirs: reservoirs are not homogeneous tanks, production and injection are areally distributed and occur at different times and fluid flow is directional. Nevertheless, MBA is a commonly used analysis technique and has been found to yield reasonably acceptable results.

The general material balance equation relates the original oil, gas, and water volumes in the reservoir to production volumes and current pressure conditions and fluid properties. The assumption of a tank behaviour means that the reservoir is considered to have the same pressure and fluid properties at all location in the reservoir. Consider Figure MBA-2

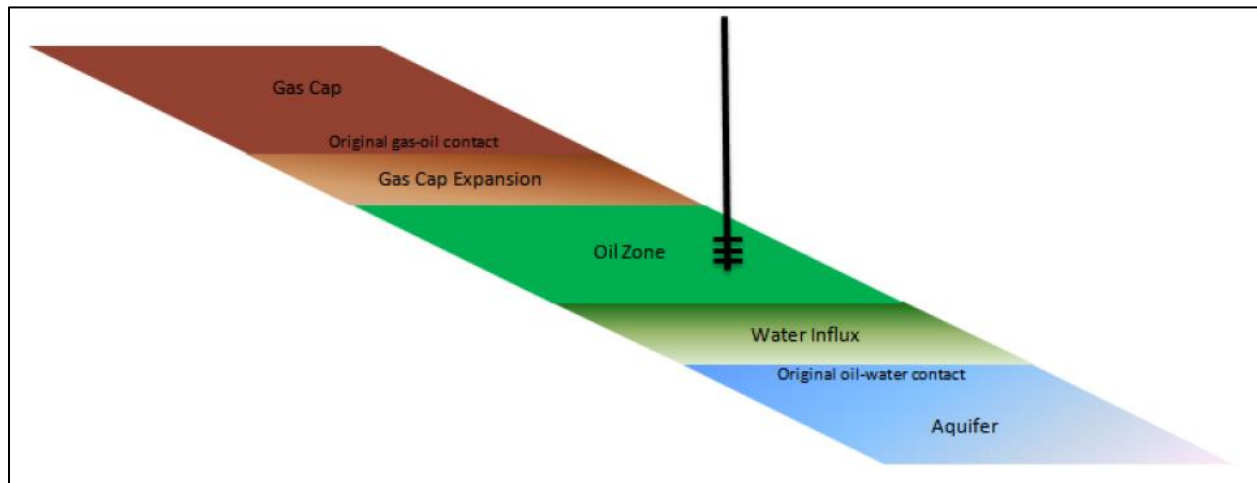


Figure MBA-2: Reservoir Material Balance

The simplest way to visualize material balance is that if the measured surface volume of oil, gas and water were returned to a reservoir at the reduced pressure, it must fit exactly into the volume of the total fluid expansion plus any fluid influx.

The general material balance for an oil reservoir can be expressed as follows:

$$\begin{aligned} \text{Net Reservoir Withdrawal} = & \text{Expansion of Oil} \\ & + \text{Original Dissolved Gas} \\ & + \text{Expansion of Gas Cap} \\ & + \text{Reduction in Hydrocarbon Pore Volume} \\ & + \text{Natural Water influx} \\ & + \text{Gas/Water Injection Volumes} \end{aligned}$$

The general material balance for a gas reservoir can be expressed as follows:

$$\begin{aligned} \text{Net Reservoir Withdrawal} = & \text{Expansion of Gas} \\ & + \text{Reduction in Hydrocarbon Pore Volume} \\ & + \text{Natural Water influx} \end{aligned}$$

## MBA.2 Data Input

Figure MBA-3 shows the data input options for the PE<sup>2</sup> Essentials MBA tool. Data can be input from an Excel spreadsheet. After importing the production data, it can be saved to a DVXv file through the 'Save Production/PVT Data' button on the main screen (Figure MBA-1).

Figure MBA-4 shows the PVT input screen.

**Data Import**

**Units**  
☒ Oilfield  
☐ Metric

**Data Input**  
☒ DVXv File  
☐ Excel File

**Fluid Type**  
☒ Oil  
☐ Gas

**Display**  
☒ Cum ☐ Inc

**Info:** Oil SPE w Aquifer - Case 2

**Excel Input Parameters**

	Column	Start R...	End Row
Years or Date			
Inc Oil Volume (mbbls)			
Inc Gas Volume (mmscf)			
Inc Water Volume (mbbls)			
Inc Gas Inj Volume (mmscf)			
Inc Water Inj Volume (mbbls)			
Reservoir Pressure (psi)			

Date	Years	Oil	Gas	Water	Gas Inj	Wat Inj	ResPress
1/1/1984	1	0	0	0	0	0	2740
12/31/1984	366	7880	5988.8	0	0	0	2500
12/31/1985	731	18420	15564.9	0	0	0	2290
12/31/1986	1096	29150	26832.58	0	0	0	2109
12/31/1987	1461	40690	39676.82	0	0	0	1949
12/30/1988	1826	50140	51393.5	0	0	0	1818
12/30/1989	2191	58420	62217.3	0	0	0	1720
12/30/1990	2556	65390	71602.05	0	0	0	1608
12/30/1991	2921	70740	79228.8	0	0	0	1535
12/29/1992	3286	74540	85348.3	0	0	0	1480
12/29/1993	3651	77430	89818.8	0	0	0	1440

Open Excel File Import Data Continue Cancel

Figure MBA-3: PE<sup>2</sup> Essentials Volumetric (MB) Analysis Tool, Data Input

**PVT/Reservoir Properties**

Oil API: 34

Separator Gas Gravity: 0.6

Separator Pressure (psi): 0

Separator Temperature (°F): 0

H<sub>2</sub>S - mol%: 0

N<sub>2</sub> - mol%: 0

CO<sub>2</sub> - mol%: 0

Bubble Point Pressure (psi): 2740

Water Salinity (ppm NaCl): 35000

Reservoir Pressure (psi): 2740

Reservoir Temp (°F): 200

Porosity (dec): 0.25

Water Saturation (dec): 0.05

Corrected Gas G: 0.6

Gas Pc (psi): 672.5

Gas Tc (°R): 358.5

GORi (scf/bbl): 633.95

Boi (rbbl/stbbl): 1.4177

Bwi (rbbl/stbbl): 1.0344

Import PE Tools dB PVT Properties

Continue

Figure MBA-4: PE<sup>2</sup> Essentials Volumetric (MB) Analysis Tool, PVT/Reservoir Data Input

The PVT parameters can be entered manually or imported from a PE<sup>2</sup> Essentials PE Tools database. Clicking 'Import PE Tools db PVT Properties' will open a sheet that will give the option of entering PVT data stored with a well or PVT data from a stored PVT model (Figure MBA-5).

Figure MBA-5: Importing PVT Data from the PE Tools Database

Selecting the appropriate button will list the options available for the database. Click on the relevant well/tool and the PVT data will be imported into the tool. The remaining data is entered manually.

### MBA.3 General Oil Material Balance

The general material balance equation for an oil reservoir can be expressed as the equation of a straight line, as follows:

$$F = N(E_o + mE_g + E_{fw}) + W_e \quad (\text{MBA-1})$$

Where:  $F$  is net withdrawal at reservoir conditions in rbbl,  $N$  is the original oil in place in stbbl,  $E_o$  is the expansion of oil and original gas in solution in rbbl/stbbl,  $m$  is the initial gas cap volume fraction (initial hydrocarbon volume of the gas cap / initial hydrocarbon volume of the oil zone) in rbbl/rbbl,  $E_g$  is the expansion of the gas cap gas in rbbl/stbbl,  $E_{fw}$  is the expansion of the connate water and reduction in the hydrocarbon pore volume due to connate water expansion and decrease in the pore volume in rbbl/stbbl, and  $W_e$  is cumulative water influx from the aquifer in rbbl.

The terms in the general oil material balance equation are as follows:

$$F = N_p [B_o + (R_p - R_s)B_g] + W_p B_w - W_i B_w - G_i B_g \quad (\text{MBA-2})$$

$$\begin{aligned}
 E_o &= (B_o - B_{oi}) + (R_{si} - R_s)B_g \\
 E_g &= B_{oi} B_{gi} (B_g - B_{gi}) \\
 E_{fw} &= (1 + m) B_o C_e \Delta P \\
 C_e &= (C_w S_{wi} + C_f) / (1 - S_{wi}) \\
 W_e &= U S(p,t)
 \end{aligned}$$

Where:

-  $F$  is net withdrawal at reservoir conditions in rbbl,  $N_p$  is the cumulative oil production in stbbl,  $B_o$  is the oil formation volume factor at current conditions rbbl/stbbl,  $R_p$  is the cumulative oil-gas ratio ( $G_p/N_p$ ) in scf/bbl,  $R_s$  is gas in solution at current conditions in scf/stbbl,  $B_g$  is gas formation volume factor at current conditions in rbbl/scf,  $W_p$  is cumulative water production in stbbl,  $B_w$  is water formation volume factor at current conditions in rbbl/stbbl,  $W_i$  is cumulative water injection in stbbl, and  $G_i$  is cumulative gas injection in scf.

-  $E_o$  is the expansion of oil and original gas in solution in rbbl/stbbl,  $B_o$  is the oil formation volume factor at current conditions rbbl/stbbl,  $B_{oi}$  is the oil formation volume factor at initial conditions rbbl/stbbl,  $R_{si}$  is gas in solution at original conditions in scf/bbl,  $R_s$  is gas in solution at current conditions in scf/bbl, and  $B_g$  is gas formation volume factor at current conditions in rbbl/scf.

-  $E_g$  is the expansion of the gas cap gas in rbbl/stbbl,  $B_{oi}$  is the oil formation volume factor at initial conditions rbbl/stbbl,  $B_{gi}$  is gas formation volume factor at initial conditions in rbbl/scf, and  $B_g$  is gas formation volume factor at current conditions in rbbl/scf.

-  $E_{fw}$  is the expansion of the connate water and reduction in the hydrocarbon pore volume due to connate water expansion and decrease in the pore volume in rbbl/stbbl,  $m$  is the initial gas cap volume fraction (initial hydrocarbon volume of the gas cap / initial hydrocarbon volume of the oil zone) in rbbl/rbbl,  $B_o$  is the oil formation volume factor at current conditions rbbl/stbbl,  $C_e$  is the effective compressibility of the connate water and the pore volume in 1/psi, and  $\Delta P$  is the change in reservoir pressure ( $P_i - P_r$ ) in psi.

-  $C_e$  is the effective compressibility of the connate water and the pore volume in 1/psi,  $C_w$  is the water compressibility in 1/psi,  $S_{wi}$  is the initial connate water saturation, and  $C_f$  is the pore volume compressibility in 1/psi.

-  $W_e$  is cumulative water influx from the aquifer in rbbl,  $U$  is the aquifer constant in rbbl/psi, and  $S(p,t)$  is the aquifer function which is dependent on the type of aquifer in psi.



### MBA.3.1 Undersaturated Oil / Depletion Drive Reservoir

For an undersaturated oil / depletion drive reservoir, the  $E_g$  and  $W_e$  terms in the general material balance equation are zero, simplifying the oil material balance equation to:

$$F = N (E_o + E_{fw}) = NE_t \quad (\text{MBA-3})$$

This indicates that for an undersaturated oil / depletion drive reservoir, a plot of  $F$  versus  $E_t$  (Figure MBA-6) will yield a straight line going through the origin and having a slope of  $N$ . In some cases, a reservoir will exhibit depletion drive very early in its production life.

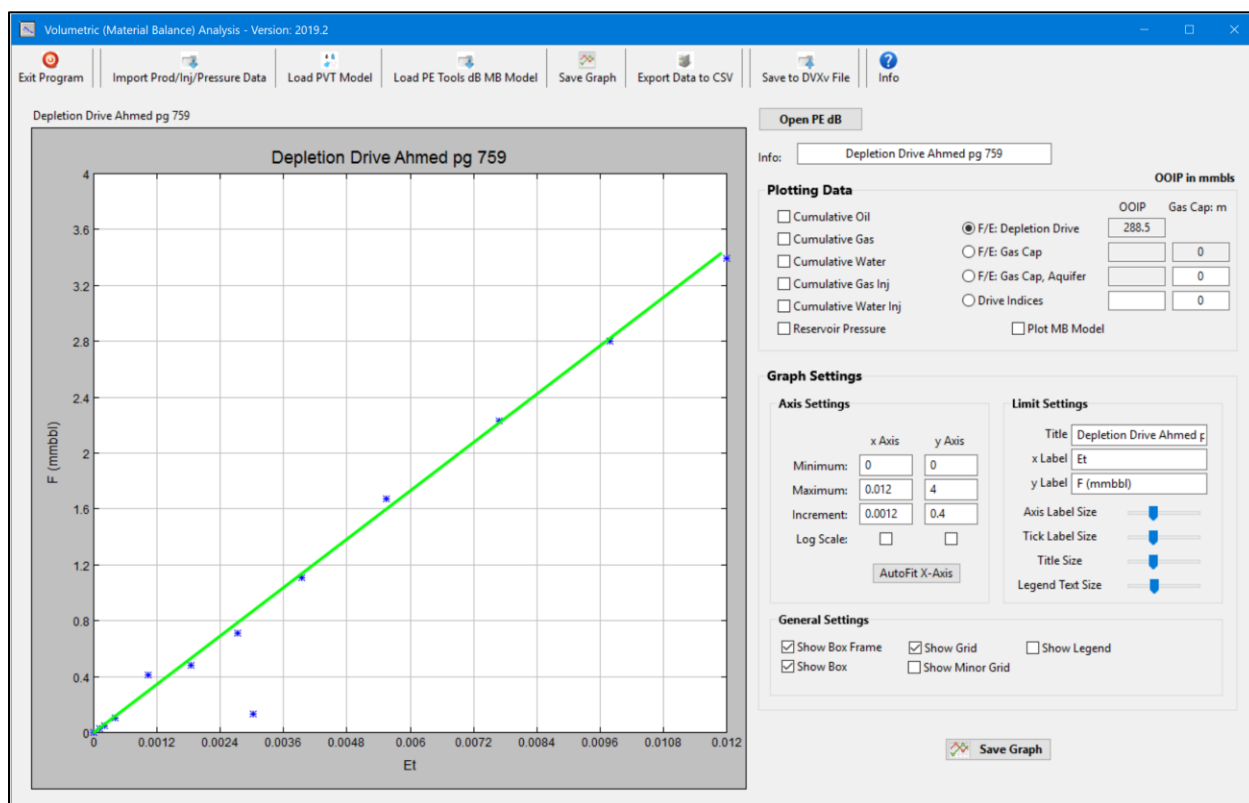


Figure MBA-6: Volumetric Analysis – Depletion Drive Analysis

Figure MBA-5 includes data presented on page 759 in Ahmed and the data file is included as 'PE<sup>2</sup> Essentials Oil Well Volumetric Surveillance Data Depletion Drive Ahmed pg 759.DVXv' in the "Example Input Files\DVX Model Files\Volumetric Analysis" directory. The oil initially in place was reported by Ahmed to be 257 mmstbbls.

Refer to MBexamples.xlsx in the "Example Input Files\Excel Files" directory for complete information for all the cases presented in this section.

Figure MBA-7 presents the data from a theoretical water drive oil reservoir. This reservoir had an initial oil in place of 150 mmbbls. This data is included as 'PE Essentials Oil Well Volumetric

Surveillance Data Water Drive.DVXv' in the Example Input Files\DVX Model Files\Volumetric Analysis directory.

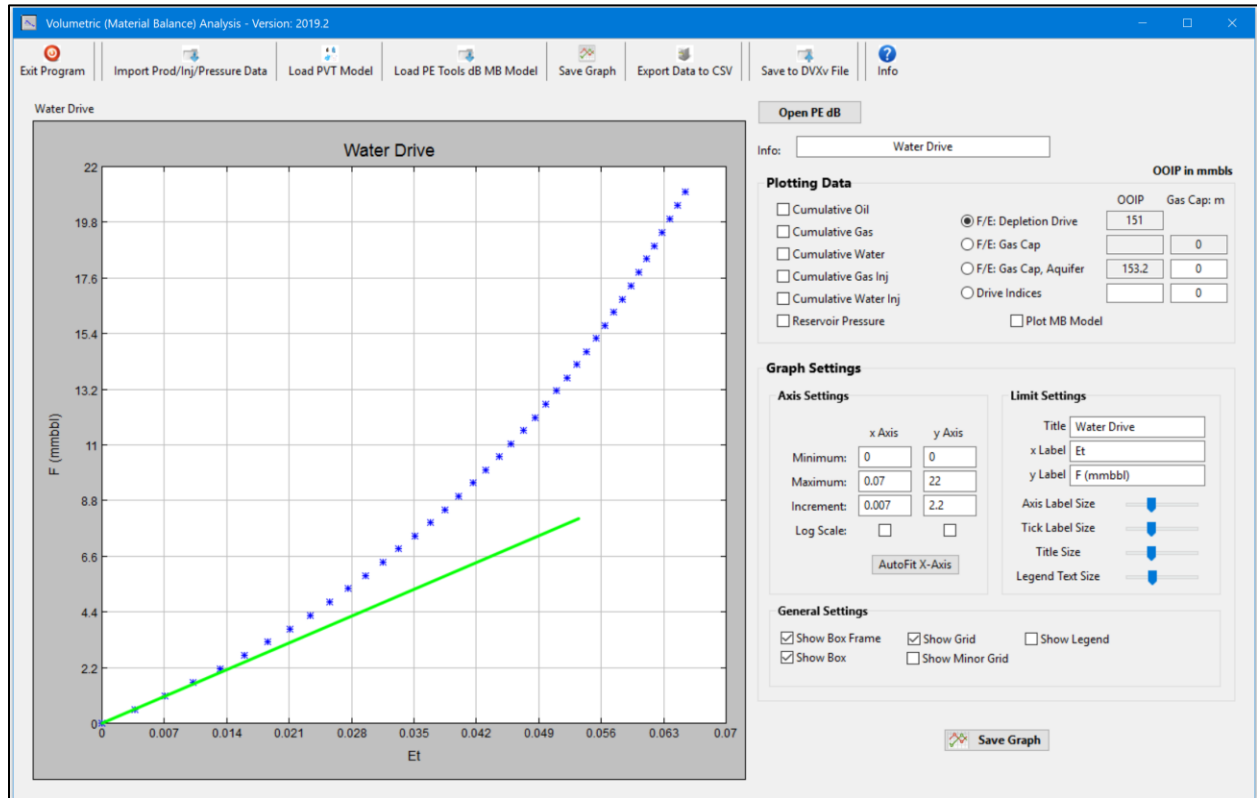


Figure MBA-7: Volumetric Analysis – Depletion Drive Analysis of Water Drive Reservoir

A water drive reservoir may exhibit a depletion drive at very early times, but this is not always the case. Caution should be used when attempting this type of analysis on a water drive reservoir. The reservoir in Figure MBA-6 is obviously a water drive reservoir based on the non-linear trend of the data.

Note that the straight line can be moved by dragging either the start point or end point of the line.

### MBA.3.2 Gas Cap Drive Oil Reservoir

For an oil reservoir containing a gas cap, the  $W_e$  term is zero and the  $E_{fw}$  term can be disregarded since the compressibility of the gas is an order of magnitude greater than the compressibility of the water or the rock. The oil material balance equation becomes:

$$F = N(E_o + mE_g) \quad (\text{MBA-4})$$

$$F/E_o = N + mN(E_g/E_o)$$

Equation MBA-4 is the equation of straight line having a slope of  $mN$  and an intercept of  $N$ . Figure MBA-8 is an example of a theoretical gas cap drive oil reservoir. This reservoir had an initial oil in place of 150 mmbbls and an initial gas cap volume factor,  $m$ , of 0.5.

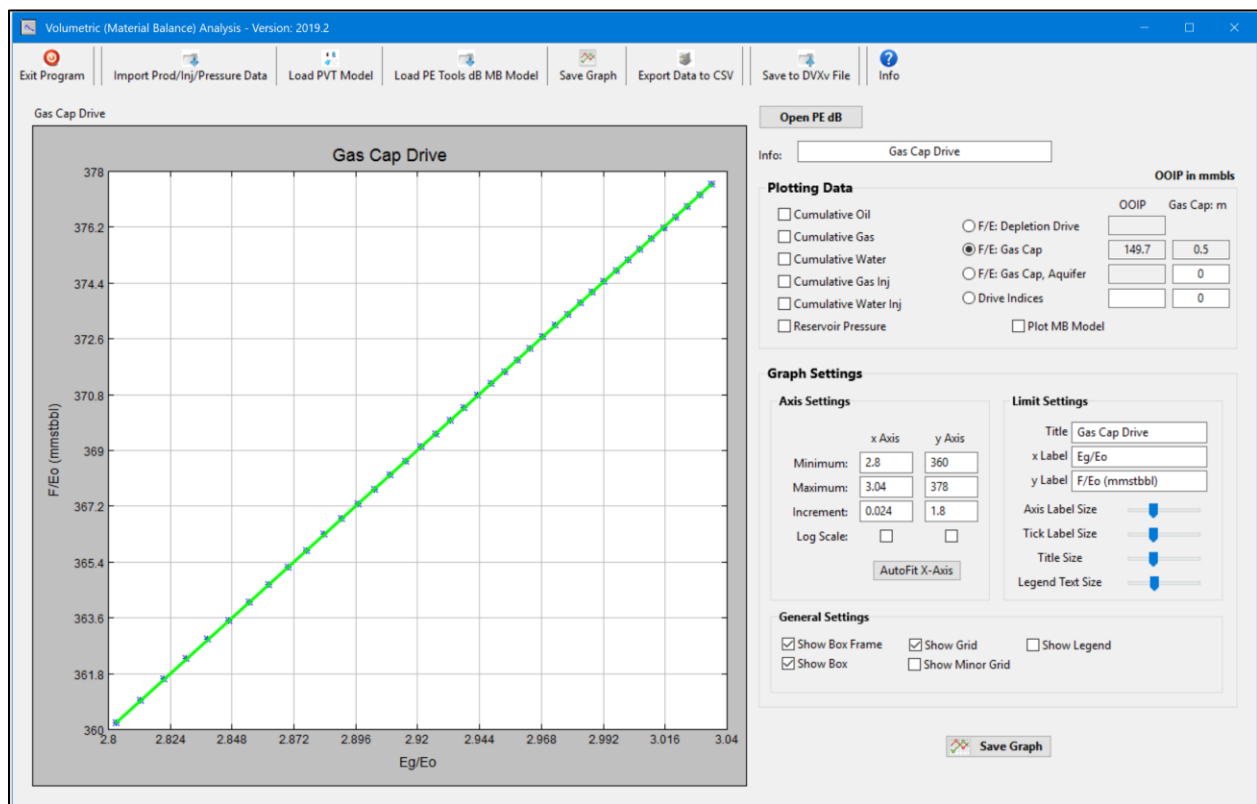


Figure MBA-8: Volumetric Analysis – Gas Cap Drive Reservoir

Once the straight line is placed on the graph, the values for  $N$  and  $m$  are automatically calculated.

Note that the straight line can be moved by dragging either the start point or end point of the line.

### MBA.3.3 Water Drive Oil Reservoir

For an oil reservoir containing an aquifer, only the  $E_g$  term in the general material balance equation is zero. The oil material balance equation becomes:

$$F = N(E_o + E_{fw}) + W_e \quad (\text{MBA-5})$$

$$F/(E_o + E_{fw}) = N + W_e/(E_o + E_{fw})$$

$$F/E_t = N + W_e/E_t$$

The  $W_e$  term is a difficult term to determine without knowledge of the aquifer type and properties. Refer to Section 5.6 for complete information on aquifer modeling. To generate a plot of Equation MBA-5, the  $W_e$  data for a given aquifer is generated and the plot is examined. If the plot is not a straight line, a new aquifer model is used to generate a different set of  $W_e$  data and the plot re-examined.

This is a time-consuming process so in 1978 Campbell et al (Campbell, R.R. and Campbell, J.M.; Mineral Property Economics, vol. 3, Petroleum Property Evaluation, Campbell Petroleum Series, 1978) published the Campbell Method for a water drive reservoir. For this method,  $F/E_t$  versus  $F$  is plotted. The intercept of the line will yield  $N$  and the slope is a function of the aquifer performance.

Figure MBA-9 is the same example that was presented in Figure MBA-7.

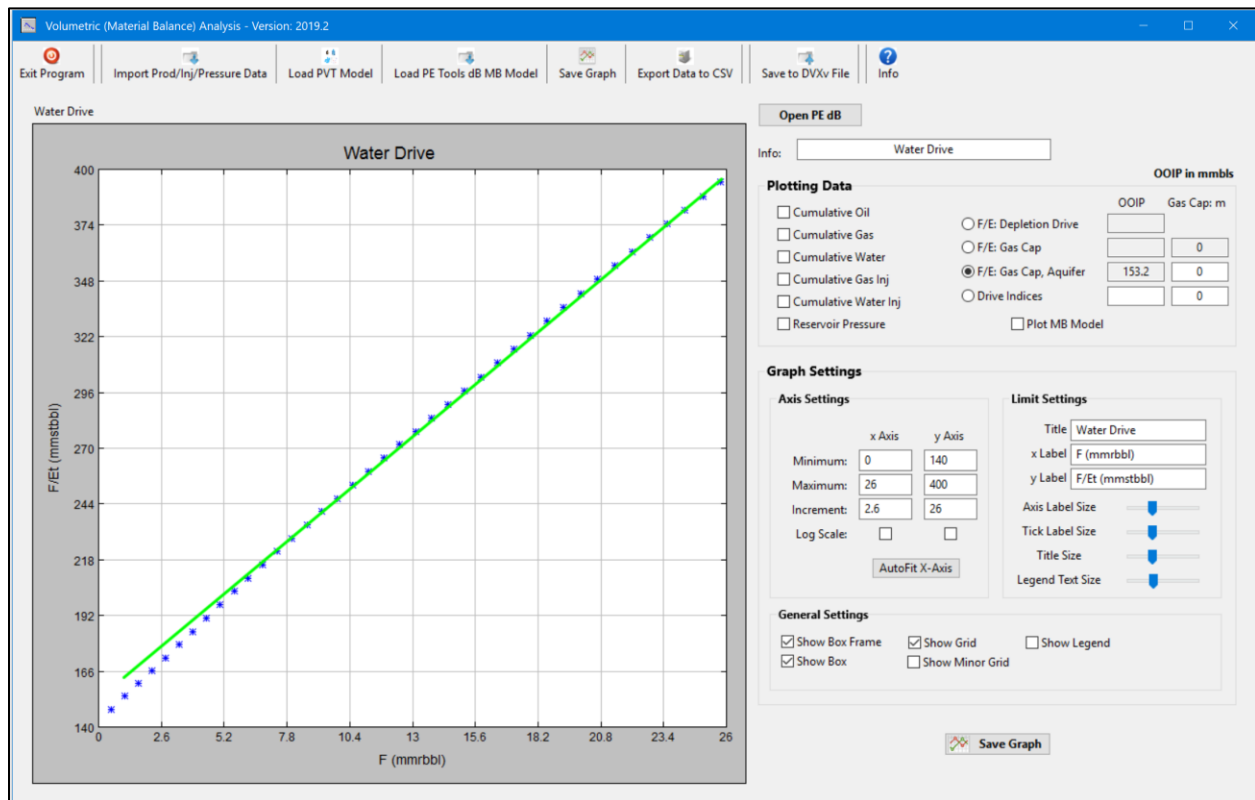


Figure MBA-9: Volumetric Analysis – Water Drive Analysis

### MBA.3.4 Combination Gas Cap / Water Drive Oil Reservoir

For an oil reservoir containing a gas cap and an aquifer, all terms in the general material balance equation are required for analysis. The problem can very quickly become unconstrained and difficult to obtain a unique solution. The oil material balance equation becomes:

$$\begin{aligned}
 F &= N(E_o + mE_g + E_{fw}) + W_e \\
 F/(E_o + mE_g + E_{fw}) &= N + W_e/(E_o + mE_g + E_{fw}) \\
 F/E_t &= N + W_e/E_t
 \end{aligned}
 \tag{MBA-6}$$

There are three unknowns in Equation MBA-6;  $N$ ,  $W_e$  and  $m$ . The Campbell method is used by assuming a value for  $m$  and calculating  $N$ .

For the theoretical example included as 'PE Essentials Oil Well Volumetric Surveillance Data Gas Cap Water Drive.DVXv' in the "Example Input Files\DVX Model Files\Volumetric Analysis" directory, a gas cap ratio,  $m$ , of 0.5 was entered for the analysis. OOIP was estimated to be 148 mmstb. Figure MBA-10 shows the analysis plot for this data.

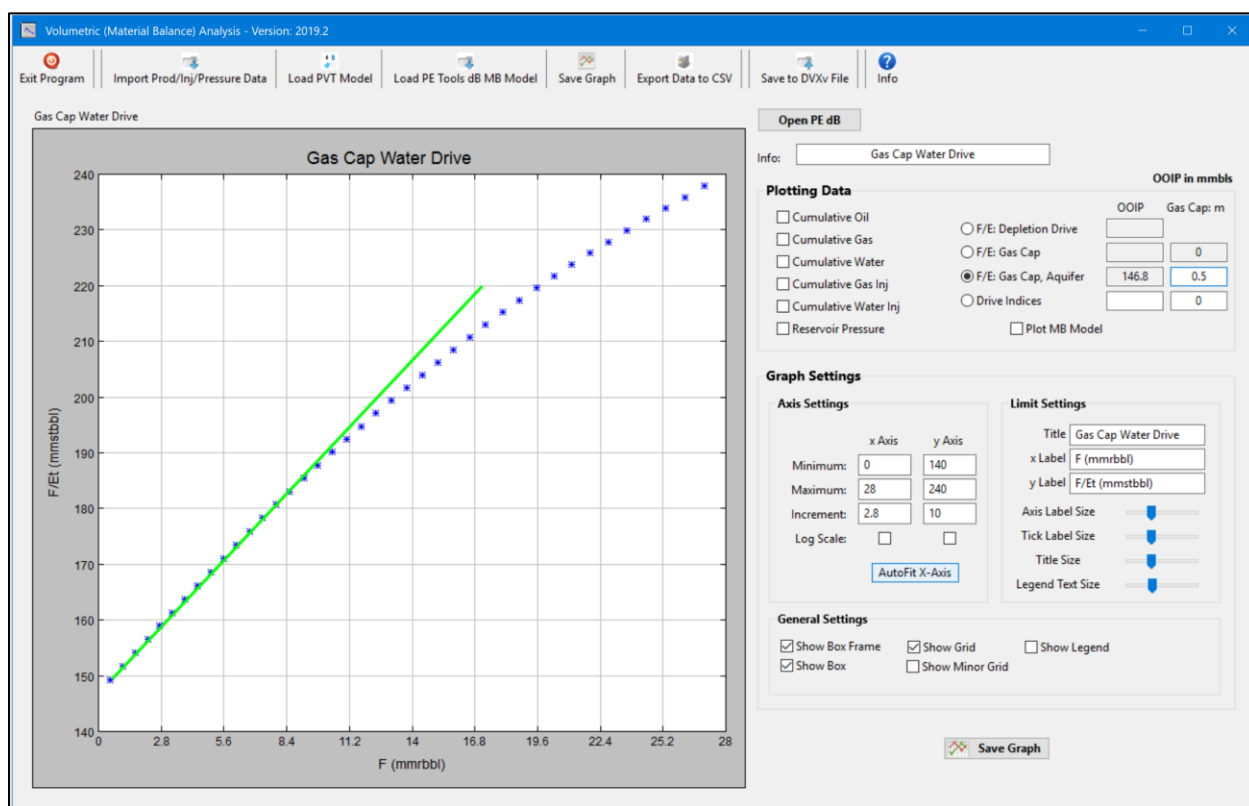


Figure MBA-10: Volumetric Analysis – Gas Cap / Aquifer Combination Drive Analysis

Results from the Oil Material Balance tool can be incorporated to assist with the analysis - refer to the example in Section MBA.3.6.

### MBA.3.5 Drive Indices for an Oil Reservoir

If the oil zone withdrawal terms are separated from the remaining terms in the general material balance equation, the following is obtained:

$$N_p [B_o + (R_p - R_s)B_g] = N(E_o + mE_g + E_{fw}) - W_p B_w - W_i B_w - G_i B_g + W_e \quad (\text{MBA-7})$$

By definition,  $m = G B_{gi} / N B_{oi}$ . By replacing the terms for the other expressions and dividing by the left hand side, Equation MBA-8 is obtained. Note that the  $E_{fw}$  has been replaced by the term "Rock".

$$1 = \frac{N[(R_{si} - R_s)B_g - (B_{oi} - B_o)] + G(B_g - B_{gi}) - G_p B_g + G_i B_g + W_e - W_p B_w + W_i + \text{Rock}}{N_p B_o + N_p (R_p - R_s) B_g} \quad (\text{MBA-8})$$

From Equation MBA-8, the drive indices are defined as follows:

$$SDI = \frac{N[(R_{si} - R_s)B_g - (B_{oi} - B_o)]}{N_p B_o + N_p (R_p - R_s) B_g} \quad (\text{MBA-9})$$

$$GDI = \frac{G(B_g - B_{gi}) - G_p B_g + G_i B_g}{N_p B_o + N_p (R_p - R_s) B_g} \quad (\text{MBA-10})$$

$$WDI = \frac{W_e - W_p B_w + W_i}{N_p B_o + N_p (R_p - R_s) B_g} \quad (\text{MBA-11})$$

$$EDI = 1.0 - SDI - GDI - WDI \quad (\text{MBA-12})$$

Where: SDI is the solution gas drive index, GDI is the gas drive index, WDI is the water drive index, and EDI is the compressibility expansion drive.

Since the sum of the drive indices is one, calculating the three main drive indices (SDI, GDI, WDI) will allow the calculation of the fourth index, EDI.

Following an analysis, an evaluation of the drive index can be performed to confirm that the results make sense. For the Figure MBA-9 example in Section MBA.3.4, a plot of the drive indices was generated (Figure MBA-11) using the assumed value for  $m$  and the estimated value for OOIP obtained from the analysis.

The Drive Indices plot shows that the reservoir drive started out as solution gas and gas cap drive, then as production progressed, water drive became more dominant.

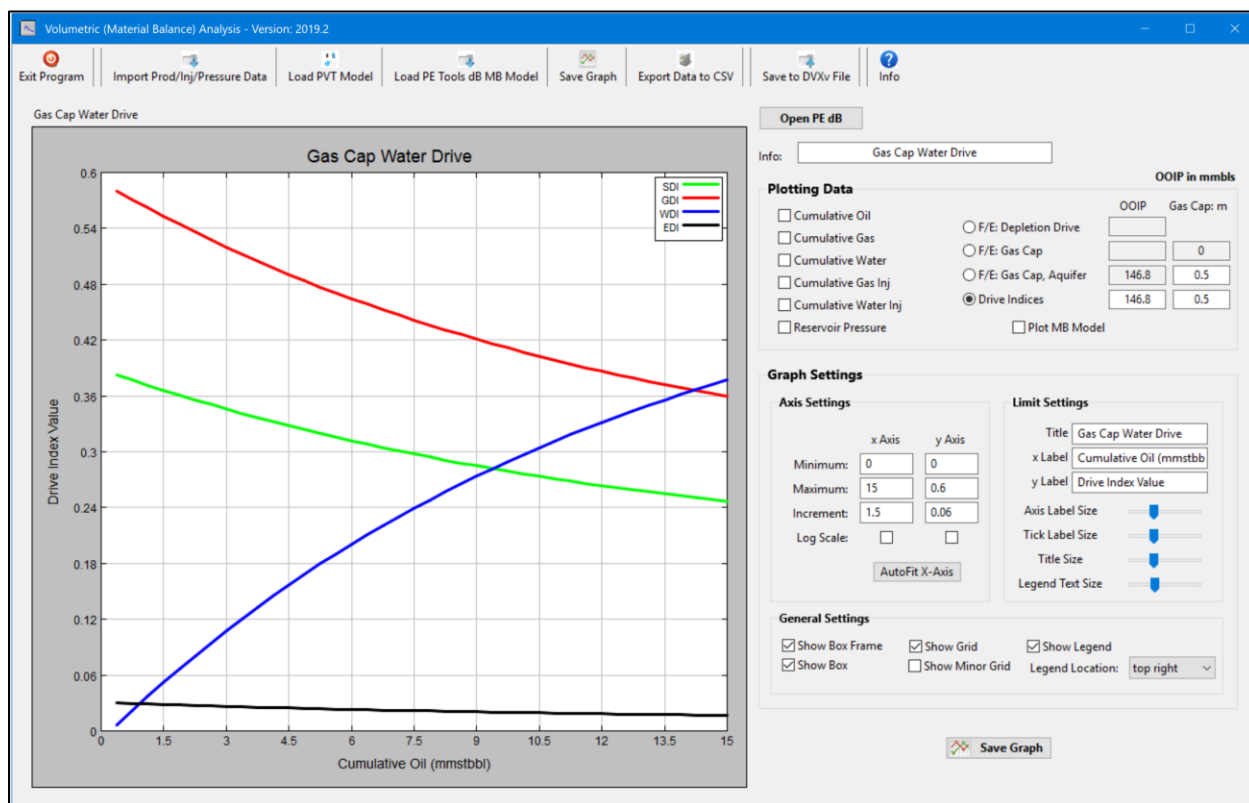


Figure MBA-11: Volumetric Analysis – Combination Drive Reservoir, Drive Index Analysis

### MBA.3.6 Water Drive Reservoir Example

An example of a water drive reservoir was history matched to a Fetkovich finite aquifer (refer to PE Essentials Oil Material Balance Tool documentation). Table MBA-1 presents the data.

Years	Pressure (psi)	Cum Oil (mstb)	Cum Gas (mmscf)	Cum Wat (mbbls)	Years	Pressure (psi)	Cum Oil (mstb)	Cum Gas (mmscf)	Cum Wat (mbbls)
0	3000	0	0	0	11	2698	5274.3	3711.7	207.7
1	2923	564.2	395.8	3.3	12	2680	5563.7	3916.2	237.3
2	2880	1418.8	996	15.7	13	2665	5846.5	4116	269.1
3	2848	2155.3	1513.9	32.7	14	2650	6113.6	4304.8	301.8
4	2821	2766.9	1944.2	52.3	15	2633	6386.7	4498	338.6
5	2800	3265.5	2295.2	72.2	16	2620	6642.3	4678.9	375.5
6	2780	3686.7	2591.9	92.6	17	2607	6874.9	4843.6	411.4
7	2762	4058	2853.5	113.6	18	2593	7104.3	5006	449.4
8	2744	4400.1	3094.8	136	19	2580	7328.5	5164.8	488.9
9	2730	4702.4	3308	158.1	20	2568	7539.7	5314.4	528.4
10	2713	4992.3	3512.6	182					

Table MBA-1: Volumetric Analysis Example – Water Drive

The data in Table MBA-1 is included in the 'Smith pg 12-71.xlsx' spreadsheet located in the "Book Examples\Example MBA\Water Drive" directory.

The data was imported and is included in the 'PE Essentials Oil Well Volumetric Surveillance Data Smith pg 12-71.DVXv' file. Figure MBA-12 shows the PVT and reservoir properties for this example.

PVT/Reservoir Properties	
Oil API	44
Separator Gas Gravity	0.6
Separator Pressure (psi)	
Separator Temperature (°F)	
H <sub>2</sub> S - mol%	0
N <sub>2</sub> - mol%	0
CO <sub>2</sub> - mol%	0
Bubble Point Pressure (psi)	3000
Water Salinity (ppm NaCl)	35000
Reservoir Pressure (psi)	3000
Reservoir Temp (°F)	200
Porosity (dec)	0.2
Water Saturation (dec)	0.2
Corrected Gas G	0.6
Gas P <sub>c</sub> (psi)	672.5
Gas T <sub>c</sub> (°R)	358.5
GOR <sub>i</sub> (scf/bbl)	705.97
Bo <sub>i</sub> (rbbl/stbbl)	1.4523
Bw <sub>i</sub> (rbbl/stbbl)	1.0341

Import PE Tools dB PVT Properties

Continue

Figure MBA-12: Volumetric Analysis Example – PVT Data

According to Smith et al and confirmed by the history match of the production history presented in the Oil Material Balance Tool Example, the initial oil in place for this reservoir was 26.6 mmbbls.

Figure MBA-13 presents the Campbell plot for this data.

The straight line through the early time data indicated 41.6 mmbbls. This is obviously too high which suggests that the aquifer was affecting the pressure even at early times. In order to evaluate this data, the 'Plot MB Model' option was used to compare the history matched reservoir/aquifer response with the observed response.

The first time 'Plot MB Model' is checked, the material balance models available in the PE Tools database will be listed for selection (Figure MBA-14).



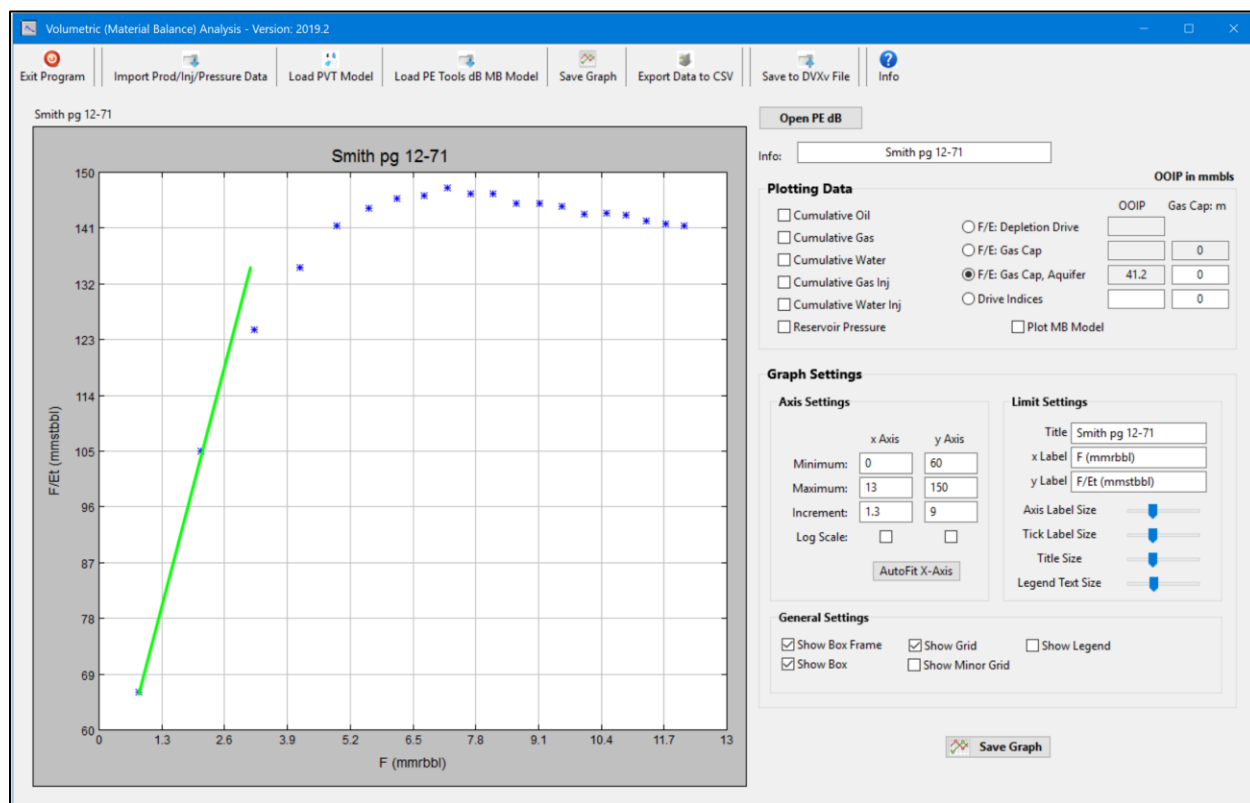


Figure MBA-13: Volumetric Analysis Example – Volumetric Analysis

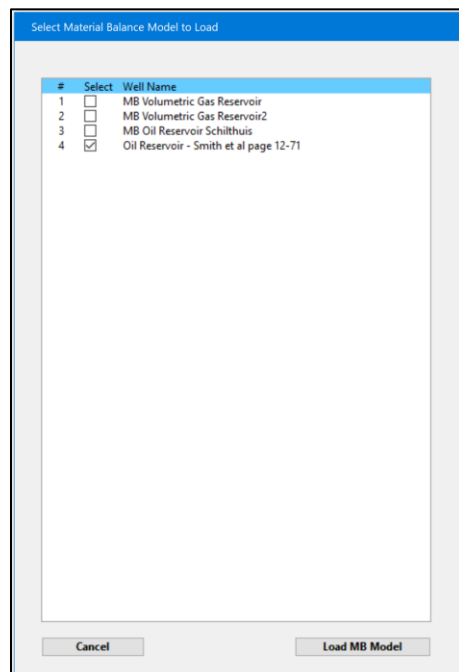


Figure MBA-14: Volumetric Analysis Example – Selecting MB Model

After choosing a material balance model, it is plotted. This is shown in Figure MBA-15.

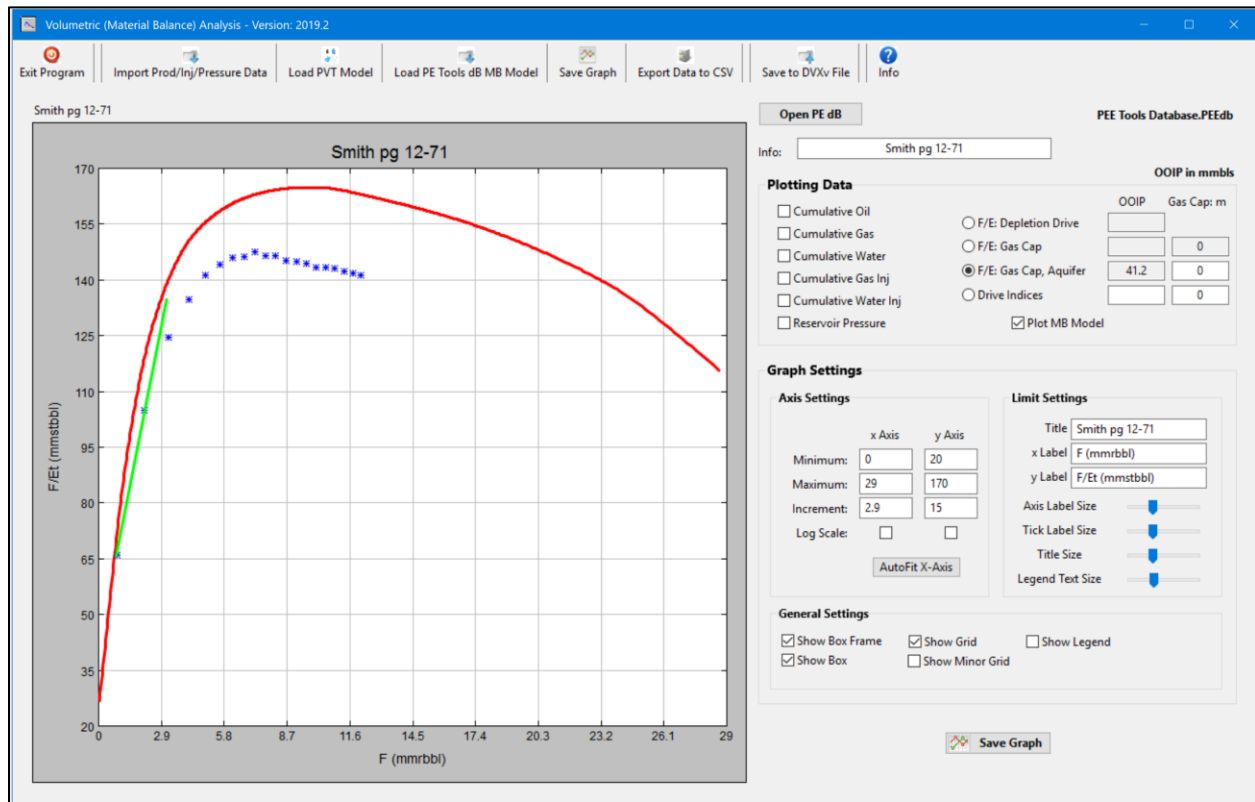


Figure MBA-15: Volumetric Analysis Example – Volumetric Analysis with MB Model

From Figure MBA-15, it is apparent that the green straight line should be steeper (lower  $N$ ) as expected. In addition, additional work could be performed on the reservoir/aquifer model to improve the match, if required.

Figure MBA-16 shows the drive index analysis for this example assuming an initial oil in place of 26.6 mmbbls.

From the plot of the drive indices, the performance of the reservoir/aquifer model is very similar to the response of the historical data.

The plots indicate that water drive was the dominant drive for the reservoir, confirming the conclusion that water was influencing the pressure at early times and that the value of  $N$  obtained from Figure MBA-13 was too high.

It should be noted that a close-to-perfect match in Figure MBA-15, can be obtained by assuming a 24 mmbbls initial oil in place. Since fluid properties are different, a difference in results is expected.

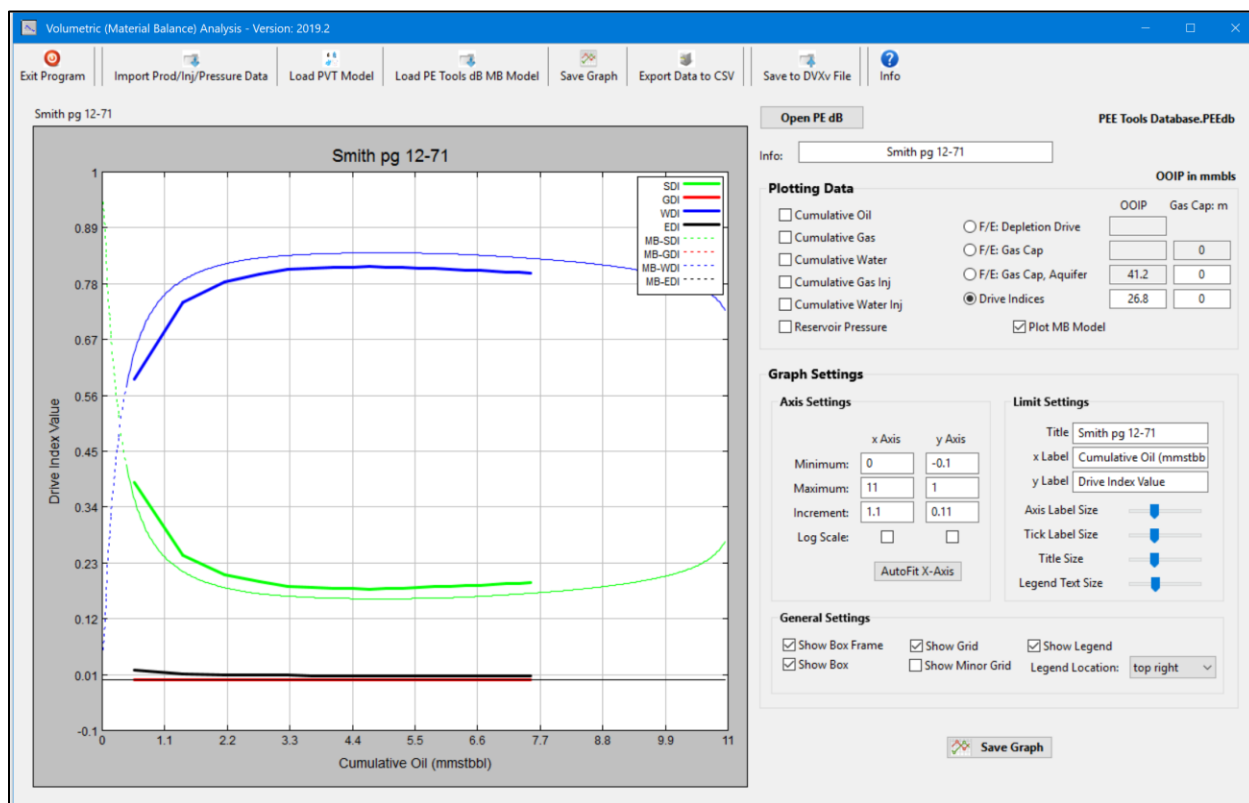


Figure MBA-16: Volumetric Analysis Example – Drive Indices with MB Model

## MBA.4 General Gas Material Balance

The general material balance equation for a gas reservoir can be expressed as the equation of a straight line, as follows:

$$F = G(E_g + E_{fw}) + W_e \quad (\text{MBA-13})$$

Where:  $F$  is net withdrawal at reservoir conditions in rbbl,  $G$  is the original gas in place in scf,  $E_g$  is the expansion of the gas cap gas in rbbl/scf,  $E_{fw}$  is the expansion of the connate water and reduction in the hydrocarbon pore volume due to connate water expansion and decrease in the pore volume in rbbl/scf, and  $W_e$  is cumulative water influx from the aquifer in rbbl.

The terms in the general gas material balance equation are as follows:

$$\begin{aligned} F &= G_{wgp} B_g + W_p B_w \\ G_{wgp} &= G_p + N_{pc} F_c \\ E_g &= B_g - B_{gi} \\ E_{fw} &= B_{gi} C_e \Delta P \\ C_e &= (C_w S_{wi} + C_f) / (1 - S_{wi}) \\ F_c &= 132.79 S_c / M_c \\ S_c &= 141.5 / (131.5 + ^\circ\text{API}) \end{aligned}$$

$$M_c = 6084 / (^\circ\text{API} - 5.9)$$

$$W_e = U S(p,t)$$

Where:

- $F$  is net withdrawal at reservoir conditions in rbbl,  $G_{wgp}$  is the cumulative wet gas production in scf,  $B_g$  is gas formation volume factor at current conditions in rbbl/scf,  $W_p$  is cumulative water production in stbbl, and  $B_w$  is water formation volume factor at current conditions in rbbl/stbbl.
- $G_{wgp}$  is the cumulative wet gas production in scf,  $G_p$  is the cumulative dry gas production in scf,  $N_p$  is the cumulative condensate production in stbbl,  $F_c$  is the condensate conversion factor in scf/stbbl,  $S_c$  is condensate specific gravity,  $^\circ\text{API}$  is the API gravity of the condensate, and  $M_c$  is the molecular weight of condensate.
- $E_g$  is the gas expansion rbbl/scf,  $B_{gi}$  is gas formation volume factor at initial conditions in rbbl/scf, and  $B_g$  is gas formation volume factor at current conditions in rbbl/scf.
- $E_{fw}$  is the expansion of the connate water and reduction in the hydrocarbon pore volume due to connate water expansion and decrease in the pore volume in rbbl/stbbl,  $B_{gi}$  is gas formation volume factor at initial conditions in rbbl/scf,  $C_e$  is the effective compressibility of the connate water and the pore volume in 1/psi, and  $\Delta P$  is the change in reservoir pressure ( $P_i - P_r$ ) in psi.
- $C_e$  is the effective compressibility of the connate water and the pore volume in 1/psi,  $C_w$  is the water compressibility at current conditions in 1/psi,  $S_{wi}$  is the initial connate water saturation, and  $C_f$  is the pore volume compressibility at current conditions in 1/psi.
- $W_e$  is cumulative water influx from the aquifer in rbbl,  $U$  is the aquifer constant in rbbl/psi, and  $S(p,t)$  is the aquifer function which is dependent on the type of aquifer in psi.

#### MBA.4.1 Gas Expansion / Volumetric Gas Reservoir

For a volumetric, depletion drive reservoir, the drive energy is the expansion of the gas and the  $E_{fw}$  and  $W_e$  terms in the general material balance equation are zero, simplifying the gas material balance equation to:

$$F = G E_g \quad (\text{MBA-14})$$

Incorporating all the terms for these parameters and including the expression for  $B_g$ , the material balance equation, for a volumetric gas reservoir, becomes the conventional  $P/Z$  equation:

$$P/Z = P_i/Z_i (1 - G_p/Z_i) \quad (\text{MBA-15})$$

From the above expression, a plot of  $P/Z$  versus  $G_p$  will yield a straight line which can be extrapolated to 0 to yield the original gas in place,  $G$ .

Figure MBA-16 is a plot of the data included as 'PE Essentials Gas Well Volumetric Surveillance Data Gas SPE16484 - Case 1.DVXv' in the "Example Input Files\DVX Model Files\Volumetric Analysis" directory.

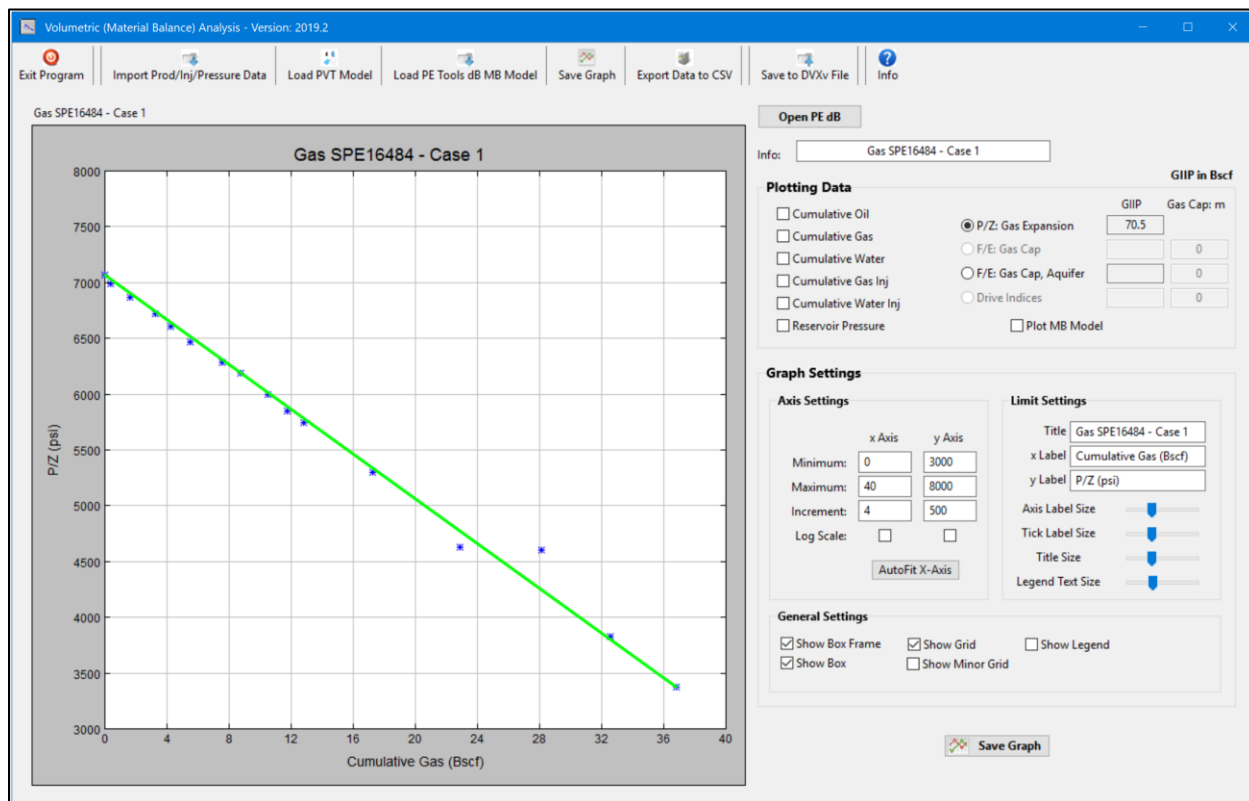


Figure MBA-16: Volumetric Analysis – Volumetric Gas Reservoir

This example is a volumetric gas reservoir which, based on the P/Z plot, contains 70.5 Bscf of gas initially in place.

#### MBA.4.2 Water Drive Gas Reservoir

For a gas reservoir containing an aquifer, the  $E_{fw}$  term can be neglected because it is very small (by an order of magnitude) when compared to the  $E_g$  term. The general material balance equation becomes:

$$F = GE_g + W_e \quad (\text{MBA-16})$$

$$W_e = U S(p,t) \quad (\text{MBA-17})$$

The final form of the material balance equation for a gas reservoir containing an aquifer is:

$$F/E_g = G + U S(p,t)/E_g \quad (\text{MBA-18})$$

The definitions of  $U$  and  $S(p,t)$  depend on the type of aquifer.

For most gas reservoirs containing an aquifer, the P/Z versus  $G_p$  plot can be used to evaluate the early production time data to obtain an estimate of the initial gas in place,  $G$ .

Figure MBA-17 presents the data from 'PE Essentials Gas Well Volumetric Surveillance Data Gas w Aquifer SPE16484 - Case 2.DVXv' in the "Example Input Files\DVX Model Files\Volumetric Analysis" directory.

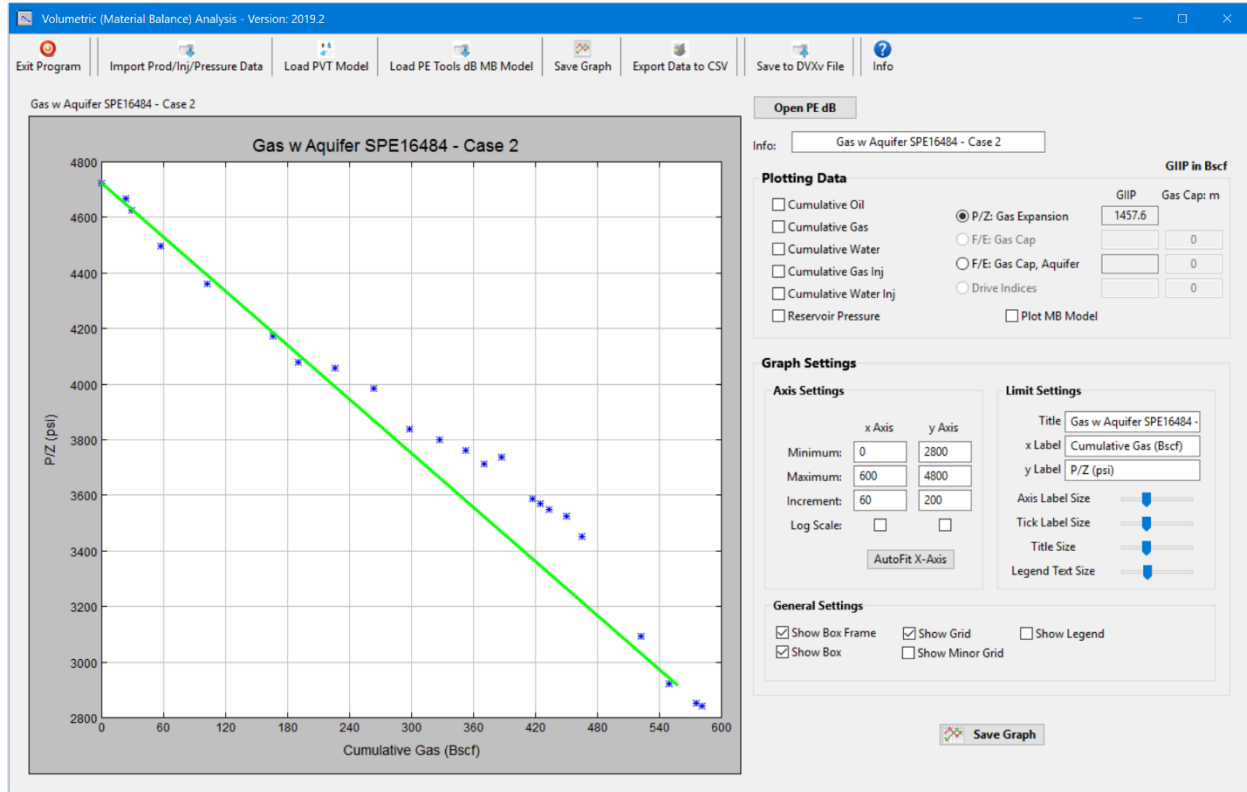


Figure MBA-17: Volumetric Analysis – Gas Reservoir with Aquifer, Expansion Drive Analysis

In the early stages of production, the reservoir appears to behave like an expansion drive / volumetric reservoir. A straight line on the P/Z plot indicates a gas initially in place of approximately 1350 Bscf.

Figure MBA-18 shows the water drive analysis for this example.

To evaluate this plot, the gas in place from the previous analysis was used to direct the analysis. This analysis yields a similar initial gas in place of 1306 Bscf.

It should be noted that this solution is not unique. More in-depth analysis may be required whenever an aquifer is present in a reservoir.

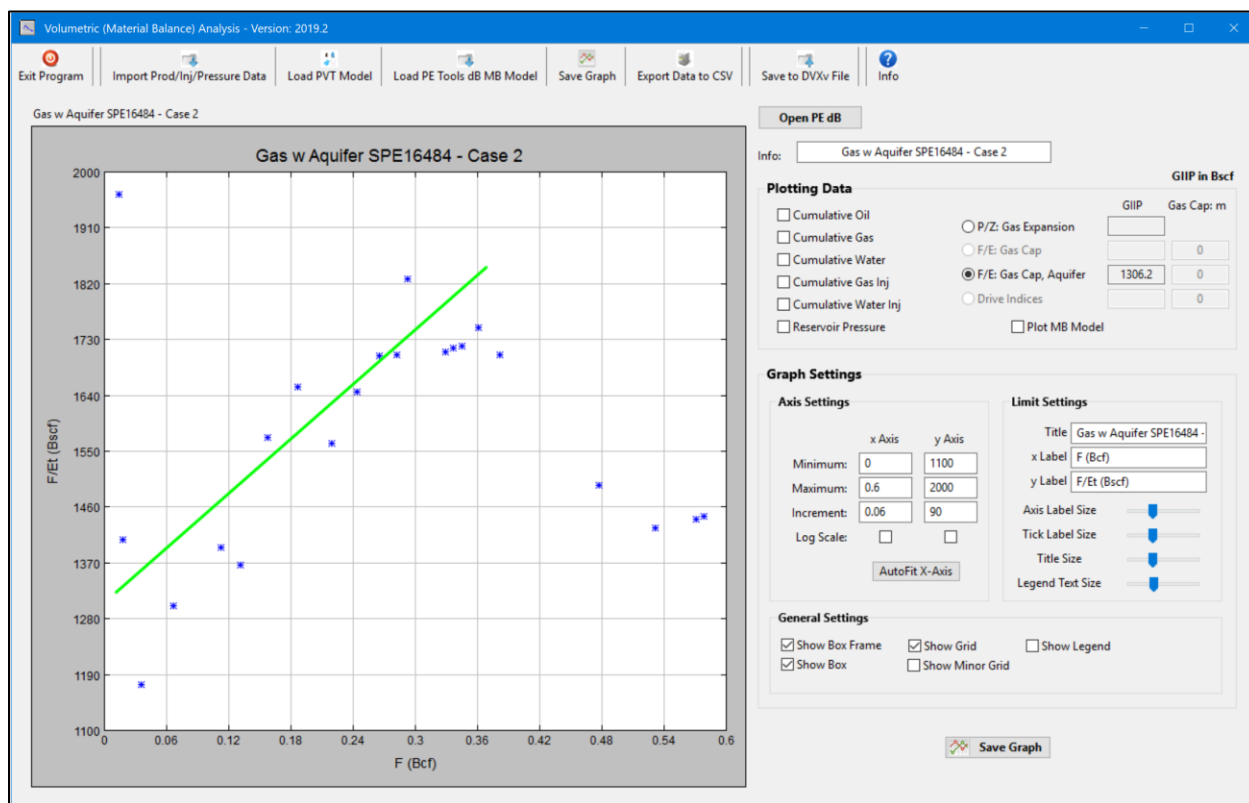


Figure MBA-18: Volumetric Analysis Example – Gas Reservoir With Aquifer, Water Drive

### MBA.4.3 Depletion Drive Gas Reservoir Example

In the Gas Material Balance Tool example, a multi-tank history match was generated for a low-perm gas reservoir. The production data for this example was input into the Volumetric (MB) Analysis tool for analysis (Figure MBA-19). The data file is included as 'PE Essentials Gas Well Volumetric Surveillance Data Multi-Tank Gas Reservoir.DVXv' in the "Book Examples\Example MBA\ Gas Depletion Drive" directory.

Data Import

Units

☒ Oilfield  
☐ Metric

Data Input

☒ DVXv File  
☐ Excel File

Fluid Type

☐ Oil  
☒ Gas

Display

☒ Cum  
☐ Inc

Info:

Multi-Tank Gas Reservoir

Excel Input Parameters

Column

Start R...

End Row

Years or Date

Inc Oil Volume (mmbbl)

Inc Gas Volume (mmscf)

Inc Water Volume (mmbbl)

Inc Gas Inj Volume (mmscf)

Inc Water Inj Volume (mmbbl)

Reservoir Pressure (psia)

Date	Years	Oil	Gas	Water	Gas Inj	Wat Inj	ResPress
0	0	0	0	0	0	0	4000
0.249315	0.2493151	0	311.053	0	0	0	3723.56
0.49863	0.4986301	0	587.78	0	0	0	3497.2
0.747945	0.7479452	0	835.945	0	0	0	3309.06
0.99726	0.9972603	0	1050.12	0	0	0	3150.54
1.246575	1.246575	0	1263.95	0	0	0	3015.32
1.49589	1.49589	0	1454.15	0	0	0	2983.97
1.745205	1.745205	0	1641.83	0	0	0	2966.53
1.994521	1.994521	0	1826.78	0	0	0	2944.08
2.243836	2.243836	0	2008.56	0	0	0	2921.14
2.493151	2.493151	0	2186.86	0	0	0	2895.71
2.742466	2.742466	0	2361.5	0	0	0	2869.38
2.991781	2.991781	0	2532.36	0	0	0	2842.63
3.241096	3.241096	0	2699.41	0	0	0	2815.82
3.490411	3.490411	0	2862.66	0	0	0	2789.23
3.739726	3.739726	0	3022.13	0	0	0	2763.03
3.989041	3.989041	0	3177.89	0	0	0	2737.34
4.238356	4.238356	0	3330.01	0	0	0	2712.26
4.487671	4.487671	0	3478.57	0	0	0	2687.83
4.736986	4.736986	0	3623.66	0	0	0	2664.09
4.986301	4.986301	0	3765.38	0	0	0	2641.05

Open Excel File

Import Data

Continue

Cancel

Figure MBA-19: Volumetric Analysis Example – Gas Input Data

The PVT data is shown in Figure MBA-20.

**PVT/Reservoir Properties**

Oil API	55	Reservoir Pressure (psi)	4000
Separator Gas Gravity	.7224	Reservoir Temp (°F)	197
Separator Pressure (psi)		Porosity (dec)	0.2
Separator Temperature (°F)		Water Saturation (dec)	0.2
H <sub>2</sub> S - mol%	0	Corrected Gas G	0.7163
N <sub>2</sub> - mol%	.544	Gas P <sub>c</sub> (psi)	669.9
CO <sub>2</sub> - mol%	.587	Gas T <sub>c</sub> (°R)	394.4
Dew Point Pressure (psi)	4000	CGR <sub>i</sub> (bbls/scf)	0
Water Salinity (ppm NaCl)	35000	B <sub>gi</sub> (ft <sup>3</sup> /scf)	0.0042
		B <sub>wi</sub> (rbbl/stbbl)	1.0316

Import PE Tools dB PVT Properties      Continue

Figure MBA-20: Volumetric Analysis Example – PVT Data

A depletion drive analysis indicated 6.1 Bscf gas initially in place (Figure MBA-21) and Figure MBA-22 confirms that the multi-tank gas material balance model is valid for this reservoir. Note the multi-tank gas material balance model indicated 3 Bscf in tank 1 and 50 Bscf in tank 2.

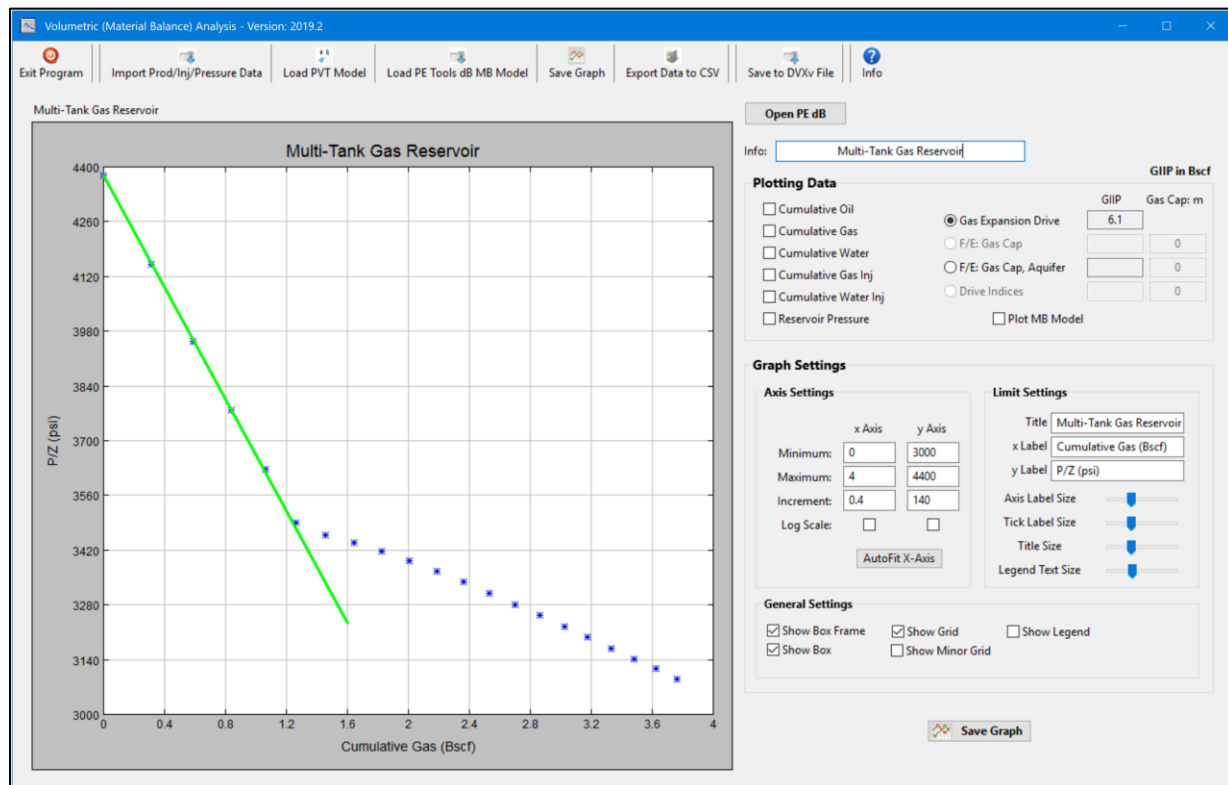
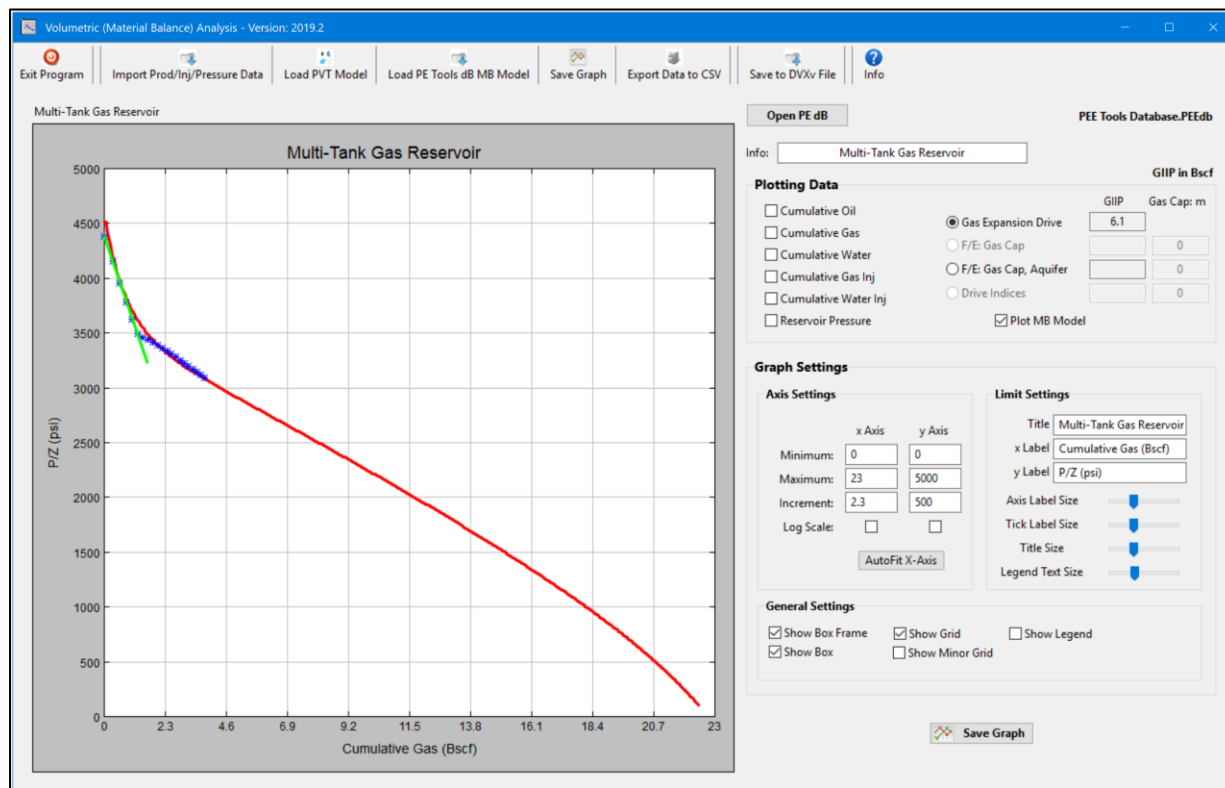


Figure MBA-21: Volumetric Analysis Example – Depletion (P/Z) Analysis



Figure MBA-22: Volumetric Analysis Example – Depletion ( $P/Z$ ) Analysis with Gas MB Model

## Hydrate Analysis Tool

Natural gas hydrates are crystals formed by water, natural gases and associated liquids, in a ratio of 85 mole% water to 15 mole% hydrocarbons. Hydrates can form anywhere and anytime that hydrocarbons and water are present at the appropriate temperature and pressure, such as in wells, flow lines, valves and meter discharges.

Low temperatures and high pressures will cause hydrate formation, but it is also a function of gas composition. In a pipeline, hydrates usually form at the hydrocarbon-water interface, and accumulate as flow pushes them downstream. In wells, hydrates can form at any point in which hydrate formation conditions are met.

Three conditions are required to form hydrates:

- Free water and natural gas. Gas molecules ranging in size from methane to butane are typical hydrate components, including CO<sub>2</sub>, N<sub>2</sub>, and H<sub>2</sub>S. The water in hydrates can come from free water produced from the reservoir, or from condensed water resulting from the cooling of the gas phase.
- Low temperatures are required for hydrate formation; but, even though hydrates are 85 mole% water, the temperature does not have to be below the freezing point of water for hydrates to occur. Hydrates can easily form at 38°-40°F or higher temperatures with high pressure.
- High pressures can cause hydrate formation. At 38°F, common natural gases form hydrates at pressures as low as 100 psi. At 1500 psi, common gases can form hydrates at temperatures as high as 66°F. Since pipelines typically operate at higher pressures, hydrate prevention can be a primary consideration.

There are a number of techniques that can be used to prevent hydrate formation:

- Water removal provides the best protection for pipelines. Free water is removed through separation, and water dissolved in the gas can be removed by drying with tri-ethylene glycol (TEG) to obtain water contents less than 7 lb<sub>m</sub>/MMscf. Water removal is not normally possible for a producing well, so other prevention schemes must be used.
- Maintaining high temperatures keeps the system in the hydrate-free region. High fluid temperature may be retained by adding heat by circulating hot fluids or electrical heating, although this may not be economical in most cases.
- The pressure may be decreased below hydrate formation pressure. This leads to the concept of adding system pressure drops at high temperature points (e.g. bottom-hole chokes during testing). However, this may not be feasible in production situations.
- Most frequently hydrate prevention means injecting an inhibitor such as methanol (MeOH) or mono-ethylene glycol (MEG), which decreases the hydrate formation temperature below the operating temperature.
- Kinetic inhibitors are low molecular weight polymers dissolved in a carrier solvent which are injected into the water phase in pipelines. These inhibitors work by bonding to the hydrate surface and preventing crystal formation and growth for a period longer than the free water residence time in the well/pipeline. Water is then removed at the facilities.

Depressurization is often the main tool for hydrate plug removal, but the preferred solution is to prevent the formation of hydrate plugs in the first place, through design and operating practices. The use of many gallons of inhibitors may be costly on a continuous basis but these expenses are easily overshadowed when considering the formation of a hydrate causing production to stop.

The PE<sup>2</sup> Essentials Hydrate Analysis tool enables the determination of the hydrate formation temperature using simple gas specific gravity techniques as well as the more accurate gas composition techniques. In addition, the tool includes the capability of estimating the inhibitor volumes required to protect the wells and pipelines. The tool can model a number of hydrate inhibitors, although the modeling of kinetic inhibitors is not included in this version of the tool.

An excellent reference is Carroll, J; Natural Gas Hydrates, A Guide for Engineers, Gulf Professional Publishing, 2020.

### HYD.1 Hydrate Prediction – Specific Gravity Methods

A total of six specific gravity (SG) based correlations are included in the Hydrate Analysis tool (Figure HYD-1).

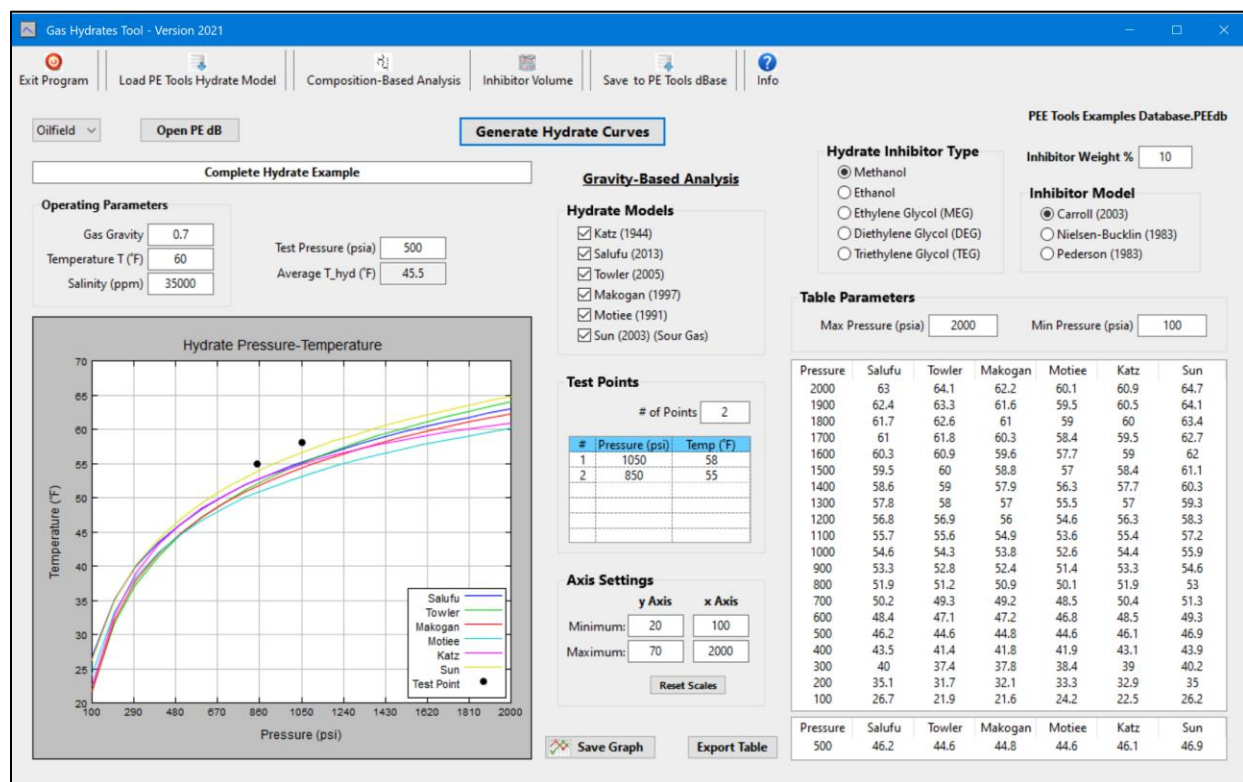


Figure HYD-1: PE<sup>2</sup> Essentials Hydrate Analysis Tool – Gravity Based Analysis

Although the SG method may not be highly accurate it has a high level of appeal because of its simplicity. There are numerous SG-based correlations published in various papers, books and journals. It was found that a number of these correlations have errors in their formulas. The most famous problem is with the Kobayashi et al correlation published by the SPE (ref: Kobayashi, R., Song, K.Y., Sloan, E.,D., Bradley, H.B. (Editor), Petroleum Engineers Handbook. SPE, Richardson, TX, 1987, 25-1, 25-28). Numerous authors, including myself, have attempted to correct the equation but were unsuccessful.

Because of the limitations in the SG models, several correlations have been included in the Hydrate tool to allow a range of values to be determined. Note, unless otherwise specified, the hydrate temperature is reported in °F and pressure is in psi.

### HYD.1.1 Katz (1944)

The Katz correlation is based on the charts published by Katz in 1944 (ref: Katz, D., L.: Prediction of Conditions for Hydrate Formation in Natural Gases, Petroleum Technology, TP 1748, July 1944 – also available as SPE 945140). The Katz correlation used in the Hydrate Analysis tool was derived from Figure HYD-2. This graph was presented in the Katz reference.

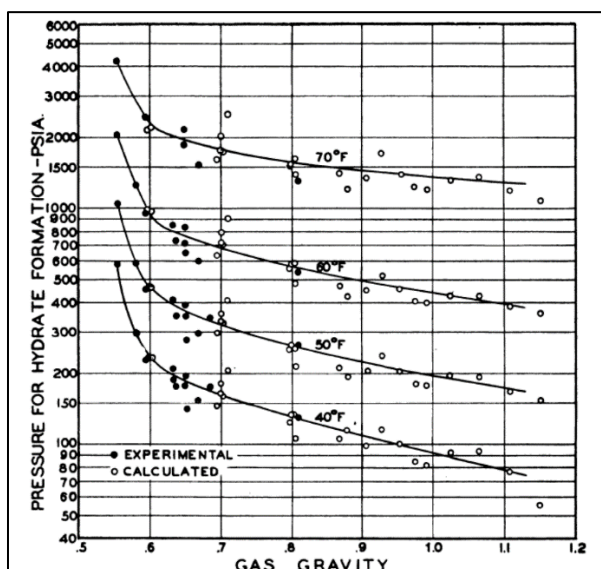


Figure HYD-2: Katz Gravity Based Correlation

Based on Figure HYD-2, the EPCI-Katz correlation equations are as follows:

$$\begin{aligned}
 \text{SG} = 0.554: & \quad T_{\text{hyd}} = -6.9347(\text{Log}(P))^4 + 87.285(\text{Log}(P))^3 - 413.58(\text{Log}(P))^2 + 909.9\text{Log}(P) - 753.98 \\
 \text{SG} = 0.6: & \quad T_{\text{hyd}} = 4.4739(\text{Log}(P))^4 - 54.971(\text{Log}(P))^3 + 242.63(\text{Log}(P))^2 - 426.21\text{Log}(P) + 277.59 \\
 \text{SG} = 0.7: & \quad T_{\text{hyd}} = 4.0118(\text{Log}(P))^4 - 46.745(\text{Log}(P))^3 + 193.95(\text{Log}(P))^2 - 310.47\text{Log}(P) + 187.71 \\
 \text{SG} = 0.8: & \quad T_{\text{hyd}} = 2.3306(\text{Log}(P))^4 - 26.969(\text{Log}(P))^3 + 108.21(\text{Log}(P))^2 - 150.09\text{Log}(P) + 82.013 \\
 \text{SG} = 0.9: & \quad T_{\text{hyd}} = 3.0565(\text{Log}(P))^4 - 32.660(\text{Log}(P))^3 + 122.60(\text{Log}(P))^2 - 163.09\text{Log}(P) + 87.230 \\
 \text{SG} = 1.0: & \quad T_{\text{hyd}} = 3.6822(\text{Log}(P))^4 - 37.602(\text{Log}(P))^3 + 135.65(\text{Log}(P))^2 - 177.03\text{Log}(P) + 94.973
 \end{aligned}$$

Figure HYD-3 presents the plots of the EPCI-Katz equations. The hydrate temperature is calculated by interpolating between the appropriate SG curves.

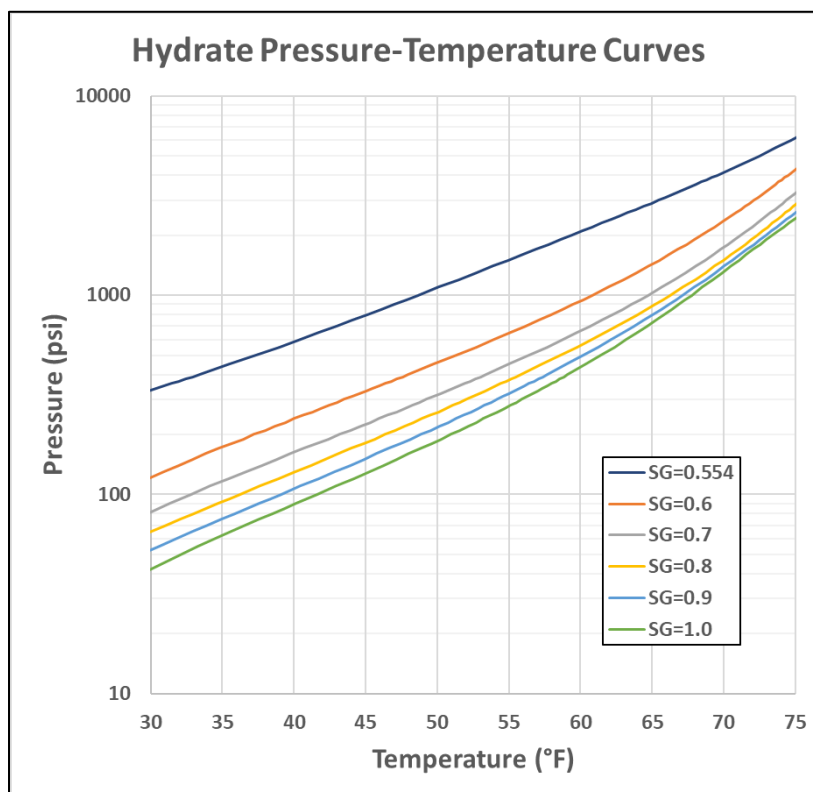


Figure HYD-3: Katz Gravity Based Pressure-Temperature Curves

### HYD.1.2 Salufu (2013)

Salufu et al observed that the water vapor pressure had an effect on the pressure of the gas molecule when hydrate was forming (ref: Salufu, S.O., and Nwakwo, P.; New Empirical Correlation for Predicting Hydrate Formation Conditions, SPE 167571, 2013).

Salufu presented a correlation for hydrate temperature,  $T_{hyd}$ , that included the effect of vapour pressure,  $P_{vw}$ , as follows:

$$\begin{aligned} SG < 0.6: \quad T_{hyd} &= 16.2602 (\ln(P e^{(P_{vw})}) - \ln(105.358 SG)) \\ 0.6 \leq SG \leq 0.84: \quad T_{hyd} &= 12.1212 (\ln(P e^{(P_{vw})}) - \ln(8.7511 SG)) \\ SG > 0.84: \quad T_{hyd} &= 10.9529 (\ln(P e^{(P_{vw})}) - \ln(2.4196 SG)) \end{aligned}$$

The water vapour pressure is calculated using Buck's equation (ref: Buck, A.L.; New Equation for Computing Vapor Pressure and Enhancement Factor, American Meteorological Society, 1982).

$$P_{vw} = 0.088648 e^{((18.678 - T_c/234.5) (T_c/(257.14 + T_c)))}$$

Where:  $P_{vw}$  is the water vapor pressure, psi, and  $T_c$  is the temperature, °C.

### HYD.1.3 Towler (2005)

In 2005, Towler and Mokhatab presented a correlation to generate  $T_{\text{hyd}}$  (ref: Towler, B. F. and S. Mokhatab, "Quickly estimate hydrate formation conditions in natural gases," Hydrocarbon Processing, Vol. 84, 2005). This correlation is as follows.

$$T_{\text{hyd}} = 13.47 \ln(P) + 34.27 \ln(SG) - 1.675 \ln(SG) \ln(P) - 20.35$$

The accuracy of the Towler correlation in predicting hydrate formation temperature reduces with increasing methane content in a binary methane-ethane system.

### HYD.1.4 Makogan (1997)

In 1997, Makogan published a simple correlation for the hydrate formation pressure as a function of temperature and gas gravity for paraffin hydrocarbons (ref: Makogan, Y.F., Hydrates of Hydrocarbons. PennWell, Tulsa, OK. 1997).

Makogan's correlation generates pressure in atm for a given temperature in °C. The correlation has been solved for hydrate temperature for use in the Hydrate tool as follows:

$$T_{\text{hyd}}(^{\circ}\text{C}) = (-0.0497 + [0.00247 - 0.1988 k (b - \log(P_{\text{atm}}))]^{0.5}) / 0.0994k$$

$$b = 2.681 - 3.811SG + 1.679SG^2$$

$$k = -0.006 + 0.011SG + 0.011SG^2$$

### HYD.1.5 Motiee (1991)

In 1991, Motiee published a correlation to calculate the hydrate temperature as a function of the pressure and the gas gravity (ref: Motiee, M., Estimate Possibility of Hydrate. Hydro. Proc. 70 (7), 98-99, July 1991).

$$T_{\text{hyd}} = -124.951 + 48.98387 \log(P) - 2.66303(\log(P))^2 + 176.9101 SG - 75.5873 SG^2 - 10.4505 SG \log(P)$$

### HYD.1.6 Sun (2013)

The specific gravity method presented above are not generally valid for sour gases and there are very few correlations that have been published specifically for sour gases. In 2013, Sun et al published a correlation based on 60 sour gas samples for the ternary mixture of  $\text{CH}_4$ ,  $\text{CO}_2$ , and  $\text{H}_2\text{S}$  (ref: Sun, C.,Y., Chen, G.,J., Lin, W., Guo, T.,M., Hydrate Formation Conditions of Sour Natural Gases, J. Chem. Eng. Data 48, 600-603, 2013). The Sun correlation generates hydrate temperature in °K from input pressure in MPa.

$$T_{\text{hyd}}(^{\circ}\text{K}) = 1000 / (4.343295 + 0.0010734 P - 0.091984 \ln(P) - 1.071989 SG)$$

## HYD.2 Hydrate Prediction – Gas Composition Methods

The gas gravity methods have a high level of appeal because of their simplicity. Despite their relative simplicity, these methods can be surprisingly accurate. For sweet natural gas mixtures, the gas gravity method is reportedly accurate to within 20% or better for estimating hydrate pressures/temperatures.

Whenever there is an increasing amount of heavier components present, the resultant hydrate characteristics change. This change can have a significant effect on the hydrate forming pressure. For example, pure methane forms a hydrate at 59°F and 1855 psi. The presence of only 1% propane results in a mixture that forms a hydrate at 59°F and 1115 psi.

If the gas composition is available, then the more accurate technique to calculate the hydrate temperature/pressure point is by the use of K-factor charts which represent vapor-solid equilibrium conditions for the hydrate forming components.

The PE<sup>2</sup> Essentials Hydrate Analysis tool (Figure HYD-4) includes two composition-based techniques for generating hydrate temperature/pressure: one based on the original Katz K-Charts presented in the GPSA Engineering Data Book, as published by Berge in 1986; and the second presented by Mann in her 1988 thesis and published by Poettmann et al in 1989.

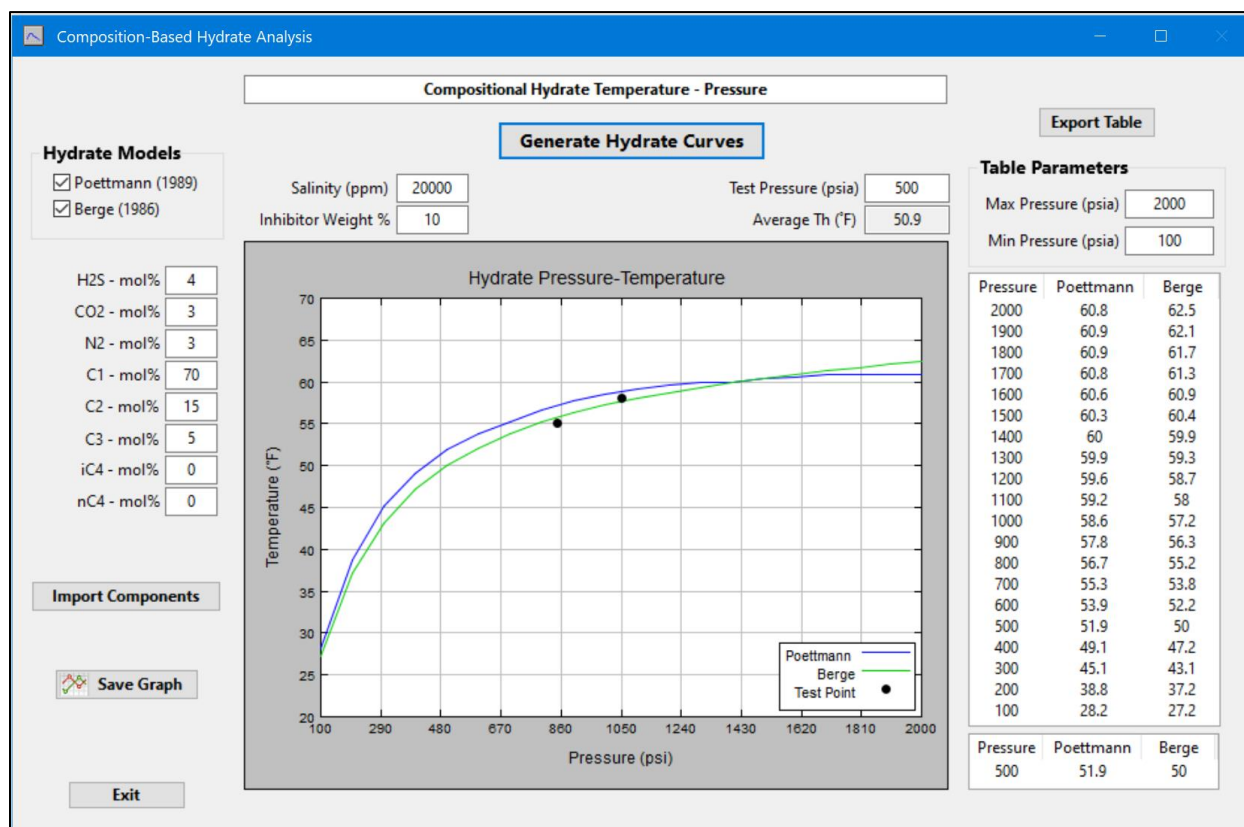


Figure HYD-4: PE<sup>2</sup> Essentials Hydrate Analysis Tool – Composition Based Analysis



## HYD.2.1 Berge (1986)

In 1986 Berge published a paper describing the use of a computer to calculate the Katz K-Factor parameters (ref: Berge, B., K., Hydrate Predictions on a Microcomputer, SPE 15306, 1986). The calculations are rather simple to implement but requires an iterative technique to generate a result.

For this version of the Hydrate Analysis tool, the Towler SG-based correlation is used to generate an initial estimate of the hydrate temperature,  $T_g$ , for a given pressure in psi. With the pressure and estimated hydrate temperature, the K-Factors are calculated for each component from the following equations.

$$K_{C1} = 1.0 - (0.014 + 15.38/P) (54.81 - 21.37 \ln(P) + 2.95(\ln(P))^2) + (0.14 + 15.38/P) T_g$$

If the calculated  $K_{C1}$  is greater than 1, then the following equation for  $K_{C1}$  should be used:

$$K_{C1} = 1.01 + 9.31/T_g - 1614.16/T_g^2 + (625.57 - 3.31T_g + 0.023T_g^2)/P + (-3.79e4 + 2.09e6/T_g - 9.82e7/T_g^2 + 1.54e9/T_g^3)/P^2$$

$$K_{C2} = e^{(-29.91 + 2779.25/P - 60251.4/P^2)} T_g^{(6.94 - 471.93/P)}$$

$$K_{C3} = -0.094 + 21.76/P - 4039.38/P^2 + 2.44e5/P^3 + (-3.5 + 2191.45/(P + 1021.19)) / (T_g + (-80.57 + 9076.44/(P + 166.9)))$$

If  $P \leq 600$  psi then use the following equation for  $K_{iC4}$ :

$$K_{iC4} = (-2.22e-6 + 6.99e-3/P + 0.74/P^2) e^{(T_g (0.14 + 1.88/P))}$$

If  $P \geq 800$  psi then use the following equation for  $K_{iC4}$ :

$$K_{iC4} = 6.66e-6 e^{(4.72e-4 P)} e^{(T_g (0.16 - 1.24e-5 P))}$$

Otherwise use the following equation for  $K_{iC4}$ :

$$K_{iC4} = 1.15e-5 e^{(0.146T_g)} + (P - 600)/200 (9.72e-6 e^{(0.145T_g)} - 1.15e-5 e^{(0.146T_g)})$$

If  $P \leq 600$  psi then use the following equation for  $K_{nC4}$ :

$$K_{nC4} = 0.25 - 1.7e-3 P + (-6.85e-4 + 3.34e-5 P) T_g$$

If  $P \geq 700$  psi then use the following equation for  $K_{nC4}$ :

$$K_{nC4} = 1.67 - 0.092T_g + 1.25e-3 T_g^2$$

Otherwise use the following equation for  $K_{nC4}$ :

$$K_{nC4} = -0.768 + 1.93e-2 T_g + (2.44 - 0.11T_g + 1.25e-3 T_g^2) (P - 600)/100$$

The value for  $K_{N2}$  presented by Berge was changed to a correlation presented in the Mann thesis which was dependant on whether or not  $H_2S$  was present in the gas.

For sweet gas ( $H_2S=0$ ), the following set of equations is used.



If  $T_g \leq 32$  °F then the following equation is used for  $K_{N_2}$ :

$$K_{N_2} = e^{(35.49 - 964/(T_g+460) - 0.001396P + 5.603 \ln(P) - 87.46/P - 0.06486(T_g+460) - 2972.6 \ln(P)/(T_g+460))}$$

Otherwise the following equation is used for  $K_{N_2}$ :

$$K_{N_2} = e^{(174.82 - 44553/(T_g+460) - 1.43e-6 P - 0.5996 \ln(P) + 20.9/P - 7798/P^2 - 0.15963(T_g+460))}$$

If  $T_g > 32$  °F then the following equation is used for  $K_{N_2}$ :

$$K_{N_2} = e^{(8.83643 - 2551.94/(T_g+460) - 0.00725046P)}$$

Otherwise the following equation is used for  $K_{N_2}$ :

$$K_{N_2} = e^{(74.02 - 45325/(T_g+460) + 5.56e-5 P - 0.32788(\ln(P))^2 + 815.4/P - 29564/P^2 + 1185861 \ln(P)/(T_g+460)^2)}$$

$$K_{CO_2} = -0.025 + 194.99/P - 1.085e5/P^2 + (-4.29 + 269.82/P - 2.38e6/P^2)/(T_g + (-57.03 - 4.99e-3 P))$$

$$K_{H_2S} = e^{(11.28 - 4.34 \ln(P)) T_g^{(-2.15 + 0.914 \ln(P))}}$$

Following the calculation of the K-Factors, the sum of  $\Sigma Y_i/K_i$  is calculated. Where the  $Y_i$  is the mol fraction of the gas component and  $K_i$  is the corresponding K-Factor. If the sum is not equal to 1, a new estimate of hydrate temperature is made and the K-Factor calculations are performed again.

## HYD.2.2 Poettmann (1989) – Mann (1988)

In 1988, Susan Mann published a thesis describing a new set of K-Factors representing the vapor-solid equilibrium conditions for gas-hydrate mixtures. Her results were subsequently published by Poettmann et al in 1989 (ref1: Mann, S., L., Vapor-Solid Equilibrium Ratios for Structure II Natural Gas Hydrates, Colorado School of Mines, 1988. Ref2: Poettmann, F., H., Sloan Jr., E., D., Mann, S., L., McClure, L., M., Vapor-solid Equilibrium Ratios for Structure I and II Gas Hydrates, Proceedings 68th Annual GPA Convention, San Antonio, TX, 1989).

The general form of the Poettmann equation for K-Factor is as follows:

$$\ln(K) = A + B(SG) + C(T_g) + D/P + E/P^2 + F(0.001P)^2 + G/SG + H(0.001P)^3 + I(SG)(P) + J(\ln(P)) + L(P) + M/T_g$$

The following table lists a subset of the constants used in the Poettmann equation.

Component	A	B	C	D	E	F	G	H	I	J	L	M
C <sub>1</sub>	-3.8862	-2.6891	0.016296	1.098	555.2	-0.01637	-0.25993	0.00089	1.3690E-04	-0.33731	0	0
C <sub>2</sub>	-48.4314	0.4489	0.116384	155.33	-985.5	0.18459	-1.32568	-0.03029	-2.6145E-04	-1.48522	0	0
C <sub>3</sub>	-46.0752	0.4199	0.120725	-135.638	0	-0.30192	-1.4989	0.01152	3.7850E-05	-2.70863	0.0020863	0
n-C <sub>4</sub>	-48.23	0.0354	0.107702	351.28	-19,245	0.25439	-1.9692	-0.05415	3.0153E-04	-0.82554	0	0
i-C <sub>4</sub>	-54.626	0.1238	0.115242	338.11	-18,643	0.24466	-1.889	-0.05132	2.2811E-04	-0.87306	0	0
N <sub>2</sub>	9.5205	-2.2112	0	-11.86	1,765.3	-0.02781	0.08466	0.00759	-2.50E-04	-0.29777	0	-2,494.9

Table HYD-1: Example of Poettmann/Sloan Constants

For a complete list of the constants and equations, refer to the Mann thesis. The determination of hydrate temperature is iterative and follows the technique described in Section HYD.2.1.

### HYD.3 Hydrate Temperature Depression

The hydrate temperature will be naturally depressed by the presence of NaCl in the free water – water of condensation is fresh. The main technique used to depress the hydrate temperature is to add an inhibitor to the flow stream.

#### HYD.3.1 Salinity Temperature Depression – McCain (1990)

The SG-based routines include a calculation of the hydrate suppression capability of saline water. In 1959, Katz published a curve that presented the hydrate temperature depression caused by water containing sodium chloride. McCain published a correlation that was generated from the Katz curve (ref: McCain, W., D., The Properties of Petroleum Fluids, PennWell Books, 1990).

The correlation generates a salinity-based hydrate temperature reduction,  $\Delta T_s$ , in °F, for a given water salinity, in percent.

$$\begin{aligned}\Delta T_s &= c_1 \text{NACL}\% + c_2 \text{NACL}\%^2 + c_3 \text{NACL}\%^3 \\ c_1 &= 2.20919 - 10.5746 \text{ SG} + 12.1601 \text{ SG}^2 \\ c_2 &= -0.106056 + 0.722692 \text{ SG} - 0.85093 \text{ SG}^2 \\ c_3 &= 0.00347221 - 0.0165564 \text{ SG} + 0.019764 \text{ SG}^2\end{aligned}$$

#### HYD.3.2 Basic Inhibitor Temperature Depression

The SG-based and composition-based hydrate temperature routines include a calculation of the hydrate temperature suppression resulting from the addition of inhibitors. For a more rigorous calculation of the effects of inhibitors, refer to Section HYD.4, describing the module to calculate inhibitor volumes.

To estimate the effect of the inhibitor, the inhibitor is specified using the ‘Hydrate Inhibitor Type’ table. This version of the Hydrate Analysis tool is limited non-ionic inhibitors, namely: methanol, ethanol, monoethylene glycol (MEG), diethylene glycol (DEG) and triethylene glycol (TEG).

The relevant properties of these inhibitors are presented in Table HYD-2.

Chemical	Methanol	Ethanol	MEG	DEG	TEG	Water
Chemical Formula	CH <sub>4</sub> O	C <sub>2</sub> H <sub>6</sub> O	C <sub>2</sub> H <sub>6</sub> O <sub>2</sub>	C <sub>4</sub> H <sub>10</sub> O <sub>3</sub>	C <sub>6</sub> H <sub>14</sub> O <sub>4</sub>	H <sub>2</sub> O
Molar Mass	32.04	46.069	62.068	106.12	150.174	18.015
Density, g/cm <sup>3</sup>	0.792	0.7893	1.1132	1.118	1.1255	1
Density, lb <sub>m</sub> /gal	6.503	6.587	9.29	9.33	9.393	8.345
Constant, K <sub>H</sub>	1297	1297	1500	2222	3000	-
Constant, C <sub>M</sub>	0.21	0.21	-1.25	-8	-15	-

Table HYD-2: Inhibitor Properties

The constants listed in the table are used in the appropriate inhibitor model.

The temperature suppression of an inhibitor is a function of its mol% concentration in the water phase. The performance of the inhibitors is presented in Figure HYD-5.

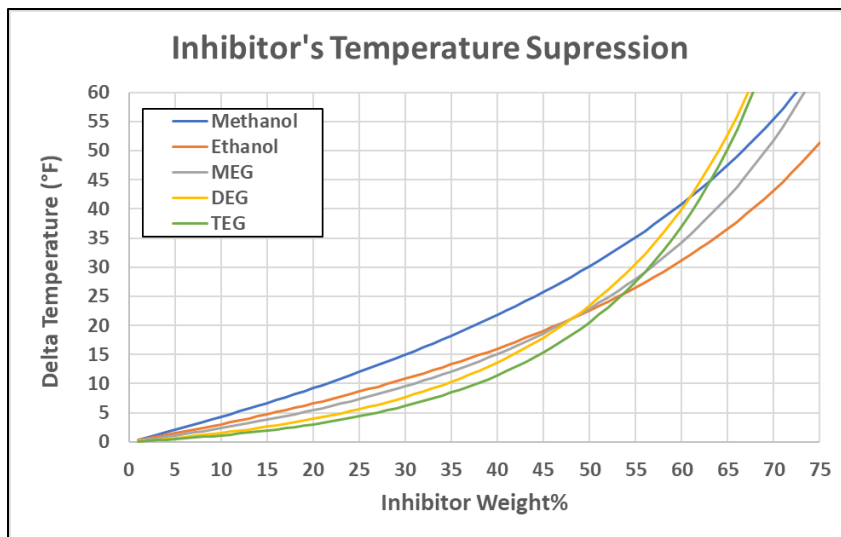


Figure HYD-5: Inhibitor Hydrate Temperature Suppression (after Carroll)

There are three inhibitor models available in the Hydrate Analysis tool for determining the hydrate temperature suppression.

### HYD.3.2.1 Hammerschmidt (1934), mod: Pedersen (1989)

In 1934 Hammerschmidt published a model to predict inhibitor performance (ref: Hammerschmidt, E.,G. "Formation of Gas Hydrates in Natural Gas Transmission Lines", Industrial and Engineering Chemistry, 1934). The Hammerschmidt constant,  $K_H$ , presented with the original equation was modified by Pederson and are those presented in Table HYD-2 (ref: Pedersen, K.,S., Fredenslund, A., Thomassen, P., Properties of Oils and Natural Gases. Gulf Publishing, Houston, TX, 1989).

The Hammerschmidt equation is widely used and is presented below.

$$\Delta T_i = K_H \text{ wt\%} / \text{MW} (100 - \text{wt\%})$$

Where  $\Delta T_i$  is the resulting hydrate temperature depression, in °F,  $K_H$  is the Hammerschmidt constant listed in Table HYD-2, MW is the molecular weight of the inhibitor and wt% is the concentration of inhibitor in weight%.

### HYD.3.2.2 Nielsen-Bucklin (1983)

In 1983, Nielsen and Bucklin developed an alternative model for methanol inhibitors that was based on first principles (ref: Nielsen, R.,B. and Bucklin, R., W., "Why not use methanol for hydrate control?", Hydrocarbon Processing, Vol. 62, No.4, 71-78, April 1983).

Nielsen and Bucklin presented a theoretical basis for the development of the Hammerschmidt equation for low methanol concentrations. They derived the Hammerschmidt equation using the freezing point depression of an ideal solution and truncating the higher order terms. They suggested that the Hammerschmidt equation was only valid at methanol concentrations up to 0.20 mass fraction. For higher methanol concentrations, Nielsen and Bucklin developed the following equation for  $\Delta T_i$ , in °F, based on the mole fraction,  $x_i$ , of inhibitor.

$$\Delta T_i = -129.6 \ln(1 - x_i/100)$$

$$x_i = [\text{wt\%/MW}_i] / [\text{wt\%/MW}_i + (100 - \text{wt\%})/\text{MW}_w]$$

Where wt% is the weight percent of inhibitor,  $\text{MW}_i$  is the molecular weight of the inhibitor (Table HYD-2) and  $\text{MW}_w$  is the molecular weight of water (18.01523).

Nielsen and Bucklin claimed their equation was valid to 90 wt% methanol.

From 1983 to 1987 the Gas Processors Association sponsored research to measure hydrate points and corresponding effects of inhibitors such as methanol and glycol. The result of this study was that the Gas Processors and Suppliers Association (GPSA) Engineering Data Book recommends the Hammerschmidt equation is valid up to 25 wt% methanol concentrations. The Nielsen-Bucklin equation was recommended for methanol concentrations ranging from 25-50 wt%.

### HYD.3.2.3 Carroll (2003)

The Hammerschmidt and Nielsen-Buckner models were developed to model methanol as the inhibitor. In 2003, Carroll published a modification to the Nielsen-Buckner model that extended the validity of the equation to all the commonly used inhibitors (ref: Carroll, J., Natural Gas Hydrates A Guide for Engineers, Gulf Professional Publishing, 2003).

The basis for the Carroll model was the same as that for the Nielsen-Bucklin equation with the addition of an activity coefficient to account for the type and concentration of the inhibitor. The Carroll model yields a hydrate depression,  $\Delta T_i$  in °F, based on the mole fraction,  $x_i$ , of inhibitor as follows.

$$\Delta T_i = -129.6 [C_M x_i^2 + \ln(1 - x_i)]$$

The constant  $C_M$  (Table HYD-2) was called the Margules constant by Carroll.

## HYD.4 Hydrate Inhibitor Volume

The PE<sup>2</sup> Essentials Hydrate Analysis Tool includes an option for calculating the volume of inhibitor required to depress the hydrate temperature by a given amount (Figure HYD-6). This module includes the option to include a “Safety Factor” to be considered when calculating the volumes of inhibitor.

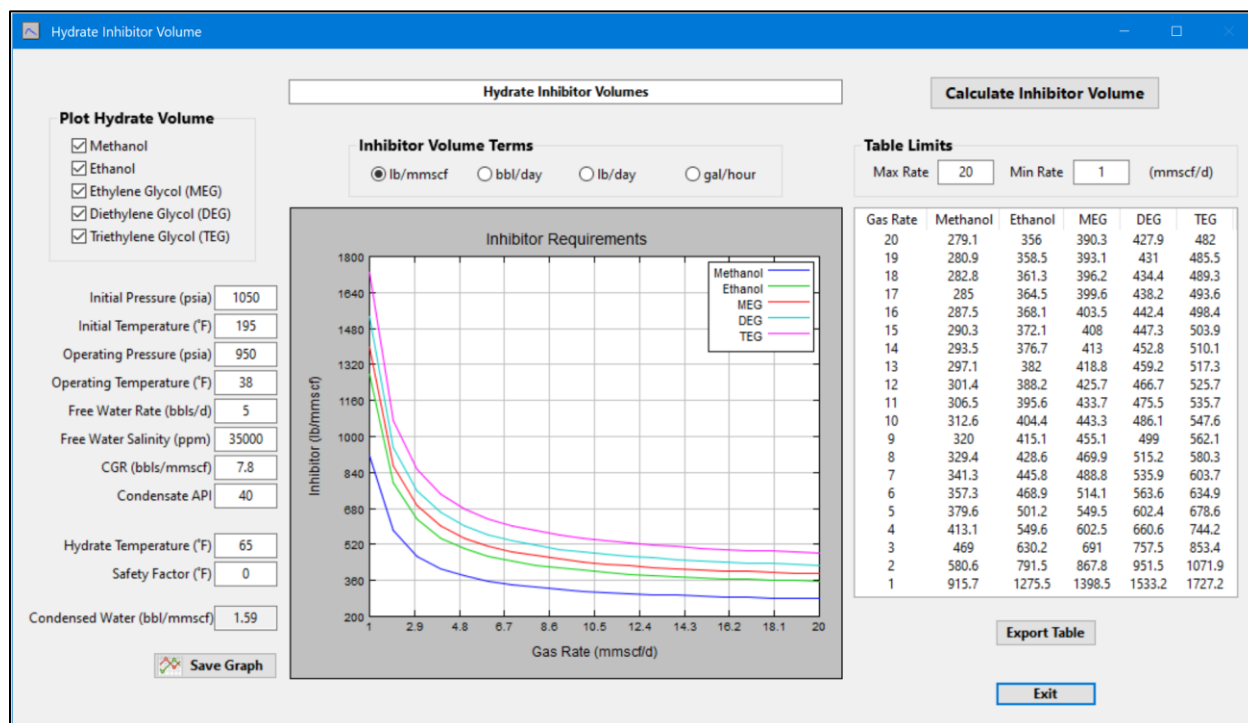


Figure HYD-6: PE<sup>2</sup> Essentials Hydrate Analysis Tool – Inhibitor Volume

The calculation of inhibitor volume is made up of the following: the amount of inhibitor required in the water phase; the temperature depression resulting from salinity of the free water; the inhibitor loss due to vaporization; and inhibitor absorption by the condensate.

The temperature depression caused by water salinity was presented in Section HYD.3.1.

### HYD.4.1 Inhibitor Required for Water Phase

There are two sources of water in the production stream: free water and water of condensation from the gas. The free water has salinity and has a partial protection for hydrate formation (Section HYD.3.1) but still needs to be inhibited. The water of condensation is fresh and, as a result, is prone to forming hydrates.

The water measured at surface is a combination of free plus condensed water. To determine the amount of condensed water that is generated from the gas, set the ‘Free Water Rate’ to zero and

run the tool. The 'Condensed Water' value can then be used to determine the actual free water rate to be entered for the final run.

Note that the free water rate is assumed to be constant but condensed water rate is a function of the gas rate. The tool is not a forecasting tool so using Water-Gas Ratio for free water rate is not warranted.

The calculation of condensed water is based on the correlations published by Moshfeghian (ref: Moshfeghian, M., Lean Sweet Natural Gas Water Content Correlation, Tips of the Month, PetroSkills, John M. Campbell & Co., September 2014).

Water Content of gas (Figure HYD-7), in bbls/mmscf, at a pressure, P in psi, and temperature, T in °F, is given by the following equation for the temperature range of 41°F to 149°F.

$$W_{\text{Content}} = 2.617 A/P + 0.1781 B$$

$$A = 3698.8338 e^{[-(0.007248 T - 2.8009)^2]}$$

$$B = 5.6269 e^{[-(0.006418 T - 2.4165)^2]}$$

Refer to the reference for the A and B equations for other temperature ranges.

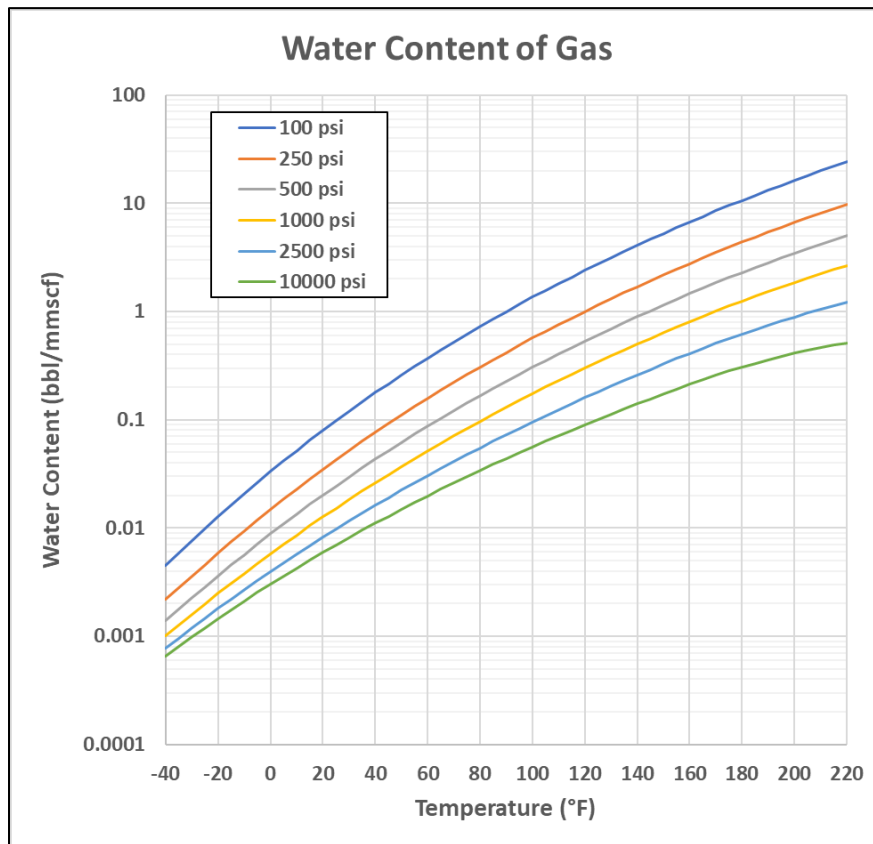


Figure HYD-7: Water Content of Gas

The water resulting from condensation (WCondensation) is the difference between the WContent of the gas at initial temperature/pressure and at operating temperature/pressure.

The free water is assumed to be constant and independent of the gas rate and is converted to lb<sub>m</sub>/mmscf as follows - assuming 1 mmscf.

$$\text{FreeWater [lb}_m\text{/mmscf]} = (\text{bbl/d}) (42 \text{ gal/bbl}) (8.345 \text{ lb}_m\text{/gal}) / 1\text{mmscf/d}$$

The minimum amount of inhibitor required to suppress the hydrate temperature is based on the total volume of water (WTotal = WCondensation + FreeWater) that is to be inhibited and the type of inhibitor.

The temperature suppression of an inhibitor is a function of its concentration in the water phase. The performance of the inhibitors, presented in Figure HYD-5, was re-plotted as Figure HYD-8.

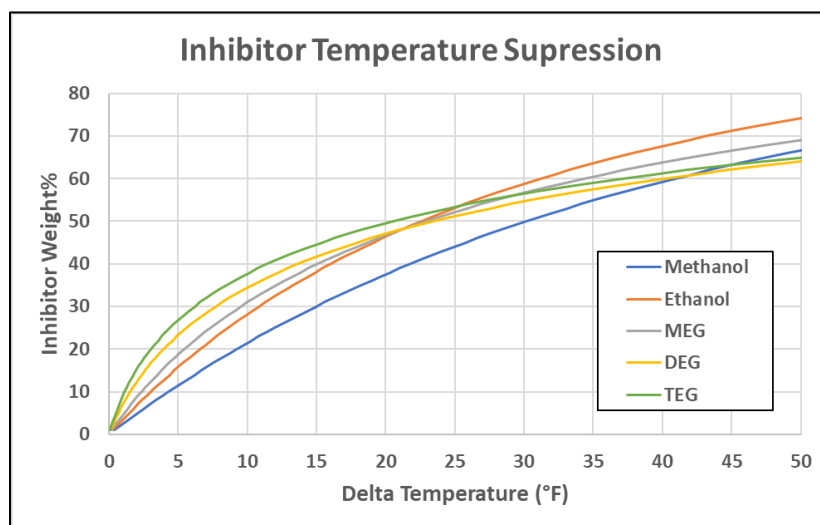


Figure HYD-8: Inhibitor Hydrate Temperature Suppression (after Carroll)

To simplify calculation of the minimum inhibitor required, in wt%, to suppress the temperature,  $\Delta T$  in °F, by a specified amount, the following EPCI-generated equations can be used.

Methanol:

$$\text{wt\%} = 2.637\text{e-}5 \Delta T^3 - 0.008898 \Delta T^2 + 1.3239 \Delta T + 0.2273$$

Ethanol:

$$\text{wt\%} = -4.4305\text{e-}7 \Delta T^4 + 1.507\text{e-}4 \Delta T^3 - 0.02193 \Delta T^2 + 1.8989 \Delta T + 0.218$$

MEG:

$$\text{wt\%} = 1.519\text{e-}08 \Delta T^5 - 5.181\text{e-}6 \Delta T^4 + 0.0007027 \Delta T^3 - 0.05068 \Delta T^2 + 2.414 \Delta T + 0.4411$$

DEG:

$$\text{wt\%} = -7.262\text{e-}10 \Delta T^6 + 2.736\text{e-}7 \Delta T^5 - 4.067\text{e-}5 \Delta T^4 + 0.003066 \Delta T^3 - 0.1282 \Delta T^2 + 3.389 \Delta T + 1.168$$

TEG:

$$\text{wt\%} = -1.3\text{e-}9 \Delta T^6 + 4.676\text{e-}7 \Delta T^5 - 6.652\text{e-}5 \Delta T^4 + 0.004671 \Delta T^3 - 0.1783 \Delta T^2 + 4.048 \Delta T + 1.933$$

After the wt% of inhibitor required to suppress the hydrate temperature is determined, the minimum volume of inhibitor required is calculated based on the total water in the system.

$$\text{InhibitWater [lb}_m\text{/mmscf]} = \text{wt\%} * \text{WTotal} / (100 - \text{wt\%})$$

It should be noted that the calculation of wt% includes any safety factor included in the input parameters. The value for InhibitWater is the minimum amount of inhibitor required to protect the system based solely on the water content.

## HYD.4.2 Inhibitor Lost to the Vapor Phase

Inhibitor lost to the vapor phase is a problem when using methanol as an inhibitor. Vapor loss for the other inhibitors (MEG, DEG, TEG) is orders of magnitude less than what occurs for methanol and is ignored in the Hydrate Analysis tool calculations. No information is available on Ethanol, but it is not commonly used for hydrate prevention.

The calculation of methanol vapor loss is based on the correlations published by Moshfeghian (ref: Moshfeghian, M., A Simple Model for Estimation of Methanol Loss to Vapor Phase, Tips of the Month, PetroSkills, John M. Campbell & Co., August 2011)

The calculation of loss to the vapor phase is based on K-values. The K-value is defined as the mole fraction of methanol in vapor phase,  $y_v$ , divided by the mole fraction of methanol in the aqueous liquid phase,  $x_a$ ,  $K\text{-value} = y_v/x_a$ . K-value is calculated from the following correlation.

$$K\text{-value} = 1/P^* e^{(5.37 (1 + \omega) (1 - 1/T^*))}$$

$$T^* = (T + 459.69) / 615$$

$$P^* = P / 35$$

$$\omega = 2.95 - 0.02607 P^* + 8.92828e-5 P^{*2} - 0.851257 / T^*$$

The estimated K-value is used to calculate the mole fraction of methanol in the vapor phase based on the mole fraction of methanol in the aqueous phase, which is calculated from the weight% of methanol in the aqueous phase. The vapor loss is calculated in lb<sub>m</sub>/mmscf as follows.

$$x_a = \text{wt\%/}32.04 / [\text{wt\%/}32.04 + (100 - \text{wt\%})/18.015]$$

$$y_v = x_a K\text{-value}$$

$$\text{VaporLoss [lb}_m\text{/mmscf]} = 84471.4 y_v$$

The constant 84471.4 is a conversion factor obtained as follows.

$$\text{lb}_m\text{/mmscf} = (y_v [\text{lb}_{\text{mole}} \text{ MeOH} / \text{lb}_{\text{mole}} \text{ of gas}]) (32.04 \text{ lb}_m\text{/lb}_{\text{mole}} \text{ MeOH}) (\text{lb}_{\text{mole}} / 379.3 \text{ scf gas}) (10^6 \text{ scf/mmscf gas})$$



Since the effect of gas composition is small, the K-value correlations are expressed in terms of pressure and temperature (Figure HYD-9).

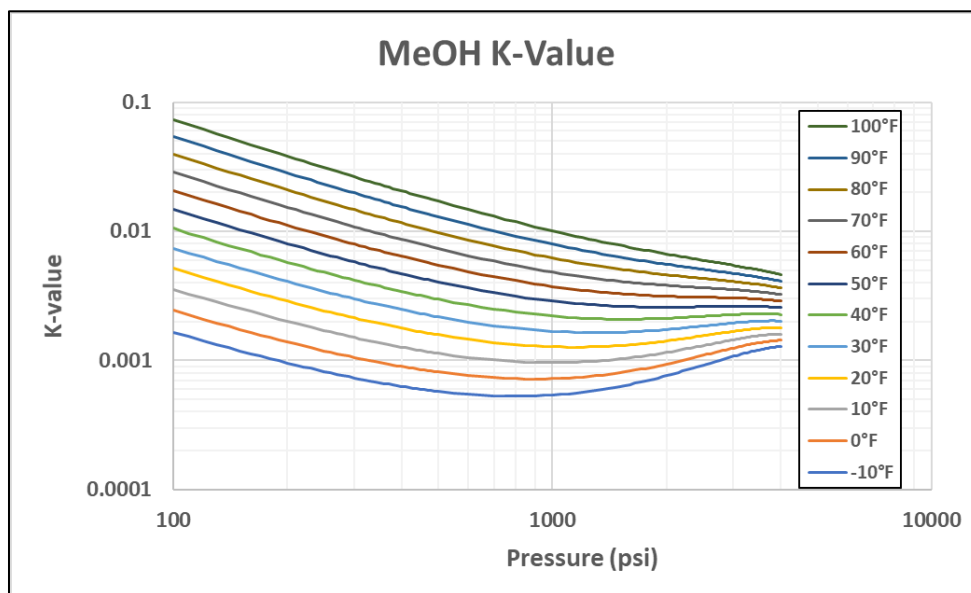


Figure HYD-9: Methanol K-Value for Vapor Phase

An example of the resulting value of  $\text{lb}_m/\text{mmscf}$  for methanol lost to the vapor phase for a system at 40°F is presented in Figure HYD-10.

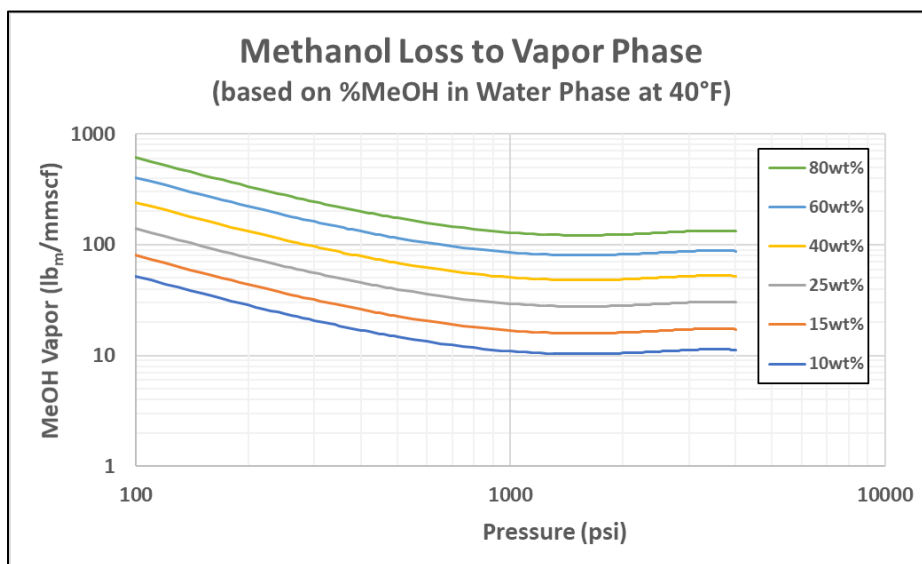


Figure HYD-10: Methanol Lost to Vapor Phase at 40°F

Note: This calculation is valid only for methanol. No loss is assumed for the other inhibitors.

### HYD.4.3 Inhibitor Lost to Condensate Phase

The calculation of the inhibitor lost to the condensate is based on data published by Ng et al (ref: Ng, H., J., Chen, C., J., Vapour-Liquid and Vapour-Liquid-Liquid Equilibria for H<sub>2</sub>S, CO<sub>2</sub>, Selected Light Hydrocarbons, and a Gas Condensate in Aqueous Methanol or Ethylene Glycol Solutions," GPA Research Report RR-149, Gas Processors Association, Tulsa, Gas Research Institute, Chicago, 1995). The published data was for methanol and MEG. Since no other published data is available for the other inhibitors, the MEG correlation is used for all other inhibitors in the Hydrate Analysis tool.

The calculation of inhibitor lost to the condensate phase is based on  $K_L$ -values. The  $K_L$ -value is defined as the mole fraction of methanol in the condensate,  $y_c$ , divided by the mole fraction of methanol in the aqueous liquid phase,  $x_a$ ,  $K_L = y_c/x_a$ .

The Ng data indicated that the  $K_L$ -value was only a function of temperature (Figure HYD-11). The correlation equations, in terms of temperature,  $T$  in °F, are as follows.

$$\text{MeOH: } K_L\text{-value} = e^{[5.9 - 5404.5 (1/(T + 459.69))]}$$

$$\text{MEG: } K_L\text{-value} = e^{[4.2 - 7266.4 (1/(T + 459.69))]}$$

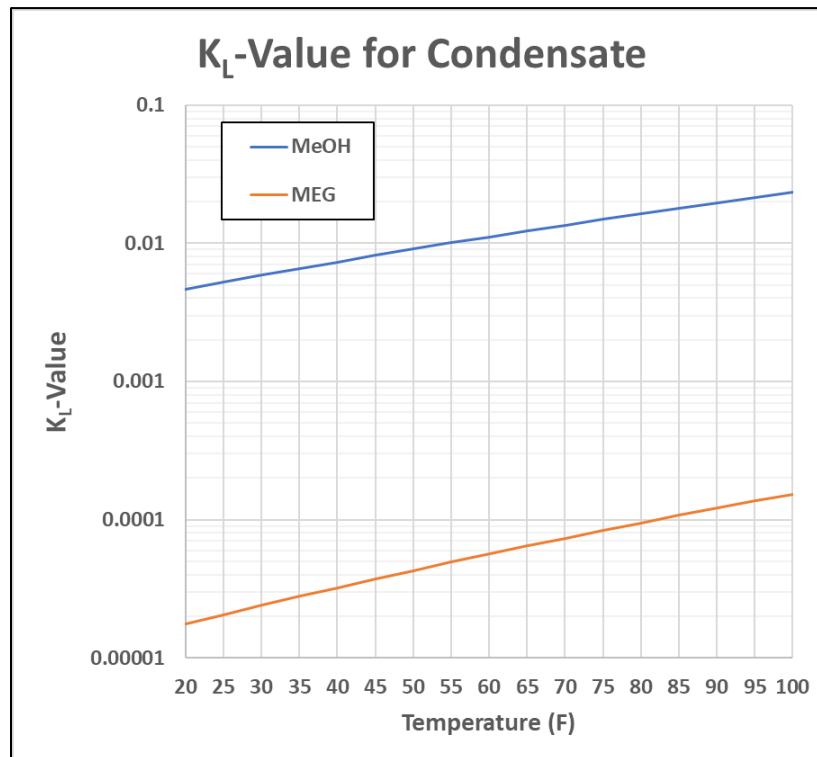


Figure HYD-11: Methanol and MEG  $K_L$ -Value for Condensate Phase

The estimated  $K_L$ -value is used to calculate the mole fraction of the inhibitor in the condensate,  $y_c$ , based on the mole fraction of inhibitor in the aqueous phase,  $x_a$ . The mole fraction in the

aqueous phase is calculated from the weight% of inhibitor in the aqueous phase, calculated in Section HYD.4.1.

$$\begin{aligned}
 x_a &= \text{wt\%/MW} / [\text{wt\%/MW} + (100 - \text{wt\%})/18.015] \\
 y_c &= x_a K_L\text{-value} \\
 \text{wt\%\_Inh} &= y_c \text{ MW} / (90 + y_c (\text{MW} - 90)) \\
 \text{CondLoss [lb}_m\text{/mmscf]} &= 349.86 \text{ SG}_{\text{cond}} \text{ CGR wt\%\_Inh}
 \end{aligned}$$

MW is the molecular weight of the inhibitor from Table HYD-2 wt%\_Inh is the weight percent of inhibitor in the condensate and the 349.86 is a conversion factor [(42gal/bbl) (8.33lb<sub>m</sub>/gal)].

#### HYD.4.4 Total Inhibitor Required

After calculation of the appropriate volumes, the total inhibitor required to protect the system to the given temperature is the sum of the volumes.

$$\text{Total Inhibitor [lb}_m\text{/mmscf]} = \text{InhibitWater} + \text{VaporLoss} + \text{CondLoss}$$

The volume of inhibitor is calculated using the density of the inhibitor.

$$\text{Inhibitor Volume [gal/mmscf]} = \text{Total Inhibitor [lb}_m\text{/mmscf]} / \text{Inhibitor Density [lb}_m\text{/gal]}$$

Daily inhibitor injection requirements are then determined based on the gas rate.

$$\text{Inhibitor Rate [gal/day]} = \text{Inhibitor Volume [gal/mmscf]} \text{ Gas Rate [mmscf/d]}$$

If a commercial inhibitor solution is being used which has an inhibitor concentration of less than 100%, the concentration of the solution needs to be considered when calculating the required injection rates.

#### HYD.4.5 Example

A subsea gas pipeline has wellhead conditions of 195°F and 1050 psia. The gas flowing through the pipeline has a specific gravity of 0.7 and is cooled by the surrounding water to a seabed temperature of 38°F. There is a pipeline pressure drop to 950 psia at the outlet. Gas exits the pipeline at a rate of 10 mmcsf/d. The gas produces condensate at a ratio of 7.8 bbl/mmcsf, with an average density of 40°API. The gas well produces 5 bwpd free water with a salinity of 35,000ppm. The hydrate temperature of the gas is 65°F.

Find the rate of inhibitor injection needed to prevent hydrate formation in the pipeline. For this example, the use of methanol will be worked out.

- From Section HYD.3.1:  $\Delta T_s = 2.5^\circ\text{F}$  for a salinity of 3.5%, therefore the required  $\Delta T$  for inhibitor protection is reduced from 27°F to 24.5°F

- From Section HYD.4.1, WContent of gas at 1050 psi and 195 °F is 1.6 bbl/mmscf and WContent of gas at 950 psi and 38 °F is 0.02 bbl/mmscf. Net water of condensation is 1.5 bbl/mmscf or 15.7 bwpd at 10 mmscf/d
- The free water rate is assumed to be a constant and assuming gas of 1 mmscf/d, then Total water = (1.5 bbl/mmscf + 5 bbl/10 mmscf) (42 gal/bbl) (8.345 lb<sub>m</sub>/gal). So WTotal = 701 lb<sub>m</sub>/mmscf
- The weight percent of methanol required to inhibit hydrates to a ΔT of 24.5 is wt% = 27.7%
- MeOH to inhibit water = wt% WTotal / (100 - wt%). So InhibitWater = 268.6 lb<sub>m</sub>/mmscf
- Methanol lost to vapor (Section HYD.4.2) is calculated at T = 38°F and P = 950 psi: T\* = 0.8092, P\* = 27.143, omega = 1.2562 and x<sub>a</sub> = 0.177. Results are K-value = 0.002117, y<sub>v</sub> = 0.0003752 and VaporLoss = 31.7 lb<sub>m</sub>/mmscf
- Methanol lost to condensate (Section HYD.4.3) is calculated where CGR = 7.8, SG<sub>cond</sub> = 0.8251, K<sub>L</sub>-value = 0.00702, x<sub>a</sub> = 0.177, y<sub>c</sub> = 0.001242 and wt%<sub>inh</sub> = 0.0004425. So CondLoss = 0.996 lb<sub>m</sub>/mmscf
- Total inhibitor required = InhibitWater + VaporLoss + CondLoss. So total MeOH required is 301.3 lb<sub>m</sub>/mmscf. For 10 mmscf/d, the 100% inhibitor injection would be 3013 lbm/day or 463 gal/day or 10.5 bbl/day or 19 gal/hr. If required, these values would have to be modified to take into account the weight percent of the commercial solution used.

## PE Forecast Essentials

The Forecast Essentials section contains the following:

- Hydraulically Fractured Unconventional Well Forecasting
- Basic Reservoir Simulator
- Stream Tube WaterFlood Simulator
- Miscible/Immiscible CO<sub>2</sub> WAG WaterFlood Simulator
- Gas Material Balance – Multi-Tank
- Oil Material Balance
- Decline Curve Analysis
- Monte Carlo Simulation: Decline Curve Production Forecast
- Retrograded Condensate
- Type Curve Generation

## Unconventional Forecast Simulator Tool

The PE<sup>2</sup> Essentials ‘Unconventional Forecast’ tool includes models that are used to generate forecasts for hydraulically fractured horizontal, unconventional oil and gas wells (Figure UNC-1).

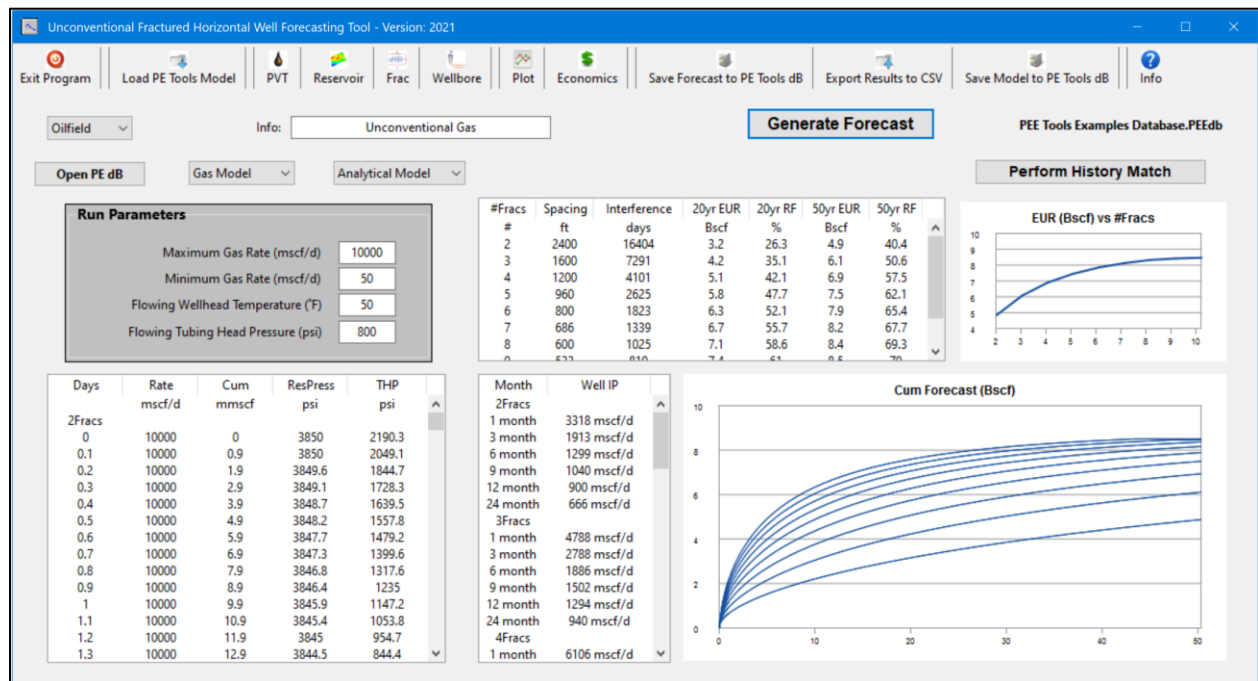


Figure UNC-1: PE<sup>2</sup> Essentials – Unconventional Forecast Tool

The unconventional forecasting tool incorporates the following:

- Analytical Model: an unconventional, hydraulically fractured well forecasting engine based on SPE144093 type curves.
- Numerical Model: a reservoir simulator based engine to generate forecasts for unconventional, hydraulically fractured wells. The simulator is based on the US DOE BOAST simulator (Ref: DOE/BC--89/3/SP, DOE/BC/14831-18 and NIPER-542).
- Both gas and depletion drive oil material balance models are included in the Analytical Model.
- A Sales Gas model to predict wellhead (sales gas and condensate) properties of the raw gas stream based on a surface flash.
- Gas well tubing pressure drop correlations: Average TZ for single phase gas, Guo-Ghalambor to model mist flow of gas/condensate/oil and water and Modified Hagedorn & Brown for high liquid yield gas wells (Note that annulus flow is not modeled in this version).
- Oil well tubing pressure drop correlation is limited to Modified Hagedorn & Brown.
- Frac water flow back modeling for gas wells can be incorporated when using the Analytical Model. This is an empirical pseudo model and includes an "acceleration" factor to either increase or decrease the rate of frac water recovery and ultimate volume of frac water recovered. This model will account for the additional tubing pressure drop caused by production of frac water.
- A History Match tool is included that can use either the Analytical or Numerical Model to history match an oil or gas well. This tool can be used to evaluate the net effectiveness of the frac program (as well as history match other reservoir parameters).
- The integrated Economics Tool can be used to optimize completion parameters and determine the economically optimum number (in terms of PIR) of fracs to place in the well.
- PE<sup>2</sup> Essentials - Unconventional Forecast can be run in either Oilfield or Metric units (the program will convert the units, so the numbers do not have to be re-entered, if a run in both units is required).

Tool output (Figure UNC-1) includes frac 'Spacing' in feet/meters and frac 'Interference' time in days. These parameters are calculated as follows.

$$\text{FracSpacing} = \text{Lateral Length} / \#\text{Fracs}$$

$$\text{FracInter in days} = 9.875 \phi \mu c \text{ FracSpacing}^2 / k$$

The FracInter equation above assumes that FracSpacing is entered in feet. For meters, the value of the constant, 9.875, becomes 106.3.

### UNC.1 Analytical Model

The Analytical Model forecast engine is based on the Productivity Index (PI) type curves published by LeBlanc et al (LeBlanc, D., Martel, T., Graves, D., Tudor, E. and Lestz, R., Application of Propane (LPG) Based Hydraulic Fracturing In The McCully Gas Field, New Brunswick, Canada, SPE 144093, June 2011). The type curves were also presented by LeBlanc et al in World Oil (LeBlanc, D., Huskins, L., Lestz, R., Application of Propane Based Hydraulic Fracturing in the McCully Gas Field, New Brunswick Canada, July 2011).

The dimensionless PI type curves incorporated into the Unconventional Forecast tool's Analytical Model are shown in Figure UNC-2.

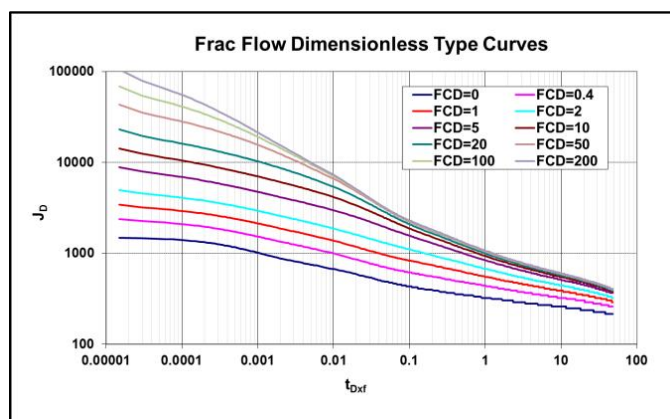
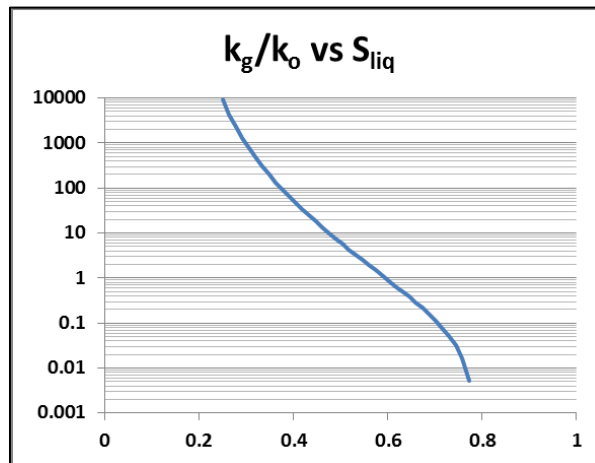


Figure UNC-2: Dimensionless PI Type Curves for Hydraulic Fractures

The Analytical Model includes a gas reservoir material balance (P/Z) model and an oil reservoir material balance model that assumes natural depletion of an oil reservoir with no aquifer or gas cap. The analytical reservoir material balance models are used to generate the reservoir pressure forecast for the reservoir as well as the GOR forecast for an oil reservoir.

For gas reservoirs, the material balance formulation is a straightforward P/Z versus cumulative production for a volumetric gas reservoir. For oil reservoirs, the material balance formulation is more complex. Only a solution gas drive is considered in the current version of the Unconventional Forecasting model.

For an oil reservoir, a  $k_{rg}/k_{ro}$  versus saturation model is required to determine the  $k_{ro}/k_{rg}$  development as saturations change. The empirical equations for 2-phase (oil/gas) relative permeabilities presented by Honarpour et al (Honarpour, M., M., Koederitz, L., F. and Harvey, A., H., "Empirical Equations for Estimating Two-Phase Relative Permeability in Consolidated Rock", Transactions AIME, 1982) are used to predict relative permeability variations in terms of saturation (Figure UNC-3).


 Figure UNC-3:  $k_{rg}/k_{ro}$  versus Saturation

These equations for  $k_{rg}/k_{ro}$  are as follows.

$$k_{rg}/k_{ro} = a / b \quad (\text{UNC-1})$$

$$a = 0.98372 (S_o / (1 - S_{wi}))^4 [(S_o - S_{org}) / (1 - S_{wi} - S_{org})]^2$$

$$b = 1.1072 K_{rgSorg} [(S_g - S_{gc}) / (1 - S_{wi})]^2 + 2.7794 K_{rgSorg} S_{org} (S_g - S_{gc}) / (1 - S_{wi})$$

Where:  $S_o$  is the current oil saturation,  $S_{org}$  is the residual oil saturation in an oil/gas system,  $S_{wi}$  is the initial water saturation,  $K_{rgSorg}$  is the gas relative permeability at  $S_{org}$ ,  $S_g$  is the current gas saturation and  $S_{gc}$  is the critical gas saturation.

Once the  $k_{rg}/k_{ro}$  value is determined for a given  $S_o$ , the value for  $k_{ro}$  can be calculated based on Corey's method (Corey, A., T., "The Interrelation Between Gas and Oil relative Permeabilities", Producers Monthly, 1954). This value is required for productivity calculations using the type curves. Corey's equation for  $k_{ro}$  in oil/gas systems as follows.

$$k_{ro} = [1 - S_g / (1 - S_{wi})]^4 \quad (\text{UNC-2})$$

Where:  $S_g$  is the current gas saturation and  $S_{wi}$  is the initial water saturation.

The material balance forecast for oil reservoir pressure and GOR performance is determined using Turner's Method as presented by Mian (Mian, M., A., Petroleum Engineering Handbook for the Practicing Engineer, PennWell Publishing, 1992).

The Turner technique involves an iterative procedure to predict GOR at a given pressure assuming a value for  $N_p$  and  $G_p$ . The requirements for the technique are solution Gas-Oil Ratio, RS, versus pressure correlation and  $k_{rg}/k_{ro}$  versus saturation models. RS is calculated using equations presented in the PVT tools information.

Starting with estimated pressure and GOR for a given  $N_p$  and  $G_p$ , the iterative equation is:



$$N_{pn} = a/b + c/d \quad (\text{UNC-3})$$

$$a = N[B_o - B_{oi} + B_g(RS_i - RS)] + G(B_g - B_{gi})$$

$$b = B_o - B_g RS + 0.5B_g(GOR_n - GOR_{n-1})$$

$$c = B_g[G_{pn-1} - 0.5N_{pn-1}(GOR_n + GOR_{n-1})]$$

$$d = B_o - B_g RS + 0.5B_g(GOR_n + GOR_{n-1})$$

Where:  $i$  is initial condition,  $n$  is the current step,  $n-1$  is the previous step,  $N$  is the OOIP,  $G$  is the GIIP,  $N_p$  is cumulative oil production,  $G_p$  is the cumulative gas production,  $GOR$  is producing gas-oil ratio and  $RS$  is solution GOR.

After calculating  $N_{pn}$ ,  $S_{on}$  is calculated as follows:

$$S_{on} = B_{ob}(N - N_{pn}) (1 - S_{wi} - S_{gc}) / NB_{oi} \quad (\text{UNC-4})$$

With the calculated  $S_{on}$ , the  $k_{rg}/k_{ro}$  value is obtained from the  $k_{rg}/k_{ro}$  model (Figure 5-3). The  $GOR$  for this step is then calculated as follows.

$$GOR_n = RS_n + (k_{rg}/k_{ro}) (\mu_o/\mu_g) (B_o/B_g) \quad (\text{UNC-5})$$

Where:  $\mu_o$ ,  $\mu_g$ ,  $B_o$  and  $B_g$  are evaluated at the current pressure.

If  $GOR_n$  and the estimated  $GOR$  are in agreement, the next step is performed; otherwise new estimates are made, and the process is repeated.

The material balance models generate the reservoir pressure, and  $GOR$  development, for the reservoir. The dimensionless PI type curves are then used to generate the well deliverability over time based on the estimated reservoir pressure,  $GOR$ , and relative permeability values ( $k_{ro}$ ) generated during the material balance calculations. The type curves include the early time, non-stabilized performance of a hydraulically fractured well as well as the transitional and stabilized periods. As a result, the full life of the well can be modeled.

These dimensionless type curves (Figure UNC.2) were generated through the use of a commercial reservoir simulator. Numerous forecasts were generated for a large number of reservoir parameters, fracture conductivity,  $k_{fw}$ , and fracture half length,  $x_f$ , values. The simulation results were converted to dimensionless parameters and used to generate type curves for the dimensionless productivity index,  $J_D$ , and dimensionless time,  $t_D$ , as a function of dimensionless fracture conductivity,  $FCD$  (Note this parameter is referred to  $C_{fD}$  in the Hydraulic Fracture Analysis tool).

Dimensionless productivity index,  $J_D$ , is used since it is not impacted by: the length of the transient period; whether or not the well is exhibiting radial flow; whether or not the well is hydraulically fractured; and whether the wellbore is vertical or horizontal. Using dimensionless productivity index, it is possible to use data from any well without additional normalization.

The dimensionless equations are as follows:

$$\text{Oil: } J_D = PI (141.2 B_o \mu_o / k_o h) \quad (\text{UNC-6})$$

$$\text{Gas (P}^2\text{): } J_D = PI (1424 \mu_g Z T / k_g h) \quad (\text{UNC-7})$$

$$t_D = 0.0036 k t / (\phi \mu c_t r_w^2) \quad (\text{UNC-8})$$

$$\text{FCD} = (k_f w_f) / (k x_f) \quad (\text{UNC-9})$$

Where: T is temperature in °R,  $\mu_o$  and  $\mu_g$  are viscosities in cp and t is time in days.

The calculation procedure is as follows: 1) For a given time, calculate  $t_D$ ; 2) The  $J_D$  for the corresponding FCD is obtained from the type curves; 3) From the cumulative production from the previous time step, the material balance data is used to obtain reservoir pressure and GOR; 4) With the parameters entered in the 'PVT', 'Reservoir', 'Frac' and 'Wellbore' models, the productivity index (PI) is calculated from  $J_D$ ; 5) The production rate and flowing pressure are calculated ('Generate Forecast').

During the forecast, once the 'Minimum Rate' is reached the well is shut in. This logic is based on assuming only natural flow from the well. Since most oil wells need to be pumped, the oil model generates a forecast based on a minimum BHP rather than THP. After the oil rate and flowing bottomhole pressures are generated, the corresponding THP is calculated.

The Analytical Model generates 50-year forecasts. The resulting forecast can be saved to the PE Tools database or to a comma-delimited file (csv) by clicking 'Export Results to CSV' for plotting using PE<sup>2</sup> Essentials Chart (Figure UNC-4) or imported into Excel for plotting.

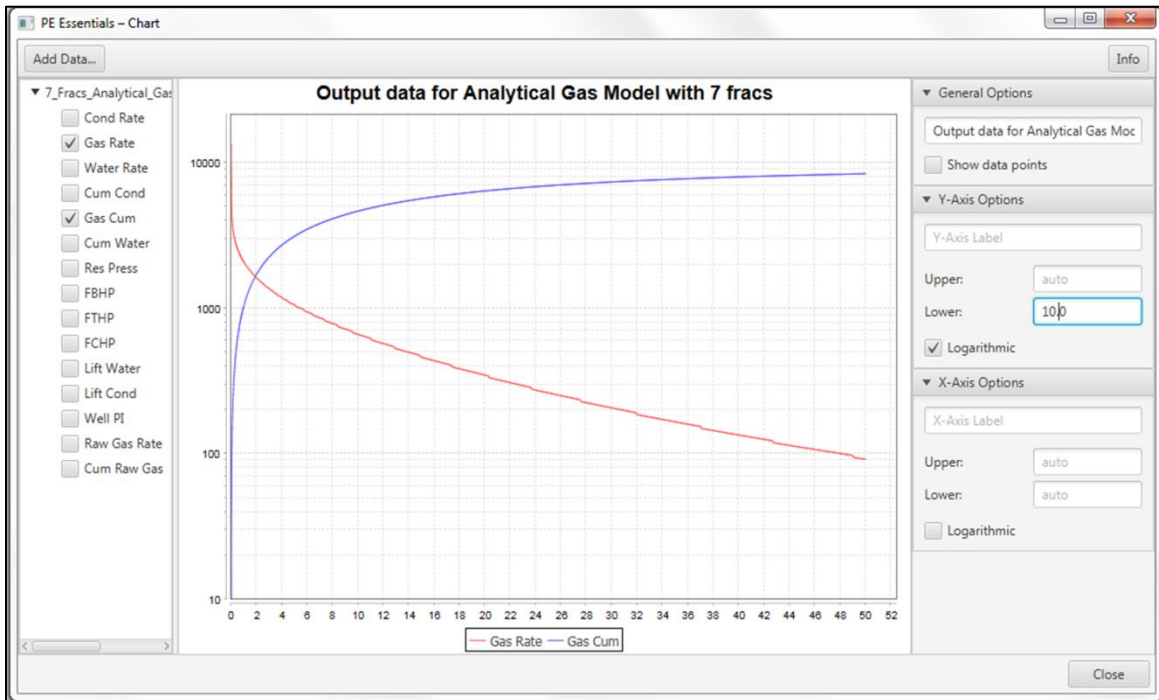


Figure UNC-4: Chart Plot of Analytical Model Forecast

## UNC.2 Numerical Model

The Numerical Model (Figure UNC-5) forecast engine is reservoir simulator based and is an implementation of the US DOE BOAST II reservoir simulator (Franchi, J., Kennedy, J., E., and Dauben, D., L., BOAST II: A Three-Dimensional, Three Phase Black Oil Applied Simulation Tool, US Department of Energy Report DOE/BC-88/2/SP, 1987). This is a public domain simulator and the fortran code can be obtained from the US DOE.

This implementation of the simulator is a stripped-down version of BOAST II specifically programmed to model a hydraulic fracture. For a description of a general-purpose version of this simulator, refer to the PE<sup>2</sup> Essentials Basic Reservoir Simulator tool.

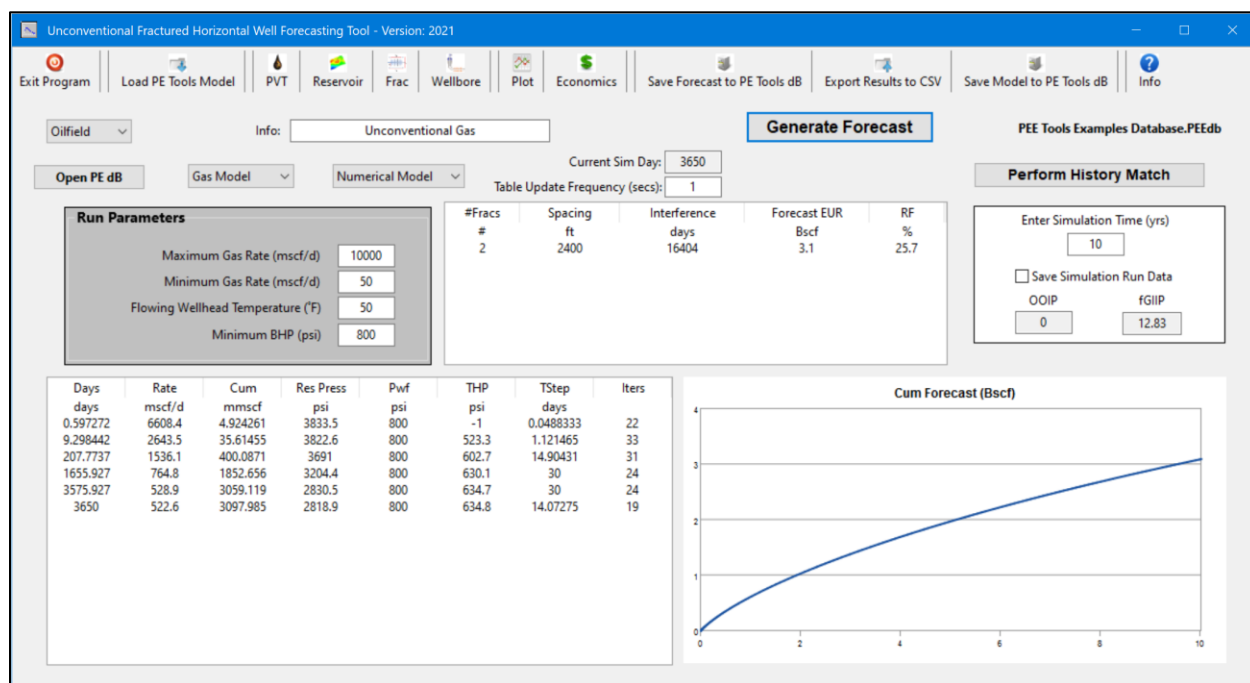


Figure UNC-5: Unconventional Forecast Model – Numerical Model

To run the numerical model, a single fracture simulation model is built internally using the parameters entered in the 'PVT', 'Reservoir', 'Frac' and 'Wellbore' models. The simulation time in years is entered and the simulator is executed ('Generate Forecast').

If 'Save Simulation Run Data' is checked, a file will be generated as the run progresses that includes time step and convergence data for every time step. This file can be examined to confirm progress of the run.

The simulation model includes a horizontal well in a 3D rectangular grid, with the horizontal well in the middle of the structure. The gridding is geometric and the top xy view of the model (showing the location of the hydraulic fracture) is shown in Figure UNC-6.

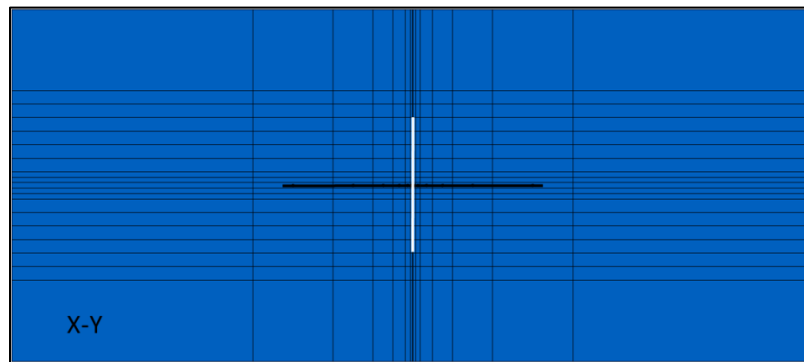


Figure UNC-6: Top View – Numerical Model Grid

The Figure UNC-6 grid represents one fracture stage. The total x-distance would be the drainage distance for this fracture stage. The total y-distance would be the drainage in the y-direction, in other words, the well spacing. X-distance multiplied by the y-distance would be the drainage area for the fracture stage.

In Figure UNC-6, the black line represents the completed well and the white line represents the fracture location and its total length is  $2x_f$ . The assumption is that the well is perforated at the fracture location but there is unstimulated reservoir communication behind casing for ~50% of the stage length.

Figure UNC.7 presents the xz cross-sectional view along the well location, showing the well completion in black, as well as the hydraulic fracture location in white. For the simulation model, the fracture is assumed to exist over 100% of the pay interval and the well is placed in the middle of the pay interval.

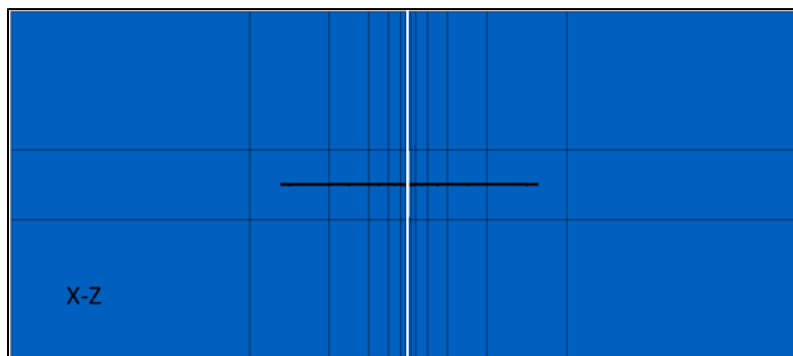


Figure UNC-7: Cross Section View – Numerical Model Grid

The simulation of a single-phase gas reservoir is relatively quick. Simulation of a multiphase oil reservoir is slower because this reservoir simulator is a basic IMPES simulator. When using the Numerical Model, the length of the forecast period has to be entered before the run will start. For gas reservoirs, 50-year forecasts are quick but for oil reservoirs, a 20-year forecast may be more practical.

In this version, the Numerical Model will only generate a forecast for one set of hydraulic fractures at a time - for example, a well with 5 fracs. To generate a forecast for different fracture scenarios, separate runs are required.

The forecast results can be saved to the PE Tools database or to a comma-delimited file (csv) by clicking 'Export Results to CSV' for plotting using PE<sup>2</sup> Essentials Chart (Figure UNC-4) or imported into Excel for plotting.

### UNC.3 PVT Model

The Gas PVT Model (Figure UNC-8) includes a flash analysis to generate gas properties to allow the forecasting of sales gas, condensate and water of vaporization from the raw gas. Refer to the PVT Tool for additional information on gas component analysis.

**Gas Properties Input**

Sales Streams		
	Gas	Liquid
H2S - mol%	0	
N2 - mol%	0.47	0
CO2 - mol%	1.81	0
C1 - mol%	85.18	0
C2 - mol%	5.44	0
C3 - mol%	3.1	19.82
iC4 - mol%	0.5	6.39
nC4 - mol%	1.22	15.6
iC5 - mol%	0.3	7.63
nC5 - mol%	0.41	10.43
C6 - mol%	0.27	6.87
C7Plus - mol%	1.3	33.25
Σ Comps	100	100

C7Plus MW: 200  
 C7Plus SG: 0.766

Gas MW: 21.94  
 Raw Gas G: 0.7574  
 Gas Pc (psi): 658.5  
 Gas Tc (°R): 388.7

Sales Gas G: 0.638  
 GHV (btu/scf): 1086  
 Shrinkage (%): 6.2  
 Propane-C3 (bbls/mmcf): 5  
 Butane-C4 (bbls/mmcf): 6.5  
 CGR-C5+ (bbls/mmcf): 37  
 Condensate Density (°API): 67.5  
 Water (bbls/mmcf): 0.276  
 Dew Point Pressure (psi): 4530.1

Import PE Tools dB Components  
 Generate Gas Components  
 Return

Figure UNC-8: Unconventional Forecast – Gas PVT Model

The PVT gas components can be entered manually or imported from a PE<sup>2</sup> Essentials PE Tools database. Clicking 'Import PE Tools db Components' will list the available component data stored in the PE Tools database (Figure UNC-9).

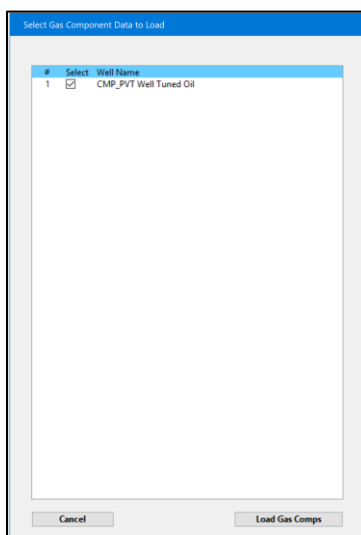


Figure UNC-9: Importing Gas Components from the PE Tools Database

The entered gas components should represent the recombined raw gas stream. This information is used to evaluate the liquid content of the raw gas, the shrinkage factor, the gas gravity and the gross heating value of the sales gas.

If gas compositions are not available, pseudo gas components can be generated from the gas gravity by clicking 'Generate Gas Compositions' (Figure UNC-10). Refer to PVT Tools for more information on generation of gas compositions.

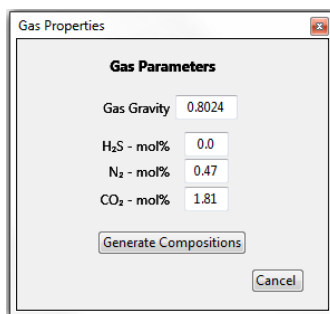


Figure UNC-10: Generating Gas Compositions for Gas PVT Model

To calculate the sales gas components, it is assumed that 25% of the propane, 50% of the butane and 99.5% of the pentanes+ are recovered from the raw gas stream.

The water content of the gas is used to in the Analytical Model to generate the net water produced at surface at wellhead pressure and temperature conditions. The forecast will be a function of the producing pressure and temperature entered on the main screen of the unconventional forecasting model (Figure UNC-1).

For the Gas Model, the forecast results represent sales gas volumes. To access the raw gas volumes, 'Export Results to CSV' after the run and import the resulting CSV file into a spreadsheet.

For the Oil PVT Model, separator pressure and temperature are entered as well as the oil properties to correct the gas gravity for separator conditions (Figure UNC-11).

Figure UNC-11: Unconventional Forecast - Oil PVT Model

The oil PVT parameters can be entered manually or imported from a PE<sup>2</sup> Essentials PE Tools database. Clicking 'Import PE Tools db PVT Properties' will open a sheet that will give the option of entering PVT data stored with a well or PVT data from a stored PVT model (Figure UNC-12).

Figure UNC-12: Importing Oil PVT Data from the PE Tools Database

Selecting the appropriate button will list the options available for the database. Click on the relevant well/tool and the PVT data will be imported into the tool. Note - To disable the gas gravity correction routine, enter 114.7psi / 790.8kPa and 60°F / 15.55°C for the separator conditions.

## UNC.4 Oil/Gas Reservoir Models

The inputs for the Reservoir Model are self-explanatory. Because of the large variation in valid parameters, the program does not test the input value to determine the validity of the reservoir parameters. It is up to the engineer to ensure that valid parameters are entered.

Figure UNC-13 presents the Gas Reservoir Model and Figure UNC-14 presents the Oil Reservoir Model.

Figure UNC-13: Unconventional Forecast - Gas Reservoir Model

Figure UNC-14: Unconventional Forecast - Oil Reservoir Model



The reservoir properties can be imported from one of the well models in the PE Tools database. After clicking 'Import PE Tools dB Reservoir Properties' a screen will open listing the available well models in the database.

'Reservoir Length' is used to determine the GIIP/OIIP and to construct the x-grids for the Numerical Model. It is not necessarily the same value as the 'Lateral Length' entered in the Wellbore Model.

'Reservoir Width' is the sum of the distance to the two drainage boundaries from the horizontal well. This is also equivalent to the well spacing and is used to build the y-grids in the numerical model.

The 'Water RSW' parameter is calculated based on the water salinity entered into the Oil PVT Model (Figure UNC-11) and is used in the Numerical Model.

### UNC.5 Fracture Model

The Frac Model is used to enter the hydraulic fracture parameters. Figures UNC-15 and UNC-16 show the fracture models for gas and oil models when using the Analytical Model and Figure UNC-17 presents the fracture model for the Numerical Model.

The 'Frac Parameters' dialog box includes the following fields and controls:

- Effective Fracture Half Length,  $x_f$  (ft): 250
- Propped Fracture Width (in): 0.25
- Effective Fracture Permeability (md): 500
- MIN Number of Fractures to Model: 2
- MAX Number of Fractures to Model: 3
- Dimensionless Fracture Conductivity, FCD: 0.21
- ☒ Include Frac Water Flowback
- 0.5 Current WGR (bbls/mmscf)
- 1 FlowBack Acceleration Factor (0.5 to 2.0)
- Buttons: 'Import PE Tools dB Frac Parameters' and 'Return'

A schematic diagram on the right shows a horizontal well with multiple fractures. Labels include  $N_f$  for the number of fractures,  $x_f$  for the fracture half-length,  $L_x$  for the total fracture length, and  $L_y$  for the well spacing.

Figure UNC-15: Unconventional Forecast - Fracture Model – Gas Model, Analytical Model

Effective Fracture Half Length,  $x_f$  (ft)

250

Propped Fracture Width (in)

0.25

Effective Fracture Permeability (md)

500

MIN Number of Fractures to Model

2

MAX Number of Fractures to Model

3

Dimensionless Fracture Conductivity, FCD

0.21

Import PE Tools dB Frac Parameters

Return

Figure UNC-16: Unconventional Forecast - Fracture Model – Oil Model, Analytical Model

Effective Fracture Half Length,  $x_f$  (ft)

250

Propped Fracture Width (in)

0.25

Effective Fracture Permeability (md)

500

Number of Fractures to Simulate

2

Dimensionless Fracture Conductivity, FCD

0.21

Import PE Tools dB Frac Parameters

Return

Figure UNC-17: Unconventional Forecast - Fracture Model – Gas and Oil Numerical Model

In all cases, the frac parameters can be imported from the PE Tools database. Figure UNC-18 is a schematic of the hydraulically fractured horizontal well model.

From Figure UNC-18,  $N_f$  is the total number of fractures placed in the well,  $L_x$  is the reservoir length,  $L_y$  is the reservoir width (well spacing) and  $x_f$  is the fracture half length. Drainage area for the horizontal well is  $L_x \times L_y$ .

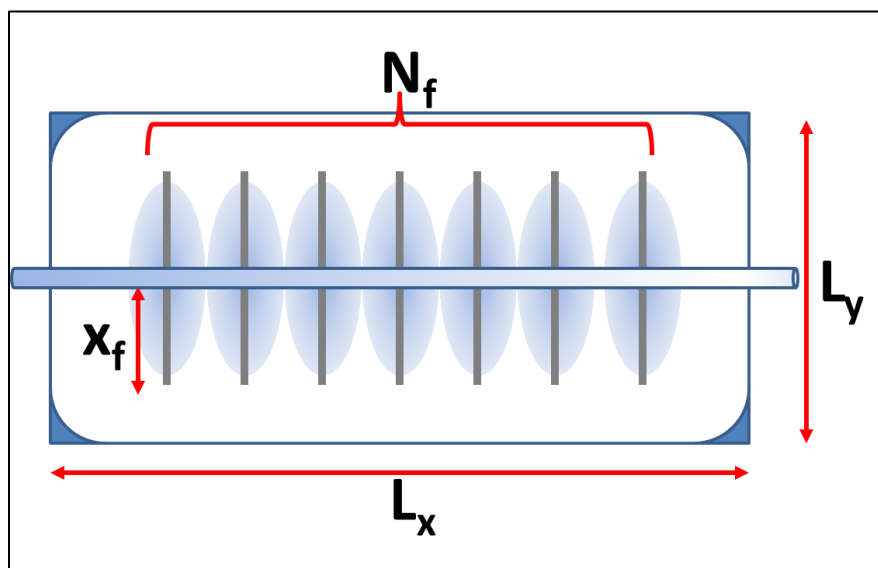


Figure UNC-18: Hydraulically Fractured Horizontal Well Model

When using the Analytical Model, minimum and maximum hydraulic fracture values can be entered so that a range of fractures can be modeled during one forecast run. If only a single hydraulic fracture scenario is required, the same value for the minimum and maximum number of fractures should be entered.

The Frac Model for gas includes an option to incorporate a 'Frac Water Flowback' model. The flowback model is an empirical pseudo model with no theoretical basis. It is based on information presented in the SPE paper (144093). The model is calibrated to the well's current producing (or assumed initial) WGR which is entered in the Frac Model. The water flowback model also includes a 'Flowback Acceleration Factor' to either increase or decrease the rate of frac water recovery and the ultimate volume of frac water recovered. If using this model, make sure that the volume of frac water produced is QC'd since there is no upper limit built into the model – the water production is included in the csv results file generated by 'Save Results'. If recovered volume is too high, reduce the acceleration factor. The Frac Water Flowback Model has been included for development planning (water handling) purposes.

The main purpose of the Frac Water Flowback Model is to include the additional tubing pressure drop that occurs during the flowback of frac water. If this model is used, then either the Guo-Ghalambor or Hagedorn-Brown tubing correlations should be used to model the wellbore pressure drop.

## UNC.6 Wellbore Model

The default tubing pressure drop correlation for a gas well is the Average TZ correlation, with the option to use Guo-Ghalambor or Modified Hagedorn-Brown correlations. For an oil well, the only available option is the Modified Hagedorn-Brown correlation.

Since production of gas, condensate and water is included when modeling a gas well, the Guo-Ghalambor correlation has been included for multi-phase pressure drops. Although this correlation includes up to 4-components: gas, water, condensate and sand; sand production is assumed to be zero in the Unconventional Forecast Model.

Single phase gas well tubing correlations, like the Average TZ correlation, are normally valid when WGR is less than 100 bbls/mmscf ( $561\text{m}^3/10^6\text{sm}^3$ ). Since Guo-Ghalambor is a multi-phase correlation, it may extend the range of WGR validity for a gas well, but caution should be used when accepting the results for high WGR's. If the Frac Water Flowback Model is used, then the more rigorous Modified Hagedorn-Brown correlation may be more appropriate.

In this version of the Unconventional Forecast Model, forecasts are generated for horizontal wells only (Figure UNC-19). Well models can be imported from the PE Tools database.

Figure UNC-19: Unconventional Forecast - Horizontal Well Model

The 'Lateral Length' and the number of fractures entered in the Fracture Model, are used to generate the x-distance, or the drainage distance for the fracture stage. Both the Analytical Model and the Numerical Model generate a forecast for a single fracture. The total well production is the summation of production from the total number of fractures.

The Analytical Model's Gas Model forecast also calculates minimum gas flow rate required to lift water or condensate based on the Turner correlation (refer to THP-BHP Gas Tool) and are included in the CSV file when the results are exported to a CSV file.

To disable the tubing calculations and perform a forecast at bottomhole conditions, enter -1 for 'Measured Depth to Top of Lateral' and enter the value for flowing BHP for the flowing tubing head pressure on the main screen.

### UNC.7 Forecast Plotting

The 'Unconventional Forecast' tool includes a very basic plotting package to view overall forecast results (Figure UNC-20). It is possible to save the plots to a png file by selecting "Save Graph".

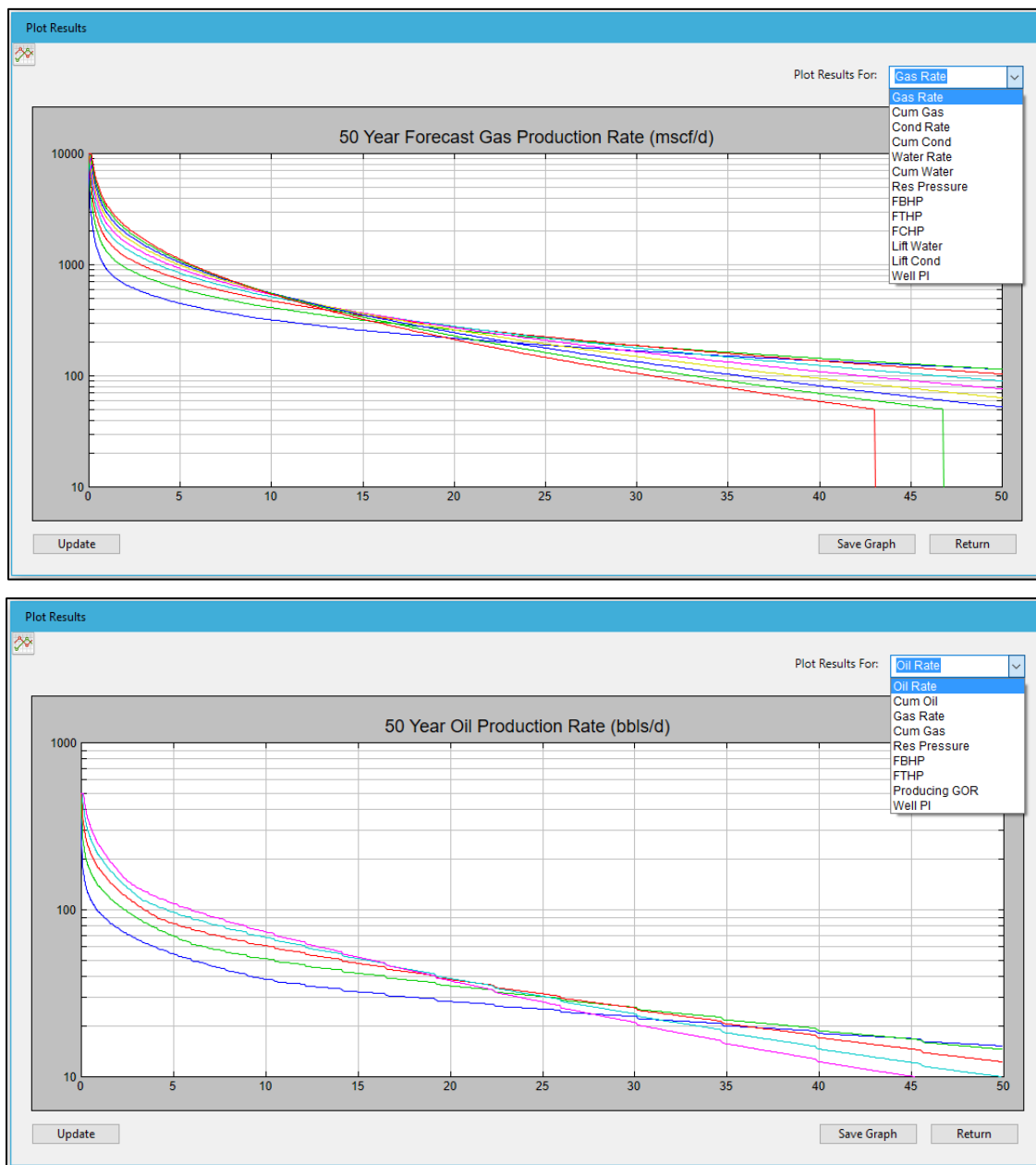


Figure UNC-20: Unconventional Forecast Plotting

For more in-depth data analysis and more flexibility with plotting, export the results to a csv file and use PE<sup>2</sup> Essentials Chart or import the file into a spreadsheet.

The Plot Window can remain open during subsequent runs. To plot the new forecast data, click the “Update” button.

## UNC.8 Unconventional Forecast Economics Model

The Unconventional Forecast Model includes an Economics Model (Figure UNC-21). This model is set up specifically to use the current unconventional forecast results, along with the entered capital and op costs, to generate a basic economic analysis. For a general use economics model refer to the Scoping Economics tool or CAPE.

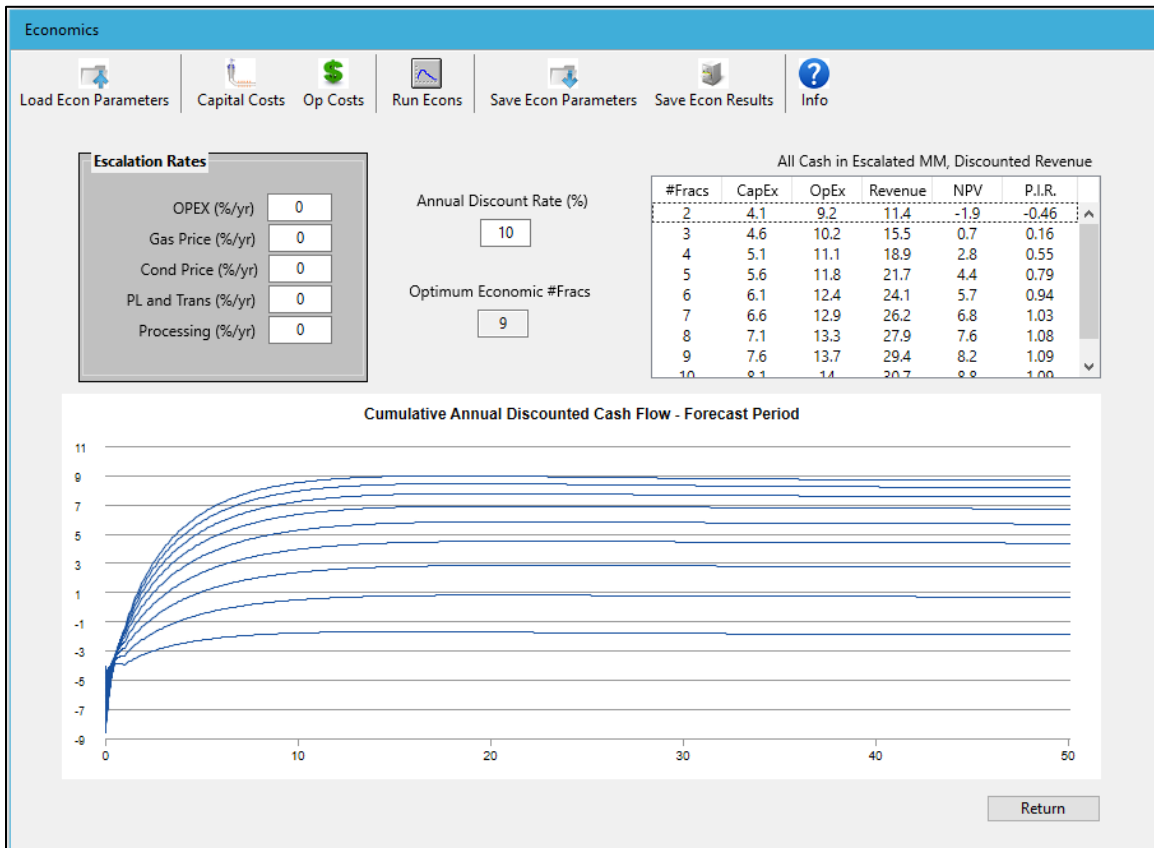
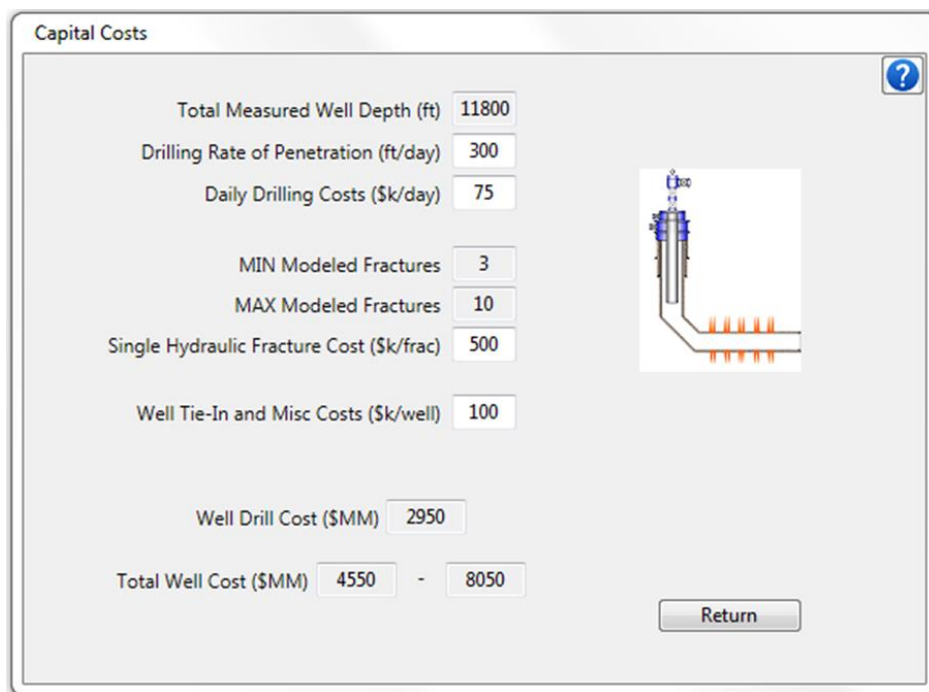


Figure UNC-21: Unconventional Forecast - Economics Model

If a number of frac cases are included in the forecast, then the Economics Model allows the engineer to evaluate the optimum economic number of fracs to be placed in the well.

The capital costs (Figure UNC-22) and operating costs (Figures UNC-23 - gas and UNC-24 - oil) are entered separately. The Gas/Oil pricing is entered in the 'Op Costs' model and should be entered in \$US. All other costs should be entered in the local currency. The 'Conversion Factor' converts the oil/gas prices to the local currency for calculations. Output is presented in the local currency.

Escalation factors and discount factor are entered on the main screen (Figure UNC-21).

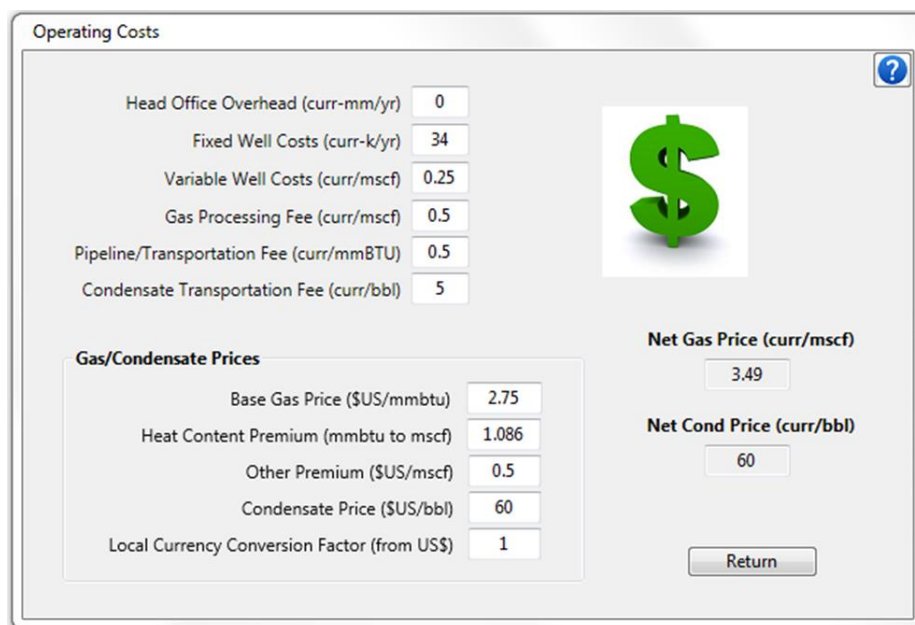


**Capital Costs**

Total Measured Well Depth (ft)	11800
Drilling Rate of Penetration (ft/day)	300
Daily Drilling Costs (\$k/day)	75
MIN Modeled Fractures	3
MAX Modeled Fractures	10
Single Hydraulic Fracture Cost (\$k/frac)	500
Well Tie-In and Misc Costs (\$k/well)	100
Well Drill Cost (\$MM)	2950
Total Well Cost (\$MM)	4550 - 8050

Return

Figure UNC-22: Economics Model – Capital Costs



**Operating Costs**

Head Office Overhead (curr-mm/yr)	0
Fixed Well Costs (curr-k/yr)	34
Variable Well Costs (curr/mscf)	0.25
Gas Processing Fee (curr/mscf)	0.5
Pipeline/Transportation Fee (curr/mmBTU)	0.5
Condensate Transportation Fee (curr/bbl)	5

**Gas/Condensate Prices**

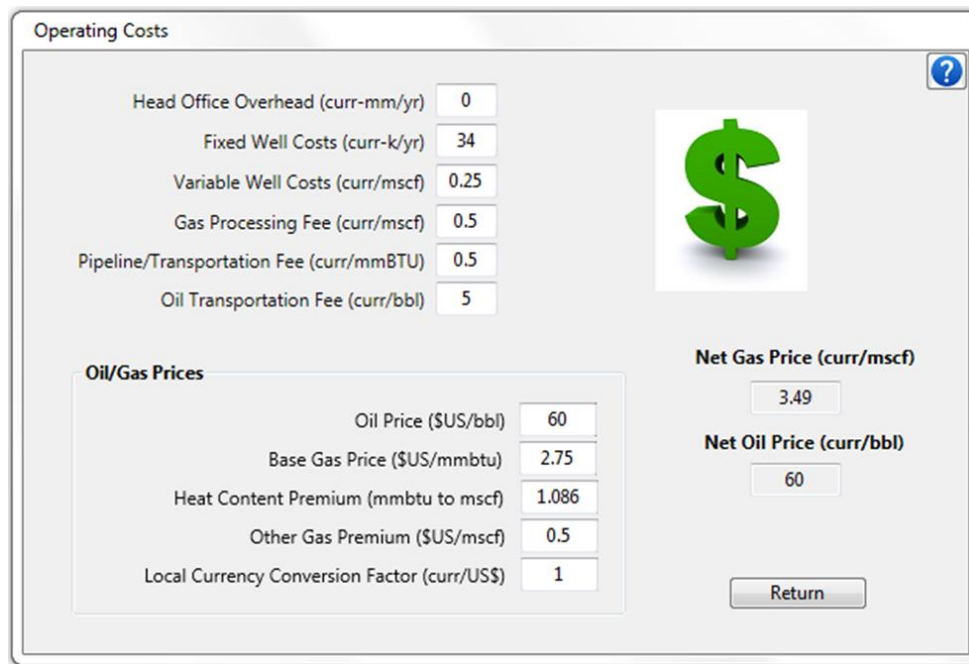
Base Gas Price (\$US/mmbtu)	2.75
Heat Content Premium (mmbtu to mscf)	1.086
Other Premium (\$US/mscf)	0.5
Condensate Price (\$US/bbl)	60
Local Currency Conversion Factor (from US\$)	1

**Net Gas Price (curr/mscf)**  
3.49

**Net Cond Price (curr/bbl)**  
60

Return

Figure UNC-23: Economics Model – Operating Costs (Gas Well)



Operating Costs	
Head Office Overhead (curr-mm/yr)	0
Fixed Well Costs (curr-k/yr)	34
Variable Well Costs (curr/mscf)	0.25
Gas Processing Fee (curr/mscf)	0.5
Pipeline/Transportation Fee (curr/mmBTU)	0.5
Oil Transportation Fee (curr/bbl)	5

Oil/Gas Prices	
Oil Price (\$US/bbl)	60
Base Gas Price (\$US/mmbtu)	2.75
Heat Content Premium (mmbtu to mscf)	1.086
Other Gas Premium (\$US/mscf)	0.5
Local Currency Conversion Factor (curr/US\$)	1

Net Gas Price (curr/mscf)	3.49
Net Oil Price (curr/bbl)	60

Return

Figure UNC-24: Economics Model – Operating Costs (Oil Well)

Following the economics run, the 'Optimum Economic #Frac' is presented on the main screen (Figure UNC-21). This is calculated as the number of fractures that maximizes the Profit-to-Investment Ratio (PIR).

$$\text{PIR} = \text{CumCF}_{\text{disc}} / \text{TotalWellCosts} \quad (\text{UNC-10})$$

Where:  $\text{CumCF}_{\text{disc}}$  is the discounted cumulative annual cash flow and  $\text{TotalWellCosts}$  is the capital cost of the well (assumed to be sunk costs).

### UNC.8.1 Total Well Costs

The total well costs are assumed to be sunk costs so no escalation or discounting is applied to this cost. The well cost is calculated with Equation UNC-11.

$$\text{TotalWellCosts} = (\text{DailyCost})(\text{WellMD})/\text{ROP} + (\#\text{Frac})(\text{FracCost}) + \text{TieInCost} \quad (\text{UNC-11})$$

Where:  $\text{DailyCost}$  is the daily drilling cost,  $\text{WellMD}$  is the measured depth of the well,  $\text{ROP}$  is the rate of penetration,  $\#\text{Frac}$  is the total number of hydraulic fractures,  $\text{FracCost}$  is the cost per frac and  $\text{TieInCost}$  is the cost to tie-in the well, clean up the well and any other costs associated with the well.



### UNC.8.2 Escalation Factors

The cost of a number of operating parameters can be escalated over time to take inflation into account. The following parameters can be escalated:

- Operating Expense
  - Head Office Overhead
  - Fixed Well Costs
  - Variable Well Costs
- Gas Processing Fee
- Gas Pipeline and Transportation Expense
- Oil/Condensate Transportation Fee
- Oil/Gas Price

The Annual Escalation Rates are entered on the main economics sheet and cost is escalated as shown in Equation UNC-12.

$$\text{EscFactor} = (1 + \text{EscRate}/100)^t \quad (\text{UNC-12})$$

Where: EscFactor is the annual escalation, EscRate is the escalation rate entered on the main sheet (Figure UNC-21) and t is the time in years.

### UNC.8.3 Discount Rate

To take the time value of money into account, all future revenue is converted to a common reference point in time. This is assumed to be the current year or the present (hence the term, 'present value'). This is achieved by discounting future cash flow. Discounting converts a future sum of money into the equivalent of present-day cash.

The rate used for discounting future cash flow is called the discount factor and is entered as the 'Annual Discount Rate' on the main sheet (Figure UNC-21). The annual discount factor is calculated with Equation UNC-13.

$$\text{DiscFactor} = (1 + \text{DiscRate}/100)^{-t} \quad (\text{UNC-13})$$

Where: DiscFactor is the annual discount applied to the cash flow, DiscRate is the discount rate entered on the main sheet (Figure UNC-21) and t is the time in years.

The present value, PV, of a net cash flow, CF, received at some future time, t, is calculated with Equation UNC-14.

$$\text{PV}_t = \text{CF}_t \text{ DiscFactor}_t \quad (\text{UNC-14})$$

Where the subscript t is the time in years at which the cash flow is received.

## UNC.8.4 Oil/Gas Prices

For this version of the Economics Model, oil/gas price is assumed to be flat except for the escalation rate that is entered. To enter future gas/oil prices, the 'Scoping Economics' tool should be used.

The oil/gas prices for an oil well or the gas/condensate prices for a gas well are entered in the 'Operating Costs' model (Figure UNC-25).

Oil/Gas Prices		Gas/Condensate Prices	
Oil Price (\$US/bbl)	60	Base Gas Price (\$US/mmbtu)	2.75
Base Gas Price (\$US/mmbtu)	2.75	Heat Content Premium (mmbtu to mscf)	1.086
Heat Content Premium (mmbtu to mscf)	1.086	Other Premium (\$US/mscf)	0.5
Other Gas Premium (\$US/mscf)	0.5	Condensate Price (\$US/bbl)	60
Local Currency Conversion Factor (curr/US\$)	1	Local Currency Conversion Factor (from US\$)	1

Figure UNC-25: Economics Model – Oil/Gas Prices

Net gas price is calculated based on the base gas price, the heat content premium and any other gas premium (or discounts) and then converted to the local currency. Net oil/condensate price is converted to the local currency.

$$\text{NetGasPrice} = [(\text{BaseGasPrice})(\text{HeatContent}) + \text{Premium}](\text{LocalConversion}) \quad (\text{UNC-15})$$

$$\text{NetOilPrice} = (\text{OilPrice})(\text{LocalConversion}) \quad (\text{UNC-16})$$

The final net gas and oil prices are presented on the Operating Cost model sheet (Figures UNC-23 and UNC-24).

## UNC.8.5 CapEx, OpEx, Revenue, Net Present Value and PIR

For this version of the Economics Model, all capital expenditures, CapEx, are assumed to be sunk costs so there are no escalations or discounting of the well costs. The economics forecast starts at a negative value equal to the well costs.

The net gas and oil/condensate prices are escalated prior to being discounted. This esc/disc price is then applied to the appropriate production stream to generate the future net present value revenue stream.

$$\text{NetGasPrice}_{\text{esc}} = (\text{NetGasPrice})(\text{EscFactor}_{\text{gas}}) \quad (\text{UNC-17})$$

$$\text{NetOilPrice}_{\text{esc}} = (\text{NetOilPrice})(\text{EscFactor}_{\text{oil}}) \quad (\text{UNC-18})$$

$$\text{NetGasRevenue}_{\text{disc}} = (\text{NetGasPrice}_{\text{Esc}})(Q_g)(\text{ProdDays})(\text{DiscFactor}_t) \quad (\text{UNC-19})$$

$$\text{NetOilRevenue}_{\text{disc}} = (\text{NetOilPrice}_{\text{Esc}})(Q_o)(\text{ProdDays})(\text{DiscFactor}_t) \quad (\text{UNC-20})$$

$$\text{TotalNetRevenue}_{\text{npv}} = \text{NetGasRevenue}_{\text{disc}} + \text{NetOilRevenue}_{\text{disc}} \quad (\text{UNC-21})$$

The total net present value revenue,  $\text{TotalNetRevenue}_{\text{npv}}$ , is calculated on an annual basis and added together to generate the project revenue for the complete production forecast for a given fractured well. These calculations are performed for each fractured well case and the results are added to the results table on the Economics sheet (Figure UNC-26).

All Cash in Escalated MM, Discounted Revenue					
#Fracs	CapEx	OpEx	Revenue	NPV	P.I.R.
3	4.6	15.4	38.3	18.5	4.05
4	5.1	15.6	40.4	19.8	3.92
5	5.6	15.6	41.6	20.5	3.69
6	6.1	15.6	42.3	20.8	3.43
7	6.6	15.5	42.8	20.8	3.17
8	7.1	15.4	43.2	20.7	2.93
9	7.6	15.4	43.4	20.5	2.72
10	8.1	15.3	43.6	20.3	2.52

Figure UNC-26: Economics Model – Results Table

The operating costs are escalated based on the escalation rates entered into the model (Figure UNC-21).

$$\begin{aligned} \text{TotalOpCosts}_{\text{Esc}} = & (\text{HeadOffice})(\text{EscFactor}_{\text{OpEx}}) + \\ & (\text{FixedCost})(\text{EscFactor}_{\text{OpEx}}) + \\ & (\text{VariableCosts})(Q_g)(\text{ProdDays})(\text{EscFactor}_{\text{OpEx}}) + \\ & (\text{PipeLineFee})(Q_g)(\text{ProdDays})(\text{EscFactor}_{\text{Pipeline}}) + \\ & (\text{GasProcessFee})(Q_g)(\text{ProdDays})(\text{EscFactor}_{\text{Process}}) + \\ & (\text{OilProcessFee})(Q_o)(\text{ProdDays})(\text{EscFactor}_{\text{Process}}) \end{aligned} \quad (\text{UNC-22})$$

The total cumulative, escalated operating costs are then discounted (Equation UNC-23) and added to the results table on the Economics sheet (Figure UNC-26).

$$\text{TotalOpCosts}_{\text{disc}} = (\text{TotalOpCosts}_{\text{esc}})(\text{DiscFactor}_t) \quad (\text{UNC-23})$$

The net present value is calculated with Equation UNC-24:

$$\text{NPV} = \text{TotalNetRevenue}_{\text{npv}} - \text{TotalOpCosts}_{\text{disc}} - \text{CapEx} \quad (\text{UNC-24})$$

Profit to investment ratio is then calculated with Equation UNC-25:

$$\text{PIR} = \text{NPV} / \text{CapEx} \quad (\text{UNC-25})$$

Both NPV and PIR are presented on the results table on the Economics sheet (Figure UNC-26).

The 'Optimum Economic #Fracs' is determined as the number of fractures that maximizes PIR. This value is reported on the main Economics sheet (Figure UNC-21).

If an additional forecast is generated in the main program, the economic analysis results will be automatically updated when the Economics model is re-opened.

Once the economic runs are completed the resulting economic forecast information can be saved to a csv file by 'Save Econ Results' and imported into PE<sup>2</sup> Essentials Chart (Figure UNC-27). A separate file for each hydraulic fracture forecast is saved.

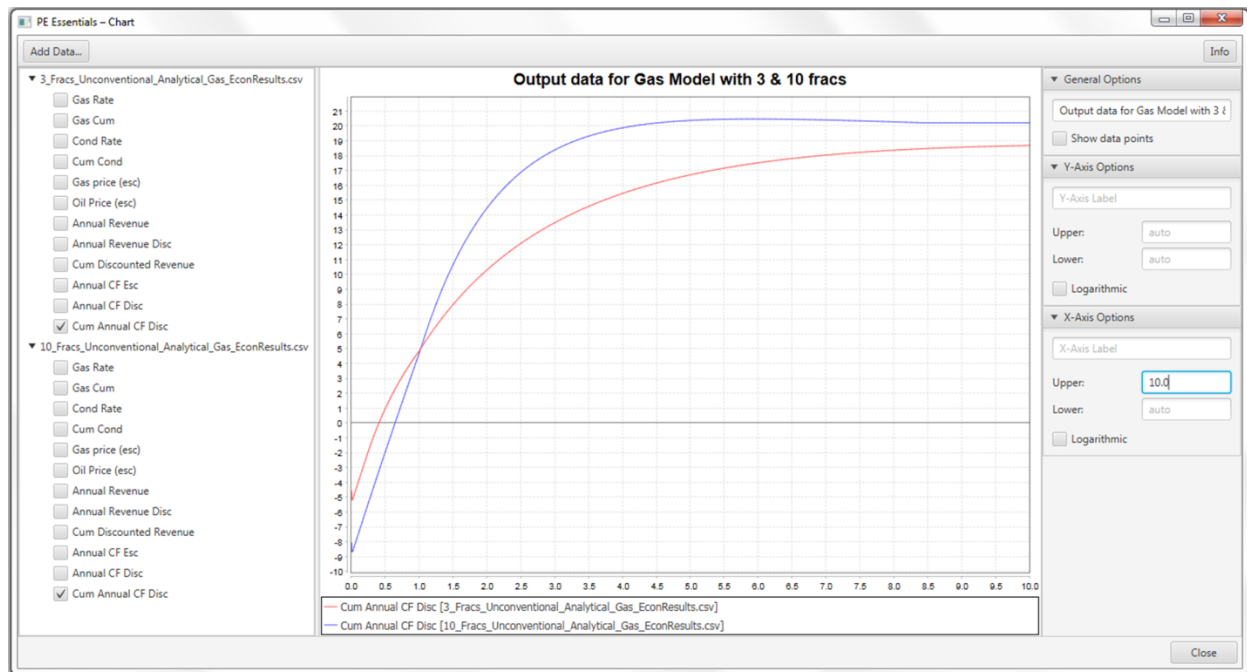


Figure UNC-27: Economics Model – Output Results

### UNC.9 History Match Tool

The History Match Tool (Figure UNC-28) is a very powerful tool that enables the engineer to evaluate the net effectiveness of the frac program (as well as other parameters). Refer to Section UNC.10 for an example using this tool. Note the history match in Figure UNC-28 was generated using the 'History Match Model' in the PE Tools database and Excel history file (History\_Fracs\_NoWater.xlsx) is included in the "PE Essentials\Example Input Files\ Example Input Files\Excel Files" directory.

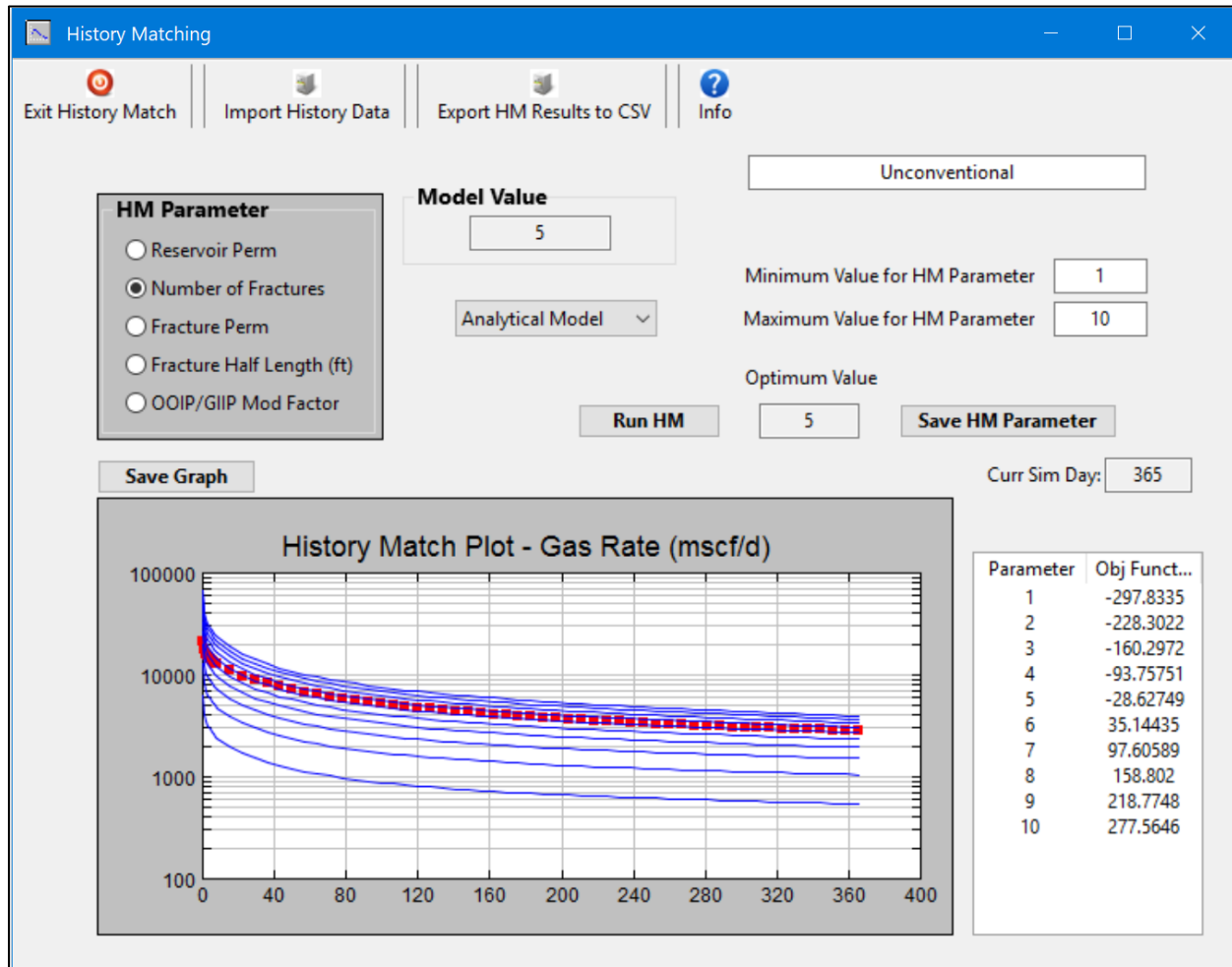


Figure UNC-28: History Match Tool

The base model and frac parameters used in history matching are entered on the main screen.

The historical production data is imported through the 'Import History' button. History data can be imported from the PE Tools database or an Excel Spreadsheet (Figure UNC-29). The Data Import page will specify the units for the historical data. Refer to the info button on the Data

Import sheet for information on the file formats. If the gas model is being used, gas rate will be plotted otherwise oil rate will be plotted (Figure UNC-28) after the data is loaded.

History Match Data Import

**Data Input**

☐ PE Tools dB ☒ Excel File [Link to Excel File](#)

Note: Gas rate in mscf/d, liquid rate in bbls/d and Pressure in psi

**Excel Input Parameters**

	Column	Start Row	End Row
Time in Days	a	4	63
Gas Rate	b	4	63
Oil/Condensate Rate	c	4	63
Water Rate	d	4	63
Pressure	e	4	63

[Import Data](#)

Days	Gas Rate	Oil Rate	Wat Rate	BHP
0.1	21036.2	bopd	bwpd	psi
1	17622.9	1176.6	5.6	800
2	16211.5	1082.4	5.2	800
3	15283.5	1020.4	4.9	800
4	14561.2	972.2	4.6	800
5	13976.5	933.2	4.4	800
6	13496.8	901.1	4.3	800
7	12903.7	861.5	4.1	800
8	12716.2	849	4	800
15	11046.9	737.6	3.5	800
22	9796.2	654.1	3.1	800
29	8917	595.4	2.8	800
36	8224.2	549.1	2.6	800
43	7667.4	511.9	2.4	800
50	7191.8	480.2	2.3	800
57	6776.9	452.5	2.2	800
64	6431.1	429.4	2	800
71	6135.5	409.6	2	800
78	5859.4	391.2	1.9	800
85	5624	375.5	1.8	800
92	5406.6	361	1.7	800
99	5221.1	348.6	1.7	800
106	5044.5	336.8	1.6	800
113	4902.8	327.4	1.6	800
120	4752.5	317.3	1.5	800

[Continue](#)

Figure UNC-29: import History Data

A history match of a number of parameters can be performed (Figure UNC-30). The history match routine will report the optimum value for the chosen parameter based on the well's production history, which can then be compared to the expected value. It should be noted that the 'Fracture Half Length' is always entered in feet.

When a history match parameter is chosen, the value from the model is shown as 'Model Value' on the main page (Figure UNC-28).

**HM Parameter**

☐ Reservoir Perm

☒ Number of Fractures

☐ Fracture Perm

☐ Fracture Half Length (ft)

☐ OOIP/GIIP Mod Factor

Figure UNC-30: History Match Parameters

If matching on 'Number of Fractures', 'Fracture Perm' or 'Fracture Half Length', the effectiveness of the frac program can be evaluated by comparing the history match results to the expected values.

It is possible to force a history match run on a specific value by entering the same value for the minimum and maximum values.

The Numerical Model (reservoir simulator) can be used for history matching but it will increase the time required to find the optimum parameter. The Analytical Model could be used to perform a preliminary match, and then the numerical Model used to finalize the history match.

Note that the History Match Model uses BHP as the matching constraint. If only THP is available for a gas well, the 'THP-BHP Gas Well' model can be used to generate the BHP and export the history file for use in the History Match Model.

Following the history match run, the generated optimum history match parameter can be saved to the model through "Save HM Parameter" which will transfer the matched parameter ("Optimum Value") to the original model. If the parameter is not saved, it will be discarded during the next operation. Multiple parameters can be sequentially matched and saved but only one parameter can be matched at a time.

The updated model, including any saved history match parameters, can be used for forecasting. The updated model should be saved to retain the history match parameters.

None of the intermediate history match runs are saved. To save the history match results, re-run the history match with the 'Optimum Value' set as the maximum and minimum values then save the results by 'Export HM Results to CSV'. This will save the history match results to a CSV file. This file can be imported into PE Essentials Chart for plotting (Figure UNC-31).

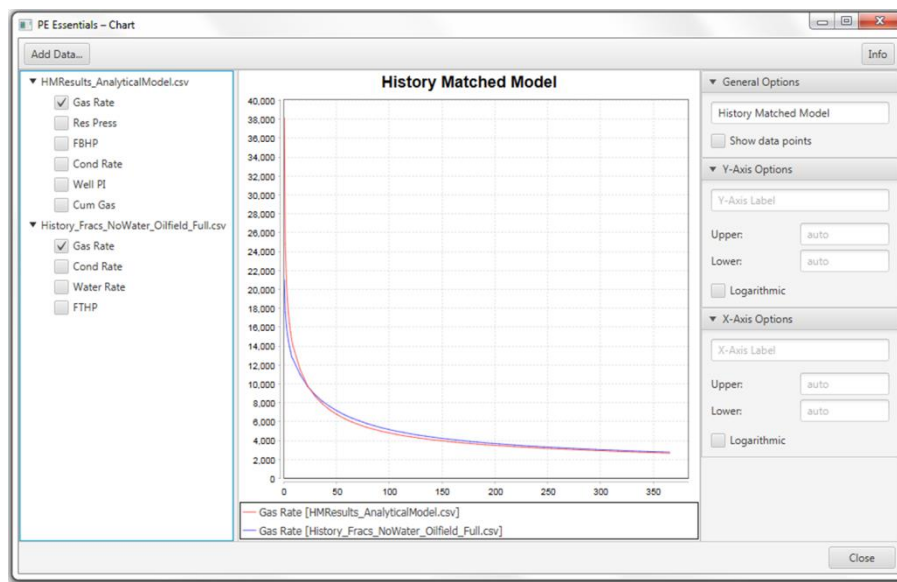


Figure UNC-31: History Match / Historical Data Comparison



## UNC.10 Unconventional Forecast Example

A very dry unconventional gas reservoir was tested by a horizontal well completed without fracs. The production data (HistoryData\_Example\_Well With BHP.xlsx in “Book Examples\Example Unconventional Forecast\Unconventional Forecast\History” directory) is presented in Table UNC-1 and Figure UNC-32. The question is: what is the optimum number of fractures for a future horizontal well in this reservoir.

Days	THP (psi)	mcf/d	Days	THP (psi)	mcf/d	Days	THP (psi)	mcf/d	Days	THP (psi)	mcf/d	Days	THP (psi)	mcf/d	Days	THP (psi)	mcf/d
1	577	772	31	573	236	61	548	273	91	532	476.6	121	559	273	151	552	332.4
2	577	2197.6	32	583	539.4	62	561	268.6	92	538	469.6	122	558	429.2	152	553	273
3	987	1290.6	33	561	107	63	555	388.6	93	537	718.8	123	556	324.2	153	553	396
4	564	906	34	554	614.6	64	542	437.6	94	548	426	124	554	441.2	154	562	291.8
5	571	869.2	35	552	188.8	65	541	322.6	95	604	126.4	125	567	542.8	155	558	289.4
6	573	673.2	36	556	342	66	543	176.6	96	611	55.6	126	553	489.4	156	561	383.8
7	574	633.2	37	538	428.6	67	542	52.8	97	564	702	127	553	208.4	157	559	363.6
8	555	590.2	38	548	364.4	68	812	20.4	98	559	740	128	589	1146.6	158	557	190.2
9	569	681.2	39	555	318.4	69	553	824.2	99	559	523	129	592	526.6	159	555	368.6
10	572	544.6	40	533	467.6	70	543	363	100	563	414.4	130	600	474.8	160	556	507.6
11	568	340.2	41	546	318.4	71	550	471.2	101	560	365.4	131	593	868.6	161	548	142.8
12	559	668	42	741	134	72	549	344.6	102	561	389.4	132	556	1049.8	162	559	604.4
13	560	508.8	43	525	504.4	73	543	441.4	103	560	404.8	133	553	245.2	163	556	489
14	572	330.8	44	545	414.4	74	544	112.4	104	565	302.4	134	578	519.8	164	560	210.2
15	564	589.2	45	549	375	75	545	491	105	563	381.4	135	553	621	165	560	403.2
16	567	477.4	46	549	387	76	544	399.6	106	564	285	136	559	207.8	166	559	459.2
17	565	447.4	47	559	254.4	77	548	106.8	107	564	383.8	137	563	531.8	167	558	261.8
18	574	514	48	559	415.6	78	535	567	108	562	346.2	138	565	414.6	168	557	262.6
19	563	442.8	49	574	278.4	79	528	300.6	109	566	380.8	139	563	429	169	557	468.8
20	595	436.4	50	555	424.2	80	548	168.8	110	575	314.8	140	564	230.8	170	557	309.4
21	621	267	51	561	288.6	81	569	43	111	566	290.2	141	562	433.2	171	558	261.2
22	568	485.8	52	553	287.8	82	573	21	112	560	450.4	142	561	427.8	172	556	276
23	578	474.8	53	552	400.2	83	564	90.4	113	564	327.2	143	562	221.6	173	542	512.8
24	641	411.6	54	556	320	84	600	86.8	114	549	321.4	144	560	439	174	540	326.8
25	614	405.4	55	560	283.2	85	600	111	115	551	328.6	145	560	305.6	175	546	280.8
26	558	246.6	56	551	402	86	579	77.6	116	556	400.6	146	561	294.4	176	545	286.2
27	729	33.6	57	547	185.2	87	544	18.4	117	557	374.2	147	560	393.8	177	544	280.6
28	557	595.8	58	547	489.6	88	561	1082.8	118	557	284.6	148	561	313.2	178	544	443.4
29	567	559.8	59	547	316.2	89	537	1253.2	119	560	335	149	554	270.2	179	548	384.8
30	566	403.2	60	549	405	90	534	689.6	120	561	360.8	150	551	397	180	555	275.4

Table UNC-1: Example Flow Data: Dry Gas Well Example

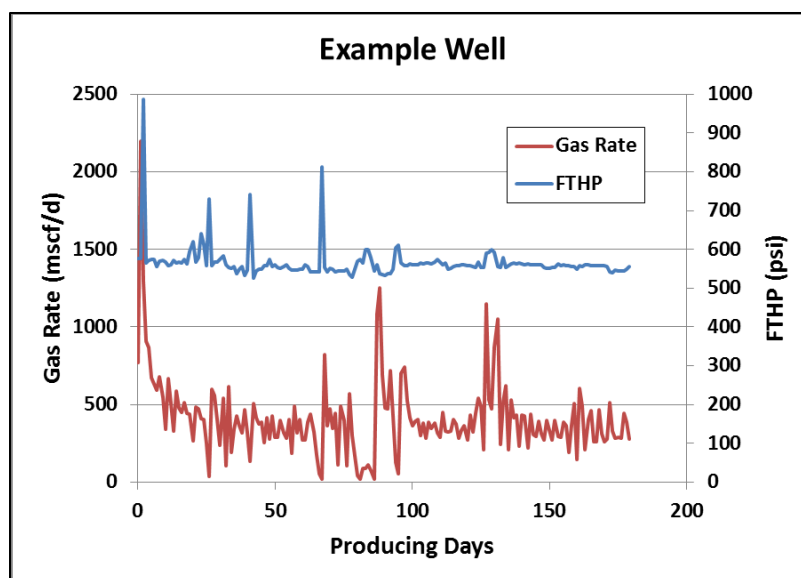


Figure UNC-32: Example Data



**Step 1:** Determine gas properties using the 'Generate Gas Components' in the PVT section of the Unconventional Forecast Model.

The gas produced from the well had an average gas gravity of 0.6, CO<sub>2</sub> mol% of 0.3, N<sub>2</sub> mol% of 1.5 and there was minimal condensate production from the well.

The gas components were generated by clicking the 'Generate Gas Components'. These components were then modified to match the gas specific gravity of ~0.6 and CGR<1 (Figure UNC-33).

**Gas Properties Input**

**Sales Streams**

	Gas	Liquid
H2S - mol%	0	0
N2 - mol%	1.51	0
CO2 - mol%	0.3	0
C1 - mol%	92.82	0
C2 - mol%	3.95	0
C3 - mol%	1.31	71.35
iC4 - mol%	0.03	4.92
nC4 - mol%	0.08	12.3
iC5 - mol%	0	4.9
nC5 - mol%	0	6.53
C6 - mol%	0	0
C7Plus - mol%	0	0

Gas MW: 17.47  
 Raw Gas G: 0.6032  
 Gas Pc (psi): 664.2  
 Gas Tc (°R): 356.5  
 Sales Gas G: 0.5964  
 GHV (btu/scf): 1044  
 Shrinkage (%): 2.4  
 Propane-C3 (bbbls/mmcsf): 2.8  
 Butane-C4 (bbbls/mmcsf): 0.8  
 CGR-C5+ (bbbls/mmcsf): 0.6  
 Condensate Density (°API): 93.7  
 Water (bbbls/mmcsf): 0.211  
 Dew Point Pressure (psi): 801.6

Σ Comps: 100    100    100

C7Plus MW: 200  
 C7Plus SG: 0.766

**Generate Gas Components**    **Return**

Figure UNC-33: Gas Components – Matched Gas Gravity, Example Well

**Step 2:** Create Reservoir Model using estimated/known parameters (Figure UNC-34).

**Gas Reservoir Properties**

Average Perm (md): 0.001  
 Average Pay (ft): 262  
 Average Sw: 0.1  
 Average Porosity: 0.04  
 Res Temperature (°F): 156  
 Reservoir Pressure (psi): 4350  
 Reservoir Length (ft): 2400  
 Reservoir Width (ft): 750  
 Reservoir Well radius (in): 4

Initial Gas In Place (Bscf): 4.448  
 Sales Gas In Place (Bscf): 4.341  
 Condensate In Place (mmbbls): 2.7  
 Initial Bg (f³/scf): 0.00382  
 Initial Gas Viscosity (cp): 0.02394  
 Initial Gas Z Factor: 0.95298  
 Initial cg (10⁻⁴/psi): 1.61

Area (Acres): 41.3

**Return**

Figure UNC-34: Estimated Reservoir Model – Example Well

**Step 3:** Create Wellbore Model using known parameters (Figure UNC-35).

The 'Wellbore Properties' dialog box contains the following fields and values:

- Measured Depth to Top of Lateral (ft): 10800
- True Vertical Depth to Top of Lateral (ft): 10800
- Lateral Length (ft): 4800
- Tubing ID (in): 1.995
- Depth of Tubing (ft): 10800
- Casing ID (in): 6
- Tubing Correlation: Guo-Ghalambor

A schematic diagram on the right shows a vertical wellbore with a lateral section at the bottom. Labels include 'Tubing Depth', 'Top of Lateral', and 'Casing ID'. A 'Return' button is at the bottom right.

Figure UNC-35: Wellbore Model – Example Well

**Step 4:** Build the wellbore model and convert flowing THP to BHP using the THP-BHP Gas Well Tool (Figure UNC-36 and Figure UNC-37). THP data is in the 'THP to BHP Unconventional Example Data.xlsx' located in the "PE Essentials\ Book Examples\Example Unconventional Forecast\THP-BHP" directory.

The software interface displays the following sections:

- Well Options:** Vertical Well (checked), Annular Flow (unchecked), Horizontal Well (unchecked).
- Tubing Correlation:** Average TZ (unchecked), Guo-Ghalambor (Sand) (checked), Hagedorn-Brown (unchecked).
- Fluid Properties:**
  - Gas Gravity: 0.6033, Reservoir Press (psi): 4350
  - H<sub>2</sub>S - mol%: 0, Reservoir Temp (°F): 156
  - CO<sub>2</sub> - mol%: 0.3, CGR (bbls/mmscf): 0.6
  - N<sub>2</sub> - mol%: 1.5, Cond API: 95
  - NACL (ppm): 30000
- Gas Properties:**
  - Reservoir Pressure: 4350 psia
  - Reservoir Temperature: 156 °F
  - Gas G - no acid gas: 0.5949 <>
  - Gas Pc: 670 psia
  - Gas Tc: 354.9 °R
  - Z: 0.952 <>
  - Gas Compressibility: 16.222E-5 1/psi
  - Gas Viscosity: 0.0237 cp
  - Gas Expansion (1/Bg): 262.2 scf/ft<sup>3</sup>
  - Water Content (WGR): 0.271 bbls/mmscf
- Wellbore Parameters:**
  - Tubing OD (in): 2.875, Top Perf (ftMD): 10800
  - Tubing ID (in): 1.995, Bottom Perf (ftMD): 10900
  - Tubing Depth (ftMD): 10800, Top Perf (RTVD): 10800
  - Casing ID (in): 6, Bottom Perf (RTVD): 10900
  - Flow Temperature (°F): 50
  - Pipe Roughness (in): 0.0006, ΔP Correction Factor: 1
- Tables:**
  - THP Table:** Columns: THP (psi), WGR (bbl/mmscf), Sand Rate (ft<sup>3</sup>/d), Gas Rate (mmscf/d). Row 1: 0, 0, 0, 0.
  - Output Table:** Columns: THP (psi), WGR (bbl/mmscf), Sand Rate (ft<sup>3</sup>/d), Gas Rate (mmscf/d), BHP (psi), Min Qg (water) (mmscf/d), Min Qg (sand) (mmscf/d).
- Plots:** Z Factor, cg (10<sup>-3</sup>), Viscosity, 1/Bg.
- Diagram:** Wellbore schematic showing tubing depth, top and bottom perforations, and total depth.

Figure UNC-36: THP-BHP Model – Example Well

**PE Essentials THP>BHP Data Import**

**Data Input**

☐ CSV File ☒ Excel File

Note: Gas rate in mscf/d, liquid rate in bbls/d and sand rate in ft<sup>3</sup>/d

**Excel Input Parameters**

	Column	Start Row	End Row
Tubing Head Pressure	b	5	187
Gas Rate	c	5	187
Condensate Rate	d	5	187
Water Rate	e	5	187
Sand Rate	f	5	187

**THP to BHP Conversion**

**Tubing Correlation**

☐ Average TZ ☒ Guo-Ghalambor (Sand) ☐ Hagedorn-Brown

#	THP	Gas mscf/d	Cond bcpd	Water bwpd	Sand ft <sup>3</sup> /d	BHP psi
1	577	772	0	0	0	740.5
2	577	2197.6	0	0	0	884.1
3	987	1290.6	0	0	0	1265
4	564	906	0	0	0	733.3
5	571	869.2	0	0	0	739.1
6	573	673.2	0	0	0	730.3
7	574	633.2	0	0	0	729.5
8	555	590.2	0	0	0	704.3
9	569	681.2	0	0	0	726
10	572	544.6	0	0	0	723.3
11	568	340.2	0	0	0	711.2
12	559	668	0	0	0	713
13	560	508.8	0	0	0	708.2
14	572	330.8	0	0	0	716
15	564	589.2	0	0	0	715.3
16	567	477.4	0	0	0	714.5
17	565	447.4	0	0	0	710.8
18	574	514	0	0	0	724.4
19	563	442.8	0	0	0	708.2
20	595	436.4	0	0	0	747.4
21	621	267	0	0	0	775.3
22	568	485.8	0	0	0	715.9
23	578	474.8	0	0	0	728
24	641	411.6	0	0	0	803.5
25	614	405.4	0	0	0	769.9
26	558	246.6	0	0	0	696.8
27	729	33.6	0	0	0	907.2
28	557	595.8	0	0	0	707
29	567	559.8	0	0	0	717.7
30	566	403.2	0	0	0	710.6
31	672	326	0	0	0	716.1

Figure UNC-37: Convert THP to BHP – Example Well

After conversion of THP to BHP, export the data to a CSV file. Import the BHP data into the history file for the well (refer to 'HistoryData\_Example\_Well With BHP.xlsx' in the "PE Essentials\ Book Examples\Example Unconventional Forecast\THP-BHP" directory).

**Step 5:** Select 'History Match' and import the history data from the Excel file (Figure UNC.38). Perform a history match of the data to determine the permeability of the reservoir (Figure UNC-39) and 'Save HM Parameter' which was 0.002md.

**PE Essentials History Match Data Import**

**Data Input**

☐ CSV File ☒ Excel File

Note: Gas rate in mscf/d, liquid rate in bbls/d and THP/BHP in psi

**Excel Input Parameters**

	Column	Start Row	End Row
Time in Days	a	5	187
Gas Rate	b	5	187
Oil/Condensate Rate	c	5	187
Water Rate	d	5	187
FTHP / BHP	e	5	187

Figure UNC-38: Permeability History Match – Example Well

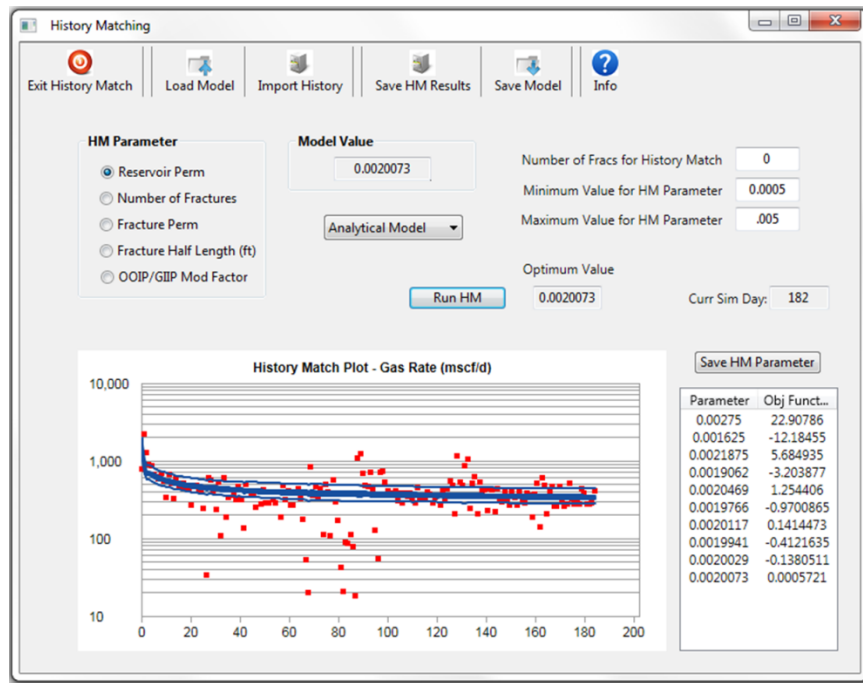


Figure UNC-39: Permeability History Match – Example Well

It should be noted that a history match could also be generated based on the number of hydraulic fractures in the well (Figure UNC-40). This well was not hydraulically fractured so this history match is rejected, and the permeability was matched instead (Figure UNC-39).

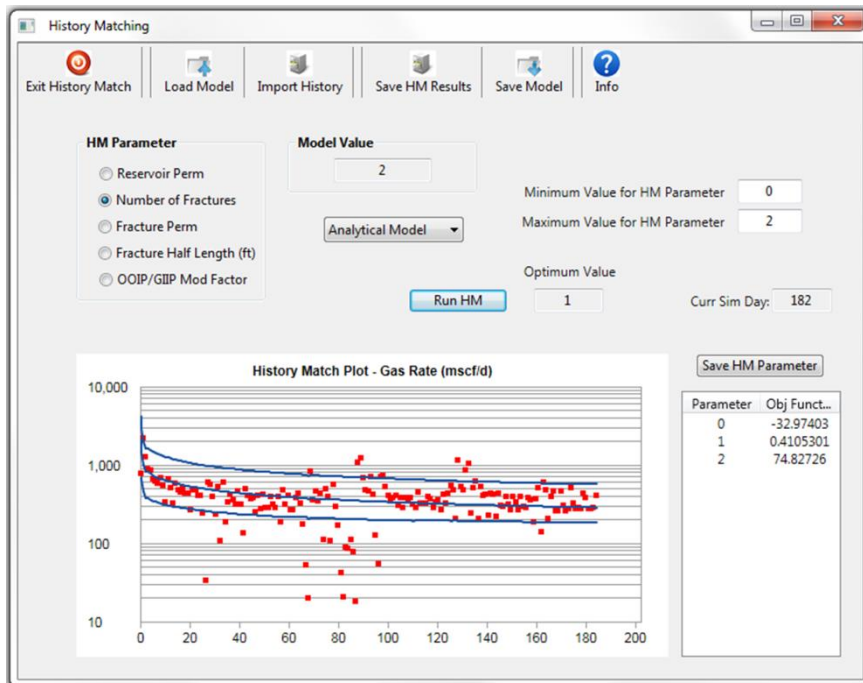


Figure UNC-40: Number of fractures History Match – Example Well

**Step 6:** Generate fracture parameters with the 'Hydraulic Fracture Design Model' (Figure UNC-41).

**Horizontal Well, Hydraulic Fracture Design - Version: 2017.1**

Exit Program | Load Model | Save Model | Save Frac Parameters | Info

Oilfield

**Hydraulic Fracture Parameters**

Proppant Permeability	1.5	Darcy
Proppant Specific Gravity	2.5	<dec>
Packed Porosity	0.35	<dec>
Total Propped Height	262	ft
Proppant Mass	10000	lbm
Number of Stages	6	<>

**Analysis Results**

Optimized FCD	2.2	<dec>	Optimized $X_f$	205.1	ft
Optimized $I_x$	0.547	<dec>	Optimized $W_f$	0.007	in
Total Well JD	1.644	<dec>			
Stabilized Well PI	0.049	mmscfd/psi <sup>2</sup>			
Stabilized Potential @ 1000psi	674.5	mscf/d			
Equivalent Skin Factor for Well	-5.7	<>			

**Reservoir Parameters**

Well Spacing	750	ft	Reservoir Area	41.3	Acres
Length of Lateral	2400	ft	Frac Pay Thickness	262	ft
Frac Pay Thickness	262	ft	Fracture Area	247.93	Acres
Reservoir Permeability	0.002	md	Fracture Spacing	400	ft
Wellbore Diameter	8	in			

**Deliverability Parameters**

Reservoir Pressure	3850	psi	<input checked="" type="radio"/> Gas Well
Viscosity	0.02	cp	<input type="radio"/> Oil Well
Z Factor	1	<>	
Reservoir Temperature	160	°F	

**Diagrams:**

- Top diagram: Schematic of a horizontal well with multiple fractures. Labels include 'Well Lateral', 'Propped Height', 'Stage Spacing', and 'W<sub>f</sub>'.
- Bottom diagram: Schematic of a fracture within a reservoir. Labels include 'Reservoir Thickness', 'Propped Height', 'X<sub>f</sub>', and 'Well Spacing'.

Figure UNC-41: Hydraulic Fracture Design – Example Well

Save the model to the PE Tools database for import into the Unconventional Forecast model.

**Step 7:** Import the fracture design parameters into the Frac Properties. (Figure UNC-42)

**Frac Parameters**

Effective Fracture Half Length,  $x_f$  (ft) 205.1

Propped Fracture Width (in) 0.007

Effective Fracture Permeability (md) 1500

MIN Number of Fractures to Model 5

MAX Number of Fractures to Model 15

Dimensionless Fracture Conductivity, FCD 2.1

☐ Include Frac Water Flowback

Import Frac Parameters

Return

**Diagram:** Schematic of a fracture system showing a horizontal well with multiple fractures. Labels include  $N_f$  (number of fractures),  $L_y$  (fracture length),  $L_x$  (well spacing), and  $x_f$  (fracture half length).

Figure UNC-42: Hydraulic Fracture Parameters – Example Well

**Step 8:** Generate a forecast using ~100 acre well drainage and a range of hydraulic fractures (Figures UNC-43 and UNC-44).

**Gas Reservoir Properties**

Average Perm (md)	0.00203	Initial Gas In Place (Bscf)	11.86
Average Pay (ft)	262	Sales Gas In Place (Bscf)	11.576
Average Sw	0.1	Condensate In Place (mmbbls)	7.1
Average Porosity	0.04	Initial Bg (ft <sup>3</sup> /scf)	0.00382
Res Temperature (°F)	156	Initial Gas Viscosity (cp)	0.02394
Reservoir Pressure (psi)	4350	Initial Gas Z Factor	0.95298
Reservoir Length (ft)	4800	Initial cg (10 <sup>-4</sup> /psi)	1.61
Reservoir Width (ft)	1000		
Reservoir Well radius (in)	4		
Area (Acres)	110.2		

**Return**

Figure UNC-43: Reservoir Parameters – 100 Acre Drainage, Example Well

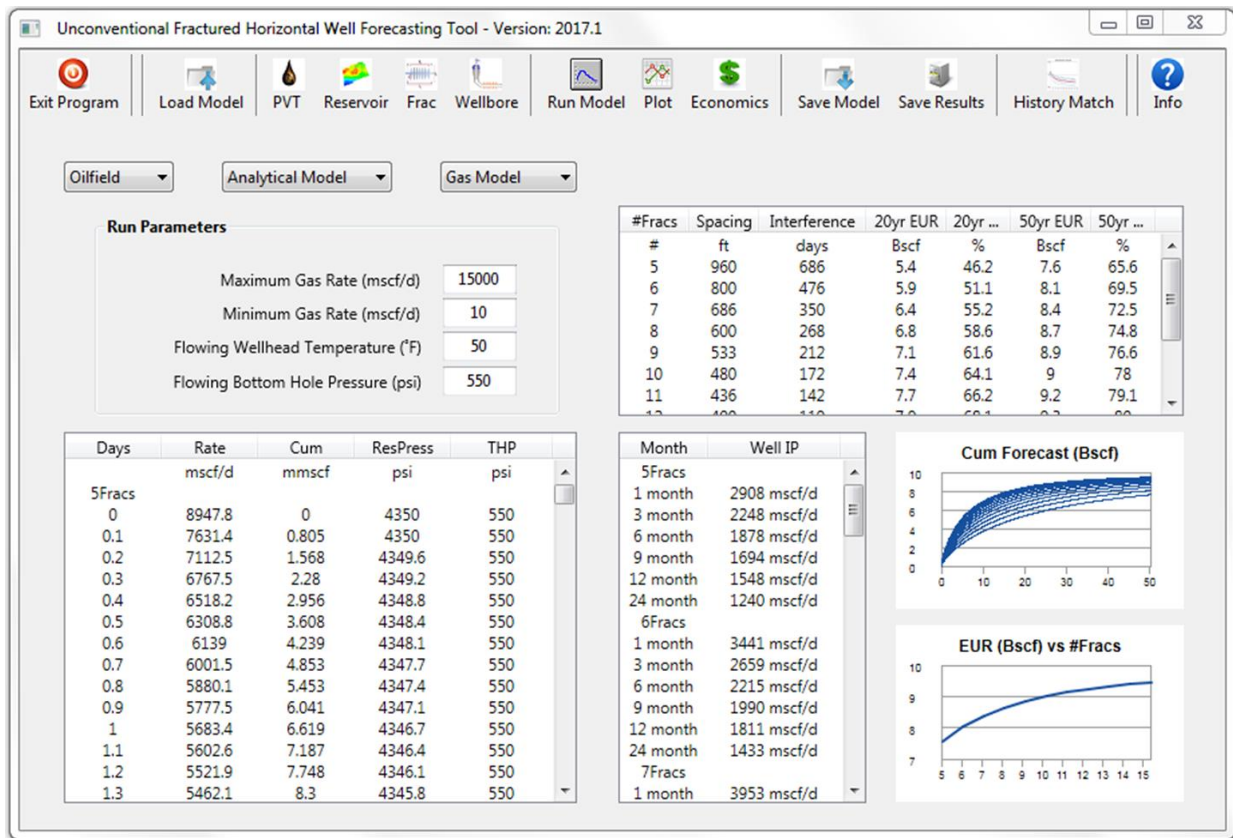


Figure UNC-44: Unconventional Forecast – Example Well



**Step 9:** Enter the Economics Model and enter Capital Costs and Operating Costs (Figure UNC-45).

Figure UNC-45: Capital and Operating Costs – Example Well

**Step 10:** Run the Economics assuming a gas price escalation of 5%/year (Figure UNC-46).

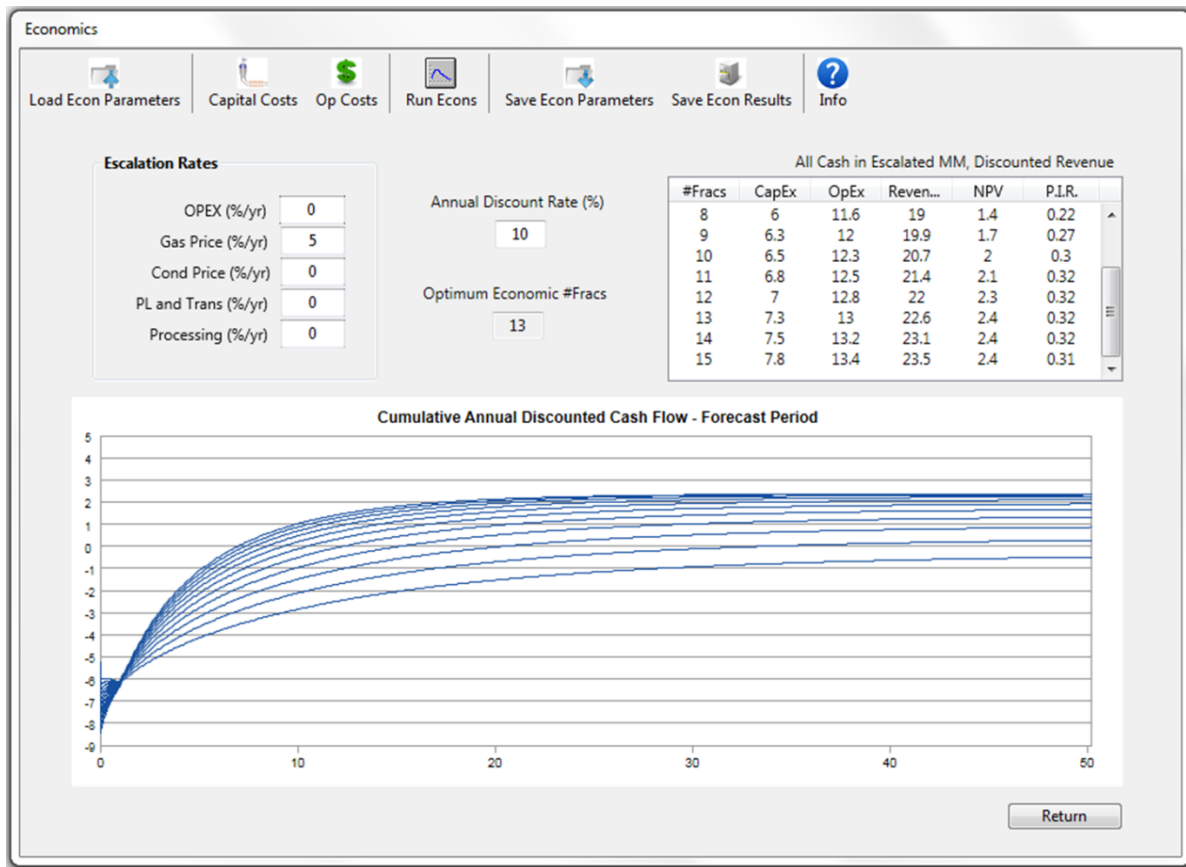


Figure UNC-46: Economics Results – Example Well

The result is that at \$2.75/mscf, the optimum number of hydraulic fractures would be 13.

## Basic Reservoir Simulation Tool

The PE<sup>2</sup> Essentials ‘Basic Reservoir Simulator’ (Figure SIM-1) is a single well numerical simulator based on the DOE BOAST (Black Oil Applied Simulation Tool) public domain simulator. A number of versions of the DOE simulator exist and the PE<sup>2</sup> Essentials implementation of the simulator incorporates a number of options from the different versions. An excellent reference on the practical aspects of reservoir simulation is the book by Mike Carlson – Practical Reservoir Simulation published by PennWell in 2003.

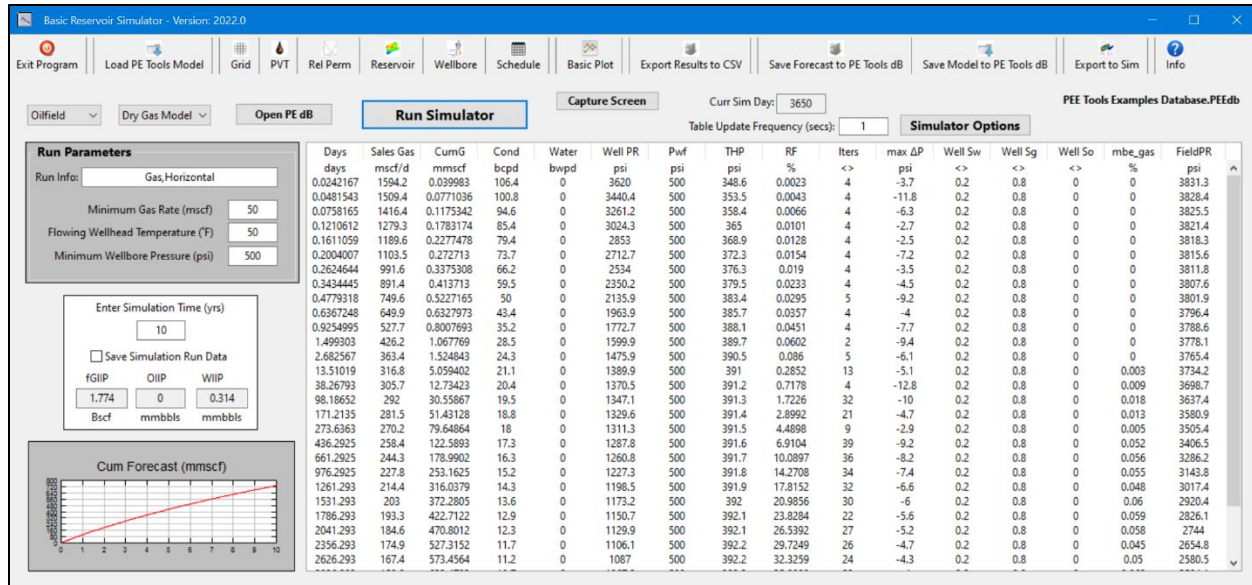


Figure SIM-1: PE<sup>2</sup> Essentials – Basic Reservoir Simulator Tool

The PE<sup>2</sup> Essentials Basic Reservoir Simulator can model recovery using a vertical or horizontal well in a gas or oil reservoir. For a gas reservoir, only a dry, volumetric gas reservoir is modeled (no retrograde condensate, no aquifer). For an oil reservoir, all phases can be modeled and there is an option to model a dipping reservoir to allow both up dip gas-oil and down dip water-oil contacts. Since the simulator is an IMPES solution, caution should be used if modeling gas coning or water cusping.

The Unconventional Forecasting tool includes a stripped-down version of this simulator specifically designed to model a single stage of a horizontal hydraulically fractured well.

The Basic Reservoir Simulator includes an option to export the reservoir model ('Export to Sim') to a data file that can be run by an industry standard simulator. The DOE BOAST III executable (max grid size: 30 x 28 x 7), manual and example data file are included in the 'PE Essentials/Public/BOAST III' directory.

During a run of the PE<sup>2</sup> Essentials Basic reservoir Simulator, a file with the extension '.dvxg' is stored in the "PE Essentials\Simulator Run Files" directory. This file contains the dynamic grid



information for the forecast. The file name includes the date and the entered 'Run Info' as well as a randomly generated number (eg - 201766\_Gas, Horizontal,1-frac\_757.dvvg). The number included on the initial run will be incremented by 1 for re-runs. The dynamic grid data can be imported and examined using 'Basic Plot'. Note that previously stored '.dvvg' files can be imported into the simulator and examined without running the model by loading the model and then clicking 'Basic Plot'.

Note that checking the 'Save Simulation Run Data' will save and update a run file as the run progresses in the "PE Essentials\Simulator Run Files" directory with a similar file naming convention as described above for the dvvg file but with a '.csv' extension. To compare forecasts from different runs, the 'Save Simulation Run Data' option can be used and the forecast data imported into PE Essentials Chart and compared with other runs.

There are a number of model input files included in the PE Essentials Tools Database included in the "Example Input Files\PEE Tools Database" directory as described below.

- Gas,NonComLayers:  
Layered dry gas reservoir section with non-communicating layers.  
Layer communication set to zero by placing 'shale' streaks between each layer.
- Gas,Horizontal:  
Dry gas reservoir section with a horizontal well in the x-direction.  
The horizontal well is placed in i=2 to 14, j=10 and layer 2.
- Gas,Horizontal,1-frac:  
Dry gas reservoir section with a hydraulically fractured horizontal well at 2-14,10,2.  
Model of one frac assuming a 500ft frac stage and a 1000ft well spacing.  
Frac has an  $x_f$  of 200ft and is placed at i=8 by modifying the perms in i=8 and j=5 to 15.  
The equivalent fracture permeability of 5 md for this grid system was calculated from:  
$$k_f = \text{FCD Perm } x_f / dx(8), \text{ where FCD}=5, \text{ Perm}=0.1, x_f=200 \text{ and } dx(8)=2.$$
  
Maximum time step size for this model was limited to 0.5 days.
- Oil,Dipping,GaussianPermPoro:  
Model of a dipping oil reservoir section with a gas cap and a large active aquifer.  
Aquifer is modeled with large outer blocks.  
Aquifer strength is modeled by increasing permeability in the aquifer blocks.
- Oil,Dipping,GaussianPermPoro,Metric:  
Model of a dipping oil reservoir section with a gas cap and a large active aquifer.  
Aquifer is modeled with large outer blocks.  
Aquifer strength is modeled by increasing permeability in the aquifer blocks.

Note that the 'Export to Sim' button will generate a data input file that can be used with an industry standard simulator.

## SIM.1 Grid Construction

The 'Grid' button will open the grid construction sheet (Figure SIM-2).

The 'Grid Properties' window is divided into several sections:

- Grid Dimensions:** Number of x-grids (15), Number of y-grids (11), Number of z-grids (5), Reservoir Depth (7000 ft).
- X Grid Block Sizes:** A table with columns Start, End, and dx (ft). Rows show ranges from 1 to 15 with corresponding dx values (300, 100, 50, 100, 300).
- Y Grid Block Sizes:** A table with columns Start, End, and dy (ft). Rows show ranges from 1 to 11 with corresponding dy values (250, 100, 50, 100, 250).
- Z Grid Block Sizes and Layer Average Properties:** A table with columns Start, End, dz (ft), Porosity, kx, ky, and kz. Row 1 shows values 1 to 5, 50, 0.2, 0.5, 0.5, 0.1.
- Buttons:** Enter Faults (x/y), Enter Barriers (z), Mod X/Y Perm, Inactivate Cells, Reset X Grid, Reset Y Grid, Reset Z Grid, Export Grid Properties, Store Data.
- Other:** Dipping Reservoir checkbox, 0 Degrees, Info button.

Figure SIM-2: Basic Reservoir Simulator – Grid Construction

The grid entry form will increase in size as the grid dimensions are entered (Figure SIM-3) until the final grid is entered.

The 'X Grid Block Sizes' table is shown in three states:

- Initial state with one row: Start 1, End to, dx (ft) =.
- Intermediate state with two rows: Start 1 to 2 = 300, and Start 3 to =.
- Final state with six rows: Start 1 to 2 = 300, 3 to 3 = 100, 4 to 4 = 50, 5 to 5 = 100, 6 to 15 = 300.

Figure SIM-3: Grid Construction – Entering Grid Block Sizes

After entering the average layer properties, it is possible to apply variability to the model's porosity and permeability through a Gaussian distribution routine (Figure SIM-4).

The 'Apply Gaussian Variability to Average Layer Properties' window includes:

- Seed:** -1
- +/-% for Gaussian Distribution:** Porosity (25), kx (25), ky (25), kz (25).
- Apply/Remove Gaussian Variability:** Four checkboxes for Porosity, kx, ky, and kz, all currently unchecked.

Figure SIM-4: Grid Construction – Variable Properties

By checking the appropriate box, a Gaussian distribution routine will modify the entered value based on the input +/-% range (Figure SIM-5).

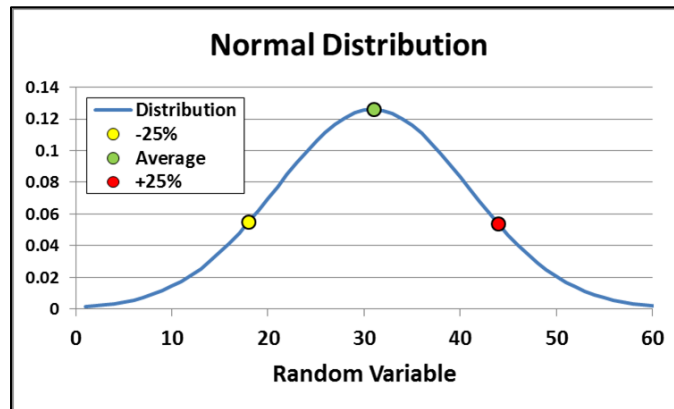


Figure SIM-5: Grid Construction – Property Variation

To generate the same 'random' distribution, a seed value should be entered.

If a dipping reservoir (Figure SIM-6) is being modeled, then the 'Dipping Reservoir' box should be checked and a dipping angle,  $\alpha$ , is entered (insert on Figure SIM-6).

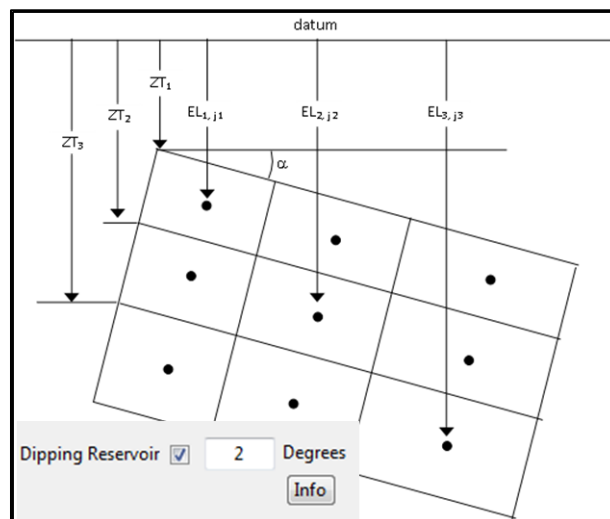


Figure SIM-6: Grid Construction – Dipping Reservoir

Only vertical faults can be modeled and they are assumed to be vertical planes extending from the top to the bottom of the reservoir. Faults are modeled as zero transmissibility at the fault location. Up to 10 faults can be specified in the reservoir model (Figure SIM-7).

**Fault Parameters**

Number of faults (max=10)  Info

	X or Y	Start I	End I	Start J	End J
Fault 1	<input type="text"/>	<input type="text"/>	<input type="text"/>	<input type="text"/>	<input type="text"/>
Fault 2	<input type="text"/>	<input type="text"/>	<input type="text"/>	<input type="text"/>	<input type="text"/>
Fault 3	<input type="text"/>	<input type="text"/>	<input type="text"/>	<input type="text"/>	<input type="text"/>
Fault 4	<input type="text"/>	<input type="text"/>	<input type="text"/>	<input type="text"/>	<input type="text"/>
Fault 5	<input type="text"/>	<input type="text"/>	<input type="text"/>	<input type="text"/>	<input type="text"/>
Fault 6	<input type="text"/>	<input type="text"/>	<input type="text"/>	<input type="text"/>	<input type="text"/>
Fault 7	<input type="text"/>	<input type="text"/>	<input type="text"/>	<input type="text"/>	<input type="text"/>
Fault 8	<input type="text"/>	<input type="text"/>	<input type="text"/>	<input type="text"/>	<input type="text"/>
Fault 9	<input type="text"/>	<input type="text"/>	<input type="text"/>	<input type="text"/>	<input type="text"/>
Fault 10	<input type="text"/>	<input type="text"/>	<input type="text"/>	<input type="text"/>	<input type="text"/>

Modify Grid

**Fault segments**

Figure SIM-7: Grid Construction – Faults

Fault location is determined by the grid block number in the x- and y-direction, and the relative position of the fault in the block. As an example, for a sealing fault in grid 2,4 as indicated in Figure SIM-7, the fault is represented by two segments located at (2,4). The right segment is labeled 'X' because the fault is on the east side of the grid block center and will have a constant x-grid value and variable y-grid values. The northern segment is labeled 'Y' since the fault is located on the north side of the grid block and will have a constant y-grid value and variable x-grid values.

To model a slanted fault, set it up as two vertical faults, one x-fault at I=2 and a y-fault at J=4, as shown in Figure SIM-8.

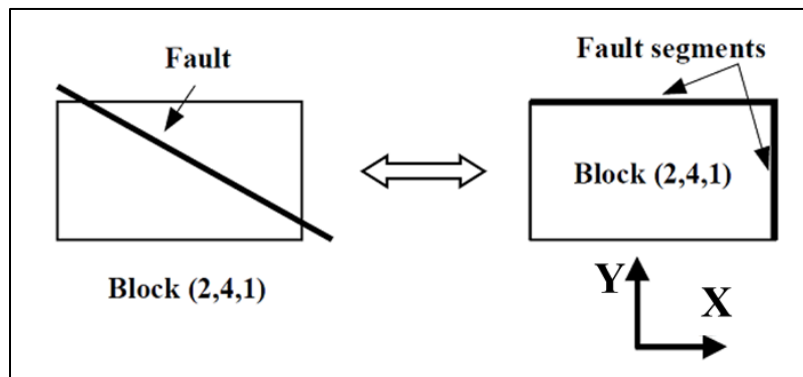


Figure SIM-8: Grid Construction – Modeling a Slanted Fault

Shale barriers can be entered and are modeled as zero z transmissibility (Figure SIM-9).

Shale Barriers

Number of shale barriers (max=10)

	Start I	End I	Start J	End J	Layer K
Barrier 1	1	15	1	11	1
Barrier 2	1	15	1	11	2
Barrier 3	1	15	1	11	3
Barrier 4	1	15	1	11	4
Barrier 5	1	15	1	11	5

3D Grid Visualization: X=1 to 6, Y=1 to 6, Z=1 to 6

Barrier Slices (Right): 1, 2, 4, 6

Buttons: Info, Store Data

Figure SIM-9: Grid Construction – Shale Barriers

Shale barriers can be used to restrict communication between layers. The shale layers have zero thickness and are modeled as zero transmissibility across the layer. Shale layers can be entered over any portion of the layer.

There is an option to enter up to 10 modifications to the x and y permeability values (Figure SIM-10). X and Y permeability values can be entered simultaneously by specifying 'X/Y'.

Modify X/Y Permeability

Number of kx/ky Perm Mods (max=10)

	X,Y or XY	Start I	End I	Start J	End J	Start K	End K	Value
Perm Mod 1								
Perm Mod 2								
Perm Mod 3								
Perm Mod 4								
Perm Mod 5								
Perm Mod 6								
Perm Mod 7								
Perm Mod 8								
Perm Mod 9								
Perm Mod 10								

Button: Modify Grid

Figure SIM-10: Grid Construction – Permeability Modifications

As an example, this option could be used to model an aquifer in a reservoir. Figure SIM-11 shows the modelling of a strong aquifer by setting x-perm and y-perm to 1000md.

Modify X/Y Permeability								
Number of ix/iy Perm Mods (max=10) 1								
	X/Y or XY	Start I	End I	Start J	End J	Start K	End K	Value
Perm Mod 1	xy	15	15	1	11	1	5	1000

Modify Grid

Figure SIM-11: Grid Construction – Modelling an Active Aquifer Using Permeability

Shale and tight streaks within layers can be modeled by inactivating grid cells in the model. Inactivating a complete layer can be implemented when commingled separate intervals, with no inter-layer crossflow, are being produced. Inactivating a cell sets the porosity and permeabilities for that cell to  $1 \times 10^{-10}$ .

There is an option to enter up to 10 regions containing inactive cells (Figure SIM-12).

Inactive Cells					
Number of Inactive Regions (max=10) 10					
	Start I	End I	Start J	End J	Layer K
Region 1					
Region 2					
Region 3					
Region 4					
Region 5					
Region 6					
Region 7					
Region 8					
Region 9					
Region 10					

Store Data

Figure SIM-12: Grid Construction – Specifying Inactive Regions/Cells

After the grid has been fully defined, the grid values can be saved to a 'csv' file through 'Export Grid Properties'. This grid file can be imported into an external plotting program, but it is not formatted for input into PE Essentials Chart.

## SIM.2 PVT Properties

The PVT input properties are dependent on whether the 'Dry Gas Model' (Figure SIM-13) or the 'G/O/W Model' (Figure SIM-14) is being used.

**Gas Properties Input**

**Sales Streams**

	Gas	Liquid
H2S - mol%	0	0
N2 - mol%	0.47	0
CO2 - mol%	1.81	0
C1 - mol%	85.18	0
C2 - mol%	5.44	0
C3 - mol%	3.1	19.82
iC4 - mol%	0.5	6.39
nC4 - mol%	1.22	15.6
iC5 - mol%	0.3	7.63
nC5 - mol%	0.41	10.43
C6 - mol%	0.27	6.87
C7Plus - mol%	1.3	33.25

H2S - mol%   
 N2 - mol%   
 CO2 - mol%   
 C1 - mol%   
 C2 - mol%   
 C3 - mol%   
 iC4 - mol%   
 nC4 - mol%   
 iC5 - mol%   
 nC5 - mol%   
 C6 - mol%   
 C7Plus - mol%   
 Σ Comps   
 C7Plus MW

Gas MW   
 Raw Gas G   
 Gas Pc (psi)   
 Gas Tc (°R)   
 Sales Gas G   
 GHV (btu/scf)   
 Shrinkage (%)   
 Liquids (bbls/mmssc)   
 Liquid Density (°API)   
 Water (bbls/mmssc)

Figure SIM-13: PVT Properties – Dry Gas Model

**Oil Properties**

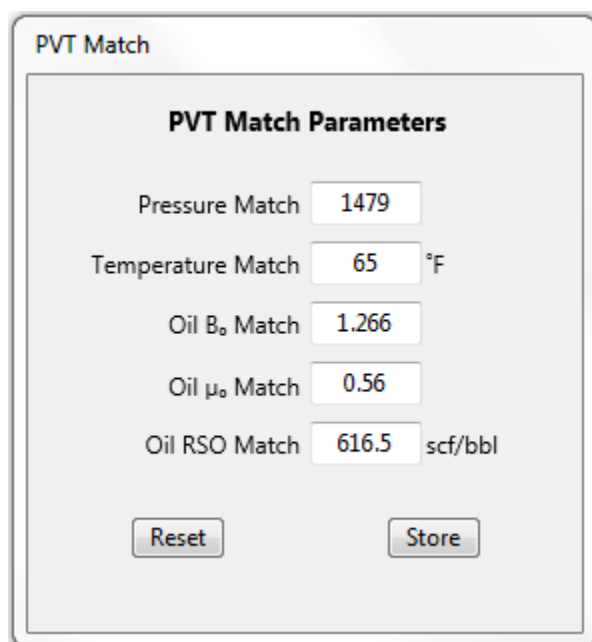
Oil API   
 Separator Gas Gravity   
 Separator Pressure (psi)   
 Separator Temperature (°F)   
 Water Salinity (ppm NaCl)

Corrected Gas G   
 Gas Pc (psi)   
 Gas Tc (°R)

Figure SIM-14: PVT Properties – Gas/Oil/Water Model

The Basic reservoir Simulator uses the PVT BASE correlations as described for the PVT tool. PVT properties can also be imported from the PE Tools database.

The oil model includes an option to calibrate the oil properties to lab-derived or EOS-derived properties. This is implemented through the 'Match PVT Parameters' button (Figure SIM-14 and SIM-15).



The screenshot shows a software window titled "PVT Match". Inside, there is a section titled "PVT Match Parameters". This section contains five input fields, each with a label and a value: "Pressure Match" with the value "1479", "Temperature Match" with the value "65" and a unit "°F" to its right, "Oil B<sub>o</sub> Match" with the value "1.266", "Oil μ<sub>o</sub> Match" with the value "0.56", and "Oil RSO Match" with the value "616.5" and a unit "scf/bbl" to its right. At the bottom of the window, there are two buttons: "Reset" and "Store".

Figure SIM-15: PVT Properties – Match Oil Properties

The matching parameters can be obtained from a laboratory PVT report or can be generated by the PE<sup>2</sup> Essentials Basic EOS PVT program. The pressure and temperature point entered for the match is normally the reservoir temperature and the bubble point pressure of the oil.

The match routine will apply a constant correction to all the values calculated by the internal routines. The adjusted oil parameters are used in the simulator. Refer to the PVT tool for more information on matching oil PVT properties.



### SIM.3 Relative Permeability

The relative permeability inputs are dependent on whether the 'Dry Gas Model' (Figure SIM-16) or the 'G/O/W Model' (Figure SIM-17) is being used.

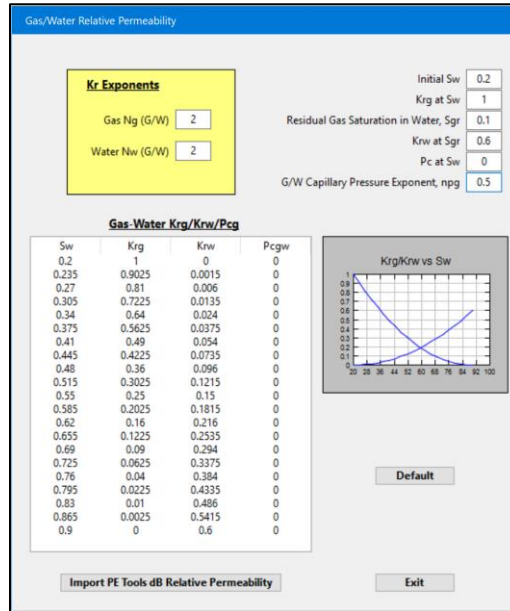


Figure SIM-16: Relative Permeability – Gas Model

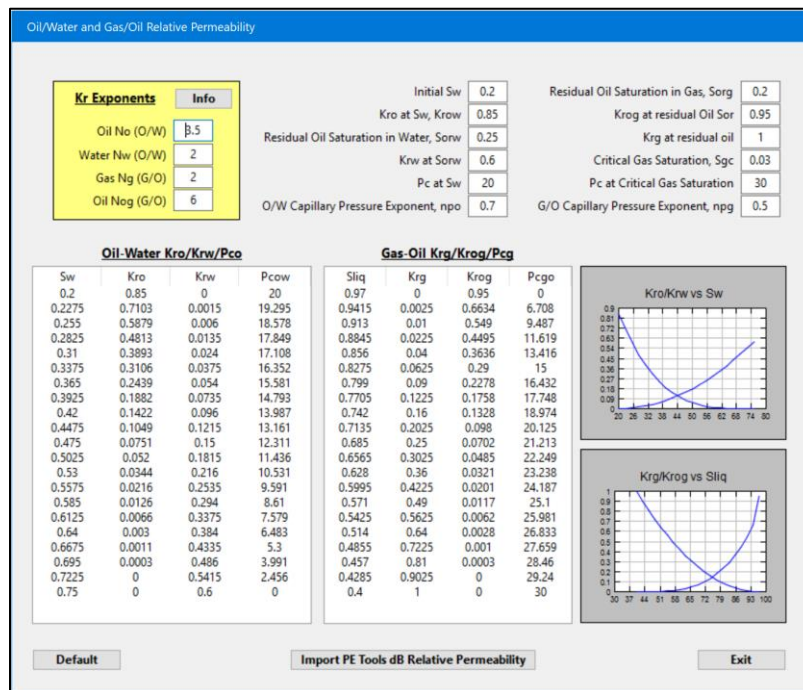


Figure SIM-17: Relative Permeability – Gas/Oil/Water Model

The letter  $k$  represents the absolute permeability of the reservoir (in md) and  $k_o$ ,  $k_g$  and  $k_w$  represent the effective permeability to oil, gas and water. The fluid saturations,  $S_o$ ,  $S_g$  and  $S_w$  must also be specified to fully define the conditions for the value of effective permeability. Studies have shown that a reservoir's effective permeability in terms of the reservoir fluid is a function of the saturation of that fluid and the wetting characteristics of the reservoir.

Since there are many possible values for saturation, effective permeability is normally reported as relative permeability:  $k_{ro}$ ,  $k_{rg}$  and  $k_{rw}$ .

$$k_{ro} = k_o/k$$

$$k_{rg} = k_g/k$$

$$k_{rw} = k_w/k$$

Effective permeability ranges from zero to  $k$  so relative permeabilities range from zero to one.

$$0 \leq k_{ro}, k_{rg}, k_{rw} \leq 1.0$$

When all three phases are present in the reservoir, the sum of the relative permeabilities is variable and less than or equal to one:  $k_{ro} + k_{rg} + k_{rw} \leq 1.0$ .

#### Oil-Water System ( $K_{ro}/K_{rw}$ and $P_{cow}$ )

For an oil-water system the relative permeability analytical equations use exponents as follows.

$$k_{ro} = k_{row} ((1 - S_w - S_{orw})/(1 - S_{wi} - S_{orw}))^{N_o}$$

$$k_{rw} = k_{rwe} ((S_w - S_{wi})/(1 - S_{wi} - S_{orw}))^{N_w}$$

$$P_{cow} = P_{c(S_{wi})} ((1 - S_w - S_{orw})/(1 - S_{wi} - S_{orw}))^{N_{po}}$$

Where  $N_o$  is the exponent for oil,  $N_w$  is the exponent for water and  $N_{po}$  is the oil capillary pressure exponent,  $k_{row}$  is the  $k_{ro}$  at  $S_{wi}$ ,  $S_{wi}$  is the initial water saturation,  $S_w$  is the desired water saturation,  $S_{orw}$  is the residual oil saturation,  $k_{rwe}$  is the  $k_{rw}$  at  $S_{orw}$ ,  $P_{cow}$  is the oil-water capillary pressure and  $P_{c(S_{wi})}$  is the capillary pressure at  $S_{wi}$ .

#### Gas-Oil System ( $K_{rog}/K_{rg}$ and $P_{cog}$ )

For gas-oil system the relative permeability analytical equations are as follows.

$$k_{rg} = k_{rg(S_{org})} ((S_g - S_{gc})/(1 - S_{wi} - S_{org} - S_{gc}))^{N_g}$$

$$k_{rog} = k_{roge} ((1 - S_g - S_{wi} - S_{org})/(1 - S_{wi} - S_{org}))^{N_{og}}$$

$$P_{cog} = P_{c(S_{gc})} ((S_g - S_{gc})/(1 - S_{wi} - S_{org} - S_{gc}))^{N_{pg}}$$

Where  $N_g$  is the exponent for gas,  $N_{og}$  is the exponent for oil in gas and  $N_{pg}$  is the gas capillary pressure exponent,  $k_{rg(S_{org})}$  is the  $k_{rg}$  at  $S_{org}$ ,  $S_{org}$  is the residual oil saturation in gas,  $S_{gc}$  is the critical gas saturation,  $k_{roge}$  is the  $k_{ro}$  at  $S_{org}$ ,  $S_{wi}$  is the initial water saturation,  $S_g$  is the desired gas saturation,  $P_{cog}$  is the gas-oil capillary pressure and  $P_{cog(S_{gc})}$  is the capillary pressure at  $S_{gc}$ .

Normalized water saturation is calculated as  $S_{wn} = (S_w - S_{wi}) / (1 - S_{wi} - S_{orw})$

The following can be used (with caution) as a rule of thumb.

Oil Wet:

No  $\geq 6$

Nw  $< 3$

K<sub>row</sub>  $\geq 0.5$

Intermediate Wet:

6  $< \text{No} \leq 3$

5  $< \text{Nw} \leq 3$

Water Wet:

No  $< 3$

Nw  $\geq 5$

K<sub>row</sub>  $< 0.5$

There is an option to default the parameters.

## SIM.4 Reservoir Parameters

The reservoir input parameters are dependent on whether the 'Dry Gas Model' (Figure SIM-18) or the 'G/O/W Model' (Figure SIM-19) is being used.

Gas Reservoir Properties	
Average Perm (md)	0.01
Average Pay (ft)	300
Average Sw	0.2
Average Porosity	0.06
Reservoir Length (ft)	500
Reservoir Width (ft)	1000
Res Temperature (°F)	160
Reservoir Pressure (psi)	3850
Reservoir Well radius (in)	4
Gas-Water Contact (ft)	7300
Area (Acres)	11.5
Initial Bg (ft³/scf)	0.0040436
Initial Gas Viscosity (cp)	0.0281
Initial Gas Z Factor	0.8877083
Initial cg (10⁻⁴/psi)	1.83
<input type="button" value="Import PE Tools dB Reservoir Parameters"/>	
<input type="button" value="Exit"/>	

Figure SIM-18: Reservoir Parameters – Gas Model

Oil Reservoir Properties	
Average Perm (md)	71.2941
Average Pay (ft)	250
Average Sw	0.2
Average Porosity	0.1982
Reservoir Length (ft)	8650
Reservoir Width (ft)	2650
Res Temperature (°F)	160
Reservoir Pressure (psi)	3850
Reservoir Well radius (in)	4
Bubble Point Pressure (psi)	3875
Area (Acres)	526.2
Initial Bo (bbl/sbbl)	1.444
Initial Oil Viscosity (cp)	0.56
Solution GOR (scf/bbl)	811.5573
Initial co (10 <sup>-3</sup> /psi)	1.312
Water RSW (scf/sbbl)	14.61685
Gas/Oil Contact (ft)	7100
Oil/Water Contact (ft)	7250

Buttons: Import PE Tools dB Reservoir Parameters, Exit

Figure SIM-19: Reservoir Parameters – Gas/Oil/Water Model

The reservoir inputs are similar to the inputs for the Unconventional Forecast Model. Refer to the Unconventional Forecast tool for more information.

## SIM.5 Wellbore Parameters

The wellbore input parameters are dependent on whether a vertical well (Figure SIM-20) or horizontal well (Figure SIM-21) is being modeled.

Wellbore Properties	
<input checked="" type="radio"/> Vertical Well <input type="radio"/> Horizontal Well	
Vertical Well Grid Location (I, J)	8 6
Top Completion Layer (K)	2
Bottom Completion Layer (K)	3
Measured Depth to Top of Completion (ft)	7138.0
True Vertical Depth to Top of Completion (ft)	7000
Tubing ID (in)	2.441
Depth of Tubing (ft)	7000
Casing ID (in)	6
Tubing Correlation	Hagedorn-Brown

Diagram labels: Tubing Depth, Top Perf, Bot Perf, Total Depth

Buttons: Import PE Tools dB Well Model, Exit

Figure SIM-20: Wellbore Parameters – Vertical Well

**Wellbore Properties**

☐ Vertical Well  
☒ Horizontal Well

Start Horizontal Well Location (I, J)    
 Horizontal Completion Layer (K)   
 End Horizontal Well Block (end I)   
 Measured Depth to Top of Completion (ft)   
 True Vertical Depth to Top of Completion (ft)   
 Tubing ID (in)   
 Depth of Tubing (ft)   
 Casing ID (in)   
 Tubing Correlation

The diagram on the right shows a vertical wellbore with a horizontal lateral section at the bottom. Labels indicate 'Tubing Depth' and 'Top of Lateral'.

Figure SIM-21: Wellbore Parameters – Horizontal Well

The main difference between the well inputs is in how the location of the well is entered into the model. For a vertical well the top and bottom completion layer are specified along with the I,J grid location for the wellhead. For a horizontal well, the starting location of the lateral (I, J) is specified, the layer of the completion (K) and the ending block (I) for the lateral are specified.

The available tubing correlations are dependent on the fluid model being used; only the Modified Hagedorn-Brown correlation is available for an oil reservoir.

## SIM.6 Well Schedule

The 'Schedule' button is used to input the scheduling parameters for the well. It can also be used to enter historical data if the simulator is being used to generate a history match prior to forecasting (Refer to Section SIM.9 for an example of importing a historical schedule). Figure SIM-22 shows the schedule input screens. It is possible to enter a schedule manually (maximum of 10 events) or import a schedule from either a CSV file or an Excel spreadsheet.

Importing a schedule file will overwrite any previous schedule data as well as any manually entered schedule events. Up to ten schedule events can be entered manually (there is no limit on the number of imported schedule events).

Figure SIM-22: Importing a Well Schedule

The first time is always '0' since it represents the start of the simulation. All other items can be entered for any time but subsequent events must be increasing in time. If more than 10 items are required, they must be entered using the 'Import Schedule' option. It should be noted that for a gas reservoir, 'Rate' is the gas rate in mscf/d or  $10^3 \text{sm}^3/\text{d}$ . For an oil reservoir, rate is bopd or  $\text{m}^3/\text{d}$ . BHP is entered in psi or kPa. In all cases time is entered in years. Refer to the info button for more information on file formats.

Completion layers in a vertical well, or 'I' blocks in a horizontal well, can be opened and closed during the simulation using the 'Open/Close Block' input box. This allows recompletion of sections of the well. To open or close a grid block, it must be included in the original completion description of the well (Section SIM.5).

To shut in a layer, or I-block, enter the layer or I-block number as a negative value. For instance, '-3' will shut-in layer 3 in a vertical well. To reopen the layer, enter a positive value ('3' will reopen layer 3). Once shut-in, a layer or I-block, will remain shut in until it is specifically re-opened in the schedule. Multiple schedule items can occur at the same time by entering the same time for the activity.

When using a historical schedule, the BHP values in the schedule file should be set to 15 psi or 101 kPa. This value is specified since the rate is used as the known parameter and BHP is calculated by the simulator. The BHP value in a schedule file is the minimum flowing pressure and will be used to modify the rate.

To allow modelling of the shut in of a well, the minimum rate on the main screen should be set to -1. This ensures the simulation is not stopped because of a minimum rate caused by the shut in.

## SIM.7 Simulator Options

The 'Simulator Options' (Figure SIM-23) allow the execution parameters of the simulator to be modified.

Figure SIM-23: Simulator Options

If a number of runs are being made, it may be worthwhile to generate a couple short runs to determine the optimum parameters to be used for that specific model. The Simulator Options are saved with the model so they do not have to be re-entered.

'Run Control Parameters' (Figure SIM-24) control how the run progresses and is terminated.

Figure SIM-24: Simulator Options – Run Control Parameters

The following describes each of the parameters.

Nmax: Maximum number of time steps allowed before run is terminated

Factor1: Factor for increasing time step size under automatic time step control

Factor1 = 1.0 for a fixed time step size of  $\Delta T$

Factor2: Factor for decreasing time step size under automatic time step control

Factor2 = 1.0 for a fixed time step size of  $\Delta T$

WORmax: Limiting maximum field water-oil ratio, in bbl/bbl ( $\text{m}^3/\text{m}^3$ )  
simulation will be terminated if total producing WOR exceeds WORmax

GORmax: Limiting maximum field gas-oil ratio, in scf/bbl ( $\text{scm}/\text{m}^3$ )  
simulation will be terminated if total producing GOR exceeds GORmax

Pb Repressure: Bubble Point repressurisation algorithm  
0 = no repressurisation; 1 = repressurisation will be performed

avgPmin: Limiting minimum average field pressure, psia/kPaa  
simulation terminated if average reservoir pressure falls below avgPmin

avgPmax: Limiting maximum average field pressure, psia/kPaa  
simulation terminated if average reservoir pressure exceeds avgPmax

$\Delta T$ : Initial time-step size (days)

$\Delta T_{\min}$ : Minimum time-step size (days)

$\Delta T_{\max}$ : Maximum time-step size (days)

The Run Control Parameter that can significantly impact the run time is ' $\Delta T_{\max}$ '.

'Solution Control Parameters' (Figure SIM-25) controls the solution tolerance for the iteration. Iterations will be performed until all tolerances have been met.

The figure shows a 'Solution Control Parameters' dialog box. It contains several input fields and two radio buttons. The fields are: 'Max Iterations' with a value of 200, 'ΔPtolerance (TOL)' with a value of 0.01, 'OMEGA' with a value of 1.2, 'ΔOMEGA (TOL1)' with a value of 0.0001, 'ΔSmax' with a value of 0.01, and 'ΔPmax' with a value of 50. To the right of these fields are two radio buttons: 'LSORx' and 'LSORz'. The 'LSORz' radio button is selected, indicated by a blue dot. At the bottom right of the dialog box is an 'Info' button.

Figure SIM-25: Simulator Options – Solution Control Parameters

There are no specific optimum values for these parameters; the user should experiment with several different values, especially LSORx vs LSORz, to see which ones will yield the optimal result for a particular problem.

Max Iterations: Maximum number of iterations for LSOR convergence

ΔPtolerance: Maximum acceptable pressure change for LSOR iteration convergence.

OMEGA: LSOR solution acceleration parameter.

The initial value for OMEGA must be in the range  $1.0 < \text{OMEGA} < 2.0$ .

ΔOMEGA: Parameter for determining when to change OMEGA.



$\Delta\text{OMEGA} = 0.0$  the initial value is used for the entire simulation

$\Delta\text{Smax}$ : Maximum saturation change (fraction) permitted in any grid-block.

$\Delta\text{Pmax}$ : Maximum pressure change permitted in any grid-block.

The Solution Control Parameters that impact the run time are the ' $\Delta\text{Ptolerance}$ ' and ' $\text{OMEGA}$ '.

'Output Grid Parameters' (Figure SIM-26) control the timing for the generation of an output file of the grid parameters.

Figure SIM-26: Simulator Options – Output Grid Parameters

All the parameters default to zero and have to be set if run time grid files are required. The parameters are described below.

Map Output: Enable saving of solution grid data based on the output interval

Enter '1' to enable, '0' to disable output maps

Pressure Map: Output map of map of grid block pressures

File name: PE\_Essentials\_ResSim\_PrMAP.csv

Sw Map: Output map of map of grid block water saturations

File name: PE\_Essentials\_ResSim\_SwMAP.csv

So Map: Output map of map of grid block oil saturations

File name: PE\_Essentials\_ResSim\_SoMAP.csv

Sg Map: Output map of map of grid block gas saturations

File name: PE\_Essentials\_ResSim\_SgMAP.csv

Pb Map: Output map of map of grid block saturation pressures

File name: PE\_Essentials\_ResSim\_PbMAP.csv

Output maps will be generated at the specified interval. For an output interval of 365 days, maps will be output every 365 days (+/-). For an output interval of 0 days, maps will be output after initialization and at the end of the simulation.

One of the issues with an IMPES solution is when the flow through a cell during a time step is more than 100% of the mobile phase existing in that cell. This occurrence tends to destabilize the

solution of the equations since the material balance of the system is impacted. In a simulation model, this normally occurs in the wellbore grid blocks. To remedy this situation, a technique termed ‘Stabilized IMPES’ is implemented in the PE Essentials Basic Reservoir Simulator.

Stabilized IMPES ensures that the throughput in any cell at any time step is limited to less than 100%. If throughput is >100%, the time step size is reduced and the time step is recalculated. This continues until the throughput in the cell is less than the defined throughput value. This value has been set at 75% for this simulator.

The result of implementing a Stabilized IMPES routine is that the initial time step, and subsequent rate changes, can cause incremental time step sizes to be dramatically reduced. The simulator time step size will recover as flow stabilizes. To account for Stabilized IMPES, the minimum step size,  $\Delta t_{min}$  (Figure SIM-24) should be set to a very small value.

Note that all the run files and grid files generated by this tool are stored in the ‘Simulator Run Files’ directory. As a result, an old run can be imported into the plotting tool by loading model but not running it. Then open the plot module and load the run file from the ‘Simulator Run Files’ directory.

## SIM.8 Quick Plot

The ‘Quick Plot’ button will generate plots of the production forecast, grid parameters and forecast grid parameters. The following examples are from a run of the Oil,Dipping,GaussianPermPoro model.

### SIM.8.1 Production Forecast Plots

Following a run, the production forecast plotting options are shown in Figure SIM-27.

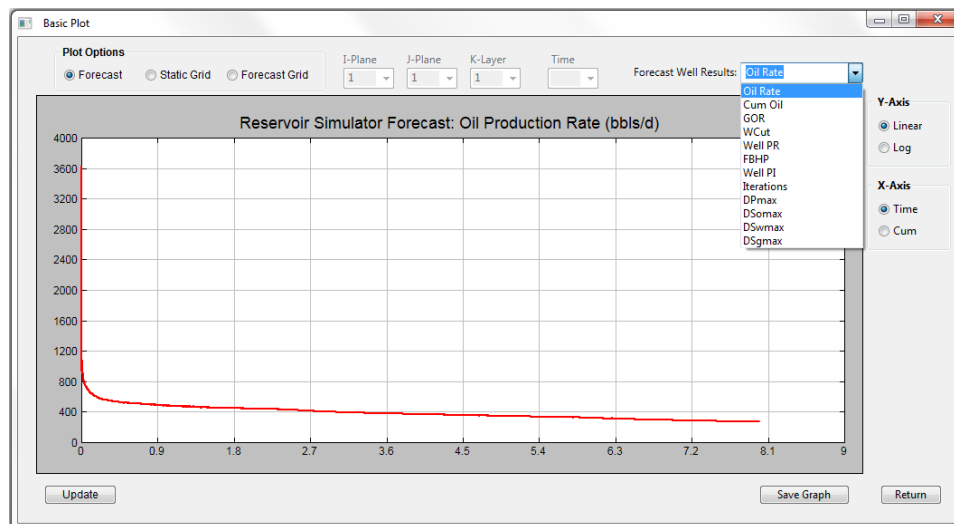


Figure SIM-27: Simulator Options – Production Plot

The production parameters available for plotting are dependent on whether a gas model or an oil model is being used. The data can also be plotted on a log scale and in terms of cumulative volume (Figure SIM-28).

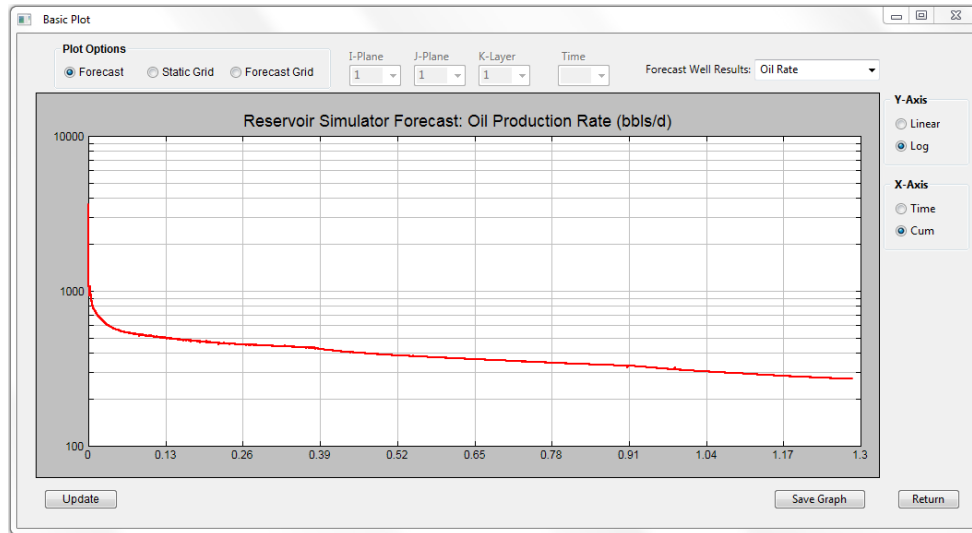


Figure SIM-28: Simulator Options – Production Plot Options

## SIM.8.2 Static Grid Plots

The grid parameters can be plotted as shown in Figure SIM-29. When plotting the grid, the location of the wellbore is presented in red and the faults are presented in blue.

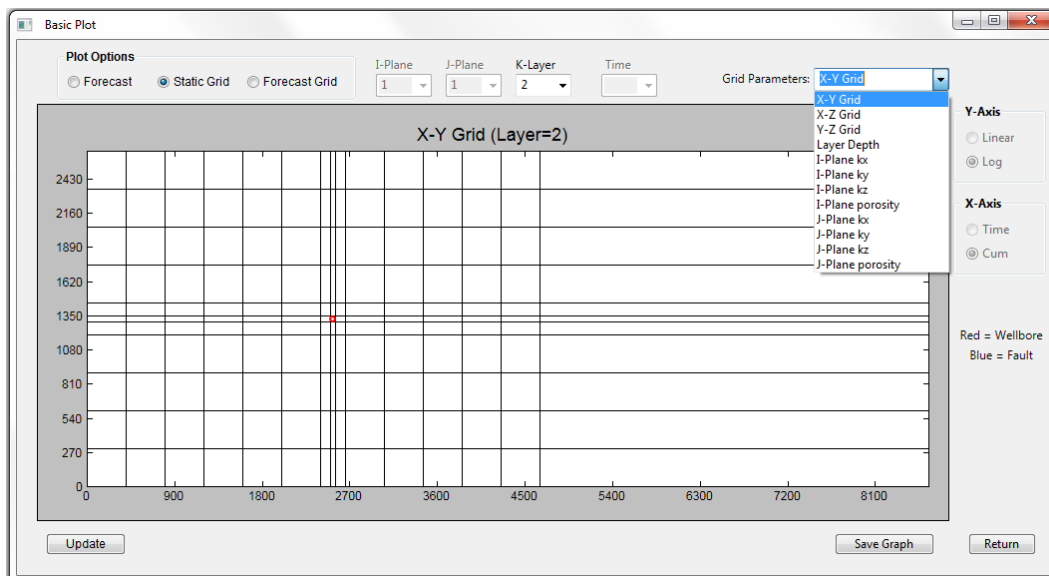


Figure SIM-29: Simulator Options – Static Grid Plot

Figure SIM.30 is an x-y plot of layer 2 showing the location of the horizontal well in the Gas,Horizontal model.

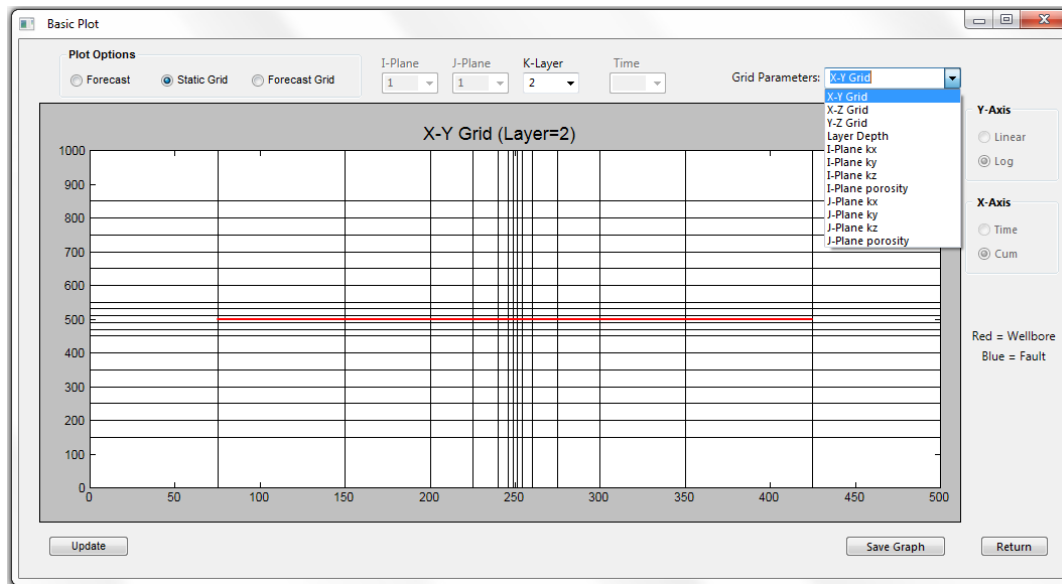


Figure SIM-30: Simulator Options – Static Grid Plot: Horizontal Well

Figure SIM-31 shows the depth to the top of the grid blocks in the x-z plane. This model is a 'Dipping Reservoir' model with gas/oil and oil/water contacts.

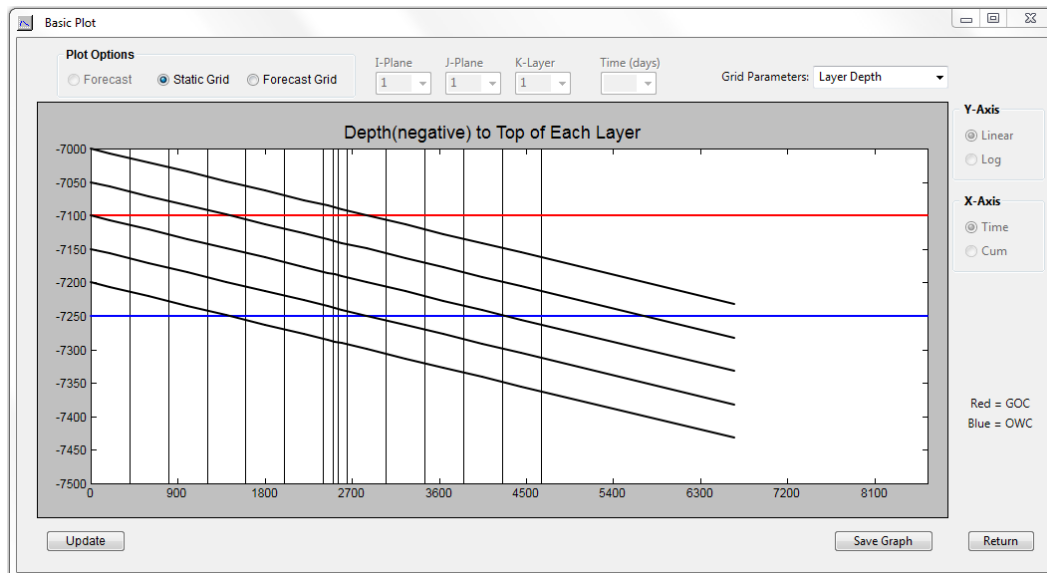


Figure SIM-31: Simulator Options – Static Grid Plot: Layer Depths

Figure SIM-32 shows the Gaussian modified  $k_x$  permeability along the J=6 plane. Note that this model included a strong aquifer in the large outer grid block ( $k=1000\text{md}$ ).

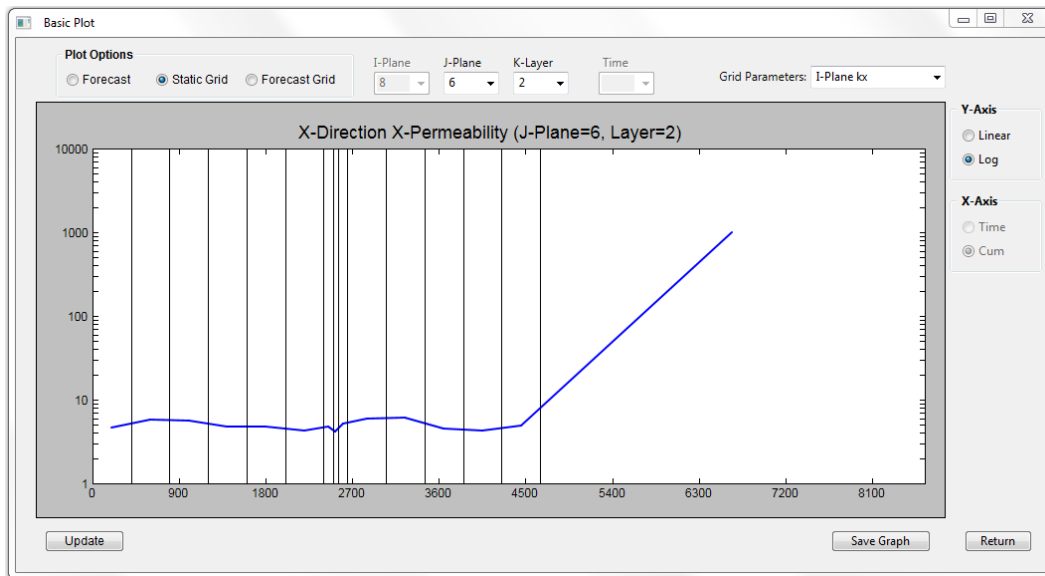


Figure SIM-32: Simulator Options – Static Grid Plot: X-Permeability

Figure SIM-33 presents the Gaussian modified porosity along the I=8 plane.

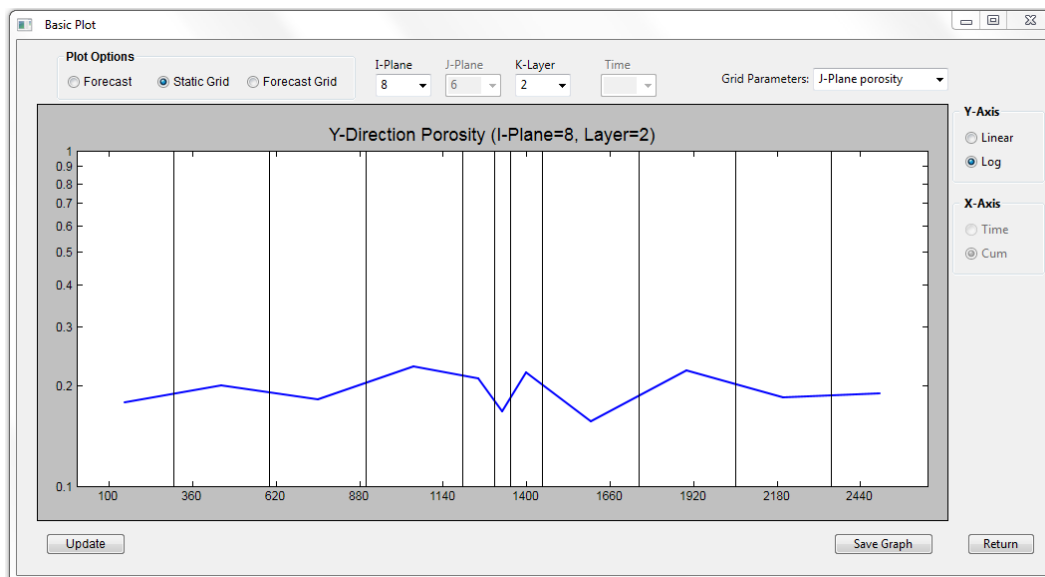


Figure SIM-33: Simulator Options – Static Grid Plot: Porosity

All the available plotting options for the static grid properties allow the model to be QC'd.

## SIM.8.2 Dynamic Grid Plots

The dynamic grid parameters at a specific forecast time can be plotted as shown in Figure SIM-34. Either an X cross section or a Y cross section can be plotted.

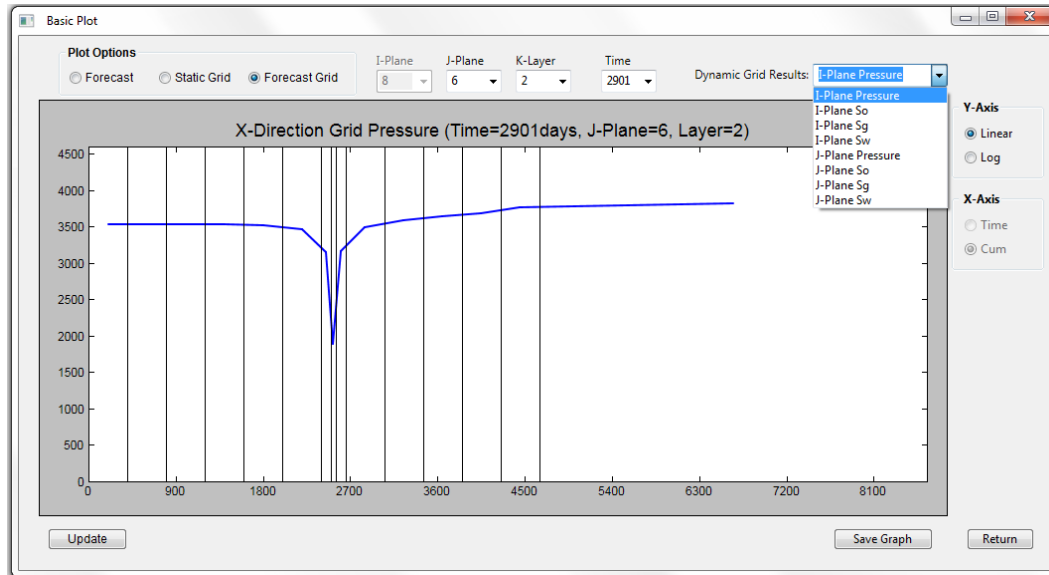


Figure SIM-34: Simulator Options – Dynamic Grid Plot: Pressure

Figures SIM-35 and SIM-36 show water encroachment into the lower well completion.

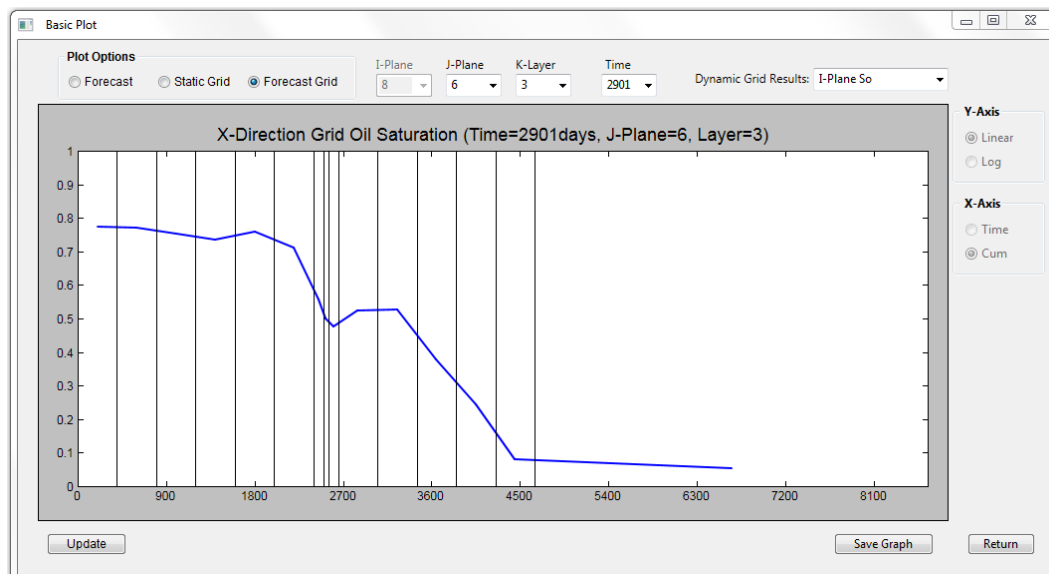


Figure SIM-35: Simulator Options – Oil Saturation, Lower Well Completion Layer

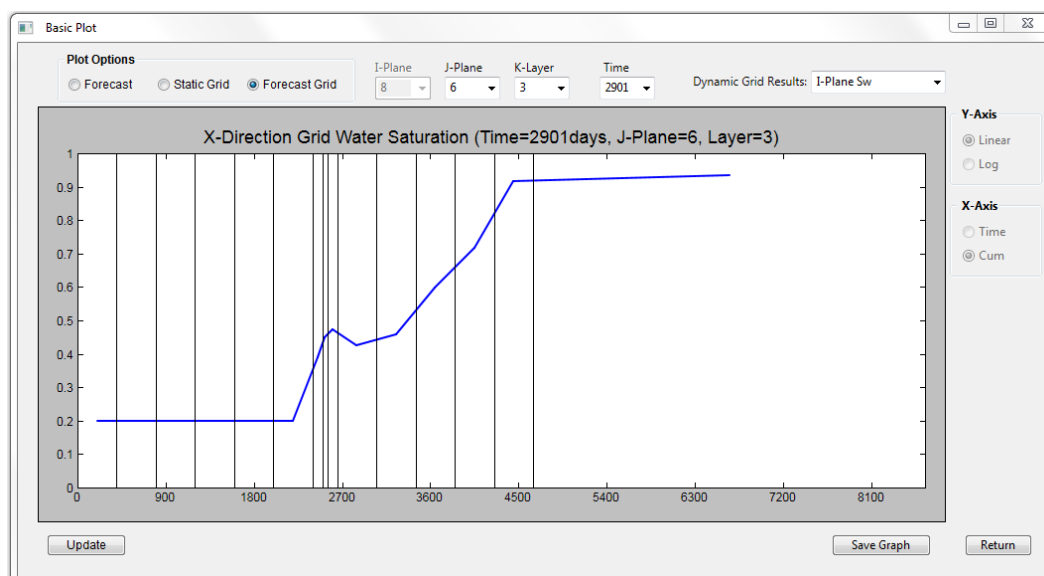


Figure SIM-36: Simulator Options – Water Saturation, Lower Well Completion Layer

‘Save Graph’ will save the active plot to a ‘png’ file. The ‘Update’ button can be used to dynamically update the production plot as the run progresses.

### SIM.9 Example – History Matching a Horizontal Oil Well Test

This example was generated as a demonstration of importing and using a schedule file to match the historical data.

A horizontal test well was drilled into a tight oil reservoir to test the productivity of the reservoir and obtain parameters for future drilling and completion programs. The well was completed without cement using a pre-perforated liner with external casing packers to isolate and test specific intervals.

The well was produced for a total of 203 days and the production data is included in the ‘Horizontal Oil Well Test.xlsx’ file located in the “PE Essentials\ Book Examples\Example Basic Reservoir Simulator” directory. The Excel file includes the schedule for input into the simulator.

A CSV file containing the production history was generated from the Excel file for plotting purposes (‘Horizontal Oil Well Test History Data.csv’).

The Horizontal Oil Well Test model located in the ‘PEE Tools Database Book Examples’ database file located in the “Book Examples\PEE Tools Database Examples” directory includes the model construction parameters. The best guess estimate of permeability for this tight oil reservoir was 0.1 md, as shown on figure SIM-37.

**Grid Properties**

**Grid Dimensions**

Number of x-grids: 25  
 Number of y-grids: 10  
 Number of z-grids: 3  
 Reservoir Depth: 3281 ft

Dipping Reservoir: ☐ 0 Degrees  
 Info

Enter Faults (x/y)  
 Enter Barriers (z)  
 Mod X/Y Perm  
 Inactivate Cells

Reset X Grid  
 Reset Y Grid  
 Reset Z Grid

Export Grid Properties

**X Grid Block Sizes**

Start: 1 to End: 25 = dx (ft): 410

**Y Grid Block Sizes**

Start: 1 to End: 10 = dy (ft): 410

**Z Grid Block Sizes and Layer Average Properties**

Start: 1 to End: 3 = dz (ft): 31  
 Porosity: 0.05  
 kx: 0.1  
 ky: 0.1  
 kz: 0.1

**Apply Gaussian Variability to Average Layer Properties**

Seed: -1  
 +/-% for Gaussian Distribution: 25  
 Apply/Remove Gaussian Variability: ☐ ☐ ☐ ☐

Store Data

Figure SIM-37: Grid Properties – Horizontal Test Well

No other modifications were made to the grid. The remaining model parameters can be viewed by clicking the appropriate buttons. The wellbore information is presented in Figure SIM-38.

**Wellbore Properties**

☐ Vertical Well  
☒ Horizontal Well

Start Horizontal Well Location (I, J):    
 Horizontal Completion Layer (K):   
 End Horizontal Well Block (end I):   
 Measured Depth to Top of Completion (ft):   
 True Vertical Depth to Top of Completion (ft):   
 Tubing ID (in):   
 Depth of Tubing (ft):   
 Casing ID (in):   
 Tubing Correlation: Hagedorn-Brown

Import PE Tools dB Well Model

Exit

Diagram: A vertical wellbore with a horizontal lateral section. Labels include Tubing Depth, Top of Lateral, and a diagram of the wellbore structure.

Figure SIM-38: Wellbore Properties – Horizontal Test Well



Figure SIM-38 shows that the horizontal well was completed in layer 2 and is located from grid block (3, 8) to grid block (12, 8). In fact, the well was actually completed in two intervals, equivalent to grid blocks (3, 8) to (4, 8) and grid blocks (9, 8) to (12, 8). The schedule is used to shut-in the intervening grid blocks, (5, 8) to (8, 8).

Figure SIM-39 shows the import of the schedule file from the Excel spreadsheet. In total, there were 179 schedule events imported for this well. If a forecast is also required, the forecast parameters can be manually entered by changing the 'Number of Well Schedule Events' to a number between 2 and 10 on the 'Well Schedule' page.

**PE Essentials Simulation Schedule Import**

**Data Input**

☐ CSV File ☒ Excel File

Note: Oil rate in bopd and minimum BHP in psi

**Excel Input Parameters**

	Column	Start Row	End Row
Time in Years	a	3	180
Oil Rate	b	3	180
Minimum BHP	c	3	180
Skin Factor	d	3	180
Layer # open/close	e	3	180

**Well Schedule**

Number of Well Schedule Events: 1  
Total Number of Schedule Events: 178

	Time	Oil Rate	BHP	Skin	Open/Close Block
Schedule 1	0.55602	59.1	15	0	0

Figure SIM-39: Wellbore Properties – Horizontal Test Well

Figure SIM-40 shows the data in the Excel file that was imported in Figure SIM-39.

Time yrs	Rate bopd	BHP psi	Skin <>	Layer O/C #
0	24.2	15	0	-5
0	24.2	15	0	-6
0	24.2	15	0	-7
0	24.2	15	0	-8
0.005904	50.7	15	0	0
0.008643	60.9	15	0	0
0.011385	71.1	15	0	0
0.014123	121.8	15	0	0
0.016863	74.1	15	0	0
0.019602	35.2	15	0	0
0.022344	133.5	15	0	0
0.025086	77.1	15	0	0
0.027823	83.6	15	0	0
0.030561	74.5	15	0	0
0.033305	85.8	15	0	0
0.036041	70.3	15	0	0
0.038788	89.6	15	0	0

Figure SIM-40: Well Schedule – Excel File

A forecast was generated for the model and the results were exported to a CSV file by clicking 'Save Results' and then compared to the BHP history data using PE<sup>2</sup> Essentials Chart. A second run was made using a permeability of 0.15 md which appears to yield a closer match to the historical BHP (Figure SIM-41).

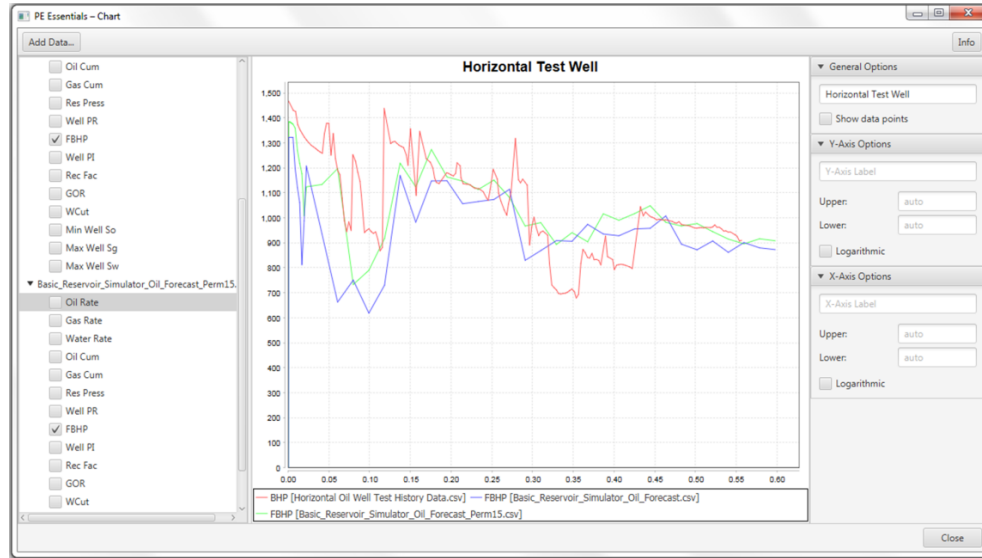


Figure SIM-41: Pressure History Match – Horizontal Test Well

For future analysis, a permeability of 0.15md would then be used.

## Streamtube Waterflood Simulation Tool

The PE<sup>2</sup> Essentials ‘StreamTube WaterFlood’ tool is a simplified streamtube simulation model based on the Leighton and Higgins model (Leighton, A., J. and Higgins, R., V., Improved Method to Predict Multiphase Waterflood Performance for Constant Rates or Pressures, United States Department of the Interior, Bureau of Mines Report of Investigation #8055, 1975). An excellent reference on streamtube simulation is the book by Datt-Gupta and King – Streamline Simulation: Theory and Practice published by SPE in 2007.

A streamtube is a region bounded by two streamlines (Figure SWF-1: Reference – Figure 6 from [http://petrowiki.org/Scaleup\\_to\\_full\\_field\\_miscible\\_flood\\_behavior](http://petrowiki.org/Scaleup_to_full_field_miscible_flood_behavior)).

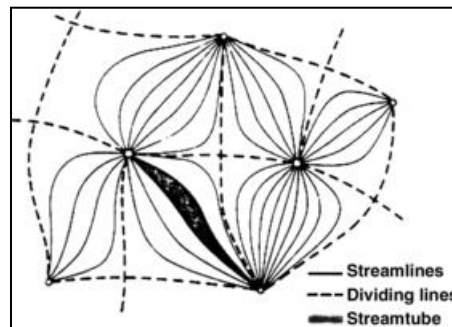


Figure SWF-1: Streamlines and Streamtubes

In Figure SWF-1, the dashed lines outline the area that is being affected by the injector-producer pair. The solid lines are streamlines and represent the tangent of the  $v_x$ - $v_y$  velocity field at a given point at a snapshot in time in the reservoir. They could also (very loosely) be considered to represent the ‘time of flight’ for a particle along the path of the streamline – so the shortest time (highest velocity) to go from the injector to the producer follows the straightest streamline. The streamline is a map of the instantaneous velocity field in the reservoir and does not necessarily represent the physical movement of the particles.

The filled area on Figure SWF-1 is the area between two streamlines and is termed a streamtube. All fluid movement remains within the streamtube since the streamlines are tangential to the fluid velocity. The wider the streamtube the slower the flow and the narrower the streamtube, the faster the flow (flow is cross-sectional area times velocity). As indicated on Figure SWF-1, the fastest flow will occur in a direct line from the injector to the producer – narrowest streamtube.

Streamline simulation provides an alternative to the grid-based techniques used in numerical reservoir simulation. Streamlines represent a snapshot of the instantaneous flow field and thereby produce data such as drainage regions associated with injector-producer well pairs and flow rate allocation between injector-producer pairs that can be quickly determined and are not easily determined by other numerical reservoir simulation techniques.

The PE<sup>2</sup> Essentials 'Stream Tube WaterFlood' tool is used to simulate a pattern waterflood at a constant water injection rate or at a constant pressure (Figure SWF-2).

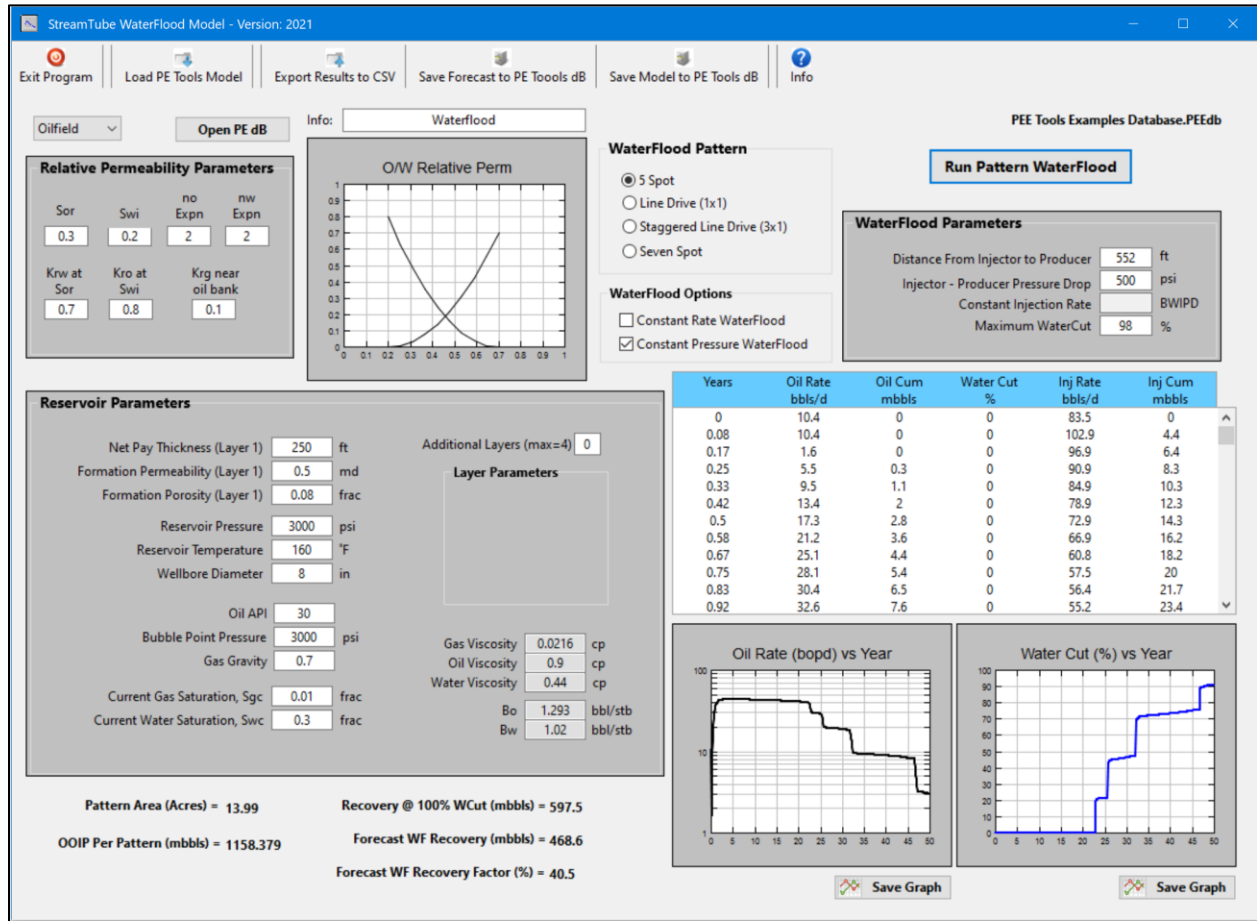


Figure SWF-2: PE<sup>2</sup> Essentials - StreamTube WaterFlood Tool

Four streamtube models are included in this model (Figure SWF-3):

- 5 Spot: 1-to-1 ratio of producer to injector
- Line Drive: 1-to-1 ratio of producer to injector
- Staggered Line Drive (4 Spot): 1-to-3 ratio of producer to injector
- 7 Spot: 1-to-2 ratio of producer to injector

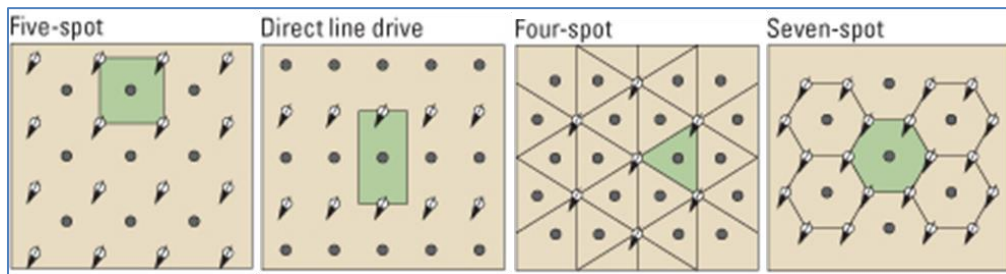


Figure SWF-3: StreamTube WaterFlood Model - Patterns

Note that this model is similar to the Miscible/Immiscible CO<sub>2</sub> WAG WaterFlood Simulator in that they both simulate a waterflood using a streamtube simulator, but this model is limited to waterflood simulations only.

### SWF.1 Reservoir Model

Entering the reservoir model is comprised of inputting 'Reservoir Parameters' and 'Corey Function' (Figure SWF-4) to generate relative permeabilities.

**Reservoir Parameters**

Net Pay Thickness (Layer 1)	50	ft
Formation Permeability (Layer 1)	0.5	md
Formation Porosity (Layer 1)	0.08	frac
Reservoir Pressure	3000	psi
Reservoir Temperature	160	°F
Wellbore Diameter	8	in
Oil API	30	
Bubble Point Pressure	3000	psi
Gas Gravity	0.7	
Current Gas Saturation, S <sub>gc</sub>	0.01	frac
Current Water Saturation, S <sub>wc</sub>	0.3	frac

Additional Layers (max=4) 4

**Layer Parameters**

Poro	Pay	Perm
0.08	50	1
0.08	50	0.2
0.08	50	0.5
0.08	50	0.7

Gas Viscosity 0.0216 cp  
Oil Viscosity 0.9 cp  
Water Viscosity 0.44 cp  
Bo 1.293 bbl/stb  
Bw 1.02 bbl/stb

**Corey Function**

Sor	Swi	no Expn	nw Expn
0.3	0.2	1	1
K <sub>rw</sub> at Sor	K <sub>ro</sub> at Swi	K <sub>rg</sub> near oil bank	
0.7	0.8	0.1	

Figure SWF-4: StreamTube WaterFlood Model - Reservoir Parameters

Most of the reservoir parameters and the Corey function parameters are straightforward. The 'Current Gas Saturation' and the 'Current Water Saturation' enable initialization of the reservoir at a depleted condition.

The 'Layer Parameters' allow some degree of heterogeneity to be modeled.

### SWF.2 Pattern Waterflood Model

Choosing the waterflood model to use for the simulation is comprised of three options (Figure SWF-5).

**StreamTube WaterFlood Model**

- ☐ 5 Spot
- ☒ Line Drive (1x1)
- ☐ Staggered Line Drive (3x1)
- ☐ Seven Spot

**WaterFlood Options**

- ☒ Constant Rate WaterFlood
- ☐ Constant Pressure WaterFlood

**WaterFlood Parameters**

Distance From Injector to Producer	552	ft
Injector - Producer Pressure Drop		psi
Constant Injection Rate	1000	BWIPD
Maximum WaterCut	98	%

Figure SWF-5: StreamTube WaterFlood Model - Waterflood Parameters

One of the four available patterns is chosen and whether this is to be a constant pressure waterflood or a constant rate waterflood. The distance between the injector and producer is entered and, depending on the option chosen, constant pressure drop between the injector and the producer is entered or the constant injection rate. Achieving the maximum water cut value will stop the simulation.

After running the forecast, the results are presented in a table and as plots (Figure SWF-6).

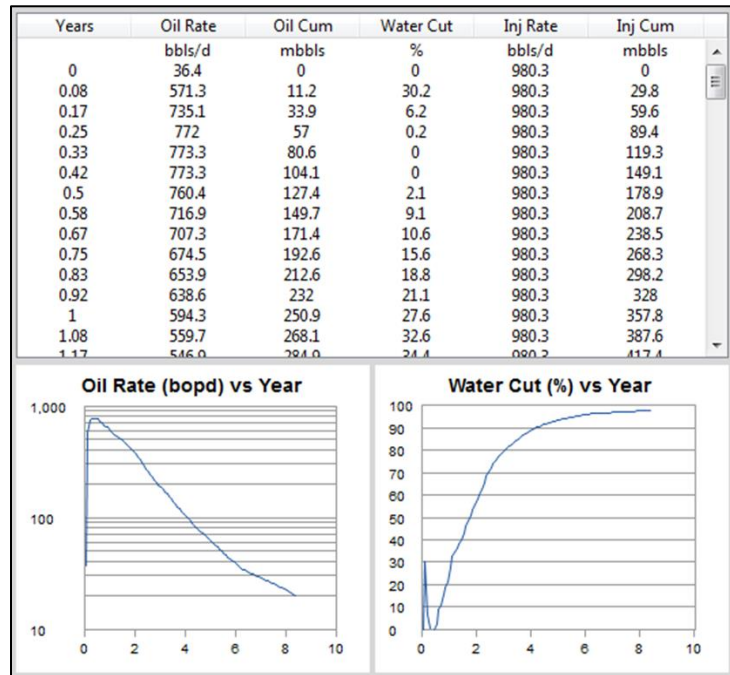


Figure SWF-6: StreamTube WaterFlood Model - Results

'Export Results to CSV' will save the forecast to a 'csv' file for plotting and comparison purposes (PE<sup>2</sup> Essentials Chart). The waterflood forecast can also be saved to the PE Tools database.

### SWF.3 Example - Choosing a Waterflood Pattern

As an example, consider Figure SWF-7 which shows producing well locations in the Weyman – Glasscock County of Texas.

The concept to be investigated is that a pattern waterflood is to be implemented to increase the ultimate oil recovery from the area. Some of the producers will be converted to injectors for the re-development of the area.

A common practice is to keep the best wells as producers and convert the poor wells to water injectors, which normally defines the pseudo waterflood pattern that will be implemented. The



reality is that the best producers make the best injectors and that more thought should go into selecting a pattern to implement.

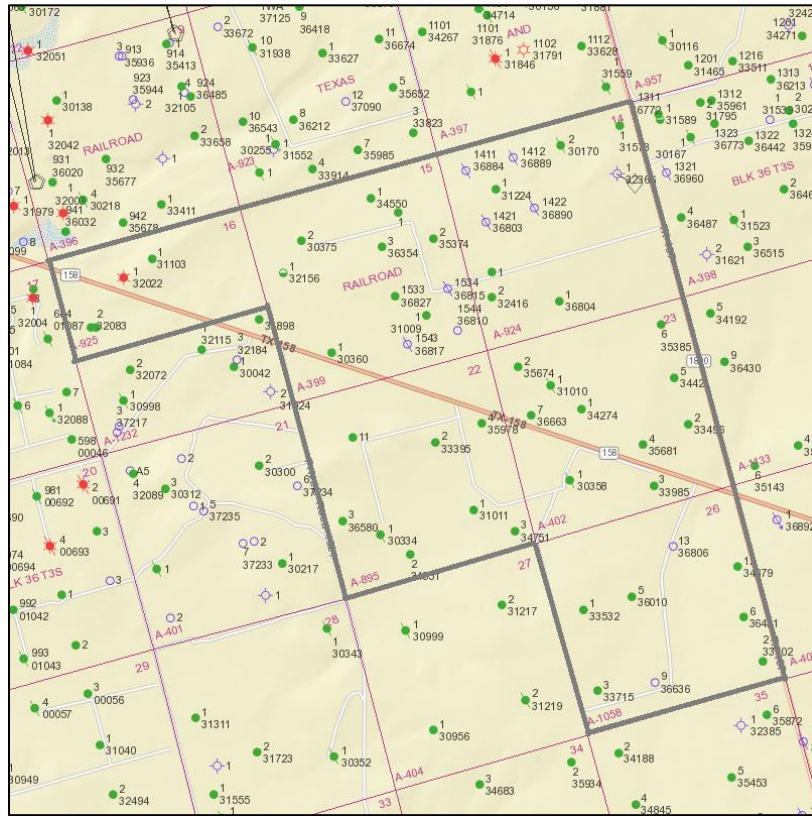


Figure SWF-7: Well Locations in Weyman - Glasscock County of Texas

The StreamTube WaterFlood Model can be used to perform preliminary evaluation of the recovery resulting from utilizing different waterflood patterns.

The model presented in Figure SWF-8 was used to evaluate the recovery resulting from different waterflood patterns. In order to make an equivalent comparison, the ‘Distance From Injector to Producer’ was modified for each pattern in order to set up all patterns to flood a 14 acre area. The models are saved in the ‘PEE Tools Database Book Examples.PEEdb’ located in the “PE Essentials 2022\Book Examples\PEE Tools Database Examples” directory.

The results for each forecast were exported and compared with PE<sup>2</sup> Essentials Chart (Figures SWF-9).

The recovery factors for each pattern are as follows:

- 5 spot: 50.9%
- 7 spot: 53.3%
- Line Drive: 54.4%
- Staggered LD: 53.0%

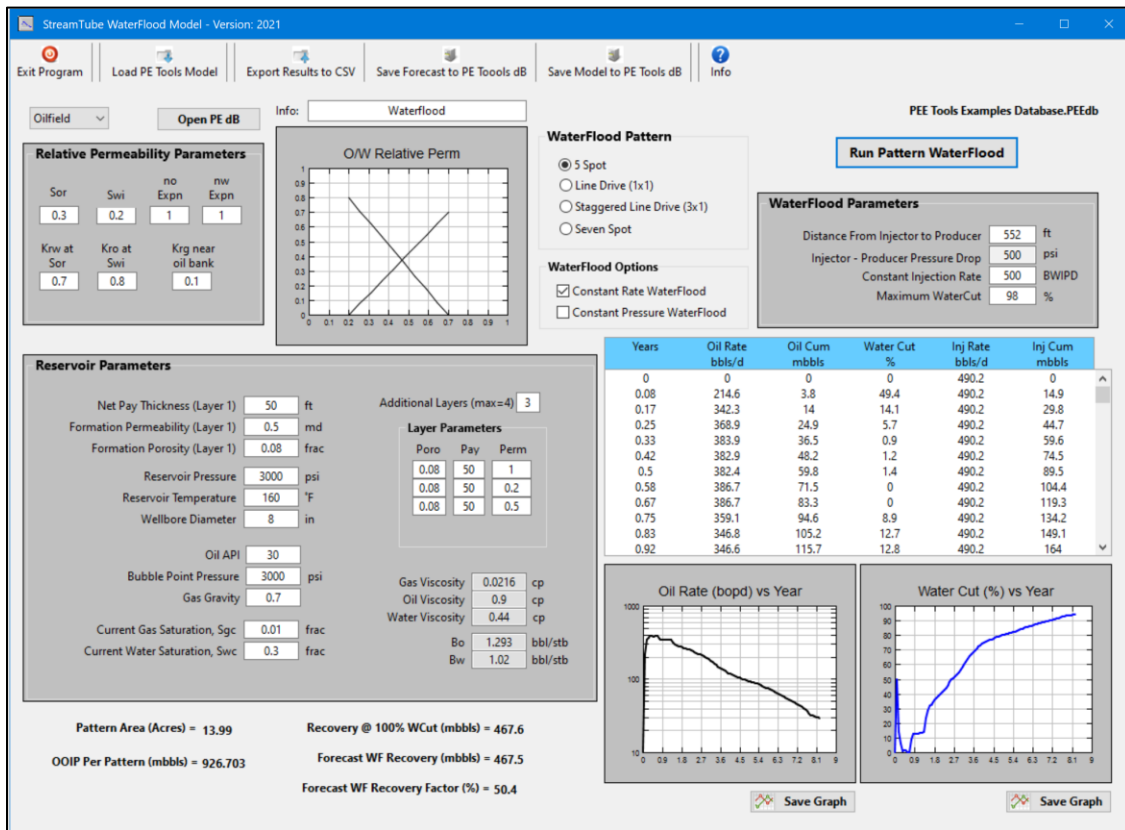


Figure SWF-8: WaterFlood Model for Comparison

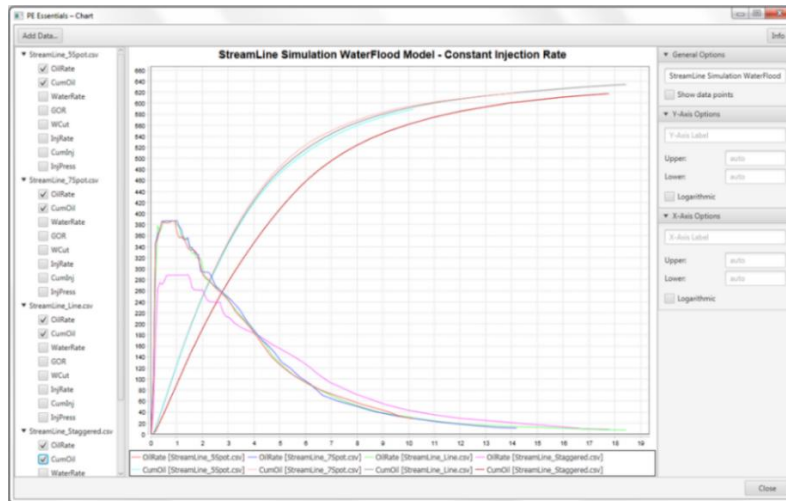


Figure SWF-9: WaterFlood Pattern Comparisons – 14 Acre Patterns

From this example, with all other things being equal, a line drive pattern will yield the highest oil recovery. At this point more analyses, including economics, should be run.



## Misc/Immisc CO<sub>2</sub> WAG Simulation Tool

The PE<sup>2</sup> Essentials ‘Misc/Immisc CO<sub>2</sub> WAG WF’ tool is a streamtube simulation model based on the DOE “CO<sub>2</sub> Miscible Flood Predictive Model” (1986). This public domain simulation model was developed for the DOE to estimate economically recoverable oil from reservoirs amenable to CO<sub>2</sub> miscible flood processes. The DOE program can be used for both secondary (mobile oil) and tertiary (residual oil) floods, and for either continuous CO<sub>2</sub> injection or water-alternating-gas (WAG) processes. Texaco modified the program in 1994 and re-named it CO<sub>2</sub>-Prophet. The CO<sub>2</sub>PM executable, manual and example data files are included in the ‘PE Essentials/Public/CO<sub>2</sub>Miscible’ directory.

Rather than re-build the program in the PE<sup>2</sup> Essentials development environment, this tool will build a data file for the CO<sub>2</sub>PM program and then runs the executable. The results are then imported into the Misc/Immisc CO<sub>2</sub> WAG WF tool for evaluation (Figure CO2-1).

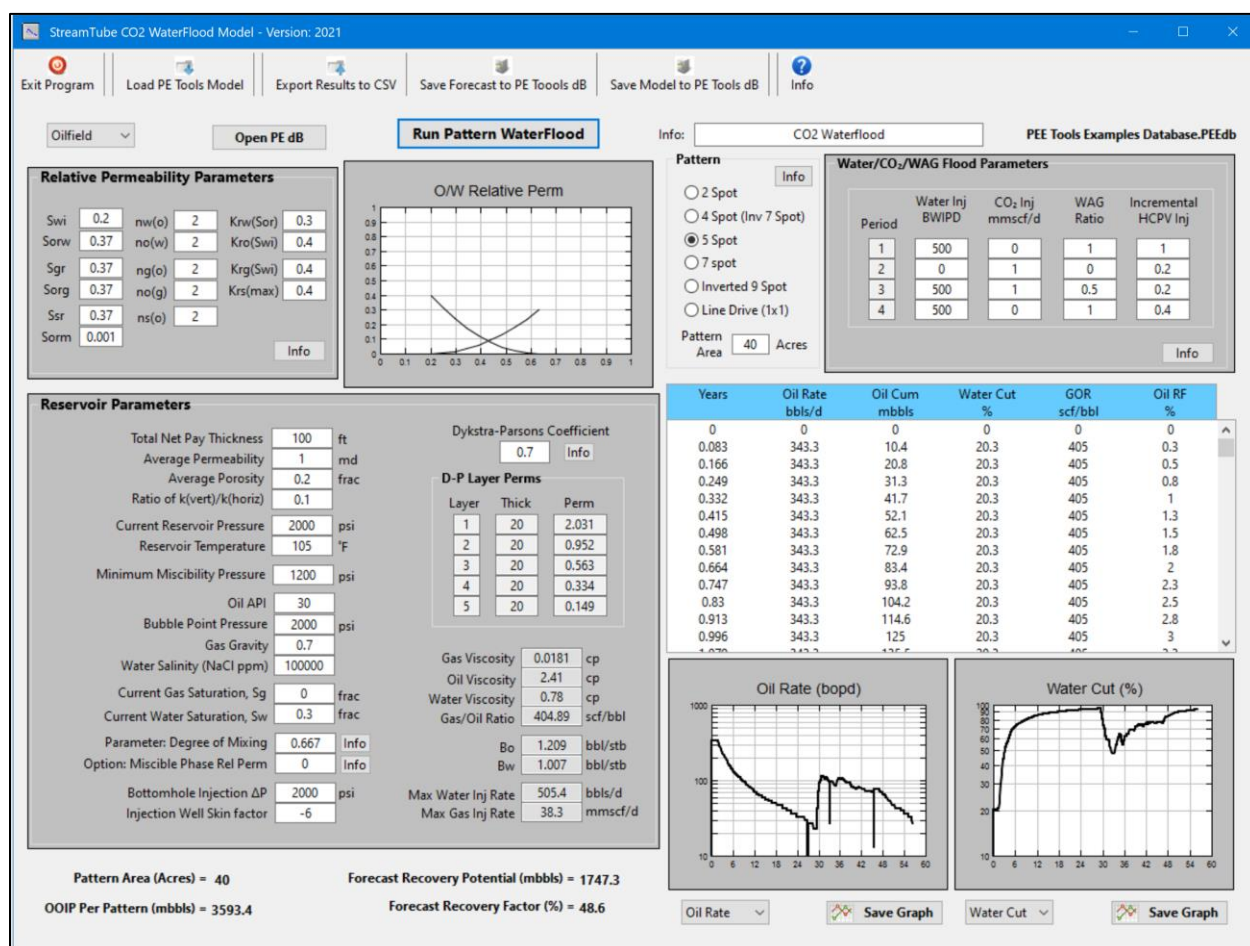


Figure CO2-1: PE<sup>2</sup> Essentials – Misc/Immisc CO<sub>2</sub>, WAG, WaterFlood StreamTube Tool

For more information on miscibility and miscibility pressures, refer to EOR / Heavy Oil Tool.

Six streamtube models are included in this model (Figure CO2-2):

- 2 Spot: 1-to-1 ratio of producer to injector
- 4 Spot: 1-to-2 ratio of producer to injector
- 5 Spot: 1-to-1 ratio of producer to injector
- 7 Spot: 1-to-2 ratio of producer to injector
- Inverted 9 Spot: 1-to-3 ratio of producer to injector
- Line Drive: 1-to-1 ratio of producer to injector

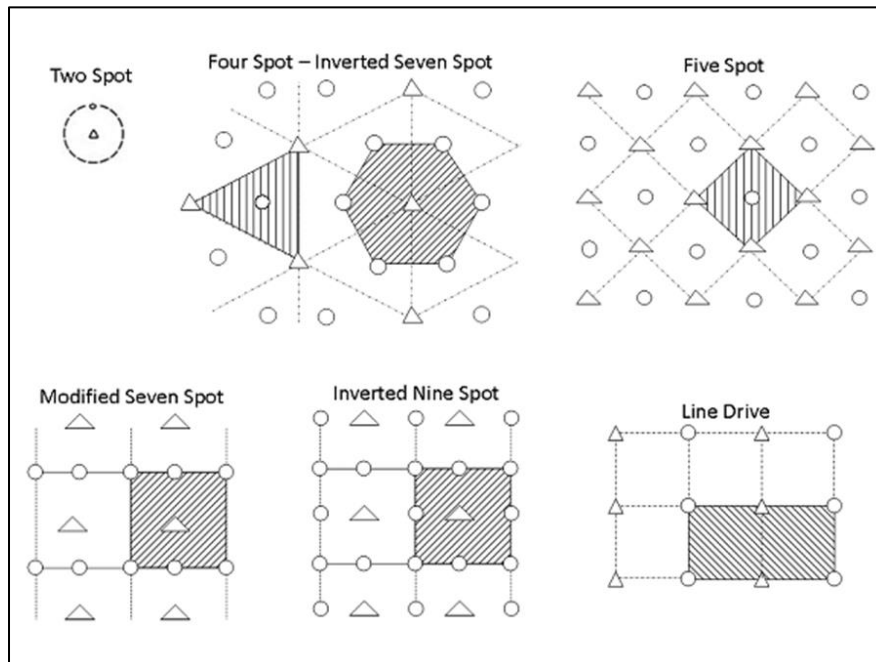


Figure CO2-2: Misc/Immisc CO<sub>2</sub> WAG WF Tool - Patterns

This tool can simulate straight waterfloods as well as miscible/immiscible gas/CO<sub>2</sub> and Water-Alternating-Gas (WAG) pattern floods. Up to four periods of injection can be simulated sequentially in the PE<sup>2</sup> Essentials implementation of the DOE model. For example, a sequence of a waterflood, followed by CO<sub>2</sub> injection, followed by a CO<sub>2</sub> WAG and followed by a final waterflood could be simulated.

For a straight waterflood, information for only one period is entered. Alternatively, up to four waterflood periods at different injection rates could also be modeled.

Since this is an in-depth streamtube simulation model, data over and above the input required for the PE<sup>2</sup> Essentials StreamTube WaterFlood tool has to be entered.

'Export Results to CSV' will save the forecast to a 'csv' file for plotting and comparison purposes (PE<sup>2</sup> Essentials Chart). The waterflood forecast can also be saved to the PE Tools database.

## CO2.1 Reservoir Model

Entering the reservoir model is comprised of inputting 'Reservoir Parameters' (Figure CO2-3). In addition to the normal reservoir parameters, additional parameters are required for the model.

Reservoir Parameters		
Total Net Pay Thickness	100	ft
Average Permeability	1	md
Average Porosity	0.2	frac
Ratio of k(vert)/k(horiz)	0.1	
Current Reservoir Pressure	2000	psi
Reservoir Temperature	105	°F
Minimum Miscibility Pressure	1200	psi
Oil API	30	
Bubble Point Pressure	2000	psi
Gas Gravity	0.7	
Water Salinity (NaCl ppm)	100000	
Current Gas Saturation, Sg	0	frac
Current Water Saturation, Sw	0.3	frac
Parameter: Degree of Mixing	0.667	<input type="button" value="Info"/>
Option: Miscible Phase Rel Perm	0	<input type="button" value="Info"/>
Bottomhole Injection ΔP	2000	psi
Injection Well Skin factor	-6	

Dykstra-Parsons Coefficient		
	0.7	<input type="button" value="Info"/>

D-P Layer Perms		
Layer	Thick	Perm
1	20	2.031
2	20	0.952
3	20	0.563
4	20	0.334
5	20	0.149

Gas Viscosity	0.0181	cp
Oil Viscosity	2.41	cp
Water Viscosity	0.78	cp
Gas/Oil Ratio	404.89	scf/bbl
Bo	1.209	bbl/stb
Bw	1.007	bbl/stb
Max Water Inj Rate	505.4	bbls/d
Max Gas Inj Rate	38.3	mmscf/d

Figure CO2-3: Misc/Immisc CO<sub>2</sub> WAG WF Tool - Reservoir Parameters

For more information on the input parameters, refer to the 'CO2-Manual.pdf' and the 'CO2ProfitManual.pdf' located in the 'PE Essentials/Public/CO2Miscible' directory.

It should be noted that the program does not check the reasonableness of the input data; it is up to the user to enter realistic data. The program will inform the user if the results generated by using the input data are unrealistic (normally causes a divide-by-zero error in the simulator).

The 'Max Water Inj Rate' and 'Max Gas Inj Rate' are calculated after the reservoir parameters have been input and are presented on the input sheet (Figure CO2-3).

### CO2.1.1 Minimum Miscibility Pressure

The 'Minimum Miscibility Pressure' is used to determine whether the flood will be completely miscible (reservoir pressure is greater than the MMP), partially miscible (reservoir pressure is greater than 0.75 MMP but less than MMP), or totally immiscible (reservoir pressure is less than 0.75 MMP). MMP must be set below the reservoir pressure for the flood to be completely miscible. MMP can be estimated using the PE<sup>2</sup> Essentials EOR/Heavy Oil Tool.

### CO2.1.2 Degree of Mixing

The mixing parameter approach ('Degree of Mixing'), as proposed by Todd and Longstaff, is used for simulation of a miscible CO<sub>2</sub> process. Mixing parameter models simulate the mixing and viscous fingering which occurs in miscible displacements by adjusting solvent and oil viscosities. These adjustments alter the fractional flow of solvent and oil.

The mixing parameter,  $\omega$ , is used to adjust the viscosities of the solvent and the oil. Omega determines the effective viscosity of the solvent and oil. If the mixing parameter is set to 0.0, then there is no mixing and the solvent and oil viscosities are equal to their individual immiscible values. If the mixing parameter is set to 1.0, then there is complete mixing, and the oil and solvent viscosities are made equal.

### CO2.1.3 Miscible Phase Relative Permeability Option

In the model, there are three phases which can flow: water, oil, and gas/solvent (the terms gas and solvent are used interchangeably). The only gas phase that is permitted in the model is the solvent phase. A separate hydrocarbon gas does not exist in the model. The relative permeability equations which are used for simulating both miscible and immiscible flow are constructed from two-phase flow equations.

For immiscible flow (reservoir pressure is less than 0.75 MMP), the water relative permeability ( $k_{rw}$ ) is a function only of  $S_w$ . The gas (or solvent) relative permeability ( $k_{rg}$ ,  $k_{rs}$ ) in immiscible flow is a function of the gas (i.e., solvent) saturation only. The three-phase oil relative permeability ( $k_{ro3}$ ) is determined using the modified Stone method (refer to PE<sup>2</sup> Essentials Gas/Oil/Wat PVT / Rel Perm Tool for information on relative permeability).

$$k_{ro3} = (a - k_{rg} - k_{rw}) / k_{ro}$$

$$a = (k_{ro}/k_{row} + k_{rw})(k_{rog}/k_{row} + k_{rg})$$

For miscible flow (reservoir pressure greater than MMP) there are actually only two phases, water and a miscible phase composed of solvent and oil. The water relative permeability is the same as it is in immiscible flow and remains a function of only the water saturation. However, the miscible phase relative permeability ( $k_{rm}$ ) must be computed since it is not measured.

There is no definitive way to compute or handle the miscible phase relative permeability. There are three options for calculation of  $k_{rm}$ . The option to calculate the miscible phase relative permeability,  $k_{rm}$ , can be selected as:

- Option=0: Use linear variation between solvent/gas and oil relative permeability
- Option=1: Use average of oil and solvent/gas relative permeability
- Option=2: Use oil relative permeability

The third option (Option=2), which sets  $k_{rm}$  equal to  $k_{ro}$ , the oil phase relative permeability, is the standard formulation in most mixing parameter models. However, the first option which makes  $k_{rm}$  a saturation weighted average is physically more realistic. In addition, the saturation weighted formulation produces results closest to those of a compositional simulator when  $k_{rg}$  parameters are used for the solvent relative permeability,  $k_{rs}$ .

### CO2.1.4 Dykstra-Parsons Coefficient

The Dykstra-Parsons coefficient is a common measure of reservoir heterogeneity. There is a large variation in reservoir permeability when there is a large Dykstra-Parsons coefficient. For reservoirs with large variations in reservoir permeability, the recovery will be greatest in the highest permeability layer.

The Dykstra-Parsons coefficient normally varies from 0.1 to 0.9 and can have a large impact on recovery. The Dykstra-Parsons coefficient is used to calculate the permeability variation between the layers in the model. This variation, in turn, determines the relative injectivity of fluids in each layer. This calculation of layer permeabilities is done internally in the program and the results are presented on the main screen.

### CO2.2 Relative Permeability

The relative permeability parameters are entered in the 'Rel Perm Data' Section (Figure CO2-4).

Relative Permeability Parameters					
Swi	0.2	nw(o)	2	Krw(Sor)	0.3
Sorw	0.37	no(w)	2	Kro(Swi)	0.4
Sgr	0.37	ng(o)	2	Krg(Swi)	0.4
Sorg	0.37	no(g)	2	Krs(max)	0.4
Ssr	0.37	ns(o)	2		
Sorm	0.001				

Info

Figure CO2-4: Misc/Immisc CO<sub>2</sub> WAG WF Tool - Relative Permeability

### CO2.3 Pattern Waterflood Model

Choosing the waterflood pattern to use for the simulation is comprised of two options (Figure CO2-5).

Period	Water Inj BWIPD	CO <sub>2</sub> Inj mmscf/d	WAG Ratio	Incremental HCPV Inj
1	500	0	1	1
2	0	1	0	0.2
3	500	1	0.5	0.2
4	500	0	1	0.4

Figure CO2-5: Misc/Immisc CO<sub>2</sub> WAG WF Tool - Waterflood Parameters

The waterflood pattern is chosen and the area of the pattern is entered. This will set up the distance from the injector to the producer.

The 'WAG Ratio' is the amount of time water is injected, relative to the time gas is injected. For water injection, the number is 1.0; for CO<sub>2</sub> injection, the number is 0.0; for WAG injection, the number is greater than 0.0 but less than 1.0. For example, if the number is 0.6, then 60% of the time water is injected and 40% of the time CO<sub>2</sub> is injected at the specified rates.

The hydrocarbon pore volume parameter (HCPV) determines the cumulative volume injected for that period. Up to four periods are entered and the model is executed.

### CO2.4 Example: Waterflood Model Comparison

A comparison between the two streamline waterflood models was made using similar data in each model. The models were run out to a 98% water cut. For the Misc/Immisc CO<sub>2</sub> WAG WF Model, this was done by injecting 1.25 HCPV. Figure CO2-6 shows the Misc/Immisc CO<sub>2</sub> WAG WF Model results and Figure CO2-7 shows the StreamTube WaterFlood Model results. The models are saved in the 'PEE Tools Database Book Examples.PEEdb' located in the "PE Essentials 2019\Book Examples\PEE Tools Database Examples" directory.

The Misc/Immisc CO<sub>2</sub> WAG WF Model, in general, shows a similar waterflood development as the StreamTube WaterFlood Model. In terms of recovery, they are similar with the Misc/Immisc CO<sub>2</sub> WAG WF Model indicating an ultimate recovery of 55.0% compared to 54.6% for the StreamTube WaterFlood Model.



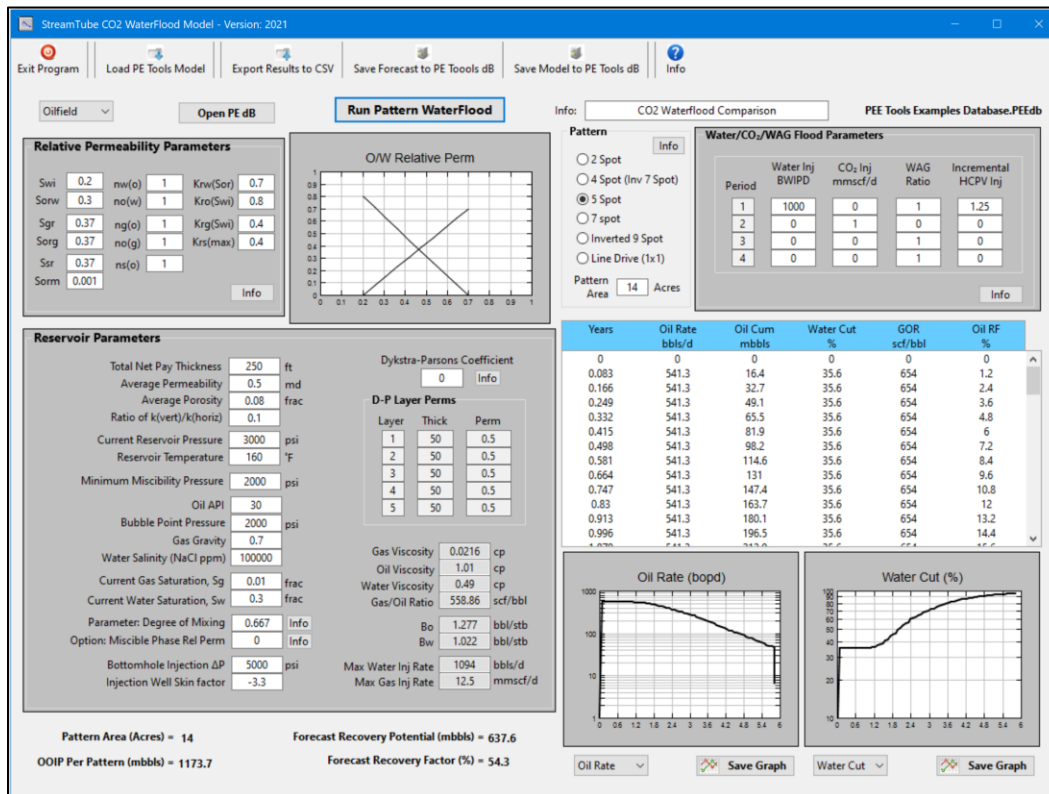
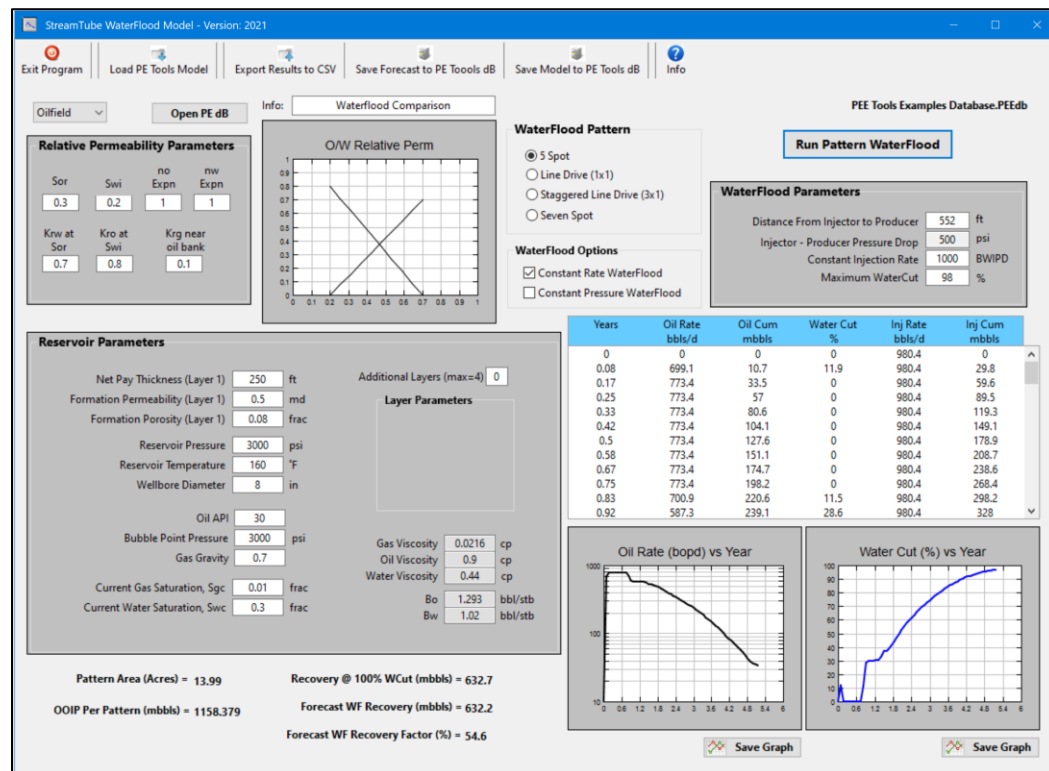
Figure CO2-6: Misc/Immisc CO<sub>2</sub> WAG WF Tool Results - Comparison Run

Figure CO2-7 StreamTube Waterflood Tool Results - Comparison Run

## Gas Material Balance Analysis Tool

The general material balance (MB) equation can be applied to all reservoir types and was first developed by Schilthuis in 1936. It is a tank model equation that accounts for production from an initial point to any point in time as follows:

$$\begin{aligned} (\text{oil} + \text{gas} + \text{water}) \text{ produced} = & \text{oil expansion} + \text{gas expansion} + \\ & \text{oil zone and gas zone pore volume expansion} + \\ & \text{connate water expansion} + \text{water influx} + \\ & \text{water injected} + \text{gas injected} \end{aligned}$$

For a gas reservoir, the material balance equation simplifies to Equation GMB-1

$$G_p B_g = \text{GIIP} (B_g - B_{gi}) \quad (\text{GMB-1})$$

Expanding the term for  $B_g$  and simplifying, Equation 5-26 becomes Equation GMB-2.

$$G_p (P_i/Z_i) = \text{GIIP} (P_i/Z_i - P/Z) \quad (\text{GMB-2})$$

Where:  $G_p$  is gas production,  $P_i$  is the initial pressure,  $Z_i$  is the Z-factor at  $P_i$ , GIIP is the initial gas in place,  $P$  is the current pressure and  $Z$  is the Z-factor at  $P$ .

The material balance equation is zero-dimensional, meaning that it is based on a tank model and does not take into account the geometry of the reservoir, the reservoir drainage area, the position of the well or orientation of the well.

A material balance tank is equivalent to a single grid block in a numerical reservoir simulation model. In a numerical simulator, the conditions in a large number of communicating material balance tanks (grid blocks) are solved simultaneously.

Most reservoirs are made up of compartments that are separated by faults that may be closed or open (partially or fully). If the faults are closed, then there is no communication between the tanks and they can be modelled as isolated material balance tanks. If the faults are totally open, then the whole reservoir can be modelled as one material balance tank.

However, if the faults separating different compartments are semi-permeable, a transfer of fluid from one compartment to the other (governed by the pressure difference between the compartments) will occur.



## GMB.1 Multi-Tank Gas MB Model

The PE<sup>2</sup> Essentials 'Gas Material Balance' tool was designed to model a fractured unconventional gas reservoir. It creates a multi-tank material balance model that includes transmissibility between the tanks in the form of a connection factor (Figure GMB-1). Note: Although the tool was designed to forecast multi-tank production, a forecast for a single tank can be generated by setting the connection factor to zero.

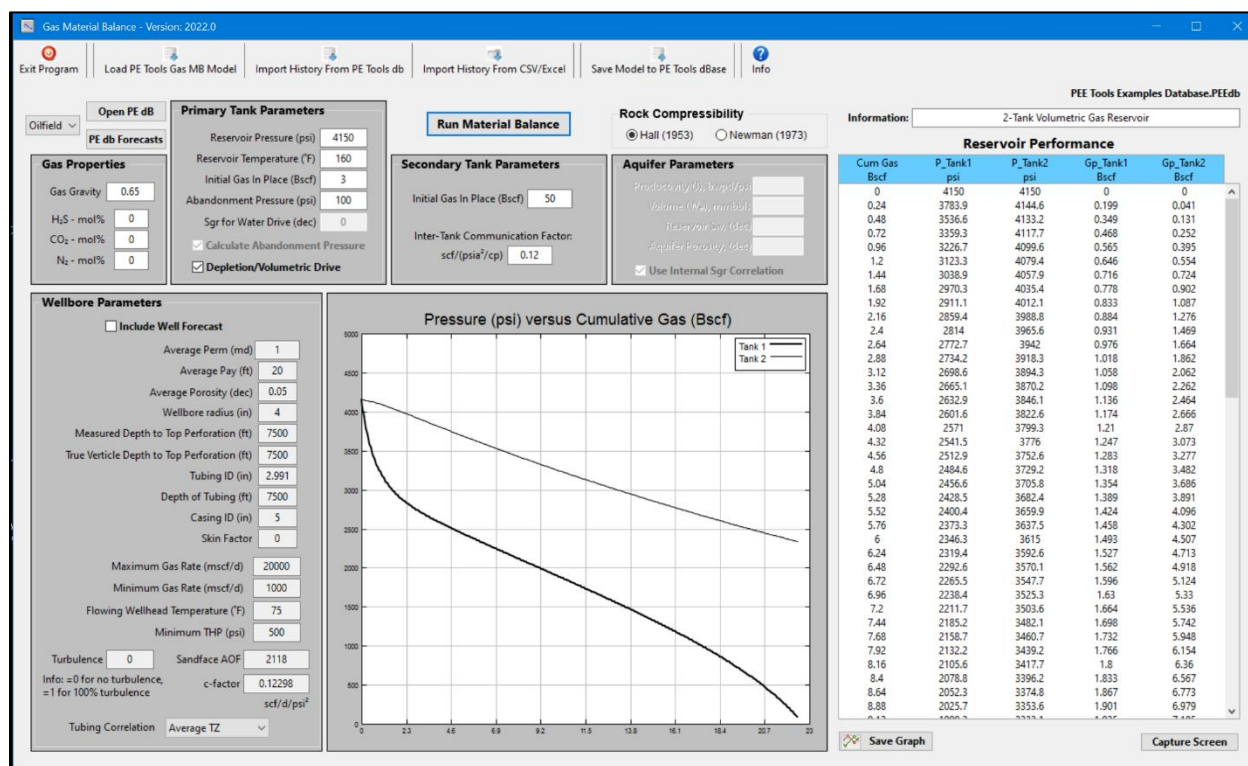


Figure GMB-1: PE<sup>2</sup> Essentials Multi-Tank Gas Material Balance Tool

The Gas Material Balance tool uses two interconnected tanks to generate the initial high decline, evident in fractured low perm / unconventional reservoirs, followed by the lower long-term depletion period. In general terms, the primary tank would be considered the near-frac reservoir area and the secondary tank would be the reservoir that feeds the fractured system.

Once calibrated, the multi-tank model could be used to generate type curves for a specific area based on reservoir parameters rather than a straight averaging of production data. This would allow variability to be applied to specific well forecasts to generate a range of forecasts for economic evaluation purposes.

The gas material balance model includes the option of using either the Hall correlation (refer to PVT tool) or the Newman correlation (Equation GMB-3) to model rock compressibility.

$$C_r = 9.732 \times 10^{-5} / (1 + 55.867 * \text{Porosity}) \quad (\text{GMB-3})$$

## GMB.2 Water Drive Gas MB Model

The PE<sup>2</sup> Essentials 'Gas Material Balance' tool can also model a gas reservoir containing an aquifer (Figure GMB-2). The aquifer is modeled as a Fetkovich finite aquifer.

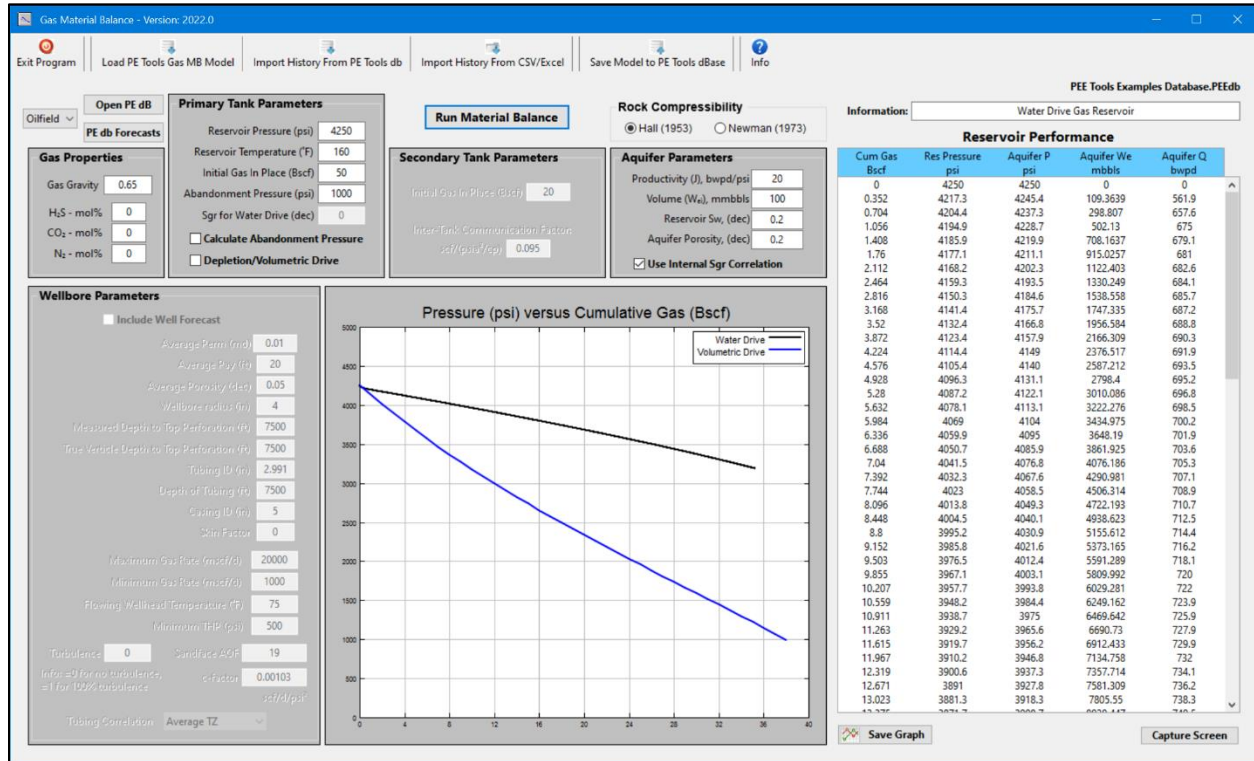


Figure GMB-2: PE<sup>2</sup> Essentials Gas/Aquifer Material Balance Tool

Refer to the oil material balance tool for complete information on the Fetkovitch aquifer.

When running the gas/aquifer MB model, the response of no-aquifer is also plotted. This is useful when plotting historical data, to evaluate the strength of the aquifer.

With the current version of the tools, it is not possible to forecast production using the gas/aquifer MB model.

One of the issues with a water drive gas reservoir is that there will be bypassed gas saturation remaining in the reservoir as the aquifer encroaches into the gas zone. This residual gas saturation is termed Sgr and causes the recovery factor for water drive gas reservoirs to be less than a depletion drive gas reservoir – for the same abandonment pressure.

There are two options for Sgr in the PE Essentials Gas MB tool: the Sgr value can be directly entered in the 'Sgr for Water Drive' box or an internal correlation can be used. The internal correlation is an unpublished EPCI-derived correlation.

The  $S_{gr}$  correlation was developed using core derived data for  $S_{gr}$ , porosity and  $S_{gi}$ .

Figure GMB-3a and GMB-3b presents the correlations developed from the core data.

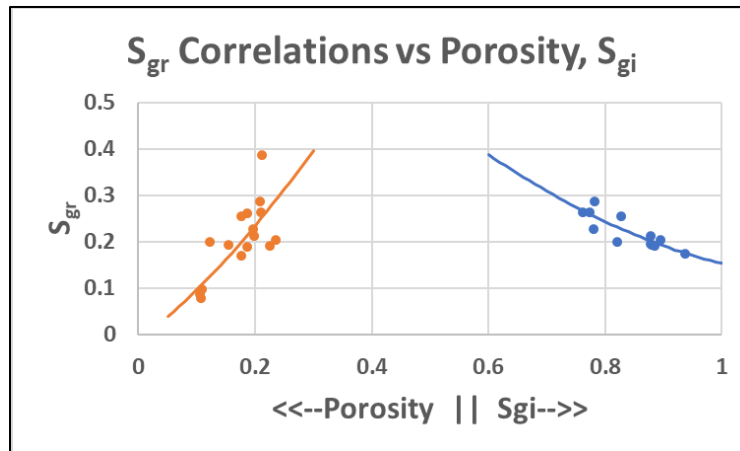


Figure GMB-3a: EPCI  $S_{gr}$  Correlations with Core Data

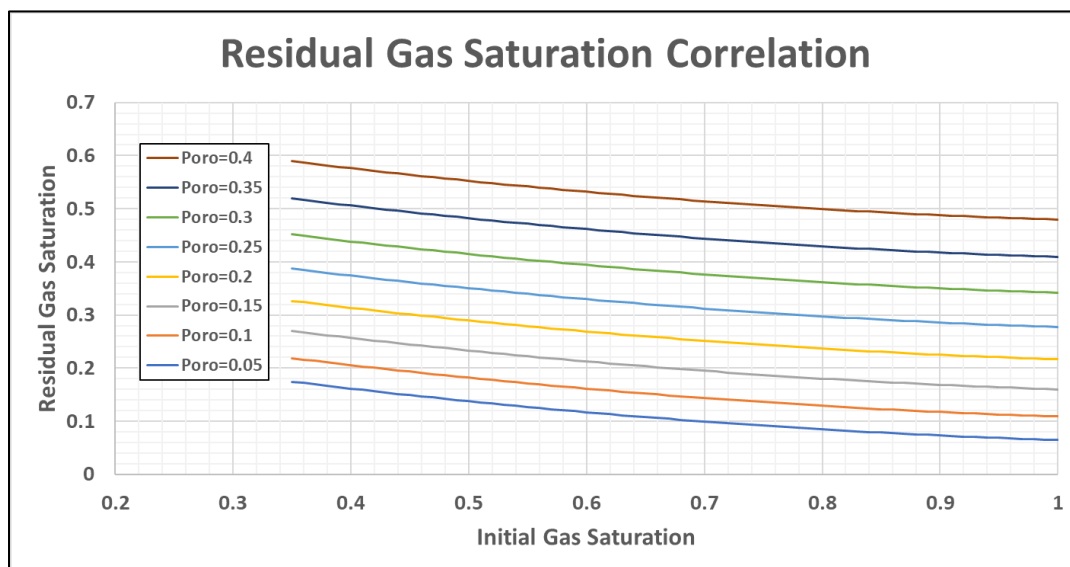


Figure GMB-3b: EPCI  $S_{gr}$  Correlations

The correlation equation is presented as Equation GMB-4.

$$S_{gr} = 0.15196 S_g^2 - 0.40689 S_g + 1.4476 \text{ Por}^{1.2861} + 0.25611 \quad (\text{GMB-4})$$

### GMB.3 MB Tank Parameters

Dry gas material balance tanks do not require a large amount of input data in order to generate a forecast. There are four input sections for the multi-tank model (Figure GMB-3).

Gas Properties	Primary Tank Parameters	Secondary Tank Parameters	MatBal Forecast Parameters
Gas Gravity: 0.65	Reservoir Pressure (psi): 4250	Initial Gas In Place (Bscf): 20	Minimum Primary Tank Pressure (psi): 200
H <sub>2</sub> S - mol%: 0	Reservoir Temperature (°F): 160	Inter-Tank Communication Factor:	
CO <sub>2</sub> - mol%: 0	Initial Gas In Place (Bscf): 2	scf/(psia <sup>2</sup> /cp): 0.095	
N <sub>2</sub> - mol%: 0			

Figure GMB-3: Gas Material Balance Tool – Input Parameters

The 'Gas Properties' input parameters are straight forward. There is no compositional analysis performed on the gas in this model.

The 'Primary Tank Parameters' sets up the properties of the initial high decline tank. This is the tank where all the well production comes from. For a single tank model, only the parameters for this tank have to be entered.

The 'Secondary Tank Parameters' assigns the GIIP of the external reservoir to this tank and sets the 'Inter-Tank Communication Factor' which determines the amount of support supplied to the primary tank. Setting the 'Inter-Tank Communication Factor' to zero will stop all communication between the tanks.

The 'MatBal Forecast Parameters' specifies the final depletion pressure for the primary tank. If zero is entered here, the model will default to 100psi (690 kPa).

Based on the parameters listed in Figure GMB-3, the material balance depletion profile is shown in Figure GMB-4 and Figure GMB-5.

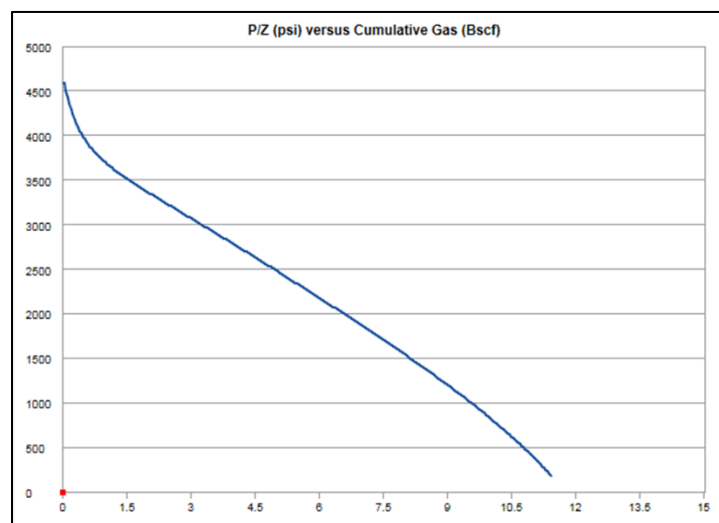


Figure GMB-4: Gas Material Balance Tool – MB Depletion Plot

Month	Cum Gas	P_Tank1	P_Tank2	Gp_Tank1	Gp_Tank2
#	Bscf	psi	psi	Bscf	Bscf
1	0.04	4250	4250	0.036	0.004
2	0.08	4139.2	4248.8	0.069	0.011
3	0.12	4041.4	4246.6	0.099	0.021
4	0.16	3954.5	4243.4	0.127	0.033
5	0.2	3876.6	4239.5	0.152	0.048
6	0.24	3806.4	4234.9	0.175	0.065
7	0.28	3743.3	4229.6	0.197	0.083
8	0.32	3685.4	4223.9	0.217	0.103
9	0.36	3632.9	4217.6	0.235	0.125
10	0.4	3590.4	4210.2	0.253	0.147
11	0.44	3551.8	4202.4	0.27	0.17
12	0.48	3515.8	4194.5	0.286	0.194
13	0.52	3482.6	4186.3	0.301	0.219
14	0.56	3451.9	4177.9	0.315	0.245
15	0.6	3422.9	4169.3	0.329	0.271
16	0.64	3395.7	4160.5	0.342	0.298
17	0.68	3370.5	4151.5	0.355	0.325
18	0.72	3346.6	4142.4	0.368	0.352
19	0.76	3323.8	4133.1	0.38	0.38
20	0.8	3302	4123.7	0.391	0.409
21	0.84	3281.6	4114.2	0.403	0.437
22	0.88	3262.1	4104.5	0.414	0.466
23	0.92	3243.3	4095	0.425	0.495
24	0.96	3225.1	4085.4	0.435	0.525
25	1	3207.6	4075.8	0.445	0.555
26	1.04	3190.8	4066.1	0.456	0.584
27	1.08	3174.7	4056.4	0.466	0.614
28	1.12	3159	4046.6	0.475	0.645
29	1.16	3143.7	4036.7	0.485	0.675
30	1.2	3128.8	4026.9	0.494	0.706
31	1.24	3114.1	4016.9	0.504	0.736
32	1.28	3099.8	4007	0.513	0.767
33	1.32	3086	3997.1	0.522	0.798
34	1.36	3072.5	3987.3	0.531	0.829
35	1.4	3059.2	3977.5	0.54	0.86
36	1.44	3046.1	3967.7	0.549	0.891

Figure GMB-5: Gas Material Balance Tool – MB Depletion Table

The data presented in Figure GMB-5 are as follows: 'Cum Gas' is the total production from the multi-tank model; 'P\_Tank1' and 'P\_Tank2' are the pressures in Tank1 and Tank2, respectively; and 'Gp\_Tank1' and 'Gp\_Tank2' are the production volumes contributed by each tank to the total production.

If a match to historical production is required, the history data is imported, and the tank parameters are modified until a match is achieved (refer to the example in Section GMB.6). Historical production data can be imported from a CSV file or an Excel spreadsheet (Figure GMB-6).

PE Essentials Material Balance Historical Data Import

**Data Input**

☒ CSV File ☐ Excel File

Note: Gas volume in mmscf, reservoir pressure in psi

**Excel Input Parameters**

	Column	Start Row	End Row
Days			
Incremental Production			
Reservoir pressure			

Figure GMB-6: Gas Material Balance Tool – Importing Historical Data

## GMB.4 Material Balance Tank Forecast

Once the depletion characteristics of the multi-tank model are finalized, it is possible to add a well to the primary tank and generate a production forecast (Figure GMB-7).

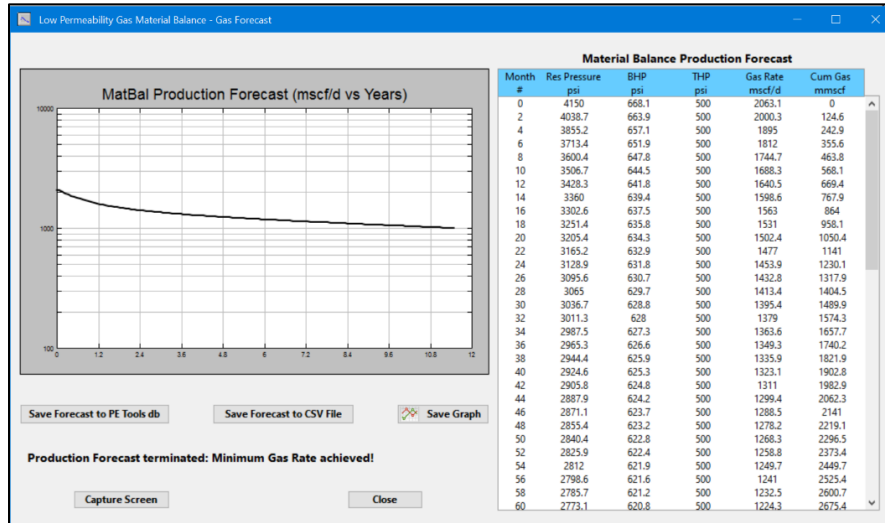


Figure GMB-7: Gas Material Balance Tool – Production Forecast

To generate a forecast, check the 'Include Wellbore Calculations' box (Figure GMB-1) and enter the well parameters before running the material balance forecast (Figure GMB-8).

**Wellbore Parameters**

☒ Include Well Forecast

Average Perm (md)

Average Pay (ft)

Average Porosity (dec)

Wellbore radius (in)

Measured Depth to Top Perforation (ft)

True Vertical Depth to Top Perforation (ft)

Tubing ID (in)

Depth of Tubing (ft)

Casing ID (in)

Skin Factor

Maximum Gas Rate (mscf/d)

Minimum Gas Rate (mscf/d)

Flowing Wellhead Temperature (°F)

Minimum THP (psi)

Turbulence  Sandface AOF

Info: =0 for no turbulence, =1 for 100% turbulence c-factor

Tubing Correlation

Figure GMB-8: Gas Material Balance Tool – Wellbore Parameters

The input wellbore parameters are straightforward. The 'Turbulence' parameter is a normalized parameter from 0 to 1 where 0 = no turbulence, or laminar flow, and 1 = maximum turbulence

The production forecast can be saved to PE Tools database for import into other tools.

## GMB.5 Gas Material Balance Example

Table GMB-1 lists the historical production data for a vertical well in tight gas sand reservoir.

Days	Inc Prod mmscf	Pressure psi		Days	Inc Prod mmscf	Pressure psi
1	3.418165	4000		1001	174.64	2869.38
91	311.053	3723.56		1092	170.86	2842.63
182	276.727	3497.2		1183	167.05	2815.82
273	248.165	3309.06		1274	163.25	2789.23
364	224.175	3150.54		1365	159.47	2763.03
455	203.83	3015.32		1456	155.76	2737.34
546	190.2	2983.97		1547	152.12	2712.26
637	187.68	2966.33		1638	148.56	2687.83
728	184.95	2944.98		1729	145.09	2664.09
819	181.78	2921.14		1820	141.72	2641.05
910	178.3	2895.71				

Table GMB-1: Production History

The estimated reservoir parameters for Tank 1 are entered into the Material Balance tool (Figure GMB-9) and the historical production data is imported into the model (Figure GMB-10). The Gas MB models are contained in the PE Tools database located in the “PE Essentials 2022\Book Examples\PEE Tools Database Examples” directory and the production data resides in the ‘Multitank\_Example.xlsx’ file in the “PE Essentials\Book Examples\Example Gas Multi-Tank MBal” directory.

Gas Material Balance - Version 1.01

Oilfield

Open PE dB

PE dB Forecasts

Load PE Tools Gas MB Model

Import History From PE Tools db

Import History From CSV/Excel

Save Model to PE Tools dBase

Info

Primary Tank Parameters

Reservoir Pressure (psi)

4000

Reservoir Temperature (°F)

197

Initial Gas In Place (Bscf)

10

Abandon Tank Pressure (psi)

200

☐ Calculate Abandon Tank Pressure

☒ Depletion/Volumetric Drive

Run Material Balance

Rock Compressibility

☒ Hall (1953)
 ☐ Newman (1973)

Secondary Tank Parameters

Initial Gas In Place (Bscf)

50

Inter-Tank Communication Factor: scf/(psia<sup>3</sup>/cp)

0

Aquifer Parameters

Productivity D<sub>i</sub>, kmD/gp

Volume V<sub>well</sub>, mmscf

Reservoir Sep. Coef

Aquifer Porosity, Gas

Gas Properties

Gas Gravity

0.7224

H<sub>2</sub>S - mol%

0

CO<sub>2</sub> - mol%

0.587

N<sub>2</sub> - mol%

0.544

Wellbore Parameters

☐ Include WellBore Calculations

Average Perm (md)

0

Average Pay (ft)

0

Average Porosity (dec)

0

Wellbore radius (in)

0

Measured Depth to Top Perforation (ft)

0

True Vertical Depth to Top Perforation (ft)

0

Tubing ID (in)

0

Depth of Tubing (ft)

0

Casing ID (in)

0

Skin Factor

0

Maximum Gas Rate (mscf/d)

0

Minimum Gas Rate (mscf/d)

0

Flowing Wellhead Temperature (°F)

0

Minimum THP (psi)

0

Turbulence

0

Rate @ 50%DD

0

Info: =0 for no turbulence, =1 for 100% turbulence; between 0 and 1 for intermediate turbulence.

Tubing Correlation

Average TZ

Information:

Multi-Tank Gas MB Example Tank1

Reservoir Performance

Cum Gas Bscf	P_Tank1 psi	P_Tank2 psi	Gp_Tank1 Bscf	Gp_Tank2 Bscf

Figure GMB-9: Estimated Tank1 Parameters



PE Essentials Material Balance Historical Data Import

**Data Input**  
☐ CSV File  
☒ Excel File Open Excel File

Note: Gas volume in mmscf, reservoir pressure in psi

**Excel Input Parameters**

	Column	Start Row	End Row
Days	a	3	23
Incremental Production	b	3	23
Reservoir pressure	c	3	23

Import Data Exit

Days	Cum Gas	Res Press
1	3.418165	4000
91	314.4712	3723.56
182	591.1982	3497.2
273	839.3632	3309.06
364	1063.538	3150.54
455	1267.368	3015.32
546	1457.568	2983.97
637	1645.248	2966.33
728	1830.198	2944.98
819	2011.978	2921.14
910	2190.278	2895.71
1001	2364.918	2869.38
1092	2535.778	2842.63
1183	2702.828	2815.82
1274	2866.078	2789.23
1365	3025.548	2763.03
1456	3181.308	2737.34
1547	3333.428	2712.26
1638	3481.988	2687.83
1729	3627.078	2664.09
1820	3768.798	2641.05

Figure GMB-10: Production History

The first step to evaluating this well is to determine the characteristics of the Tank1. This is done by setting the connection factor to zero and matching on the early data (Figure GMB-11).

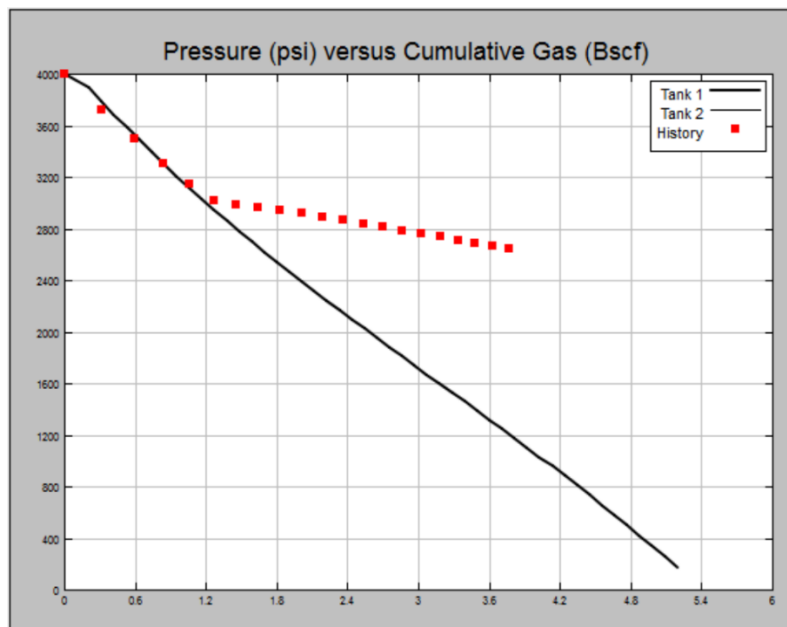


Figure GMB-11: Tank 1 Match

The value of 5.3 Bscf will be a maximum value for this tank. When the second tank is added, the volume in this tank will be reduced because of pressure support from Tank2.



The second step is to add the second tank and match the production history (Figure GMB-12). The final match occurred with Tank1 containing 3 Bscf and Tank2 containing 38 Bscf.

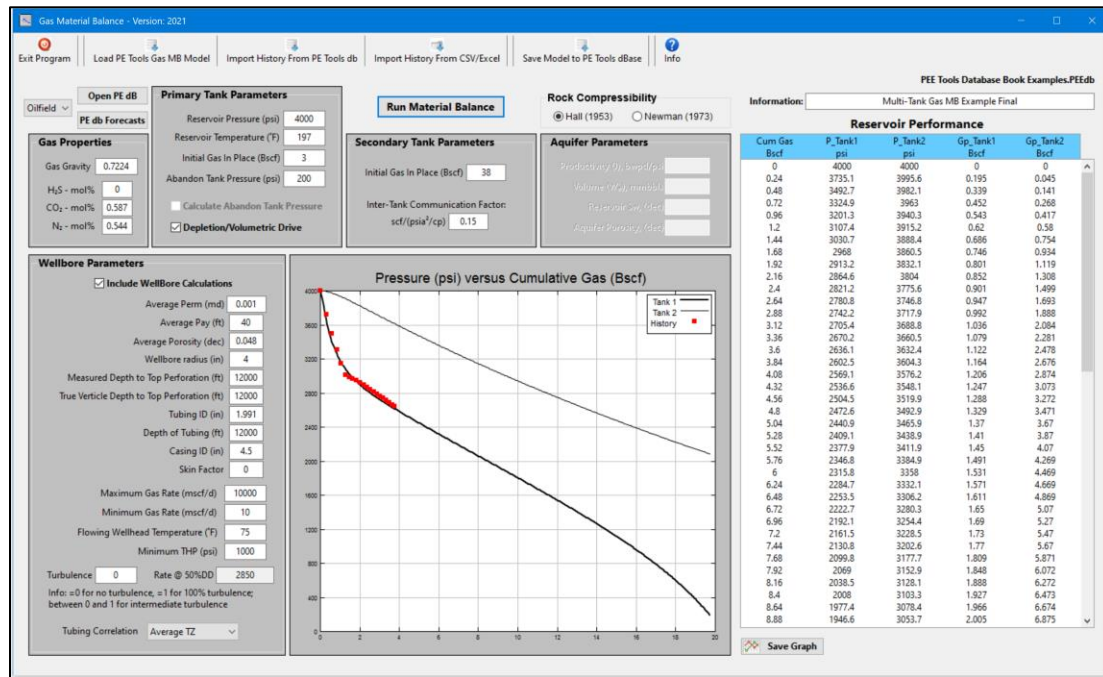


Figure GMB-12: Multi Tank Match

Prior to generating a forecast, the wellbore parameters are entered and modified until the historical production forecast matches the production history. The final reservoir parameters for this example are presented in Figure GMB-13. After the production history is matched a production forecast is then generated (Figure GMB-14).

**Wellbore Parameters**

☒ Include Wellbore Calculations

Average Perm (md) 0.001

Average Pay (ft) 40

Average Porosity (dec) 0.048

Wellbore radius (in) 4

Measured Depth to Top Perforation (ft) 12000

True Vertical Depth to Top Perforation (ft) 12000

Tubing ID (in) 1.991

Depth of Tubing (ft) 12000

Casing ID (in) 4.5

Skin Factor 0

Maximum Gas Rate (mscf/d) 10000

Minimum Gas Rate (mscf/d) 10

Flowing Wellhead Temperature (°F) 75

Minimum THP (psi) 1000

Tubing Correlation Average TZ

Figure GMB-13: Multi Tank Forecast Well Parameters

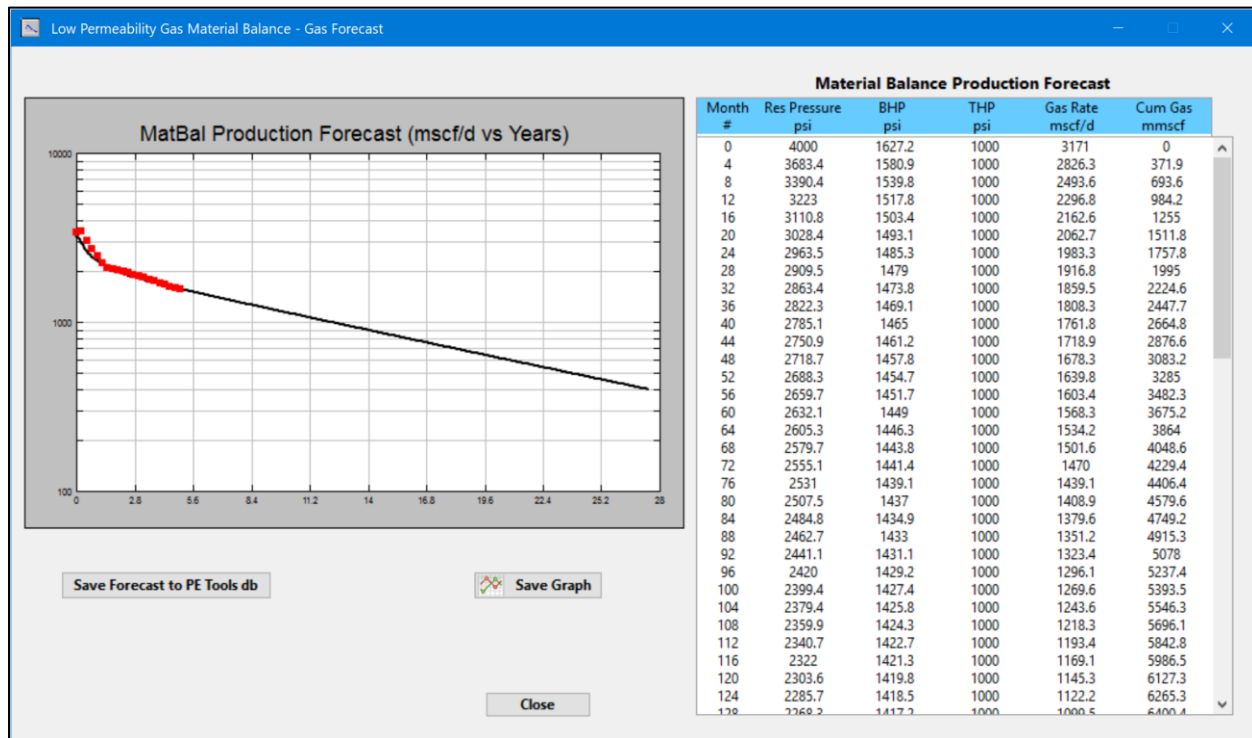


Figure GMB-14: Multi Tank Gas Rate History Match and Forecast

The material balance forecast can be saved to the PE Tools database for use in other tools.

## Oil Material Balance Analysis Tool

PE<sup>2</sup> Essentials 'Oil Material Balance' analysis and forecasting tool (Figure OMB-1) may be more appropriate for use with conventional reservoirs than with unconventional reservoirs. It can be used with unconventional reservoirs, but caution should be exercised when reporting and using the results.

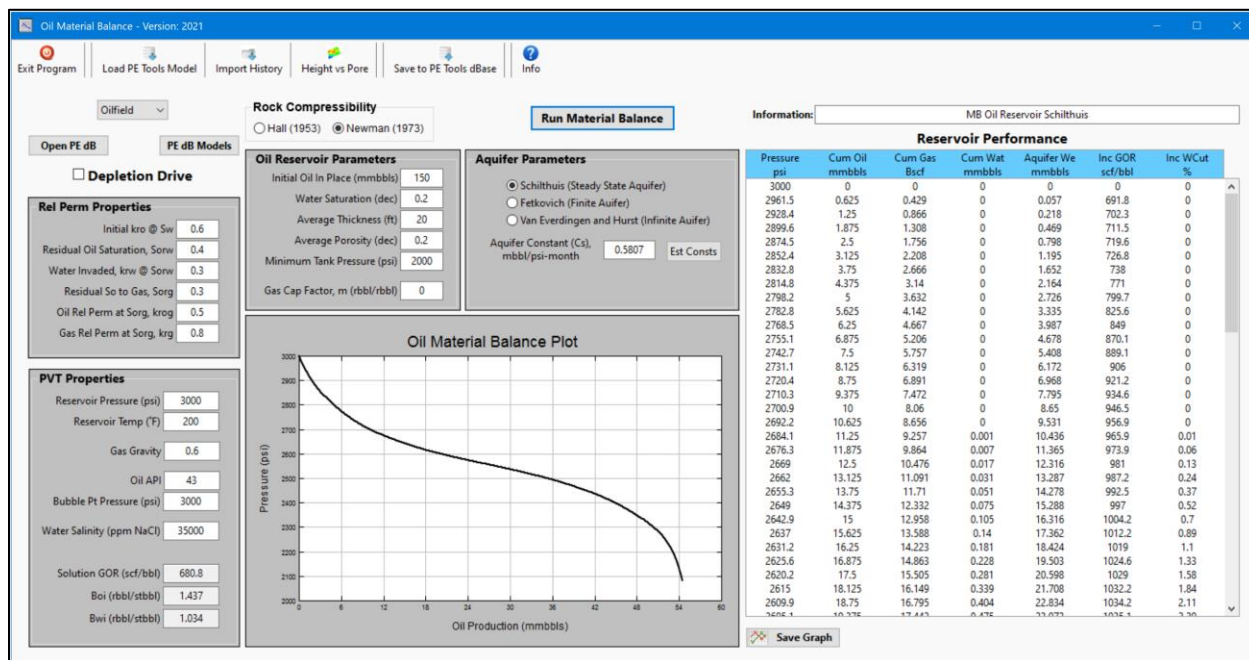


Figure OMB-1: PE<sup>2</sup> Essentials Oil Material Balance Analysis

One of the “anomalous” responses that has been observed when producing unconventional oil reservoirs, is that the PVT properties of the oil may not follow the conventional correlations that are used in PE<sup>2</sup> Essentials. Research is underway on this topic.

### OMB.1 General Material Balance

Nearly all hydrocarbon reservoirs contain water-bearing rocks called aquifers. The aquifers may be substantially larger than the oil or gas reservoirs so that they can appear to be infinite in size

There are numerous textbooks that cover material balance. The main references for the following information is Mian, M.A.; Petroleum Engineering Handbook for the Practicing Engineer, Volume 1, PennWell, 1992 and Smith, C.R., Tracy, G.W., and Farrar, R.L.; Applied Reservoir Engineering, Volume 2, OGI, 1992.

The general material balance equation relates the original oil, gas, and water volumes in the reservoir to production volumes and current pressure conditions and fluid properties. The

assumption of a tank behaviour means that the reservoir is considered to have the same pressure and fluid properties at all locations in the reservoir. Consider Figure OMB-2.

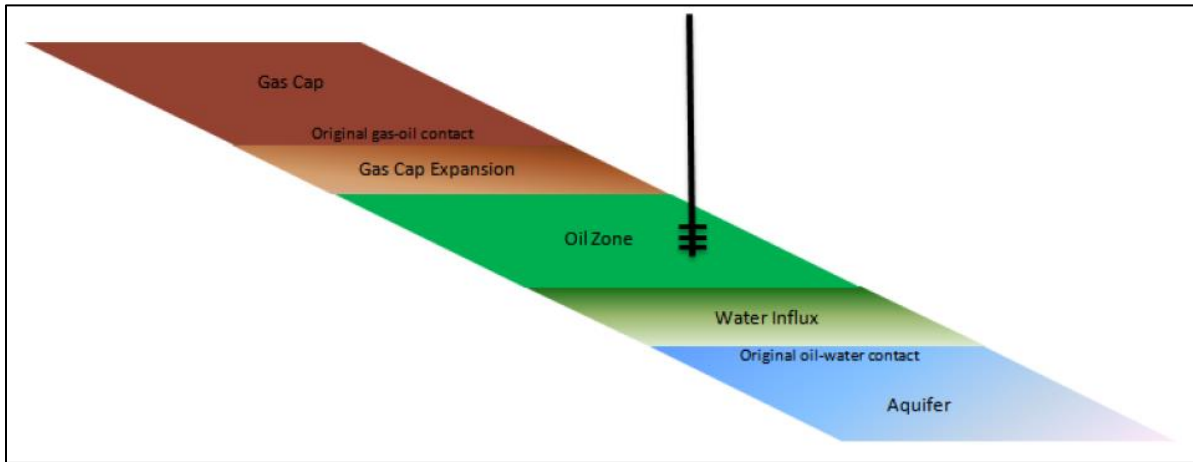


Figure OMB-2: Reservoir Material Balance

The simplest way to visualize material balance is that if the measured surface volume of oil, gas and water were returned to the reservoir at the reduced pressure, it must fit exactly into the volume of the total fluid expansion plus any fluid influx.

The general material balance for an oil reservoir can be expressed as follows:

$$\begin{aligned} \text{Net Reservoir Withdrawal} = & \text{Expansion of Oil} \\ & + \text{Original Dissolved Gas} \\ & + \text{Expansion of Gas Cap} \\ & + \text{Reduction in Hydrocarbon Pore Volume} \\ & + \text{Natural Water influx} \end{aligned}$$

The general oil material balance equation is presented as Equation OMB.1.

$$N = \frac{N_p B_o + (G_{ps} + G_{pc} - N_p R_s) B_g - G_i B_g + (W_p - W_i) B_w - W_e}{(B_o - B_{oi}) + (R_{si} - R_s) B_g + m B_{oi} (B_g - B_{gi}) / B_{gi} + B_{oi} (1 + m) (S_w c_w + c_f) \Delta P / (1 - S_w)} \quad (\text{OMB.1})$$

Where:

$$N_p B_o = \text{oil production}$$

$$G_{pc} B_g = \text{gas cap production}$$

$$(G_{ps} - N_p R_s) B_g = \text{liberated solution gas production}$$

$$G_i B_g = \text{gas injection}$$

$$W_p B_w = \text{water production}$$

$W_i B_w$  = water injection

$W_e$  = water influx from the aquifer

$N(B_o - B_{oi})$  = expansion of initial oil

$N(R_{si} - R_s)B_g$  = volume occupied by liberated gas

$mNB_{oi} \left( \frac{B_g - B_{gi}}{B_{gi}} \right)$  = gas cap expansion

$\frac{NB_{oi}(1+m)}{1-S_w} S_w c_w \Delta P$  = water expansion

$\frac{NB_{oi}(1+m)}{1-S_w} c_f \Delta P$  = rock expansion

$\Delta P = P_i - P_r$  = pressure drop from initial pressure

Most of the terms in the material balance equation are either measured or derived from fluid properties (PVT). The most significant issue is the determination of the aquifer influx term,  $W_e$ . Aquifer models are normally used to predict  $W_e$ .

## OMB.2 Aquifer Models

As reservoir fluids are produced and reservoir pressure declines, a pressure differential develops between the aquifer and the reservoir causing water to encroach into the hydrocarbon bearing zone. It is this water encroachment that leads to the water influx term,  $W_e$ , in the material balance equation.

Aquifers are commonly classified by their degree of pressure maintenance as an active water drive; a partial water drive; or a limited water drive. The term active water drive refers to an aquifer in which the rate of water influx equals the reservoir total production rate. Active water drive reservoirs are normally evident by their slow reservoir pressure decline.

Since wells are seldom (intentionally) drilled into an aquifer, there is uncertainty concerning the porosity, permeability, thickness, geometry and extent of the aquifer. Commonly, these properties are estimated using the reservoir properties.

Several models have been developed for estimating water influx that are based on assumptions that describe the characteristics of the aquifer. The most common aquifer models are:

- Steady State Aquifer Model (Schilthuis)
- Finite Aquifer Model (Fetkovich)
- Unsteady State Infinite Aquifer Model (Van Everdingen and Hurst)

The PE<sup>2</sup> Essentials Oil Material Balance forecasting tool includes all three of these models. To disable aquifer calculations and run a depletion drive model, check 'Disable Aquifer'.

## OMB.2.1 Schilthuis Steady State Aquifer Model

The simplest method for characterizing water influx was presented by Schilthuis in 1936 (Figure OMB-3). This model is often tried first since the calculations are considerably less involved than with either of the other two methods and can be performed by hand.

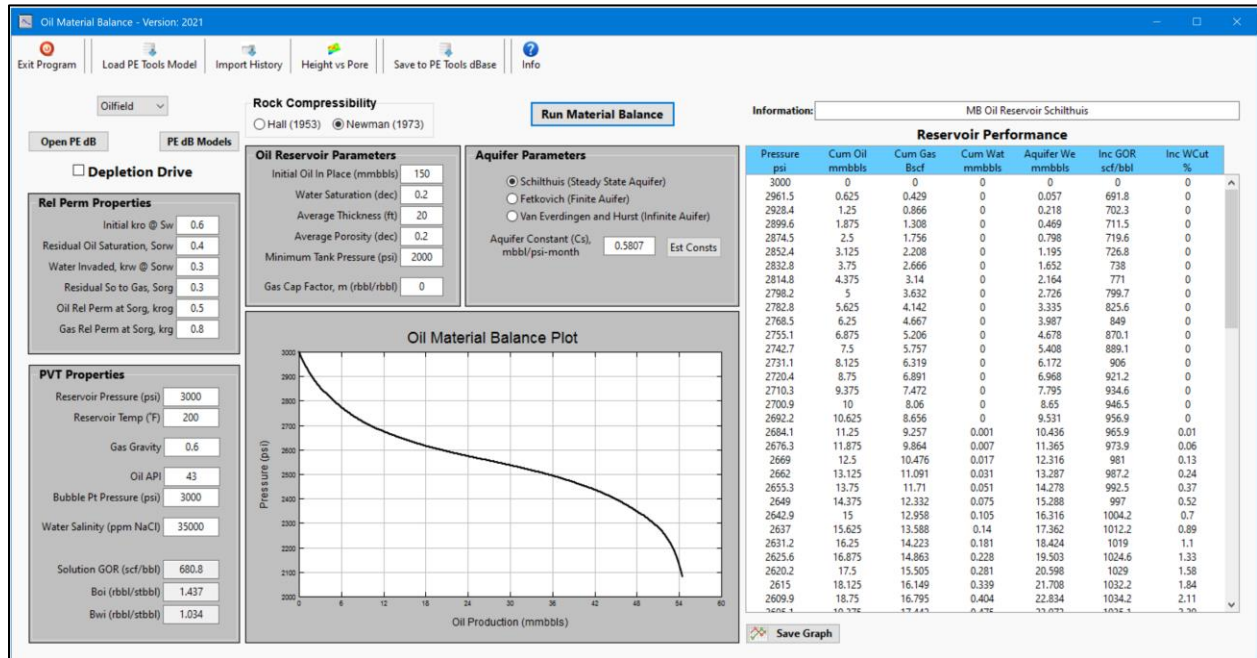


Figure OMB-3: Schilthuis Aquifer Model

The limitation of the Schilthuis model is the assumption that the aquifer is very large and highly permeable. It is assumed that the permeability is so high that the pressure gradient across the aquifer itself is negligible. In addition, the aquifer is assumed to be so large that the pressure within the aquifer never declines; i.e., the initial pressure,  $P_i$  always exists within the aquifer.

In practical terms, for this model to be valid, the reservoir/aquifer system must have a relatively high permeability: 50 md or more; the aquifer must be at least 10 to 20 times as large as the reservoir and preferably at least 100 times as large.

Aquifer water rate is based on Darcy's law for steady state fluid flow:

$$q_w = C(P_i - P_r) \quad (\text{OMB.2})$$

Where:  $q_w$  is the aquifer water rate in bbls/d,  $C$  is the water influx constant bbl/d/psi,  $P_i$  is the initial pressure in psi, and  $P_r$  is the current reservoir pressure in psi.

Equation OMB.2 is integrated to generate the cumulative water influx,  $W_e$ , for the material balance equation.

$$W_e = C_s \int_0^t (P_i - P_r) dt$$

$$(W_e)_n = C_s \sum_{j=1}^n [(P_i - 0.5(P_{r(j-1)} + P_{r(j)})) \Delta t_j] \quad (\text{OMB.3})$$

Where:  $(W_e)_n$  is cumulative water influx at time  $t_n$  in mbbbls,  $C_s$  is the Schilthuis aquifer constant in mbbbls/(month-psi), and time change,  $\Delta t$ , is in months.

For practical purposes, as a starting point when trying to match the aquifer performance,  $C_s$  can be estimated as follows:

$$C_s = \frac{0.0002152 k_a h_a \theta / 360}{\mu_w \ln(r_a / r_e)} \quad (\text{OMB.4})$$

Where:  $C_s$  is the Schilthuis aquifer constant in mbbbl/(month-psi),  $k_a$  is the aquifer permeability in md,  $h_a$  is the thickness of the aquifer in feet,  $\theta$  is the encroachment angle in degrees,  $\mu_w$  is the aquifer water viscosity in cp,  $r_a$  is the radius of the aquifer in feet, and  $r_e$  is the radius of the reservoir in feet.

As an example, for the aquifer parameters below, calculate  $W_e$  at 2976.6 psi and 3 months.

$$P_i = 3000 \text{ psi} \quad k_a = 500 \text{ md} \quad h_a = 20 \text{ ft} \quad \mu_w = 0.8 \text{ cp} \quad r_a = 20,000 \text{ ft} \quad r_e = 1000 \text{ ft} \quad \theta = 360$$

From the aquifer parameters,  $C_s = 0.8979$  mbbbl/(month-psi). So, influx is calculated as follows:

$$W_e = 0.8979 [3000 - 0.5(3000 + 2976.6)] 3 = 31.5 \text{ mbbbl}$$

## OMB.2.2 Fetkovich Aquifer Model

In 1971, Fetkovich developed a method for predicting the water influx of a finite aquifer (Figure OMB-4). Fetkovich began with the premise that the productivity index concept is adequate for describing water influx from a finite aquifer into a hydrocarbon reservoir. In other words, the water influx rate is directly proportional to the pressure drop between the average aquifer pressure and the pressure at the oil/water contact.



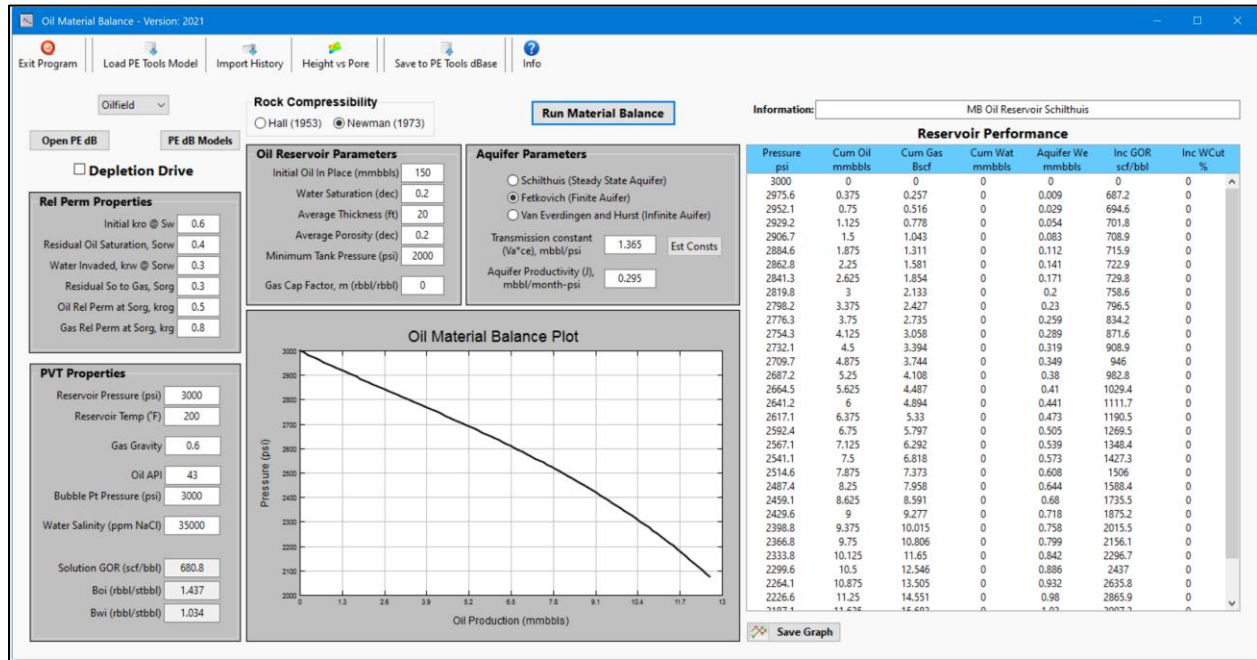


Figure OMB-4: Fetkovich Aquifer Model

The Fetkovich model uses two basic equations, the productivity index equation for the aquifer and an aquifer material balance equation for a constant compressibility. These equations are as follows:

$$q_w = J(P_a - P_f) \quad (\text{OMB.6})$$

$$W_e = V_a c_e (P_i - P_a) \theta / 360 \quad (\text{OMB.7})$$

Where:  $q_w$  is water influx rate from the aquifer in mbbbl/month,  $J$  is the aquifer productivity index in mbbbl/month-psi,  $P_a$  is the average aquifer pressure in psi,  $P_f$  is the pressure at the reservoir/aquifer boundary in psi,  $W_e$  is the cumulative water influx in mbbbls,  $V_a$  is the initial volume of water in the aquifer in mbbbls,  $c_e$  is the effective aquifer compressibility ( $c_w + c_f$ ) in 1/psi,  $c_w$  is the water compressibility in 1/psi,  $c_f$  is the formation compressibility in 1/psi,  $P_i$  is the initial pressure in the aquifer in psi, and  $\theta$  is the encroachment angle in degrees.

After manipulations and integrations (not presented here) the final equations for  $W_e$  is:

$$(W_e)_n = V_a c_e B \left[ \sum_{j=1}^n P_{a(j-1)} - 0.5 \sum_{j=1}^n (P_{f(j-1)} + P_{f(j)}) \right] \theta / 360$$

$$B = 1 - e^{-\left( \frac{J \Delta t}{V_a c_e} \right)}$$

$$J = \frac{0.0002152 k_a h_a \theta / 360}{\mu_w [\ln(r_a / r_e) - 0.75]} \quad (\text{OMB.8})$$



Where:  $(W_e)_n$  is cumulative water influx at time  $t_n$  in bbls,  $B$  is the Fetkovich aquifer constant,  $P_{a(j-1)}$  is the average aquifer pressure at the end of time step  $(j-1)$ ,  $P_{f(j)}$  is the average pressure at the oil/water contact at time step  $j$ ,  $\Delta t$  is time change in months,  $J$  is the aquifer productivity index for a finite aquifer with a no flow outer boundary in mbbbl/(month-psi),  $k_a$  is the aquifer permeability in md,  $h_a$  is the thickness of the aquifer in feet,  $\mu_w$  is the aquifer water viscosity in cp,  $r_a$  is the radius of the aquifer in feet,  $r_e$  is the radius of the reservoir in feet.

As an example, for the aquifer parameters below, calculate  $W_e$  at 2976.6 psi and 3 months.

$P_i=3000\text{psi}$   $k_a=500\text{md}$   $h_a=20\text{ft}$   $\mu_w=0.8\text{cp}$   $r_a=100,000\text{ft}$   $r_e=1000\text{ft}$   $C_e=7 \times 10^{-6}$   $V_a=2,195$  mmbbbls

From the aquifer parameters,  $J = 0.6978$  mbbbl/(month-psi),  $B = 0.1274$  and  $V_{aCe} = 15.365$  mbbbls/psi. Water influx is as follows:

$$W_e = (15.365) (0.1274) [3000 - 0.5(3000 + 2976.6)] = 22.9 \text{ mbbbl}$$

The water influx,  $W_e$ , for the Fetkovich aquifer is similar to the infinite Schilthuis aquifer since the  $r_a/r_e$  ratio is 100, which is equivalent to an infinite aquifer.

It should be noted that the Fetkovich model can be used for non-circular aquifers through the  $\theta/360$  term and modifying the  $J$  calculation as follows:

a) Finite aquifer, no flow outer boundary

$$\text{Radial: } J = \frac{0.0002152 k_a h_a \theta / 360}{\mu_w [\ln(r_a / r_e) - 0.75]} \quad \text{Linear: } J = \frac{0.0001028 k_a h_a w}{\mu_w L}$$

b) Finite aquifer, constant pressure outer boundary

$$\text{Radial: } J = \frac{0.0002152 k_a h_a \theta / 360}{\mu_w \ln(r_a / r_e)} \quad \text{Linear: } J = \frac{0.00003426 k_a h_a w}{\mu_w L}$$

Where:  $J$  is the productivity index of the aquifer in mbbbls/month-psi,  $\theta$  is the encroachment angle in degrees,  $w$  is the width of the linear aquifer in feet, and  $L$  is the length of the linear aquifer in feet.

### OMB.2.3 Van Everdingen and Hurst Unsteady State Infinite Aquifer Model

In 1949, Van Everdingen and Hurst (VEH) proposed the most complete formulation of an aquifer model (Figure OMB-5). They solved the diffusivity equation for the aquifer-reservoir system by applying the Laplace transformation to the equations representing aquifer flow. Van Everdingen and Hurst assumed that the aquifer is characterized by uniform thickness, constant permeability, uniform porosity, constant rock compressibility and constant water compressibility.

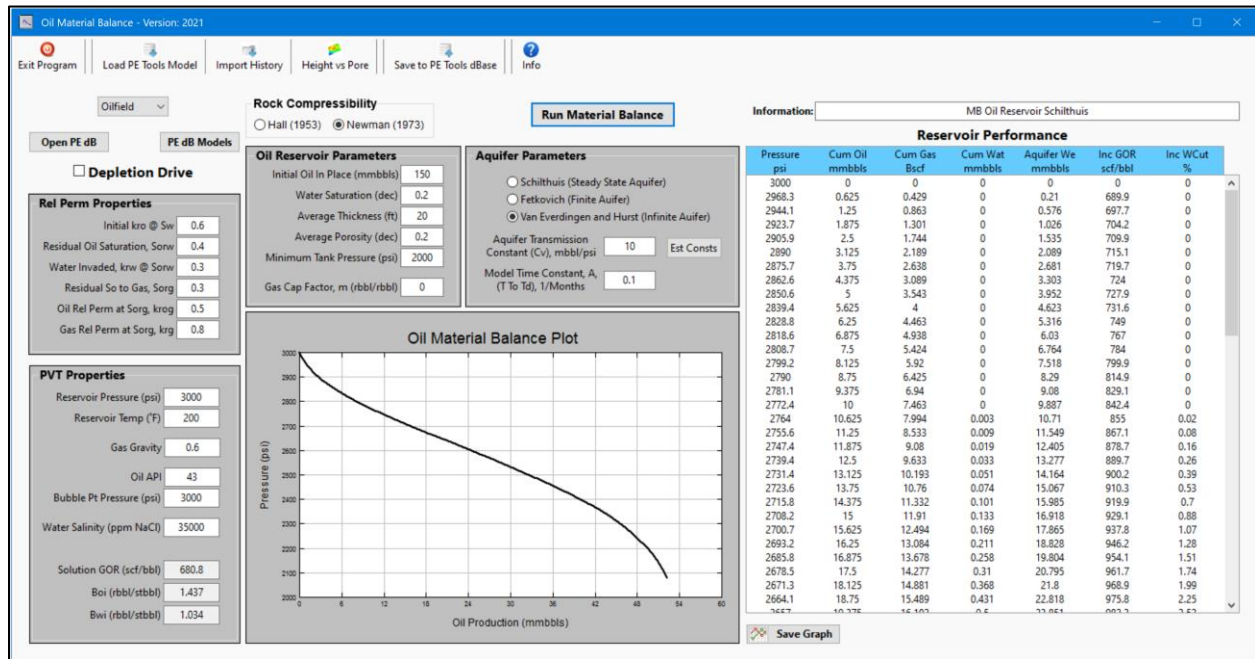


Figure OMB-5: Van Everdingen and Hurst Aquifer Model

Van Everdingen and Hurst expressed the mathematical relationship for calculating water influx in the form of a dimensionless parameter that is called cumulative influx function  $Q(t_d)$ . This dimensionless parameter was expressed as a function of the dimensionless time  $t_D$  and dimensionless radius  $r_D$ , and as a result the solution to the diffusivity equation was generalized and is applicable to any aquifer where the flow of water into the reservoir is essentially radial.

The Van Everdingen and Hurst solution was presented in tabulated and graphical form which made it difficult to use. In 1988, Klins, M.,A.; Bouchard, A.,J.; and Cable, C.,L. presented a paper (A Polynomial Approach to the Van Everdingen-Hurst Dimensionless Variables for Water Encroachment, SPE 15433) that included equations that could be used to implement the VEH solution. The equations for an infinite aquifer presented in Appendix F of the SPE paper have been implemented in the Van Everdingen and Hurst aquifer model in PE<sup>2</sup> Essentials.

The Van Everdingen and Hurst equation for water influx is as follows:

$$W_e = C_v \Delta P Q(t_d) \quad (\text{OMB.9})$$

$$C_v = 0.001119 \phi_a h_a c_e r_e^2 \theta / 360 \quad (\text{OMB.10})$$

$$t_d = At \quad (\text{OMB.11})$$

$$A = \frac{0.1924 k_a}{\phi \mu_w c_e r_e^2} \quad (\text{OMB.12})$$

$$\Delta P_j = 0.5(P_{j-2} - P_j) \quad (\text{OMB.13})$$

Where:  $W_e$  is cumulative water influx in mbbbls,  $C_v$  is the Van Everdingen and Hurst aquifer transmission constant in mbbbls/psi,  $\Delta P_j$  is the constant pressure drop across the aquifer for time step  $j$  (note  $\Delta P_1 = 0.5(P_i - P_1)$ ) in psi,  $Q(t_d)$  is the cumulative influx function,  $t_d$  is dimensionless time,  $\phi_a$  is the aquifer porosity in decimal,  $h_a$  is the aquifer thickness in feet,  $c_e$  is the effective aquifer compressibility ( $c_w + c_f$ ) in 1/psi,  $c_w$  is the water compressibility in 1/psi,  $c_f$  is the formation compressibility in 1/psi,  $r_e$  is the radius of the reservoir in feet,  $\theta$  is the encroachment angle in degrees,  $k_a$  is the aquifer permeability in md,  $\mu_w$  is the aquifer water viscosity in cp,  $t$  is time in months, and  $A$  is a time constant used to convert  $t$  to  $t_d$ .

From SPE 15433,  $Q(t_d)$  can be calculated as follows:

a)  $t_d \leq 0.01$

$$Q(t_d) = \frac{2\sqrt{t_d}}{\sqrt{\pi}} \quad (\text{OMB.14})$$

b)  $0.01 \leq t_d < 200$

$$Q(t_d) = \frac{b_0(t_d)^{b_7} + b_1(t_d) + b_2(t_d)^{b_8} + b_3(t_d)^{b_9}}{b_4(t_d)^{b_7} + b_5(t_d) + b_6} \quad (\text{OMB.15})$$

c)  $t_d > 200$

$$Q(t_d) = 10^{(b_{10} + b_{11} \ln(t_d) + b_{12} [\ln(t_d)]^{b_{13}})} \quad (\text{OMB.16})$$

Where:  $b_0 = 1.129552$ ,  $b_1 = 1.160436$ ,  $b_2 = 0.2642821$ ,  $b_3 = 0.01131791$ ,  $b_4 = 0.5900113$ ,  $b_5 = 0.04589742$ ,  $b_6 = 1.00$ ,  $b_7 = 0.5002034$ ,  $b_8 = 1.500$ ,  $b_9 = 1.979139$ ,  $b_{10} = 4.3989$ ,  $b_{11} = 0.43693$ ,  $b_{12} = -4.16078$ , and  $b_{13} = 0.09$

For the aquifer parameters below, calculate  $W_e$  at 2976.6 psi and 3 months.

$$P_i = 3000 \text{ psi} \quad k_a = 500 \text{ md} \quad h_a = 20 \text{ ft} \quad \mu_w = 0.8 \text{ cp} \quad r_e = 1000 \text{ ft} \quad C_e = 7 \times 10^{-6} \quad \phi_a = 0.2 \quad \theta = 360$$

From the aquifer parameters,  $C_v = 0.03133$  mbbbl/psi,  $A = 85.8928$  /month and  $t_d = 257.7$ . Since  $t_d > 200$ , equation OMB.16 is used to calculate  $Q(t_d) = 93.2866$ . Water influx is as follows:

$$W_e = (0.03133) (93.2866) 0.5(3000 - 2976.6) = 34.2 \text{ mbbbl}$$

For a finite aquifer, the SPE paper uses Bessel functions and hyperbolic cosecants to calculate  $Q(t_d)$ . The finite aquifer model has not been implemented in this version of PE<sup>2</sup> Essentials tools. The Fetkovich model should be used for finite aquifers.

### OMB.3 Depletion Drive Option

If the 'Depletion Drive' box is checked, the oil material balance tool will run a model using a depletion / solution gas formulation (Figure OMB-6). There is no gas cap or aquifer when using this option. Recovery above and below the bubble point pressure, as well as the formation of a secondary gas cap, is modeled.

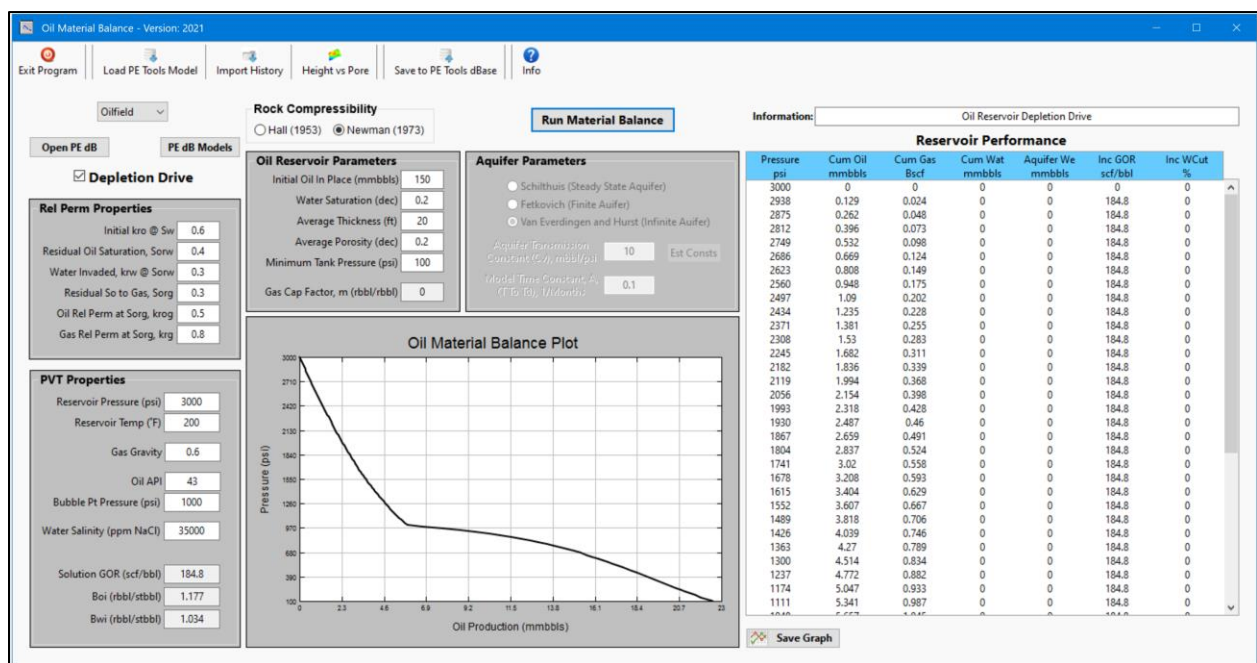


Figure OMB-6: Depletion Drive Model

If a match to historical production is required, the history data is imported with 'Import History' and the tank parameters are modified until a match is achieved (refer to the example in Section OMB.6).

The data generated by the PE<sup>2</sup> Essentials Oil Material Balance tool can be saved to the PE Tools database for import into other tools, including the PE<sup>2</sup> Essentials Volumetric (MB) Analysis tool for comparison to field data.

### OMB.4 Height versus Pore Volume

Material balance analysis assumes that the system is a dimensionless tank – this would be similar to building a 1-block reservoir simulation model. This assumption does not allow evaluation of fluid contact depth or movement of the fluid contacts.

In a reservoir containing an aquifer, the water from the aquifer will encroach into the oil zone, increasing the water saturation. In classical material balance calculations, the water saturation in the tank will increase uniformly (no variation of  $S_w$  in the reservoir). However, if the increase in water saturation is related to a pore volume fraction, then the movement of the OWC can be calculated and more relevant water cut forecasts can be generated.

The PE<sup>2</sup> Essentials Oil Material Balance tool subdivides the tank into 10 intervals (Figure OMB-7).

Height Of Reservoir vs Unflooded Pore Volume			
Height Above OWC (ft)		Percent of Pore Volume	
0	to 2	18.2	
2	to 4	16.4	
4	to 6	14.5	
6	to 8	12.7	
8	to 10	10.9	
10	to 12	9.1	
12	to 14	7.3	
14	to 16	5.5	
16	to 18	3.6	
18	to 20	1.8	Total
			100

Exit

Figure OMB-7: Height vs Pore Volume

The calculation of water-oil ratios (WOR), becomes a two-step process. The conventional material balance WOR is calculated as follows:

$$WOR_{est} = (k_{rw} / k_{ro}) * (\mu_o / \mu_w)$$

The  $WOR_{est}$  is then corrected based on the location of the oil-water contact as follows:

$$WOR = WOR_{est} * [\text{Height Water} / (\text{Total Height} - \text{Height Water})] * (B_o / B_w)$$

The  $[\text{Height Water} / (\text{Total Height} - \text{Height Water})]$  term represents the movement of the water contact in the reservoir.

### OMB.5 Aquifer Model Comparison

As a check on the different aquifer models, a comparison was made by inputting parameters for an infinite aquifer. Figure OMB-8 presents the comparison showing that all aquifer models yield similar results for a similar infinite aquifer.

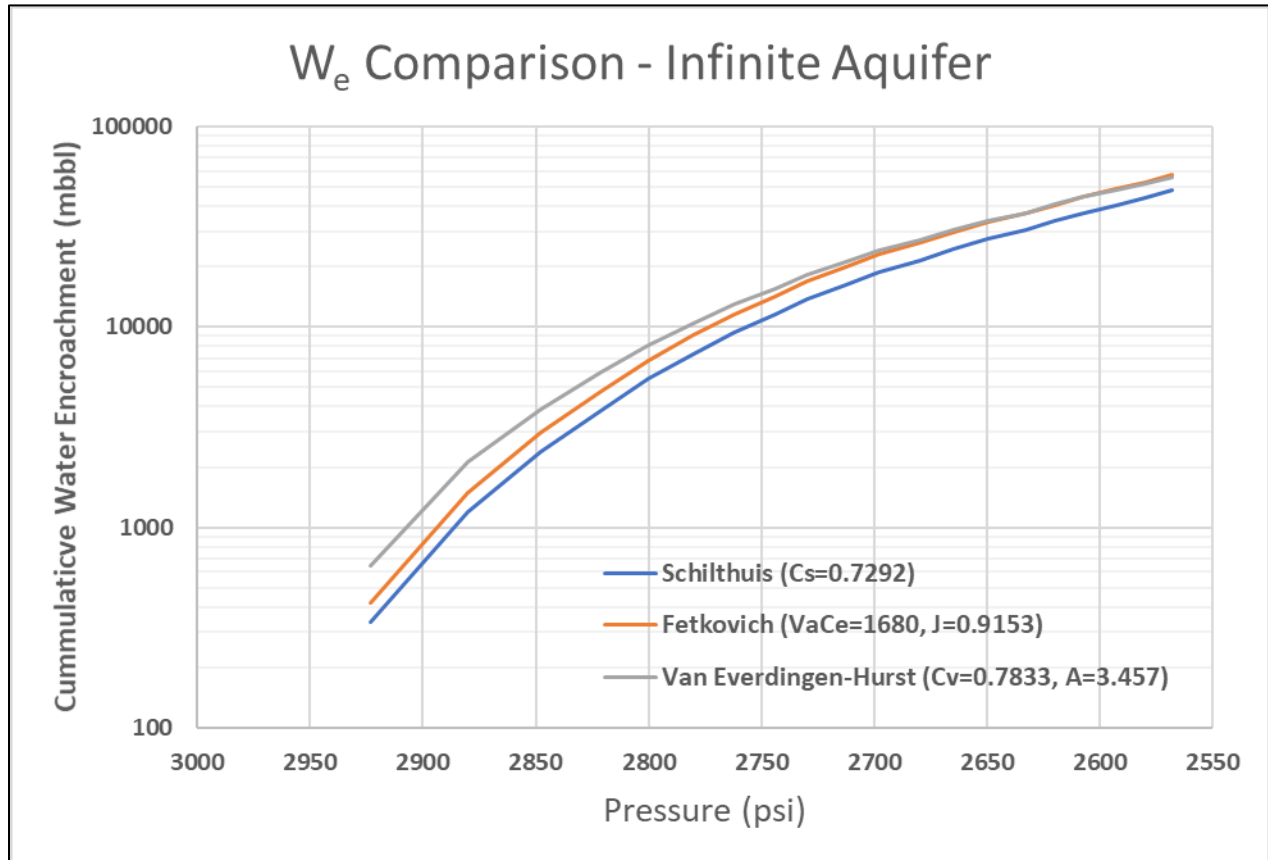


Figure OMB-8: Aquifer Model Comparison

It is possible to use the tool to estimate the value for the aquifer constants before generating a run by entering the aquifer properties. This is accessed by clicking the 'Est Const' button on the main screen.

Alternatively, after manually changing the aquifer constants to generate a match, the 'Est Const' option can be used to determine the equivalent aquifer parameters that will yield the final matched aquifer constants (refer to Section OMB.6).

## OMB.6 Oil Material Balance Example – History Match

For history matching, reservoir pressure/volume history is imported through the “Import History” button. The aquifer properties can then be modified to yield a good match of the historical data which will then be used to forecast depletion of the reservoir.

Figure OMB-9 shows the importing of the example data presented by Smith et al on page 12-71; included as ‘MB Data.xlsx’ in the “Book Examples\Example Oil Mat Bal” directory. The actual Oil MBal models are included in the ‘PEE Tools Database Book Examples’ database included in the “Book Examples\PEE Tools Database Examples” directory.

**PE Essentials Material Balance Historical Data Import**

**Data Input**  
☒ CSV File  
☐ Excel File  
 Open Excel File

Note: Oil and water volumes in mmbbl, gas volume in mmscf and reservoir pressure psi

**Excel Input Parameters**

	Column	Start Row	End Row
Date or Years			
Inc Oil Production			
Inc Gas Production			
Inc Water Production			
Reservoir pressure			

**Display**  
☒ Cum ☐ Inc

Years	Cum Oil	Cum Gas	Cum Wat	Res Press
0	0	0	0	3000
1	564.2	395.8	3.3	2923
2	1418.8	996	15.7	2880
3	2155.3	1513.9	32.7	2848
4	2766.9	1944.2	52.3	2821
5	3265.5	2295.2	72.2	2800
6	3686.7	2591.9	92.6	2780
7	4058	2853.5	113.6	2762
8	4400.1	3094.8	136	2744
9	4702.4	3308	158.1	2730
10	4992.3	3512.6	182	2713
11	5274.3	3711.7	207.7	2698
12	5563.7	3916.2	237.3	2680
13	5846.5	4116	269.1	2665
14	6113.6	4304.8	301.8	2650
15	6386.7	4498	338.6	2633
16	6642.3	4678.9	375.5	2620
17	6874.9	4843.6	411.4	2607
18	7104.3	5006	449.4	2593
19	7328.5	5164.8	488.9	2580
20	7539.7	5314.4	528.4	2568

Import Data Exit

Figure OMB-9: Example Data from Smith et al

This example was evaluated using the Fetkovich aquifer model and matched with the following aquifer input parameters (Figure OMB-10).

**Estimate Aquifer Constants**

Aquifer Permeability (md)	125	Aquifer Porosity (dec)	0.2
Aquifer Thickness (ft)	20	Encroachment Angle	360
Water Viscosity (cp)	0.8	Aquifer Volume (mmbbl)	4919
Aquifer Radius (ft)	40000	Reservoir Radius (ft)	5000
Total Compressibility ( $/10^6$ psi)	7		

Reset Parameters Cancel Calculate and Close

Figure OMB-10: Example Data from Smith et al – Matched Aquifer Parameters



A run was initially made using basic aquifer constants, then iterations were made by varying the constants until an acceptable match to the historical data was achieved.

As a rule of thumb, if early history is not matched, modify the 'J' constant for the Fetkovich aquifer model or the 'A' constant for the Van Everdingen and Hurst aquifer model. Late time pressure support is matched by varying the transmission constants for either aquifer model after the early time trend is matched.

The final history matched model is included in the 'PEE Tools Database Book Examples' database and yields the history match presented in Figure OMB-11. Note that, for the match, initial oil in place was assumed to be the value reported by Smith et al and the aquifer properties were modified to obtain the match.

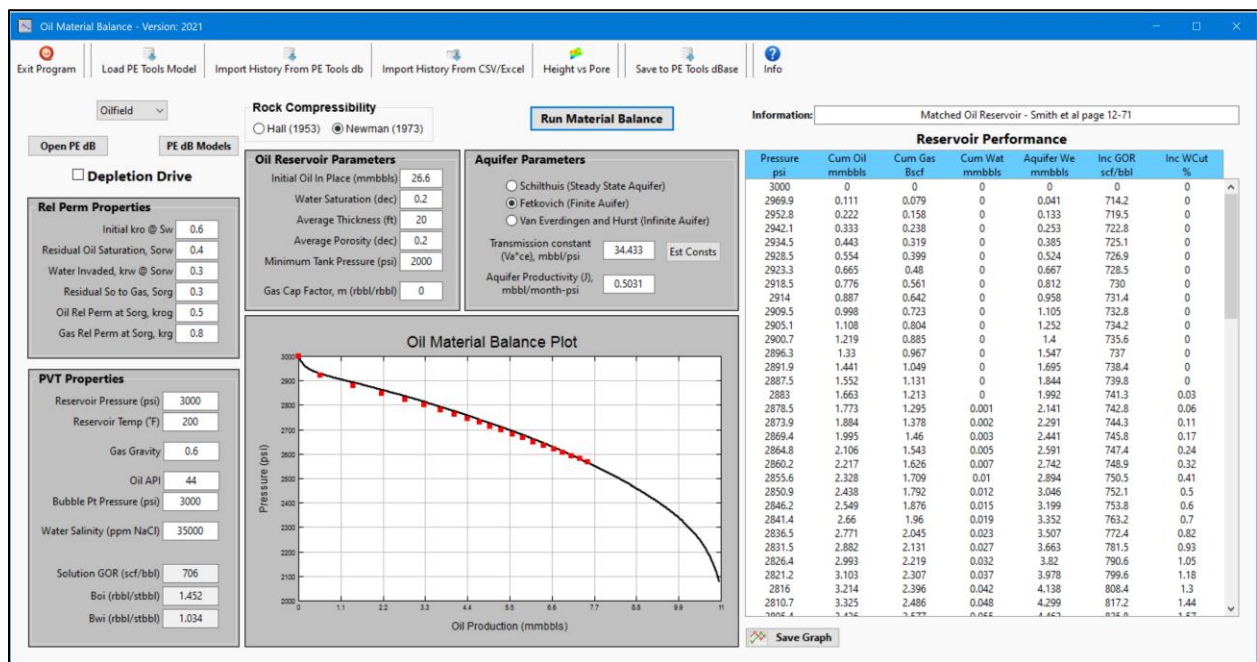


Figure OMB-11: Example Data from Smith et al – History Match

At the end of the history data, the reservoir pressure was 2568 psi. The  $W_e$  at this time was 11.6 mmbbls (versus 10.3 mmbbls as reported in Smith et al).

A closer match to the Smith et al aquifer estimate could be achieved by modifying the relative permeability parameters. Note that the Smith et al example was not generating a forecast, it was just attempting to "back out" oil in place and aquifer performance. The PE<sup>2</sup> Essentials Oil Material Balance tool is a forecasting tool so all the reservoir effects are taken into account.

The material balance forecast will be saved with the model in the PE Tools database ('Save to PE Tools dBase') for use with other tools.



## Decline Curve Analysis

### DCA.1 Introduction

Oil and gas wells usually reach a maximum rate shortly after completion after which they start declining in production. A production “decline curve” indicates the amount of oil and gas produced per unit of time for several consecutive periods. If the flowing conditions remain constant, the resulting decline curve may be consistent and, if projected into the future, will yield information as to the future production from the well.

Decline curve analysis (DCA) is a graphical procedure used for analyzing declining production trends and forecasting future performance of oil and gas wells. Fitting a line through the plot of a well’s performance history and assuming the trend will continue into the future forms the basis of DCA. The caveat is that in the absence of stabilized production trends, DCA cannot be expected to give reliable results. Since DCA is a means of predicting future well production based on past production history, it is also a technique that can be used to identify well production problems.

Decline curves are the most common means used to forecast oil and gas production since: they use data which is easy to obtain; the decline curves are easy to plot; they yield results on a time basis; and they are relatively easy to analyze.

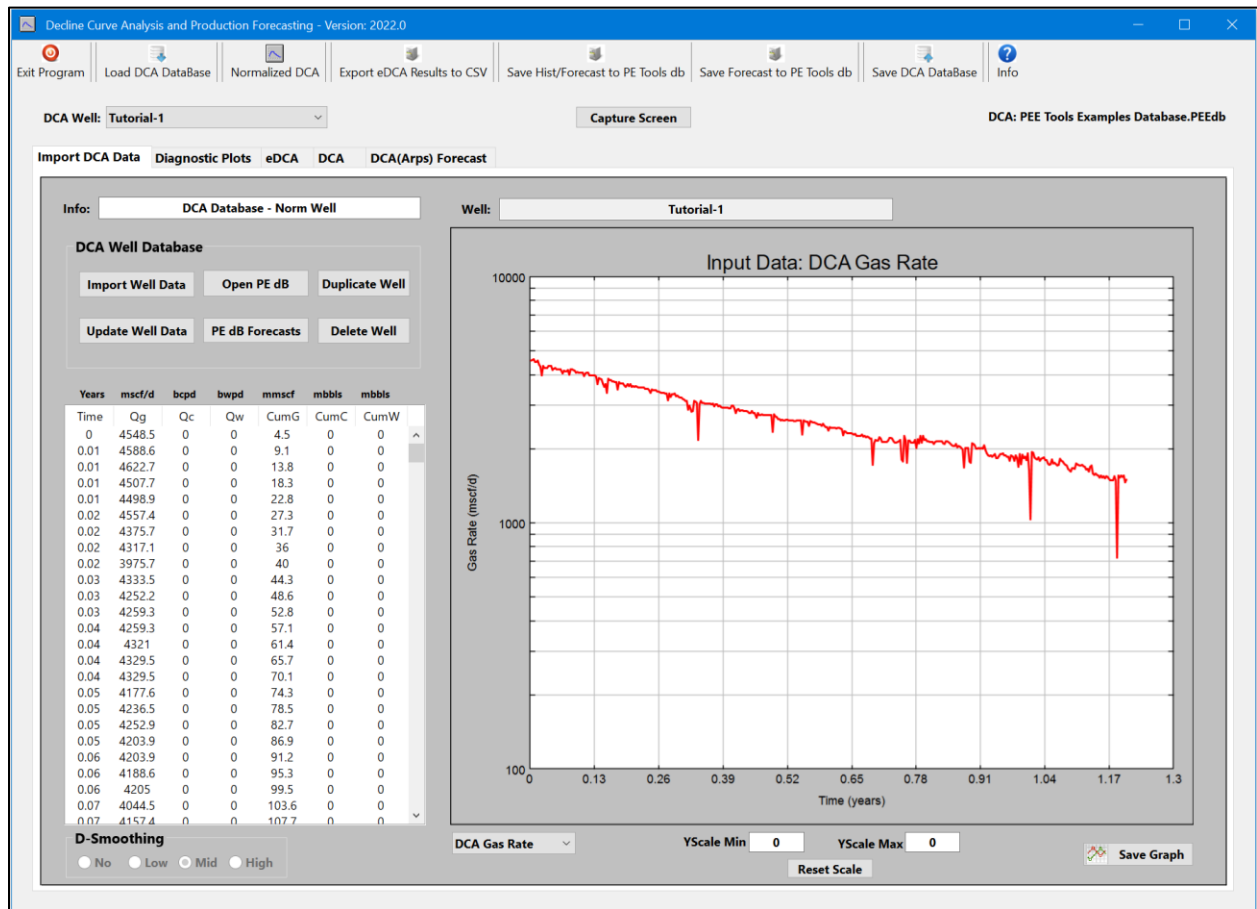
For more in-depth information on decline curve analysis and the models/equations available to perform the analysis, refer to the Appendices. Appendix DCA1 describes a number of the concepts associated with DCA including decline factors; the decline equations; and considerations to keep in mind when performing DCA. Appendix DCA2 includes the formulations of each of the decline models used in this tool. Appendix DCA3 presents the mathematical definitions of DCA parameters.

### DCA.2 Decline Curve Analysis Tool

PE<sup>2</sup> Essentials Decline Curve Analysis (DCA) is a tool that can be used to generate decline parameters for a well and generate a forecast (Figure DCA-1).

An Excellent reference for this type of analysis is Poston, S., W. and Poe Jr., B. D., Analysis of Production Decline Curves, SPE, 2008.

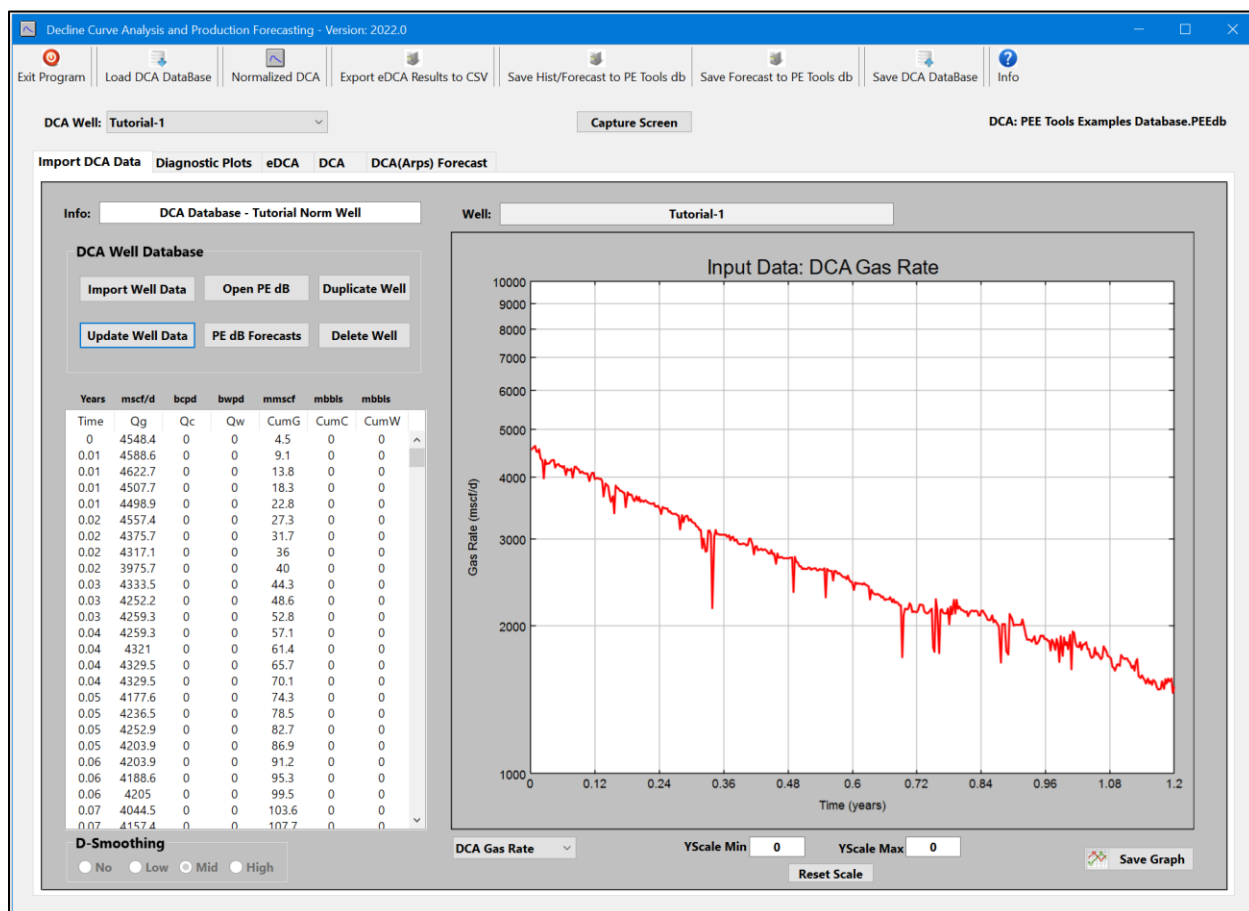
The ‘Decline Curve Analysis’ tool will generate the best-fit solution for the decline curve based on the decline model chosen. Optionally, the parameters generated by the PE<sup>2</sup> Essentials ‘Monte Carlo DC Forecast’ tool can be imported for use in the tool. Following decline curve analysis, a production forecast can be generated.


 Figure DCA-1: PE<sup>2</sup> Essentials – Decline Curve Analysis Tool

The active Database being used for DCA is listed in the upper right area of the DCA tool screen. It should be noted that the NormDCA (Section DCA.7) data is not part of the DCA database but is stored separately in the Tools Database. Both the DCA database and the NormDCA data can be stored in the same PEE Tools Database or different databases.

The active well is chosen from the dropdown menu on the upper left of the DCA tool screen.

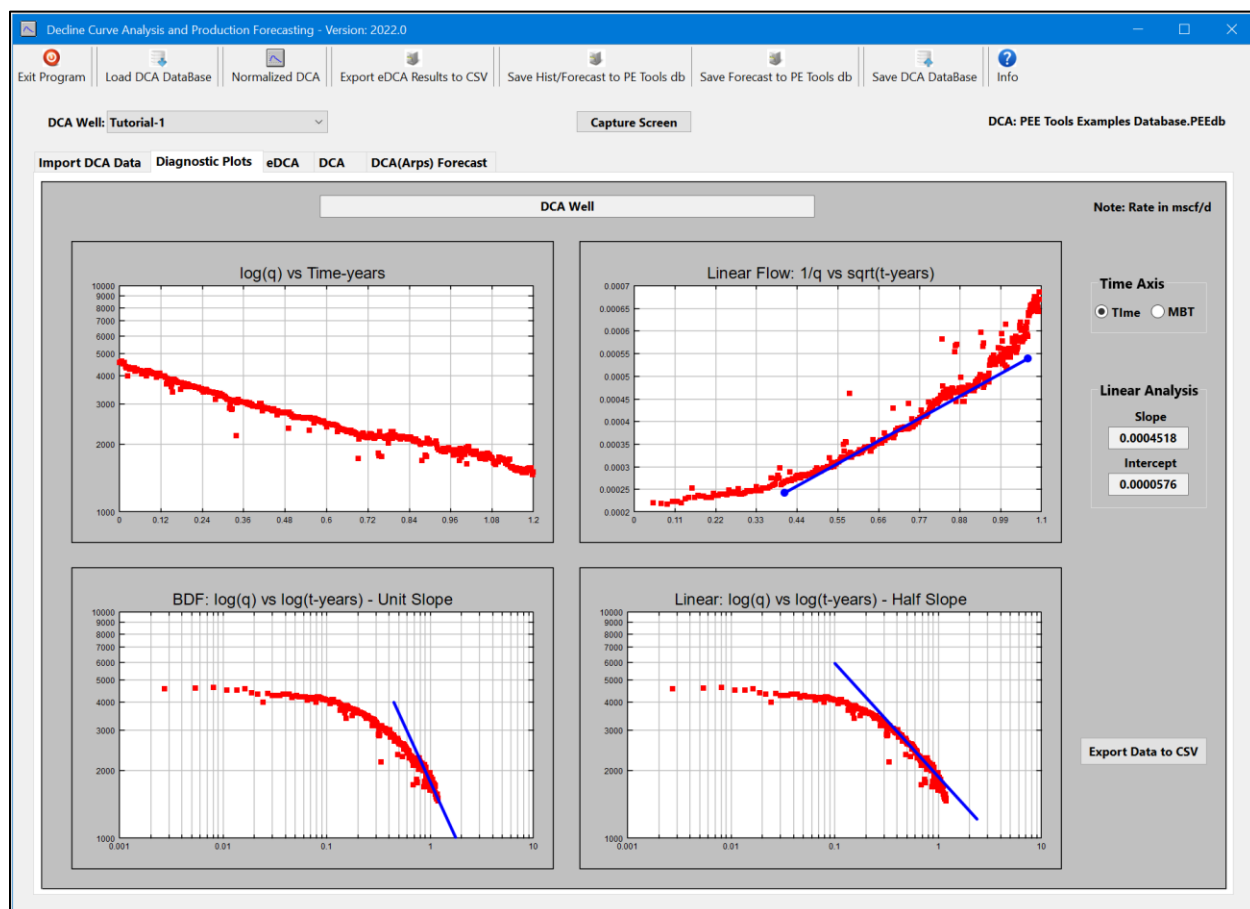
Note that there are two data points that are off trend in this data. To edit out these data points, the PDA tool was loaded and the Tutorial-1 well was chosen. Then on the 'Data Validation/Diagnostic tab, all rates less than 1100 were edited out. The well was then updated to the PDA Tools database. Then on the DCA screen (Figure DCA-1), the 'Update Well Data' button was clicked and the Tutorial-1 well was updated (Figure DCA-1a).

Figure DCA-1a: PE<sup>2</sup> Essentials – Decline Curve Analysis Tool – Edited Data

To determine the existence of the analyzable, boundary dominated flow (BDF) period, the 'Diagnostic Plots' tab is used (Figure DCA-2).

Four plots are presented on this tab: 1/rate vs square root(time); log(rate) vs log(time); producing month vs time; and log(rate) vs time. Plots can be presented using material balance time (MBT) as well.

The lower two plots in Figure DCA-2 include an automatic calculation of a straight line. The square root(time) straight line can be used to determine if linear flow occurred, which can be evident in hydraulically fractured wells. The slope of this line is proportional to the permeability where  $1/\text{slope} \sim \sqrt{k}$  – refer to PDA tool documentation for additional information.

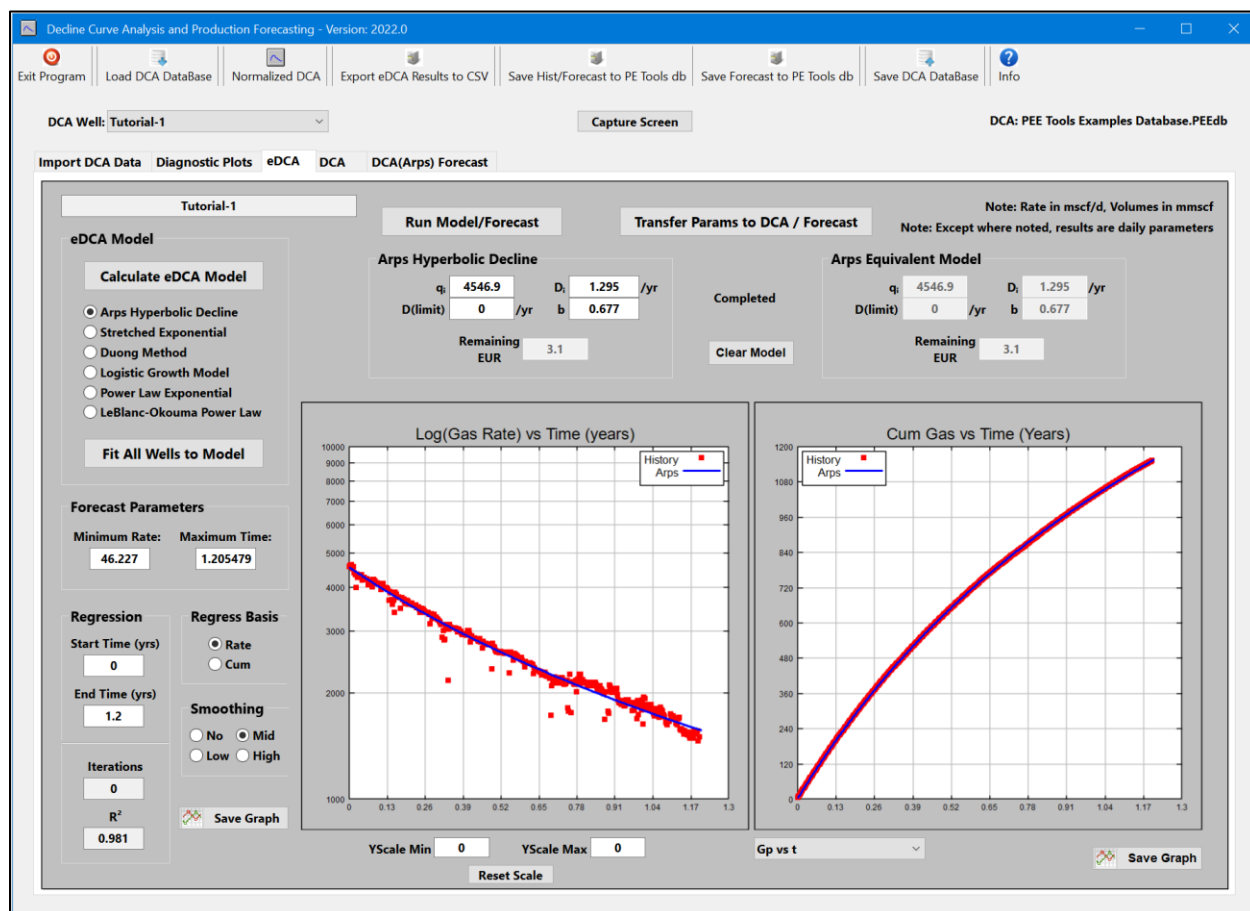

 Figure DCA-2: PE<sup>2</sup> Essentials – Diagnostic Plots

No calculations are generated for these plots, they are presented for visual diagnostics. The slope and intercept of the 'Linear Flow' plot (upper right) is presented for external calculations if required. It should be noted that linear flow appears to have occurred for approximately 1.5 months for the Tutorial-1 well.

The unit slope line on the BDF plot can be moved to determine the start of the analyzable period.

The PE<sup>2</sup> Essentials Decline Curve Analysis tool includes enhanced decline curve analysis called eDCA (Figure DCA-3). With eDCA, it is possible to fit the production data to the following DCA models:

- Arps Hyperbolic Decline
- Stretched Exponential Decline
- Duong Decline
- Logistic Growth Decline
- Power Law Exponential Decline
- LeBlanc-Okouma Power Law Decline

Figure DCA-3: PE<sup>2</sup> Essentials – Enhanced Decline Curve Analysis (eDCA)

When using eDCA (Section DCA.4), the Arps equivalent parameters for the modeled well of interest can be transferred to the DCA and DCA(Arps) Forecast tabs by clicking the 'Transfer Params to DCA / Forecast' button. This will allow a forecast to be generated for the well as well as to generate Monte Carlo DCA forecasts.

It should be noted that in order to generate a valid equivalent Arps model for any eDCA model, other than Arps, that is valid for the production forecast, a forecast 'End Time (yrs)' should be entered and either the 'Generate DCA Model' or the 'Run Model/Forecast' button clicked. When using the Arps eDCA model, this forecast step is not required since the Arps and the equivalent Arps models are the same.

The selected eDCA model will be forecasted to the entered end time and the combined history and forecast will be used to generate the equivalent Arps model that will be valid for the entire forecast period.

Refer to Section DCA.4 for information on using eDCA.

The 'DCA' tab (Figure DCA-4), is used to modify the Arps equivalent parameters or to generate a different fit to the Arps model if so desired.

This tab is also used to generate the DCA analysis of the other phases (Section DCA.5) for use in DCA forecasting.

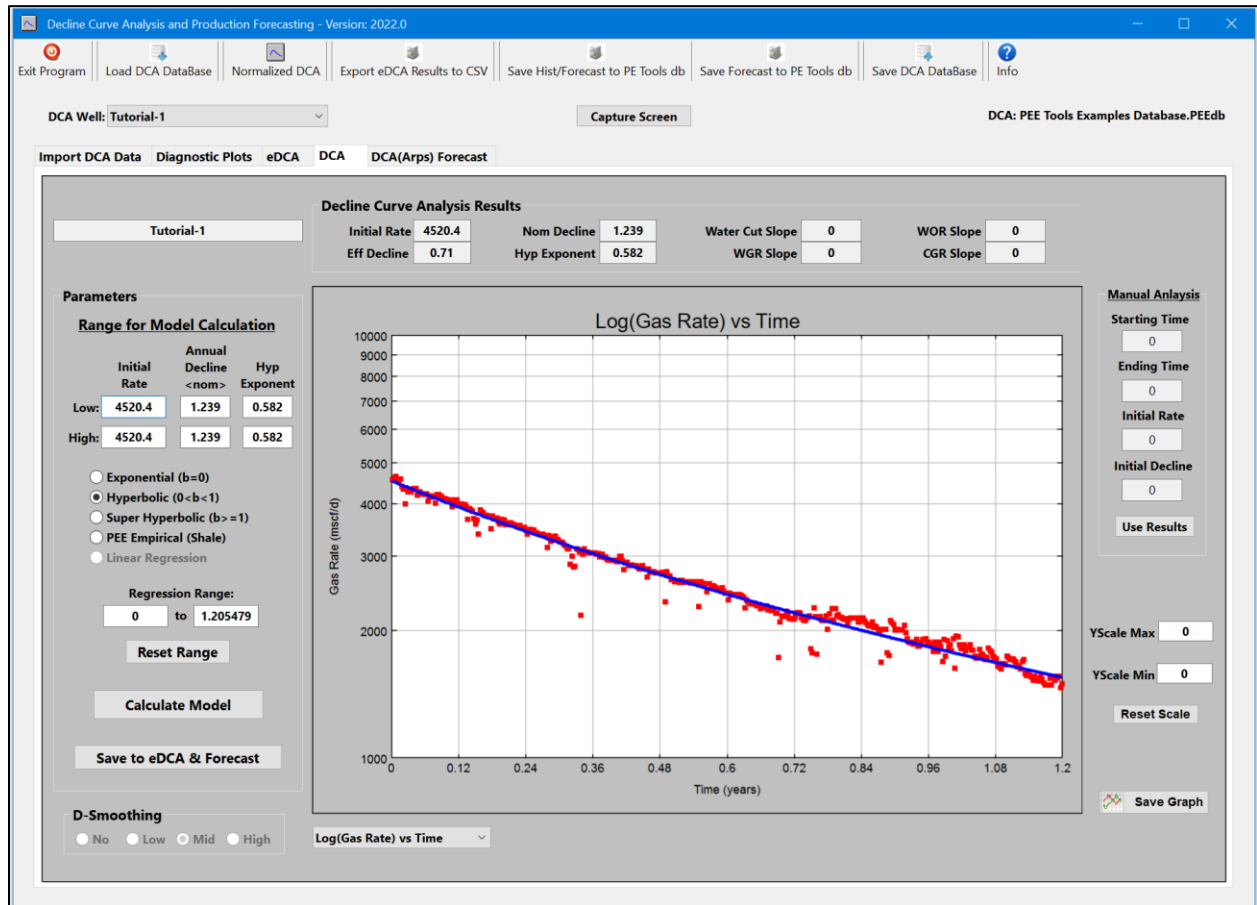


Figure DCA-4: PE<sup>2</sup> Essentials – Arps Decline Curve Analysis Parameters

If the Arps model parameters are modified on this tab, the 'Save to eDCA / Forecast' button is clicked to transfer the results to the other tabs. This is not necessary for the analysis of the other phases which are automatically saved for forecasting.

It is possible to perform all the analysis on this tab, rather than eDCA, to generate the Arps DCA model parameters.

Refer to Section DCA.5 for information on generating DCA parameters with this tab.

The 'DCA(Arps) Forecast' tab (Figure DCA-5), is used to generate a production forecast based with the Arps equivalent parameters.

If the DCA forecast parameters for the other phases were generated on the 'DCA' tab, then this forecast will also be included in the forecast. It is possible to set the secondary phase ratios to constants for the forecast.

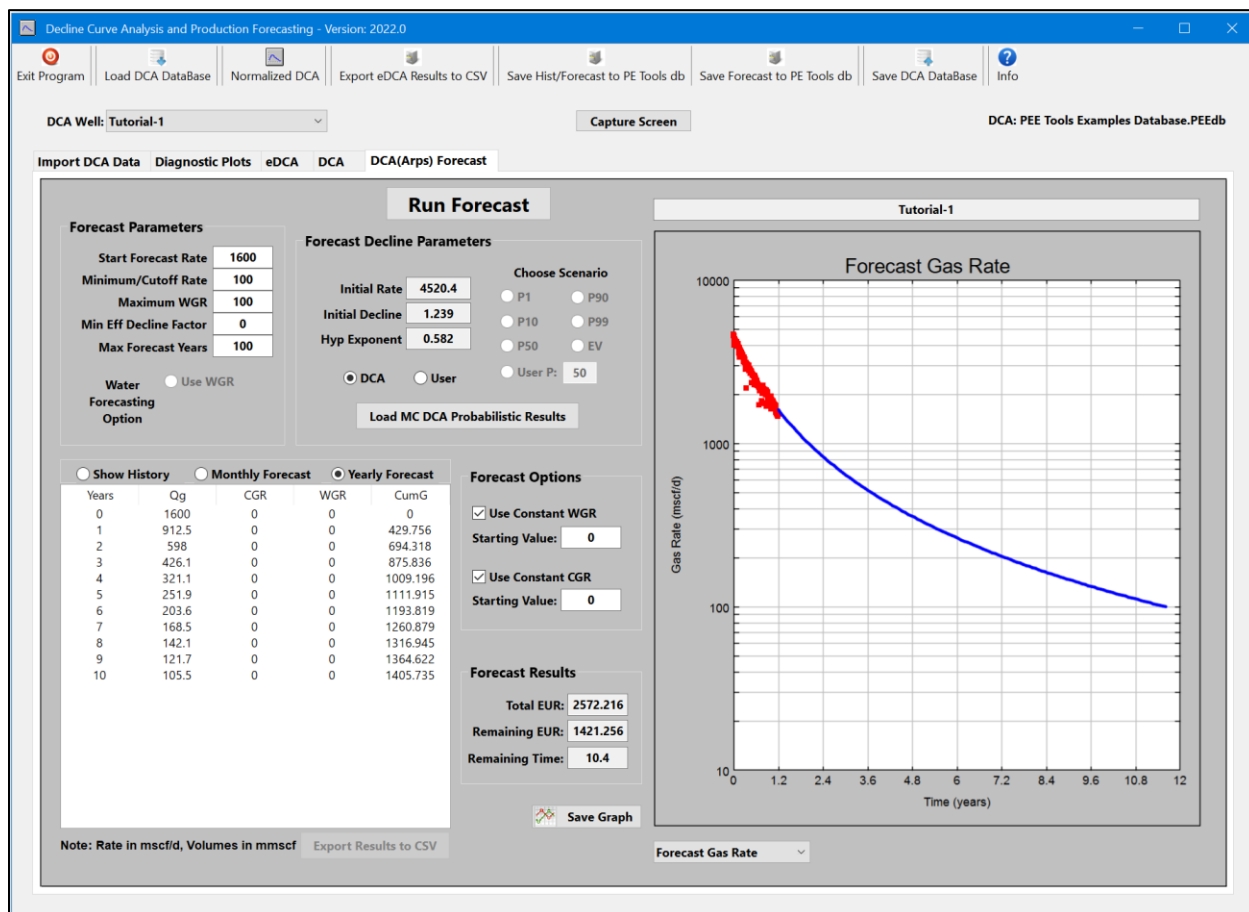
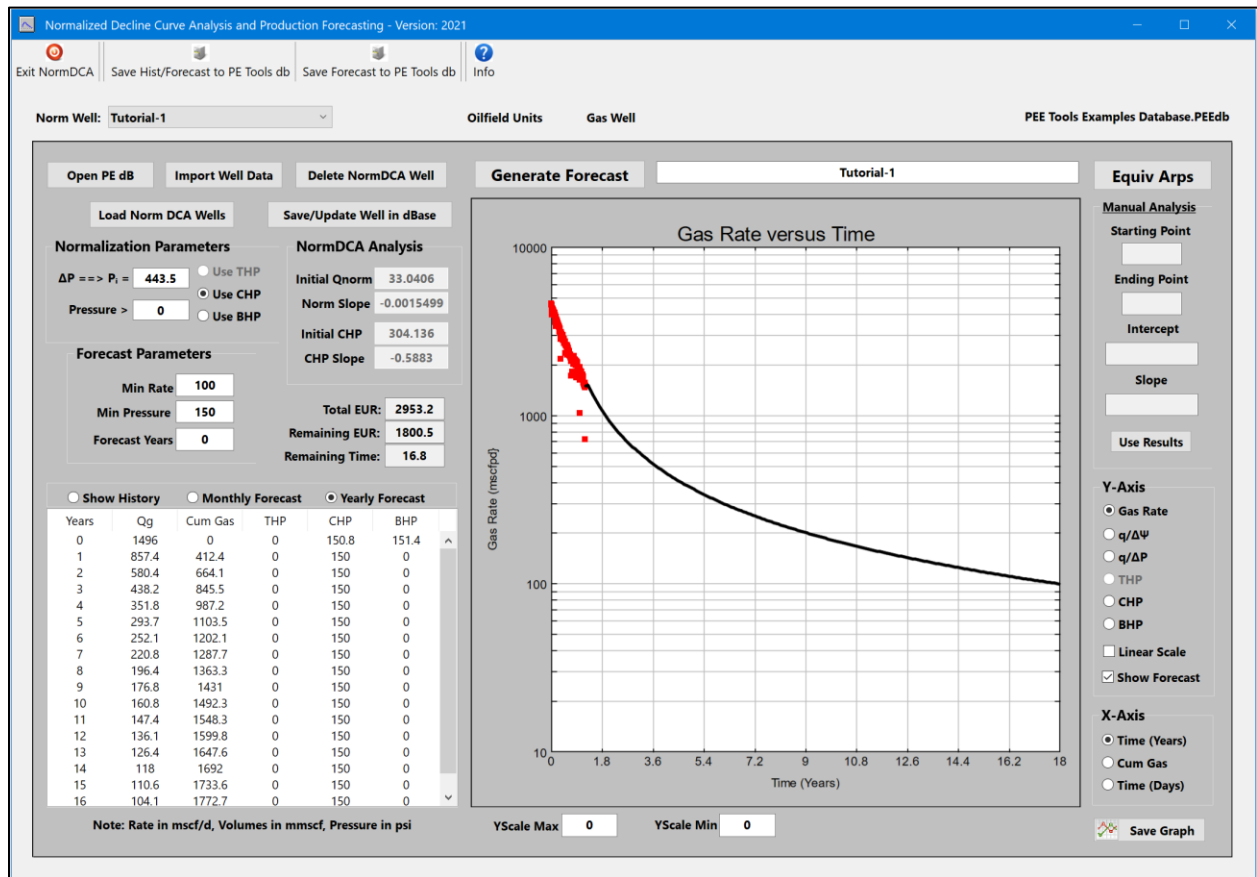


Figure DCA-5: PE<sup>2</sup> Essentials – DCA(Arps) Production Forecast

Refer to Section DCA.6 for more in-depth information on generating DCA forecasts with this tab.

Normalized DCA (Figure DCA-6) is used to generate an analysis and production forecast for choked, constant rate wells.

The base reference for normalized decline curve analysis is Anderson, S., Anderson, D., Edwards, K., Epp, K., Stalgorova, K., Pressure Normalized Decline Curve Analysis for Rate-Controlled Wells, SPE 162923, 2012.


 Figure DCA-6: PE<sup>2</sup> Essentials – Norm DCA Analysis and Production Forecast

Refer to Section DCA.7 for more in-depth information on generating NormDCA analysis and forecasts.

### DCA.3 Production Data Import

The PE<sup>2</sup> Essentials Decline Curve Analysis tool includes a DCA database that can include multiple gas wells, oil wells and fields at the same time (Figure DCA-7).

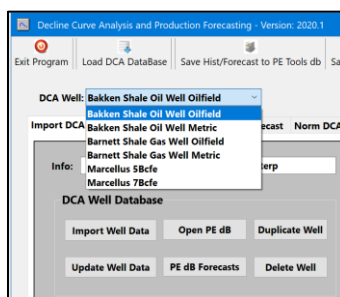


Figure DCA-7: Decline Curve Analysis – DCA Database



The DCA database is independent of the PE Tools database and can be stored either independent of the PE Tools database or in the PE Tools database.

To import data into the DCA database the 'Import Well Data' button on the 'Import DCA Data' tab is clicked (Figure DCA-8). The available wells in the current PE Tools database will be listed and can be imported into the DCA tool (Figure DCA-9).

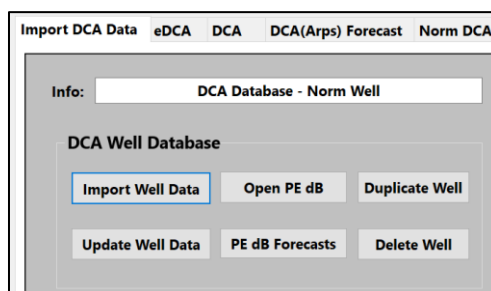


Figure DCA-8: Decline Curve Analysis – Well Data Import

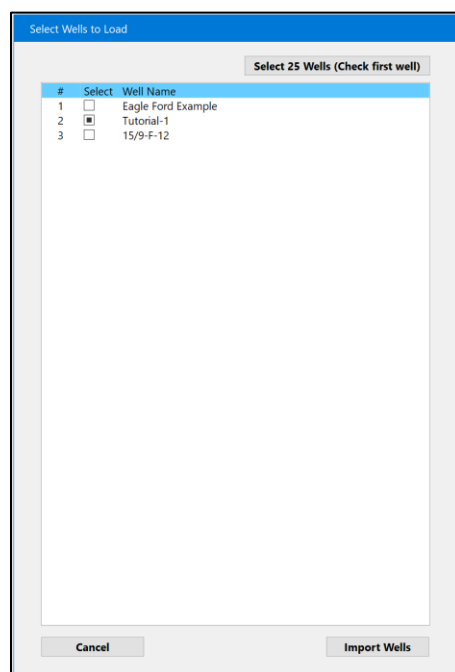


Figure DCA-9: Decline Curve Analysis – Data Import Options

Well data is imported from the PE Tools database. This ensures that only edited analyzable data is imported into the DCA tool. Note that if a well is already available in the DCA database, that well will be disabled and cannot be re-entered. To re-enter a DCA well, delete it from the DCA database (not the PE Tools database) using the 'Delete Well' button on the 'Import DCA Data' tab.

To permanently save the DCA data, click the 'Save DCA Database' menu button. This will present an option to save the DCA database to the PE Tools database or to a standalone DCA database (DVX) file.

To add additional production data to the well, select the well from the dropdown menu and click the 'Update Well Data' button. This will update the production data from the PE Tools database – make sure the correct PE Tools database is open.

To duplicate a well (for what-if analyses) or to delete a well from the DCA database, select the well from the dropdown menu and click the 'Duplicate Well' or the 'Delete Well' button. A confirmation screen will be displayed before the action occurs.

Note that any changes to the DCA database are not permanent until the 'Save DCA Database' button is clicked to update the database.

After the well data is entered, or a well is selected, the production data is listed and plotted for review purposes (Figure DCA-10).

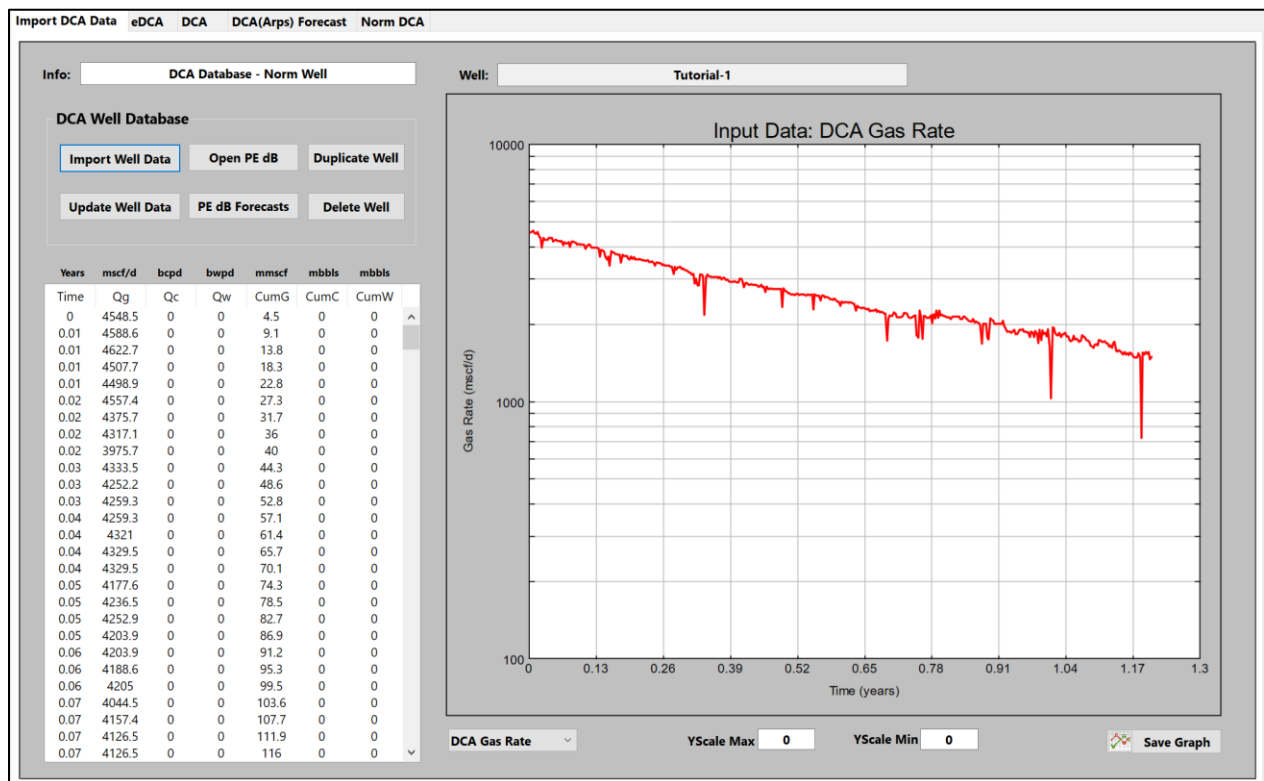


Figure DCA-10: Decline Curve Analysis – Input Data Review

The tool includes the capability of plotting each of the input parameters as well as a number of calculated parameters such as calculated annual decline factor.

### DCA.4 Enhanced DCA (eDCA)

Figure DCA-2 shows the eDCA tab which is used to perform the DCA analysis. eDCA includes 6 different decline models (Figure DCA-11). The included models are as follows:

- Arps Hyperbolic Decline
- Stretched Exponential Decline
- Duong Decline
- Logistic Growth Decline
- Power Law Exponential Decline
- LeBlanc-Okouma Power Law Decline

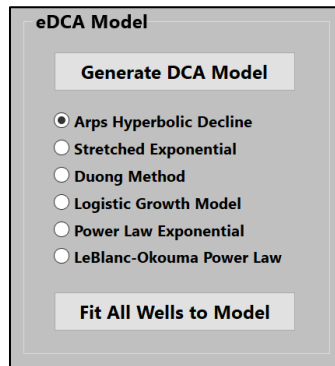


Figure DCA-11: PE<sup>2</sup> Essentials – eDCA Models

The reference documents and information for each model are listed in Appendix DCA2.

For the analysis of well performance, diagnostic plots are used to identify characteristic features exhibited by production data. Diagnostic plots help to identify flow regimes (e.g., bi-linear or linear flow, compound linear flow, etc.) and compare data to a well and reservoir model. Generation of diagnostic plots is performed in the PE<sup>2</sup> Essentials PDA tool.

#### DCA.4.1 Model Fitting in eDCA

Since eDCA includes numerical derivatives of noisy production data, it may be necessary to apply a “smoothing factor” to the derivate formulation. Figure DCA-12 shows the options for the derivative calculation and smoothing.

Match Basis	Smoothing
<input checked="" type="radio"/> Rate	<input type="radio"/> No <input checked="" type="radio"/> Mid
<input type="radio"/> Cum	<input type="radio"/> Low <input type="radio"/> High

Figure DCA-12: PE<sup>2</sup> Essentials – eDCA: Derivative Options

Derivatives can be calculated using cumulative production if the rate data is too noisy. This will yield a very smooth derivative but the forecast cumulative may be an issue.

In the eDCA tool, an automatic model fitting routine is performed by multi-component linear regression using the Levenberg–Marquardt algorithm (refer to the Wikipedia website: [https://en.wikipedia.org/wiki/Levenberg%E2%80%93Marquardt\\_algorithm](https://en.wikipedia.org/wiki/Levenberg%E2%80%93Marquardt_algorithm) for information about this algorithm). The regression interval can be restricted by entering the start time and end time of the period (Figure DCA-13).

**Regression**

Start Time (yrs)

0

End Time (yrs)

1.205479

Figure DCA-13: PE<sup>2</sup> Essentials – eDCA: Regression Interval

Caution should be used when restricting the regression interval. It is possible that the regression will indicate exponential decline if the early time is not included in the regression.

To fit an eDCA model, the model is chosen (Figure DCA-11) and the ‘Generate DCA Model’ button is clicked (Figure DCA-14) and the best-fit for the model will be generated.

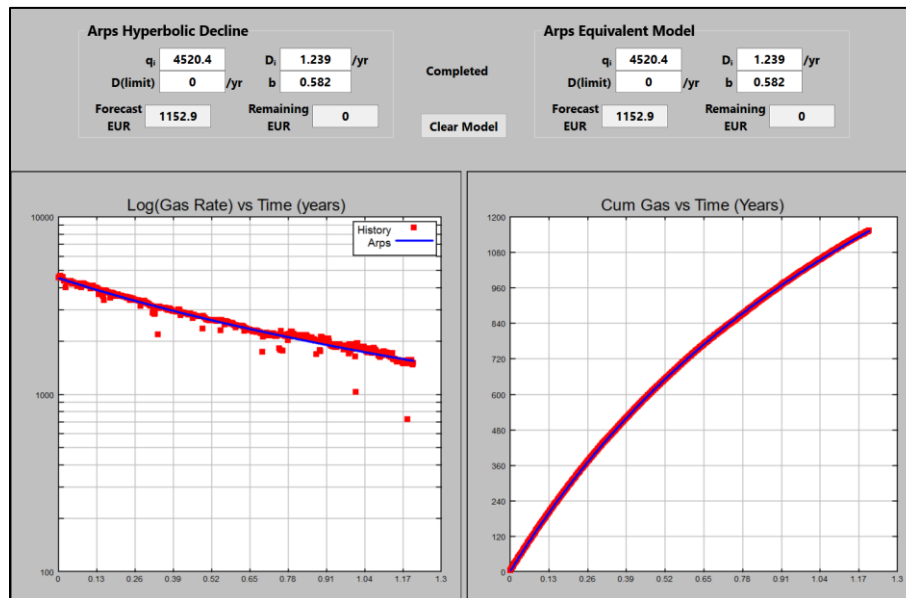


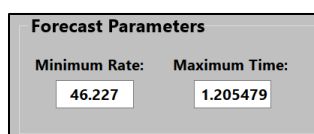
Figure DCA-14: PE<sup>2</sup> Essentials – eDCA Model Generation

If the DCA database contains more than one well, the 'Fit All Wells to Model' button can be clicked and all wells in the database will be fitted to the chosen model.

### DCA.4.2 Equivalent Arps Parameters

If an eDCA model other than Arps is selected, the equivalent Arps parameters that will yield a similar result as the eDCA model will be generated for the model (Figure DCA-14).

To generate a DCA Arps-based forecast from the eDCA model, the forecast parameters are entered (Figure DCA-15) and the 'Run Model/Forecast' button is clicked. This button is also clicked if the eDCA model parameters are modified and a new Arps equivalent model is to be generated.



Forecast Parameters	
Minimum Rate:	Maximum Time:
46.227	1.205479

Figure DCA-15: PE<sup>2</sup> Essentials – eDCA: Generating a Forecast

The equivalent Arps parameters will approximate the match and the forecast. If required, a value for  $D_{lim}$  (Figure DCA-14) can be entered to improve the late time match of the equivalent Arps forecast.

After completing the eDCA analysis, the equivalent Arps parameters for the selected eDCA model are transferred to the 'DCA' tab and the 'DCA(Arps) Forecast' tab by clicking the 'Transfer Equiv Arps Params to DCA' button.

The eDCA generated forecast can be saved to the PE Tools database by clicking the appropriate button on the main menu. The eDCA model parameters can be exported to a csv file by clicking the 'Report eDCA Results' button on the main menu. A single well or multiple well data can be exported to the CSV file (Figure DCA-16).

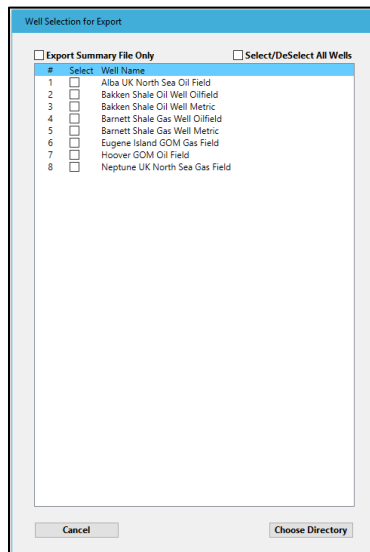
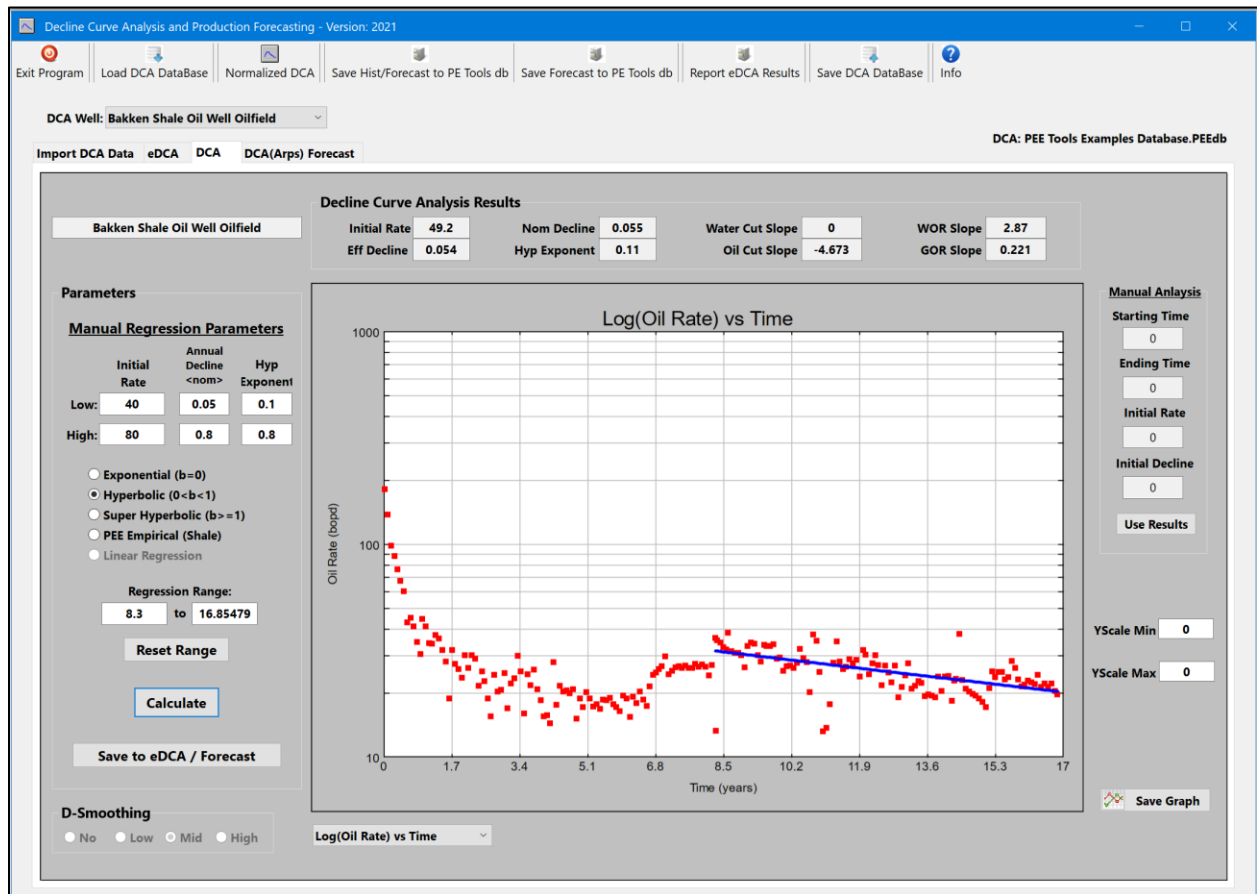


Figure DCA-16: PE<sup>2</sup> Essentials – Export eDCA Results

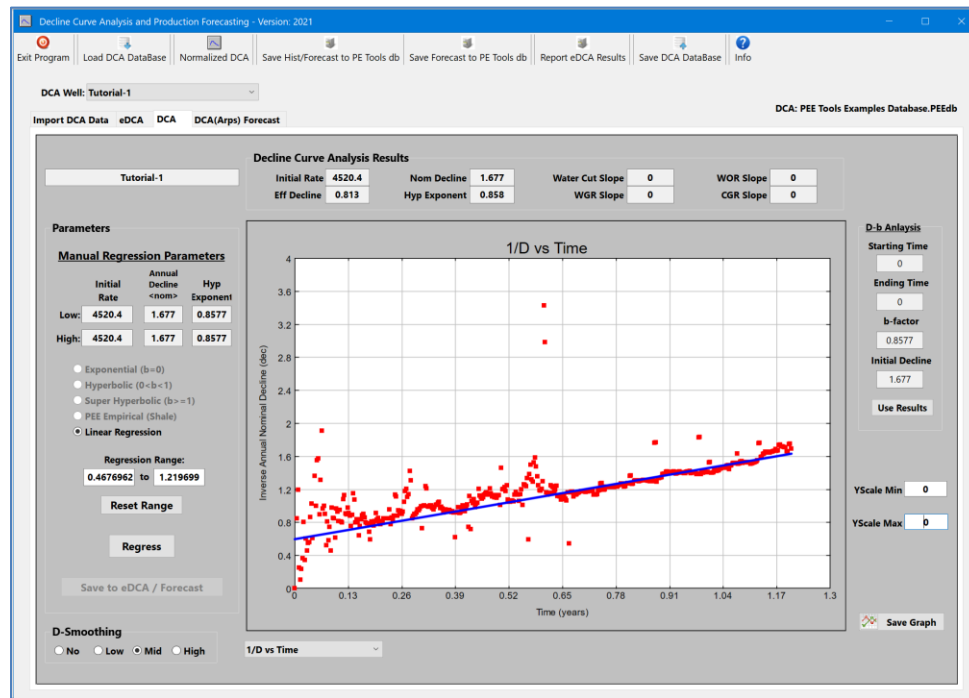
### DCA.5 DCA Parameters

The PE<sup>2</sup> Essentials Decline Curve Analysis tool can be used as an Arps model production decline curve and forecasting tool on the 'Arps' tab (Figure DCA-17). This tab is also where the secondary phase forecasting models are generated.

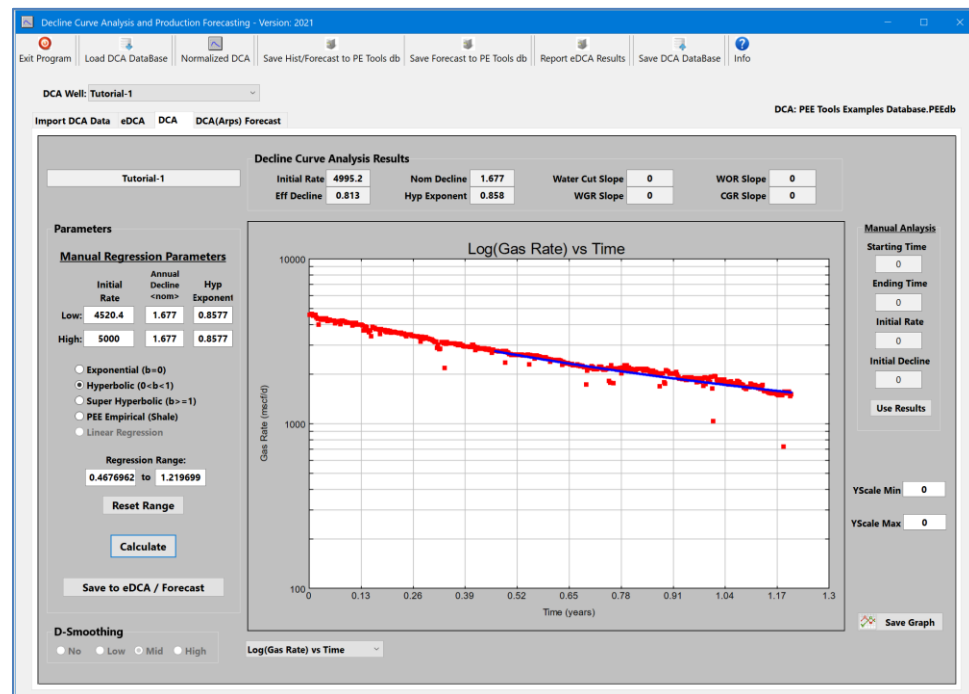
Figure DCA-17: PE<sup>2</sup> Essentials – Arps DCA Analysis

As a starting point, two points can be entered on the plot and an exponential DCA model will be generated and is shown in the 'Manual Analysis' box. To transfer the analysis to the Arps model, click the 'Use Results' button. The type of Arps model can then be modified by varying the parameters until an acceptable match is achieved. To modify the line, just enter two more points and click 'Use Results' when the line is satisfactory, and the original line will be replaced.

The 'Manual Analysis' option only generates parameters for an exponential decline. Alternatively, a new analysis option has been added to the DCA tab and is accessed by selecting '1/D vs Time' on the drop-down menu. (Figure DCA-18) – also refer to Section A1.3.2.2.


 Figure DCA-18: PE<sup>2</sup> Essentials – Estimating Hyperbolic Parameters

This option allows an estimate of hyperbolic decline and b parameters to be generated. The initial rate is not generated and must be entered manually (Figure DCA-19).


 Figure DCA-19: PE<sup>2</sup> Essentials – Estimating Initial Rate



After the 'Calculate' button is clicked, the optimum model is generated and plotted within the X-Range specified in the 'Model X-Plot Range'. The results are also summarized in the 'Decline Curve Analysis Results' box.

This tab is also where the secondary phase forecast models, water and GOR/CGR, are generated for forecasting purposes (Figure DCA-20).

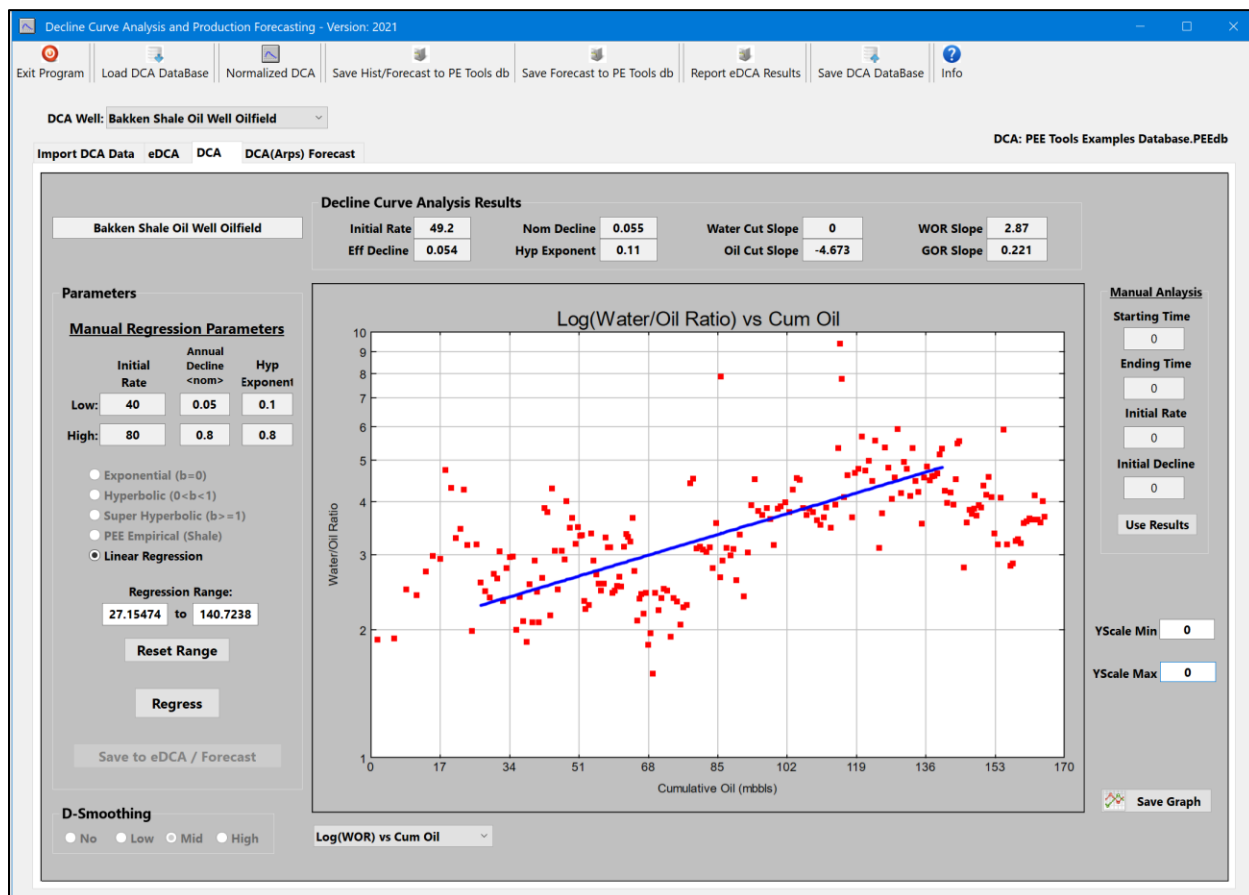


Figure DCA-20: PE<sup>2</sup> Essentials – Secondary Phase Analysis

Secondary phase models are based on a linear relationship with Cum Oil/Gas. Water and GOR/CGR forecast models are not required to generate a production forecast, but if available, water and oil/condensate rates will be included in the DCA production forecast.

There are two options to generate the secondary phase forecast models. Two points can be placed on the graph (and moved around by clicking and dragging the point) and the resulting analysis transferred to the DCA forecast model by clicking the 'Use Results' button.

Alternatively, a linear regression can be used to generate the forecast model for the secondary phase or used to refine the manually generated forecast model. Regression will generate the forecast model for the 'Model X-Plot Range' and save it to the DCA forecasting model.

## DCA.6 DCA Production Forecasting

After entering the 'Forecast Parameters' (Figure DCA-21) on the 'DCA(ARPS) Forecast' tab, a forecast can be generated by clicking the 'Run Forecast' button (Figure DCA-22).

### Forecast Parameters

Start Forecast Rate	20
Minimum/Cutoff Rate	2
Maximum Water Cut	100
Min Eff Decline Factor	0
Max Forecast Years	100

Water ☒ Use Oil Cut

Forecasting ☐ Use Water Cut

Option ☐ Use WOR

Figure DCA-21: Decline Curve Analysis – Production Forecast Parameters

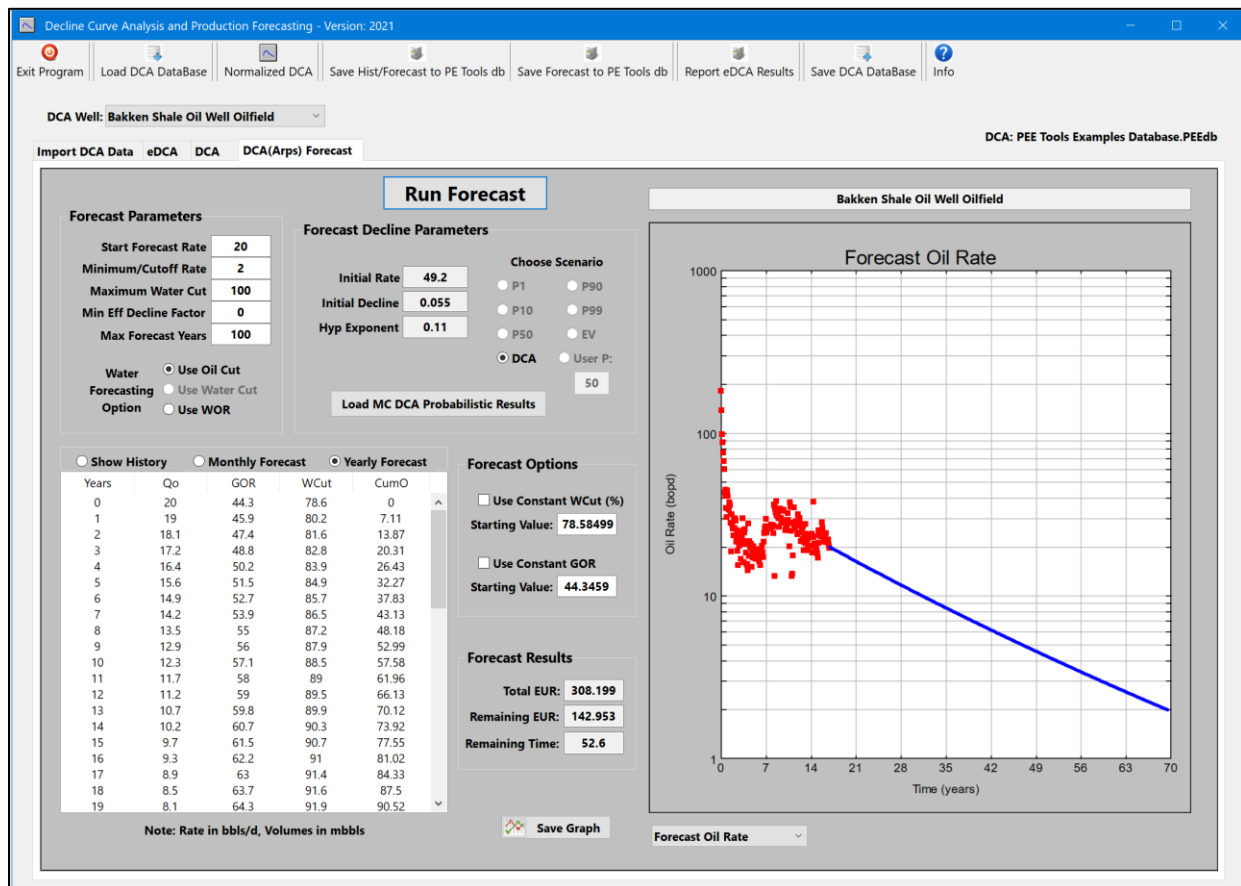


Figure DCA-22: Decline Curve Analysis – Production Forecast

The transferred eDCA/DCA results are used and the forecast begins at the end of the production history. To change the 'Forecast Decline Parameters', use the eDCA or DCA tabs. Note that all forecasts are generated using the equivalent Arps parameters.

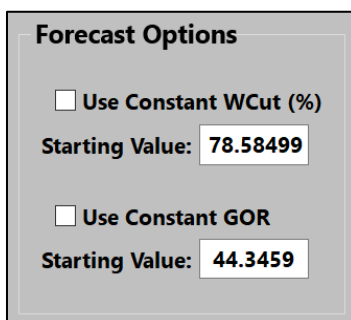
To generate a forecast, the default is to start the forecast from the final rate but this can be changed to any starting rate by entering a value in the 'Start Forecast Rate' (Figure DCA-18). To reset the rate to the last historical rate, set the 'Start Forecast Rate' value to zero prior to clicking the 'Run Forecast' button.

The 'Min Eff Decline Factor' is used with hyperbolic forecasts. Once the minimum decline factor is reached, the forecast will revert to an exponential decline forecast at the specified minimum decline factor for the remainder of the forecast period.

The 'Water Forecasting Option' is available if a forecast model has been generated for the water data on the 'DCA' tab. The water forecast options available to be used for forecasting will depend on which secondary phase forecasting models are available.

The 'Minimum/Cutoff Rate' and 'Maximum Water Cut' ('Maximum WGR' for a gas well) parameters are used to limit the duration of the forecast. The forecast time will be unlimited unless these parameters limit the forecast, or the time period is limited by entering 'Max Forecast Years'.

The 'Forecast Options' section (Figure DCA-23) modifies the secondary phase forecast. To forecast a secondary phase at a constant value, or zero, check the appropriate box and enter the required value for 'Starting Value'. This value will be used for the entire secondary phase forecast.



**Forecast Options**

☐ Use Constant WCut (%)  
Starting Value: 78.58499

☐ Use Constant GOR  
Starting Value: 44.3459

Figure DCA-23: Decline Curve Analysis – Production Forecast Options

If the secondary phase forecast model has been generated, it is possible to modify the starting value for the forecast. The default value for a secondary phase is the final historical value. For example, the value of 78.58499 in Figure DCA-21 is the final historical water cut for this well but this could be changed to any other value to start the forecast.

Note that for an oil well, water cut is always entered for the water phase starting value regardless of what water forecasting model is used.

As an alternative to using the Arps parameters generated by the DCA tool, decline parameters generated by the PE<sup>2</sup> Essentials Monte Carlo DC Forecast tool and stored in the PE Tools database can be imported for forecasting (Figure DCA-24).

**Forecast Decline Parameters**

Initial Rate: 46  
 Initial Decline: 0.05  
 Hyp Exponent: 0.13

**Choose Scenario**

☐ P1    ☐ P90  
☐ P10    ☐ P99  
☐ P50    ☐ EV  
☒ DCA    ☐ User P: 50

Load MC DCA Probabilistic Results

Figure DCA-24: Decline Curve Analysis – Optional Forecast Decline Parameters

Once Monte Carlo decline parameters are loaded, the specific parameters to be used for the forecast are chosen and the forecast is run.

To save alternative forecasts, the well should be duplicated for each forecast. To run and store a P10, P50 and P90 forecast, three versions of the well are required to be saved to the database.

The PE<sup>2</sup> Essentials Monte Carlo DC Forecast tool generates and saves decline parameters for the P01 to P99 values. As a result, any of the Pxx parameters can be used to generate a forecast by selecting the 'User P' option and entering the specific Pxx value to use.

The forecast results can be saved to the PE Tools database for import into other PE<sup>2</sup> Essentials tools by using the 'Save Forecast to PE Tools dB' or 'Save History/Forecast to PE Tools dB' button. Saving the history and the forecast data allows full cycle economics to be run.

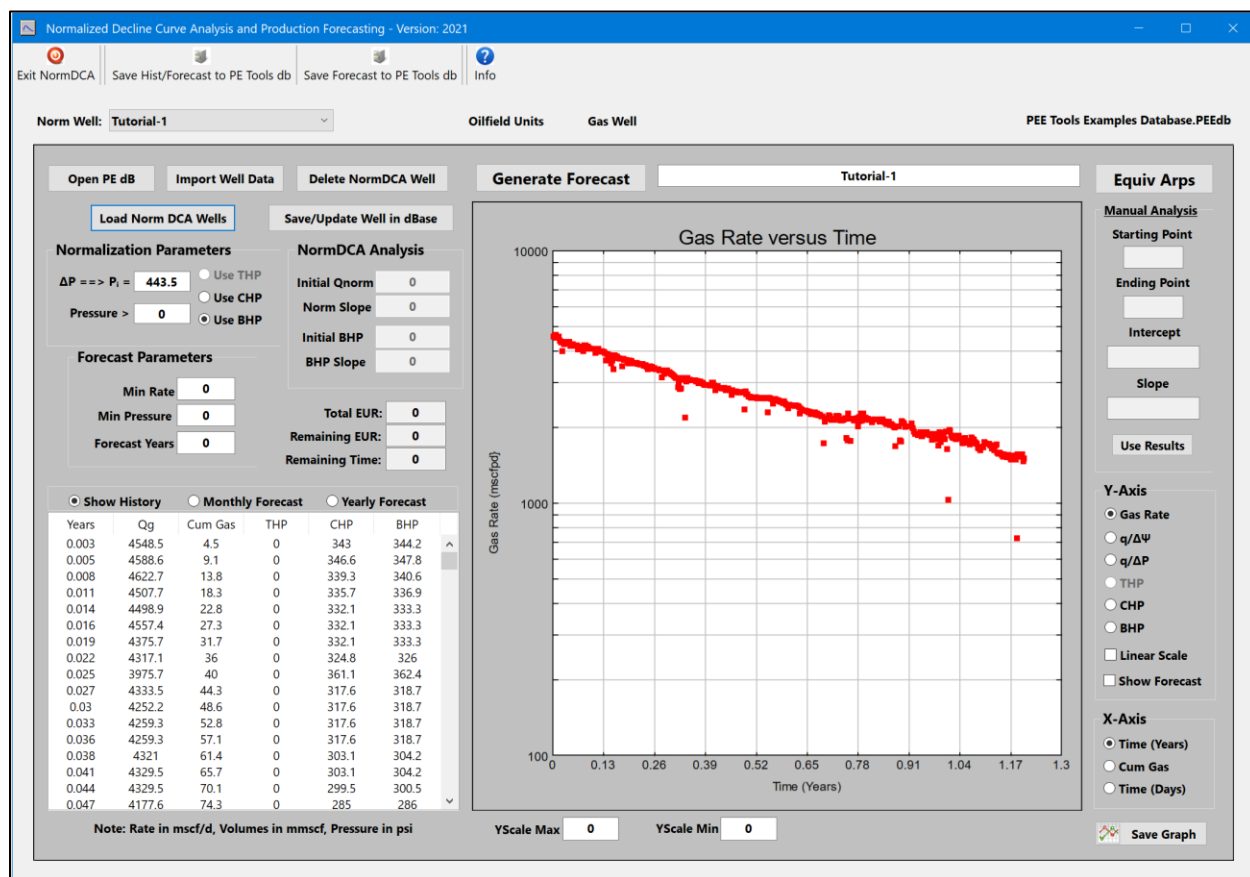
After the forecast has been saved to the PE Tools database, the PE<sup>2</sup> Essentials Production Analysis Tool can be used to view and export the data to a csv file.

## DCA.7 Normalized DCA

The DCA tool includes a normalized DCA technique that is used to perform decline curve analysis for choked, constant rate wells (Figure DCA-25). It is accessed from the 'NormDCA' tab.

The NormDCA well data is not part of the DCA database but is stored separately in the PE Tools Database because of the different data requirements for NormDCA. Normalized DCA requires pressure (THP, CHP or BHP) and PVT data which is not required for conventional eDCA/DCA.

Since NormDCA requires a forecast of flowing pressure (THP, CHP or BHP) only gas wells can be analyzed and forecasted by the PE<sup>2</sup> Essentials DCA tool. To analyze and forecast oil wells, water and gas forecasting would have to be included to forecast flowing pressures.

Figure DCA-25: PE<sup>2</sup> Essentials – Normalized Decline Curve Analysis (NormDCA) Tool

For a description of the NormDCA technique refer to Appendix A2.8.

Norm DCA wells can only be loaded from the 'Norm DCA' tab. Clicking the 'Import Well Data' button will read the current PE Tools database and present a list of gas wells in the database that include pressure, which is required for NormDCA analysis. This will also pre-load any Norm DCA wells that are available in the database.

Selecting and loading a well will automatically create and add the NormDCA well to the PE Tools database. After analyzing the well, the 'Update Well in dBase' button should be clicked to update and save the analysis in the database. Note – you must update the well in the database before changing to another well if you want to save the analysis.

NOTE – to copy a well to a new well in the same PE Tools database, change the name of the well before clicking 'Update Well in dBase'. A new NormDCA well will be created with the new well name.

After NormDCA wells have been created and saved to a PE Tools database, 'Load Norm DCA Wells' will load the well list for subsequent runs. To add additional wells to the well list, click the

'Import Well Data' button to list the wells that are available for NormDCA analysis. Wells from other PE Tools databases can be imported this way after the database has been opened.

To copy NormDCA wells to another database, load the NormDCA wells, open the target PE Tools database and copy each well to the target database using the 'Update Well in dBase' button.

NormDCA analysis is performed by placing two points on the  $q/\Delta p$  or  $q/\Delta \Psi$  versus Cum plot to generate a straight. The line can be moved by dragging one of the end points of the line. 'Use Results' will transfer the data to the appropriate 'DCA Analysis' box for use (Figure DCA-26 and Figure DCA-27).

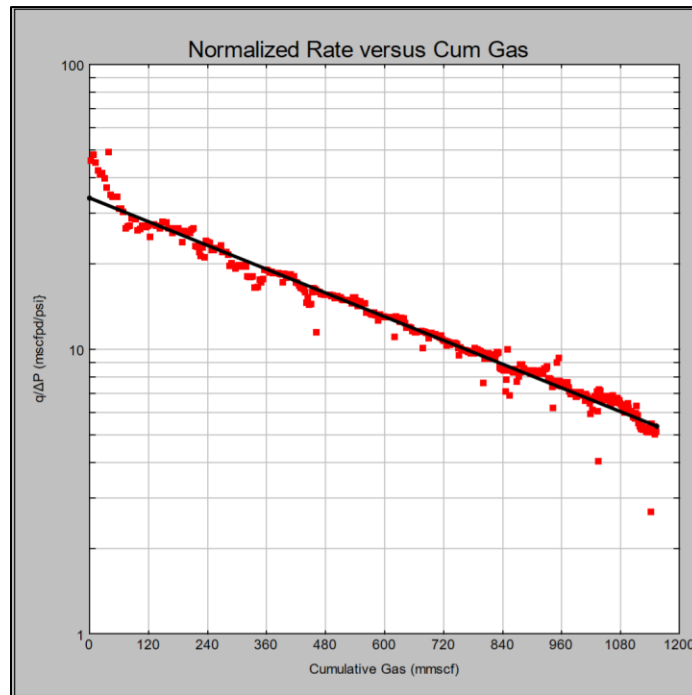


Figure DCA-26: NormDCA – Normalized Rate Plot

NormDCA Analysis	
Initial Qnorm	35.09
Norm Slope	-0.0016962
Initial CHP	306.93
CHP Slope	-0.5833

Figure DCA-27: NormDCA – NormDCA Parameters

Note, it is only possible to place points on the plot when the proper parameters and scales are selected for the graph.

The second part of the analysis is to set up the pressure forecasting model. Choose whether to use THP, CHP or BHP in 'Normalization Parameters' (Figure DCA-28) and enter the value for  $P_i$ . The 'Pressure >' option enables removing low pressures from the plot.

**Normalizatiuon Parameters**

$\Delta P ==> P_i =$   ☐ Use THP

☒ Use CHP

Pressure >  ☐ Use BHP

Figure DCA-28: NormDCA – Normalization Parameters

Select time for the x-axis and place two points on the plot to generate a straight line on the Pressure versus time plot (Figure DCA-29). Clicking the 'Use Results' button will transfer the data to the appropriate 'DCA Analysis' boxes.

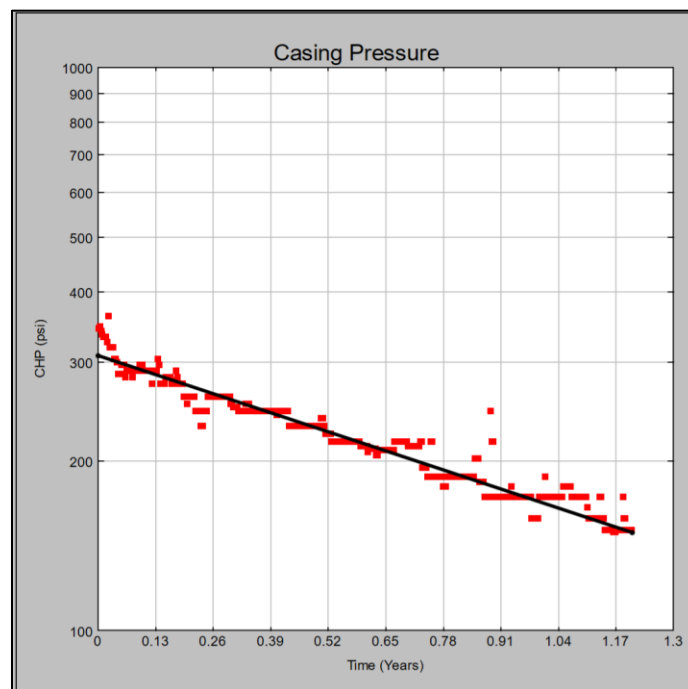


Figure DCA-29: NormDCA – Pressure Plot

As an option, 'Min Rate', 'Min Pressure' and 'Forecast Years' can be entered to limit the forecast (Figure DCA-30). Entering zeros for these parameters will run the forecast out to a maximum of 50 years.

Forecast Parameters	
Min Rate	100
Min Pressure	0
Forecast Years	0

Figure DCA-30: NormDCA – Forecast Parameters

Note that 'Min Pressure' should be entered and represents the pressure at which the well is no longer choked and the rates start to declining.

A forecast is generated by clicking the 'Generate Forecast' button. The monthly or yearly forecast results, as well as the historical data, can be viewed by selecting the relevant button. The NormDCA well forecast can be saved to the PE Tools database for subsequent use.

For the 'Y-Axis' options (Figure DCA-31), checking/unchecking the 'Show Forecast' box will cycle between the forecast and the analysis plot. Note – only the analyzed plots will include the analysis straight line. For example, if CHP analysis is selected, the analysis line will only be plotted on the CHP vs Years plot.

Y-Axis	
<input type="radio"/>	Gas Rate
<input type="radio"/>	$q/\Delta\psi$
<input type="radio"/>	$q/\Delta P$
<input type="radio"/>	THP
<input checked="" type="radio"/>	CHP
<input type="radio"/>	BHP
<input type="checkbox"/>	Linear Scale
<input type="checkbox"/>	Show Forecast

Figure DCA-31: NormDCA – y-Axis Options

Following the NormDCA forecast the equivalent Arps parameters representing the forecast can be generated by clicking the 'Equiv Arps' button (Figure DCA-32).

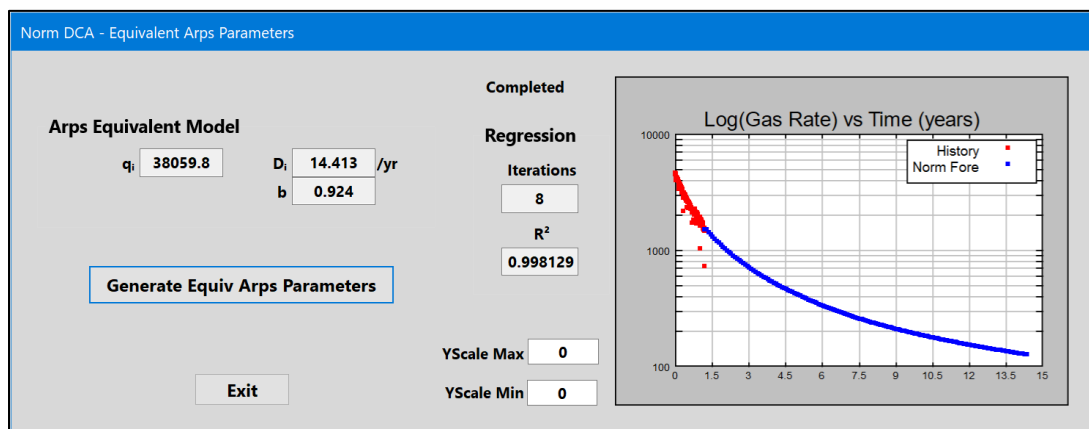


Figure DCA-32: NormDCA – Equivalent Arps Parameters for NormDCA



## DCA.8 DCA Example – Marcellus

Marcellus production data (Figure DCA-33 and Table DCA-1) was downloaded from the Internet: <http://shale.typepad.com/marcellusshale/production-curve>.

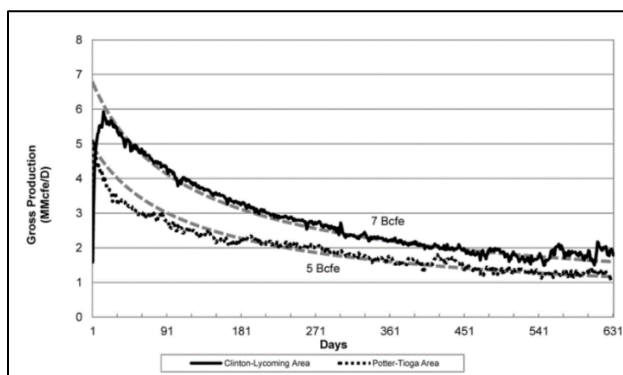


Figure DCA-33: Marcellus Production Curves

Marcellus Production Curve								
Days	mcsf/d	mcsf	Days	mcsf/d	mcsf	Days	mcsf/d	mcsf
1	1600	1600	211	3030	30300	421	2000	20000
11	5500	55000	221	2930	29300	431	1980	19800
21	5600	56000	231	2890	28900	441	2000	20000
31	5400	54000	241	2880	28800	451	1940	19400
41	5050	50500	251	2800	28000	461	1850	18500
51	4950	49500	261	2700	27000	471	1875	18750
61	4780	47800	271	2720	27200	481	1950	19500
71	4600	46000	281	2650	26500	491	1950	19500
81	4450	44500	291	2600	26000	501	1780	17800
91	4250	42500	301	2700	27000	511	1800	18000
101	4050	40500	311	2350	23500	521	1700	17000
111	4000	40000	321	2300	23000	531	1650	16500
121	3850	38500	331	2450	24500	541	1800	18000
131	3750	37500	341	2300	23000	551	1650	16500
141	3680	36800	351	2270	22700	561	1800	18000
151	3550	35500	361	2220	22200	571	1700	17000
161	3450	34500	371	2200	22000	581	1870	18700
171	3340	33400	381	2130	21300	591	1650	16500
181	3280	32800	391	2150	21500	601	1650	16500
191	3200	32000	401	2050	20500	611	1500	15000
201	3050	30500	411	2030	20300	621	1700	17000

Table DCA-1: Marcellus Production Data

The data in Table DCA-1 is available in the 'Marcellus 7Bcf Data.xlsx' file located in the "PE Essentials\Book Examples\Example Marcellus\DCA" directory. The Excel data was imported into a PE Essentials Production Database (PEE Database Book Examples.DVXdb) which is located stored in the "Book Examples\PEE Production Database" directory using the Production Database Tool.

The data was then imported into PDA and stored in a PE Tools database (PEE Tools Database Book Examples.PEEdb) located in the "Book Examples\PEE Tools Database Book Examples" directory (Figures DCA-34 and DCA-35).

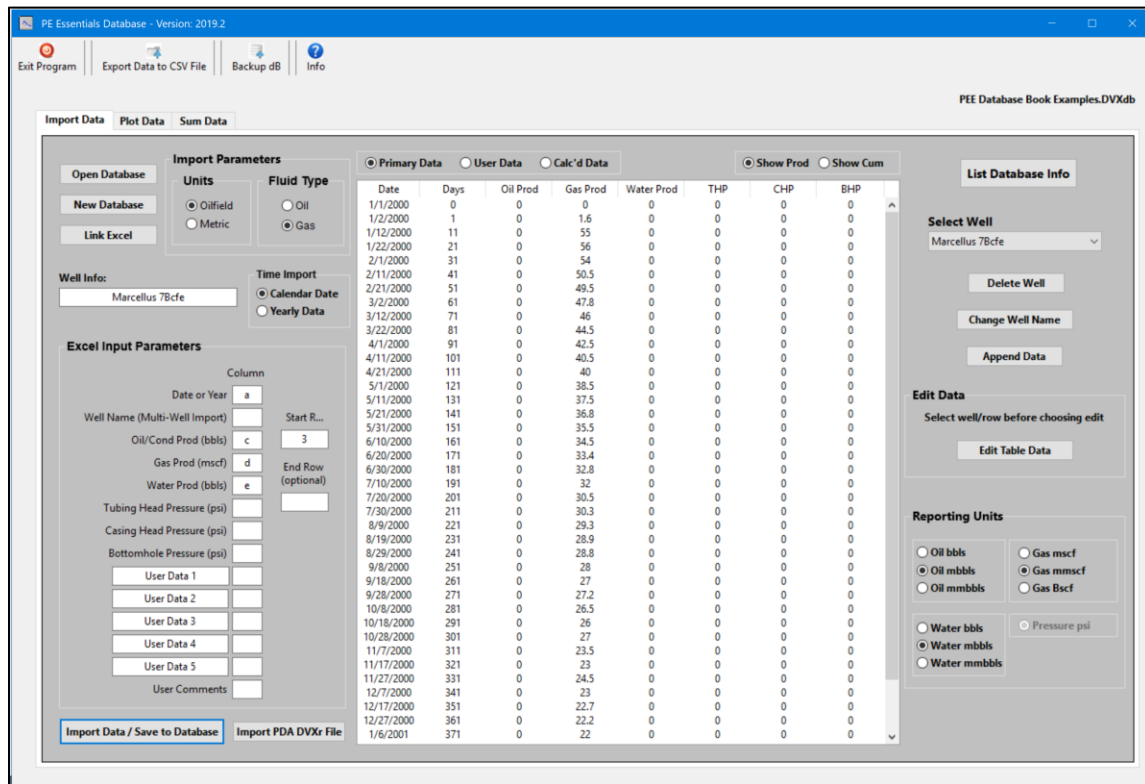


Figure DCA-34: Marcellus Production Data Imported to Production Database

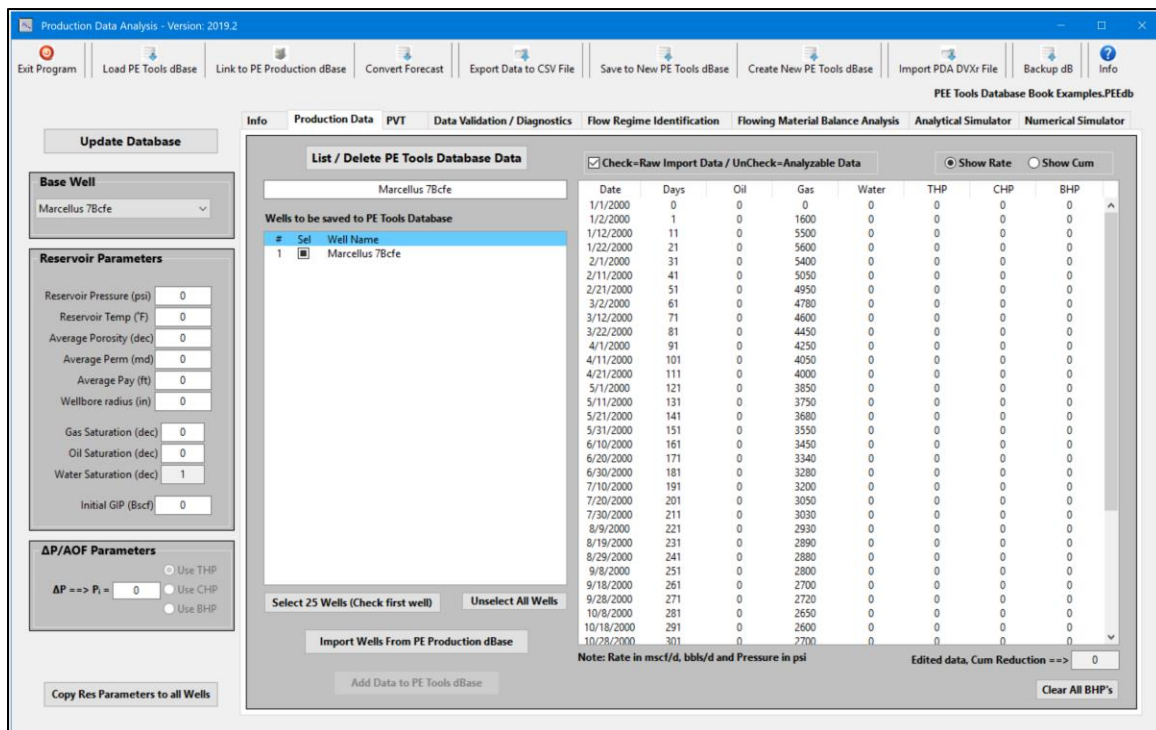


Figure DCA-35: Marcellus DCA Example Production Data

The data was then imported into the DCA tool by clicking 'Import Well Data' (Figure DCA-33) and saved to a standalone DCA database 'PE\_Essentials\_DCA\_DataBase\_Marcellus.dvx' in the "Book Examples\Example Marcellus \DCA" directory.

The log(rate) versus cumulative plot indicated a straight line so 'Super Hyperbolic' was chosen for the regression analysis. Regression was started after 0.1 years to filter out the early data. The results are shown in Figure DCA-36.

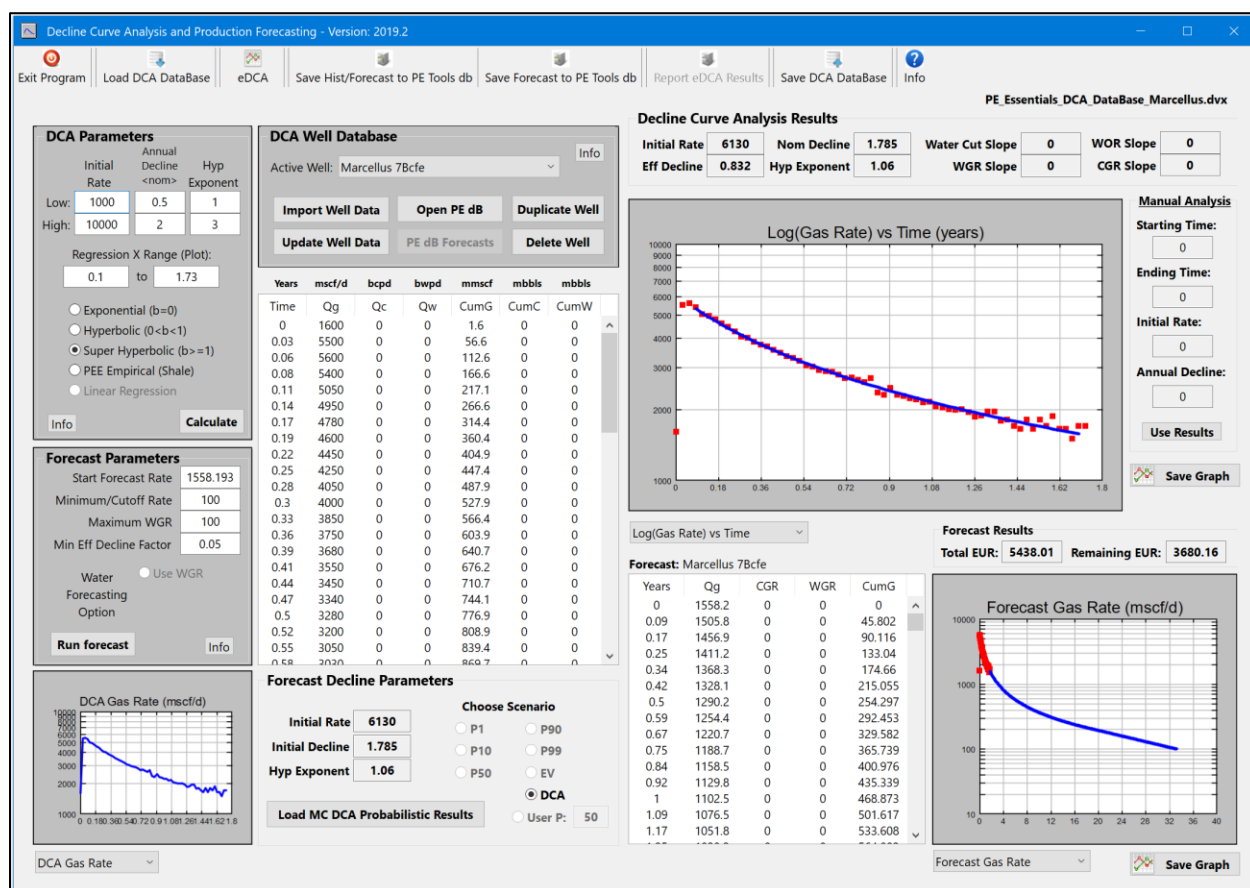


Figure DCA-36: Marcellus DCA Analysis

Note that the 'Start Forecast Rate' of 1558 mscf/d is the rate indicated by the decline curve at the end of producing time. It is possible to change the rate for the start of the forecast to a more appropriate value.

This example is continued in Example included with the PE<sup>2</sup> Essentials Mont Carlo DC Forecast tool.

## Appendix DCA1 – DCA Theory & Practice

### A1.1 Introduction

There are numerous phases in the development of an oil or gas field and “estimated ultimate recovery” (EUR) calculation techniques are different for each phase (Figure A1.1).

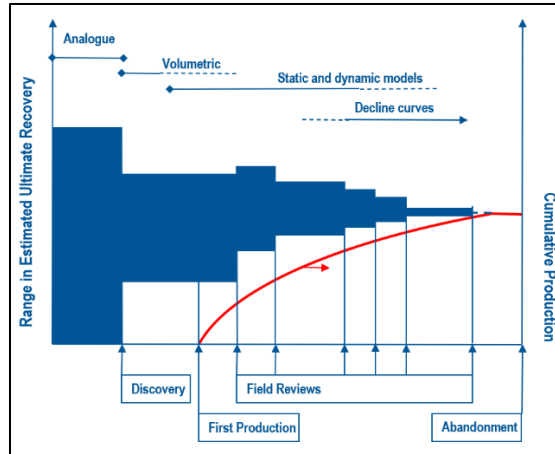


Figure A1.1 – Production Forecasting based on Field Development Phase

During the exploration phase, there is no specific information available about the reservoir so analogue field information is used to generate EUR. After discovery and during the delineation phase, in-place volumes and reservoir parameters are determined and models are used to generate production forecasts and determine EUR. Models can be as simple as well type-curves or analytical models, to a full reservoir simulation model. During the production life of the field, these models are updated/calibrated and continue to be used to update production forecasting and EUR.

All production has an initial transient flow period followed by a boundary-dominated flow period. During the transient flow period, the pressure at the flow boundary remains constant at the initial reservoir pressure and the boundary moves away from the well into the reservoir. This period of a well's flow is characterized by very high decline rates. When the flow boundary reaches the actual reservoir boundary, which could be the flow boundary of another well, the pressure at the boundary starts to decline and the well exhibits boundary-dominated flow. It is within this flow period that traditional decline curve analysis is performed.

Analysis of a decline curve is possible after the declining production trend has been established and flowing pressure is relatively constant. This typically occurs anytime after >35% of the ultimate recovery has been produced. Decline curve analysis is the preferred tool of reserves evaluators/auditors.

## A1.2 Decline Curve Analysis Theory

Production decline analysis is an empirical technique that extrapolates trends in the production data from oil and gas wells. The purpose of decline curve analysis is to generate a forecast of future production rates and to estimate the ultimate recoverable volumes (EUR).

Oil and gas wells will initially reach a maximum rate after which they start declining in production. A production “decline curve” indicates the amount of oil and gas produced per unit of time for several consecutive periods. If the flowing conditions (pressure) remain constant, the resulting decline curve may be consistent and, if projected into the future, will yield information as to the future production from the well.

DCA is a graphical procedure used for analyzing declining production trends and forecasting future performance of oil and gas wells. Fitting a line through the plot of a well’s performance history and assuming the trend will continue into the future forms the basis of DCA. The caveat is that in the absence of stabilized production trends, DCA cannot be expected to give reliable results. Since DCA is a means of predicting future well production based on past production history, it is also a technique that can be used to identify well production problems.

All decline curve analysis models begin with the concept of the instantaneous decline rate ( $D$ ), which is called the nominal decline, and is defined as the fractional change in rate ( $dq$ ) per unit time ( $dt$ ) and is presented as Equation A1-1. Note to convert  $D$  from annual to monthly,  $D_m = D/12$  and for daily,  $D_d = D/365$ .

$$D = -\frac{1}{q} \frac{dq}{dt} = -\frac{d(\ln(q))}{dt} \quad (\text{A1-1})$$

When production is plotted as flow rate versus time, the nominal decline is equal to the slope at a point in time ( $\frac{dq}{dt}$ ) divided by the rate ( $q$ ) at that point (Figure A1-2).

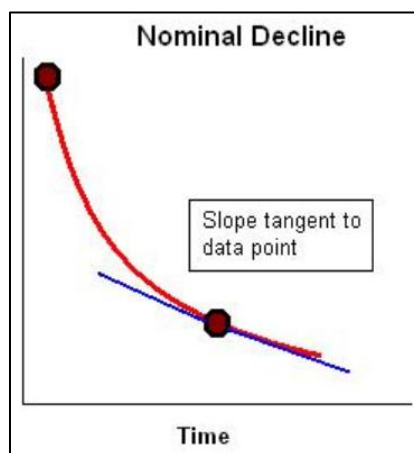


Figure A1-2: Nominal Decline

This calculation method for the decline factor is termed the tangent method.

Excellent references for DCA are as follows:

- Poston, S., W. and Poe Jr., B. D.; Analysis of Production Decline Curves, SPE, 2008<sup>(1)</sup>
- Poston, S., W.; Laprea-Bigott, Marcelo and Poe Jr., B. D., Analysis of Oil and Gas Production Performance, SPE, 2019<sup>(2)</sup>
- Monograph 4, Estimating Ultimate Recovery of Developed Wells in Low-Permeability Reservoirs, SPEE, August 2016<sup>(3)</sup>
- LeBlanc, Don; Petroleum Engineering & Economics Essentials: Tools and Techniques to Evaluate Unconventional (and Conventional) Wells and Reservoirs, [https://www.eastexpetroleum.com/PE\\_Essentials](https://www.eastexpetroleum.com/PE_Essentials), 2022<sup>(4)</sup>

There are several models available for use in decline curve analysis:

- Arps
- Stretched Exponential Decline
- Duong Decline
- Logistic Growth Decline
- Power Law Exponential Decline
- LeBlanc-Okouma Power Law Decline

Only the Arps and Stretched Exponential Decline (SEDM) models are presented herein. Information on the other models is available in the LeBlanc<sup>(4)</sup> reference.

### A1.2.1 Arps General Decline Model

Historically there are three types of production decline trends that have been presented: exponential, hyperbolic and harmonic. With the development of unconventional and shale reservoirs, additional decline trends have been observed: transient, super-hyperbolic.

The decline equations defining these trends are not necessarily grounded in fundamental theory but are based on empirical observations of production decline, although there is some theoretical basis for the decline processes. It can be demonstrated that under certain conditions, such as constant well flowing pressure, the fluid flow equation under boundary dominated flow is equivalent to an exponential decline.

Arps introduced a constant b-factor to account for the observation that the nominal decline factor may change over time (Equation A1-2).

$$b = \frac{d(\frac{1}{D})}{dt} = \text{constant} \quad (\text{A1-2})$$

Integrating Equation A1-2 from 0 to t and defining the initial decline rate at t = 0 as  $D_i$ , then:

(A1-3)

$$D = \frac{D_i}{1 + bD_it}$$

Using Equation A1-1, Equation A1-3 can be rewritten as Equation A1-4

$$-\frac{d(\ln(q))}{dt} = \frac{D_i}{1 + bD_it} \quad (\text{A1-4})$$

Integrating Equation A1-4 from 0 to  $t$  yields the Arps general decline equation (Equation A1-5). This is a hyperbolic equation, valid for  $b > 0$  and is plotted in Figure A1-3.

$$q = q_i(1 + bD_it)^{-1/b} \quad (\text{A1-5})$$

Where:

$q$  = Instantaneous Rate at time  $t$  [Volume / Unit Time]

$q_i$  = Initial Instantaneous Rate [Volume / Unit Time]

$D_i$  = Initial Nominal Decline Factor [Fraction / Unit Time]

$b$  = Hyperbolic Exponent factor (Valid for all  $b \neq 1$ )

$t$  = Time in units consistent with units in the decline and rate parameters

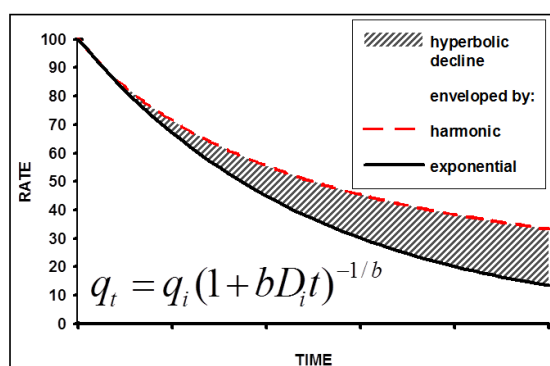


Figure A1-3: Arp's Hyperbolic Decline Equation

In general terms, the  $b$ -factor has the following characteristics:

- $b = 0$ : Exponential decline (linear: log rate versus time)
- $0 < b < 1$ : Hyperbolic decline (non-linear: log rate versus time)
- $b = 1$ : Harmonic decline (linear: log rate versus cum)
- $b > 1$ : Super harmonic / Transient decline (tight sands and shale)
- $b = 2$ : Ideal Linear flow (fractured well)
- $b = 4$ : Ideal Bilinear flow (horizontal fractured well)

### A1.2.1.1 Exponential Decline (b=0)

When  $b = 0$ , Equation A1-3 indicates that  $D$  is a constant ( $D = D_i$ ) and Equation A1-1 can be integrated from 0 to  $t$  to yield the exponential rate decline equation (Equation A1-6).

$$q = q_i e^{-Dt} \quad (A1-6)$$

Where:

$q$  = Instantaneous Rate at time  $t$  [Volume / Unit Time]

$q_i$  = Initial Instantaneous Rate ( $t = 0$ ) [Volume / Unit Time]

$D$  = Nominal Decline Factor [Fraction / Unit Time]

$t$  = Time in units consistent with the decline and rate

The exponential decline equation (Equation A1-6) can be integrated with respect to time. This results in the cumulative volume produced since time 0 (Equation A1-7). Note at time 0,  $q = q_i$ .

$$Q_p = \frac{q_i - q}{D} \quad (A1-7)$$

Where:

$Q_p$  = Volume produced to rate  $q$  from time zero

The signature for exponential rate decline is a straight line on a log(rate) versus time plot and a rate versus cumulative production plot.

Exponential decline has been observed for the following conditions.

- Oil reservoirs above the bubble point (undersaturated oil)
- Oil reservoirs with gravity drainage from down dip wells
- Oil reservoirs with solution gas drive and unfavourable  $k_g/k_o$
- Gas reservoirs with high reservoir pressure (liquid-like compressibility)
- Gas reservoirs with wells experiencing liquid-loading problems

### A1.2.1.2 Effective Decline Factor

Although nominal decline is used in all the decline equations, effective decline is a more intuitive decline measurement. Unlike nominal decline, it can be read directly from tabular data. It is generated by the slope of a straight line from time 0 to a point 1-year later (Figure A1-4).

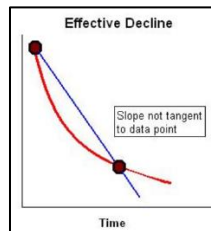


Figure A1-4: Effective Decline



The effective decline equation is defined by equation A1-8 and is also called the secant method. It is commonly used when manually forecasting from tabular data.

$$D_e = \frac{q_i - q}{q_i} \quad (\text{A1-8})$$

Where:

$D_e$  = Effective Decline Factor [Fraction / Unit Time]

$q_i$  = Instantaneous Rate at time 0 [Volume / Unit Time]

$q$  = Instantaneous Rate at time one year [Volume / Unit Time]

The most common time period used to evaluate  $D_e$  is one year. If no time period is stated, a yearly period is implied. Effective decline ( $D_e$ ) in units of volume per year can be converted to effective monthly decline ( $D_{em}$ ) or effective daily decline ( $D_{ed}$ ) using Equation A1-9 or A1-10.

$$D_{em} = 1 - (1 - D_e)^{1/12} \quad (\text{A1-9})$$

$$D_{ed} = 1 - (1 - D_e)^{1/365} \quad (\text{A1-10})$$

Some confusion exists regarding these decline factors, but both the nominal (tangent) and effective (secant) decline factors are theoretically correct. The main difference between the decline factors is that the nominal decline is a continuous function, used in the equations relating to decline curve analysis, and the effective decline factor is a stepwise function that is easy to calculate and use with tabular historical data.

For exponential decline, it is simple to convert from a nominal decline factor to an effective decline factor and vice versa using Equations A1-11 and A1-12.

$$D_e = 1 - e^{-D} \quad (\text{A1-11})$$

$$D = -\ln(1 - D_e) \quad (\text{A1-12})$$

As an example, an annual effective decline factor of 0.37 will give a nominal decline factor (Equation A1-12) of 0.46. Converting the nominal decline factor to a daily decline is 0.00126 ( $D/365$ ). To calculate the daily effective decline factor, Equation A1-10 is used to give 0.00127.

### A1.2.1.3 Hyperbolic Decline ( $0 < b < 1$ )

Commonly accepted  $b$  values for single porosity reservoirs with good drive energy usually range between 0 and 1. Reservoirs with low permeability, multi-porosity, fracture stimulations or poor reservoir drive energy (gravity drainage) may demonstrate  $b$  factors greater than 1 but they seldom go above 2.

Hyperbolic decline is the most commonly observed decline trend. It occurs when  $0 < b < 1$  in the hyperbolic decline equation (Equation A1-5). Equation A1-5 has three constants: the initial production rate ( $q_i$ ), the initial decline rate ( $D_i$ ), and the hyperbolic exponent ( $b$ ).

The hyperbolic decline equation can be integrated to yield the cumulative production (Equation A1-13).

$$q = q_i(1 + bD_i t)^{-1/b} \quad (\text{A1-5})$$

$$Q_p = \frac{q_i^b}{(1-b)D_i} (q_i^{1-b} - q^{1-b}) \quad (\text{A1-13})$$

Where:

$Q_p$  = Volume produced to rate  $q$  from time zero

$q$  = Instantaneous Rate at time  $t$  [Volume / Unit Time]

$q_i$  = Initial Instantaneous Rate ( $t = 0$ ) [Volume / Unit Time]

$D_i$  = Initial Nominal Decline [Fraction / Unit Time]

$b$  = Hyperbolic Exponent

$t$  = Time in units consistent with the decline and rate

The decline factor is not a constant but changes with time. The hyperbolic exponent is the rate of change of the decline rate with respect to time. This means that 'b' is actually the second derivative of production rate with respect to time. The nominal decline factor at any time,  $D(t)$ , can be determined from the hyperbolic exponent as shown in Equation A1-3.

$$D(t) = \frac{D_i}{1 + bD_i t} \quad (\text{A1-3})$$

#### A1.2.1.4 Modified Hyperbolic Decline

Extrapolation of curves exhibiting hyperbolic behaviour over long periods of time may result in unrealistically high reserves because of the continuously decline  $D$ . To avoid the problem of overestimating production, it is common practice to convert the hyperbolic decline into an exponential decline at some future time.

For example, assume that the decline rate starts at 30% and decreases through time in a hyperbolic trend. When it reaches a specified value, 10% for example, the hyperbolic decline (Equation A1-5) can be changed to an exponential decline (Equation A1-7) and the forecast continued using the exponential decline rate of 10%. In other words, the forecast is converted to an exponential forecast when  $D(t) = D_{lim}$ .

The rate at which the conversion occurs ( $q_{lim}$ ) can be calculated from Equation A1-14 and the corresponding time ( $t_{lim}$ ) can be calculated from Equation A1-15.

$$q_{lim} = q_i \left( \frac{D_{lim}}{D_i} \right)^{1/b} \quad (\text{A1-14})$$

$$t_{lim} = \frac{\left( \frac{q_i}{q_{lim}} \right)^b - 1}{bD_i} \quad (\text{A1-15})$$

The rate ( $q$ ) for the modified hyperbolic decline is calculated with Equations A1-5 and A1-16. Cumulative production is calculated with Equations A1-13 and A1-17:

$$\text{For } D > D_{lim}: q = q_i(1 + bD_it)^{-1/b} \quad (\text{A1-5})$$

$$\text{For } D \leq D_{lim}: q = q_{lim}e^{-(D_{lim}(t-t_{lim}))} \quad (\text{A1-16})$$

$$\text{For } D > D_{lim}: Q_p = \frac{q_i^b}{(1-b)D_i}(q_i^{1-b} - q^{1-b}) \quad (\text{A1-13})$$

$$\text{For } D \leq D_{lim}: Q_p = \frac{q_i^b}{(1-b)D_i}(q_i^{1-b} - q_{lim}^{1-b}) + \frac{q_{lim} - q}{D_{lim}} \quad (\text{A1-17})$$

Where:

- $Q_p$  = Volume produced to rate  $q$  from time zero
- $q$  = Instantaneous Rate at time  $t$  [Volume / Unit Time]
- $q_i$  = Initial Instantaneous Rate ( $t = 0$ ) [Volume / Unit Time]
- $q_{lim}$  = Instantaneous Rate at  $t = t_{lim}$  [Volume / Unit Time]
- $t_{lim}$  = Time when  $D = D_{lim}$  [Fraction / Unit Time]
- $D_i$  = Initial Nominal Decline [Fraction / Unit Time]
- $D_{lim}$  = Limiting Nominal Decline / Exponential Decline [Fraction / Unit Time]
- $b$  = Hyperbolic Exponent
- $t$  = Time in units consistent with the decline and rate

#### A1.2.1.5 Harmonic Decline ( $b=1$ )

When  $b=1$ , this is called harmonic decline. The existence of a harmonic decline may be indicating that production is still in the transient flow period. It may also be evident in reservoirs with extremely large and active aquifers or in very efficient water floods. The signature of harmonic decline is a straight line on a log(rate) versus cumulative plot or a log(rate) vs log(time) plot.

The harmonic decline equations use Equation A1-5 with  $b = 1$  and are given as Equations A1-18 and A1-19.

$$q = \frac{q_i}{(1 + D_it)} \quad (\text{A1-18})$$

$$Q_p = \frac{q_i}{D_i} \ln\left(\frac{q_i}{q}\right) \quad (\text{A1-19})$$

Where:

- $Q_p$  = Volume produced to rate  $q$  from time zero
- $q$  = Instantaneous Rate at time  $t$  [Volume / Unit Time]
- $q_i$  = Initial Instantaneous Rate ( $t = 0$ ) [Volume / Unit Time]
- $D_i$  = Initial Nominal Decline [Fraction / Unit Time]
- $t$  = Time in units consistent with the decline and rate

### A1.2.1.6 Modified Harmonic Decline

Since nominal decline is not constant, unconstrained harmonic curves will severely overestimate future production. To avoid the problem of overestimating production, it is common practice to convert the harmonic decline into an exponential decline at some future time. The nominal decline factor at time,  $D(t)$ , can be determined from Equation A1-3, with  $b = 1$ .

$$D(t) = \frac{D_i}{1 + D_i t} \quad (\text{A1-20})$$

For example, assume that the decline rate starts at 30% and decreases through time in a harmonic trend. When it reaches a specified value, 10% for example, the harmonic decline (Equation A1-18) can be changed to an exponential decline (Equation A1-7) and the forecast continued using the exponential decline rate of 10%. In other words, the forecast is converted to an exponential forecast when  $D(t) = D_{lim}$ .

The rate at which the conversion occurs ( $q_{lim}$ ) can be calculated from Equation A1-21 and the corresponding time ( $t_{lim}$ ) can be calculated from Equation A1-22.

$$q_{lim} = q_i \left( \frac{D_{lim}}{D_i} \right) \quad (\text{A1-21})$$

$$t_{lim} = \frac{\left( \frac{q_i}{q_{lim}} \right) - 1}{D_i} \quad (\text{A1-22})$$

The rate for the modified harmonic decline is calculated with Equations A1-18 and A1-16. Cumulative production is calculated as follows (Equations A1-19 and A1-23):

$$\text{For } D > D_{lim}: q = \frac{q_i}{(1 + D_i t)} \quad (\text{A1-18})$$

$$\text{For } D \leq D_{lim}: q = q_{lim} e^{-(D_{lim}(t - t_{lim}))} \quad (\text{A1-16})$$

$$\text{For } D > D_{lim}: Q_p = \frac{q_i}{D_i} \ln\left(\frac{q_i}{q}\right) \quad (\text{A1-19})$$

$$\text{For } D \leq D_{lim}: Q_p = \frac{q_i}{D_i} \ln\left(\frac{q_i}{q_{lim}}\right) + \frac{q_{lim} - q}{D_{lim}} \quad (\text{A1-23})$$

Where:

$Q_p$  = Volume produced to rate  $q$  from time zero

$q$  = Instantaneous Rate at time  $t$  [Volume / Unit Time]

$q_i$  = Initial Instantaneous Rate ( $t = 0$ ) [Volume / Unit Time]

$q_{lim}$  = Instantaneous Rate at  $t = t_{lim}$  [Volume / Unit Time]

$t_{lim}$  = Time when  $D = D_{lim}$  [Fraction / Unit Time]

$D_i$  = Initial Nominal Decline [Fraction / Unit Time]

$D_{lim}$  = Limiting Nominal Decline / Exponential Decline [Fraction / Unit Time]

### A1.2.1.7 Super-Harmonic Decline ( $b > 1$ )

Hyperbolic curve fits with a  $b$ -factor greater than 1 usually imply production is being influenced by long-term transient behavior. Common reasons for  $b > 1$  are as follows:

- The interpretation is wrong and a value where  $b < 1$  will fit the data
- The reservoir is still in transient flow (tight reservoir, shale reservoir)
- The reservoir is layered
- Fractured well

As an example,  $b = 2$  corresponds to transient linear flow and is commonly found when analysing hydraulically fractured, unconventional reservoirs. Caution must be exercised with these cases and decline factor limits should be built into the forecast to capture the eventual transition from transient to boundary dominated (exponential) flow.

Super harmonic decline is calculated using the hyperbolic equation (Equations A1-5 and A1-13).

$$q = q_i(1 + bD_it)^{-1/b} \quad (\text{A1-5})$$

$$Q_p = \frac{q_i^b}{(1-b)D_i} (q_i^{1-b} - q^{1-b}) \quad (\text{A1-13})$$

Where:

$Q_p$  = Volume produced to rate  $q$  from time zero

$q$  = Instantaneous Rate at time  $t$  [Volume / Unit Time]

$q_i$  = Initial Instantaneous Rate ( $t = 0$ ) [Volume / Unit Time]

$D_i$  = Initial Nominal Decline [Fraction / Unit Time]

$b$  = Hyperbolic Exponent

$t$  = Time in units consistent with the decline and rate

The modifications presented in Section A1.2.1.4 must also be applied to the super harmonic production forecasts.

## A1.3 Decline Curve Analysis Practice

DCA is most reliable for wells producing at high drawdown with a relatively constant flowing pressures, so that the production rate decline follows the decline in reservoir pressure. Because of this link to reservoir pressure, application of DCA techniques was historically restricted to the boundary dominated flow period. However, development of tight and unconventional reservoirs has extended its usage to the transient flow period, necessitating the development of alternative techniques that attempt to match the transient and boundary-dominated flow. The decline curve analysis presented by Arps is predominantly applicable to boundary dominated flow (depletion period), whereas SEP, for example, focuses on the early period of production (transient flow) and as a result is specifically applicable to tight/shale reservoirs.

When performing DCA, always consider the type of producing mechanism and use the appropriate analysis. In addition to gas, oil and liquid rates, take note of changes in pressure, water cut and GOR, as appropriate. Be aware of changes to skin (positive or negative) and take downtime into account.

### A1.3.1 Identifying Flow Regimes

To use the Arps DCA techniques, the existence of a boundary dominated flow (BDF) period needs to be confirmed. If BDF cannot be identified in a tight/shale well, then the SEDM could be used. It should be noted that pseudo-steady state flow and steady state flow are not the same as BDF.

#### A1.3.1.1 Transient, Pseudo Steady State, Steady State, Boundary Flow

Pressure transient analysis is based on the assumption that the well flows at a constant rate where decline curve analysis assumes that the well flows at a constant pressure.

Several terms are used when describing flow regimes in a well (Figure A1-5):

- **Transient Flow** — Pressure migrates outward from the well without encountering any boundaries; no pressure depletion occurs
- **Linear / Bilinear Flow** — A special form of transient flow that occurs in tight/shale or horizontal hydraulically fractured wells when well pressure is maintained constant; no pressure depletion occurs
- **Steady State Flow** — Pressure has reached all of the boundaries but the static pressure at the boundary does not decline, termed a “constant pressure boundary”, which can occur for waterfloods or infinite aquifers; no pressure depletion occurs
- **Pseudo-Steady State Flow** — Pressure has reached all of the boundaries and the static pressure is declining at the boundary and correspondingly at the well since production rate is held constant; pressure depletes
- **Boundary-Dominated Flow** — Pressure has reached all the boundaries and the static pressure is declining at the boundary, but not at the well since flowing pressure is maintained constant and rate declines; pressure depletion occurs

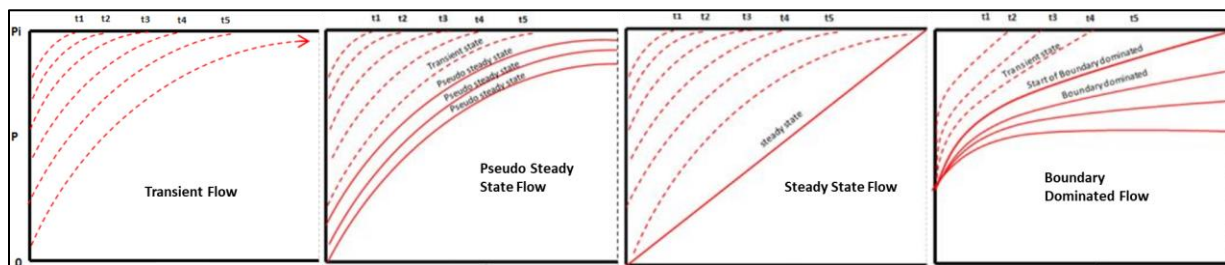


Figure A1-5: Representation of Flow Regimes

Pseudo steady state is normally associated with well testing or wells operating under a rate constraint. The well flow rate is maintained constant and the flowing pressure declines.

Boundary dominated flow is normally associated with long term production and decline curve analysis where a well is constrained by surface pressures (separators, pipelines, etc). In this case, the flowing pressure is approximately constant, and the rate declines.

In reality, although well head pressure may be constant, the bottom hole pressure may not be constant since tubing pressure drop will change as flow rate declines and flowing fluid properties change. For gas wells, this is not significant for lower flowing pressures but fluid properties (water-oil ratio, GOR) will impact pressure drop in naturally flowing oil wells.

When pressure is moderately changing, the concept of “Material Balance Time” ( $t_{mb} = cum/rate$ ) was developed to provide a correction of the actual production to an equivalent constant pressure production. Plotting production data using  $t_{mb}$  allows solutions with both declining rates and pressures to appear similar to the equivalent constant pressure solution, similar to the superposition time function in pressure transient analysis but applied to boundary dominated flow in DCA.

#### A1.3.1.2 Boundary Dominated Flow

Although the Arps equations can handle a number of flow regimes, it was developed to handle boundary dominated flow (BDF). BDF is identified by plotting the data as  $\log(q)$  vs  $\log(t)$  and confirming that a section with a straight line having a slope of 1 (unit slope) exists (Figure A1-6).

To assist in flow regime identification, lines with  $\frac{1}{4}$  slope and  $\frac{1}{2}$  slope can be used to identify bilinear and linear flow periods, respectively.

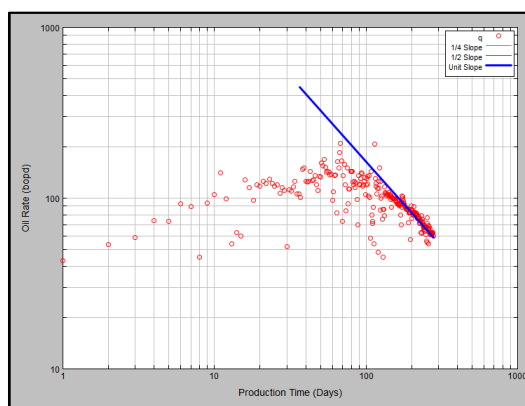


Figure A1-6: Example: Identification of Boundary Dominated Flow

Boundary dominated flow (unit slope) was evident in the Eagle Ford example after approximately 150 days (0.41 years) of production.

### A1.3.2 Determining Arps DCA Model and Arps DCA Parameters

#### A1.3.2.1 Determining Arps DCA Model

Production data can be plotted in different ways to identify a representative decline model. If a plot of  $\log(q)$  vs  $t$  and a plot of  $q$  vs  $Q_p$  (cum production) exhibit a straight line (Figure A1-7), then the decline trend is exponential and the exponential decline model should be used.

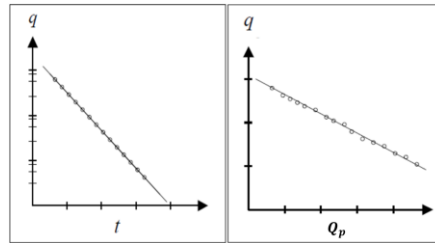


Figure A1-7: Identification of Exponential Decline

If a plot of  $\log(q)$  vs  $\log(t)$  and a plot of  $\log(q)$  vs  $Q_p$  exhibit a straight line (Figure A1-8), then the decline trend is harmonic and the harmonic decline model should be used.

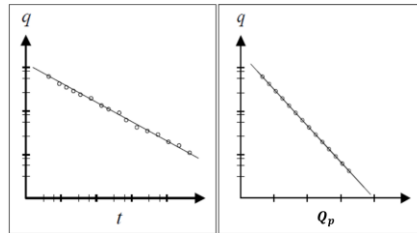


Figure A1-8: Identification of Harmonic Decline

If no straight line is observed on these plots, the hyperbolic, super harmonic or the SEDM decline model may be applicable.

#### A1.3.2.2 Determining Arps DCA Parameters

All decline curve analysis models are based on the concept of the instantaneous nominal decline rate ( $D$ ), as presented as Equation A1-1 and the corresponding Equation A1-3.

$$D = -\frac{1}{q} \frac{dq}{dt} \quad (\text{A1-1})$$

$$D = \frac{D_i}{1 + bD_i t} \quad (\text{A1-3})$$



Equation A1-3 can be rearranged into Equation A1-24 which is the equation of a straight line having a slope of  $b$  and an intercept of  $1/D_i$ . Figure A1-9 is a plot of Equation 3.2-1.

$$\frac{1}{D} = bt + \frac{1}{D_i} \quad (\text{A1-24})$$

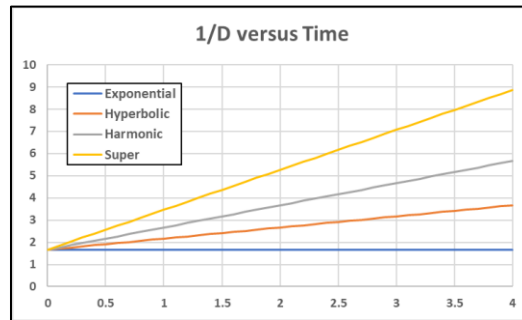


Figure A1-9: Plot of Equation A1-24

Figure A1-10 presents the plot generated using Eagle Ford example data. The slope ( $b$ ) of the plot is 0.91 and the intercept ( $1/D_i$ ) is 0.22 for an initial annual nominal decline ( $D_i$ ) of 4.

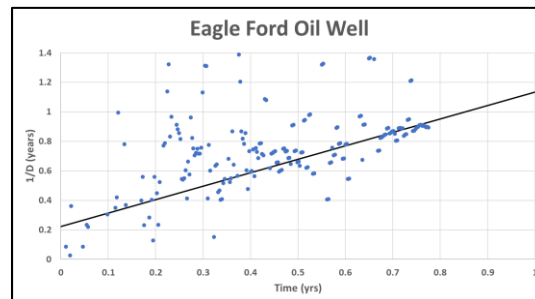


Figure A1-10: Example

Figure A1-11 presents the resulting Arps hyperbolic analysis. The blue decline curve in Figure A1-11 was generated assuming an initial rate ( $q_i$ ) of 295 bopd.

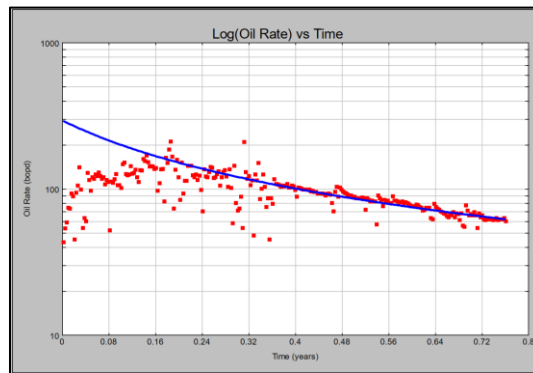


Figure A1-11: Example DCA

If the slope on the  $\frac{1}{D}$  vs  $t$  plot is equal to or greater than 1, then analysis using the SEDM could be used rather than using Arps harmonic or super harmonic DCA (refer to Section A1.2.1.7).

### A1.3.3 Multi-Segment DCA

The multi-segment DCA method uses DCA model segments, and complete analysis can be any combination of decline curve analysis models. For instance, the multi-segment DCA could be used to capture distinct flow regimes, including transient flow ( $b > 1$ , SEDM), harmonic decline ( $b = 1$ ), hyperbolic decline ( $0 < b < 1$ ), and exponential decline ( $b = 0$ ). Figures A1-12 and A1-13 present a conceptual three-segment DCA.

The multi-segment method is well-suited for unconventional reservoirs that exhibit multiple flow regimes and could be used as an alternative to the Stretched Exponential decline model.

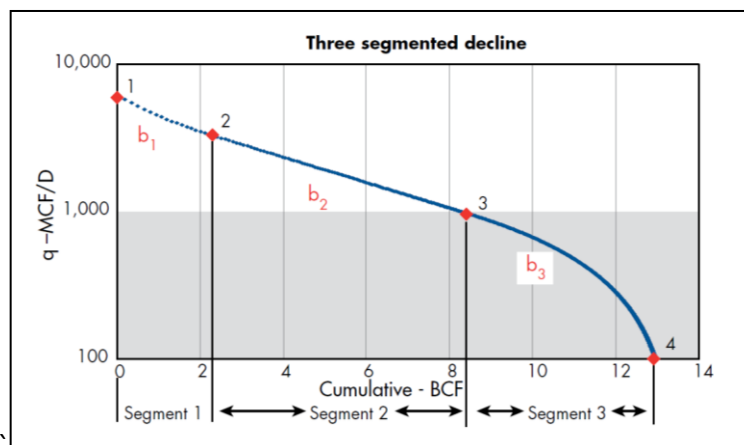


Figure A1-12: Conceptual Multi-Segment DCA

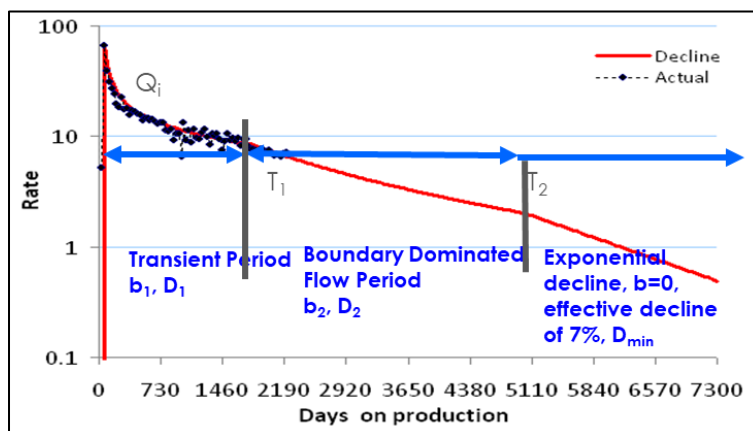


Figure A1-13: Multi-Segment DCA Forecast

### A1.3.4 General Considerations for Arps b-factor

As a rule of thumb, a general guide for the ranges of b-factor for specific reservoir production characteristics are as follows:

- Undersaturated Oil Reservoir
  - Exponential:  $b = 0$
- Solution Gas Drive / Gas Cap Reservoirs
  - Increasing GOR:  $b = 0.0$  to  $0.1$
  - Poor Mobility Ratio:  $b = 0.1$  to  $0.3$
  - Moderate GOR:  $b = 0.3$  to  $0.6$
  - High API:  $b = 0.6$  to  $0.8$
- Waterflood
  - Constant Pressure:  $b \geq 0.8$
- Gas Reservoir
  - High Pressure:  $b = 0$
  - Low-to-Mod Pressure:  $b = 0.3$  to  $0.5$
  - Increasing Pwf:  $b$  trends towards  $0.0$
- Unconventional
  - Shale:  $b > 1$  (use SEDM)

When determining the decline period, use the most representative period in history, preferably BDF, that would also be representative the future. Calculate the decline trend during the representative period and determine the starting point (rate and time) for the forecast. Finally, consider the constraints under which the forecast is to be generated.

### A1.3.5 Water Drive / Waterflood Considerations

Typically, water drive oil reservoirs (either natural drive or waterflood) can be difficult to analyze by decline analysis techniques because drawdown increases as water breakthrough occurs due to total fluid mobility declines. Also, the total reservoir fluid production rate may be increased near and after breakthrough in order to maintain required oil production. Finally, pressure balancing can cause drainage pattern changes and variable deliverability.

Most successful waterfloods are implemented in good continuity reservoirs with moderate to high permeabilities and, as a result, well interference may occur. Because of well interference effects, individual well decline analysis should be used with caution. It may be better to use an aggregate analysis of a complementary group of interfering wells.

Field cases as well as analytical / simulation modelling generally supports hyperbolic/harmonic decline for late stage waterflood behavior, in other words the value of  $b$  normally is between 0.8 and 1.0. This does not mean that exponential decline or super harmonic decline cannot occur in waterflood reservoirs, but whenever it is observed, it is common that non-reservoir factors are influencing the performance.

The waterflood decline analysis period should meet the following criteria:

- Undersaturated oil reservoir, no free gas
- Water Cut should be greater than 50%
- Voidage replacement ratio should be close to one
- Well count should be relatively constant
- Injection and total fluid production rates should be relatively constant
- The reservoir pressure should be relatively constant
- Producing well pressures should be constant
- The GOR should be relatively constant
- The volume of water injected should be greater than 25% of the hydrocarbon pore volume

The main DCA plots for water drive and waterflood reservoirs are as follows:

- Log(Oil Rate) vs Cum Oil
- Log(Oil Cut) vs Cum Oil
- Log(WOR) vs Cum Oil
- Log(Cum Liquid) vs Cum Oil

### A1.3.6 Reserves

A major use of decline curve analysis is to generate an estimate of reserves. Even for assets where history matched simulation models are available, a cross check with DCA is normally made to give increased confidence in the numbers.

Financial institutions tend to accept DCA estimates over other, more technical methods. The ultimate recovery numbers become more important than the profiles. Application of constraints in the production system, operating costs, capital costs and well behavior all need to be taken into account to generate reliable reserve estimates.

There are many, equally valid ways to use DCA to determine low/most likely/high values, the following technique is suggested:

- If the hyperbolic constant,  $b$ , is between 0.3 and 0.7, use it as most likely
- For the low case, use a  $0.5b$  value with a min = 0.0
- For the high case, use a  $1.5b$  value with a max = 0.9

Forecasts generated based on decline analysis (whether production profiles or reserves) should be fundamentally grounded in a good understanding of the factors that control production. No 'One size fits all' principal applies when it comes to application of DCA, specifically, using an exponential decline for water drive, solution gas drive and gravity drainage systems is neither technically, nor empirically, justified.

Oil reservoirs producing with high water cut or high GOR need to be analyzed using ratio plots - Log(WOR) vs Cum Oil, Log(GOR) vs Cum Oil, Watercut vs Cum Oil - in addition to conventional plots to ensure there is no over-estimation of volumes based on rate plots alone. Care needs to be taken to understand the minimum criteria for application of these plots. For example Log(WOR) vs Cum Oil should only be used if WOR is equal to or higher than 1 (water cut is equal to, or higher than, 50%).

### A1.3.7 Non-Ideal Behaviour Which May Require Special Consideration

General items to look out for:

- Reconciled/allocated data
- Invented data
- Splits – especially water
- Changing skin factors / stimulation
- Anything not yet observed – water/gas breakthrough, coning, cusping, etc
- Piston-like displacement – use Buckley Leverett or simulation
- Constant  $P_{wf}$ , be aware of changes in choke settings, lift gas, etc
- Transient behaviour
- Downtime: Unscheduled and scheduled downtime will distort decline trends

It is recommended to filter out downtime data before fitting a decline curve through the production data, and then applying a ‘downtime factor’ to the resulting profile. You can also use recorded uptime or producing hours to adjust the production data prior to analysis. Be aware of transient effects after prolonged downtime - these effects should be filtered out.

### A1.3.8 Noisy Data

Available historic data tends to be in a monthly or yearly format. Today, data may be available in a daily format. Daily data can result in very noisy data (Figure A1-14). Note that the GW-01 well is an example Granite Wash well.

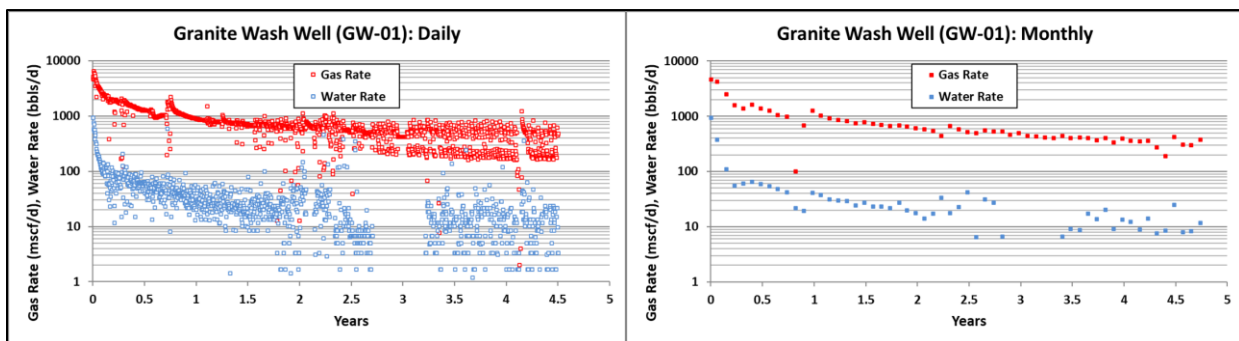


Figure A1-14: Daily vs Monthly Data for GW-01 Well.

The noisy data may be resolved by using monthly data as shown in Figure A1-14. The issue with this is that the number of data points available for analysis is significantly reduced unless there is significant historical data.

As an alternative, applying a moving average to the daily data could be used to “smooth” the data. Figure A1-15 presents 3-Day, 5-Day and 8-Day moving averages of the GW-01 data.

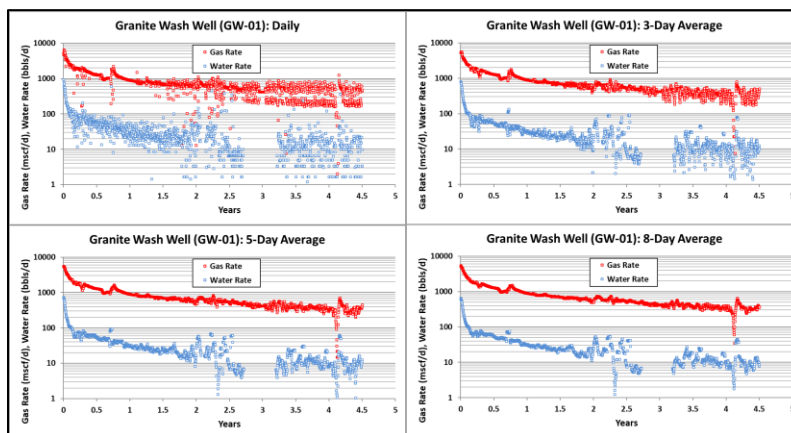


Figure A1-15: Smoothing Daily Data by Moving Average - GW-01 Well.

When smoothing using a moving average, the minimum averaging that yields acceptable data should be applied. For the different averaging presented in Figure A1-15, the 5-Day moving average appears sufficient to analyse the data.

### A1.3.9 Use of De-Superposition

Full field profiles can be difficult to match for a number of reasons:

- Incremental development
- Different depletion processes in different parts of the field
- Wells or field segments coming on and off production

It is straightforward to split out various wells and/or field segments (de-superposition) and perform decline analysis on each one separately. In most cases, a well-by-well analysis will give a better result than a single full-field analysis.

The requirement for de-superposition is dependent on whether or not boundary dominated flow has been achieved. For wells under boundary dominated flow, the well drainage volumes in a bounded reservoir are proportional to the rates of withdrawal from each drainage volume. In other words,  $q/Q_p$  is a constant for each well and for the total reservoir. For boundary dominated flow, analysis by summation of wells or analysis at an overall reservoir level should give identical results. This assumes uniform reservoir properties – faults and large changes in permeability or different production mechanisms may result in different  $q/Q_p$  ratios for different groups of wells.

## Appendix DCA2 – Model Formulations

This appendix provides a summary of the time-rate relations used in the PE<sup>2</sup> Essentials eDCA tool, as well as formulations for the various diagnostic functions (i.e.,  $q(t)$ ,  $D(t)$ ,  $b(t)$ ,  $\beta(t)$ ,  $q/G_p(t)$  and  $\zeta(t)$ ) which are incorporated into the tools.

### A2.1 Arps Hyperbolic Model

Reference: Arps, J.J. 1945. Analysis of Decline Curves. Trans. AIME 160: 228-247.

The hyperbolic rate decline relation termed the Arps decline model is given as Equation A1.5:

$$q(t) = \frac{q_i}{(1 + bD_i t)^{1/b}} \quad (\text{A1.5})$$

Where:  $q(t)$  is the rate at time  $t$ ,  $q_i$  is the rate at time 0,  $b$  is the hyperbolic exponent,  $D_i$  is the initial nominal decline factor and  $t$  is cumulative production time.

If the Arps hyperbolic rate decline relation is used when long term transient flow regimes are evident (i.e.  $b \gg 1.0$ ), then extrapolation of the Arps hyperbolic relation will almost always lead to significant overestimations of EUR and future performance.

Since the Arps hyperbolic relation can often model the early-time flow behavior, the industry has adopted a protocol to "constrain" the ultimate extrapolation by including a terminal exponential decline trend — hence, the "modified hyperbolic" designation. The modified hyperbolic model (Appendix A2.2) is enabled in eDCA by entering a value for  $D_{lim}$  in the Arps model (Figure A2-1).

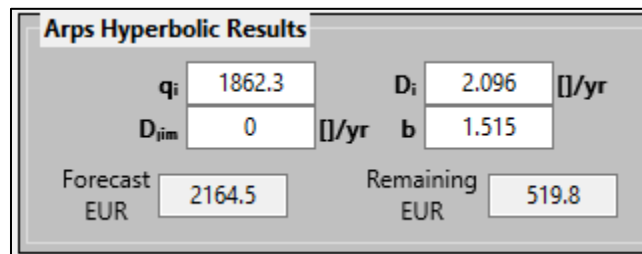


Figure A2-1: PE<sup>2</sup> Essentials – eDCA: Arps Model

After the  $D_{lim}$  is reached the Arps equation reverts to the exponential decline equation (Equation A1-6).

It should be noted that the decline factors are presented as annual values and as a fraction.

The defining equations for the Arps Model are as follows:



$$q(t) = \frac{q_i}{(1 + bD_i t)^{1/b}} \quad (\text{A2.1})$$

$$D(t) = \frac{D_i}{(1 + bD_i t)} \quad (\text{A2.2})$$

$$b(t) = b \quad (\text{A2.3})$$

$$\beta(t) = \frac{D_i t}{(1 + bD_i t)} \quad (\text{A2.4})$$

$$\frac{q(t)}{G_p(t)} = \frac{(1 - b)D_i}{(1 + bD_i t)^{(1/b)} - (1 + bD_i t)} \quad (\text{A2.5})$$

## A2.2 Modified Hyperbolic Model

Reference: Robertson, S. Generalized Hyperbolic Equation; USMS SPE 18731, 1988.

This model has two trends — an initial trend that is hyperbolic (i.e., for  $t < t_{\text{exp}}$ ), and a final trend that is exponential (i.e., for  $t > t_{\text{exp}}$ ) — where  $t_{\text{exp}}$  is the time of change from hyperbolic to exponential.

For the hyperbolic function, the modified hyperbolic model follows the Arps Hyperbolic model, Equations A2.1 to A2.5). For times greater than  $t_{\text{exp}}$ ,  $D_i = D_{\text{lim}}$  (constant terminal decline) and the model becomes exponential.

The defining equations for the Modified Hyperbolic Model (for  $t > t_{\text{exp}}$ ) are as follows:

$$q(t) = q_i \exp[-D_i t] \quad (\text{A2.6})$$

$$D(t) = D_i \quad (\text{A2.7})$$

$$b(t) = 0 \quad (\text{A2.8})$$

$$\beta(t) = D_i t \quad (\text{A2.9})$$

$$\frac{q(t)}{G_p(t)} = D_i \frac{\exp[-D_i t]}{(1 - \exp[-D_i t])} \quad (\text{A2.10})$$

## A2.3 Stretched Exponential Model (SEPD)

Reference: Valkó, P.P. 2009. Assigning Value to Stimulation in the Barnett Shale: A Simultaneous Analysis of 7000 Plus Production Histories and Well Completion Records. Paper SPE 119369

presented at the SPE Hydraulic Fracturing Technology Conference, College Station, TX, 19-21 January.

The stretched exponential rate decline relation presented by Valkó is given as Equation A2.11 (Figure A2.2):

$$q(t) = \hat{q}_i \exp[-(t / \tau)^n] \quad (\text{A2.11})$$

Where:  $q(t)$  is the rate at time  $t$ ,  $\hat{q}_i$  is the rate at time 0,  $\tau$  and  $n$  are model terms and  $t$  is cumulative production time.

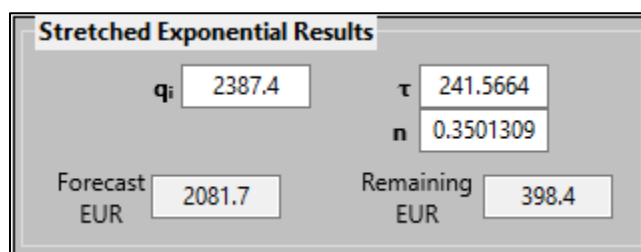


Figure A2-2: PE<sup>2</sup> Essentials – eDCA: Stretched Exponential Decline Model

The basis for the stretched exponential decline model (SEDM) is elementary physics. The discharge of fluid from a tank against a fixed back-pressure results in an exponential decline of flow rate over time. By considering a gas reservoir as a collection of connected tanks (cells) discharging against different back-pressures and with different resistances ('time constants'), this leads to the interpretation of stretched exponential decay. The SEPD model was generated by a sum (integral) of pure exponential decays with a distribution of time constants in the form of Gamma functions. As a result, it is not simple to implement this model.

An advantage of the SEPD model is that production under variable bottom hole pressures can be modeled. Forecasts can also be generated assuming changing bottom hole pressures.

The defining equations for the Stretched Exponential Model are as follows:

$$q(t) = \hat{q}_i \exp[-(t / \tau)^n] \quad (\text{A2.11})$$

$$D(t) = n \tau^{-n} t^{n-1} \quad (\text{A2.12})$$

$$b(t) = \frac{1-n}{n} \tau^n t^{-n} \quad (\text{A2.13})$$

$$\beta(t) = n \tau^{-n} t^n \quad (\text{A2.14})$$

$$\frac{q(t)}{G_p(t)} = \frac{n}{\tau} \frac{\exp\left[-\left[\frac{t}{\tau}\right]^n\right]}{\left[\Gamma\left[\frac{1}{n}\right] - \Gamma\left[\frac{1}{n}, \left[\frac{t}{\tau}\right]^n\right]\right]} \quad (\text{A2.15})$$

## A2.4 Power Law Exponential Model (PLE)

Reference: Ilk, D., Perego, A.D., Rushing, J.A., and Blasingame, T.A. 2008. Exponential vs. Hyperbolic Decline in Tight Gas Sands — Understanding the Origin and Implications for Reserve Estimates Using Arps' Decline Curves. Paper SPE 116731 presented at the SPE Annual Technical Conference and Exhibition, Denver, CO, 21-24 September; and, Ilk, D., Rushing, J.A., and Blasingame, T.A. 2009. Decline Curve Analysis for HP/HT Gas Wells: Theory and Applications. Paper SPE 125031 presented at the SPE Annual Technical Conference and Exhibition, New Orleans, LA, 04-07 October.

The Power Law Exponential decline relation is given as Equation A2.16 (Figure A2-3):

$$q(t) = \hat{q}_i \exp[-\hat{D}_i t^n - D_\infty t] \quad (\text{A2.16})$$

Where:  $q(t)$  is the rate at time  $t$ ,  $q_i$  is the rate at time 0,  $D_i$  is the initial decline rate,  $D_\infty$  is the decline rate at infinite time,  $n$  is power exponent and  $t$  is cumulative production time.

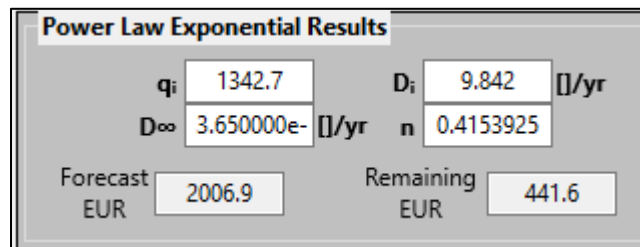


Figure A2-3: PE<sup>2</sup> Essentials – eDCA: Power Law Exponential Decline Model

The Power Law Exponential decline model (PLE) is analogous to the SEDM but was derived independently and is simpler to use. To account for the non-convergence to zero of a pure power equation, the  $D_\infty$  term was incorporated to account for the boundary dominated flow regime.

The PLE model is very flexible and can be used to match transient, transition and boundary dominated flow data.

The defining equations for the Power Law Model are as follows:

$$q(t) = \hat{q}_i \exp[-\hat{D}_i t^n - D_\infty t] \quad (\text{A2.16})$$

$$D(t) = D_{\infty} + \hat{D}_i n t^{n-1} \quad (\text{A2.17})$$

$$b(t) = \frac{\hat{D}_i (1-n) n t^n}{(D_{\infty} t + \hat{D}_i n t^n)^2} \quad (\text{A2.18})$$

$$\beta(t) = D_{\infty} t + \hat{D}_i n t^n \quad (\text{A2.19})$$

No  $q(t)/G_p(t)$  formulation is available for the Power Law Exponential relation since no closed form relation exists for the cumulative production function,  $G_p(t)$ . This is because of the complexity introduced into Equation A2.16 by the  $D_{\infty}$  term.

## A2.5 Duong Model

Reference: Duong, A.N. 2011. Rate-Decline Analysis for Fracture-Dominated Shale Reservoirs SPE Reservoir Evaluation and Engineering 14 (3): 377-387.

The Duong decline relation is given as Equation A2.20 (Figure A2-4):

$$q(t) = q_i t^{-m} \exp \left[ \frac{a}{(1-m)} [t^{(1-m)} - 1] \right] + q_{\infty} \quad (\text{A2.20})$$

Where:  $q(t)$  is the rate at time  $t$ ,  $q_i$  is the rate at time 0,  $a$  and  $m$  are model terms,  $q_{\infty}$  is the rate at infinite time and  $t$  is cumulative production time.

The Duong decline model is based on an extended linear/bilinear flow regime. It is derived from transient behavior of unconventional-fractured reservoirs. The model is extracted from the straight-line behavior of  $q/G_p$  vs. time on a Log-Log plot.

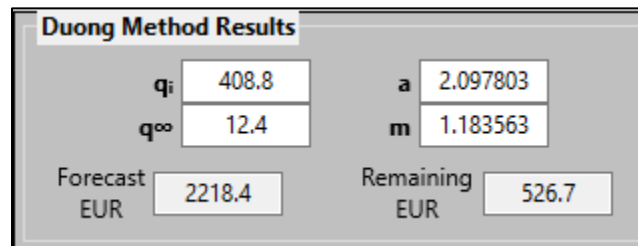


Figure A2-4: PE<sup>2</sup> Essentials – eDCA: Duong Decline Model

For the Duong model, rate does not start out at a maximum, as for the other models, but quickly reaches a maximum within days. If  $q_{\infty}$  is negative then rate will theoretically become negative,

there may be a requirement to limit the rate function using a minimum rate or a maximum time constraint before the onset of a negative rate.

The defining equations for the Duong Model are as follows:

$$q(t) = q_i t^{-m} \exp \left[ \frac{a}{(1-m)} [t^{(1-m)} - 1] \right] + q_\infty \quad (\text{A2.20})$$

$$D(t) = m t^{-1} - a t^{-m} \quad (\text{A2.21})$$

$$b(t) = \frac{m t^m [t^m - a t]}{[a t - m t^m]^2} \quad (\text{A2.22})$$

$$\beta(t) = m - a t^{(1-m)} \quad (\text{A2.23})$$

$$\frac{q(t)}{G_p(t)} = a t^{-m} \quad (\text{A2.24})$$

## A2.6 Logistic Growth Model (LGM)

Reference: Clark, A.J., Lake, L.W., and Patzek, T.W. 2011. Production Forecasting with Logistic Growth Models. Paper SPE 144790 presented at the SPE Annual Technical Conference and Exhibition, Denver, CO, 30 October-02 November.

The Logistic Growth decline relation is given as Equation A2.25 (Figure A2-5):

$$q(t) = \frac{K n a t^{(n-1)}}{[a + t^n]^2} \quad (\text{A2.25})$$

Where:  $q(t)$  is the rate at time  $t$ ,  $q_i$  is the rate at time 0,  $K$  is the carrying capacity,  $n$  is the hyperbolic exponent,  $a$  is a constant and  $t$  is cumulative production time.

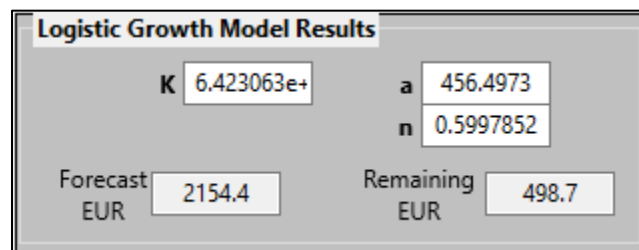


Figure A2-5: PE<sup>2</sup> Essentials – eDCA: Logistic Growth Decline Model

The Logistic Growth decline model (LGM) was adopted from population growth models. It is a modified form of hyperbolic logistic growth models. The LGM implies a growth equation which, in this case, represents the growth of cumulative oil or gas production.

The defining equations for the Logistic Growth Decline Model are as follows:

$$G_p(t) = \frac{K t^n}{[a + t^n]} \quad (\text{A2.25})$$

$$q(t) = \frac{dG_p(t)}{dt} = \frac{aK n t^{(n-1)}}{[a + t^n]^2} \quad (\text{A2.26})$$

$$D(t) = \frac{a(1-n) + (1+n)t^n}{t(a + t^n)} \quad (\text{A2.27})$$

$$b(t) = \frac{a^2(1-n_{LGM}) - 2a(n^2 - 1)t^n + (n+1)t^{2n}}{[a(1-n) + (n+1)t^n]^2} \quad (\text{A2.28})$$

$$\beta(t) = \frac{a(1-n) + (1+n)t^n}{(a + t^n)} \quad (\text{A2.29})$$

$$\frac{q(t)}{G_p(t)} = \frac{an}{t(a + t^n)} \quad (\text{A2.30})$$

## A2.7 LeBlanc-Okouma Power Law Model (LOPM)

Reference: LeBlanc, D., Okouma, V. 2018. New Rate-Decline model for unconventional reservoirs, World Oil, March 2018.

The LeBlanc-Okouma Power Law Exponential decline relation is given as Equation A2.31 (Figure A2-6):

$$q(t) = q_i t^{-\alpha} \exp(-\xi t) \quad (\text{A2.31})$$

Where:  $q(t)$  is the rate at time  $t$ ,  $q_i$  is the rate at time 0,  $\alpha$  is the power exponent,  $\xi$  is term to account for boundary dominated flow and  $t$  is cumulative production time.

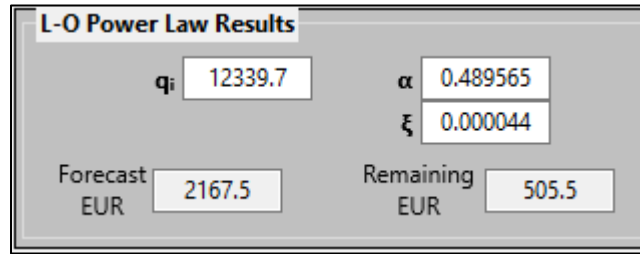


Figure A2-6: PE<sup>2</sup> Essentials – eDCA: LeBlanc-Okouma Power Law Decline Model

The LeBlanc-Okouma Power Law decline model (LOPL) is an extension of the PEE Empirical model, presented as Equation A2.35, accounting for the boundary dominated flow regime by incorporating the  $e^{(-\xi t)}$  term. The LOPL is analogous to the SEDM and PLE models but was derived independently.

If  $\xi=0$ , the LOPL is equivalent to the PEE Empirical model. In this case, the model will overpredict production unless a  $D_{lim}$  is used, which is incorporated into the DCA tool.

The LOPL decline model is easily applied and with the inclusion of a late time term,  $\xi t$ , in the power-law equation it is able to model transient, transition, and boundary-dominated flow. The LOPL Model has been shown to yield more consistent estimates of short-to-long term production in unconventional reservoirs, compared to other time-rate models, while still maintaining the capability of modeling conventional reservoirs.

The defining equations for the LeBlanc-Okouma Power Law Decline Model are as follows:

$$q(t) = q_i t^{-\alpha} e^{-\xi t} \quad (A2.31)$$

$$D(t) = \frac{\alpha + \xi t}{t} \quad (A2.32)$$

$$b(t) = \frac{\alpha}{(\alpha + \xi t)^2} \quad (A2.33)$$

$$\beta(t) = \alpha + \xi t \quad (A2.34)$$

$$q(t) = q_i t^{-\alpha} \quad (A2.35)$$

No  $q(t)/G_p(t)$  formulation is available for the LeBlanc-Okouma Power Law model since no closed form relation exists for the cumulative production function,  $G_p(t)$ . This is because of the complexity introduced into equation A2.31 by the  $\xi$  term.

## A2.8 Normalized DCA

During the early stages of production, the well may be produced at a choked rate (constant rate, variable pressure). For this situation, the flowing pressure ( $p_{wf}$ ) continues to decline. After a minimum pressure is reached, the pressure will be maintained constant and the rate will decline. It is possible to analyze the constant rate, declining pressure flow period using a technique called normalized decline curve analysis. Conventional decline curve analysis (DCA) is performed on the constant pressure, declining rate flow period.

Reference: Anderson, S., Anderson, D., Edwards, K., Epp, K., Stalgorova, K., Pressure Normalized Decline Curve Analysis for Rate-Controlled Wells, SPE 162923, 2012.

Normalized decline analysis is based on the following definition of pressure normalized rate ( $q_N$ ) in terms of initial pressure ( $p_i$ ) and flowing pressure ( $p_{wf}$ ):

$$q_N = \frac{q}{p_i - p_{wf}} \quad (\text{A2-32})$$

And, in terms of pseudo pressure,  $\Psi$ :

$$q_N = \frac{q}{\Psi_i - \Psi_{wf}} \quad (\text{A2-33})$$

Many high-pressure wells are rate restricted during early production due to operating facility and pipeline constraints. These high-pressure wells may display a harmonic decline of normalized rate with time which results in a linear relationship between normalized rate and cumulative production when plotted on a semi-log scale (Figure A2-7).

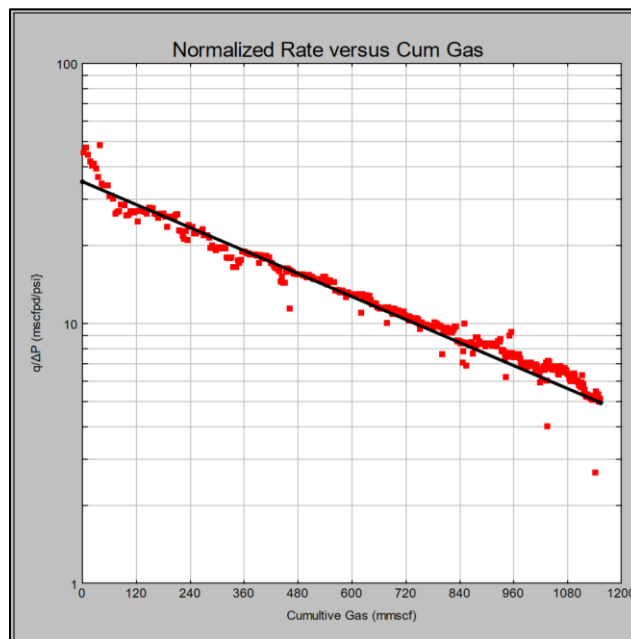


Figure A2-7: Normalized Rate vs Cumulative Production



The equation of the straight line in Figure A2-7 is given as Equation A2-34.

$$\log(q_N) = m1 Q_p + C1 \quad (A2-34)$$

Where:

$Q_p$  = Cumulative Volume

$q_N$  = Normalized Flow Rate [Rate / Pressure]

$m1$  = Slope of the  $q_N$  vs  $Q_p$  plot [1 / Time-Pressure]

$C1$  = Intercept ( $Q_p = 0$ ) of the  $q_N$  vs  $Q_p$  plot [Rate / Pressure]

Extrapolating the straight line to an abandonment  $q_N / \Delta P$  value will yield the EUR for the well.

Using Equation A2-34, a rate can be estimated for any  $Q_p$  if  $\Delta P$  is known. In order to forecast rate, the flowing pressure ( $p_{wf}$ ) as a function of time must also be known.

Future flowing pressure is dependent on future operating conditions. The general assumption for rate-restricted wells is that pressure will decline logarithmically with time until a minimum value is reached (Figure A2-8).

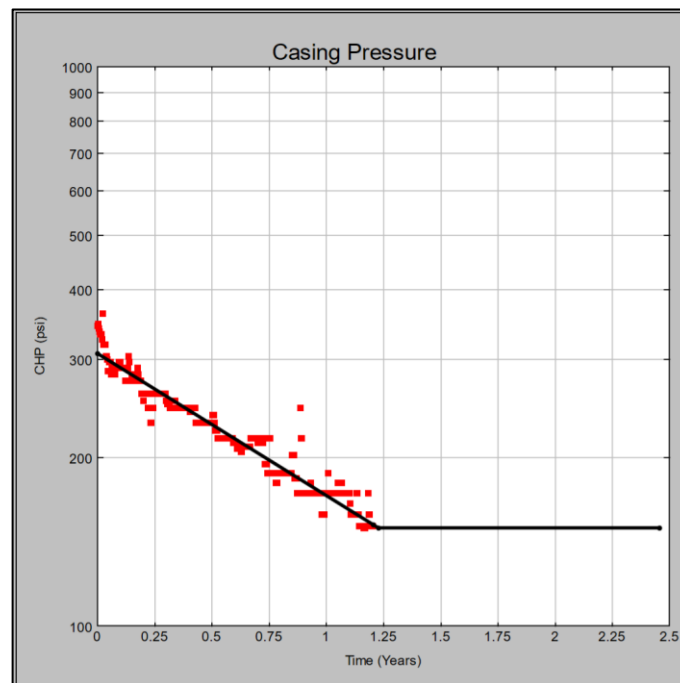


Figure A2-8: Flowing Pressure vs Time

The equation of the declining straight line in Figure A2-8, is presented as Equation 2.3-4.

$$\log(p_{wf}) = m2 t + C2 \quad (A2-35)$$

Where:

$p_{wf}$  = Flowing Pressure – CHP, THP or BHP

$t$  = Time in units consistent with forecast

$m2$  = Slope of the  $p_{wf}$  vs  $t$  plot [Unit Pressure / Unit Time]

$C2$  = Intercept ( $t=0$ ) of the  $p_{wf}$  vs  $t$  plot [Unit Pressure]

Caution must be used when attempting to forecast pressure in oil wells that have varying water and gas rates.

The procedure to generate a production forecast (Figure A2-9) using Normalized DCA, is to use the following equations and start by estimating a rate  $q_{est}$  and an incremental time  $\Delta t$ .

$$Q_p(t) = Q_p(t-1) + q_{est}(t)\Delta t$$

$$q_N(t) = 10^{[m1 Q_p(t) + C1]}$$

$$p_{wf}(t) = 10^{[m2 t + C2]}$$

$$q(t) = q_N(t)[(p_i - p_{wf}(t))]$$

Iterations are then performed until the estimated rate  $q_{est}(t)$  and the calculated rate  $q(t)$  are within an acceptable difference for each time step.

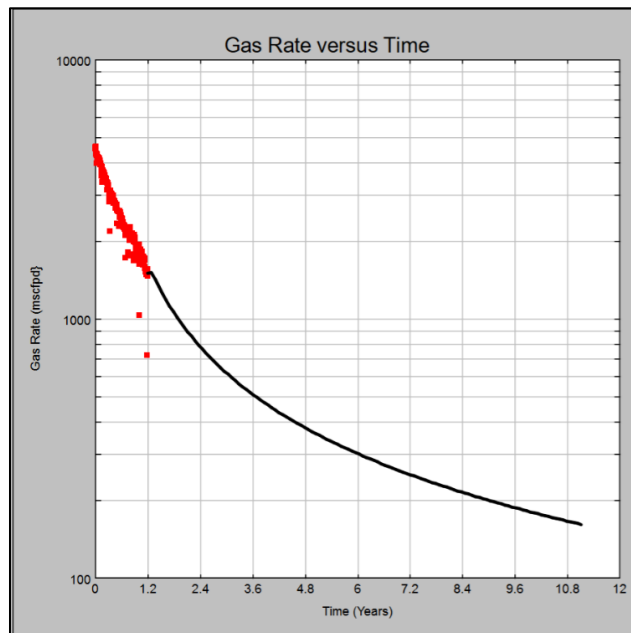


Figure A2-9: Normalized Decline Curve Forecast

### Appendix DCA3 – Miscellaneous Definitions

For rate-time decline analysis, the governing equations are based on the loss ratio concept (Equation A3.1) introduced by Arps. The base definitions are as follows:

Definition of the loss ratio:

$$\frac{1}{D(t)} \equiv -\frac{q(t)}{dq(t)/dt} \quad (\text{A3.1})$$

Definition of decline parameter:

$$D(t) \equiv -\frac{1}{q(t)} \frac{dq(t)}{dt} \quad (\text{A3.2})$$

Derivative of the loss ratio:

$$b(t) \equiv \frac{d}{dt} \left[ \frac{1}{D(t)} \right] \equiv -\frac{d}{dt} \left[ \frac{q(t)}{dq(t)/dt} \right] \quad (\text{A3.3})$$

Beta derivative – relates rate and derivative function:

$$\beta(t) \equiv \frac{1}{q(t)} \left| t \frac{dq(t)}{dt} \right| \equiv t D(t) \quad (\text{A3.4})$$

$\zeta$  (Zeta)-Derivative — time derivative of  $q(t)/G_p(t)$  , inverse material balance time:

$$\zeta(t) \equiv \frac{d}{dt} \left[ \frac{q(t)}{G_p(t)} \right] \quad (\text{A3.5})$$

Definition of reciprocal material balance time:

$$\frac{q(t)}{G_p(t)} \quad (\text{A3.6})$$

Equation A3.2 is the definition of the decline parameter,  $D(t)$ ; Equation A3.3 is the derivative of the loss-ratio,  $b(t)$ ; Equation A3.4 is the Beta function which relates rate and a derivative function; and Equation A3.5 is the Zeta function which is the derivative of  $q/G_p$  or  $q/N_p$ , Equation A3.6.

All these functions can be plotted in the PE<sup>2</sup> Essentials PDA tool.

## Monte Carlo DC Production Forecast

The PE<sup>2</sup> Essentials 'Monte Carlo DC Forecast' tool (Figure MCD-1) was developed as an extension to the PE<sup>2</sup> Essentials Decline Curve Analysis tool to include probabilistic DCA.

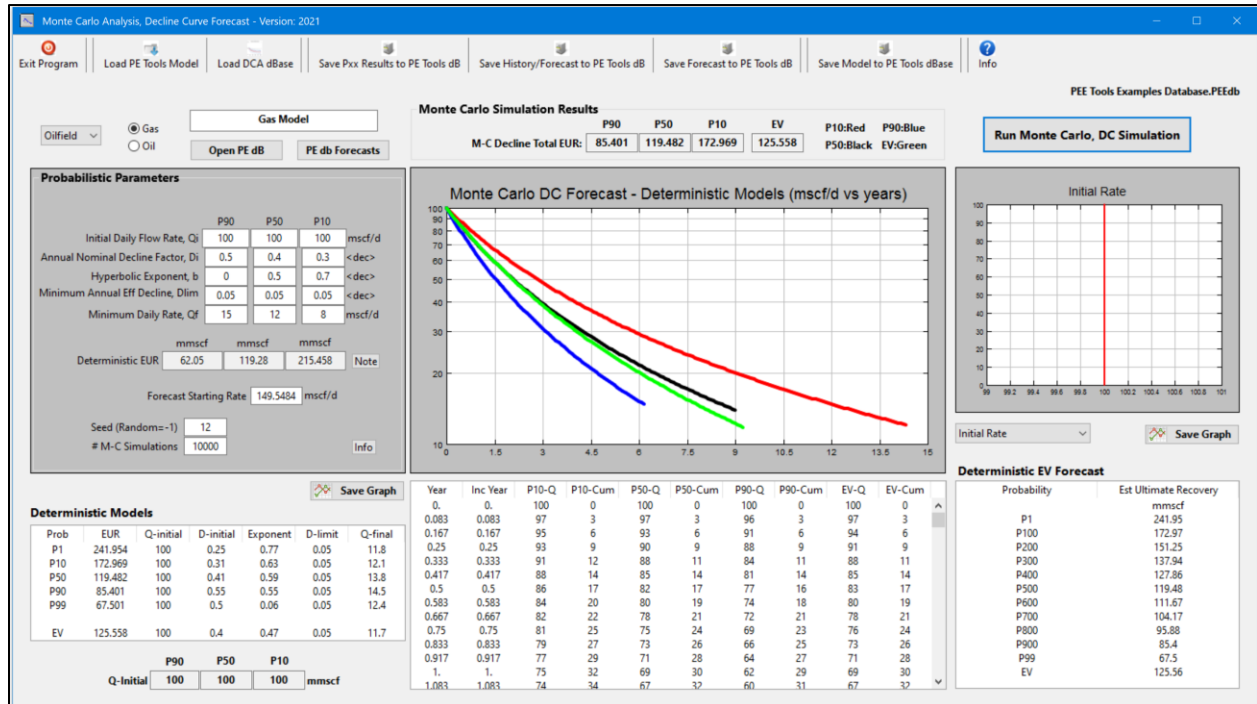


Figure MCD-1: PE<sup>2</sup> Essentials Monte Carlo DC Forecast Tool

This Monte Carlo simulation model can be used to generate probabilistic EUR values based on a probabilistic simulation of decline curve parameters. The model evaluates all the parameters that go into the decline curve equations and will produce equivalent production forecasts for specific realizations.

The tool can directly import information from a separate DCA database in order to generate a probabilistic production profile for a well that has been previously analysed (Refer to Section MCD.2). If the DCA database includes GOR/WGR/WOR/WCut analysis information, then these parameters will also be forecasted.

### MCD.1 Monte Carlo DCA

There are two options for running a Monte Carlo simulation: starting from initial conditions ( $t=0$ ) or from the end of production history. To run the forecast from the end of production history, the is imported from a separate DCA database file.

The 'Probabilistic Parameters' are entered into the model (Figure MCD-2). The P50 numbers can be based on the results of the initial analysis performed using the PE<sup>2</sup> Essentials Decline Curve Analysis tool.

	P90	P50	P10	
Initial Daily Flow Rate, Qi	100	100	100	mscf/d
Annual Nominal Decline Factor, Di	0.5	0.4	0.3	<dec>
Hyperbolic Exponent, b	0	0.5	0.7	<dec>
Minimum Annual Eff Decline, Dlim	0.05	0.05	0.05	<dec>
Minimum Daily Rate, Qf	15	12	8	mscf/d

	mmscf	mmscf	mmscf	
Deterministic EUR	62.05	119.28	215.458	Note

Seed (Random=-1) 12

# M-C Simulations 10000

Info

Figure MCD-2: Monte Carlo DC Forecast Tool – Probabilistic Parameters

As is the case for all PE<sup>2</sup> Essentials Monte Carlo simulation models, it is possible to generate a deterministic forecast by making  $P90=P50=P10$ . This essentially disables the Monte Carlo simulator.

Following Monte Carlo simulation of the EUR, the equivalent P90/P50/P10 and EV deterministic production forecasts are generated based on the decline curve realizations (Figure MCD-3 and MCD-4).

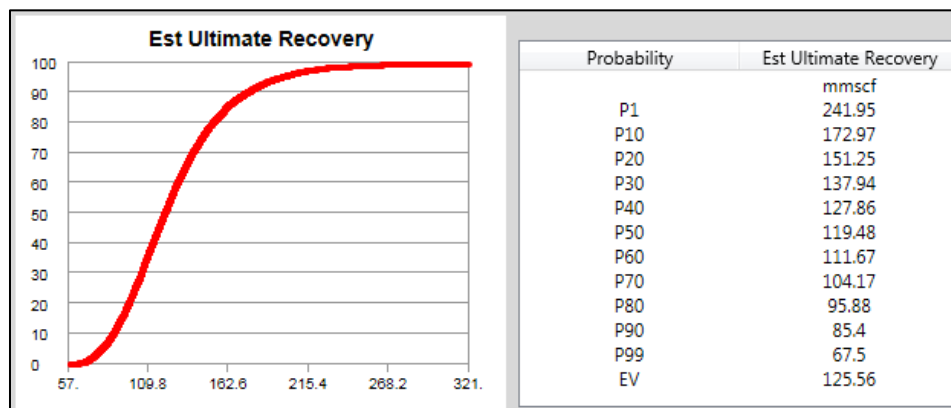


Figure MCD-3: Monte Carlo DC Forecast Tool – Probabilistic Results

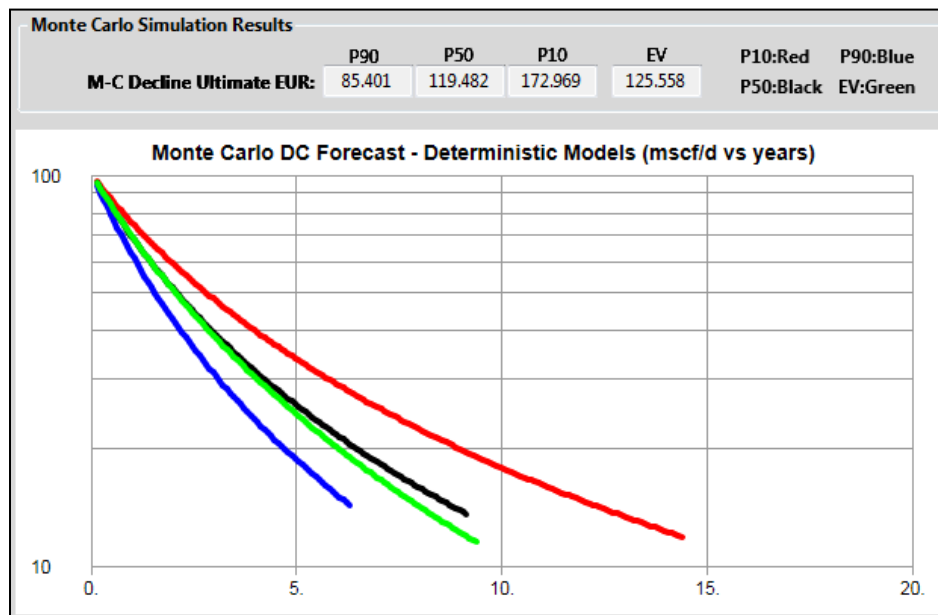


Figure MCD-4: Monte Carlo DC Forecast Tool – Probabilistic Results

A 'Seed' value is included so the same probabilistic result can be re-generated. By entering a specific seed value, the same random Gaussian distribution will be used for the simulation. Entering '-1' for the seed will generate random seed numbers so the results will be different for each simulation run.

The default number of Monte Carlo simulations is 10,000. This gives a relatively smooth probabilistic distribution curve. For slow computers, 1,000 simulations may be acceptable.

During the simulation, a deterministic model is extracted for the P1, P10, P50, P90, P99 and EV realizations (Figure MCD-5). These equivalent models can be used to represent the probabilistic models in deterministic realizations. It should be noted that these values are just one realization for the deterministic values - different values will be generated for each run if Seed=-1.

Deterministic Models						
Prob	EUR	Q-initial	D-initial	Exponent	D-limit	Q-final
P1	241.954	100	0.25	0.77	0.05	11.8
P10	172.969	100	0.31	0.63	0.05	12.1
P50	119.482	100	0.41	0.59	0.05	13.8
P90	85.401	100	0.55	0.55	0.05	14.5
P99	67.501	100	0.5	0.06	0.05	12.4
EV	125.558	100	0.4	0.47	0.05	11.7

	P90	P50	P10	
<b>Forecast Recovery:</b>	85	119	173	<b>mmscf</b>

Figure MCD-5: Monte Carlo DC Forecast Tool – Deterministic Results

'Save Pxx Results to PE Tools dB' will save the EUR results for the P1 to P99 results as well as the deterministic decline curve parameters for P1/P10/P50/P90/P99 and EV realizations (Figure MCD-5). These parameters can then be imported into the PE<sup>2</sup> Essentials Decline Curve Analysis tool to generate forecasts (refer to Section MCD.2).

It is also possible to save the history+forecast and the incremental forecast (when run from the end of the history) to the PE Tools database for use in other PE<sup>2</sup> Essentials tools.

## MCD.2 Monte Carlo DC Forecast Example – Marcellus

This is a continuation of the example presented in Section DCA.9 of the DCA document. The Parameters from the DCA database file were imported into the Monte Carlo DC Forecast tool ('Load DCA dbase') and P90 and P10 values were entered (Figure MCD-6). The DCA database file is 'PE\_Essentials\_DCA\_DataBase\_Marcellus.dvx', located in the "Book Examples\Example Marcellus Example\DCA" directory.

Importing the DCA database file data will also load history.

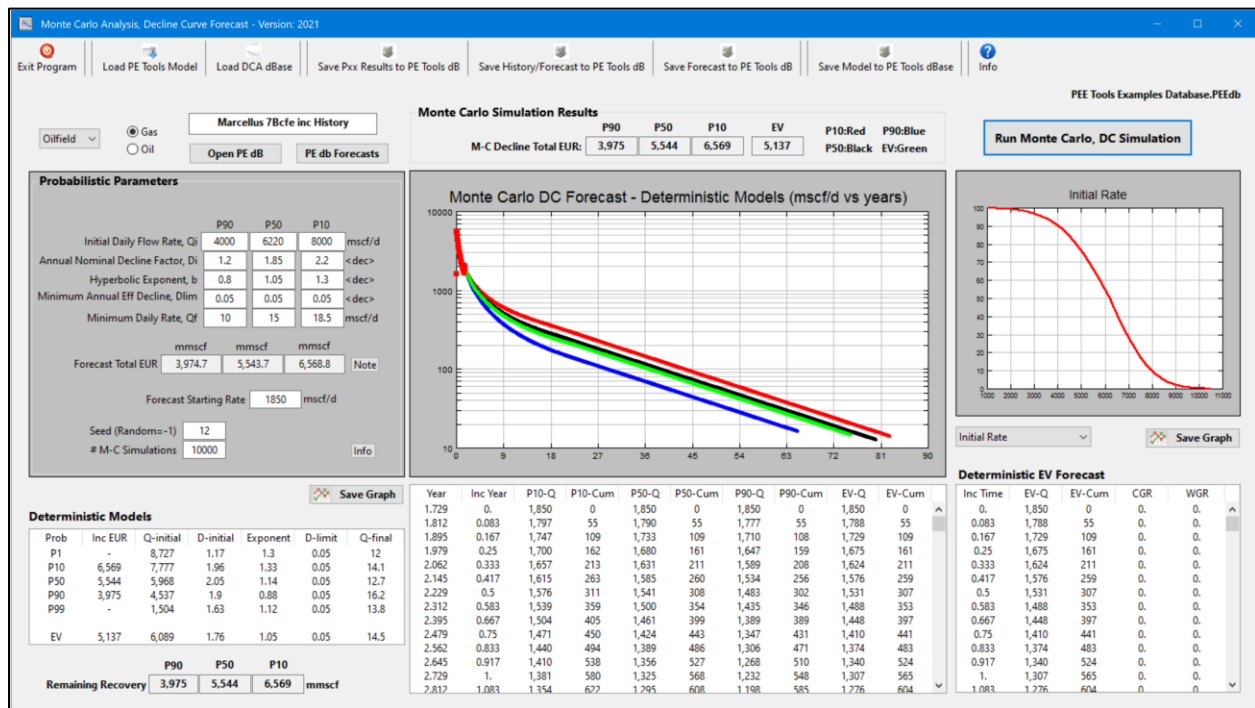


Figure MCD-6: Monte Carlo DC Forecast Tool – Marcellus Analysis

A constant 'Seed' was entered so the forecast could be re-generated and 'Run Monte Carlo DC Simulation' yielded the deterministic and probabilistic results shown in Figure MCD-7.

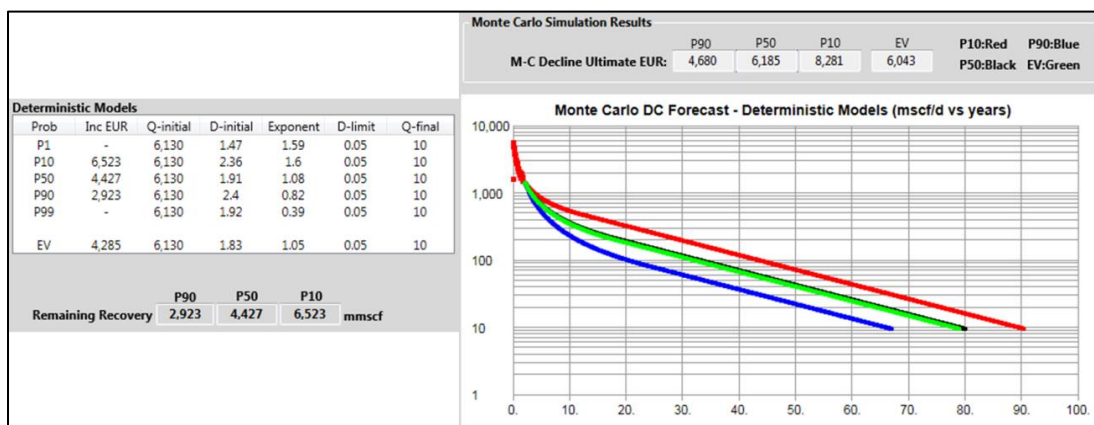


Figure MCD-7: Monte Carlo DC Forecast Tool – Deterministic Results

The results were saved using 'Save Pxx Results to PE Tools dB' and imported into the PE<sup>2</sup> Essentials Decline Curve Analysis tool. The different deterministic realizations were used to generate forecasts with the DCA tool which were then plotted with PE<sup>2</sup> Essentials Chart (Figures MCD-8 and MCD-9) and used for economic analysis.

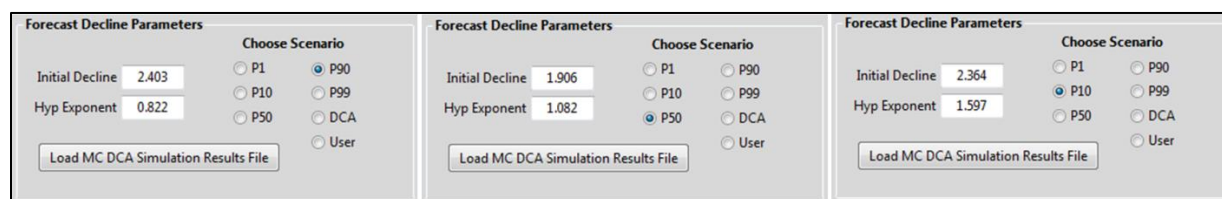
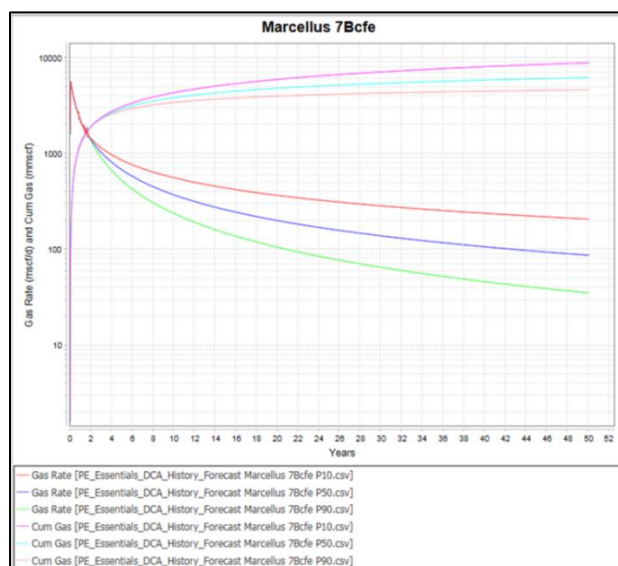


Figure MCD-8: Deterministic Values Imported into DCA Tool


 Figure MCD-9: PE<sup>2</sup> Essentials Chart – Marcellus Forecast Results



## Retrograde Condensate

Retrograde condensate fluid is a gas that has a high dew point pressure such that, at reservoir pressure and temperature conditions, condensate will form in the reservoir as pressure is reduced (Figure RCA-1). It is distinguished by a  $C_{7+}$  mole% value of 12.5 or less.

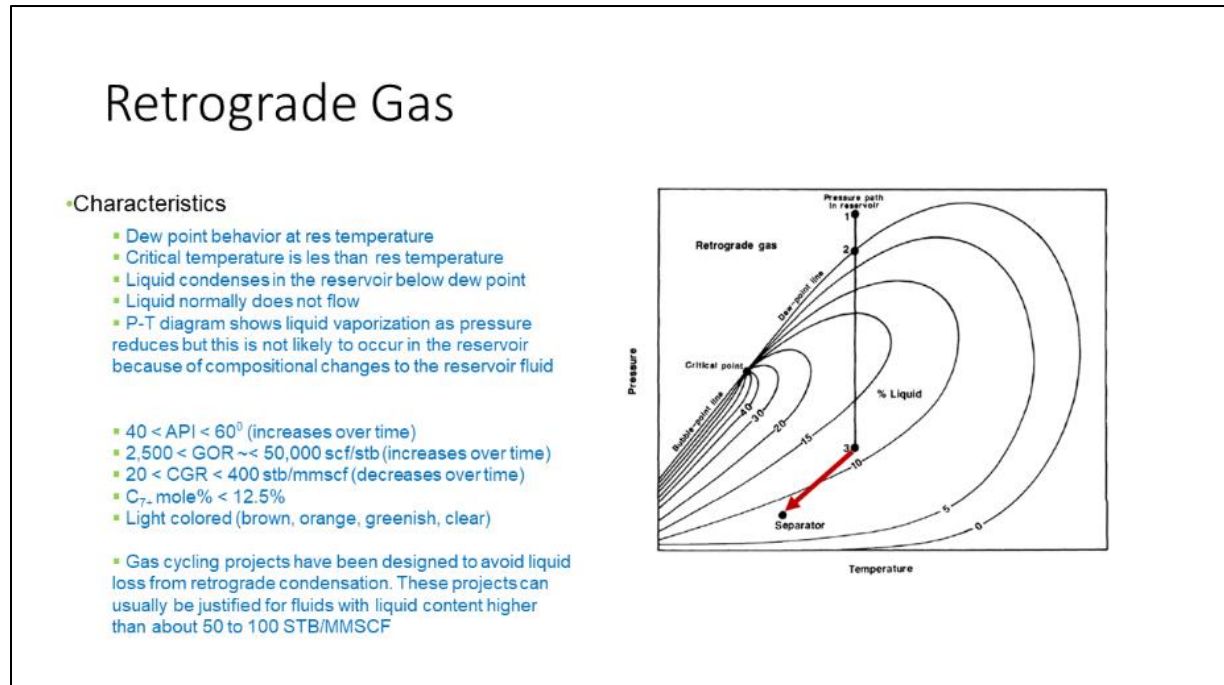
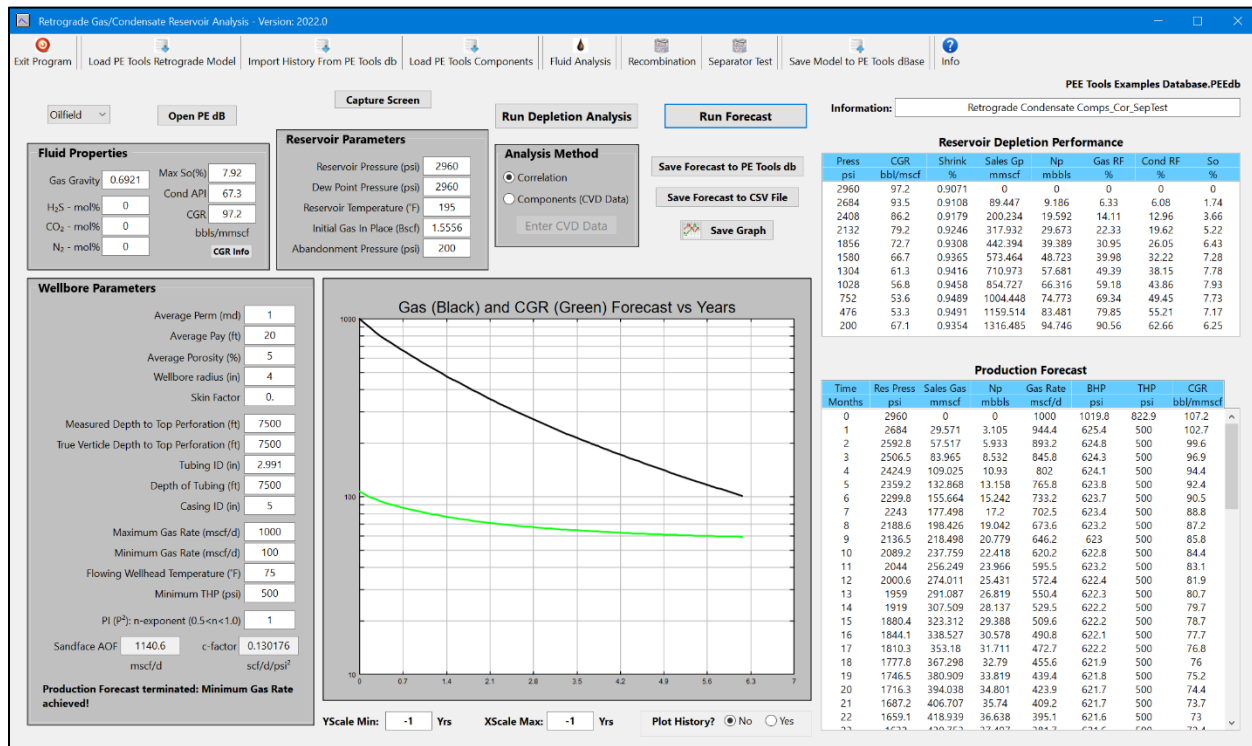


Figure RCA-1: Retrograde Condensate

The Retrograde Condensate tool (Figure RCA-2) is comprised of the following components:

- Reservoir depletion performance
  - Based on correlations; or
  - Based on CVD laboratory data
- Production forecast, which includes relative permeability effects caused by condensate banking
- Retrograde fluid characteristics/analysis using production data
- Gas/Liquid recombination to recombine representative separator fluids to specific production rates
- Separator (flash) tests to evaluate fluid characteristics and help determine optimum separator conditions
- Option to plot historical data on generated forecasts for comparison purposes


 Figure RCA-2: PE<sup>2</sup> Essentials - Retrograde Condensate Analysis Tool

It should be noted that there are a number of correlations incorporated into this tool. Correlations are good for quick estimates but when it comes to a complex system like retrograde condensate, use of laboratory data is preferred. In addition, a compositional simulation is also preferred over analytical forecasts to account for condensate dropout and banking.

The constant volume depletion (CVD) test is the basic laboratory procedure required to define the PVT properties of retrograde condensate systems. A quantity of the reservoir fluid is charged to a visual cell which is maintained at reservoir temperature.

The dew point is determined by visual inspection and the cell pressure is decreased in stages and, at each stage, the expanded fluids are withdrawn from the cell. At each stage of pressure depletion, the volume of liquid condensate deposited in the cell is measured and reported as a fraction of the initial hydrocarbon pore volume and the volume of the gas expelled is measured at both cell and standard conditions.

If the fluid is a dry gas, such that no condensate is deposited, a single-phase Z-factor is determined from material balance calculations. For a retrograde condensate gas, liquid will be deposited in the cell so that the cumulative gas production at each stage of depletion, will be less than for a dry gas. As a result, the calculated Z-factor for a retrograde condensate will be lower than the single-phase value, after pressure falls below the dew point pressure. This reduced Z-factor is termed the 2-phase Z-factor ( $Z_{2p}$ ).

Material balance calculations for a retrograde condensate reservoir require the use of the two-phase Z-factor to account for the fact that liquid condensate is left behind in the reservoir. A correlation was developed for 2-phase Z-factor by Rayes et al (Rayes, D.G., Piper, L.D., McCain, W.D., Poston, S.W., Two-Phase Compressibility Factors for Retrograde Gases, SPE20055, 1992).

The  $Z_{2P}$  value is used for all depletion calculations in retrograde condensate reservoirs. The  $Z_{2P}$  correlation implement in the Retrograde Condensate analysis tool is as follows.

$$Z_{2P} = a + b Pr + c/Tr + d Pr^2 + e/Tr^2 + f Pr/Tr$$

$$Tr = (T + 460) / Tpc$$

$$Pr = P / Ppc$$

$$a = 2.24353$$

$$b = -0.0375281$$

$$c = -3.56539$$

$$d = 0.0000829231$$

$$e = 1.53428$$

$$f = 0.131987$$

Where: T is the reservoir temperature in °F, Tpc is the pseudo reduced temperature in °R, P is pressure in psi, Ppc is the pseudo reduced pressure in psi, and a, b, c, d, e, f are correlation constants.

## RCA.1 Reservoir Depletion Performance

Reservoir depletion characteristics can be estimated through the use of correlations or through the use of laboratory CVD data. Required inputs are a function of the technique used. Regardless of the analysis method chosen, 'Reservoir Parameters' need to be entered (Figure RCA-3).

Reservoir Parameters	
Reservoir Pressure (psi)	2960
Dew Point Pressure (psi)	2960
Reservoir Temperature (°F)	195
Initial Gas In Place (Bscf)	1.5556
Abandonment Pressure (psi)	200

Figure RCA-3: Reservoir Parameter Input

The value of dew point pressure can be set equal to the reservoir pressure but if the gas is "undersaturated", then dew point pressure is less than reservoir pressure and could be estimated using the 'Separator Test' tool (Section RCA.5).

### RCA.1.1 Reservoir Depletion Using Correlations

To use correlations to predict reservoir depletion performance, choose 'Correlations' as the analysis method (Figure RCA-4).

Figure RCA-4: Analysis Method - Correlation

The use of correlations to predict reservoir depletion requires the input of fluid properties (Figure RCA-5).

Figure RCA-5: Reservoir Parameter Input

One of the key input parameters is the value for 'Max  $S_o(\%)$ ' – this is the maximum size of the condensate bank in terms of oil saturation in the reservoir. This data is normally determined by a Constant Volume Depletion (CVD) test in the lab. Without this test data, the value of maximum  $S_o$  can be derived from the historical data (refer to Section RCA.3).

The gas gravity, is normally obtained from a separator gas sample but can also determined using the separator test tool (refer to Section RCA.5).

If a CGR value of -1 is entered then CGR estimates from the internal correlation are used in the reservoir depletion calculations. Entering a specific value for CGR will calibrate the CGR correlation results to the entered value.

A correlation to predict CGR for any pressure was published in 2007 (Ovalle, A.P., Lenn, C.P., and McCain Jr, W.D.; "Tools to Manage Gas/Condensate Reservoirs; Novel Fluid-Property Correlations on the Basis of Commonly Available Field Data", SPE112977, SPE Reservoir Evaluation & Engineering, December, 2007).

This correlation is used in the Retrograde Condensate tool to predict  $CGR_p$ , at, and below, the dew point pressure.

$$CGR_p = 3.684 + 0.61967 Z_t + 0.015359 Z_t^2 \quad (RCA-1)$$

$$Z_1 = 20.809 - 6.7095 \ln(P) + 0.5136 (\ln(P))^2$$

$$Z_2 = 11.175 - 1.2965 API + 0.042311 API^2 - 0.0005438 API^3 + 2.4889e-6 API^4$$

$$Z_3 = -13.365 + 27.652 SG_{res} - 18.598 SG_{res}^2 + 4.3658 SG_{res}^3$$

$$Z_4 = -1.5309 + 0.0058453 T + 1.4035e-6 T^2$$

$$Z_t = Z_1 + Z_2 + Z_3 + Z_4$$

Where:  $CGR_p$  is the condensate-gas-ratio in bbls/mmscf at pressure  $P$  (psi),  $Z_i$  are correlation parameter equations,  $SG_{res}$  is gas specific gravity corrected to reservoir conditions and  $T$  is the reservoir temperature in °F.

For retrograde condensate, the surface  $SG$  can be corrected to reservoir condition,  $SG_{res}$ , using the following equation (Craft, B. C., and Hawkins, M.F., Applied Petroleum Reservoir Engineering, Prentice Hall, Inc. 1959).

$$Mo = 5954 / (^\circ API - 8.8) \quad (RCA-2)$$

$$OilSG = 141.5 / (131.5 + ^\circ API) \quad (RCA-3)$$

$$RS = 1000000 / CGR \quad (RCA-4)$$

$$SG_{res} = \frac{RS SG + 4600 OilSG}{RS + 133300(OilSG/Mo)} \quad (RCA-5)$$

Where:  $Mo$  is molecular weight of oil,  $CGR$  is condensate-gas-ratio in bbls/mmscf,  $API$  is condensate gravity,  $OilSG$  is the oil gravity,  $SG$  is gas gravity.

After all the parameters are entered, click the 'Run Depletion Analysis' button to generate the depletion performance of the reservoir (Figure RCA-6).

Reservoir Depletion Performance							
Press psi	CGR bbl/mscf	Shrink %	Sales Gp mmscf	Np mbbls	Gas RF %	Cond RF %	So %
2960	97.2	0.9071	0	0	0	0	0
2684	93.4	0.9109	98.874	10.14	6.99	6.71	1.74
2408	85.9	0.9183	202.05	19.788	14.24	13.09	3.66
2132	78.6	0.9252	313.169	29.232	21.99	19.33	5.22
1856	71.9	0.9315	432.269	38.429	30.24	25.42	6.43
1580	65.8	0.9373	559.382	47.355	38.99	31.32	7.28
1304	60.4	0.9425	694.538	56.01	48.23	37.04	7.78
1028	55.8	0.9469	837.751	64.443	57.98	42.62	7.93
752	52.5	0.9499	988.956	72.796	68.22	48.14	7.73
476	52.2	0.9502	1147.731	81.516	78.97	53.91	7.17
200	66.3	0.9362	1310.601	93.054	90.07	61.54	6.25

Figure RCA-6: Reservoir Depletion Performance

The  $S_o$  forecast is performed based on the input 'Max  $S_o$ ' and dew point pressure values. The calculation is based on an EPCI developed correlation for the performance of retrograde condensate based on pressure depletion. The calculation is based on normalized pressure and normalized  $S_o$  (Figure RCA-7).

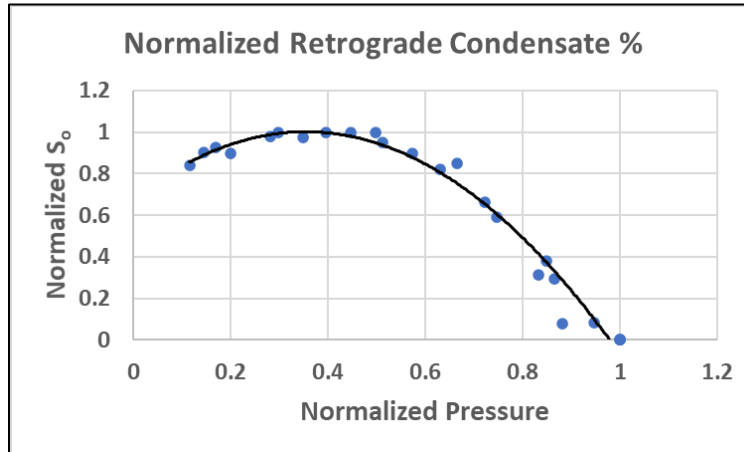


Figure RCA-7: Normalized  $S_o$  Performance Based on Pressure Depletion

$S_o$  is normalized so that the maximum  $S_o$  is normalized to  $\text{Norm}S_o = 1$ . Similarly, the pressure is normalized so that dew point pressure is one,  $\text{Norm}P = 1$  at  $P = P_d$ . The correlation equation is presented below.

$$\text{Norm}S_o = -2.5673 \text{ Norm}P^2 + 1.8222 \text{ Norm}P + 0.6783 \quad (\text{RCA-6})$$

Once  $\text{Norm}S_o$  is determined the value is simply calculated as  $S_o = (\text{Norm}S_o)(\text{max}S_o)$ .

This correlation was based on a limited amount of CVD data and will be updated if more data becomes available.

Another significant calculation for retrograde condensate reservoirs is the shrinkage that occurs because of condensate drop out. Without fluid component information, the following correlation is used to calculate the shrinkage factor.

$$\text{Shrinkage} = \frac{RS/379.4}{(RS/379.4 + 350 \text{ OilSG}/Mo)} \quad (\text{RCA-7})$$

Where:  $RS$  is calculated with Equation RCA-4,  $\text{OilSG}$  is calculated with Equation RCA-3, and molecular weight,  $Mo$ , is calculated with Equation RCA-2.

Equation RCA-7 is the ratio of the moles of net gas ( $RS/379.4$ ) divided by the moles of gas + condensate ( $RS/379.4 + 350 \text{ OilSG}/Mo$ ).

A production forecast can be generated from the reservoir depletion performance.

### RCA.1.2 Reservoir Depletion Performance Using CVD Data

The preferred technique to calculate the depletion performance of a retrograde condensate reservoir is with the use of constant volume depletion (CVD) data. After choosing 'Components (CVD Data)' (Figure RCA-8), click the 'Enter CVD Data' button to open the CVD data screen (Figure RCA-9).

Figure RCA-8: Analysis Method – Using CVD Data

Components at Dew Point		# of Pressures	Constant Volume Depletion Data (CVD) - Below Dew Point Pressure										
CO <sub>2</sub> - mol%	0	5	CVD Test Pressure ----->	2500	2000	1500	1000	500					
N <sub>2</sub> - mol%	0		N <sub>2</sub> - mole%	0	0	0	0	0					
C <sub>1</sub> - mol%	75.2		CO <sub>2</sub> - mole%	0	0	0	0	0					
C <sub>2</sub> - mol%	7.7		C <sub>1</sub> - mole%	78.3	79.5	79.8	79.3	76.8					
C <sub>3</sub> - mol%	4.4		C <sub>2</sub> - mole%	7.7	7.8	7.9	8	8.2					
iC <sub>4</sub> - mol%	3.1		C <sub>3</sub> - mole%	4.3	4.2	4.2	4.3	4.8					
nC <sub>4</sub> - mol%	0		iC <sub>4</sub> - mole%	2.8	2.7	2.7	2.8	3.3					
iC <sub>5</sub> - mol%	2.2		nC <sub>4</sub> - mole%	0	0	0	0	0					
nC <sub>5</sub> - mol%	0		iC <sub>5</sub> - mole%	1.9	1.7	1.6	1.7	2.1					
C <sub>6</sub> - mol%	2.2		nC <sub>5</sub> - mole%	0	0	0	0	0					
C <sub>7+</sub> - mol%	5.2		C <sub>6</sub> - mole%	1.6	1.4	1.3	1.3	1.5					
			C <sub>7+</sub> - mole%	3.4	2.7	2.5	2.6	3.3					
Summation	100		Moles Recovered / Total Moles in Cell (%)	18.5	23.9	35.9	57.5	76.9					
			Liquid %volume deposited (S <sub>o</sub> )	6.6	8.2	7.92	7.09	6.01					
			2-Phase Z-factor	0.794	0.782	0.782	0.779	0.772					
C <sub>7</sub> Plus MW	100.2		Summation	100	100	100	100	100	0	0	0	0	
C <sub>7</sub> Plus SG	0.6882												
Dew Pt Z-factor	0.771												

Figure RCA-9: CVD Data Input

Up to nine CVD data sets along with the data set at the dew point pressure can be entered into the tool. It should be noted that the "Liquid %volume deposited (S<sub>o</sub>)" may be labeled differently but is the S<sub>o</sub> value used in the reservoir depletion calculations

After entry of the CVD data and the reservoir parameters (Figure RCA-3), click the 'Run Depletion Analysis' button to generate the depletion performance of the reservoir (Figure RCA-10).

Reservoir Depletion Performance							
Press psi	CGR bbl/mscf	Shrink %	Sales Gp mmscf	Np mbbls	Gas RF %	Cond RF %	So %
2960	97.2	0.9128	0	0	0	0	0
2500	66.9	0.933	221.27	14.796	15.17	10.72	6.6
2000	55.4	0.9413	449.177	27.425	30.64	19.87	8.2
1500	51.7	0.9438	697.554	40.263	47.44	29.18	7.92
1000	53.6	0.942	950.177	53.804	64.55	38.99	7.09
500	66.9	0.9318	1179.181	69.128	80.27	50.1	6.01

Figure RCA-10: Reservoir Depletion Performance

A production forecast can be generated from the reservoir depletion performance.

## RCA.2 Production Forecasting

The conversion of the reservoir depletion performance to a time-based production forecast requires the input of wellbore parameters (Figure RCA-11).

**Wellbore Parameters**

Average Perm (md)

1

Average Pay (ft)

20

Average Porosity (%)

5

Wellbore radius (in)

4

Skin Factor

0.

Measured Depth to Top Perforation (ft)

7500

True Vertical Depth to Top Perforation (ft)

7500

Tubing ID (in)

2.991

Depth of Tubing (ft)

7500

Casing ID (in)

5

Maximum Gas Rate (mscf/d)

1000

Minimum Gas Rate (mscf/d)

100

Flowing Wellhead Temperature (°F)

75

Minimum THP (psi)

500

PI (P<sup>2</sup>): n-exponent (0.5 < n < 1.0)

1

Sandface AOF

1141.1

mscf/d

c-factor

0.130235

scf/d/psi<sup>2</sup>

**Production Forecast terminated: Minimum Gas Rate achieved!**

Figure RCA-11: Production Forecast – Wellbore Parameters



The inputs for wellbore parameters are straightforward and include reservoir parameters, completion parameters and production parameters. Production forecasting utilizes the following sandface productivity equation.

$$Q = c(P_i^2 - P_{wf}^2)^n \quad (\text{RCA-7})$$

Where Q is gas rate, c is the productivity index (scfpd/psi<sup>2</sup>), P<sub>i</sub> is the declining reservoir pressure, P<sub>wf</sub> is the bottomhole flowing pressure and n is the turbulence factor (no turbulence = 1, maximum turbulence = 0.5).

Once the value for n is entered, the value of the c-factor and corresponding sandface absolute open flow potential (AOF) for the well are shown.

The c-factor is calculated assuming a radial reservoir with the radius of the reservoir calculated as follows.

$$\text{Radius} = (\text{GIIP } B_g / (\pi \text{ Pay Porosity } S_g))^{1/2} \quad (\text{RCA-8})$$

Where Radius is in feet, GIIP is in scf, B<sub>g</sub> is formation volume factor in ft<sup>3</sup>/scf, Pay is in feet, Porosity is in decimal and gas saturation (S<sub>g</sub>) is in decimal. Note for simplicity, S<sub>g</sub> is assumed to be 0.8 for this calculation.

After calculating the radius of the reservoir, the c-factor is calculated from the stabilized flow equation.

$$\text{c-factor} = \frac{1000 \text{ Perm } k_{rg} \text{ Pay}}{1422 \mu_g Z (T+460) (\log(\text{Radius}/r_w) - 0.75 + S)} \quad (\text{RCA-9})$$

$$k_{RG} = (1 - S_o)^3$$

Where c-factor is the productivity index (scfpd/psi<sup>2</sup>), Perm is permeability, Pay is in feet, μ<sub>g</sub> is gas viscosity (cp), Z is gas deviation factor, T is temperature in °F, r<sub>w</sub> is the wellbore radius in feet, S is the skin factor and k<sub>rg</sub> is the relative permeability based on the condensate saturation, S<sub>o</sub>. The 1000 converts the c-factor to scfpd/psi<sup>2</sup>.

Production rate is controlled by tubing head pressure (THP) and maximum/minimum rate constraints. The Guo and Ghalambor tubing correlation is used for wellbore pressure drop calculations. This correlation was used because it is optimized for mist flow conditions.

In 2005 Guo and Ghalambor developed a four-phase (gas-oil-water-sand) pressure drop model (Guo, B. and Ghalambor, Natural gas Engineering Handbook, Gulf Publishing Company, 2005). The model was an extension of the original formulation by Guo for coal bed methane wells. The solution is a complex equation that requires iteration to solve. The model can include sand production which can occur in a hydraulically fractured well but is ignored in this implementation.

It should be noted that the Guo-Ghalambor model is a no-slip model which limits its validity to mist flow. As a result, it is not valid for gas wells that produce significant water.

$$a(\cos\phi + d^2e)MD = 144b(P_1 - P_2) + X_1 - X_2 \quad (\text{RCA-10})$$

$$X_1 = (0.5 - bM) \ln\{[(144P_1 + M)^2 + N]/[(144P_2 + M)^2 + N]\}$$

$$X_2 = M + bN/c - bM^2N^{-0.5} \{\tan^{-1}[(144P_1 + M)N^{-0.5}] - \tan^{-1}[(144P_2 + M)N^{-0.5}]\}$$

$$a = (0.0765 SG_g Q_g + 350 SG_o Q_o + 350 SG_w Q_w + 62.4 SG_s Q_s) / (4.07 T_a Q_g)$$

$$b = (5.615 Q_o + 5.615 Q_w + Q_s) / (4.07 T_a Q_g)$$

$$c = 1.2431 T_a Q_g / ID^2$$

$$d = 0.30436 (5.615 Q_o + 5.615 Q_w + Q_s) / ID^2$$

$$e = 0.18651 f_m / ID$$

$$f_m = [1.74 - 2 \log(2\delta / ID)]^{-2}$$

$$M = cde / (\cos\phi + d^2e)$$

$$N = c^2 e \cos\phi / (\cos\phi + d^2e)^2$$

$$T_a = T_{fa} = 460$$

Where:  $P_1$  is bottomhole pressure in psia,  $P_2$  is tubing head pressure in psia,  $\phi$  is the well angle measured from the vertical,  $Q_g$  is gas rate in scf/d,  $Q_o$  is oil rate in bbl/d,  $Q_w$  is water rate in bbl/d,  $Q_s$  is sand rate in ft<sup>3</sup>/d,  $SG_g$  is gas specific gravity,  $SG_o$  is oil specific gravity,  $SG_w$  is water specific gravity,  $SG_s$  is sand specific gravity,  $T_a$  is average temperature in °R for the depth increment and ID is pipe ID in inches and  $T_{fa}$  is average temperature in °F.

The wellbore pressure drop is solved using an iterative process where an estimate of the unknown pressure is made and then modified until the left-hand side of Equation RCA-9 equals the right-hand side.

The resulting production forecast includes gas and condensate volumes (Figure RCA-12). History data can be imported and included on the production plot for comparison by importing the production data from the PE Tools database and clicking the 'Yes' button for 'Plot History'. The forecast can be saved to a CSV file or the PE Tools database by clicking the appropriate button.

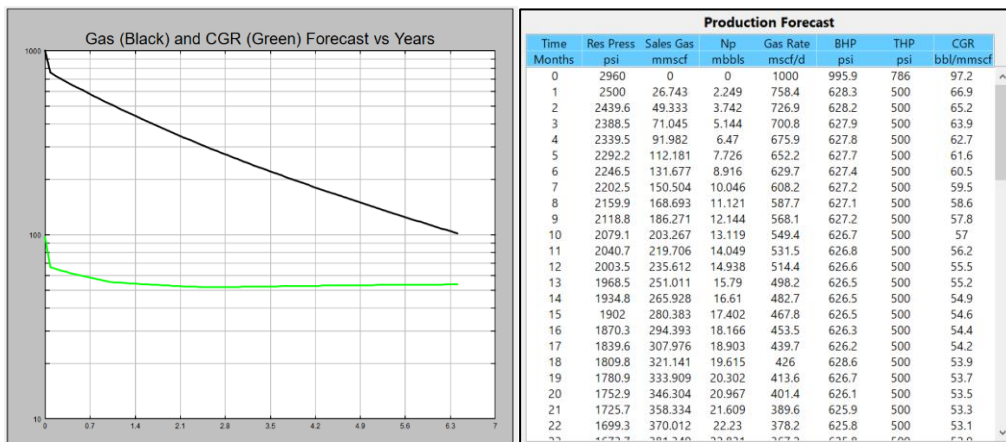


Figure RCA-12: Production Forecast

### RCA.3 Retrograde Fluid Analysis

When CVD data is not available it is possible to extract the parameters from the historical production data using correlations. Click 'Fluid Analysis' and select a well from the database (Figure RCA-13).

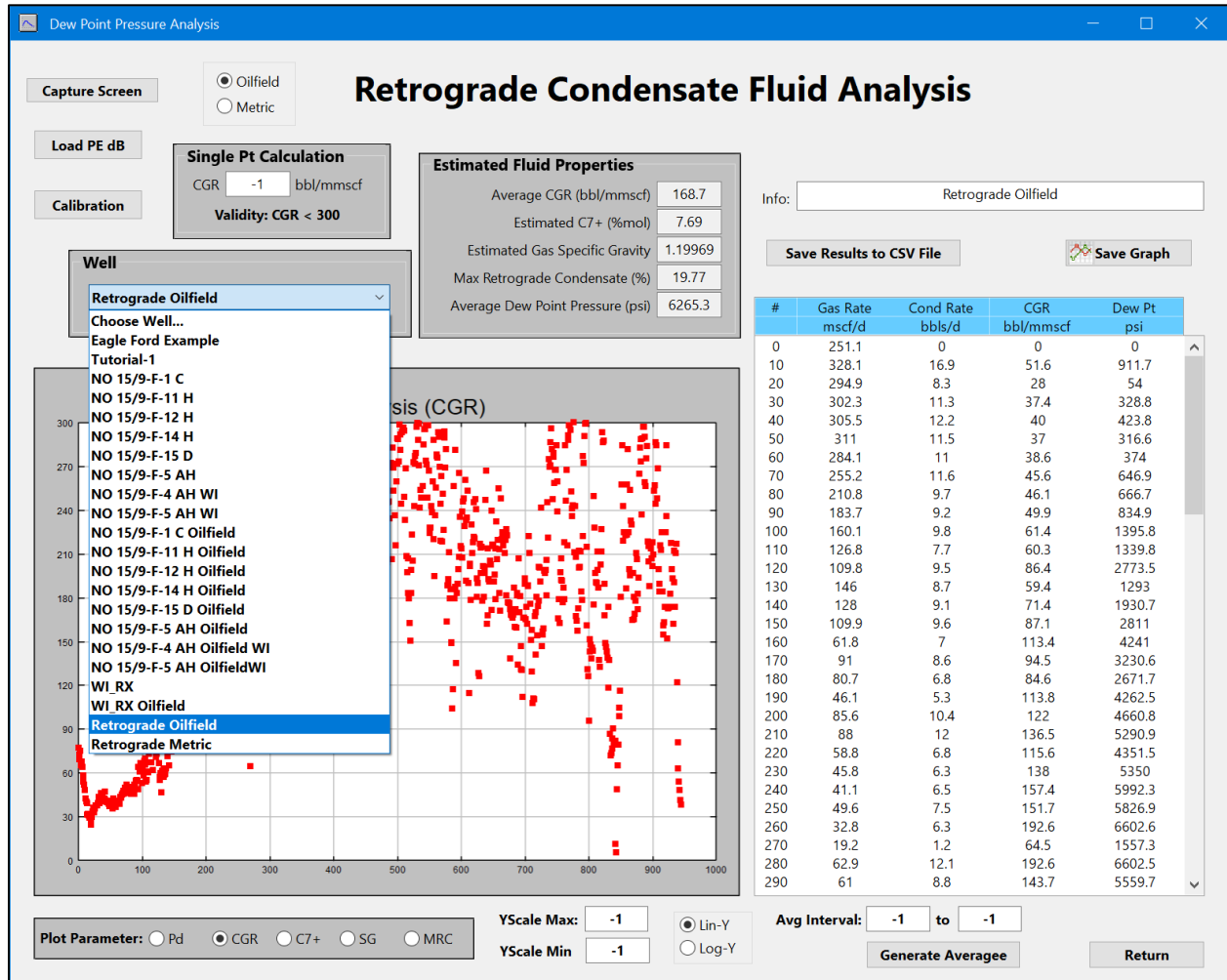


Figure RCA-13: Fluid Analysis

Once the well is selected, the data is loaded into the tool and fluid parameters (Figure RCA-14) are estimated using correlations based on CGR. The calculated parameters include dew point pressure, mole% of C7+, specific gravity of the reservoir fluid and maximum condensate banking (MRC or maxSo).



Figure RCA-14: Fluid Analysis Plot Parameters

The correlations are based on work published by Paredes, Perez and Perera (Paredes, J.E., Perez, R. and Perera, L.M; Correlations to Estimate Key Gas Condensate Properties through Field Measurement of Gas Condensate Ratio, SPE-170601-MS, 2014).

There were some issues associated with the published correlations. Valid dew point pressures were limited to CGR's in the range of 80 to 150. The Pd correlation was modified to extend the CGR range from 10 to 300. In addition, not all of the correlations presented in the reference were in terms of CGR so modifications were also incorporated to recast them all in terms of CGR.

The final correlations implemented in the Retrograde Condensate tool are as follows. It should be noted that calculations are limited to CGR's less than 300 bbl/mmscf.

- Correlation for Mole% C<sub>7+</sub>:

$$C_{7+} = a \text{ CGR}^b \quad (\text{RCA-11})$$

$$a = 0.11711$$

$$b = 0.8161$$

- Correlation for Reservoir Gas SG:

$$\text{MW} = (a \text{ CGR}^4 + b \text{ CGR}^3 + c \text{ CGR}^2 + d \text{ CGR} + e) / 28.964 \quad (\text{RCA-12})$$

$$a = 3.8 \times 10^{-9}$$

$$b = -2.7109 \times 10^{-6}$$

$$c = 0.00047587$$

$$d = 0.089608$$

$$e = 16.023$$

- Correlation for MRC (%) (MaxS<sub>o</sub>):

$$\text{MRC} = a \text{ CGR}^4 + b \text{ CGR}^3 + c \text{ CGR}^2 + d \text{ CGR} + e \quad (\text{RCA-13})$$

$$a = -1.5532 \times 10^{-9}$$

$$b = 1.3269 \times 10^{-6}$$

$$c = -0.0004405$$

$$d = 0.17311$$

$$e = -2.0095$$

- Correlation for Dew Point Pressure (psi):

$$\text{Pd} = a \text{ CGR}^4 + b \text{ CGR}^3 + c \text{ CGR}^2 + d \text{ CGR} \quad (\text{RCA-14})$$

$$a = 9.34 \times 10^{-6}$$

$$b = -0.005882$$

$$c = 1.09$$

$$d = -24.19$$

Refer to the reference for the original correlations. Figure RCA-15 presents the results for an example well from the PE Essentials PE Tools example database.

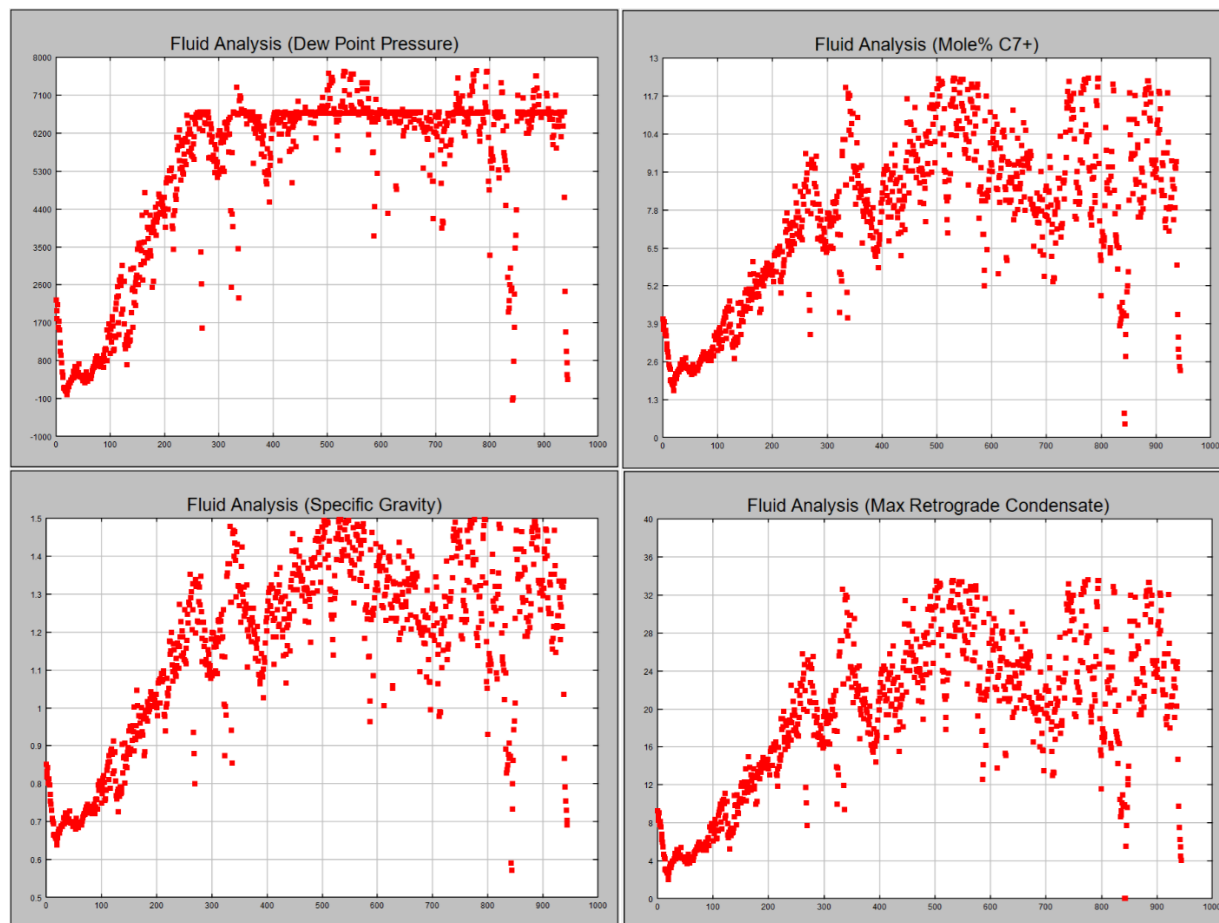


Figure RCA-15: Fluid Analysis Plots

The average for a specific interval can be calculated by setting the interval in 'Avg. Interval'. Values for a given CGR can be calculated by entering the value in 'Single Pt Calculation'. To regenerate the average results, click the 'Generate Average' button with '-1' for the interval.

If parameters for a given CGR are known, the calculations can be calibrated by clicking 'Calibration' (Figure RCA-16).

Figure RCA-16: Calibrate Fluid Parameters

## RCA.4 Fluid Recombination

Obtaining representative reservoir samples from a retrograde condensate reservoir can be difficult. To assist with performing analysis of the retrograde condensate reservoir, a gas-condensate recombination tool (Figure RCA -17) is included in the Retrograde Condensate tool.

**Oil/Gas Recombination**

**Separator Fluids**

	Liquid	Gas
CO2 - mol%	0	0
N2 - mol%	0	0
C1 - mol%	0.113	84.331
C2 - mol%	0.445	8.139
C3 - mol%	2.698	3.976
iC4 - mol%	6.418	2.225
nC4 - mol%	0	0
iC5 - mol%	12.424	0.918
nC5 - mol%	0	0
C6 - mol%	19.769	0.382
C7+ - mol%	58.132	0.03
Σ Comps	100	100
C7+ MW	114	114
C7+ SG	0.755	0.755

Oil Rate: 100.1 bopd  
Gas Rate: 1000 mscf/d

**Recombined Fluid**

CO2 - mol%	0
N2 - mol%	0
C1 - mol%	76.462
C2 - mol%	7.42
C3 - mol%	3.857
iC4 - mol%	2.617
nC4 - mol%	0
iC5 - mol%	1.993
nC5 - mol%	0
C6 - mol%	2.193
C7+ - mol%	5.459
C7+ MW	114
C7+ SG	0.755

Buttons: Recombine Fluids, Transfer to Separator, Screen Capture, Cancel

Figure RCA-17: Gas-Condensate Recombination

This tool enables the use of an offset well's gas and condensate analysis when samples are not available for the well of interest. The recombination can be performed using the CGR from the well of interest. From Figure RCA-17, the well CGR was 100.1 bbls/mmscf.

Following the recombination, the recombined fluid can be transferred to the Separator test tool by clicking the 'Transfer to Separator' button for evaluation of optimum operating conditions.

## RCA.5 Separator Test

A separator (flash) tool is included in the Retrograde Condensate tool to evaluate and optimize separator operating conditions (Figure RCA-18). Up to four operating conditions can be evaluated at the same time.

**Separator (Flash) Testing**

Save Comps to PE Tools dB

**Recombined Fluid**

CO <sub>2</sub> - mol%	0
N <sub>2</sub> - mol%	0
C <sub>1</sub> - mol%	75.2
C <sub>2</sub> - mol%	7.7
C <sub>3</sub> - mol%	4.4
iC <sub>4</sub> - mol%	3.1
nC <sub>4</sub> - mol%	0
iC <sub>5</sub> - mol%	2.2
nC <sub>5</sub> - mol%	0
C <sub>6</sub> - mol%	2.2
C <sub>7+</sub> - mol%	5.2
<b>Summation</b>	<b>100</b>
C <sub>7</sub> Plus MW	114
C <sub>7</sub> Plus SG	0.755

**Reservoir Fluid: Results**

Dew Pt Pressure	3195.8
Reservoir CGR	66.8
Reservoir SG	0.7804
Condensate API	58.9

**Reservoir Parameters**

Reservoir Pressure (psi)	195
Reservoir Temperature (°F)	195

**Run Separator Tests**

Information: Separator Testing

Separator Press: 1500, Separator Temp: 75

Comps	Sep Gas	Cond
%CO <sub>2</sub>	0	0
%N <sub>2</sub>	0	0
%C <sub>1</sub>	85.668	0.164
%C <sub>2</sub>	7.659	0.404
%C <sub>3</sub>	3.464	1.917
%iC <sub>4</sub>	1.892	4.484
%nC <sub>4</sub>	0	0
%iC <sub>5</sub>	0.835	10.157
%nC <sub>5</sub>	0	0
%C <sub>6</sub>	0.43	19.13
%C <sub>7+</sub>	0.052	63.744

Sep CGR: 91.5, Sep Gas SG: 0.6803, Cond API: 65.2

Separator Press: 1000, Separator Temp: 75

Comps	Sep Gas	Cond
%CO <sub>2</sub>	0	0
%N <sub>2</sub>	0	0
%C <sub>1</sub>	85.348	0.139
%C <sub>2</sub>	7.87	0.426
%C <sub>3</sub>	3.617	2.283
%iC <sub>4</sub>	1.952	5.441
%nC <sub>4</sub>	0	0
%iC <sub>5</sub>	0.809	11.478
%nC <sub>5</sub>	0	0
%C <sub>6</sub>	0.369	19.65
%C <sub>7+</sub>	0.036	60.583

Sep CGR: 96.2, Sep Gas SG: 0.6811, Cond API: 66.3

Separator Press: 500, Separator Temp: 75

Comps	Sep Gas	Cond
%CO <sub>2</sub>	0	0
%N <sub>2</sub>	0	0
%C <sub>1</sub>	84.331	0.113
%C <sub>2</sub>	8.139	0.445
%C <sub>3</sub>	3.976	2.698
%iC <sub>4</sub>	2.225	6.418
%nC <sub>4</sub>	0	0
%iC <sub>5</sub>	0.918	12.424
%nC <sub>5</sub>	0	0
%C <sub>6</sub>	0.382	19.769
%C <sub>7+</sub>	0.03	58.132

Sep CGR: 100.1, Sep Gas SG: 0.6921, Cond API: 67.3

Separator Press: 0, Separator Temp: 0

Comps	Sep Gas	Cond
%CO <sub>2</sub>		
%N <sub>2</sub>		
%C <sub>1</sub>		
%C <sub>2</sub>		
%C <sub>3</sub>		
%iC <sub>4</sub>		
%nC <sub>4</sub>		
%iC <sub>5</sub>		
%nC <sub>5</sub>		
%C <sub>6</sub>		
%C <sub>7+</sub>		

Sep CGR: 0, Sep Gas SG: 0, Cond API: 0

Continue

Figure RCA-18: Separator Test

The separator tool performs a single stage flash to separator conditions followed by a flash to the stock tank (15psi, 60 °F) and reports the results.

Dew point pressure is calculated as the average of the following three models. It was found that averaging the three correlations counterbalances the inherent limitations of each model.

Model 1 was developed by Ahmadi and Elsharkway (Ahmadi,A.A; Elsharkway, A., “Robust correlation to predict dew point pressure of gas condensate reservoirs”, Southwest Petroleum University, KeAi Communications Co Ltd, 2016).

$$Pd = -888.278 - 3.60639 \times C_1 T + 0.00785623 T^2 + 1467.87 \times C_1 + 0.989073 c \quad (\text{RCA-15})$$

$$a = 29014 - 52127.9 \times C_1 + 79848.3 \times C_1 SG_{C7+}^3 + 12633.6 \times C_1 \times C_7^{1/3} + 11116.5 \times C_1^2 - 58526.6 SG_{C7+}^3 + 58263.6 \times C_7^{1/3} SG_{C7+}^3 - 43792.7 \times C_7^{2/3}$$

$$b = -6991.4 + 0.00165952 MW_{C7+}^3 - 0.00122815 \times C_7^{1/3} MW_{C7+}^3 - 5.7182 \times 10^{-11} MW_{C7+}^6 - 79241 \times C_4^{1/3} \times C_7^{1/3} + 31517.4 \times C_4^{2/3} + 50917.8 \times C_7^{1/3} - 31614.2 \times C_7^{2/3}$$

$$c = 140.909 - 0.484983 b \times N_2^{1/3} + 0.576219 a \times N_2^{1/3} + 1746.2 \times N_2^{2/3} + 0.290811 b \\ + 3.33869 \times 10^{-5} b^2 + 0.484502 a$$

Where: Pd is the dew point pressure in psia, T is temperature in °F, SG<sub>C7+</sub> is the specific gravity of the C<sub>7+</sub> component, MW<sub>C7+</sub> is the molecular weight of C<sub>7+</sub> component and all component values (xC<sub>1</sub>, xC<sub>2</sub>, etc) are in decimal mole.

Model 2 was presented by Aghamiri, Tamtaji and Ghafoori (Aghamiri,S.; Tamtaji,M.; and Ghafoori,M.J., “Developing a K-value equation for predict [sic] dew point pressure of gas condensate reservoirs at high pressure”, KeAi Communications Co Ltd, 2018).

$$P_d = P_k^{((1+2*\beta)/(1+3*\beta))} / \text{Denom}^{(1/(1+3*\beta))} \quad (\text{RCA-16})$$

$$P_k = -2381.8542 + 46.341487 * M_{SG} + 6124.3049 * M_{SG}/T - 2753.2538 * (M_{SG}/T)^2 + \\ 415.42049 * (M_{SG}/T)^3$$

$$M_{SG} = MW_{C7+} SG_{C7+}$$

$$\beta = (T_{b\_mix}/T)^{(T/T_{c\_mix})}$$

$$T_{b\_mix} = \sum_i [T_{b_i}]$$

$$T_{c\_mix} = \sum_i [T_{c_i}]$$

$$\text{Denom} = \sum_i [ (0.01 * X_i) / (P_{c_i}^{\beta} * \exp(5.37 * \beta * (1 + \omega_i)) * (1 - T_{c_i}/T))] ]$$

Where the subscript i denotes the different components, X<sub>i</sub> is in mole%; T, T<sub>c</sub> and T<sub>b</sub> are in °R; and P<sub>c</sub> and P<sub>d</sub> are in psi

Model 3 was developed by Elsharkway (Elsharkway, A.M., “Predicting the dew point pressure for gas condensate reservoirs: empirical models and equations of state”, Kuwait University, 2001).

$$P_d = a_0 + a_1 + a_2 + a_3 + a_4 + a_5 + a_6 + a_7 + a_8 + a_9 + a_{10} + a_{11} \\ + a_{12} + a_{13} + a_{14} + a_{15} + a_{16} + a_{17} + a_{18} \quad (\text{RCA-17})$$

$$a_0 = 4268.85$$

$$a_1 = 0.094056 T$$

$$a_2 = -7157.87 x_{H_2S}$$

$$a_3 = -4540.58 x_{CO_2}$$

$$a_4 = -4663.55 x_{N_2}$$

$$a_5 = -1357.56 x_{C_1}$$

$$a_6 = -7776.10 x_{C_2}$$

$$a_7 = -9967.99 x_{C_3}$$

$$a_8 = -4257.10 x_{C_4}$$

$$a_9 = -1417.10 x_{C_5}$$



$$\begin{aligned}
 a_{10} &= 691.5298 \times C_6 \\
 a_{11} &= 40660.36 \times C_7 \\
 a_{12} &= 205.26 \text{ MW}_{C_7+} \\
 a_{13} &= -7260.32 \text{ SG}_{C_7+} \\
 a_{14} &= -352.413 \times C_7 \text{ MW}_{C_7+} \\
 a_{15} &= -114.519 \text{ MW}_{C_7+} / \text{SG}_{C_7+} \\
 a_{16} &= 8.133 \times C_7 \text{ MW}_{C_7+} / \text{SG}_{C_7+} \\
 a_{17} &= 94.916 \times C_7 / (x_{C1} + x_{C2}) \\
 a_{18} &= 238.252 \times C_7 / (x_{C2} + x_{C3} + x_{C4} + x_{C5} + x_{C6})
 \end{aligned}$$

Where: Pd is the dew point pressure in psia, T is temperature in °F,  $\text{SG}_{C_7+}$  is the specific gravity of the  $C_7+$  component,  $\text{MW}_{C_7+}$  is the molecular weight of  $C_7+$  component and all component values ( $x_{C1}$ ,  $x_{C2}$ , etc) are in decimal mole.

Figure RCA-19 presents the results of the three correlations and the averaging.

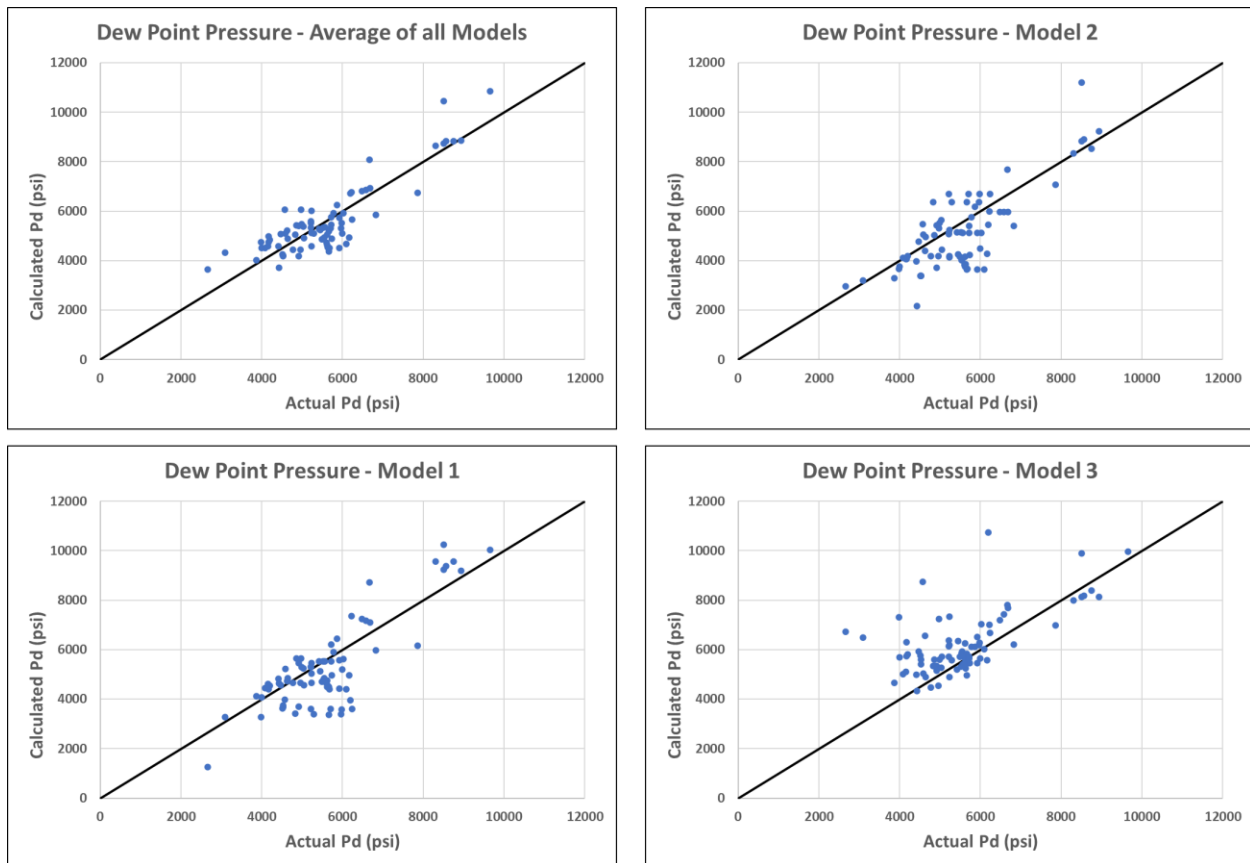


Figure RCA-19: Dew Point Pressure Correlations

## Type Curve Generation Tool

A type curve is a representation of the historical and/or future behavior for a group of wells. The question always arises of whether a type curve should be considered to be representative of the performance of future wells. Something that should always be considered when building a type curve is that the SPEE (SPEE Monographs 3 and 4) states that 50 - 100 wells may be required to generate a high confidence type curve.

The PE Essentials Type Curve Generation tool (Figure TCG-1) enables the rapid generation of a number of type curves that can be evaluated for the most appropriate type curve to use.

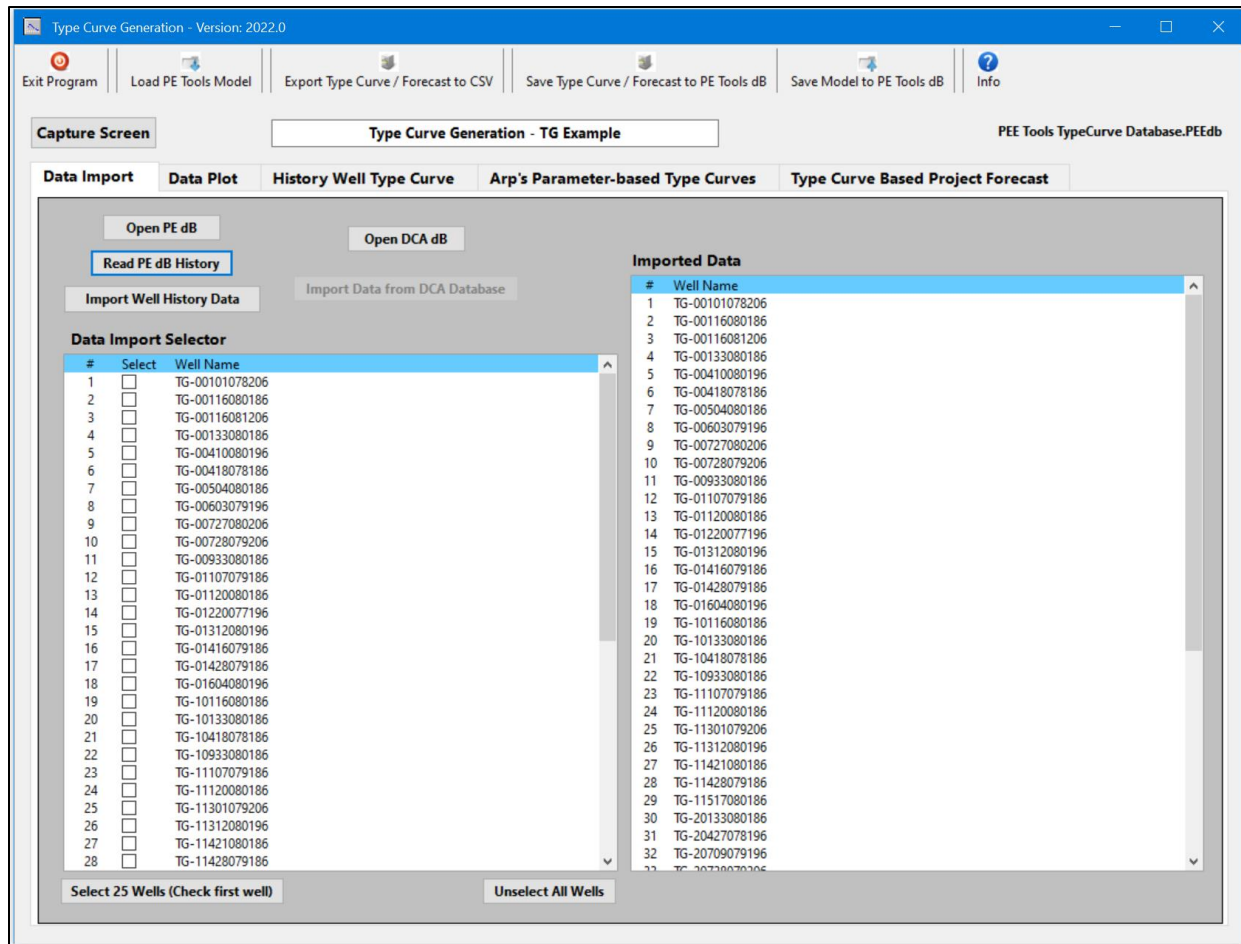


Figure TCG-1: PE<sup>2</sup> Essentials Type Curve Generation Tool

Type Curves can be generated as follows:

- Average of historical data
- P90/P50/P10 curves based on historical data
- P90/P50/P10 of DCA forecasts
- P90/P50/P10 curves based on Arps parameters
- Smoothed type curves (useful for noisy history data)

After the type curves have been built, a project-based forecast can be generated using any number of wells and type curves. Start-up delays can also be incorporated into the forecast. The forecast can be saved to the PE Tools dbase for use in the economics tools.

Note that the files used for the examples below are included in the directory: “PE Essentials 2022\Book Examples\Example Type Curve Generation”.

### TCG.1 Data Import

There are three ways to import data into the type curve tool: from the PDA tool (Figure TCG-2); from a standalone DCA database (dvx file – Figure TCG-3)); or, an Excel file containing Arps parameters (Figure TCG-4). Refer to ‘Arps Parameters.xlsx’ for an example Excel file containing Arps parameters for importing into the tool.

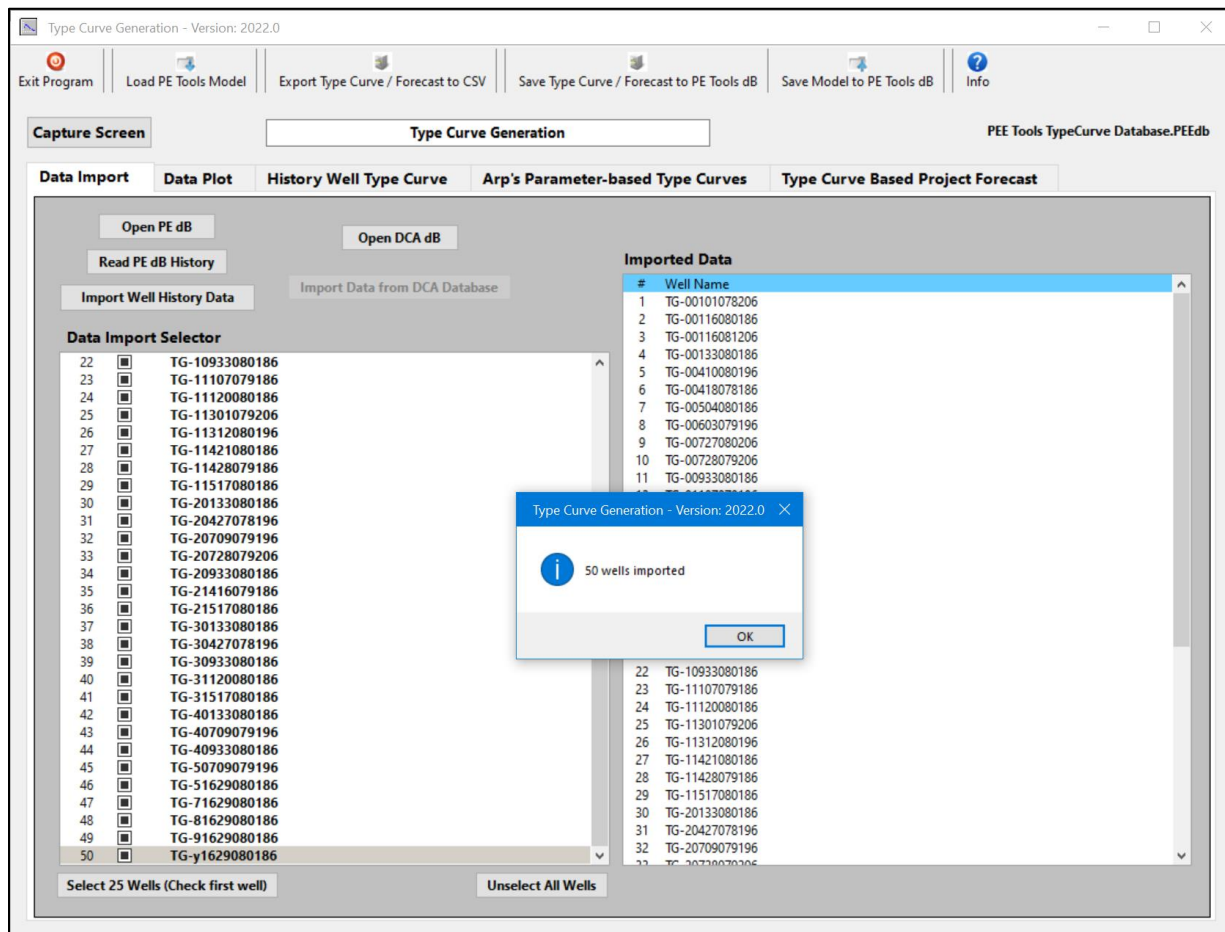


Figure TCG-2: Import History Data from PE Tools dbase

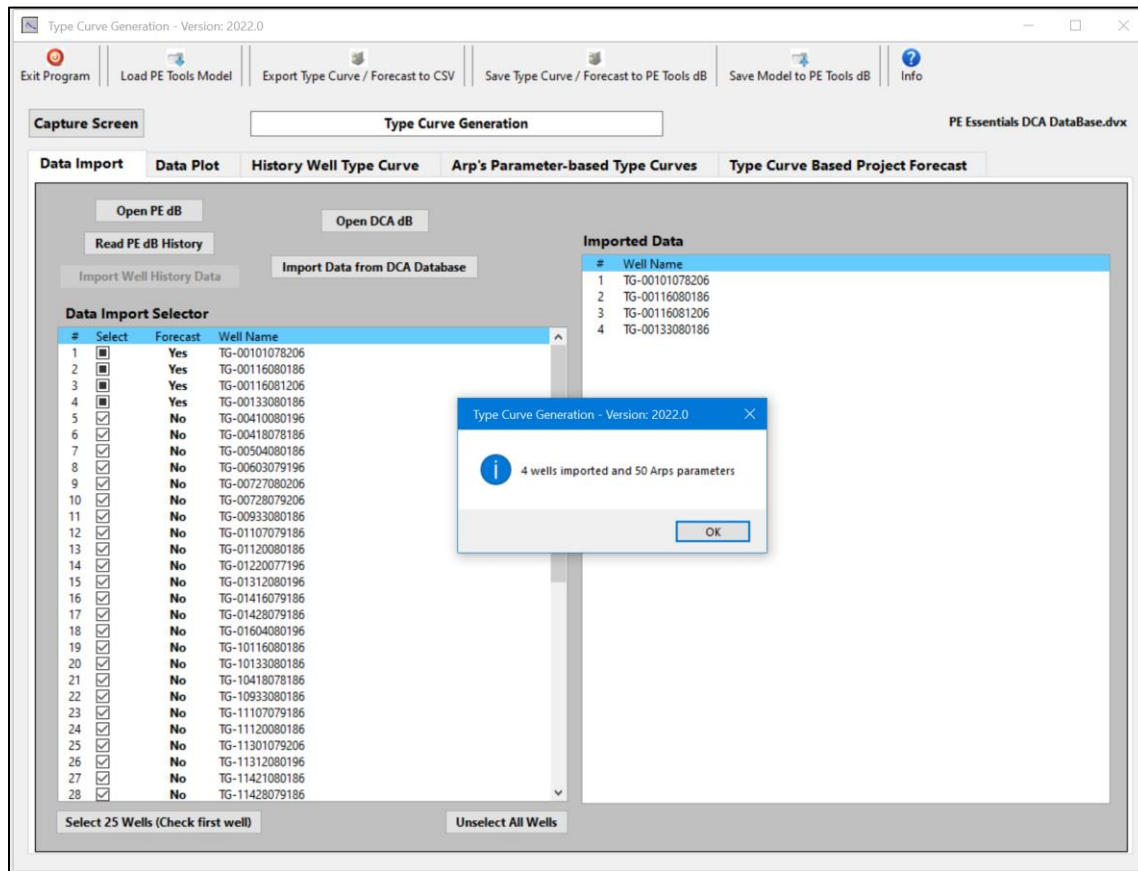


Figure TCG-3: Import DCA Forecast Data and Arps Parameters from a DCA dbase

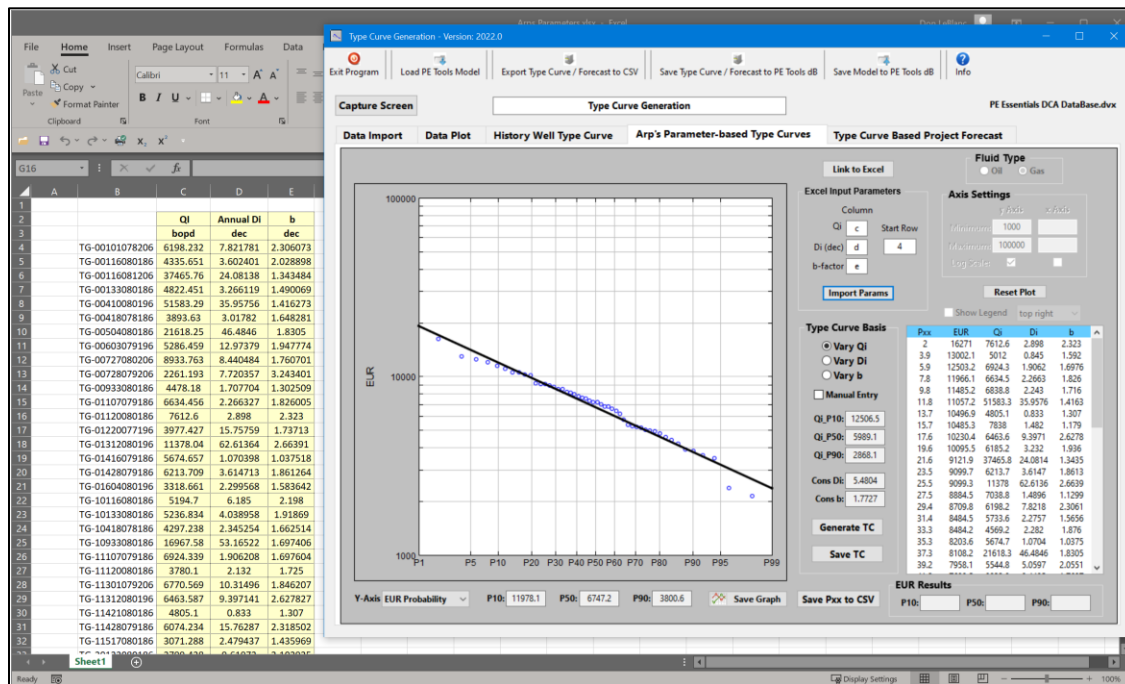


Figure TCG-4: Import Arps Parameters from an Excel file

Note that when importing from a DCA database, flow rate data for wells that include a forecast will be imported. The Arps parameters will be imported for all of the selected DCA wells,

It is possible to add wells to the type curve list by opening a new PE Tools database or DCA database and importing the well data.

Specific wells can be deleted from the well list (from the 'Data Plot' tab), including calculated type curves (Figure TCG-5). Prior to deleting the well, confirmation will be required. Note - only one well can be deleted at a time.

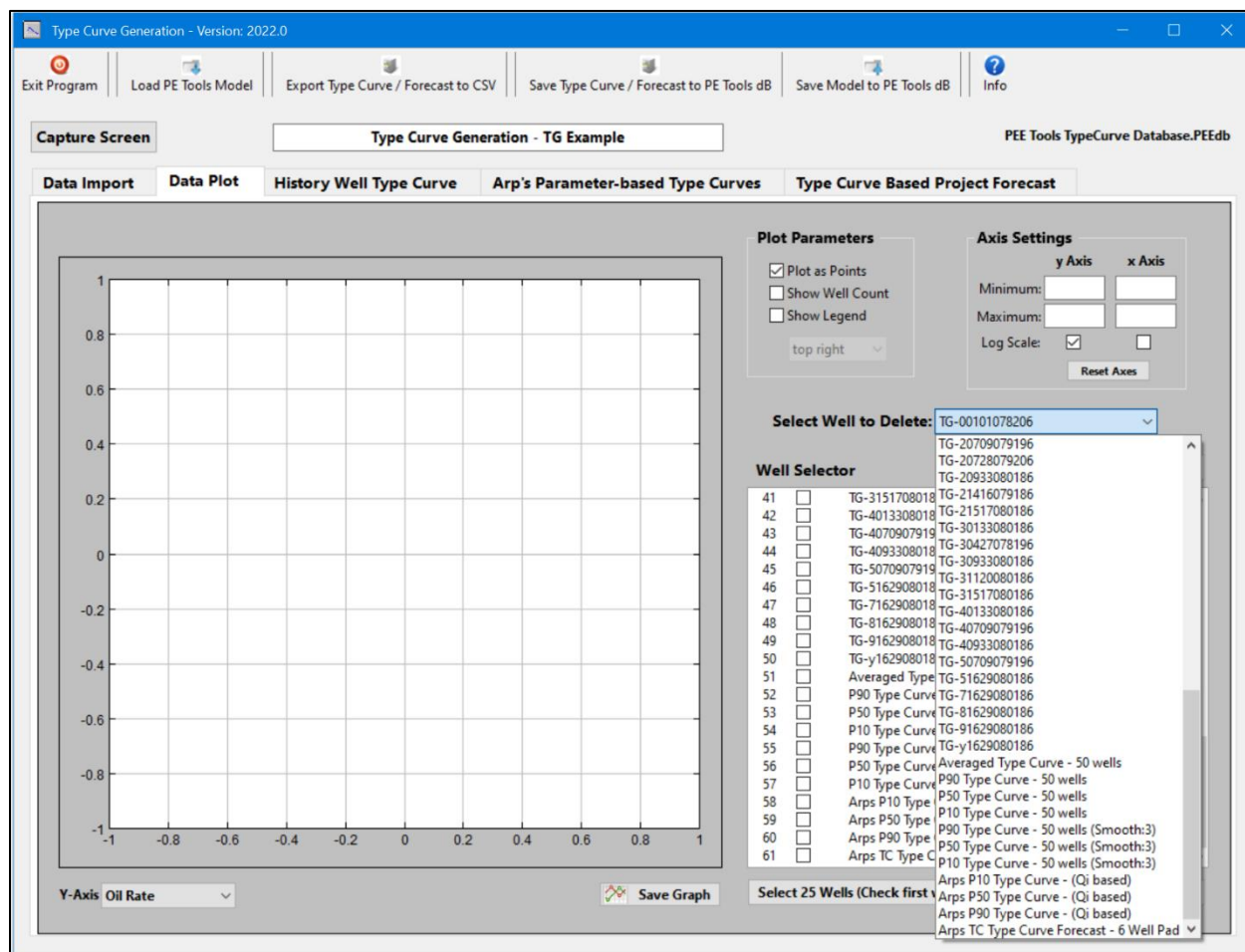


Figure TCG-5: Deleting Wells from the Well List

As a recommendation, noisy data should be smoothed prior to use in type curve generation. This can be performed using the 'Smooth Data' option available in the Production Database tool or by editing out data spikes using the 'Data Editing' option in the PDA tool.

## TCG.2 Type Curves – Historical Data

### TCG.2.1 Averaged Well Data Type Curve

The generation of a single type curve is common in the industry for a number of reasons: it is simple and quick to generate; it is simple to use in financial calculations; and, for public use it is easier to state “Our 7 Bscf type curve....” then “Our type curves range from 4 Bscf to 10 Bscf”.

The PE Essentials Type Curve Generation tool can generate a single type curve based on the average historical data from selected wells (Figure TCG-6) by selecting the appropriate wells and clicking the ‘Generate Average Well’ button. The type curve based on the averaged well data will be added to the well list.

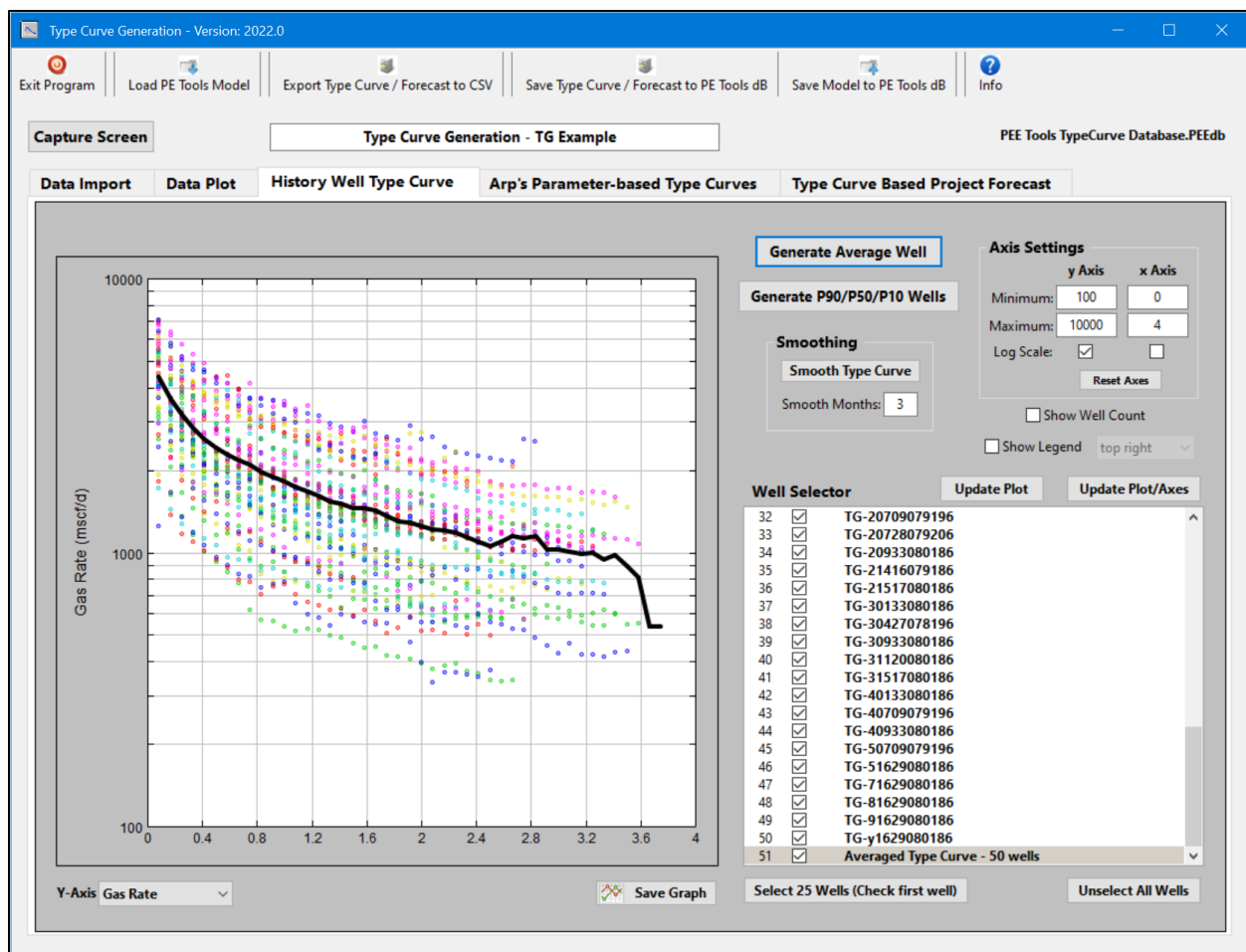


Figure TCG-6: Generating an Average Well Type Curve – Historical Data

A type curve that is generated from historical data may be noisy. Any type curve can be smoothed by selecting the type curve, specifying the smoothing interval ('Smooth Months') and clicking the 'Smooth Type Curve' button (Figure TCG-7).



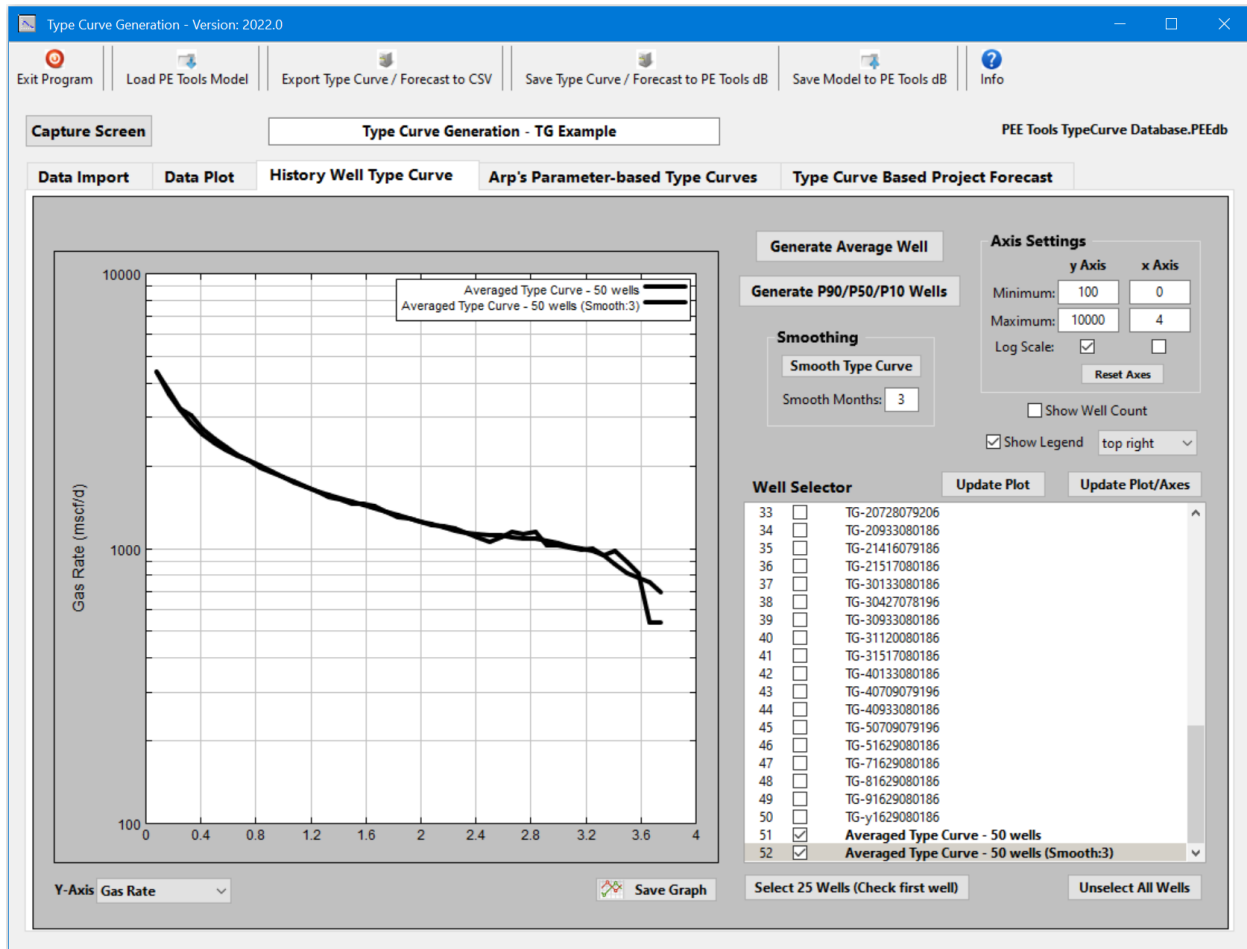


Figure TCG-7: Smoothing a Type Curve

The smoothed type curve will be added to the list of wells and can be plotted or used for project forecasts.

One issue with using a type curve based on averaged historical data is that it does not represent actual production from any one well and no well (past, present or future) will actually exhibit the type curve profile.

As an example, consider a single dice. A die has the numbers 1 to 6 on it, so rolling the die a large number of times and averaging the results will yield an average value of 3.5. In reality, although this is a valid average value, you would never make a bet on rolling a 3.5 since it would never be the result of the roll of the die.

### TCG.2.2 P90/P50/P10 Well Data Type Curve

As stated in the previous section there may be an issue using a type curve based on averaged historical data and that is that it does not represent actual production from any single current, or future, well.

The question becomes how many type curves are required to properly represent the range of values evident in the historical data? This is a very good question and difficult to answer in a generalized sense. The answer will be a function of the regional geology; fluid characteristics; well age/conditions; completions; etc. To account for this, it is reasonable to use a range of type curves for a project: low-mid-high or P90-P50-P10. Manually generating these type curves may require a significant amount of work but the results may be more representative of what will occur in the project.

The Type Curve Generation tool includes an option to perform probabilistic analysis of the historical data and generate P90, P50, and P10 type curves (Figure TCG-8).

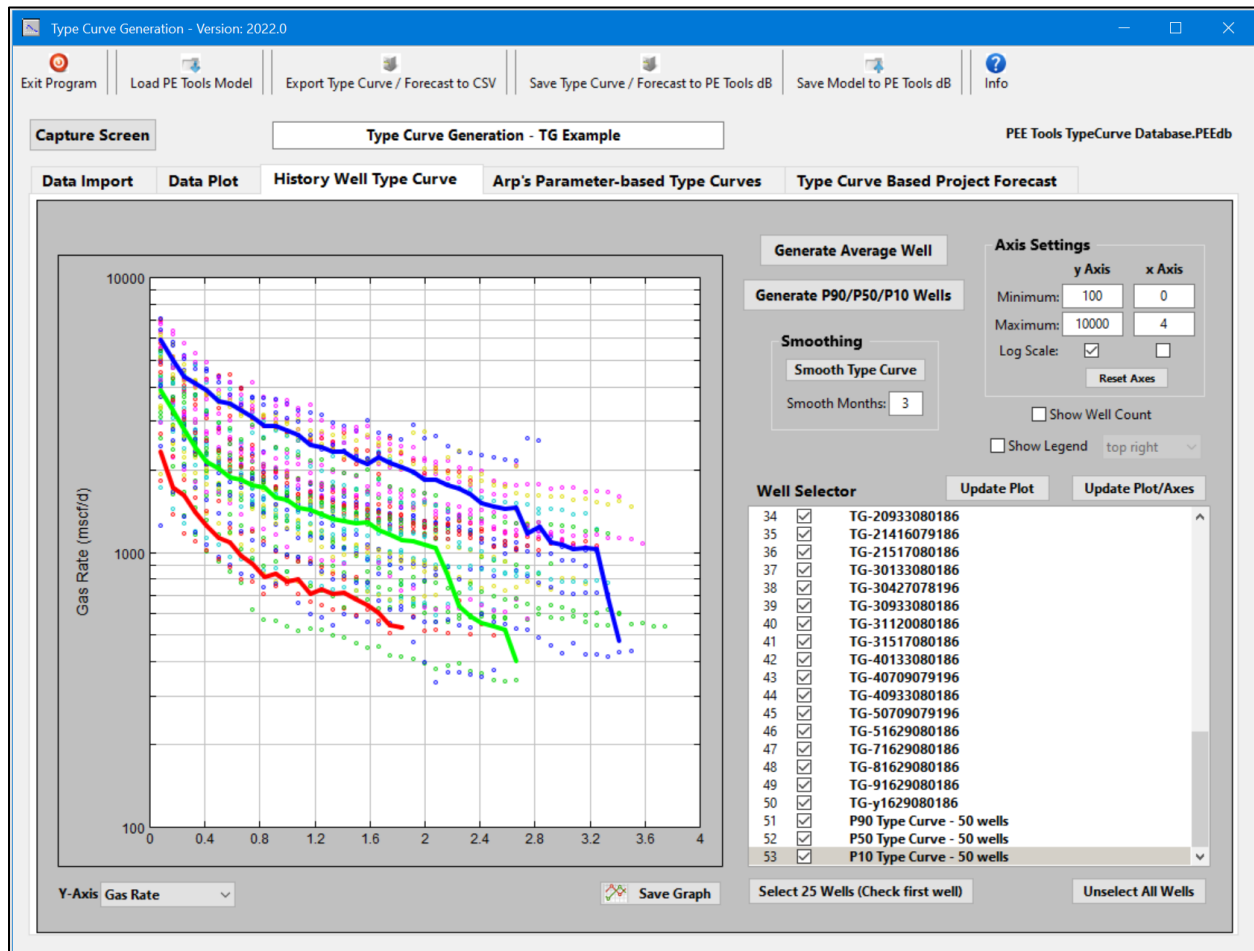


Figure TCG-8: Generating P90/P50/P10 Well Type Curve – Historical Data

The following are the definitions for the specific P-factors reported by the tool:

- P90 – There is a 90% probability that the actual value will be higher than this value and a 10% probability that it will be lower. Represents the “proven (1P)” level for reserves



- P50 – There is an equal probability that the actual value will be higher or lower than this value. Represents the “proven+probable (2P)” level for reserves
- P10 – There is a 10% probability that the actual value will be higher than this value and a 90% probability that it will be lower. Represents “proven+probable+possible (3P)” level for reserves

These type curves can also be smoothed, if required. After the P90, P50 and P10 type curves are generated, they are added to the well list, including any smoothed curves (Figure TCG-9).

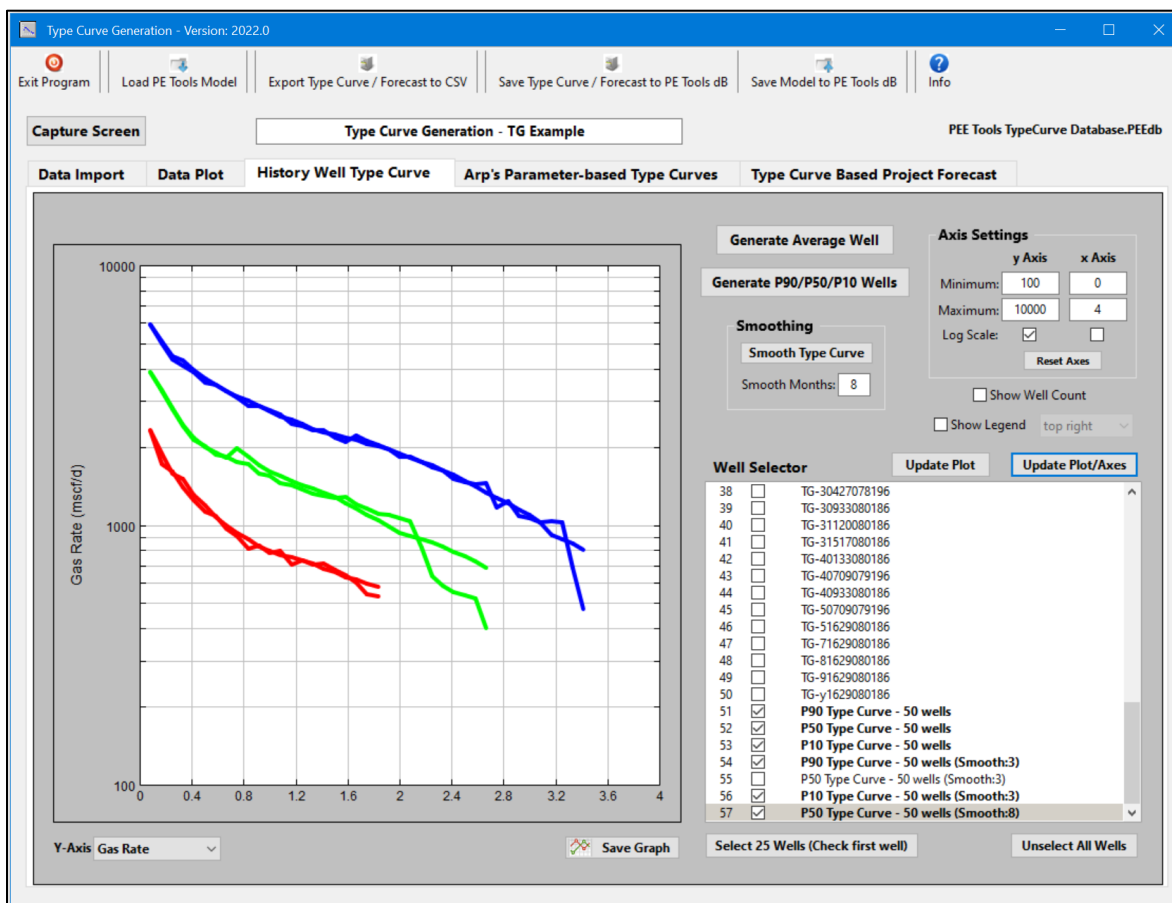


Figure TCG-9: Smoothing P90/P50/P10 Well Type Curve – Historical Data

It should be noted that, in Figure TCG-9, there is a second smoothed P50 curve with a smoothing factor of 8 months. When using a smoothing parameter of 3 for the P50 curve, the resulting curve followed the original downward trend at late time. To smooth out the curve, a larger smoothing interval was used resulting in the plotted curve.

### TGC.3 Arps Parameter Type Curves

It is possible to generate probabilistic type curves (P90/P50/P10) based on the Arps parameters generated by DCA analysis. In this case, no DCA forecasts are required, only the analysis parameters are imported into the tool (Figure TCG-10).

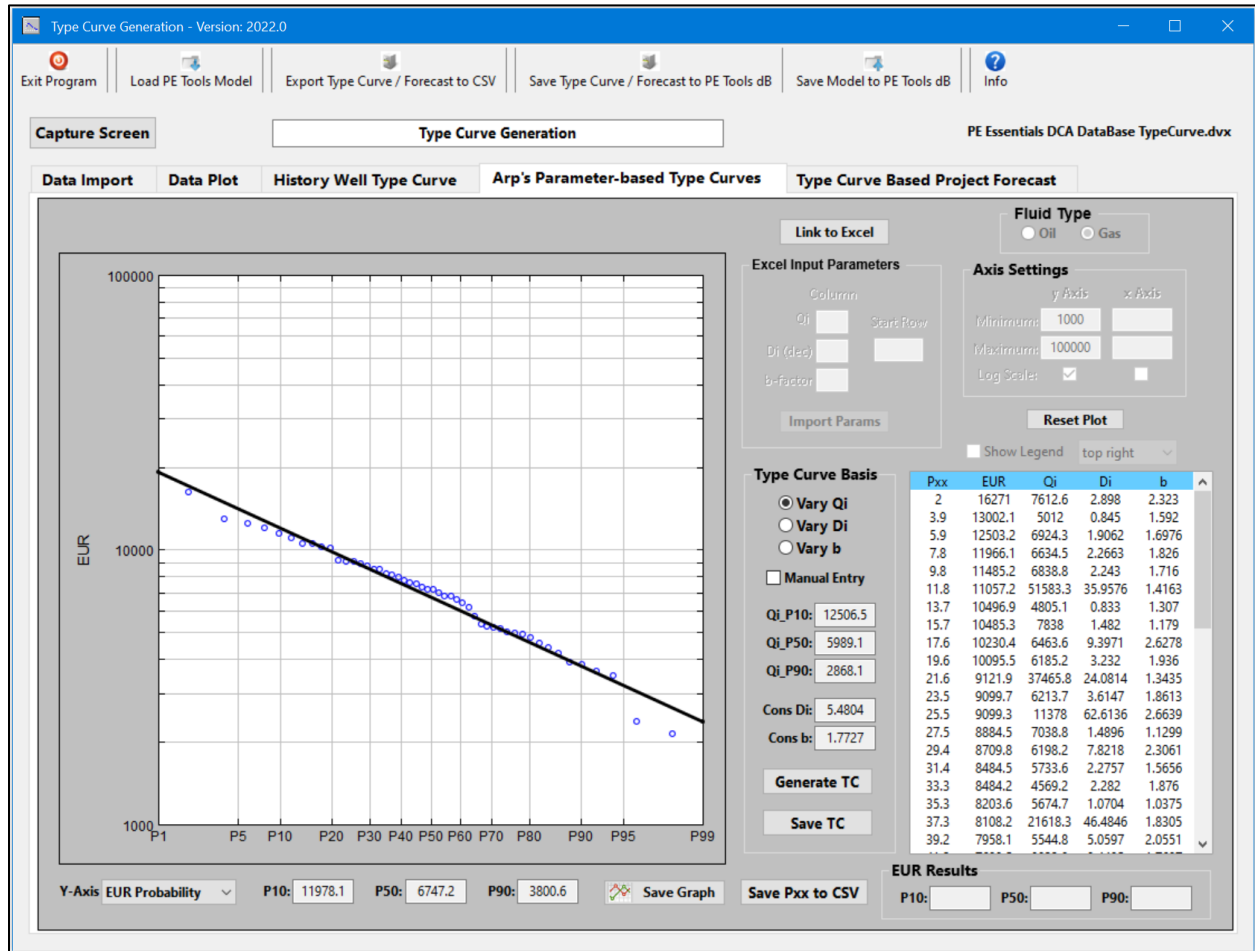


Figure TCG-10: P90/P50/P10 Well Type Curve – Arps Parameters

The Arps parameters can be imported from a PE Essentials DCA database or from an Excel file. After import of the  $Q_i$ ,  $D_i$  and  $b$  parameters, the ultimate EUR is calculated for each well model assuming a minimum annual decline factor,  $D_{min}$ , of 5%. The probabilistic distribution of the EUR calculation is then presented and the values for P90, P50 and P10 are extracted from a straight line drawn through the distribution and is shown for planning purposes.

The distribution of each Arps parameter can be plotted as well. The straight-line distribution of any parameter can be modified (Figures TGC-11 and TGC-12) by clicking and dragging the end point of the straight line.

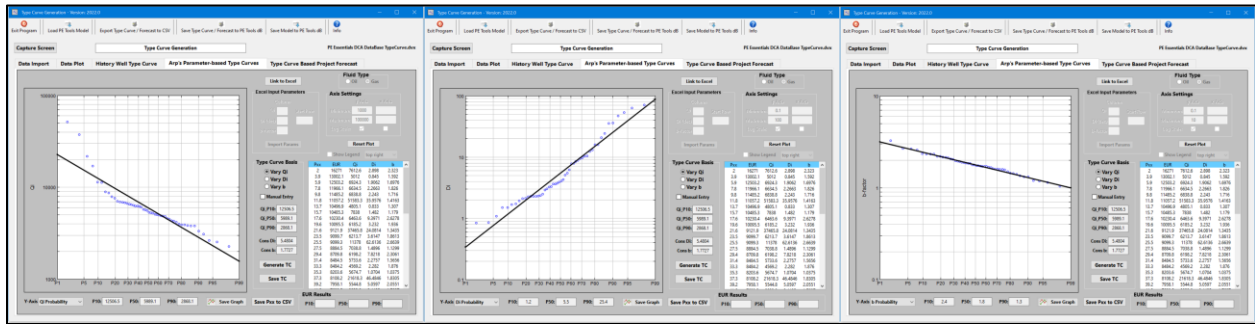


Figure TCG-11: Probabilistic Distribution of Arps Parameters

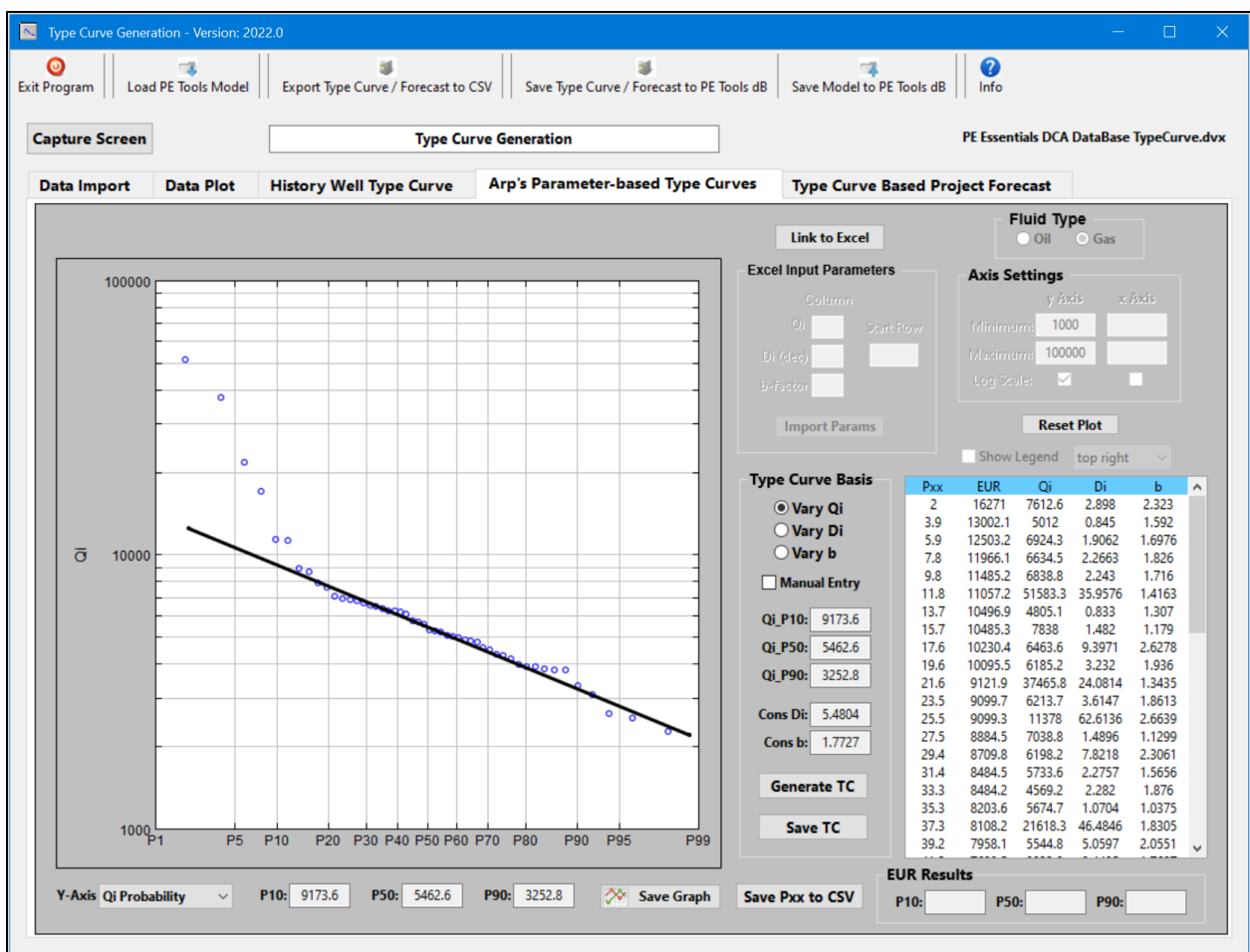


Figure TCG-12: Modifying the Distribution of Arps Parameters

It is important to have a valid distribution for the Arps parameters for the generation of the type curve.

The type curve can be generated based on any Arps parameters by choosing the appropriate 'Vary  $Q_i$ ', 'Vary  $D_i$ ' or 'Vary  $b$ ' button. Once the main parameter is chosen, the P50 value for the other parameters is used to generate the forecasts. The resulting P90/P50/P10 type curve EUR values are presented in the 'EUR Results' box for comparison purposes.

By checking 'Manual Entry' it is possible to vary any of the parameters. This helps when a specific EUR value is required.

Once the parameters are set, click the 'Generate TC' button to generate the P90, P50 and P10 type curves (Figure TCG-13). The Arps parameters can be changed to modify the EUR of the type curves. Once the curves are acceptable, clicking the 'Save TC' button will save the type curves to the well list.

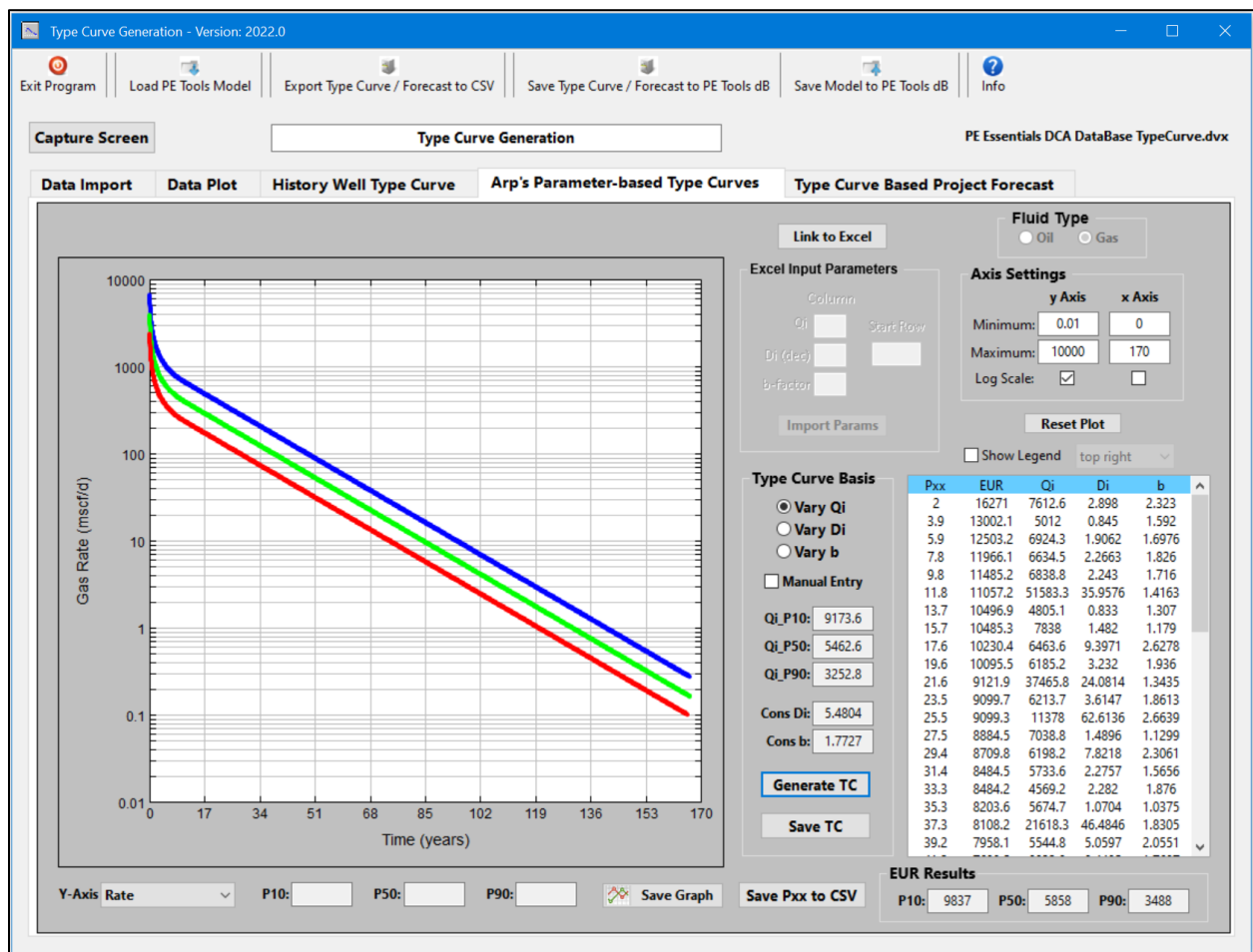


Figure TCG-13: Generating Type Curves for the Specified Arps Parameters

Numerous type curves can be generated from different combinations of Arps parameters. At any point, type curves can be saved to the PE Tools database or exported to a CSV file by selecting the appropriate menu item.

## TCG.4 Type Curve Based Project Forecast

After generating the type curves, they can be saved to the PE Tools database; exported to a CSV file; or, used to generate a project production forecast from the 'Type Curve Based Project Forecast' tab (Figure TCG-14).

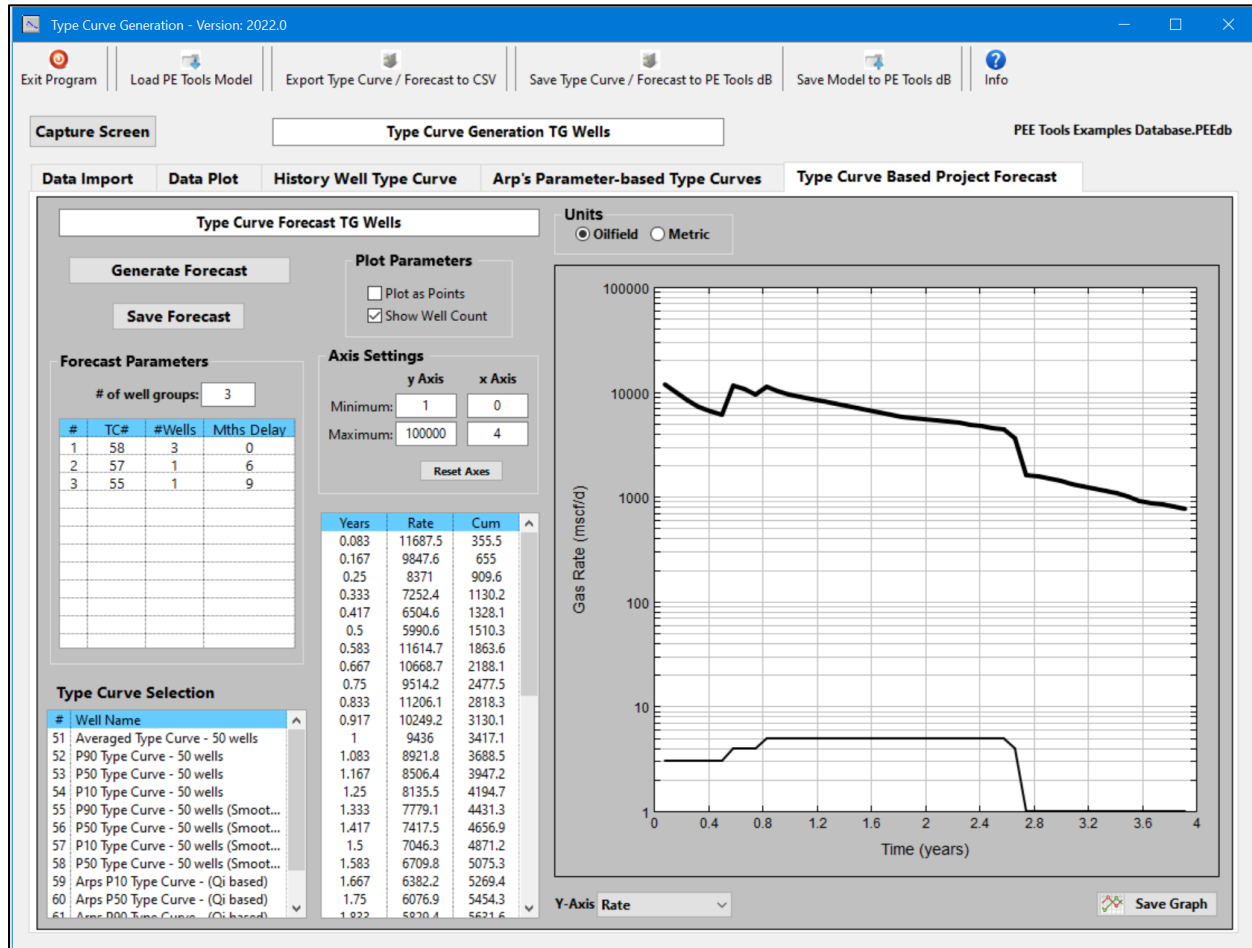


Figure TCG-14: Type Curve Project Forecast

All available type curves are listed in the 'Type Curve Selection' box. To generate a forecast, the project parameters are entered into the 'Forecast Parameters' table. After the '# of Well Groups' is entered, the Type Curve # for each well group is entered; the number of wells in each group is specified; and, the number of months to delay the group is entered.

After all project parameters are entered, clicking 'Generate Forecast' will calculate the results which are presented on the graph. If the forecast is satisfactory, clicking 'Save Forecast' will add it to the well list which can then be saved in the PE Tools database or exported to a CSV file.

### TCG.5 Type Curve Caveats

Some of the things to take into consideration when building and using type curves include the following;

- Continuously evaluate if a type curve is valid under current conditions
- Use extreme caution (meaning: do not do it!) when using a type curve for a different play or area
- In higher permeabilities, down spacing (infill drilling) may lead to reduced well EUR and invalidate the type curve
- Consider reservoir and performance differences: try to separate reservoir effects from completion effects and note that a small change in reservoir properties can result in a significant change in production
- Be aware that well outliers can have a significant impact on type curve profiles
- Changes in wellhead pressures will impact DCA results and can lead to over/under prediction of EUR
- Always review the underlying data, especially outliers
- Where possible, smooth noisy data and edit out spikes from the data
- Be aware of the impact of shutting in of poor wells – this will cause the long term average to increase as production is skewed to the longer term wells

## PE IOR/EOR/Heavy Oil Essentials

The EOR/IOR/Heavy Oil Essentials section contains the following programs:

- IOR/EOR Screening Tool
- IOR/EOR/Heavy Oil Tools

### IOR / EOR Screening Tool

The PE<sup>2</sup> Essentials 'IOR/EOR Screening Tool' performs a screening for IOR and EOR processes based on reservoir properties (Figure IOR-1).

The screenshot displays the 'IOR/EOR Screening - Version: 2021' application window. It features a menu bar with 'Exit Program', 'Load PE Tools Model', 'Save Model to PE Tools dB', and 'Info'. Below the menu is a toolbar with 'Oilfield' and 'Open PE dB' buttons. The main interface is divided into several sections:

- Fluid Properties:** Includes input fields for Oil API (30), Gas Gravity (0.8), NACL (ppm) (160), Reservoir Press (psi) (3000), Current Press (psi) (2000), Reservoir Temp (°F) (160), Bubble Pt Pressure (psi) (3000), Water Hardness (ppm) (3000), Acid number (0), and Average Perm (md) (10).
- Reservoir Parameters:** Includes input fields for Average Pay (ft) (25), Average Porosity (%) (15), Average Sw (%) (20), Residual Oil Saturation (%) (20), Current WOR (bbl/bbl) (1), Reservoir Depth (ft) (7000), kv/kh Ratio (0.2), Dykstra-Parsons Coefficient (0.75), and Min Miscible Pressure (psi) (2000). It also has radio buttons for 'Sandstone' (selected), 'Shaly Sandstone', and 'Carbonate'.
- IOR/EOR Screening Criteria:** A list of 20 criteria with checkboxes and numerical values. The criteria are: Depth (ft) (-), Oil Net Pay (ft) (> 10), Porosity (%) (-), Permeability (md) (kv > 1), kv/kh (> 0.1), Dykstra-Parsons Coef (-), SS or Carb Formation (-), Shaley Formation (Yes/No) (No), WOR (bbl/bbl) (-), Current Pressure (psi) (-), Temperature (°F) (-), Min Miscibility Pressure (psi) (-), Oil Saturation (%) (-), Residual Oil, S<sub>w</sub> (%) (-), Oil API (-), Viscosity (cp) (-), k/u<sub>o</sub> (md/cp) (-), Water Salinity (ppm) (-), Water Hardness (ppm) (-), and Acid Number (-).
- Oil Properties:** A table listing various properties and their values: Initial Reservoir Pressure (3000 psia), Initial Saturation Pressure (3000 psia), Initial Solution GOR (638.7 scf/bbl), Initial Oil Viscosity (0.826 cp), Current Reservoir Pressure (2000 psia), Current Bubble Pt Pressure (2000 psia), Current Solution GOR (409.9 scf/bbl), and Current Oil Viscosity (1.108 cp).
- Screening Results:** A table showing the results of the screening process. The table has three columns: 'IOR/EOR Process', 'Yes/No', and 'Failed Criteria'. The results are as follows:
 

IOR/EOR Process	Yes/No	Failed Criteria
<b>Horizontal Wells</b>	<b>YES</b>	
<b>Waterflood</b>	<b>YES</b>	
Hot Water Inj	No	(4) (10) (16)
Steam Inj	No	(1) (3) (4) (5) (10) (16)
Huff & Puff	No	(1) (4) (10) (16)
Immiscible Gas Inj	No	(4) (10)
In-Situ Combustion	No	(3) (4) (10) (16)
Hydrocarbon Miscible Inj	No	(4) (10) (12)
CO <sub>2</sub> Miscible Inj	No	(4) (10) (12)
Nitrogen Miscible Inj	No	(4) (10) (12) (15)
Polymer Inj	No	(4) (5) (16) (19)
Alkaline Inj	No	(4) (6) (9) (19) (20)
Surf/Poly Inj	No	(3) (4) (6) (19)
ASP Inj	No	(3) (4) (6) (19) (20)
Micellar Inj	No	(3) (4) (6) (19)
High Pressure air Inj	No	(4) (10) (15)
Surface Mining	No	(16)
Horizontal SAGD	No	(1) (2) (3) (4)

Figure IOR-1: PE<sup>2</sup> Essentials IOR / EOR Screening Tool

All the screening parameters used in this tool were obtained from published SPE papers, which are too numerous to list here.



## IOR.1 Screening Parameters

There are a number of sources that include screening parameters for IOR and EOR processes. Unfortunately, there are variations in the published parameters. Figure IOR-2 presents the criteria incorporated into the PE<sup>2</sup> Essentials IOR/EOR Screening Tool to ensure a consistent approach.

IOR/EOR Oil Recovery Processes - Screening Criteria (Oilfield)																		
Parameter	Horizontal Wells	Waterflood Inj	Hot Water Inj	Steam Inj	Huff & Puff	Immiscible Gas Inj	In-Situ Combustion	Hydrocarbon Miscible Inj	CO <sub>2</sub> Miscible Inj	Nitrogen Miscible Inj	Polymer Inj	Alkaline Inj	Surf/Poly Inj	ASP Inj	Micellar Inj	HPAI	Surface Mining	Horizontal SAGD
Depth [ft]		< 9000 ft	< 3000 ft	< 4500 ft	< 4500 ft	> 1800 ft	> 500 ft	> 4000 ft	> 2500 ft	> 6500 ft	< 9000 ft	< 9000 ft	< 8000 ft	< 9000 ft	< 8000 ft			< 4000 ft
Oil Net Pay [ft]	> 10 ft		> 20 ft	> 20 ft	> 20 ft	> 10 ft	> 15 ft						> 10 ft	> 10 ft	> 10 ft		> 10 ft	> 50 ft
Porosity [%]				> 20 %	> 20 %	> 20 %	> 20 %						> 20 %	> 20 %	> 20 %		> 20 %	> 20 %
Permeability [md]	kv > 1 md	> 5 md	> 35 md	> 200 md	> 200 md	> 10 md	> 50 md	> 10 md	> 10 md	> 10 md	> 20 md	> 20 md	> 20 md	> 50 md	> 50 md	> 10 md		> 100 md
kv/kh	> 0.1																	
Dykstra-Parsons Coef				< 0.7							< 0.6	< 0.6	< 0.6	< 0.6	< 0.6			
SS or Carb Formation				SS			SS				SS	SS	SS	SS	SS		SS	
Shaley Formation (Yes/No)	No											No	No	No	No			No
WOR (bbl/bbl)		< 10	< 10	< 10	< 10	<= Pb	< 2000 psi	> 0.75MMp	> 0.75MMp	> 0.75MMp	< 10	< 0.5				> 2100 psi		< 2500 psi
Pressure [psi]		<= Psat	< 2000 psi	< 1500 psi	< 1500 psi		< 2000 psi	> 0.75MMp	> 0.75MMp	> 0.75MMp	< 195 F	< 200 F	< 175 F	< 200 F	< 175 F	> 2100 psi		< 2500 psi
Temperature [F]		< 200 F					> 125 F	> 85 F	> 85 F	> 85 F	< 195 F	< 200 F	< 175 F	< 200 F	< 175 F	> 2100 psi		< 2500 psi
Min Miscibility P [psi]								< 0.75 Pressure	< 0.75 Pressure	< 0.75 Pressure								
Oil Saturation [%]		> 50 %	> 50 %	> 40 %	> 50 %	> 35 %	> 40 %	< 0.75 Pressure	< 0.75 Pressure	< 0.75 Pressure	> Sor+10%	> Sor+10%	> 35 %	> 35 %	> 30 %		> 8 %	> 50 %
Residual Oil, Sorw (%)																		
API - gravity		> 15	> 10	> 10	> 8	> 10	> 10	> 25	> 25	> 30 %	> 15	> 15	> 25	< 35	< 50 cp	> 30	> 7	> 7
Viscosity [cp]		< 200 cp	> 1000 cp	> 10 cp	> 1000 cp	< 500 cp	2<cp<1000	< 10 cp	< 10 cp	< 5 cp	10<cp<150	< 200 cp	< 100 cp	< 100 cp	< 50 cp	> 10000 cp		> 1000 cp
k/uo		> 0.1		> 0.02		> 0.0001	> 0.0001	> 0.0001	> 0.0001	> 0.0001	< 100,000 ppm	< 200,000 ppm	< 50,000 ppm	< 100,000 ppm	< 150,000 ppm			
Salinity of wtr [ppm]											< 1000 ppm	< 100 ppm	< 1000 ppm	< 3000 ppm	< 500 ppm			
Hardness of wtr [ppm]											> 0.1							
Acid Number																		

Figure IOR-2(a): IOR/EOR Screening Parameters – Oilfield

IOR/EOR Oil Recovery Processes - Screening Criteria (Metric)																		
Parameter	Horizontal Wells	Waterflood Inj	Hot Water Inj	Steam Inj	Huff & Puff	Immiscible Gas Inj	In-Situ Combustion	Hydrocarbon Miscible Inj	CO <sub>2</sub> Miscible Inj	Nitrogen Miscible Inj	Polymer Inj	Alkaline Inj	Surf/Poly Inj	ASP Inj	Micellar Inj	HPAI	Surface Mining	Horizontal SAGD
Depth [m]		< 2700 m	< 925 m	< 1500 m	< 1500 m	> 550 m	> 150 m	> 1200 m	> 800 m	> 2000 m	< 2700 m	< 2700 m	< 2400 m	< 2400 m	< 2750 m		> 3 m	< 1220 m
Oil Net Pay [m]	> 3 m		> 6 m	> 6 m	> 6 m	> 3 m	> 4.5 m						> 3 m	> 3 m	> 3 m		> 3 m	> 15 m
Porosity [%]		> 20 %	> 20 %	> 20 %	> 20 %	> 20 %	> 20 %						> 20 %	> 20 %	> 20 %		> 20 %	> 20 %
Permeability [md] kv/kh	kv > 1 md > 0.1	> 5 md	> 35 md	> 200 md	> 200 md	> 10 md	> 50 md	> 10 md	> 10 md	> 10 md	> 20 md	> 20 md	> 20 md	> 50 md	> 50 md	> 10 md		> 100 md
Dykstra-Parsons Coef SS or Carb Formation				< 0.7 SS			SS				< 0.6 SS	< 0.6 SS	< 0.6 SS	< 0.6 SS	< 0.6 SS		SS	
Shaley Formation (Yes/No)	No											No	No	No	No			No
WOR (m3/m3)		< 10	< 10	< 10	< 10	<= Pb	< 13800 kPa	> 0.75MMMP	> 0.75MMMP	> 0.75MMMP	< 10	< 0.5				> 17500		< 17240 kPa
Pressure [kPa]		<= Psat < 93 C	< 13800 kPa	< 10300 kPa	< 10300 kPa		> 50 C	> 0.75MMMP	> 30 C	> 30 C	< 90 C	< 93 C	< 80 C	< 80 C	< 93 C	> 17500		< 17240 kPa
Temperature [C]																		
Min Miscibility P [kPa]								< 0.75 Pressure	< 0.75 Pressure	< 0.75 Pressure								
Oil Saturation [%]		> 50 %	> 50 %	> 40 %	> 50 %	> 35 %	> 40 %	< 0.75 Pressure	< 0.75 Pressure	< 0.75 Pressure	> Sor+10%	> Sor+10%	> 35 %	> 35 %	> 30 %		> 8 %	> 50 %
Residual Oil, Sorw (%)																		
API - gravity		> 15	> 10	> 10	> 8	> 10	> 10	> 25	> 25	> 35	> 15	> 15	> 25	< 35	< 50 cp	> 30	> 7	> 7
Viscosity [mPas] k/uo		< 200 cp > 0.1	> 1000 cp	> 10 cp > 0.02	> 1000 cp	< 500 cp > 0.0001	2<cp<1000 > 0.0001	< 10 cp > 0.0001	< 10 cp > 0.0001	< 5 cp > 0.0001	10<cp<150 > 0.0001	< 200 cp > 0.0001	< 100 cp > 0.0001	< 100 cp > 0.0001	< 50 cp > 0.0001	> 10000 cp		> 1000 cp
Salinity of wtr [ppm]											< 100,000 ppm < 1000 ppm	< 200,000 ppm < 100 ppm	< 50,000 ppm < 1000 ppm	< 100,000 ppm < 3000 ppm	< 150,000 ppm < 500 ppm			
Hardness of wtr [ppm]																		
Acid Number																		

Figure IOR-2(b): IOR/EOR Screening Parameters - Metric

The PE<sup>2</sup> Essentials IOR/EOR Screening Tool parameters are accessed through the 'IOR/EOR Screening Criteria' (Figure IOR-3).



IOR/EOR Screening Criteria		
Horizontal Wells	<input checked="" type="checkbox"/>	(1)
Waterflood	<input type="checkbox"/>	(2)
Hot Water Inj	<input type="checkbox"/>	(3)
Steam Inj	<input type="checkbox"/>	(4)
Huff and Puff	<input checked="" type="checkbox"/>	(5)
Immiscible Gas Inj	<input checked="" type="checkbox"/>	(6)
In-Situ Combustion	<input type="checkbox"/>	(7)
Hydrocarbon Miscible Inj	<input type="checkbox"/>	(8)
CO2 Miscible Inj	<input type="checkbox"/>	(9)
Nitrogen Miscible Inj	<input type="checkbox"/>	(10)
Polymer Inj	<input type="checkbox"/>	(11)
Alkaline Inj	<input type="checkbox"/>	(12)
Surf/Poly Inj	<input type="checkbox"/>	(13)
ASP Inj	<input type="checkbox"/>	(14)
Micellar Inj	<input type="checkbox"/>	(15)
High Pressure Air Inj	<input type="checkbox"/>	(16)
Surface Mining	<input type="checkbox"/>	(17)
Horizontal SAGD	<input type="checkbox"/>	(18)
Oil API	-	(19)
Viscosity [cp]	-	(20)
k/μo [md/cp]	-	
Water Salinity [ppm]	-	
Water Hardness [ppm]	-	
Acid Number	-	

Figure IOR-3: IOR/EOR Screening Criteria

## IOR.2 IOR / EOR Screening

In order to determine the applicability of a specific process, the fluid properties (Figure IOR-4) and reservoir parameters have to be entered (Figure IOR-5).

Not all parameters have to be entered. For example, if a miscible flood is not contemplated, then the 'Min Miscibility Pressure' does not have to be entered.

After input of the appropriate parameters, the results of the screening are presented (Figure IOR-6) along with applicability of the process (Yes/No) and the 'Failed Criteria' for each process.

Fluid Properties			Oil Properties		
Oil API	30	Reservoir Press (psi)	3000	Initial Reservoir Pressure	3000 psia
Gas Gravity	0.8	Current Press (psi)	2000	Initial Saturation Pressure	3000 psia
NACL (ppm)	30000	Reservoir Temp (°F)	160	Initial Solution GOR	638.7 scf/bbl
		Sat Pressure (psi)	3000	Initial Oil Viscosity	0.826 cp
		Water Hardness (ppm)	3000	Current Reservoir Pressure	2000 psia
		Acid number	0	Current Saturation Pressure	2000 psia
				Current Solution GOR	409.9 scf/bbl
				Current Oil Viscosity	1.108 cp

Figure IOR-4: IOR/EOR Screening Tool – Fluid Parameters

**Reservoir Parameters**

Average Perm (md)	10
Average Pay (ft)	25
Average Porosity (%)	15
Average Sw (%)	20
Residual Oil Saturation (%)	20
Current WOR (bbl/bbl)	1
Reservoir Depth (ft)	7000
kv/kh Ratio	0.2
Dykstra-Parsons Coefficient	0.75
Min Miscible Pressure (psi)	2000

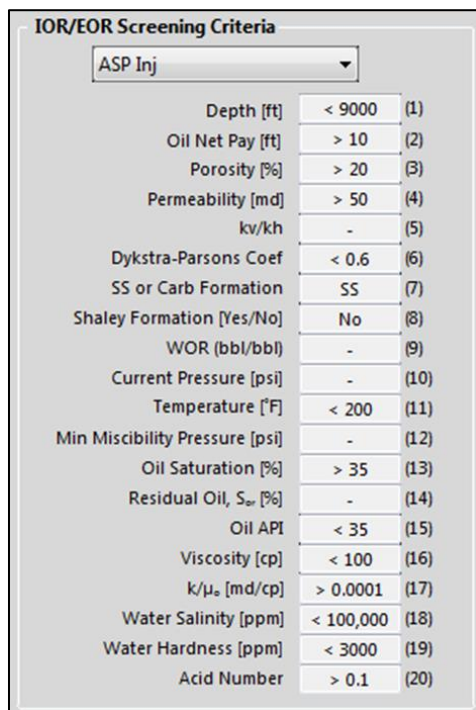
☒ Sandstone  
☐ Shaly Sandstone  
☐ Carbonate

Figure IOR-5: IOR/EOR Screening Tool – Reservoir Parameters

Screening Results		
IOR/EOR Process	Yes/No	Failed Criteria
<b>Horizontal Wells</b>	<b>YES</b>	
<b>Waterflood</b>	<b>YES</b>	
Hot Water Inj	No	(4) (16)
Steam Inj	No	(1) (3) (4) (5) (10) (16)
Huff & Puff	No	(1) (4) (10) (16)
<b>Immiscible Gas Inj</b>	<b>YES</b>	
In-Situ Combustion	No	(3) (4) (16)
Hydrocarbon Miscible Inj	No	(10)
CO <sub>2</sub> Miscible Inj	No	(10)
Nitrogen Miscible Inj	No	(10) (15)
Polymer Inj	No	(4) (5) (16) (19)
Alkaline Inj	No	(4) (6) (9) (19) (20)
Surf/Poly Inj	No	(3) (4) (6) (19)
ASP Inj	No	(3) (4) (6) (20)
Micellar Inj	No	(3) (4) (6) (19)
High Pressure air Inj	No	(10)
Surface Mining	No	(16)
Horizontal SAGD	No	(1) (2) (3) (4)

Figure IOR-6: IOR/EOR Screening Tool – Results

To determine why a process failed, select the process on the screening guide (Figure IOR-7).



IOR/EOR Screening Criteria		
ASP Inj		
Depth [ft]	< 9000	(1)
Oil Net Pay [ft]	> 10	(2)
Porosity [%]	> 20	(3)
Permeability [md]	> 50	(4)
kv/kh	-	(5)
Dykstra-Parsons Coef	< 0.6	(6)
SS or Carb Formation	SS	(7)
Shaley Formation [Yes/No]	No	(8)
WOR (bbl/bbl)	-	(9)
Current Pressure [psi]	-	(10)
Temperature [°F]	< 200	(11)
Min Miscibility Pressure [psi]	-	(12)
Oil Saturation [%]	> 35	(13)
Residual Oil, S <sub>or</sub> [%]	-	(14)
Oil API	< 35	(15)
Viscosity [cp]	< 100	(16)
k/μ <sub>o</sub> [md/cp]	> 0.0001	(17)
Water Salinity [ppm]	< 100,000	(18)
Water Hardness [ppm]	< 3000	(19)
Acid Number	> 0.1	(20)

Figure IOR-7: IOR/EOR Screening Tool – Criteria

The 'Failed Criteria' numbers are referenced by the number on the screening guide.

## EOR / Heavy Oil Tool

A number of general purpose tools are included in the PE<sup>2</sup> Essentials 'EOR/Heavy Oil Tools' as shown in Figure EOR-1.

**Minimum Miscibility Pressure**

Oil Analysis		Injectant		Correlation	
H2S - mol%	0	N2 - mol%	0.29	<b>Gas Injection</b>	
N2 - mol%	0.18	CO2 - mol%	0.76	<input type="radio"/> Glase (1985) [1]	
CO2 - mol%	0.44	C1 - mol%	73.05	<input checked="" type="radio"/> Maklavani (2010) [2]	
C1 - mol%	43.92	C2 - mol%	13.95	<b>100% N<sub>2</sub> Injection</b>	
C2 - mol%	10.71	C3 - mol%	8.17	<input type="radio"/> Glase (1985) [1]	
C3 - mol%	8.81	C4 - mol%	2.66	<input type="radio"/> Firoozabadi (1986) [3]	
iC4 - mol%	1.3	C5 - mol%	0.62	<input type="radio"/> Sebastian (1992) [4]	
nC4 - mol%	3.99	C6 - mol%	0.5	<b>100% CO<sub>2</sub> Injection</b>	
iC5 - mol%	1.36	Σ Comps Inj	100	<input type="radio"/> Glase (1985) [1]	
nC5 - mol%	1.83	Res Temperature	150 °F	<input type="radio"/> Zang (2015) [5]	
C6 - mol%	2.55			<input type="radio"/> Chen (2013) [6]	
C7+ - mol%	24.91			<input type="radio"/> Yuan (2005) [7]	
Σ Comps	100			<input type="radio"/> Cronquist (1978) [8]	
C7+ MW	231	<b>Minimum Miscibility Pressure</b>	4734.681 psi	Correlation Limits	
C7+ Specific Gravity	0.855			References	

**PCP Pump Rates**

Eccentricity of Rotor/Stator (in)	.1968
Rotations per Minute	150
Rotor Diameter (in)	1.575
Stator Pitch, Ps (in)	1.575
Volumetric Efficiency (%)	100
PCP Pump Flow Rate (bbls/d)	43.5

**Sucker Rod Pump Rates**

Pump Speed, Strokes per Min	5
Plunger Area (in <sup>2</sup> )	50
Effective Plunger Stroke (ft)	1
Volumetric Efficiency (%)	100
Sucker Rod Pump Flow Rate (bbls/d)	445.2

**Reservoir Thermal Properties**

Oil API	20
Porosity (%)	25
Oil Saturation (%)	50
Water Saturation (%)	50
Res Temperature (°F)	122
Shale Content (%)	0
Matrix Density (g/cc)	2.65
Oil SG at Res Temperature	0.908
Water SG at Res Temperature	0.9898
Oil Specific Heat (BTU/lb-°F)	0.471
Water Specific Heat (BTU/lb-°F)	1.003
Rock Specific Heat (BTU/lb-°F)	0.198
Res Heat Capacity (BTU/ft <sup>3</sup> -°F)	35686.6
Thermal Conductivity (Btu/h-ft-°F)	1.56

**Hot/Cold Water Injection**

Water Temperature (°F)	212
Water Injection Rate (bwpd)	3145
Reservoir Temperature (°F)	98.6
Formation Thickness (ft)	19.7
Res Heat Capacity (BTU/ft <sup>3</sup> -°F)	35686.6
Injection Time (days)	100
Distance From Well (ft)	49.2
Water SG at Injection Temperature	0.9589
Water Specific Heat (BTU/lb-°F)	1.003
Temperature at 'Distance' (°F)	208.7

**SteamFlood Residual Oil Saturation**

Oil viscosity at Res Temp (cp)	18000
SteamFlood Temperature (°F)	399
S <sub>wr</sub> after SteamFlood (%)	8.2

°F	S <sub>wr</sub>	°F	S <sub>wr</sub>	°F	S <sub>wr</sub>
200	19.4	340	11.6	480	3.7
220	18.3	360	10.4	500	2.6
240	17.2	380	9.3	520	1.4
260	16	400	8.2	540	0.3
280	14.9	420	7.1	560	0
300	13.8	440	5.9	580	0
320	12.7	460	4.8	600	0

**Reservoir Temperature Distribution**

°F vs distance from well (ft)

Export Data Save Graph

Figure EOR-1: PE<sup>2</sup> Essentials EOR / Heavy Oil Tool

The EOR / Heavy Oil Tools are comprised of the following:

- Minimum Miscibility Pressure
- Reservoir Thermal Properties
- Hot/Cold Water Injection
- SteamFlood Residual Oil Saturation
- PCP Pump Rates
- Sucker Rod Pump Rates

The only input data required is the input for the specific tool that is being used.

### EOR.1 Minimum Miscibility Pressure

The 'Minimum Miscibility Pressure' tool (Figure EOR-2) calculates MMP for gas injection, nitrogen injection and carbon dioxide injection.

Oil Analysis		Injectant		Correlation
H2S - mol%	0	N2 - mol%	0.29	Gas Injection <input type="radio"/> Glasø (1985) [1] <input checked="" type="radio"/> Maklavani (2010) [2]
N2 - mol%	0.18	CO2 - mol%	0.76	
CO2 - mol%	0.44	C1 - mol%	73.05	100% N <sub>2</sub> Injection <input type="radio"/> Glasø (1985) [1] <input type="radio"/> Firoozabdi (1986) [3] <input type="radio"/> Sebastian (1992) [4]
C1 - mol%	43.92	C2 - mol%	13.95	
C2 - mol%	10.71	C3 - mol%	8.17	
C3 - mol%	8.81	C4 - mol%	2.66	100% CO <sub>2</sub> Injection <input type="radio"/> Glasø (1985) [1] <input type="radio"/> Zang (2015) [5] <input type="radio"/> Chen (2013) [6] <input type="radio"/> Yuan (2005) [7] <input type="radio"/> Cronquist (1978) [8]
iC4 - mol%	1.3	C5 - mol%	0.62	
nC4 - mol%	3.99	C6 - mol%	0.5	
iC5 - mol%	1.36	Σ Comps Inj	100	
nC5 - mol%	1.83	Res Temperature	150 °F	
C6 - mol%	2.55			
C7+ - mol%	24.91			
Σ Comps	100			
C7+ MW	231	<b>Minimum Miscibility Pressure</b>	4734.681 psi	
C7+ Specific Gravity	0.855			

Figure EOR-2: IOR/EOR/Heavy Oil Tools – Minimum Miscibility Pressure

There are a number of references available for minimum miscibility pressure (MMP) correlations. The following is a list of the correlations and references, along with their range of validity, that are used in the Minimum Miscibility Pressure model.

#### Glasø Correlation (1985)

Glasø, O.S.: Generalized minimum miscibility pressure correlation, Society of Petroleum Engineers journal, vol. 25, no. 6, pp. 927–934, December 1985. Valid for:

- Oil molecular weight of C<sub>2</sub> through C<sub>6</sub> from 34 to 54 g/mol
- For N<sub>2</sub> injection, methane concentrations in the oil from 30% to 60%
- For N<sub>2</sub> injection, molecular Weight of C<sub>7+</sub> in oil less than 200 g/mol
- Gas injection MMP from 1100 to 7000 psi
- CO<sub>2</sub> injection MMP from 900 to 4400 psi

For hydrocarbon gas injection, the following equations apply.

$$\text{MMP}_{34} = 6329 - 25.41y - (46.745 - 0.185y)z + [1.127y^{5.258}\exp(319.8zy^{-1.703})] (10^{-12}) T \quad (\text{EOR-1})$$

$$\text{MMP}_{44} = 5503 - 19.238y - (80.913 - 0.273y)z + [1.7y^{3.73}\exp(13.567zy^{-1.058})] (10^{-9}) T \quad (\text{EOR-2})$$

$$\text{MMP}_{54} = 7437 - 25.703y - (73.515 - 0.214y)z + [4.92y^{5.52}\exp(21.706zy^{-1.109})] (10^{-14}) T \quad (\text{EOR-3})$$

$x$  = MW of  $C_2$  to  $C_6$  in injected gas

$$y = (2.622 \text{ C7SG}^{0.846})^{6.588}$$

$z$  = Mol% $C_1$  in injected gas

$\text{MMP}_x$ , MMP for MW of  $x$ , is calculated as an interpolation between  $\text{MMP}_{34}$ ,  $\text{MMP}_{44}$  and  $\text{MMP}_{54}$

Where: MMP is minimum miscibility pressure in psi and  $T$  is temperature in  $^{\circ}\text{F}$ .

For  $\text{N}_2$  gas injection the following equations apply.

If molecular weight of  $C_{7+}$ ,  $\text{MWC}_{7+}$ , in the oil is greater than or equal to 160:

$$\text{MMP} = 6364 - 12.09\text{MWC}_{7+} + [1.127\text{MWC}_{7+}^{5.258}\exp(23025\text{MWC}_{7+}^{-1.703}) - 20.8] (10^{-12}) T \quad (\text{EOR-4})$$

If molecular weight of  $C_{7+}$ ,  $\text{MWC}_{7+}$ , in the oil is greater than or equal to 160:

$$\text{MMP} = 7695.1 - 12.09\text{MWC}_{7+} + [1.127\text{MWC}_{7+}^{5.258}\exp(23025\text{MWC}_{7+}^{-1.703}) - 39.77] (10^{-12}) T \quad (\text{EOR-5})$$

If the total mole% of  $C_2$  to  $C_6$  ( $x'$ ) in the oil is less than 28%, the following equation applies:

$$\text{MMP} = 93640 - 12.09\text{MWC}_{7+} + [1.127\text{MWC}_{7+}^{5.258}\exp(23025\text{MWC}_{7+}^{-1.703}) - 20.8](10^{-12})T - 99.3x' \quad (\text{EOR-6})$$

Where: MMP is minimum miscibility pressure in psi,  $\text{MWC}_{7+}$  is the molecular weight of  $C_{7+}$  in the oil,  $x'$  is the mole% of  $C_2$  to  $C_6$  in the oil and  $T$  is temperature in  $^{\circ}\text{F}$ .

For  $\text{CO}_2$  gas injection the following equations apply.

If the total mole% of  $C_2$  to  $C_6$  ( $x'$ ) in the oil is greater than or equal to 18%:

$$\text{MMP} = 810 - 3.404\text{MWC}_{7+} + [1.7\text{MWC}_{7+}^{3.73}\exp(786.8\text{MWC}_{7+}^{-1.058})] (10^{-9}) T \quad (\text{EOR-7})$$

If the total mole% of  $C_2$  to  $C_6$  ( $x'$ ) in the oil is less than 18%:

$$\text{MMP} = 2947.9 - 3.404\text{MWC}_{7+} + [1.7\text{MWC}_{7+}^{3.73}\exp(786.8\text{MWC}_{7+}^{-1.058})] (10^{-9}) T - 99.3x' \quad (\text{EOR-8})$$

Where: MMP is minimum miscibility pressure in psi,  $\text{MWC}_{7+}$  is the molecular weight of  $C_{7+}$  in the oil,  $x'$  is the mole% of  $C_2$  to  $C_6$  in the oil and  $T$  is temperature in  $^{\circ}\text{F}$ .

Maklavani Correlation (2010)

Maklavani, A.M.; Vatani, A.; Moradi, B.; Tangsirifard J.: New Minimum Miscibility Pressure (MMP) Correlation for Hydrocarbon Miscible Injections, Brazilian Journal of Petroleum and Gas, vol. 4, no. 1, pp. 11-19, 2010. Valid for:

- Temperature from 130°F to 300°F
- Methane concentration 6% to 55%
- Sum of C<sub>2</sub>-C<sub>6</sub> concentrations from 1% to 63%
- Molecular Weight of C<sub>7+</sub> from 120 to 302 g/mol
- Injection gas C<sub>2+</sub> concentrations from 0% to 48%
- Injection gas C<sub>2+</sub> molecular weight from 0 to 72 g/mol

For hydrocarbon gas injection, the following equation applies.

$$\text{MMP} = 145.04 (43.664 - 4.542\alpha + 0.689\alpha^2 - 0.132\beta) \quad (\text{EOR-9})$$

$$\alpha = (X_{\text{C}_2\text{-C}_6}^{1.72785} X_{\text{C}_1}^{0.1}) / (T^{0.5} \text{MWC}_{7+})$$

$$\beta = Y_{\text{C}_{2+}}^{(1.064+0.00686*\text{MWC}_{2+})}$$

Where: MMP is minimum miscibility pressure in psi, MWC<sub>7+</sub> is the molecular weight of C<sub>7+</sub> in the oil, X<sub>C<sub>2</sub>-C<sub>6</sub></sub> is the mole% of C<sub>2</sub> to C<sub>6</sub>, CO<sub>2</sub> and H<sub>2</sub>S in the oil, X<sub>C<sub>1</sub></sub> is the mole% of C<sub>1</sub> in the oil, Y<sub>C<sub>2+</sub></sub> is the molecular weight of C<sub>2+</sub> in the injected gas, MWC<sub>2+</sub> is the molecular weight of C<sub>2+</sub> in the injected gas and T is temperature in °F.

Firoozabadi Correlation (1986)

Firoozabadi, A.; Aziz, K.: Analysis and Correlation of Nitrogen and Lean-Gas Miscibility Pressure, SPE Reservoir Engineering, pp. 575–582, November 1986. Valid for:

- Methane concentrations in the oil from 30% to 60%
- Molecular Weight of C<sub>7+</sub> in oil is less than 200 g/mol

For N<sub>2</sub> injection the following equation applies.

$$\text{MMP} = 9433 - 188000X_{\text{C}_2\text{-C}_5} / (\text{MWC}_{7+}T^{0.25}) + 1430000[X_{\text{C}_2\text{-C}_5} / (\text{MWC}_{7+}T^{0.25})]^2 \quad (\text{EOR-10})$$

Where: MMP is minimum miscibility pressure in psi, MWC<sub>7+</sub> is the molecular weight of C<sub>7+</sub> in the oil, X<sub>C<sub>2</sub>-C<sub>5</sub></sub> is the mole% of C<sub>2</sub> to C<sub>5</sub> in the oil and T is temperature in °F.

Sebastion Correlation (1992)

Sebastion, H.M.; Lawrence, D.D.: Nitrogen Minimum Miscibility Pressures, SPE/DOE 24134, April 1992. Valid for:

- Temperature from 100°F to 300°F
- Methane concentration in the oil up to 60%



- Sum of C<sub>2</sub>-C<sub>6</sub> concentrations up to 30%
- Molecular Weight of C<sub>7+</sub> from 100 to 260 g/mol

For N<sub>2</sub> injection the following equation applies.

$$\text{MMP} = 4603 - 3283x + 4.776y - 4.008z + 2.05\text{MWC}_{7+} + 7.541(T + 460) \quad (\text{EOR-11})$$

$$x = X_{C1}(T + 460)/\text{MWC}_{7+}$$

$$y = X_{C1}^2(T + 460)^2/\text{MWC}_{7+}$$

$$z = X_{C2-C6}(T + 460)^2/\text{MWC}_{7+}$$

Where: MMP is minimum miscibility pressure in psi, MWC<sub>7+</sub> is the molecular weight of C<sub>7+</sub> in the oil, X<sub>C1</sub> is the mole% of C<sub>1</sub> in the oil, X<sub>C2-C6</sub> is the mole% of C<sub>2</sub> to C<sub>6</sub> and CO<sub>2</sub> in the oil and T is temperature in °F.

#### Zhang Correlation (2015)

Zhang, H.; Hou, D.; Kai, L.: An Improved CO<sub>2</sub>-Crude Oil Minimum Miscibility Pressure Correlation, Journal of Chemistry, 175940, vol. 2015, October 2015, Valid for:

- Molecular Weight of C<sub>7+</sub> from 130 to 402.7 g/mol
- Temperature from 71°F to 377°F
- MMP up to 10,510 psi

For CO<sub>2</sub> injection, the following equation applies.

$$\text{MMP} = 145.04 \{a[\ln(T)]^b [\ln(\text{MWC}_{7+})]^c (1 + X_{C1N2}/X_{C2-C6})^d\} \quad (\text{EOR-12})$$

$$a=0.000083397$$

$$b=3.9774$$

$$c=3.3179$$

$$d=0.17461$$

Where: MMP is minimum miscibility pressure in psi, MWC<sub>7+</sub> is the molecular weight of C<sub>7+</sub> in the oil, X<sub>C1N2</sub> is the mole% of C<sub>1</sub> and N<sub>2</sub> in the oil, X<sub>C2-C6</sub> is the mole% of C<sub>2</sub> to C<sub>6</sub>, CO<sub>2</sub> and H<sub>2</sub>S in the oil and T is temperature in °F.

#### Chen Correlation (2013)

Chen, B.L.; Huang, H.D.; Zhang, Y. et al.: An Improved Predicting Model for Minimum Miscibility Pressure (MMP) of CO<sub>2</sub> and Crude Oil, Journal of Oil and Gas Technology, vol. 35, no. 2, pp. 126–130, 2013. Valid for:

- Molecular Weight of C<sub>7+</sub> from 185 to 249 g/mol
- Temperature from 90°F to 245°F
- MMP up to 4085 psi



For CO<sub>2</sub> injection, the following equation applies.

$$\text{MMP} = 3.534 [(T - 32)^{0.8293} \text{MWC}_{7+}^{0.5382} X_{\text{C}_1\text{N}_2}^{0.1018} X_{\text{C}_2\text{-C}_6}^{-0.2316}] \quad (\text{EOR-13})$$

Where: MMP is minimum miscibility pressure in psi,  $\text{MWC}_{7+}$  is the molecular weight of C<sub>7+</sub> in the oil,  $X_{\text{C}_1\text{N}_2}$  is the mole% of C<sub>1</sub> and N<sub>2</sub> in the oil,  $X_{\text{C}_2\text{-C}_6}$  is the mole% of C<sub>2</sub> to C<sub>6</sub> in the oil and T is temperature in °F.

#### Yuan Correlation (1977)

Yuan, H.; Johns, R.T.; Egwuenu, A.M.; Dindoruk, B.: Improved MMP Correlations for CO<sub>2</sub> Floods Using Analytical Gasflooding Theory, SPE 89359, 2005[8] Cronquist, C.: Carbon Dioxide Dynamic Miscibility With Light Reservoir Oils, 4th Annual U.S. DOE Symposium, August 1977. Valid for:

- Molecular Weight of C<sub>7+</sub> from 139 to 319 g/mol
- Temperature from 70°F to 300°F
- MMP up to 10,510 psi

For CO<sub>2</sub> injection, the following equation applies.

$$\text{MMP} = 145.04 [(a + b\text{MWC}_{7+} + cX_{\text{C}_2\text{-C}_6} + (d + e\text{MWC}_{7+} + fX_{\text{C}_2\text{-C}_6}/\text{MWC}_{7+}^2) T + (g + h\text{MWC}_{7+} + i\text{MWC}_{7+}^2 + j X_{\text{C}_2\text{-C}_6}) T^2] \quad (\text{EOR-14})$$

$$\begin{aligned} a &= -9.8912 \\ b &= 0.045588 \\ c &= -0.31012 \\ d &= 0.014748 \\ e &= 8.0441 \times 10^{-4} \\ f &= 56.303 \\ g &= -8.4516 \times 10^{-4} \\ h &= 8.8825 \times 10^{-6} \\ i &= -2.7684 \times 10^{-8} \\ j &= -6.3830 \times 10^{-6} \end{aligned}$$

Where: MMP is minimum miscibility pressure in psi,  $\text{MWC}_{7+}$  is the molecular weight of C<sub>7+</sub> in the oil,  $X_{\text{C}_2\text{-C}_6}$  is the mole% of C<sub>2</sub> to C<sub>6</sub>, CO<sub>2</sub> and H<sub>2</sub>S in the oil and T is temperature in °F.

#### Cronquist Correlation (1977)

[8] Cronquist, C.: Carbon Dioxide Dynamic Miscibility With Light Reservoir Oils, 4th Annual U.S. DOE Symposium, August 1977. Valid for:

- Oil Gravity from 23.7° to 44.8° API
- Temperature from 70°F to 250°F
- MMP from 1070 to 5000 psi

For CO<sub>2</sub> injection, the following equation applies.

$$\text{MMP} = 15.993 T^x \quad (\text{EOR-15})$$

$$x = 0.744206 + 0.0011038 \text{MWC}_{5+} + 0.0015279 X_{\text{C1N2}}$$

Where: MMP is minimum miscibility pressure in psi,  $\text{MWC}_{5+}$  is the molecular weight of C<sub>5+</sub> in the oil,  $X_{\text{C1N2}}$  is the mole% of C<sub>1</sub> and N<sub>2</sub> in the oil and T is temperature in °F.

It should be noted that all of the correlations were empirically generated. For more information on the calculations associated with each correlation, the appropriate reference should be reviewed. If using a correlation outside of its published limits, caution should be used when accepting the results.

As a rule of thumb, for CO<sub>2</sub> miscibility, Zhang et al appears to be the optimum overall correlation and for hydrocarbon gas miscibility, Maklavani et al appears to be the optimum correlation.

There is no option to export the MMP results to a file.

## EOR.2 Reservoir Thermal Properties

The 'Reservoir Thermal Properties' tool (Figure EOR-3) generates thermal properties that can be used in calculations and simulators.

Reservoir Thermal Properties	
Oil API	20
Porosity (%)	25
Oil Saturation (%)	50
Water Saturation (%)	50
Res Temperature (°F)	122
Shale Content (%)	0
Matrix Density (g/cc)	2.65
Oil SG at Res Temperature	0.908
Water SG at Res Temperature	0.9898
Oil Specific Heat (BTU/lb-°F)	0.471
Water Specific Heat (BTU/lb-°F)	1.003
Rock Specific Heat (BTU/lb-°F)	0.198
Res Heat Capacity (BTU/ft <sup>3</sup> -°F)	35686.6
Thermal Conductivity (BTU/h-ft-°F)	1.56

Figure EOR-3: EOR / Heavy Oil Tools – Reservoir Thermal Properties

The equations for specific heat properties are as follows.

(EOR-16)

$$\text{OilDen} = 141.5 / (\text{API} + 131.5)$$

$$\text{OilDen}_{\text{ResTemp}} = 1047 \text{OilDen} / (1047 + T_C - 20) \quad (\text{EOR-17})$$

$$\text{WaterDen}_{\text{ResTemp}} = .001 / (0.001 + 1.436 \times 10^{-6} (-4.8872 + 0.134186 T_C + 0.00212868 T_C^2)) \quad (\text{EOR-18})$$

$$\text{SpecificHeat}_{\text{Oil}} = (1.6848 + 0.00391 T_C) / \text{OilDen}_{\text{ResTemp}}^{0.5} \quad (\text{EOR-19})$$

$$\text{SpecificHeat}_{\text{Water}} = (4.3245 - 0.003696 T_C + 0.00002428 T_C^2) \quad (\text{EOR-20})$$

$$\text{SpecificHeat}_{\text{Rock}} = 0.01381 \text{Shale\%} + 0.0083(100 - \text{Shale\%}) \quad (\text{EOR-21})$$

Where:  $T_C$  is the reservoir temperature in °C, Specific Heat is in kJ/kg-°K.

The equations for heat capacity and thermal conductivity are as follows.

$$\begin{aligned} \text{HeatCap}_{\text{Res}} = & 1000 \phi \text{OilDen}_{\text{ResTemp}} \text{SpecificHeat}_{\text{Oil}} (1 - S_w) \\ & + 1000 \phi \text{WaterDen}_{\text{ResTemp}} \text{SpecificHeat}_{\text{Water}} S_w \\ & + 1000 (1 - \phi) \text{SpecificHeat}_{\text{Rock}} \rho_{\text{ma}} \end{aligned} \quad (\text{EOR-22})$$

$$\text{ThermalCond}_{\text{Res}} = 1.7307 [\text{Cond50} - 0.00128(T - 125) (\text{Cond50} - 0.82)] \quad (\text{EOR-23})$$

$$\text{Cond50} = 0.735 - 1.3 * \phi + 0.363 S_w^{0.5} (4.45 - 0.0445 \text{Shale\%} + 0.0165 \text{Shale\%}) \quad (\text{EOR-24})$$

Where:  $\text{HeatCap}_{\text{Res}}$  is the heat capacity of the reservoir in kJ/m<sup>3</sup>-°K,  $\text{ThermalCond}_{\text{Res}}$  is the thermal conductivity of the reservoir in W/m-°K and T is the reservoir temperature in °F.

### EOR.3 Hot/Cold Water Injection

The 'Hot/Cold Water Injection' tool (Figure EOR-4) generates a thermal profile of the reservoir.

Hot/Cold Water Injection	
Water Temperature (°F)	212
Water Injection Rate (bwpd)	3145
Reservoir Temperature (°F)	98.6
Formation Thickness (ft)	19.7
Res Heat Capacity (BTU/ft <sup>3</sup> -°F)	35686.6
Injection Time (days)	100
Distance From Well (ft)	49.2
Water SG at Injection Temperature	0.9589
Water Specific Heat (BTU/lb-°F)	1.003
Temperature at 'Distance' (°F)	208.7

Figure EOR-4: EOR / Heavy Oil Tools – Hot/Cold Water Injection

The reservoir parameters and water injection parameters are entered in the 'Hot/Cold Water Injection' section. The reservoir heat capacity is estimated using the 'Reservoir Thermal Properties' tool (Section EOR.2). The reservoir temperature profile is then plotted as a function of distance from the wellbore (Figure EOR-5).

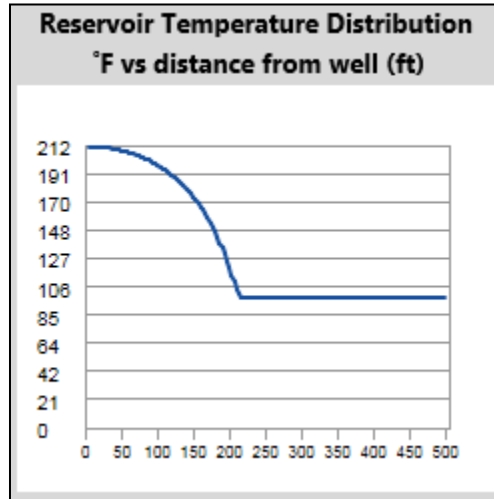


Figure EOR-5: EOR / Heavy Oil Tools – Temperature Profile

The technique to determine temperature in a reservoir at any distance from the wellbore was presented by Lauwerier (Lauwerier, H., A., The Transport of Heat in an Oil Layer Caused by the Injection of Hot Fluid, Applied Scientific Research, Volume 5, Issue 2, 1955), as reproduced below:

$$\text{TempDist} = \text{ResTemp} + (\text{InjTemp} - \text{ResTemp})\text{Comperfc} \quad (\text{EOR-25})$$

$$\text{Comperfc} = (1 + 0.278393\text{LauVar} + 0.230389\text{LauVar}^2 + 0.000972\text{LauVar}^3 + 0.078108\text{LauVar}^4)^{-4}$$

$$\text{LauVar} = \text{DimDist} / [2 (\text{DimTime} - \text{DimDist})^{0.5}]$$

$$\text{Dim\_Dist} = 3448.6 \text{ThermalCond}_{\text{Shale}} \text{Dist}^2 / (h \text{HeatCap}_{\text{Res}} \text{WaterDen}_{\text{InjTemp}} \text{SpecificHeat}_{\text{InjWater}})$$

$$\text{ThermalCond}_{\text{Shale}} = 43.752 / (T_c + 273.15)^{0.55}$$

$$\text{WaterDen}_{\text{InjTemp}} = .001 / (0.001 + 1.436 \times 10^{-6}(-4.8872 + 0.134186T_{\text{inj}} + 0.00212868T_{\text{inj}}^2))$$

$$\text{SpecificHeat}_{\text{InjWater}} = (4.3245 - 0.003696T_{\text{inj}} + 0.00002428T_{\text{inj}}^2)$$

$$\text{DimTime} = 1.098 \times 10^6 t \text{ThermalCond}_{\text{Shale}} / (h \text{HeatCap}_{\text{Res}})^2$$

Where: TempDist is temperature at a distance from the wellbore, ResTemp is reservoir temperature, InjTemp is injection water temperature,  $T_c$  is reservoir temperature in °C,  $T_{\text{inj}}$  is injection water temperature in °C, h is reservoir thickness in m, Dist is distance from the wellbore in m,  $\text{HeatCap}_{\text{Res}}$  is the heat capacity of the reservoir in  $\text{kJ/m}^3\text{-}^\circ\text{K}$ ,  $\text{ThermalCond}_{\text{Shale}}$  is the thermal conductivity of the shale in  $\text{W/m-}^\circ\text{K}$  and t is time in days.

The reservoir temperature profiles can be saved to a 'csv' file for plotting with PE<sup>2</sup> Essentials Chart (Figure EOR-6 and EOR-7) through the 'Export Distribution Data' button.

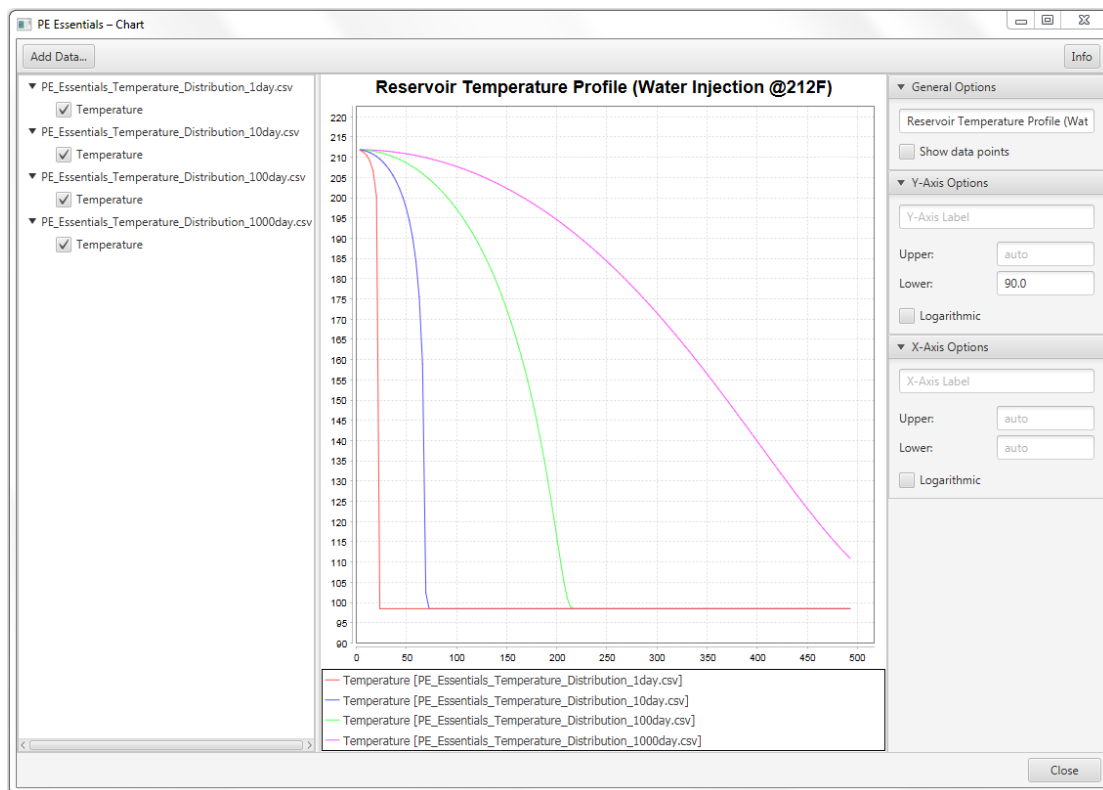


Figure EOR-6: EOR / Heavy Oil Tools – Heating Temperature Profile Over Time

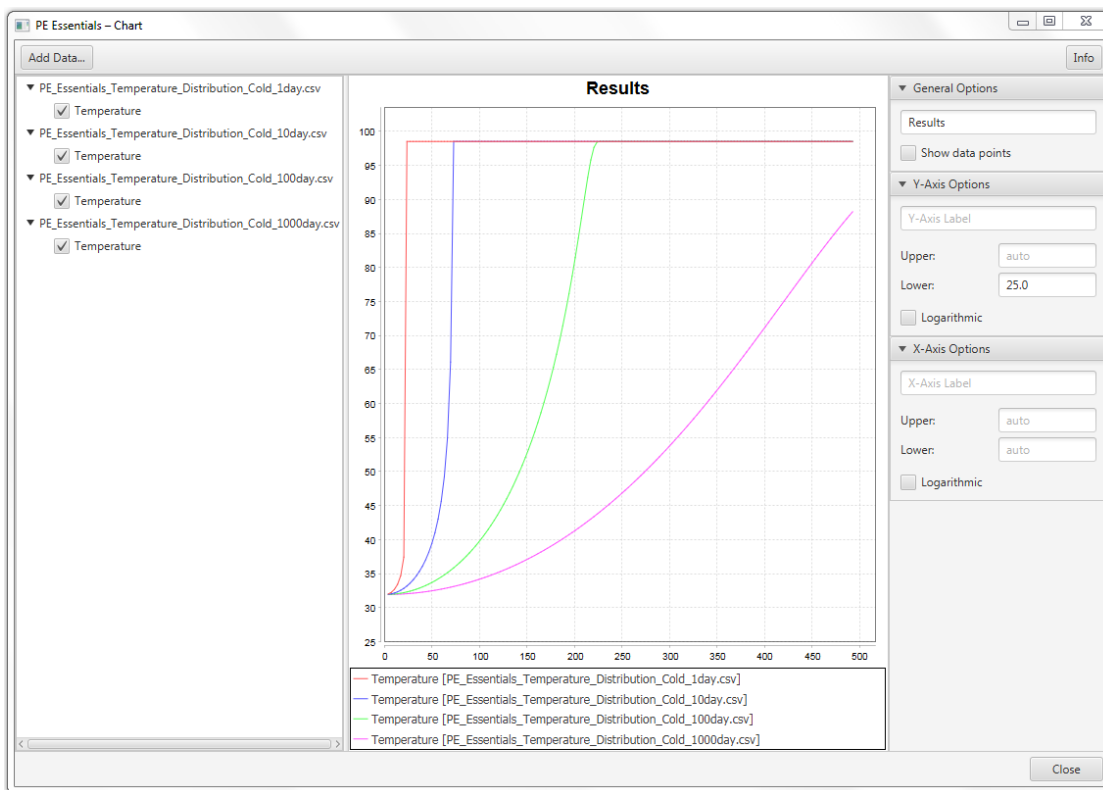


Figure EOR-7: EOR / Heavy Oil Tools – Cooling Temperature Profile Over Time

## EOR.4 SteamFlood Residual Oil

The residual oil saturation following a steam flood can be estimated based on oil viscosity and steamflood temperature using the 'SteamFlood Residual Oil Saturation' tool (Figure EOR-8).

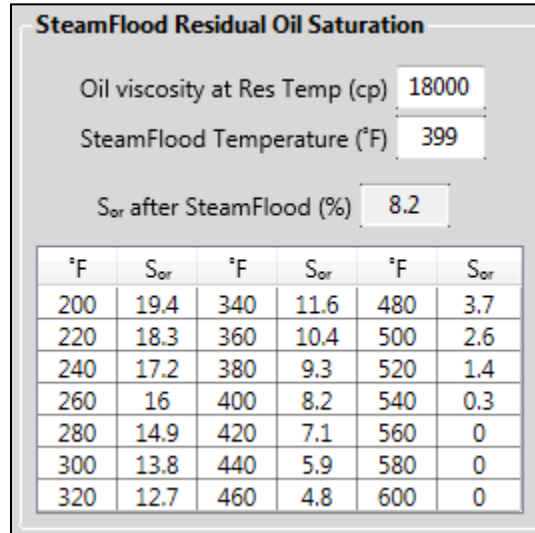


Figure EOR-8: IOR/EOR/Heavy Oil Tools – Residual oil Saturation

The S<sub>or</sub> correlation is based on results presented by Bursell and Pittman (Bursell, C., G. and Pittman, G., M., Performance of Steam Displacement in the Kern River Field, Journal of Petroleum Technology, SPE5017, August 1975). The correlation used in this tool is based on data presented as Figure 12 in the Bursell and Pittman paper.

The tool will generate the S<sub>or</sub> for the entered steam temperature and oil viscosity. It also presents a table of S<sub>or</sub> for different steam temperatures.

The correlation is presented as Equation 6-26.

$$S_{or} = 0.2736 + 1.832 \times 10^{-6} \mu - 5.617 \times 10^{-4} T_s \quad (\text{EOR-26})$$

Where: S<sub>or</sub> is the post steam flood residual oil saturation in decimal,  $\mu$  is oil viscosity and T<sub>s</sub> is steam temperature in °F.

### EOR.5 PCP and Sucker Rod Pump Rates

The rates generated by a PCP pump or a Sucker Rod pump can be calculated using the PCP and Sucker Rod Pump Rates tool shown in Figure EOR-9. This is not a pump design tool, but a tool to calculate the rates being generated at the operating conditions of the pump.

PCP Pump Rates		Sucker Rod Pump Rates	
Eccentricity of Rotor/Stator (in)	.1968	Pump Speed, Strokes per Min	5
Rotations per Minute	150	Plunger Area (in <sup>2</sup> )	50
Rotor Diameter (in)	1.575	Effective Plunger Stroke (ft)	1
Stator Pitch, Ps (in)	1.575	Volumetric Efficiency (%)	100
Volumetric Efficiency (%)	100		
PCP Pump Flow Rate (bbls/d)	43.5	Sucker Rod Pump Flow Rate (bbls/d)	445.2

Figure EOR-9: IOR/EOR/Heavy Oil Tools – Pump Rates

For a PCP pump, the equation is as follows.

$$\text{Rate}_{\text{PCP}} = 5.937 \times 10^{-3} (\text{Eccen}) (\text{Rots}) (\text{Dia}) (\text{Pitch}) (\text{Efficiency}) \quad (\text{EOR-27})$$

Where:  $\text{Rate}_{\text{PCP}}$  is the pump rate in bbls/d and all other terms are as input.

For a sucker rod pump, the equation is as follows.

$$\text{Rate}_{\text{SRP}} = 0.01781 (\text{Speed}) (\text{Area}) (\text{Stroke}) (\text{Efficiency}) \quad (\text{EOR-28})$$

Where:  $\text{Rate}_{\text{SRP}}$  is the pump rate in bbls/d and all other terms are as input.

## PE Field Development Essentials

The Field Development Essentials section contains the following program:

- Field Development Planning
- System Nodal Analysis
- Interference Analysis

## Field Development Planning Tool

The PE<sup>2</sup> Essentials 'Field Development Planning' tool can be used to generate project based forecasts using a type curve as the basis for the production forecast (Figure FDP-1).

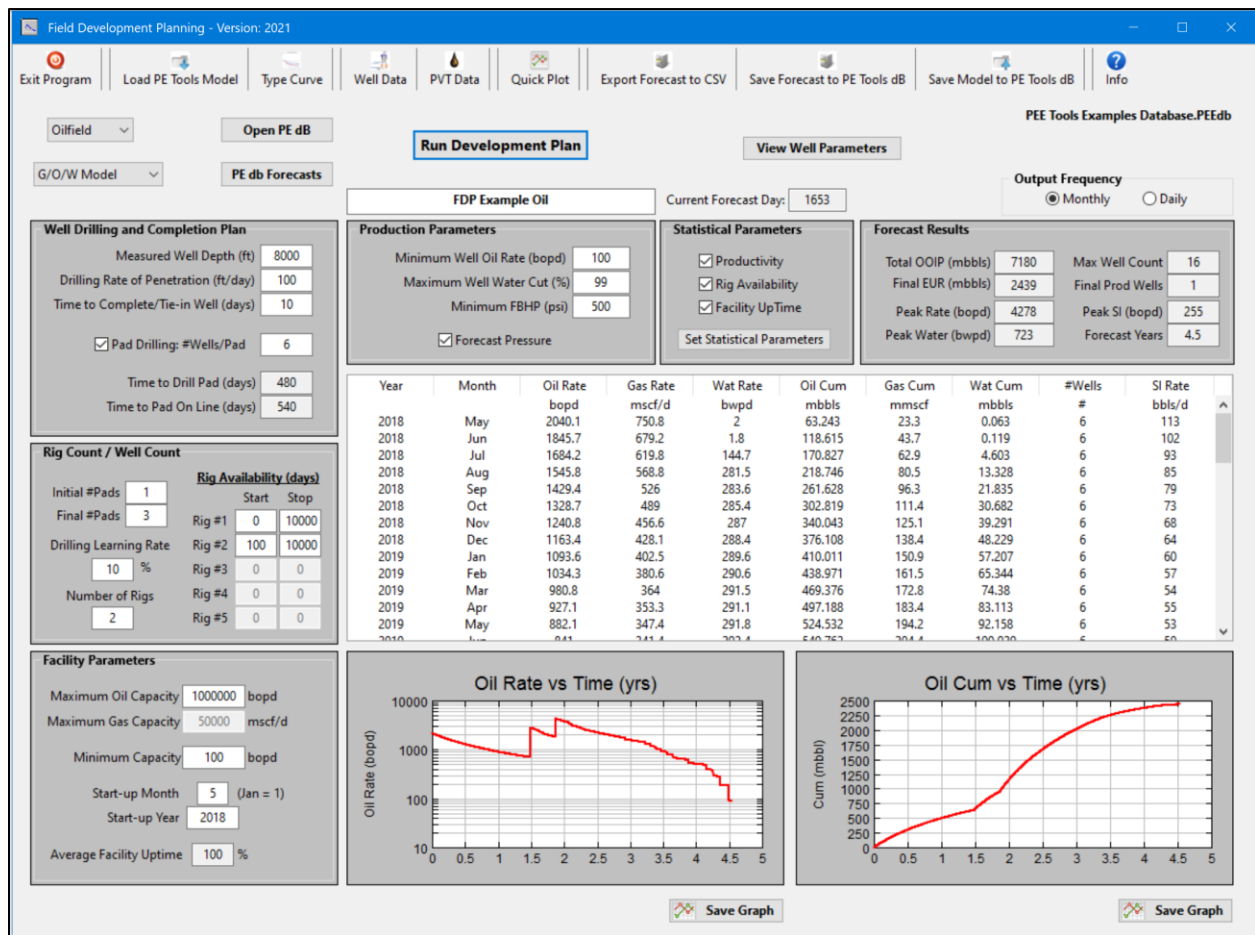


Figure FDP-1: Field Development Planning Tool

The type curve is generated by normalization of rate-cum data. The rate-cum data can be entered from an Excel spreadsheet or from forecast files generated by other PE<sup>2</sup> Essentials tools. If there is more than one well or pad in the development scenario, variations in each well's productivity can be generated through the incorporation of 'Statistical Parameters'.



If well flowing pressure data is required, the reservoir, wellbore and PVT parameters need to be entered. Most of the parameters required to calculate pressure can be entered by importing a PE<sup>2</sup> Essentials THP-BHP file.

### FDP.1 Well Type Curves

Three options are available for importing well type curve data: from an Excel file, from a PE Tools database forecast or from a separate DCA database. Figures FDP-2 and FDP-3 show an example of importing data from Excel.

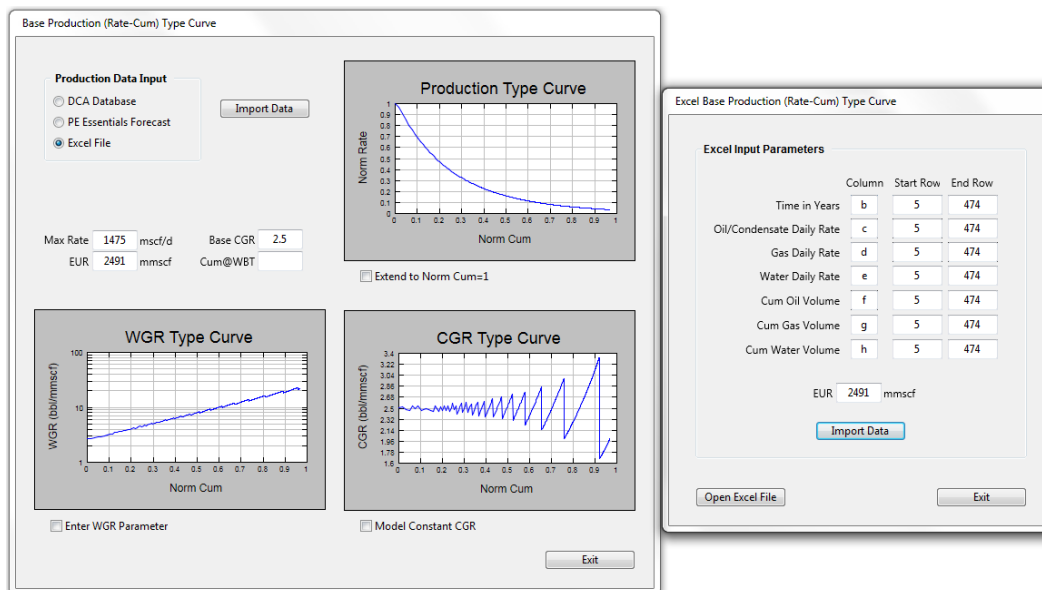


Figure FDP-2: Field Development Planning Tool – Well Type Curve Input and Generation

3	Days	Years	Cond Rate	Gas Rate	Water Rate	Cond Cum	Gas Cum	Water Cum
4			bcpd	mscf/d	bopd	mbbl	mmscf	mbbl
5	0	0	3.7	1475	3.9	0	0	0
6	31	0.084932	3.6	1425.6	3.8	0.11	44.194	0.118
7	59	0.161644	3.3	1335.8	3.7	0.204	81.596	0.222
8	90	0.246575	3.1	1257.2	3.6	0.301	120.569	0.334
9	120	0.328767	3	1185.5	3.5	0.39	156.134	0.44
10	151	0.413699	2.8	1121.9	3.4	0.477	190.912	0.546
11	181	0.49589	2.7	1065	3.4	0.557	222.863	0.647
12	212	0.580822	2.5	1013.9	3.3	0.636	254.295	0.749
13	243	0.665753	2.4	967	3.2	0.711	284.271	0.849
14	273	0.747945	2.3	925	3.2	0.78	312.021	0.944
15	304	0.832877	2.2	886.7	3.1	0.849	339.508	1.041
16	334	0.915068	2.1	851.5	3.1	0.913	365.055	1.132
17	365	1	2	819.2	3	0.976	390.45	1.226
18	396	1.084932	2	788.8	3	1.037	414.904	1.318
19	424	1.161644	1.9	762	2.9	1.091	436.241	1.4
20	455	1.246575	1.8	737.1	2.9	1.148	459.092	1.489
21	485	1.328767	1.8	713	2.8	1.201	480.484	1.574
22	516	1.413699	1.7	690.6	2.8	1.255	501.891	1.661

Figure FDP-3: Field Development Planning Tool – Excel Data

Figure FDP-4 shows an example of importing the well type curve data from a PE<sup>2</sup> Essentials DCA database. For this option, the wells in the database are loaded and a well is selected for use in the Development Planning tool.

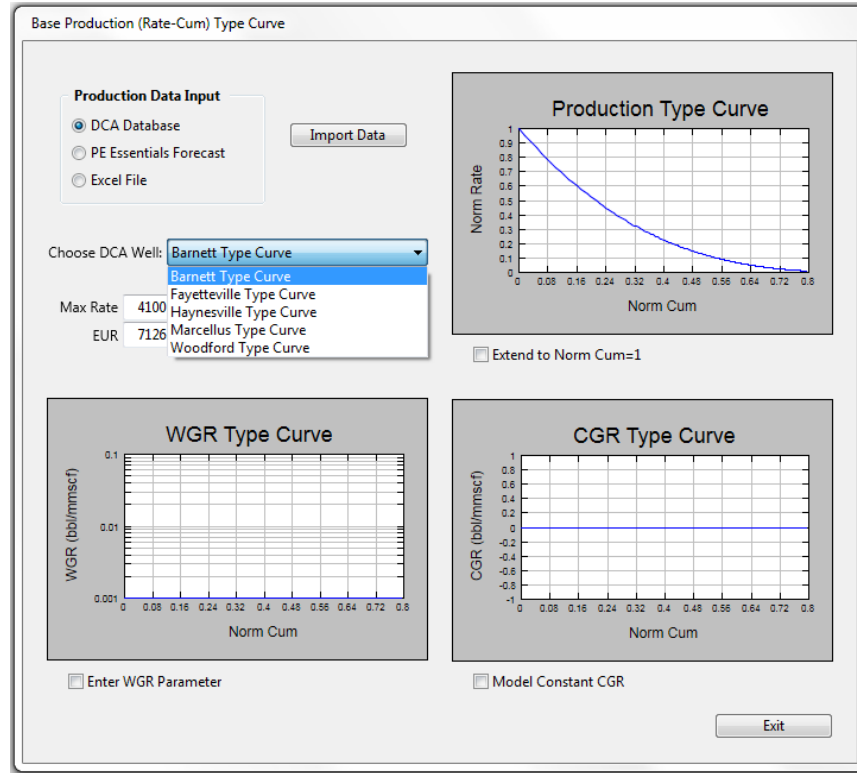


Figure FDP-4: Field Development Planning Tool – Excel Data

To generate the well type curves, the imported data is normalized to the maximum rate (Norm Rate) and the volume initially in place (Norm Cum). For DCA data, the 'Norm Cum' calculation is based on the EUR calculated from the DCA analysis results. Type curves for WGR/WOR and for CGR/GOR are generated from water and oil/condensate production data and referenced to the cumulative hydrocarbon production (Norm Cum).

It is possible to set up, or modify, a water profile by entering a value into the 'Cum@WBT' box which represents the cumulative production at water breakthrough, checking the 'Enter WGR Parameter' (or 'Enter WOR Parameter') and entering the Norm Cum value at a WGR/WOR of 10.

A constant CGR/GOR can be modeled by checking the 'Model Constant CGR' (or 'Model Constant GOR') and entering the constant value into the 'Base CGR' ('Base GOR') box.

Figure FDP-5 shows the results of these procedures.

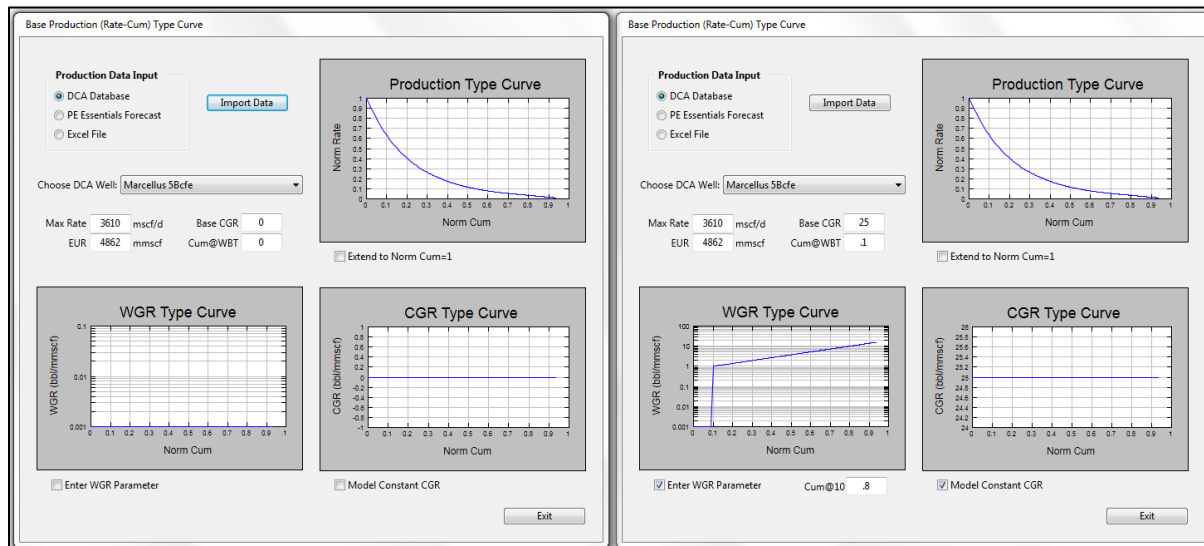


Figure FDP-5: Field Development Planning Tool – Modifying Parameters

The normalized well type curve is the basic building block for the forecasting routines in the PE<sup>2</sup> Essentials Development Planning tool. To incorporate variations in each well's production characteristic, a statistical option is available that uses a Gaussian distribution to vary the initial maximum rate and the final EUR/GIIP/OOIP value for each well. Refer to Section FDP.6 for information on use of the 'Statistical Parameters'.

## FDP.2 Well Drilling and Completion Planning

Pad drilling of unconventional wells may reduce the cost of drilling wells. The downside of pad drilling is that once the well is drilled the time to the start of its production is delayed until the entire pad is ready to be placed on production. The PE<sup>2</sup> Essentials Development Planning tool includes an option to model pad drilling (Figure FDP-6).

Figure FDP-6: Field Development Planning Tool – Well Planning

The pad drilling option is implemented by checking the 'Pad Drilling: #Wells/Pad' option and entering the number of wells to be drilled on each pad. If this option is not checked, individual sequential well drilling will be incorporated into the profile.

The time to actually drill and complete all wells on the pad will determine when a production increase will occur. For economic modelling purposes, the timing of each well on the pad is included in the forecast so that the capital spending can be modeled properly in the Economics tools.

### FDP.3 Rig Schedule Planning and Drilling Learning Rate

If more than one well or pad is included in the project, a rig schedule has to be included in order to drill the wells. The PE<sup>2</sup> Essentials Development Planning tool allows up to 5 rigs to be included in the development. The time that each rig is available is specified (Figure FDP-7).

Rig Count / Well Count		Rig Availability (days)	
		Start	Stop
Initial #Pads	1		
Final #Pads	3	Rig #1	0 10000
Drilling Learning Rate		Rig #2	100 10000
10 %		Rig #3	0 0
Number of Rigs		Rig #4	0 0
2		Rig #5	0 0

Figure FDP-7: Field Development Planning Tool – Rig/Well Planning

It should be noted that if more than one well is available at the same time, one of the wells will be delayed. This is part of the rig scheduling routines. Also, it is assumed that all rigs can drill all wells so when a rig is otherwise idle, it will be used to drill other pad wells.

A drilling learning curve is included in the PE<sup>2</sup> Essentials Field Development Planning tool to model the fact that doubling of drilling experience will reduce the required time to drill a well by a constant percentage. The learning curve model incorporated in the Field Development Planning tool was developed by T. P. Wright in 1936 and is referred to as the Cumulative Average Model or Wright's Model. Wright's model can be expressed as Equation FDP.1.

$$Y = aX^b \quad (\text{FDP.1})$$

Where: Y is the cumulative average time to drill a well, X is the cumulative number of wells, a is the time to drill the first well and b is the Learning Slope (Equation FDP.2).

$$\text{Learning Slope} = \text{Log}(\text{learning}) / \text{Log}(2) \quad (\text{FDP.2})$$

The value for 'learning' used in the tool is defined as  $(100 - \text{Learning Rate})/100$ . So, for example, entering a Learning Rate of 10% will yield a Learning Slope of -0.152. For an initial pad drilling time of 480 days, the learning curve is shown in Figure FDP-8.

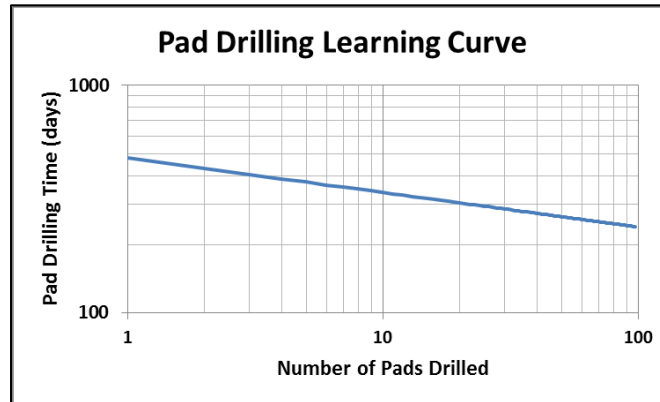


Figure FDP-8: Field Development Planning Tool – Learning Curve

Caution should be used when including a learning rate for individual wells. As well count increases, drilling time may become unrealistically low.

It should be noted that Learning Rates typically range between 0% and 30%. Learning Rates above 30% are rare according to published references.

#### FDP.4 Facility Planning and Uptime Modelling

Facility constraints, in terms of maximum and minimum capacities, are entered and used for rate cut-back and project shut-in criteria (Figure FDP-9). Minimum well rates, which are used to shut in a well, are specified in the 'Production Parameters', Section FDP.5.

Facility Parameters	
Maximum Oil Capacity	1000000 bopd
Maximum Gas Capacity	50000 mscf/d
Minimum Capacity	500 mscf/d
Start-up Month	5 (Jan = 1)
Start-up Year	2018
Average Facility Uptime	100 %

Figure FDP-9: Field Development Planning Tool – Facilities Modeling

Water production limits are not included in the PE<sup>2</sup> Essentials Development Planning tool. It is assumed that all produced water will be handled by the facilities. When modeling conventional or offshore projects this may be an issue and should be taken into account in the forecast.

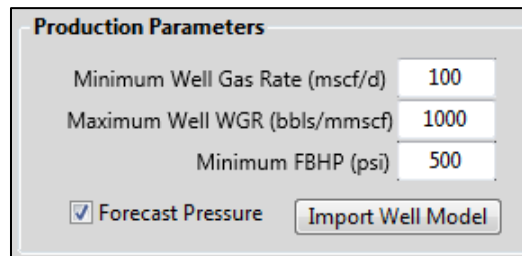
Incorporating water limits is not straightforward because water is not a primary component of the production (like oil or gas) but is a function of the cumulative production from a specific well. This means that determining the optimum well to cut back to reduce the water rate while maintaining maximum gas production will be a non-linear problem. If necessary, this type of algorithm could be incorporated into a future version of the tool.

Uptime of the facilities can be modeled as a constant parameter or can be made to vary using 'Statistical Parameters' (Section FDP.6). The cost, in production, of the facilities downtime is shown in the 'SI Rate' reported during the run (refer to Section FDP.7).

Modeling of the facility's capacity limit enables the possibility of evaluating the economics of facility debottlenecking by determining the value of the SI Rate and/or generating forecasts at different values of facility capacity for economic comparisons.

## FDP.5 Production Modeling

Production modeling can be straight forward based on the type curves or can include modeling of the well's bottom hole and tubing head pressures (Figure FDP-10).



Production Parameters	
Minimum Well Gas Rate (mscf/d)	100
Maximum Well WGR (bbls/mmscf)	1000
Minimum FBHP (psi)	500
<input checked="" type="checkbox"/> Forecast Pressure	<button>Import Well Model</button>

Figure FDP-10: Field Development Planning Tool – Production Modeling

The values entered for 'Minimum Well Gas Rate' or 'Minimum Well Oil Rate' and 'Maximum Well WGR' or 'Maximum Well WOR' are used to shut in the well. It should be noted that if minimum rate is very low, the forecast may extend for a long time if the type curve has a long 'tail'. The absolute limit for the forecast is 30,000 days.

To model pressures, the 'Forecast Pressure' option is checked. The wellbore and reservoir parameters can be imported from the PE Tools database by clicking on 'Well Data' and 'Import Well Model'. When selecting this option, the PVT parameters can also be imported from the well model (Figure FDP-11). PVT parameters can also be imported from the PE Tools database by clicking the 'Import PVT Properties' on the PVT screen (Figure FDP-12).

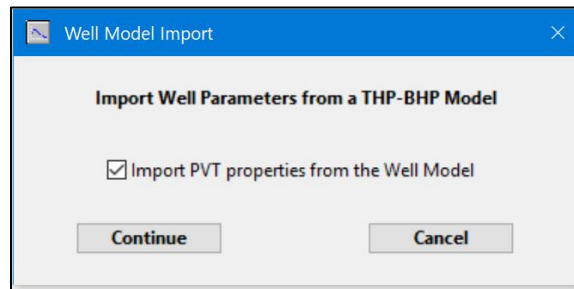


Figure FDP-11: Field Development Planning Tool – Importing Well and PVT Parameters

If the well and PVT parameters are not imported from the PE Tools database, they can be entered manually (Figure FDP-12).

Figure FDP-12: Field Development Planning Tool –Well and PVT Parameters

The entered well and reservoir parameters can be varied using the 'Statistical Parameters' option (section FDP.6). The parameters will be varied for every well in the model based on the entered Gaussian distribution.

Including pressure modeling in the forecast enables the economic evaluation of reducing the facility pressure or adding compression to the facilities. This is done by running forecasts at different pressure limits.

Well flowing pressure is calculated based on two assumptions: a) the reservoir pressure can be estimated using the calculated normalized rate-cum data; and b) the wellbore pressure drop can be defined using the LIT equation.

### FDP.5.1 Well Pressure Calculation

The PE<sup>2</sup> Essentials Development Planning tool is not a rigorous reservoir/production simulator. As a result, the pressure calculation routines should be considered as estimates only.

To calculate the reservoir pressure at any time in the forecast, it is assumed that for an unconstrained system (not choked), declining production rate is the result of declining reservoir pressure. This allows the normalized rate-cum relationship to be converted to a pressure-normalized cum relationship (Figure FDP-13).

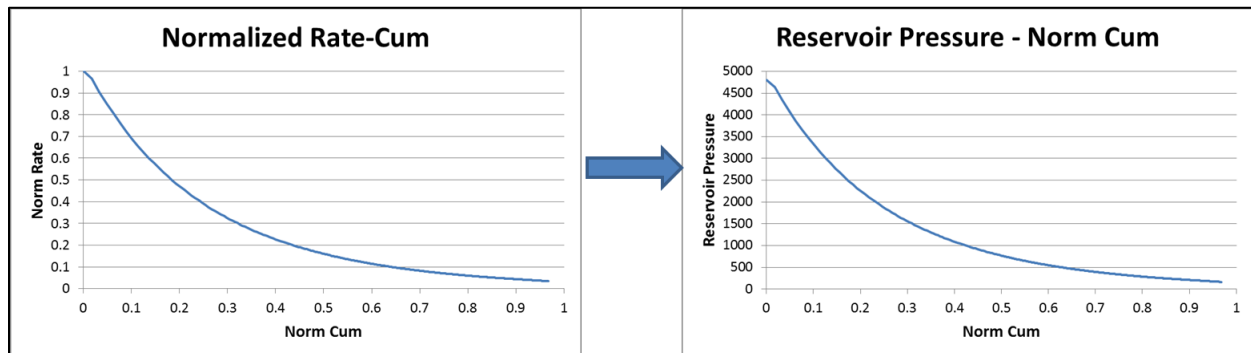


Figure FDP-13: Field Development Planning Tool – Determination of Reservoir Pressure

Using the Reservoir Pressure – Norm Cum relationship, the reservoir pressure can be estimated at any point in the forecast. With reservoir pressure, the Laminar-Inertial-Turbulent (LIT) flow equation (gas) or the Vogel equation (oil) is then used to calculate the flowing bottomhole pressure (FBHP).

For gas wells, the LIT equation is presented in Equation FDP.3 (ref: Tarek Ahmed, Reservoir Engineering Handbook, Gulf Publishing, 2001; and L. Mattar, G. Brar, and M. Mumby; Theory and Practice of the Testing of Gas Wells, Energy Resources Conservation Board, 1978).

$$\Delta P^2 = P_R^2 - \text{FBHP}^2 = a q_g + b q_g^2 \quad (\text{FDP.3})$$

$$a = 1424 \mu_g Z T_R (\ln(0.472 r_e / r_w) + \text{Skin}) / (k h)$$

$$b = 0.128 \text{ GasG } Z T_R / (k^{1.333} r_w h^2)$$

$$r_e = (\text{WellArea} * 43560)^{0.5}$$

Where:  $P_R$  is reservoir pressure at the current time in psi,  $q_g$  is the gas flow rate in mscf/d,  $\mu_g$  is gas viscosity in cp,  $Z$  is the gas deviation factor,  $T_R$  is the reservoir temperature in °R,  $r_e$  is the outer radius of the reservoir,  $r_w$  is the wellbore radius in ft (model assumes an 8 inch wellbore),  $\text{Skin}$  is the wellbore skin factor,  $k$  is reservoir permeability in md,  $h$  is the net pay in ft,  $\text{GasG}$  is gas specific gravity and  $\text{WellArea}$  is drainage area of the well in acres.

In order to check the validity of the input parameters, the absolute open flow potential (AOFP) of the well,  $\Delta P^2 = P_R^2$ , is calculated (Equation FDP.4) and compared to the maximum rate.

$$\text{AOFP} = (-a + (a^2 + 4b \Delta P^2)^{0.5}) / 2b \quad (\text{FDP.4})$$



For saturated oil wells, Fetkovitch's methodology for use of Vogel's equation is presented in Equation FDP.5 (ref: Tarek Ahmed, Reservoir Engineering Handbook, Gulf Publishing, 2001).

$$\begin{aligned}\Delta P^2 &= P_R^2 - \text{FBHP}^2 = 2P_b q_o / \text{PI} \\ \text{PI} &= 0.00708 k h / (\mu_o B_o (\ln(0.472r_e/r_w) + \text{Skin})) \\ r_e &= (\text{WellArea} * 43560)^{0.5} \\ \text{AOFP} &= \text{PI } P_R^2 / 2P_b\end{aligned}\quad (\text{FDP.5})$$

Where:  $P_R$  is reservoir pressure at the current time in psi,  $q_o$  is the oil flow rate in bopd,  $P_b$  is the bubble point pressure in psi, PI is the well productivity index in bopd/psi,  $\mu_o$  is oil viscosity in cp,  $B_o$  is the oil formation volume factor,  $r_e$  is the outer radius of the reservoir,  $r_w$  is the wellbore radius in ft (model assumes an 8-inch wellbore), Skin is the wellbore skin factor,  $k$  is reservoir permeability in md,  $h$  is the net pay in ft and WellArea is drainage area of the well in acres.

The FBHP is converted to flowing tubing head pressure (THP) for reporting purposes. When using the 'Forecast Pressure' option, the rate is controlled by FBHP. THP control is not implemented in this version of the tool.

### FDP.6 Statistical Modeling Using Gaussian Distributions

The PE<sup>2</sup> Essentials Development Planning tool includes the option to randomly vary some of the forecast parameters (Figure FDP-14).

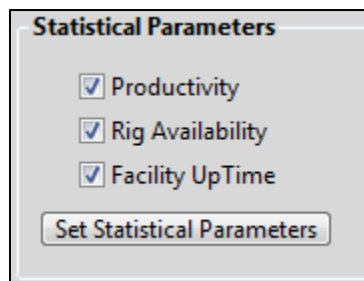


Figure FDP-14: Field Development Planning Tool – Statistical Variations

Gaussian distributions can be entered for 'Productivity', 'Rig Availability' and 'Facility UpTime' which will incorporate variations for these modeling parameters.

As the forecast proceeds, the Gaussian distribution is randomly sampled, and modifications are applied to the appropriate parameter to apply variability to the forecast. It should be noted that as for other PE<sup>2</sup> Essentials distributions, entering a 'Seed' value will generate the same variable results for each run. Entering a 'Seed' value of -1 will ensure the distribution is sampled randomly.

### FDP.6.1 Statistical Well Productivity

Well productivity can be varied in two ways. The well's type curve parameters can be varied by entering Gaussian distributions for the initial rate and/or the EUR/GIIP/OOIP values. These parameters will vary the initial productivity of each well as well as the ultimate recovery for each well (Figure FDP-15).

Type Curve Parameters		Production Parameters	
Low Rate Factor	.8	Low Perm Factor	.8
Mid Rate Factor	1	Mid Perm Factor	1
High Rate Factor	1.2	High Perm Factor	1.2
Low Cum Factor	.8	Low Pay Factor	.8
Mid Cum Factor	1	Mid Pay Factor	1
High Cum Factor	1.2	High Pay Factor	1.2
Seed			
-1		Exit	

Figure FDP-15: Field Development Planning Tool – Productivity Variations

When modeling well pressures, the reservoir permeability and/or the reservoir pay can also be varied. This will impact each well's productivity in terms of the flowing pressure limitation for the well.

The 'Minimum FBHP' (Figure FDP-10) will be used to limit the flowing pressure for the well. Once the FBHP target is reached, the well will continue to produce at this pressure until the minimum rate is reached, after which the well will be shut in. THP is calculated at each time step but is not used to control well production.

The values entered for the 'Type Curve Parameters' are used to vary the de-normalization of the original type curve entered into the model. This will ensure that no two wells have the same rate-cum profile. The entered low-mid-high values can be skewed to ensure more wells of a certain type (high or low) are modeled.

After a forecast is generated, it is possible list the actual statistical parameters used for each well by clicking 'View Well Parameters'. This generates a list of the well parameters (Figure FDP-16) and includes an option to export the data to a CSV file.

Production Statistical Parameters

**Statistical Production / Well Parameters**

Well #	Qi (bopd)	EUR (mbbls)	Perm (md)	Pay (ft)
1	400	404	0.2	300
2	396.3584	400.3219	0.1981792	297.2688
3	390.1018	394.0028	0.1950509	292.5763
4	422.3288	426.5521	0.2111644	316.7466
5	323.1419	326.3733	0.161571	242.3564
6	333.249	336.5815	0.1666245	249.9368
7	343.1977	346.6297	0.1715988	257.3983
8	354.1736	357.7153	0.1770868	265.6302
9	365.5804	369.2362	0.1827902	274.1853
10	377.2089	380.981	0.1886045	282.9067
11	389.7066	393.6037	0.1948533	292.28
12	402.8069	406.835	0.2014035	302.1052
13	416.6914	420.8583	0.2083457	312.5186
14	431.8063	436.1244	0.2159032	323.8547
15	447.6874	452.1643	0.2238437	335.7655
16	466.1489	470.8104	0.2330744	349.6116
17	471.4318	476.1461	0.2357159	353.5739
18	377.5821	381.3579	0.1887911	283.1866

Random Number Seed:

Figure FDP-16: Field Development Planning Tool – Production Well Parameters

The random seed number is also presented and can be entered into the statistical setup (Figure FDP-15) in order to generate the same well parameters for each run.

### FDP.6.2 Statistical Rig Availability

When more than one rig is included, it is possible to randomly vary the start time of when subsequent rigs will be available (Figure FDP-17).

**Rig Availability Distribution**

**Rig Start Time Gaussian Distribution Parameters**

Early Rig Start (( $\Delta d$ )  days

Mid Rig Start (normally=0)  days

Late Rig Start ( $\Delta d$ )  days

Seed

Figure FDP-17: Field Development Planning Tool – Rig Availability Variations

The rig will have either an early or a late start. The values entered for early and late start are entered as positive since the parameter is relative to the base value which is normally set to zero (on time availability). The Gaussian distribution will be randomly sampled to determine whether the rig will have an early or late start.

### FDP.6.3 Statistical Facility Uptime

The facility uptime can be varied on an annual, semi-annual or quarterly basis (Figure FDP-18).

Facility Uptime Distribution

**Uptime Gaussian Distribution Parameters**

Low Facility Uptime 90 %

Mid Facility Uptime 95 %

High Facility Uptime 98 %

**Vary Uptime**

☒ Annually

☐ Every Six months

☐ Every Three Months

Seed -1

Exit

Figure FDP-18: Field Development Planning Tool – Facility Uptime Variations

It should be noted that all pressure calculations are performed based on the gross production rate not the net production rate which results from the facility uptime. The actual cumulative volume produced for the time interval is based on the net production rate. Gross production rate can be determined by adding the reported production rate and the reported SI rate for production that is not constrained by facility maximum rate limitations.

Whenever the facility uptime is entered as 100%, the gross production rate will be the same as the net production rate.

Modeling facility uptime allows the determination of the economic value associated with facility upgrades to enhance the facility operation. This could be performed by evaluating the economic value of the SI Rate at different constant uptime values or comparing the SI Rates at a constant uptime value with random uptime values.

## FDP.7 Model Output

The PE<sup>2</sup> Essentials Development Planning tool output can be displayed in monthly or daily format (Figure FDP-19).

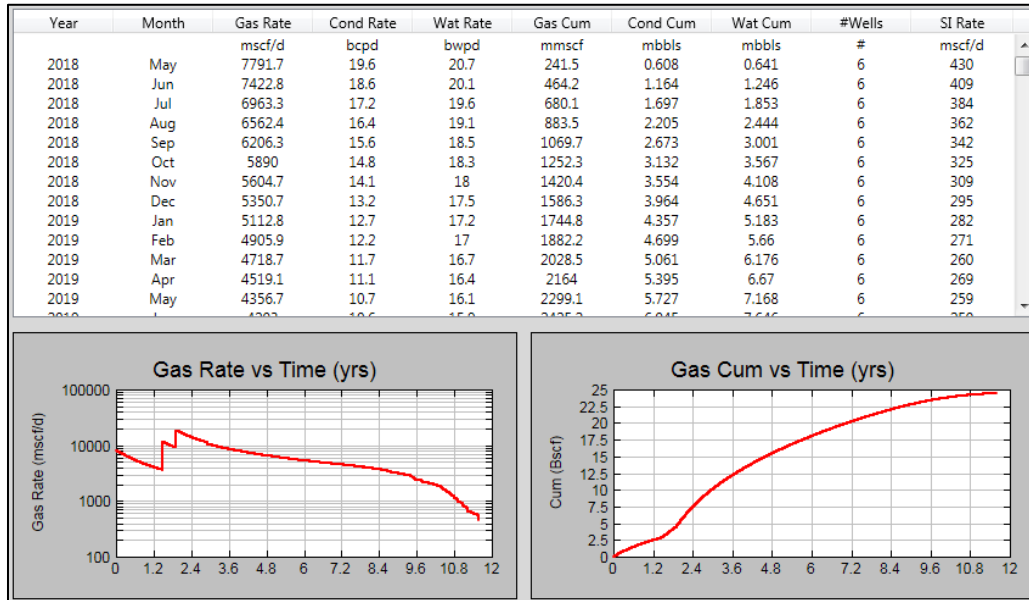


Figure FDP-19: Field Development Planning Tool – Forecast

The data can be saved to a 'csv' file in a monthly or daily format. The daily format will include the well-by-well data along with the total project forecast. If well pressures are modeled, they will be saved for each well. If pads are modeled, the pad production will be stored in the monthly file along with the total project forecast.

Note - In order to use the forecast results in the PE<sup>2</sup> Essentials economics tools, the 'Output Frequency' option should be set to 'Daily'. This will ensure all characteristics of the forecast are captured in the economics analysis.

The Development Modeling tool includes a 'Quick Plot' option to evaluate the results (Figure FDP-20).

The 'Save Graph' button will save the current graph to a 'png' file.

If the 'Quick Plot' window is left open during a subsequent run, the 'Update' button can be used to re-draw the graph with the data from a new run.

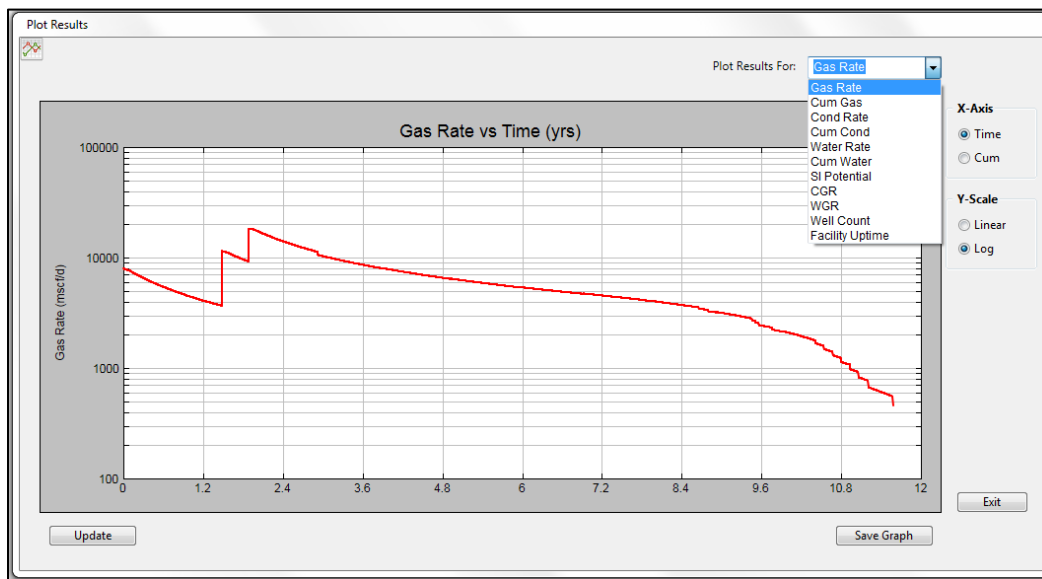


Figure FDP-20: Field Development Planning Tool – Quick Plot

For a more complete look at the results, the data can be saved to a csv file by clicking 'Export Forecast to CSV'. Note that the daily file includes well forecasts as well and depending on the number of wells in the project, the file may be too big to be imported into a spreadsheet.

## System Nodal Analysis Tool

The PE<sup>2</sup> Essentials 'Nodal Analysis' tool (Figure NOD-1) calculates the pressure drop through a system of nodes that makes up the total production system, including reservoir, wellbore, pipelines, ESP, gas lift and compressors.

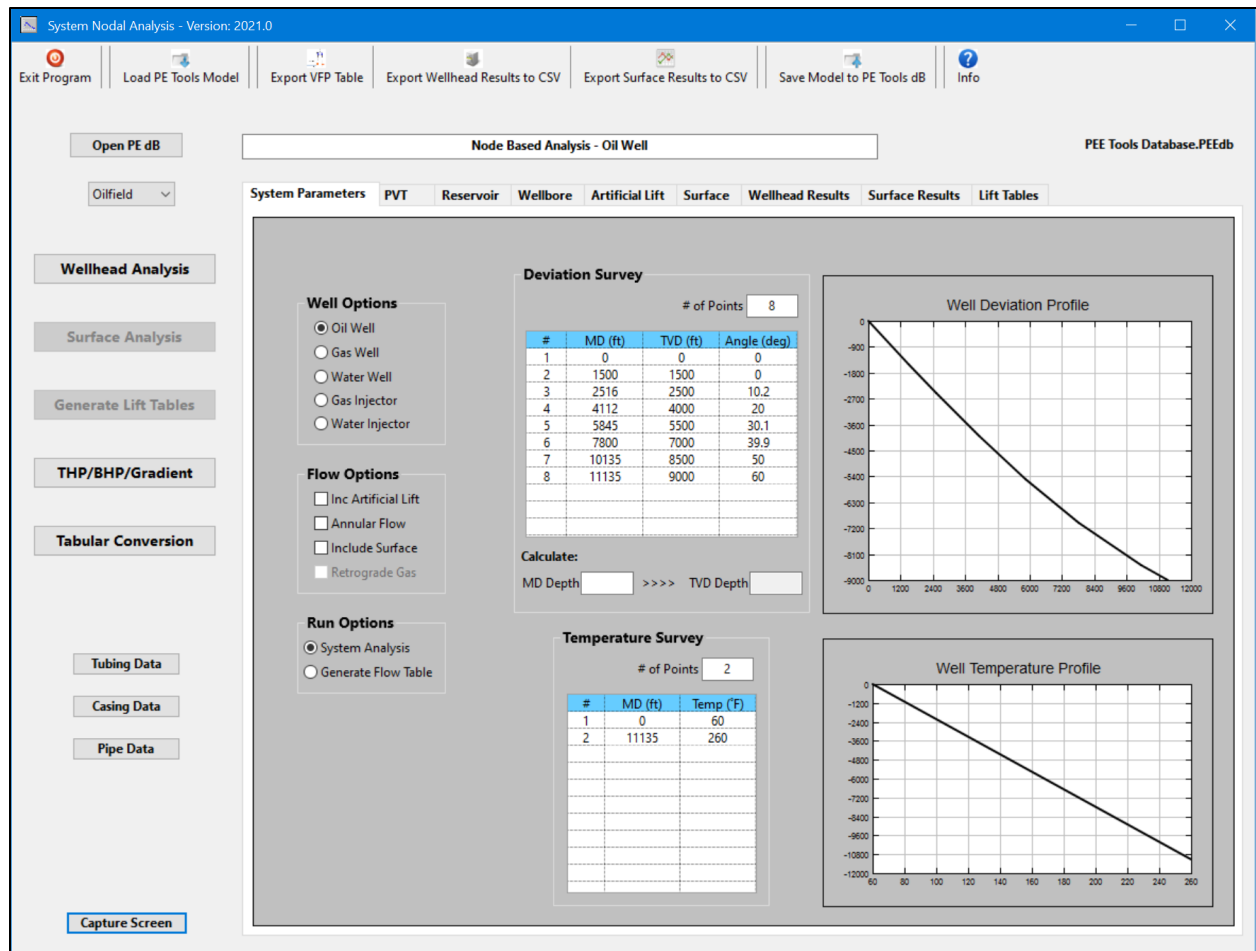


Figure NOD-1: PE<sup>2</sup> Essentials Nodal Analysis Tool

PE Essentials Nodal Analysis tool performs a node-based analysis which means it calculates pressure drop at different nodes in the system starting at the input node (downhole or surface) and continues to the output node. To improve accuracy, the entire system is subdivided into small incremental nodes to limit the pressure change over the interval.

The Nodal Analysis tool is more in-depth than the PE<sup>2</sup> Essentials 'Basic THP-BHP Gas Well' tool. It includes more well options, including wellbore trajectories, artificial lift and injectors, and includes surface pipelines which can also include compressors.

The PE<sup>2</sup> Essentials Nodal Analysis tool includes the following:

- Modeling oil, gas and water production wells
- Modeling gas and water injection wells
- Modeling of artificial lift: ESP and gas lift
- Modeling annular flow
- Modeling surface networks, including compressor
- Modeling retrograde gas wells
- Generation of simulator flow tables
- Single pressure point calculations (correlation calibration)
- Full wellbore and surface pipeline deviation surveys
- Conversion of pressure table to BHP
- Matching of oil PVT properties
- Full incorporation of reservoir IPR performance
- Gas multi-rate IPR calculations (c and n)
- Wellbore tubing correlations include:
  - Hagedorn & Brown
  - Beggs & Brill
  - Orkiszewski
  - Mukherjee & Brill
  - Gray
  - Mechanistic Model
- Surface pipeline correlations include:
  - Beggs & Brill

For more complete information on the tubing and pipeline correlations, refer to the Appendix.

There is a wellbore ‘Pressure Matching Factor’ included in the single point pressure calculation option that may assist with matching of known pressure data. Entering a value for this factor will modify the frictional gradient term in the pressure drop calculations. To change the hydrostatic gradient, modify the oil properties. Note that the pressure matching factor will be used in all wellbore pressure drop calculations but not in the surface pipeline calculations.

The wellbore results and the surface results can be exported to a CSV file. The total system results can be saved to a flow performance table which can then be imported into a reservoir simulator data file.

There are a number of general references describing fluid flow in wells and pipelines. The definitive reference is by Kermit Brown and H.Dale Beggs; “The Technology of Artificial Lift Methods, Volume 1: Inflow Performance, Multiphase Flow in Pipes, The Flowing Well”, PennWell Books, June 1980. Another excellent reference is by Eissa Al-Safran and James Brill; “Applied Multiphase Flow in Pipes and Flow Assurance, Oil and Gas Production” SPE, 2017.



There are a number of example nodal analysis models included in the 'PEE Tools Database.PEEdb' located in the 'Example Input Files\PEE Tools Database' directory. Figure NOD-2 presents the models included in the database.

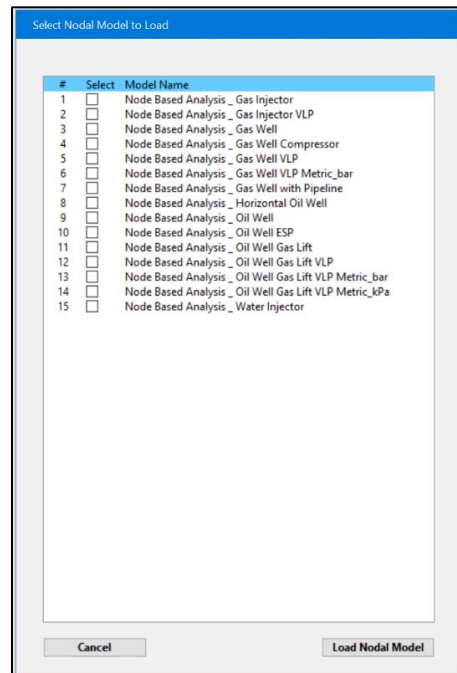


Figure NOD-2: PE<sup>2</sup> Essentials Nodal Analysis Tool – Examples

### NOD.1 Node-Based Analysis

A petroleum production system consists of two parts - the reservoir and the piping system. The reservoir is where the hydrocarbons originate, and the piping system is the means to transport the reservoir fluids from the reservoir to the processing facility. Figure NOD-3 shows a schematic of the production system with three main nodes: reservoir; well; and surface pipeline/facilities.

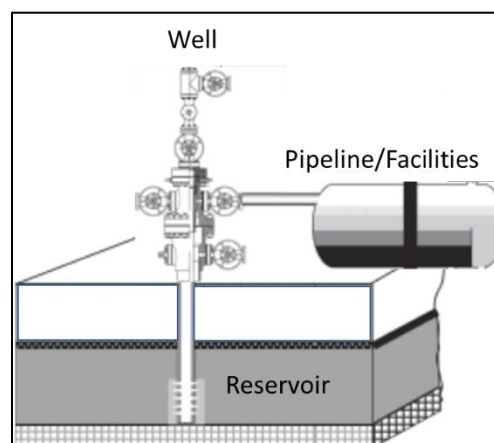


Figure NOD-3: Nodal System

In order to have flow through the system, a pressure difference is needed. Fluids will flow from the high-pressure point (reservoir) to the low-pressure point (facilities). Fluid flow through the system is governed by the conservation of energy (first law of thermodynamics) which yields a differential equation for steady state flow. For oil wells, the significant terms impacting the total pressure gradient are the hydrostatic gradient ( $\nabla P_{HH}$ ) and the friction gradient ( $\nabla P_f$ ). For low pressure gas wells, a third term representing the acceleration or kinetic gradient ( $\nabla P_a$ ), resulting from the expanding gas, may also be significant.

$$\nabla P = \nabla P_f + \nabla P_{HH} + \nabla P_a$$

For surface pipelines, the friction gradient ( $\nabla P_f$ ) is the predominant term.

For upward flow (uphill for pipelines), fluids must overcome the backpressure exerted by the effective column of fluid acting against the direction of flow. They must also overcome friction losses due to the interaction of the fluid with the pipe wall. For downward flow (downhill for pipelines), friction effects act against the direction of flow, but the effect of the hydrostatic column helps overcome some of the friction losses.

Hydrostatic pressure losses are a function of the density of the fluid in the pipe but frictional losses also depend on the fluid properties and flowing conditions within the pipe.

There are a number of calculation methods used to account for hydrostatic and frictional fluid losses under a variety of flow conditions. Research into multi-phase flow concentrates on predicting flow pattern, liquid holdup and pressure drop for the different flow conditions. The research has resulted in empirical correlation models (circa 1954+) and mechanistic models (circa 1980+) for determining flowing pressure drop.

Empirical models use data obtained from laboratory tests and liquid holdup, measured by use of quick-closing ball valves. These models were developed by correlating dimensionless numbers. Although fluids were treated as homogeneous mixtures, gas and liquid phases were permitted to travel at different velocities, with slippage effects being accounted for through empirical liquid holdup correlations. Accuracy of the empirical models tends to be restricted to the range of tested conditions.

Mechanistic modeling emerged in the early 1980's. These models include experimental data but are built from general mathematical principles. The mechanistic approach is to determine the prevailing flow pattern for a given flow condition, and then to mathematically model the flow mechanisms causing the identified flow pattern. All dominant physical parameters and mechanisms must be incorporated in a mechanistic model to achieve accurate and reliable predictions. Accuracy of mechanistic models tends to be better than empirical models over a wider range of flow conditions.

Understanding slip velocity, holdup and flow maps are fundamental to understanding multiphase flow. Holdup is the phase fraction at a node and slip is the relative phase velocity at the node. Figure NOD-4 presents an example of holdup in a pipeline with stratified flow.

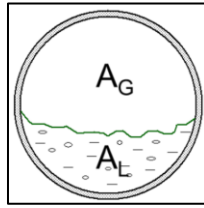


Figure NOD-4: Holdup

In stratified flow, gas will flow in the upper portion of the pipe and the liquid will flow along the bottom. The liquid holdup is a calculation of the fractional area of the pipe containing liquid and the gas holdup is fraction of the pipe containing gas. So liquid holdup,  $H_L$ , will be:

$$H_L = A_L / (A_L + A_G)$$

Slip velocity is calculated as the difference in the in-situ phase velocities at the node where:

$$V_{slip} = V_g - V_l$$

Since gas is lighter, it will generally travel faster than the liquid and this must be taken into account in the pressure drop calculations.

All models have their own unique flow pattern map (Figure NOD-5) that are based on the in-situ superficial velocities,  $v_s$ , of the phases.

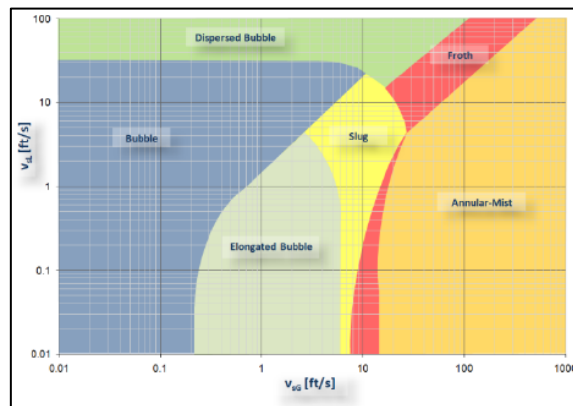


Figure NOD-5: Typical Mechanistic Model Flow Map

The superficial velocities of the liquid and gas phases are defined as the volumetric flow rate for the phase divided by the pipe cross sectional area. These velocities can be calculated based on the holdup, where  $v_{sl} = v_l * H_L$  and  $v_{sg} = v_g * (1 - H_L)$ .

Flow maps are used to determine the type of flow at the node: bubble, slug, mist, etc. Once the flow pattern is known, the appropriate pressure drop model for that flow pattern is used to calculate the pressure drop at the node.

Hydrostatic pressure loss is determined from the fluid properties at the pressure and temperature conditions at the node. Since pressure and temperature is also being calculated at the node, iteration techniques are required to calculate the results.

Frictional pressure drop also depends on the fluid properties at the pressure and temperature conditions at the node which, in addition, impacts the friction factor at the node. Friction factors are normally based on the Fanning Friction Factor (Figure NOD-6), which is a function of the dimensionless Reynolds number,  $Re$ .

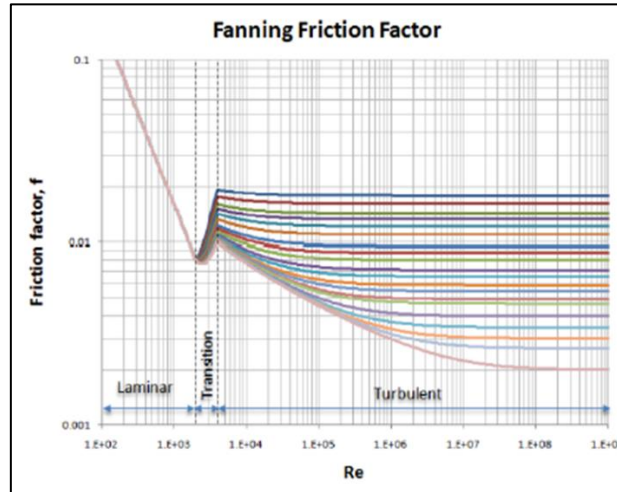


Figure NOD-6: Typical Mechanistic Model Flow Map

Reynolds number is defined as:

$$Re = \frac{1488 \rho v D}{\mu}$$

Where:  $\rho$  is the in-situ density,  $v$  is the velocity,  $D$  is the pipe diameter and  $\mu$  is the in-situ viscosity.

Numerical solution of Figure NOD-6 has been generated by a number of authors and is summarized as follows.

The friction factor,  $f$ , for a Reynolds numbers in the laminar flow regime ( $Re \leq 2000$ ) is found by:

$$f = \frac{16}{Re}$$

In the turbulent flow regime ( $Re \geq 4000$ ), the friction factor can be obtained from the Chen equation, where  $\epsilon$  is the absolute roughness of the pipe:

$$\frac{1}{\sqrt{f}} = -4.0 \log_{10} \left[ 0.2698 \left( \frac{\epsilon}{D} \right) - \frac{5.0452}{Re} \log_{10} \left\{ 0.3539 \left( \frac{\epsilon}{D} \right)^{1.1098} + \frac{5.8506}{Re^{0.8981}} \right\} \right]$$

For the transition from laminar to turbulent flow ( $2000 < Re < 4000$ ) friction factor can be estimated as:

$$f = \frac{f_{Lam}(4000 - Re) + f_{Turb}(Re - 2000)}{2000}$$

In terms of pressure drop, the single-phase friction pressure loss is given by:

$$\Delta P_f = \frac{2f\rho v^2 L}{144g_c D}$$

Where:  $f$  is the friction factor,  $\rho$  is the in-situ density,  $v$  is the in-situ velocity,  $L$  is the pipe length,  $D$  is the pipe diameter and  $g_c$  is gravitational conversion factor.

The single-phase hydrostatic pressure loss is given by:

$$\Delta P_{HH} = \frac{\rho g}{144g_c} L \cdot \sin\theta$$

Where:  $\rho$  is the in-situ density,  $g$  is the acceleration due to gravity,  $L$  is the pipe length and  $\theta$  is the angle of the pipe with respect to the horizontal

The acceleration/kinetic pressure loss is normally negligible and is ignored in multiphase calculations.

For multiphase flow, the friction pressure loss is modified by adjusting the friction factor ( $f$ ), the density ( $\rho$ ) and velocity ( $v$ ) to account for the multiphase mixture properties at the node and is dependant on the flow correlation being used.

For specific information on the available correlations refer to the Appendix.

## NOD.2 System Parameters

There are a number of options that can be chosen from the 'System Parameters' tab (Figure NOD-7).

The type of well is specified, as well as additional options to include in the nodal analysis: artificial lift, annular flow, surface piping and in the case of a gas well, retrograde gas.

The type of run – 'System Analysis' or 'Generate Flow Table' – is also specified on this tab.

The wellbore deviation survey and temperature survey are entered on this tab. When entering the wellbore deviation survey, it is possible to enter the measured depth and an angle and the tool will calculate the equivalent TVD. This is useful when modeling a future well.

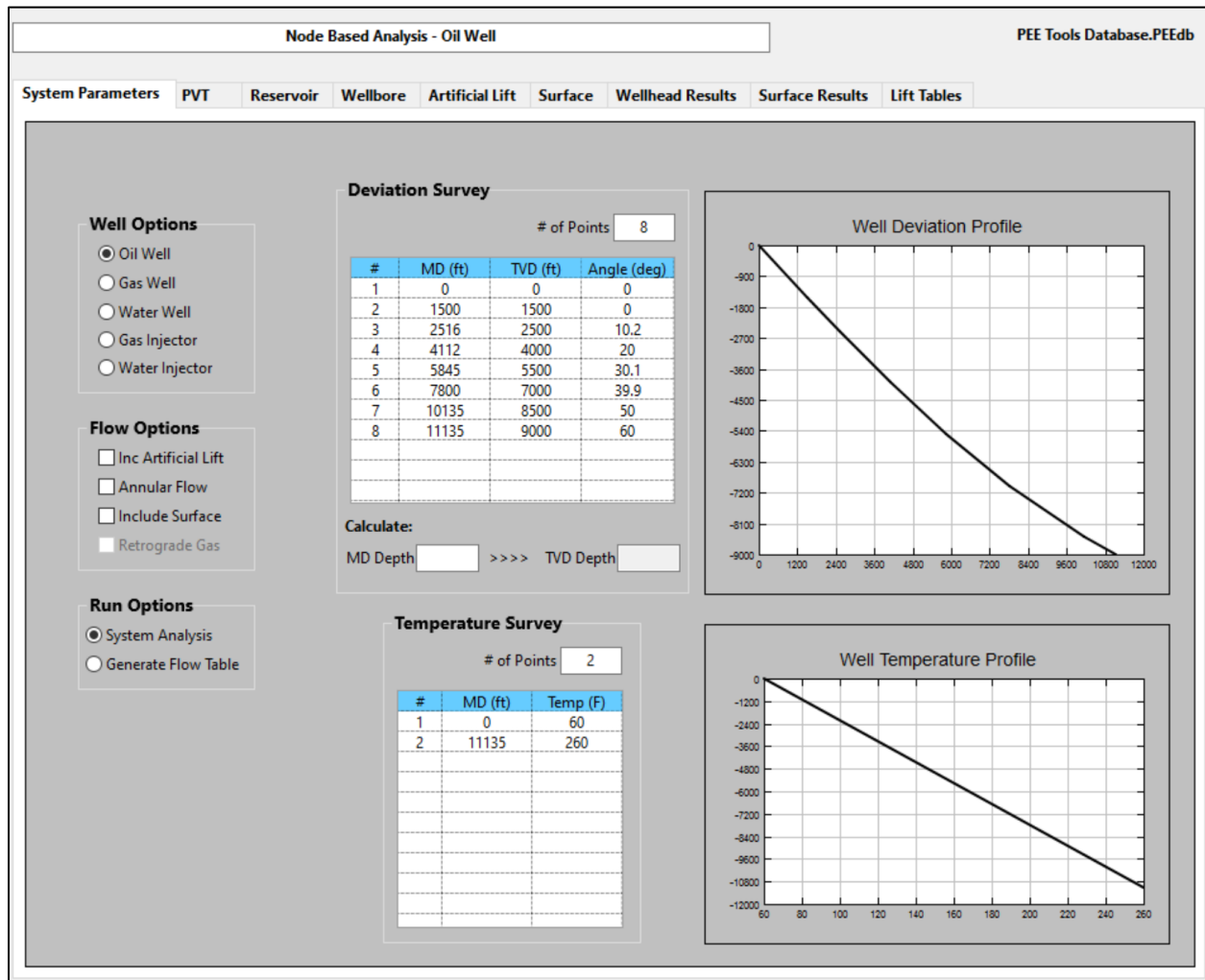


Figure NOD-7: Nodal Analysis – System Parameters

Note - the angle represents the angle from vertical, for example, a horizontal leg is at 90°.

**Recommendation:** In order to model pressure drop along a lateral, it is recommended that an angle of 89° be entered for the lateral.

### NOD.3 PVT Parameters

The PVT parameters and the reservoir conditions are entered on the 'PVT' tab (Figure NOD-8).

Node Based Analysis - Oil Well

PEE Tools Database.PEEdb

System Parameters   **PVT**   Reservoir   Wellbore   Artificial Lift   Surface   Wellhead Results   Surface Results   Lift Tables

---

**Reservoir Parameters**

Reservoir Pressure  psi

Reservoir Temperature  °F

**Gas Properties**

Gas Gravity

H<sub>2</sub>S - mol%

CO<sub>2</sub> - mol%

N<sub>2</sub> - mol%

Gas Pc (psi)

Gas Tc (°R)

Acid Free Gas G

Cond/Gas Ratio (bbls/mmscf)

Gas Viscosity (cp)

Gas Z Factor

Initial cg (10<sup>-6</sup>/psi)

Initial Bg (ft<sup>3</sup>/scf)

**Oil/Condensate Properties**

Oil/Cond API

Bubble/Dew Point Pressure (psi)

Separator Pressure (psi)

Separator Temperature (°F)

Corrected Gas G

Initial Bo (bbl/sbbl)

Initial Oil Viscosity (cp)

Solution GOR (scf/bbl)

Initial co (10<sup>-6</sup>/psi)

**Match Oil Properties**

**Water Properties**

Salinity (ppm NaCl)

Water Specific Density

Initial Bw (bbl/sbbl)

Initial Water Viscosity (cp)

Solution GWR (scf/bbl)

Initial cw (10<sup>-6</sup>/psi)

**View PVT Data**

Figure NOD-8: Nodal Analysis – PVT Parameters

The PVT parameters for all the phases should be entered in the model. It is also possible to match oil PVT properties (Figure NOD-9) to calibrate the oil PVT correlations to actual data.

PVT Match

**PVT Match Parameters**

Pressure Match

Temperature Match  °F

Oil B<sub>o</sub> Match

Oil  $\mu_o$  Match

Oil RSO Match  scf/bbl

Figure NOD-9: Nodal Analysis – Matching PVT Parameters

To match oil PVT properties, enter the values to be matched and click the ‘Store/Continue’ button. Entering zero for a specific parameter will reset the match back to the correlation values.

To view the PVT values, click the ‘View PVT Data’ (Figure NOD-10).

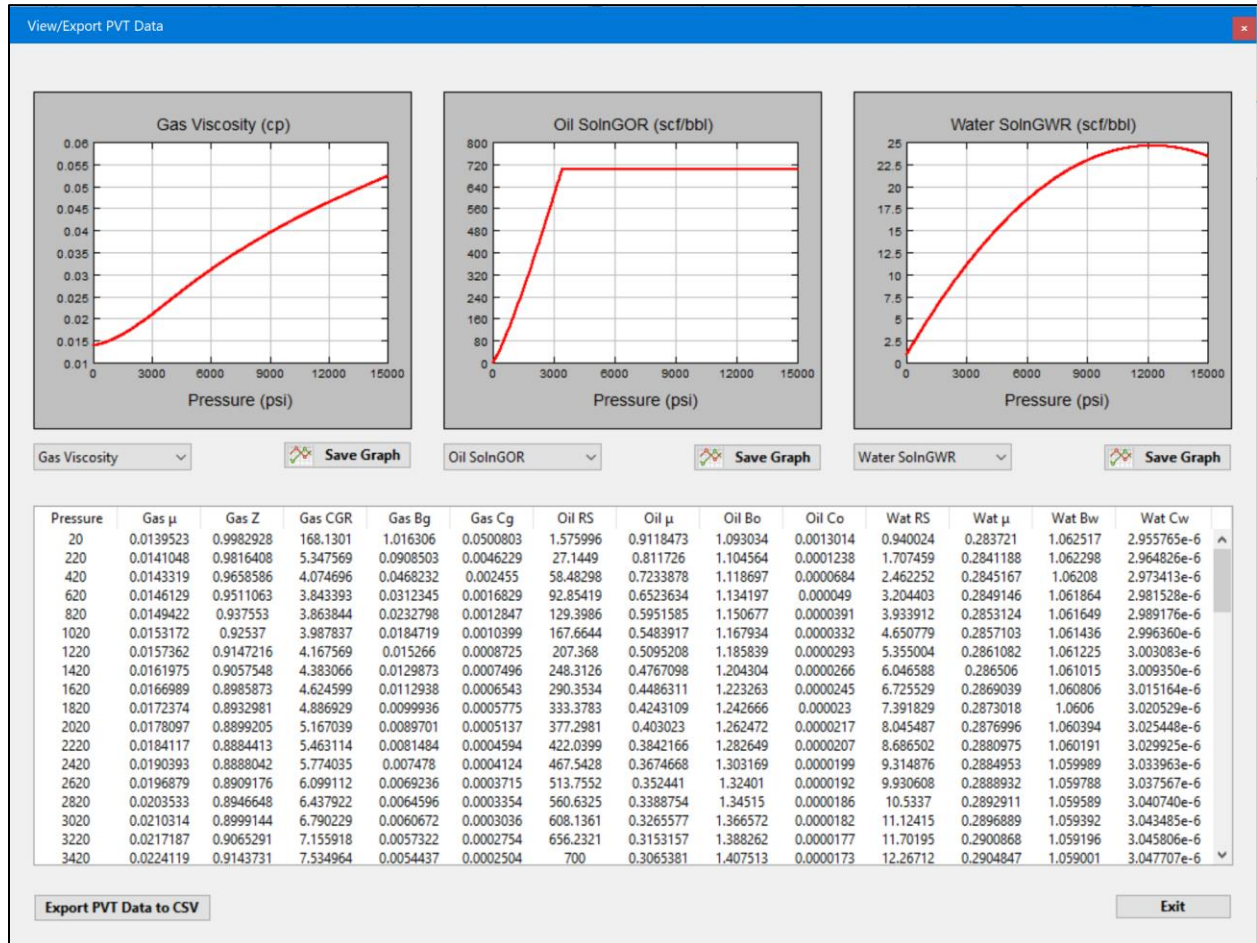


Figure NOD-10: Nodal Analysis – PVT Properties

To view a specific property, use the drop-down menus to choose the property to plot.

Clicking ‘Export PVT Data to CSV’ will save all the PVT data to a csv file.

It should be noted that although PVT data is generated, and presented, for pressures up to 15,000 psi (100,000 kPa), the validity of the correlations at the high pressures may be an issue and should be used with caution.



## NOD.4 Reservoir Parameters

To evaluate the total system performance, reservoir data is required and is entered on the 'Reservoir' tab (Figure NOD-11).

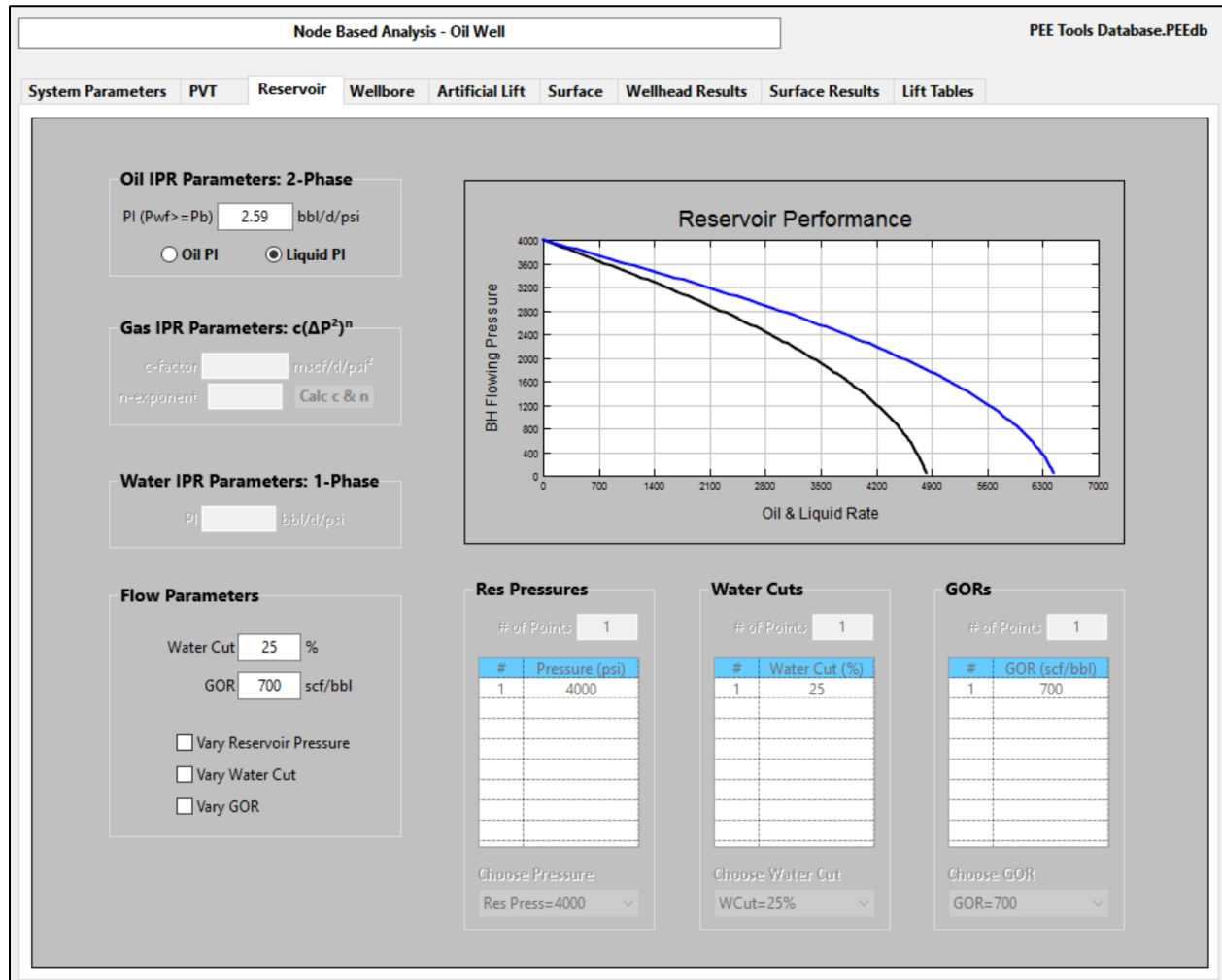


Figure NOD-11: Nodal Analysis – Reservoir Parameters

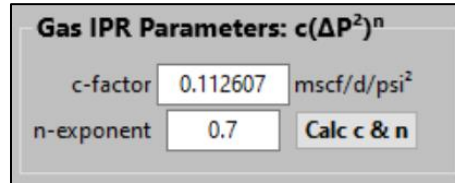
The required IPR parameters are dependent on the well option chosen on the 'System Parameters' tab. For an oil well, either the Oil PI or the liquid PI is entered (Figure NOD-12).

**Oil IPR Parameters: 2-Phase**  
 PI ( $P_{wf} > P_b$ ) 2.59 bbl/d/psi  
☒ Oil PI ☐ Liquid PI

Figure NOD-12: Nodal Analysis – Oil IPR Parameters

When 'Liquid PI' is chosen, the IPR curve is generated using the PI value and the value for water cut entered for 'Water Cut' in the 'Flow Parameters' box. The IPR plot in Figure NOD-11 shows a liquid PI calculation with 25% water cut.

For a gas well, the c and n values, in terms of  $P^2$  are entered (Figure NOD-13).



**Gas IPR Parameters:  $c(\Delta P^2)^n$**

c-factor: 0.112607 mscf/d/psi<sup>2</sup>

n-exponent: 0.7

Calc c & n

Figure NOD-13: Nodal Analysis – Gas IPR Parameters

It is possible to calculate c and n by clicking the 'Calc c & n' button (Figure NOD-14).

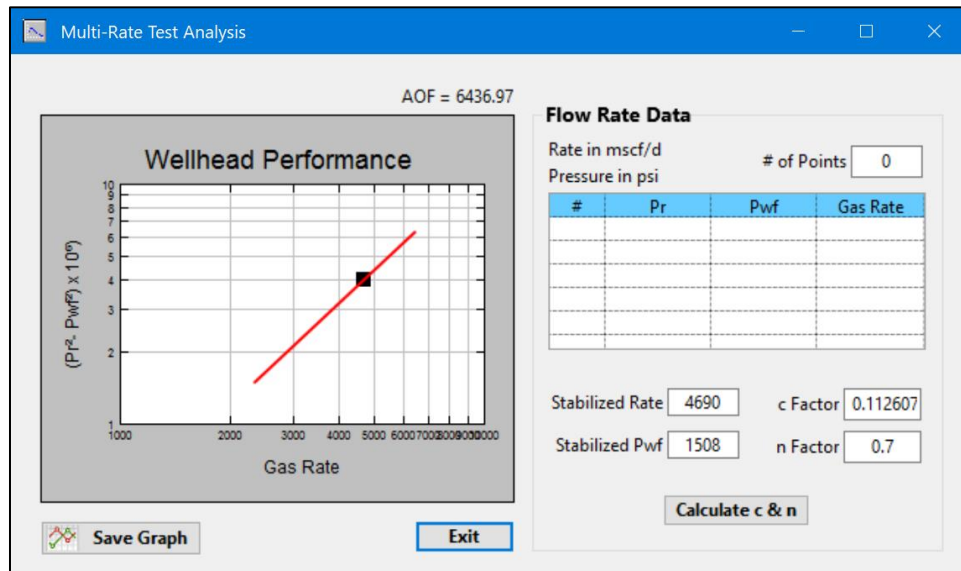
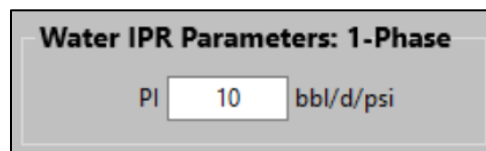


Figure NOD-14: Nodal Analysis – c and n Parameters

The c and n values can be calculated using multi-rate test data or a single stabilized flowing pressure and rate.

For a water well, the water PI is entered (Figure NOD-15).



**Water IPR Parameters: 1-Phase**

PI: 10 bbl/d/psi

Figure NOD-15: Nodal Analysis – Water IPR Parameters

The 'Flow Parameters' are entered, depending on the well type (Figure NOD-16). For injection wells, the flow parameters include maximum injection pressure.

Flow Parameters	Flow Parameters	Flow Parameters	Flow Parameters
Water Cut: 25 %	WGR: 1 bbl/mmscf	Water Cut: 100 %	Water Cut: 100 %
GOR: 700 scf/bbl	CGR: 7.04 bbl/mmscf	GWR: 700 scf/bbl	Max Inj BHP: 2000 psi
<input type="checkbox"/> Vary Reservoir Pressure	<input type="checkbox"/> Vary Reservoir Pressure	<input type="checkbox"/> Vary Reservoir Pressure	<input type="checkbox"/> Vary Reservoir Pressure
<input type="checkbox"/> Vary Water Cut	<input type="checkbox"/> Vary WGR	<input type="checkbox"/> Vary Water Cut	<input type="checkbox"/> Vary Water Cut
<input type="checkbox"/> Vary GOR	<input type="checkbox"/> Vary CGR	<input type="checkbox"/> Vary GWR	<input type="checkbox"/> Vary Max BHP

Figure NOD-16: Flow Parameters: Oil Well; Gas Well; Water Well; Injection Well

It is possible to run the system analysis for different flowing parameters (Figure NOD-17).

This is not the same as running multiple scenarios as is done for the lift table generation. This performs a system analysis at the indicated conditions. It is possible to generate a system analysis for different reservoir pressures, water cuts/WGR's, GOR's/CGR's and maximum injection BHP's depending on the well type chosen.

Flow Parameters	Res Pressures	Water Cuts	GORs																																																												
Water Cut: 25 %	# of Points: 2	# of Points: 3	# of Points: 2																																																												
GOR: 700 scf/bbl	<table border="1"> <thead> <tr> <th>#</th> <th>Pressure (psi)</th> </tr> </thead> <tbody> <tr><td>1</td><td>4000</td></tr> <tr><td>2</td><td>3000</td></tr> <tr><td></td><td></td></tr> <tr><td></td><td></td></tr> <tr><td></td><td></td></tr> <tr><td></td><td></td></tr> <tr><td></td><td></td></tr> <tr><td></td><td></td></tr> <tr><td></td><td></td></tr> </tbody> </table>	#	Pressure (psi)	1	4000	2	3000															<table border="1"> <thead> <tr> <th>#</th> <th>Water Cut (%)</th> </tr> </thead> <tbody> <tr><td>1</td><td>0</td></tr> <tr><td>2</td><td>25</td></tr> <tr><td>3</td><td>50</td></tr> <tr><td></td><td></td></tr> <tr><td></td><td></td></tr> <tr><td></td><td></td></tr> <tr><td></td><td></td></tr> <tr><td></td><td></td></tr> <tr><td></td><td></td></tr> </tbody> </table>	#	Water Cut (%)	1	0	2	25	3	50													<table border="1"> <thead> <tr> <th>#</th> <th>GOR (scf/bbl)</th> </tr> </thead> <tbody> <tr><td>1</td><td>700</td></tr> <tr><td>2</td><td>1000</td></tr> <tr><td></td><td></td></tr> <tr><td></td><td></td></tr> <tr><td></td><td></td></tr> <tr><td></td><td></td></tr> <tr><td></td><td></td></tr> <tr><td></td><td></td></tr> <tr><td></td><td></td></tr> </tbody> </table>	#	GOR (scf/bbl)	1	700	2	1000														
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#	Water Cut (%)																																																														
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2	25																																																														
3	50																																																														
#	GOR (scf/bbl)																																																														
1	700																																																														
2	1000																																																														
<input checked="" type="checkbox"/> Vary Reservoir Pressure <input checked="" type="checkbox"/> Vary Water Cut <input checked="" type="checkbox"/> Vary GOR	Choose Pressure Res Press=4000	Choose Water Cut WCut=25% WCut=0% WCut=25% WCut=50%	Choose GOR GOR=700																																																												

Figure NOD-17: Varying System Analysis Flow Parameters

To generate a run with a different parameter, enable the appropriate check box in the 'Flow Parameters' box and enter the different values in the appropriate table. To perform an analysis for different conditions, choose the appropriate value from the drop-down menu and re-run the analysis.

## NOD.5 Wellbore Parameters

The wellbore tubing correlation is selected on the 'Wellbore' tab (Figure NOD-18).

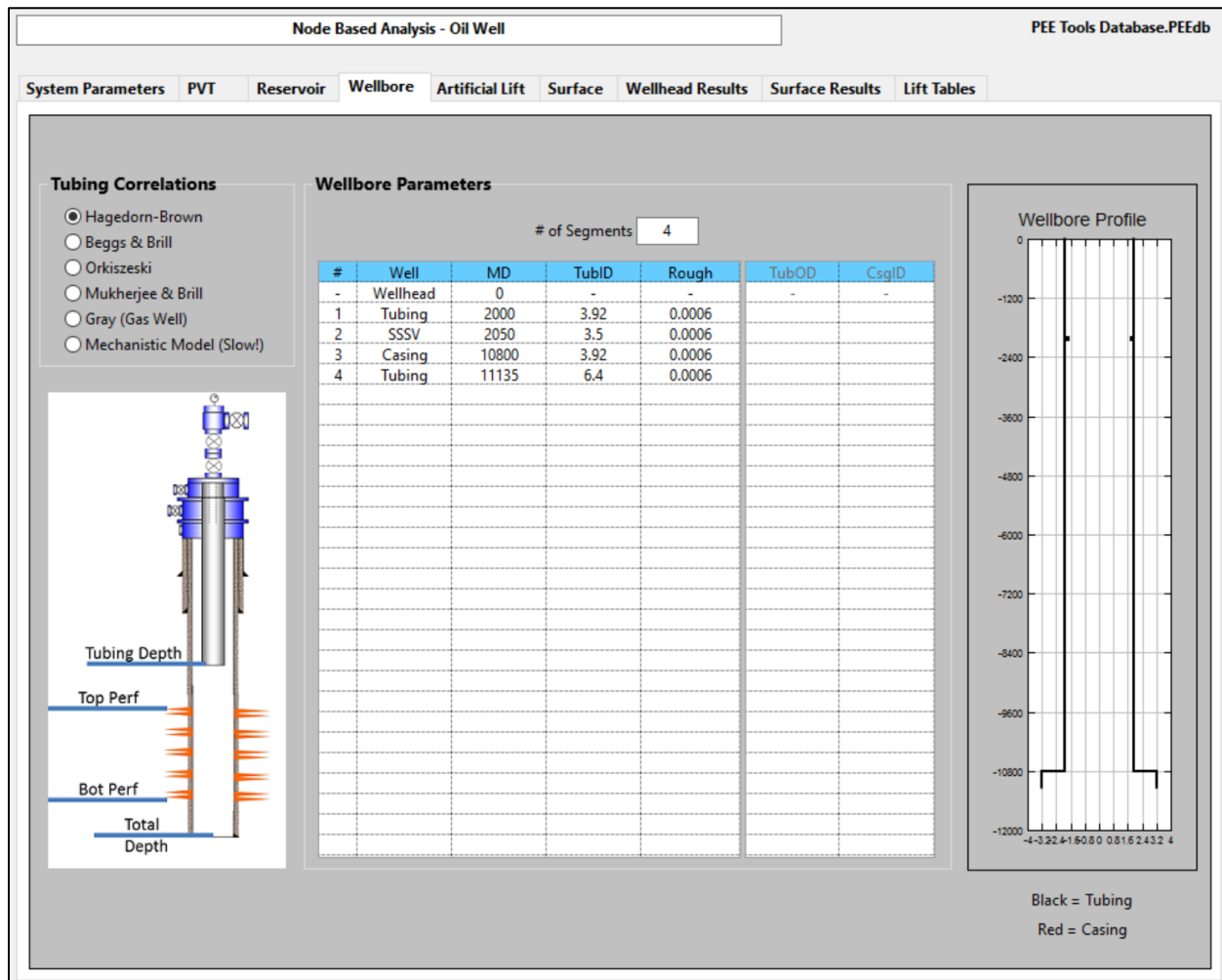


Figure NOD-18: Nodal Analysis – Wellbore Parameters

Available wellbore tubing correlations include the following:

- Hagedorn & Brown
- Beggs & Brill
- Orkiszewski
- Mukherjee & Brill
- Gray
- Mechanistic Model

The Gray correlation is specifically designed for gas. The Appendix describes the models.

The wellbore completion parameters are also entered on this tab.

## NOD.6 Artificial Lift Parameters

There are two options available for artificial lift: gas lift and ESP (Figure NOD-19). Note that the 'Inc Artificial Lift' check box on the 'System Parameters' tab needs to be checked before the Artificial Lift option is enabled.

Node Based Analysis - Oil Well ESP PEE Tools Database.PEEdb

System Parameters PVT Reservoir Wellbore **Artificial Lift** Surface Wellhead Results Surface Results Lift Tables

**Artificial Lift Option**

☐ Gas Lift  
☒ ESP

**Gas Lift Data**

# of GL Rates: 0

GLV Depth:

Max % of Lift Gas Dissolvable in Oil: 10

#	GL Rate (mscf/d)

Choose GL Rate

GL Rate:

**ESP Data**

# of Pump Freq Tables: 1

Pump Frequency: 50

# of Head Points: 6

ESP Depth: 12000

Max %Gas for Pump Cutoff: 10

#	Rate	Head
1	0	2900
2	500	2780
3	1000	2500
4	1500	1900
5	2000	880
6	2320	0

Save Pump Table

Choose ESP Table

ESP Freq=50

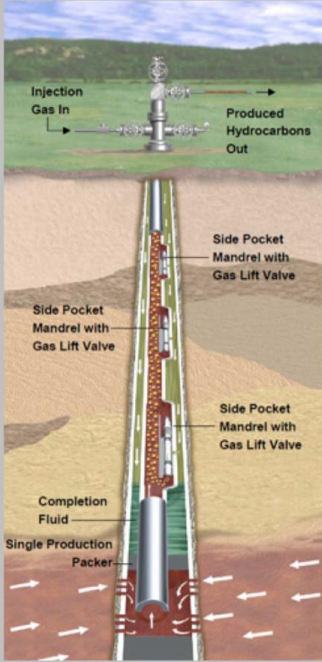
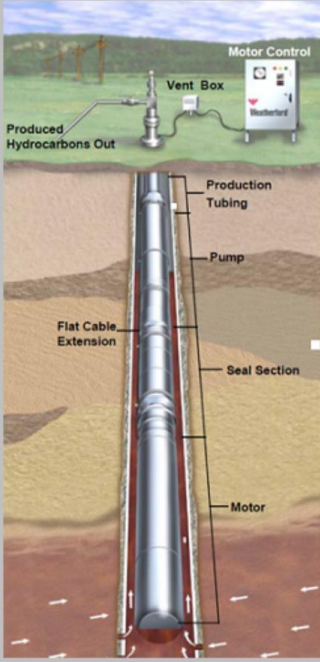



Figure NOD-19: Nodal Analysis – Artificial Lift Parameters

Although several artificial lift parameters can be entered, only one parameter can be used during a specific run of the system analysis.

Ensure that the gas lift valve depth, 'GLV Depth', (Figure NOD-20) and the location of the ESP, 'ESP Depth' (Figure NOD-20) are entered before attempting to run the analysis. In addition, for gas lift the maximum amount of lift gas that can be dissolved into the oil needs to be entered and the maximum allowed gas before the ESP will cut-off needs to be entered if they are different from the defaults.

### Gas Lift Data

# of GL Rates

GLV Depth

Max % of Lift Gas Dissolvable in Oil

#	GL Rate (mscf/d)
1	0
2	500
3	1000
4	1500
5	2500

Choose GL Rate

GL Rate=0

GL Rate=0

GL Rate=500

GL Rate=1000

GL Rate=1500

GL Rate=2500

### ESP Data

# of Pump Freq Tables

Pump Frequency

# of Head Points

ESP Depth

Max %Gas for Pump Cutoff

#	Rate	Head
1	0	2900
2	500	2780
3	1000	2500
4	1500	1900
5	2000	880
6	2320	0

Save Pump Table

Choose ESP Table

ESP Freq=50

ESP Freq=50

ESP Freq=60

Figure NOD-20: Nodal Analysis – Artificial Lift Parameters

When setting up the ESP data, 'Pump Frequency', the total '# of Head Points' and the 'ESP Depth' are entered. After the table is populated, the pump data is saved to the model by clicking the 'Save Pump Table' button. If only one table is being entered, it is saved automatically. If the table is not saved, it will not be available for the run.

It is possible to edit the pump table and gas lift table by selecting the table and modifying the appropriate parameter. For an ESP table, the 'Save Pump Table' has to be clicked to update the table in the model.

Note the pump table is saved to the model but is not updated in the database. To save the data in the PE Tools database, click the 'Save Model to PE Tools dB' on the main menu.

To select a specific gas lift value or pump frequency for the system analysis run, the value is selected from the drop-down menu.

For a system analysis, only one value of gas lift value or ESP table is used for each run based on the value selected from the drop-down menu.

## NOD.7 Surface Parameters

Along with a surface pipeline, the tool includes an option to include a compressor (Figure NOD-21). Note that the 'Inc Surface' check box on the 'System Parameters' tab needs to be checked before the surface and compressor options are enabled. The pipeline profile and specifics are entered into the 'Pipeline Parameters' table.

**Node Based Analysis - Gas Well Compressor** PEE Tools Database.PEEdb

System Parameters | PVT | Reservoir | Wellbore | Artificial Lift | **Surface** | Wellhead Results | Surface Results | Lift Tables

**Pipe Flow Correlation**  
☒ Beggs & Brill ☒ Include Compressor

**Compressor Data**  
 # of Compressor Powers: 2  
 # of Comp Ratio: 4 Compressor Power: 100  

#	Rate	Ratio
1	1000	5.6
2	2000	2.5
3	5000	1.4
4	10000	1.15

Save Comp Table  
 Choose Comp Power  
 Comp Power=100  
 Comp Power=100  
 Comp Power=50

**Pipeline Profile**  
 Graph showing pressure (0-100) vs. distance (0-12000). The profile is a flat line at 100 pressure from distance 1200 to 10800, with steep slopes at the beginning and end.

**Pipeline Parameters**  
 # of Segments: 4  

#	Pipe	Length	Elev	PipeID	Rough
-	Compressor	0	0	-	-
1	Pipe	500	0	3	0.001
2	Pipe	1000	100	3	0.001
3	Pipe	11000	100	3	0.001
4	Pipe	12000	0	3	0.001

Figure NOD-21: Nodal Analysis – Surface Parameters

If the well type on the 'System Parameters' tab is a gas well (producer or injector), then the option to add a compressor will be available. Multiple compressor tables can be entered to allow for different compressor powers. The compressor power is used as an identifier and is not part of the system analysis results other than to specify the compressor table that is used. Make sure 'Save Comp Table' is clicked after entering the compressor data.

For surface analysis, only one compressor table can be used during a run and is based on the value selected from the drop-down menu.



## NOD.8 Wellhead Results

A wellhead system analysis (Figure NOD-22) is generated by clicking the 'Wellhead Analysis' button.

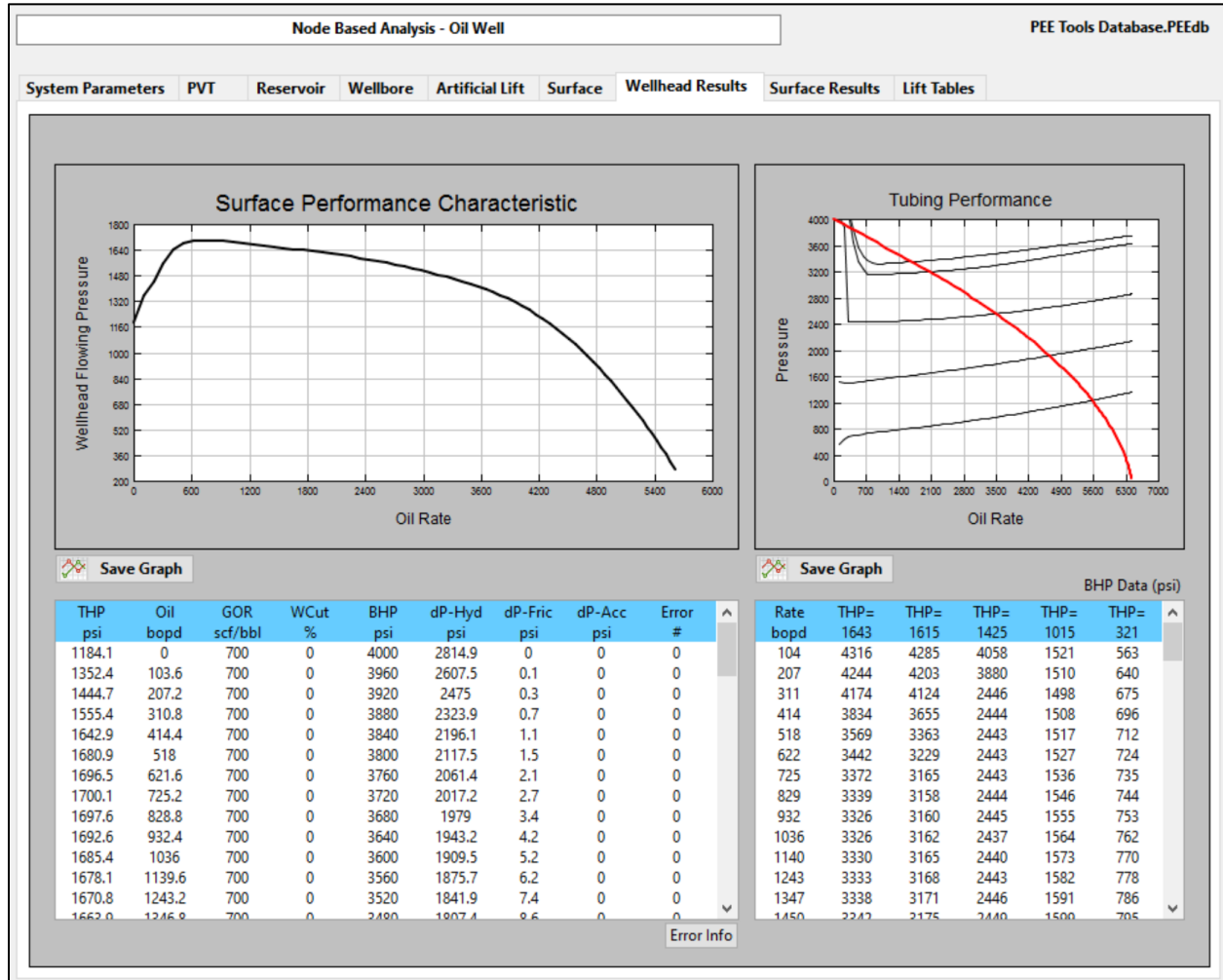


Figure NOD-22: Nodal Analysis – Wellhead Results

The wellhead system analysis proceeds by first determining the rates, based on the IPR, for pressure step increments of (Reservoir Pressure)/100. Then for the chosen water cut and GOR, or WGR and CGR for a gas well, the THP is determined based on the selected tubing correlation.

Following the wellhead analysis, five THP's are chosen internally and tubing performance curves are generated and plotted. This is done for a QC check of the calculations.

The generated 'Surface Performance Characteristic' plot data can be exported to a CSV file by clicking 'Export Wellhead Results to CSV' on the main menu.



## NOD.9 Surface Results

A surface system analysis (Figure NOD-23) is generated by clicking the 'Surface Analysis' button. This cannot be generated for a production well until the wellhead analysis has been generated.

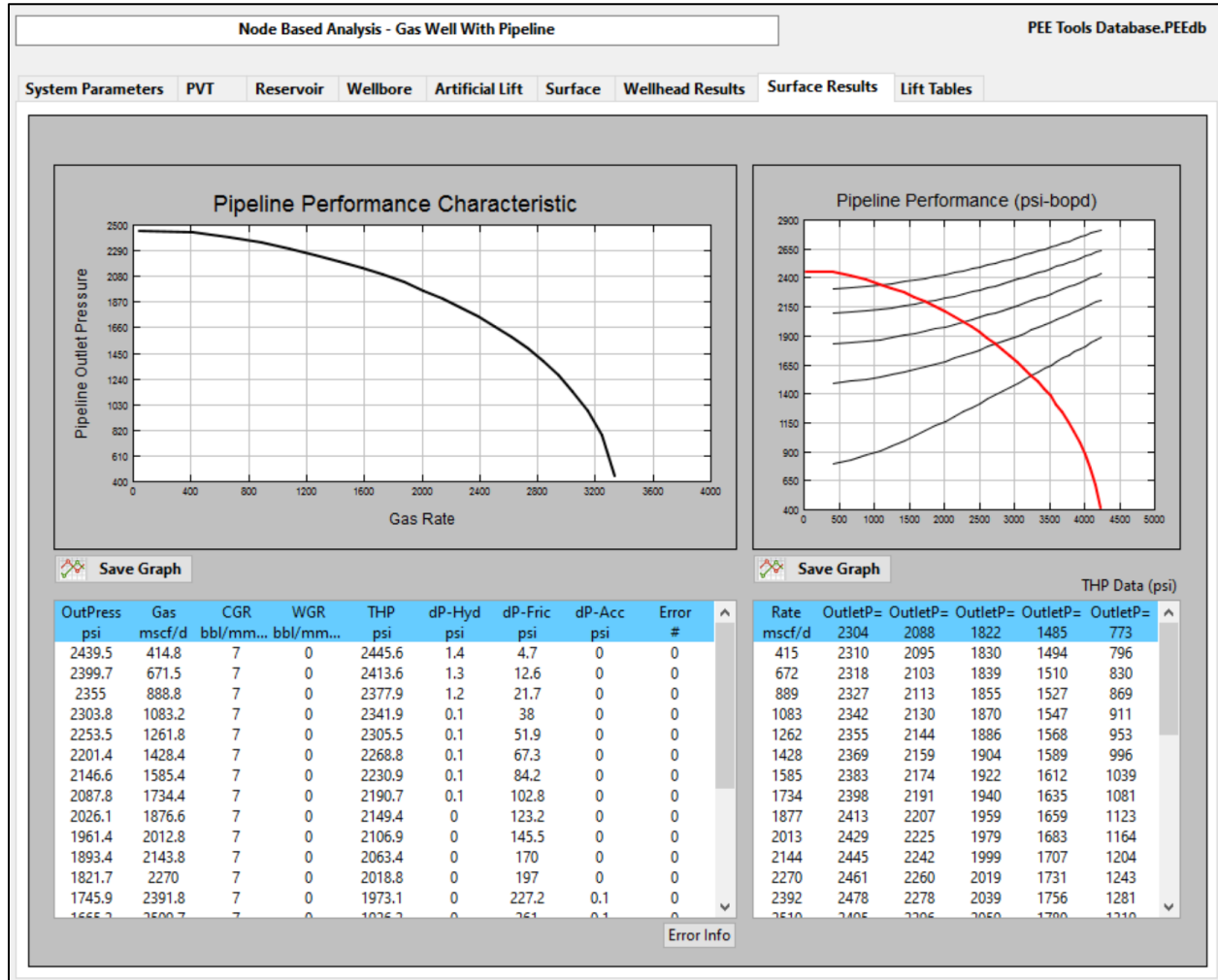


Figure NOD-23: Nodal Analysis – Surface Results

The surface system analysis proceeds by using the rates and THP's generated by the wellhead system analysis and then for the chosen water cut and GOR, or WGR and CGR for a gas well, the pressure at the outlet of the pipeline is determined. The 'Pipeline Performance Characteristic' plot represents the combined well/pipeline system performance. Following the surface analysis, five outlet pressures are internally chosen, and pipeline performance curves are generated for QC purposes.

The generated 'Pipeline Performance Characteristic' plot data can be exported to a CSV file by clicking 'Export Surface Results to CSV' on the main menu.

## NOD.10 Lift Tables

Lift tables (Figure NOD-24) are generated from the 'Lift Tables' tab after selecting the 'Generate Flow Table' option in the 'Run Options' box on the 'System Parameters' tab.

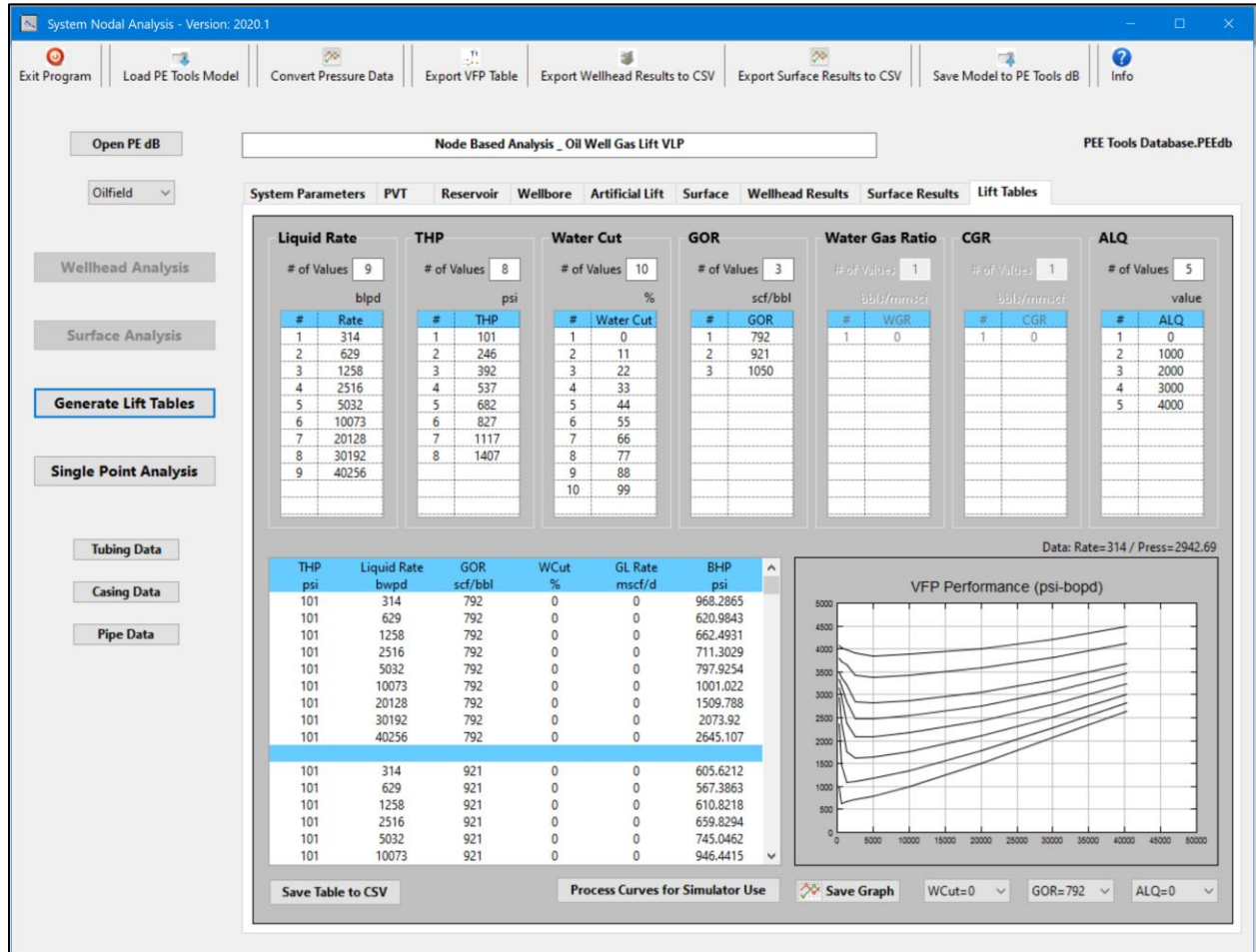


Figure NOD-24: Nodal Analysis – Lift Tables

Note that liquid rate is used for oil wells. This was done to ensure that the well rate at high water cuts does not yield unrealistic flow rates. For example, if an oil rate of 4000 bopd was specified and a water cut sensitivity of 99% was input, the total liquid rate for that point would be 400,000 blpd. Such a high rate would cause issues with the friction pressure drop calculation and the result may be an infinite pressure drop. This is captured in the table as a '0' value.

All system information needed to generate the lift tables is entered on the appropriate tabs. All appropriate options are available for inclusion in the generation of the lift tables.

For example, to include ALQ (Artificial Lift Quantity) data in the lift tables, the 'Inc Artificial Lift' checkbox on the 'System Parameters' tab has to be checked and the artificial lift data entered on the 'Artificial Lift' tab. A surface network can also be included in the generation of lift tables.

The lift tables are generated by clicking the 'Generate Lift Tables' button. After the tables have been generated, they can be saved in a csv file by clicking the 'Save Table to CSV' button or saved as a simulator VFP table by clicking 'Export VFP Table' on the main menu.

Prior to saving the lift tables for use in a simulator, the data can be modified by clicking the 'Process Curves for Simulator Use' button. This will process all the curves to remove the unstable portion of the tubing curves (Figure NOD-25).

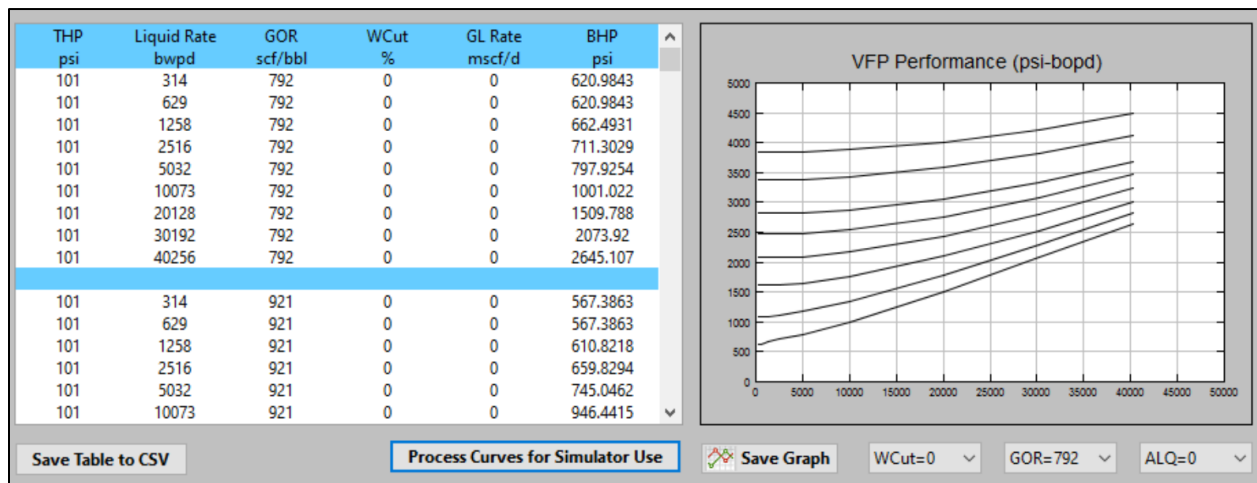


Figure NOD-25: Nodal Analysis – Lift Tables

VFP table processing step is necessary in order to use the VFP data in any simulator that requires that the VFP data to be monotonically increasing.

It should be noted that the processing of the VFP data does not modify any zero values in the table. Correcting for zero values is up to the user. They may be corrected by reducing rates or increasing tubing size.

## NOD.11 THP/BHP Gradient Matching

To calculate a single THP/BHP pressure and calibrate the pressure drop in the well, click the 'THP/BHP/Gradient' button (Figure NOD-26). This option only calculates the well pressures and does not include any surface networks included in the model.

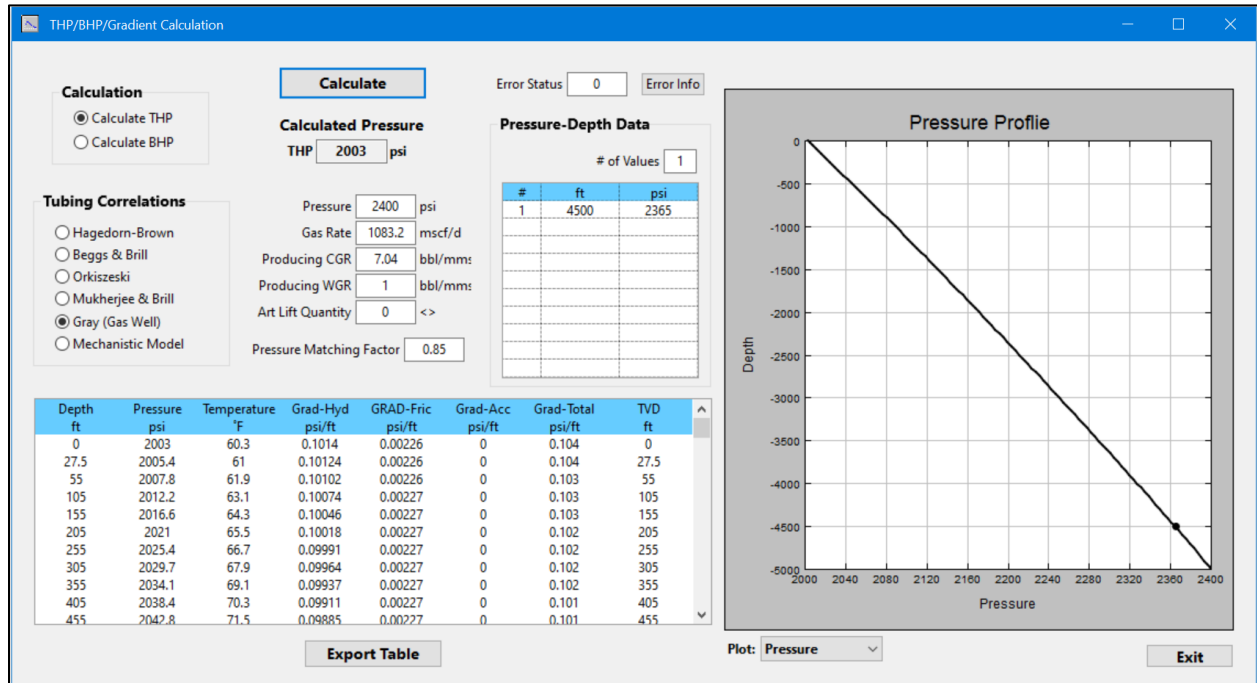


Figure NOD-26: Converting a Single THP/BHP Point to BHP/THP Point

Prior to running this option, all the well parameters must be entered, or loaded, into the tool, including the artificial lift parameters if required.

This option enables the results from the different correlations to be compared to help choose an appropriate correlation for the main run.

The wellbore 'Pressure Matching Factor' is included to match a known pressure point. Entering a value for this factor will modify the hydrostatic pressure drop equation which may yield a closer match to the known pressure. This factor will also be used in the main pressure drop calculations.

Caution should be used if the correction factor falls outside of the range of  $0.8 < \text{factor} < 1.2$ . This may indicate that the wellbore description has a problem or the fluid properties that are used to calculate the hydrostatic gradient term are not correct.

Note that the pressure matching factor will be used in all wellbore calculations but is not used in the surface pipeline calculations.

The gradient information can be saved to a CSV file using 'Export Table'.

## NOD.12 THP/BHP Pressure Conversion

To import a table of well pressure/rate data and convert it to THP/BHP, click the 'Tabular Conversion' button. This will open the 'Pressure Conversion' page (Figure NOD-27).

Figure NOD-27: Converting a Table of Well Pressure Data

The pressure/rate data can be imported from a well in the PE Tools database or an Excel spreadsheet by clicking on the 'Load Data' button. Figure NOD-28 shows the import of data from the database.

Figure NOD-28: Loading Well Pressure Data

Only database wells that contain the type of pressure requested in the 'Pressure Data' box will be listed and available for importing. Once the well pressure data is imported (Figure NOD-29), a correlation model is chosen, and conversion is performed by clicking the 'Convert ...' button. The label on the button will confirm which conversion process will occur.

#	THP	Gas mscf/d	Oil/Cond bopd	Water bwpc	BHP psi
1	177.41	107.6674	111.6475	446.9045	3990.95
2	378.88	2198.358	2495.872	2101.3	3701.39
3	377.14	1903.3	2252.575	2063.057	3723.03
4	377.51	1860.01	2059.723	1815.734	3707.53
5	372.47	1820.859	2008.46	1346.626	3616.13
6	376.92	1854.613	2058.591	1285.99	3599.38
7	374.84	1889.477	2102.118	1274.04	3589.48
8	374.45	1876.034	2072.744	1253.471	3588.04
9	375.39	1849.874	2095.01	1240.388	3583.01
10	374.9	1834.16	2067.397	1078.232	3546.23
11	373.63	1827.488	2065.699	1069.363	3543.13
12	376.95	1821.802	2011.731	1058.23	3549.37
13	376.56	1889.57	2086.959	1061.5	3541.01
14	375.36	1875.578	2085.575	1070.118	3542.4
15	376.45	1850.045	2067.523	856.2577	3487.19
16	376.34	1843.932	2080.229	860.1575	3486.92
17	374.76	1841.789	2088.783	854.3078	3483.1
18	373.3	1849.163	2079.474	852.7353	3482.42
19	374.82	1834.635	2072.618	849.3387	3483.36
20	373.79	1815.903	2045.822	855.3142	3487.01
21	372.5	1795.515	2021.732	1133.521	3563.82
22	372.17	1793.974	2015.064	834.4943	3482.89
23	372.06	1782.821	1998.207	834.3685	3484.58
24	373.19	1769.537	1984.306	834.7459	3487.11
25	373.69	1756.728	1966.694	830.3429	3488.15
26	377.95	1657.871	1830.579	778.702	3491.35
27	372.23	1282.638	1981.539	840.9101	3488.61
28	372.95	1752.865	1949.523	826.5689	3488.31
29	373.18	1749.372	1939.018	823.1723	3488.65
30	373.63	1737.652	1920.966	820.4047	3490.24
31	375.07	1712.472	1918.135	819.0838	3491.32
32	374.79	1684.654	1891.026	829.022	3497.33
33	373.44	1698.485	1899.517	844.0551	3499.81

Figure NOD-29: Converting Well Pressure Data

After the pressure data has been converted, it is possible to save the data to a CSV file by clicking the 'Export Data to CSV File'.

The converted pressures can be saved to the well in the PE Tools database by clicking the 'Update Well Pressure in PE Tools dB' button. This will add the BHP data to the well in the PE Tools database.

## Nodal Appendix

### A1 Hagedorn and Brown Correlation

In 1965 Hagedorn and Brown developed an empirical multi-phase pressure drop model (Hagedorn, A. R., Brown, K. E., “Experimental Study of Pressure Gradients Occurring During Continuous Two-Phase Flow in Small Diameter Conduits”, Journal of Petroleum Technology, April, 1965).

Modifications have been applied to the original Hagedorn and Brown (M-HB) correlation significantly extended the validity of the calculations. The modifications include the assumption that liquid holdup will be zero when the calculated value is less than the no-slip liquid holdup, and the Griffith correlation applied to bubble flow (Griffith, P. and Wallis, G. B., “Two-Phase Slug Flow”, Journal of Heat Transfer, August, 1961).

The basic pressure drop equation, disregarding the kinetic energy term, for the MHB technique is as follows.

$$144 \frac{dP}{dz} = \rho_a + f M_t^2 / (7.413 \times 10^{10} D^5 \rho_a) \quad (A1-1)$$

$$\rho_a = H_L \rho_L + (1 - H_L) \rho_g$$

Where:  $dP/dz$  is the pressure gradient in psi/ft,  $\rho_a$  is the average in-situ density in  $\text{lb}_m/\text{ft}^3$ ,  $\rho_L$  is the liquid in-situ density in  $\text{lb}_m/\text{ft}^3$ ,  $\rho_g$  is the gas in-situ density in  $\text{lb}_m/\text{ft}^3$ ,  $f$  is the friction factor,  $M_t$  is the total mass flow rate in  $\text{lb}_m/\text{d}$ ,  $D$  is the pipe diameter in ft and  $H_L$  is the liquid holdup.

Liquid holdup,  $H_L$ , is defined as the fraction of an element of pipe which is occupied by liquid at some instant as  $H_L = \text{Volume of liquid in a pipe element} / \text{volume of the pipe element}$ . The value for liquid holdup varies from zero for single phase gas flow to one for single phase liquid flow. Oil holdup is determined as  $H_O = 1 - H_L$ .

Hagedorn and Brown generated a number of empirical correlations to determine  $H_L$ . These correlations are presented In Figure A1-1.

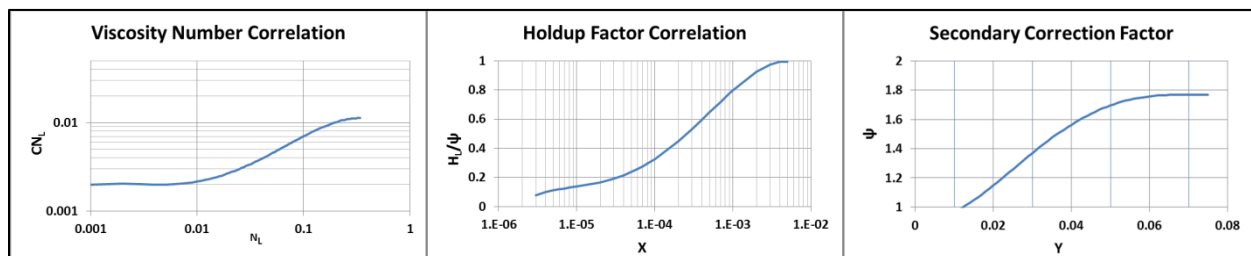


Figure A1-1: Hagedorn and Brown Liquid Holdup Correlations



Calculation of the liquid holdup is the key parameter required for calculating pressures for the M-HB technique (as well as for all other analytical multiphase techniques). For M-HB,  $H_L$  is calculated using the charts in Figure A1-1 and the following dimensionless numbers.

$$N_{LV} = 1.938 V_{SL} (\rho_L/\sigma)^{0.25}$$

$$N_{gv} = 1.938 V_{sg} (\rho_L/\sigma)^{0.25}$$

$$N_D = 120.872 D (\rho_L/\sigma)^{0.5}$$

$$N_L = 0.15726 \mu_L (\rho_L \sigma^3)^{-0.25}$$

Where:  $N_{LV}$  is the liquid velocity dimensionless number,  $V_{SL}$  is the superficial liquid velocity in ft/sec,  $V_{sg}$  is the superficial gas velocity in ft/sec,  $\sigma$  is the gas liquid interfacial tension in dynes/cm,  $N_{gv}$  is the gas velocity dimensionless number,  $N_D$  is the pipe diameter dimensionless number,  $D$  is the pipe inside diameter in feet and  $\mu_L$  is the liquid viscosity in cp.

The equation to solve the first chart in Figure A1-1 is as follows (Guo, Sun and Ghalambor).

$$CN_L = 10^a \quad (A1-2)$$

$$a = -2.6985 + -0.551b^2 + 0.54785b^3 - 0.12195b^4$$

$$b = \log(N_L) + 3$$

The equation for the second chart, which uses  $CN_L$  from Equation A1-2, is as follows.

$$H_L/\psi = -0.10307 + 0.61777c - 0.63295c^2 + 0.29598c^3 - 0.0401c^4 \quad (A1-3)$$

$$c = \log(X) + 6$$

$$X = 0.7643 N_{LV} P^{0.1} CN_L / N_{gv}^{0.575} N_D \quad (A1-4)$$

Finally, the third chart is solved with Equation A1-5 for  $\psi$ , the secondary correction factor, and liquid holdup,  $H_L$ , is calculated as follows.

$$\Psi = 0.91163 - 4.82176Y + 1232.25Y^2 - 22253.6Y^3 + 116174.3Y^4 \quad (A1-5)$$

$$Y = N_{gv} N_L^{0.38} / N_D^{2.14}$$

$$\Psi = 1 \text{ if } Y \leq 0.01$$

$$H_L = \Psi (H_L/\psi)$$

The friction factor is calculated using Equations A1-6 and A1-7.

$$f = [1.14 - 2\log(\delta/ID + 21.25/R_e^{0.9})]^{-2} \quad (A1-6)$$

$$R_e = 0.022 M_t / (D \mu_L^{HL} \mu_g^{(1-HL)}) \quad (A1-7)$$

Where:  $R_e$  is the multiphase Reynolds Number,  $D$  is the pipe inside diameter in feet,  $\mu_L$  is the liquid viscosity in cp and  $\mu_g$  is the gas viscosity in cp.



Whenever flow is in the bubble flow regime, the pressure drop equation is based on the Griffith correlation as follows.

$$144 \, dP/dz = \rho_a + f M_L^2 / (7.413 \times 10^{10} D^5 H_L^2 \rho_L) \quad (A1-8)$$

Where:  $dP/dz$  is the pressure gradient in psi/ft,  $\rho_a$  is the average in-situ density in  $\text{lb}_m/\text{ft}^3$ ,  $\rho_L$  is the liquid in-situ density in  $\text{lb}_m/\text{ft}^3$ ,  $f$  is the friction factor,  $M_L$  is the liquid mass flow rate in  $\text{lb}_m/\text{d}$ ,  $D$  is the pipe diameter in ft and  $H_L$  is the liquid holdup.

Liquid holdup and Reynolds Number for the Griffith correlation (bubble flow) is as follows.

$$H_L = 1 - 0.5 \{ 1 + 1.25 V_m - [(1 + 1.25 V_m)^2 - 5 V_{sg}]^{0.5} \}$$

$$V_m = V_{sL} + V_{sg} \quad (A1-9)$$

$$Re = 0.022 M_L / (D \mu_L) \quad (A1-10)$$

Bubble flow exists under the following condition.

$$V_{sg} / V_m < 1.017 - 0.2218 V_m^2 / D$$

Since fluid properties are a function of pressure, which will be a function of the location of the node, PE<sup>2</sup> Essentials Nodal Analysis uses a variable depth increment to calculate pressure drop.

Note that all the other PE Essentials Nodal Analysis correlations will be presented in a general format. For more specific information, the supplied references should be reviewed.

## A2 Beggs and Brill Correlation

The Beggs and Brill correlation was published in 1973 (Beggs H., Brill J.; "A Study of Two-Phase Flow in Inclined Pipes", JPT (May 1973)). The advantage of this correlation was that it was tested for all inclinations and is used for the surface pipeline calculations in the Nodal Analysis tool.

This empirical model was derived from experimental data for vertical, horizontal, inclined uphill and downhill flow of gas-water mixtures. As a result, it is one of the few published correlations capable of handling flow in all directions. It was developed measuring the flow of water and air through 1" and 1-1/2" sections of acrylic pipe that could be inclined at different angles from the horizontal.

### A3 Orkiszewski Correlation

The Orkiszewski correlation was published in 1967 (Orkiszewski, J.; "Predicting Two Phase Pressure Drop In Vertical Pipes", Journal of Petroleum Technology, 19(6); SPE-1546-PA).

### A4 Mukherjee and Brill Correlation

The Mukherjee and Brill correlation was published in 1983 (Mukherjee H., Brill J.P.; "Liquid Holdup Correlations for Inclined Two-Phase Flow", Journal of Petroleum Technology, Vol. 35, No. 5).

The Mukherjee-Brill model can be applied to wells with different inclination angles and it has been widely applied for wet gas wells.

### A5 Gray Correlation

The Gray correlation was developed by H.E. Gray in 1974 specifically for wet gas wells (Gray, H. E; "Vertical Flow Correlation in Gas Wells", User manual for API 14B, Subsurface controlled safety valve sizing computer program, API). Although this correlation was developed for vertical flow, it has been modified for vertical and inclined pipe pressure drop calculations.

### A5 Mechanistic Model Correlation

The Petalas and Aziz mechanistic model (Petalas N., and Aziz, K., "A Mechanistic Model for Multiphase Flow in Pipes", Journal of Canadian Petroleum Technology, June 2000, Volume 39, No. 6) is valid for all pipe inclinations, geometries, and fluid properties.

The model was not built for a specific set of data or fluid properties. Instead, first principles were applied to the possible flow patterns that are observed at different inclinations. For this reason, it should be applicable to all pipe inclination and fluid properties. The model is a refinement of a previous study by the authors (1996) where subsets of a database of over 20,000 laboratory measurements and data from approximately 1,800 wells were used.

The following Figure NOD.A5-1 is reproduced from the referenced paper and shows the flow chart to determine a flow regime in the mechanistic model. It is a very in-depth process and results in a significant amount of computations and as a result is the slowest correlation in the Nodal Analysis tool.

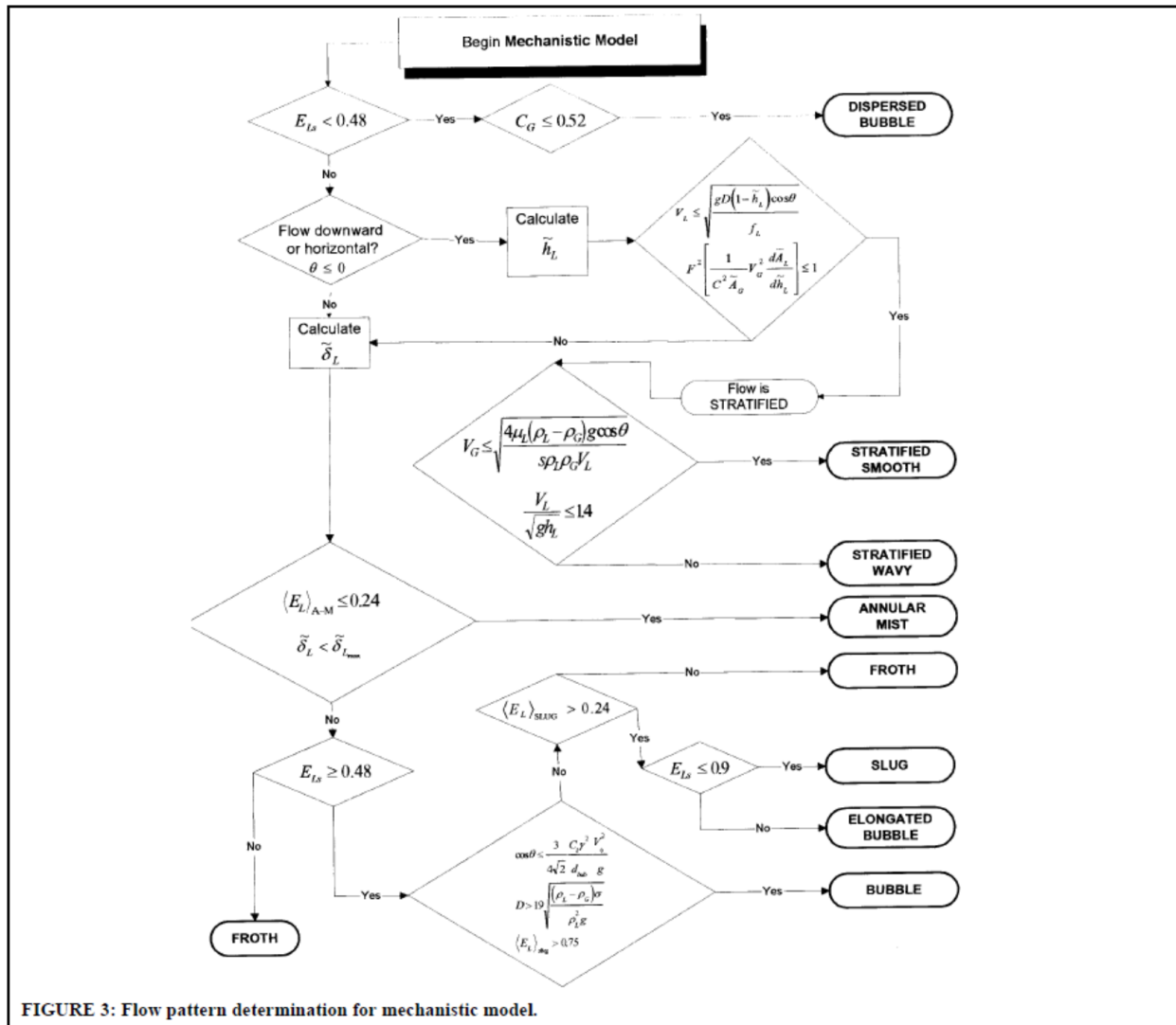


Figure NOD.A5-1: Petalas and Aziz Mechanistic Model Flow Regime Determination

## Interference Analysis

The PE<sup>2</sup> Essentials 'Interference Analysis' Tool is comprised of two components: the control section (Figure IAT-1) and the plotting/analysis section (Figure IAT-2).

**PE Essentials Interference Plot Settings**

File Info

**Interference Plot Settings**

**Plot Group #1- Forward**

Title: PE Interference - Forward

y Label: BHP & Norm-WI Rate

Interfering Well: Y-Scaling Factor: 0.3 Interfering Well: Y-Shift: 2700

x Axis y Axis

Minimum: 0 1000

Maximum: 1000 6000

Reset X Reset Y

**Plot Group #1- Reverse**

Title: PE Interference - Reverse

y Label: WI Rate & Norm-BHP

Interfering Well: Y-Scaling Factor: 1 Interfering Well: Y-Shift: 0

x Axis y Axis

Minimum: 0 0

Maximum: 2200 29000

Reset X Reset Y

**Plot Group #2- Forward**

Title: PE Interference - Forward

y Label: Liquid Prod & Norm-WI Rate

Interfering Well: Y-Scaling Factor: 0.5 Interfering Well: Y-Shift: 11000

x Axis y Axis

Minimum: 0 0

Maximum: 2200 40000

Reset X Reset Y

**Plot Group #2- Reverse**

Title: PE Interference - Reverse

y Label: WI Rate & Norm-Liquid Prod

Interfering Well: Y-Scaling Factor: 1 Interfering Well: Y-Shift: 0

x Axis y Axis

Minimum: 0 0

Maximum: 2200 29000

Reset X Reset Y

**General Settings**

☒ Show Grid ☐ Show Minor Grid ☐ Show Legend top right

**Text**

Text Font: System

Axis Label Size: [Slider]

Tick Label Size: [Slider]

Title Size: [Slider]

Legend Text Size: [Slider]

**Series Settings (Select Series First)**

Series Color: [Color Picker]

Line Style: solid

Line Width: [Slider]

Marker Style: none

Marker Size: [Slider]

☐ Solid Marker

Figure IAT-1: PE Interference Analysis Tool – Control Panel

Caution should be used when attempting production data well-to-well interference analysis. The operating conditions were not designed with interference analysis in mind. Production data is inherently noisy so if derivatives are being used, smoothing can be applied to clean up the data.

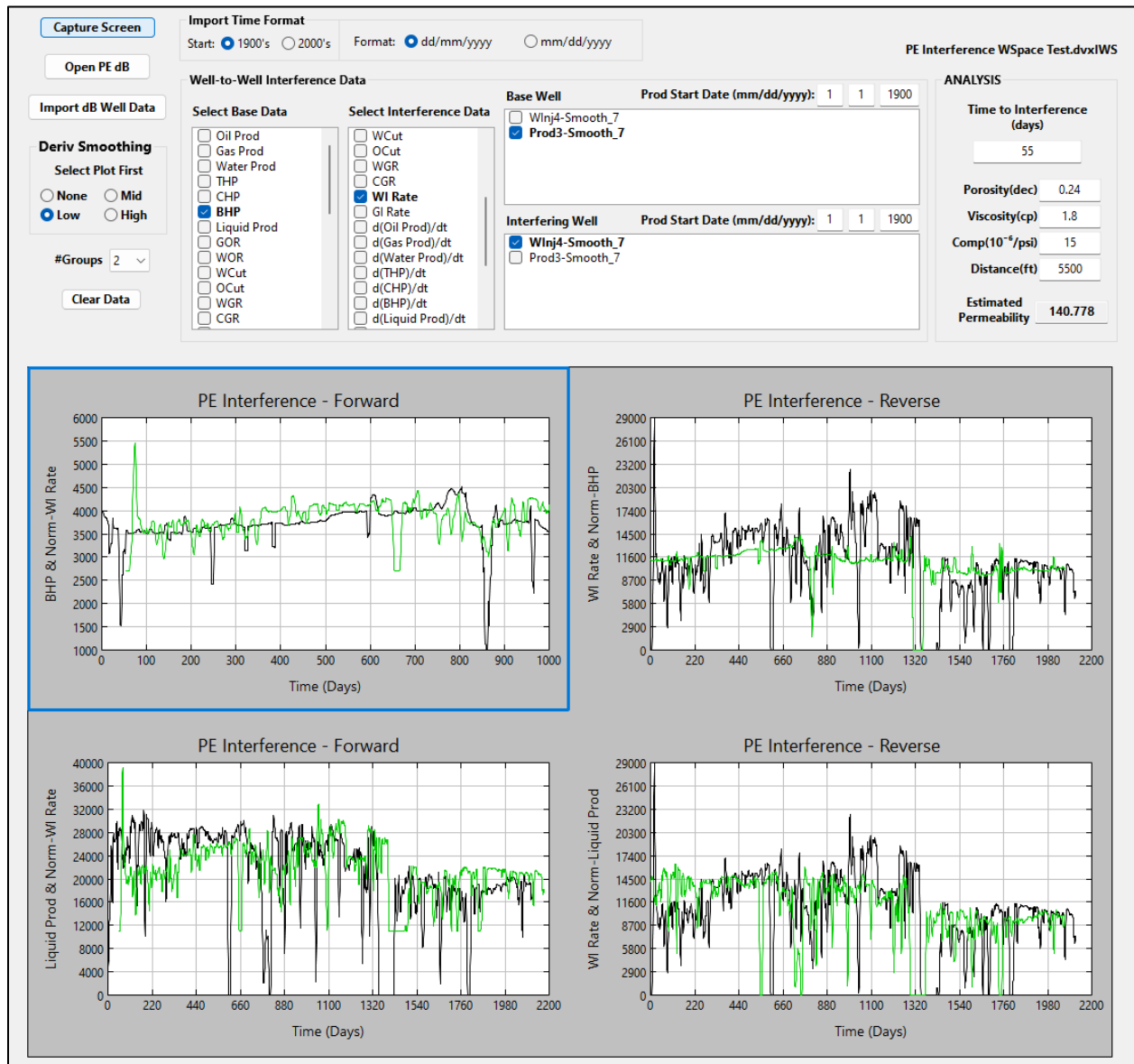


Figure IAT-2: PE Interference Analysis Tool – Plotting / Analysis

The PE Interference Analysis workspace can be stored and reloaded in the future. This is accessed through the 'File' dropdown menu (Figure IAT-3).

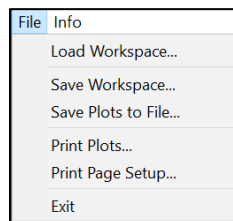


Figure IAT-3: PE Interference Analysis Tool – File Menu

## IAT.1 Methodology and Validity

Well-to-well interference analysis attempts to quantify communication between wells by identifying trends in a target well caused by the production/injection in an offset well. Interference analysis is performed using commercial software called PE Essentials.

Normal operating conditions are not designed with interference analysis in mind. Production data tends to be “noisy” and this needs to be considered when looking for interference patterns. To determine if communication is occurring, the data from the interfering well is shifted in time until the interfering well patterns, are observed in the target well. It is possible to observe interference patterns in production rates or ratios or in the derivative of the production rates or ratios. To use derivatives, production data may need to be smoothed to remove artifacts caused by noisy data.

To demonstrate the well-to-well interference methodology and demonstrate its validity, a generic simulation model was built that contained one producer and one injector. The simulation model parameters are as follows:

- Grid: 15x11x5, Dipping reservoir
- 1 Producer
- 1 Water Injector
- Prod-WI Distance = 4325 ft
- Porosity = 20%
- $k_x, k_y, k_z = 2.5$  md
- Reservoir Pressure,  $P_r = P_{bp} = 440$  psi
- Solution GOR,  $R_{Si} = 100$  scf/bbl (undersaturated oil)
- Water viscosity,  $\mu_w = 0.79$  cp
- Oil viscosity,  $\mu_o = 37.9$  cp
- Water compressibility,  $c_w = 3.0 \times 10^{-6}/\text{psi}$
- Total compressibility,  $c_t = 5.3 \times 10^{-6}/\text{psi}$
- Model 1: Water Saturation,  $S_w = 100\%$
- Model 2: Water Saturation,  $S_w = 25\%$

Figure IAT-4 presents the top view and the cross-sectional view of the generic simulation model and shows the producer/injector well locations.

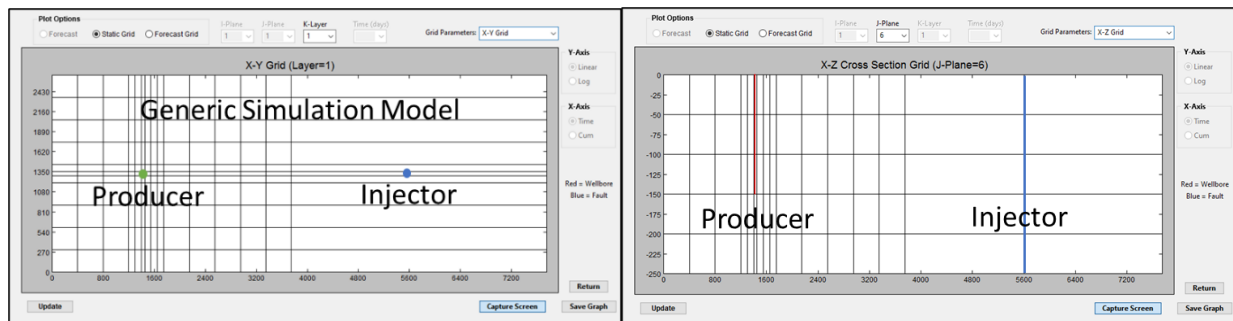


Figure IAT-4: Generic Simulation Model - Top View (left) and Cross-Sectional View (right)

Two models were used, Model 1 was initialized with 100% water because of the relatively constant reservoir parameters associated with a water reservoir. Water injection was started 3 years after the start of production and the interference response between the wells was evaluated.

The PE Essentials Interference Analysis tool can plot and analyze up to two sets of data at the same time from the same well pair. The analysis is comprised of two plots: a forward plot and a reverse plot. The assumption is that any communication that occurs in one direction should also occur in the reverse direction.

Any two sets of data can be plotted. The forward plot “fixes” the ‘Base Data’ (target well) and the ‘Interference Data’ (offset well) is time shifted to find and match patterns in the ‘Base Data’. For the reverse plot, the ‘Interference Data’ is fixed and the ‘Base Data’ is time shifted to find and match patterns in the ‘Interference Data’. Most often, the target well is a producer and the offset well is an injector.

Once the interference response is identified in the producer, the interference time is determined and the average inter-well permeability between injector and producer can be estimated from the following equation (Reference – Kuchuk, F.J., Radius of Investigation For Reserve Estimation From Pressure Transient Well Tests, 120515, 2009 – using Lee’s 1982 constant in Equation 2 of the reference):

$$k = \frac{(948/24) \phi \mu c_t d^2}{t}$$

k - average inter-well permeability in md

$\phi$  - porosity in decimal

$\mu$  - viscosity in cp

$c_t$  - total compressibility in  $\text{psi}^{-1}$  [ $c_t = (S_w c_w + S_g c_g + S_o c_o) + c_{\text{rock}}$ ]

$c_g$  - gas compressibility in  $\text{psi}^{-1}$

$c_w$  - water compressibility in  $\text{psi}^{-1}$

$c_o$  - oil compressibility in  $\text{psi}^{-1}$

$c_{\text{rock}}$  - rock compressibility in  $\text{psi}^{-1}$

d - distance in feet

t - time in days

For Model 1, the interference analysis is presented in Figure IAT-5. The left-hand plots present the raw data showing that the production well’s water rate (black curve) increased sometime after the water injection began (blue curve). The right-hand plots present the injection well data time shifted by 140 days.

Since interference effects occur after 140 days, this yields an estimated inter-well permeability of 2.5 md (using above equation). Since there are no relative permeability changes in a water bearing reservoir, the permeability throughout the reservoir should always be the initial permeability.

For Model 1 the initial reservoir permeability was input as 2.5 md, which demonstrates that the interference methodology and calculations are valid for a simple system.

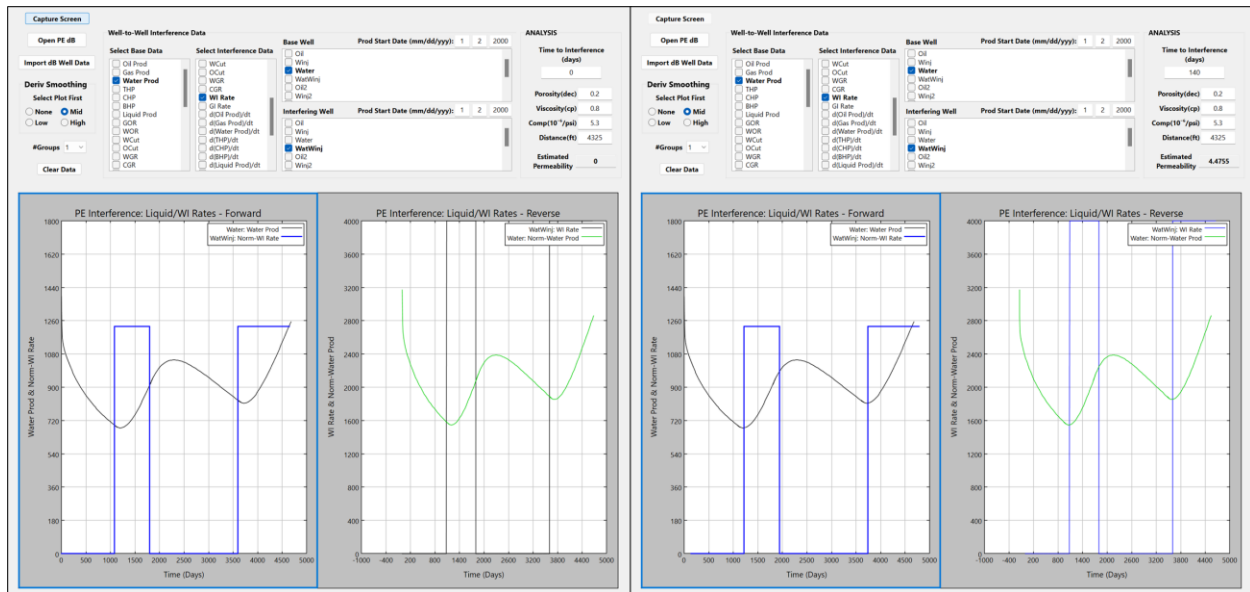


Figure IAT-5: Simulation Model 1 Interference Analysis: Left – time not shifted; right – time shifted

Model 2 was initialized as an oil-water system and water injection was started 5 years after the start of production. The interference analysis of an oil-water reservoir is more complex because of the changing  $S_w$  in the reservoir over time (Figure IAT-6). Extracting the water saturation between the producer and injector at the start of injection indicated an average of 32.5% for all five layers.

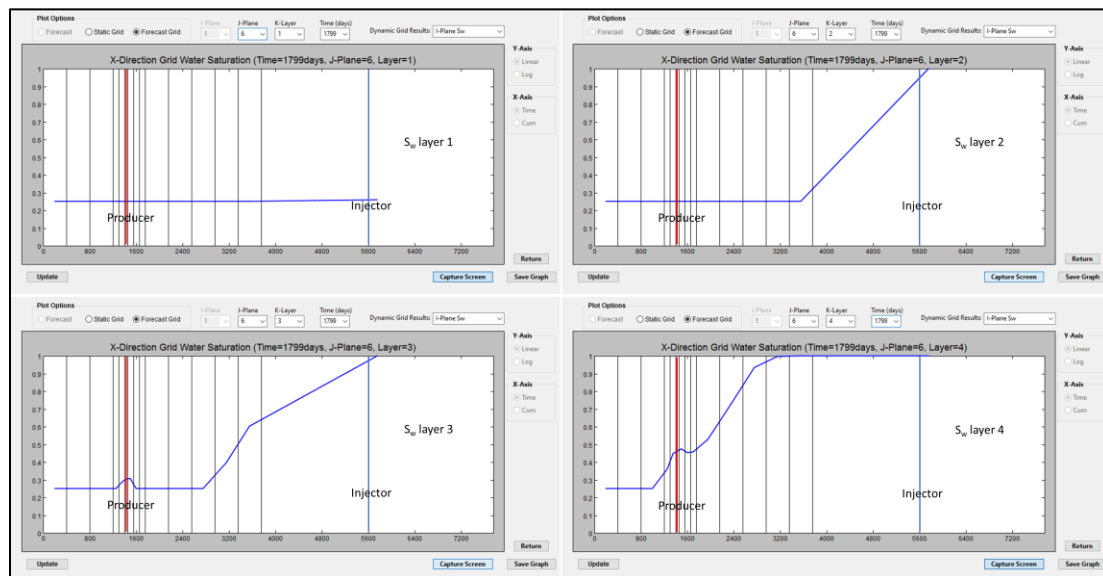


Figure IAT-6: Generic Simulation Model 2 Water Saturation at Start of Injection (Layer 5 had 100%  $S_w$ )

As  $S_w$  increases, this causes a reduction in the oil relative permeability,  $k_{ro}$ , and an increase in water relative permeability,  $k_{rw}$ . Since oil relative permeability reduces, this will result in a reduced effective oil permeability value calculated from interference analysis. Figure IAT-7 presents the input relative permeability curves for Model 2 as well as the equivalent oil and water effective permeabilities.



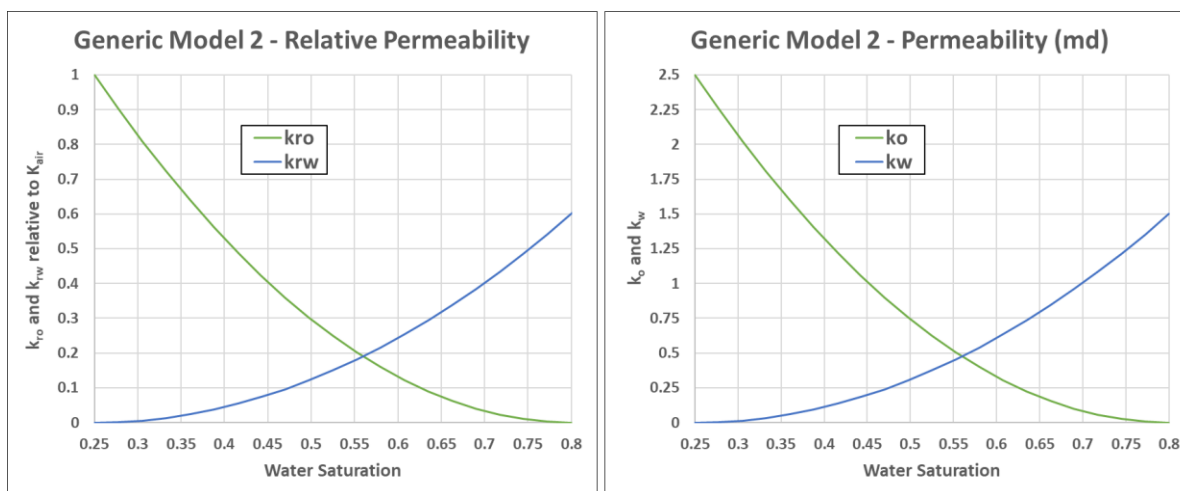


Figure IAT-7: Generic Simulation Model 2 Relative Permeability (left) and Effective Permeability (right)

With the value of interference-derived permeability in an oil-water system, the corresponding average  $S_w$  between the injector and the producer can be determined from the relative permeability curve (Figure IAT-7).

As an optional quality control, QC, on the interference results, a Water-Oil Ratio, WOR, versus water saturation curve can be generated for the field using the relative permeability ratio, the viscosity ratio and fractional flow theory.

Fractional flow theory can be used to calculate the WOR using the  $k_{rw}/k_{ro}$  data along with water viscosity,  $\mu_w$ , and oil viscosity,  $\mu_o$ . The fractional flow of water,  $f_w$ , is first calculated and then the WOR is calculated from the  $f_w$  data using the following equations:

$$f_w = \left( 1 + \frac{k_{ro}}{k_{rw}} \frac{\mu_w}{\mu_o} \right)^{-1} \quad WOR = \frac{f_w}{(1 - f_w)}$$

For Model 2, the WOR-water saturation curve is presented as Figure IAT-8. Entering the WOR plot with the actual producing WOR, the  $S_w$  in the vicinity of the well can be estimated (Figure IAT-9). Using the estimated  $S_w$  with the relative permeability data, the near-well permeability can be estimated (Figure IAT-10). Late life fields with high producing water cuts are assumed to have a uniform  $S_w$  in the vicinity of each well. From the WOR-derived  $S_w$  value, the relative permeability curves (Figure IAT-7) are used to predict the effective permeability in the vicinity of the well.

As a check on the interference results, the near-well permeability should be higher than the inter-well interference-derived permeability. This is because the average inter-well  $S_w$  will be higher resulting in a lower  $k_{ro}$  due to the presence of the injected water in the formation.

As an example, to estimate  $S_w$  from the producing WOR, at the start of Model 2's water injection the producer well's WOR was 0.537 (Water Cut = 34.9%). The resulting estimated  $S_w$  at the well is 31.7% (Figure IAT-9). Using the relative permeability data from Figure IAT-7, the expected effective oil permeability,  $k_o$ , for the Model 2 oil well will be 1.93 md and effective water permeability of 0.03 md (Figure IAT-10).

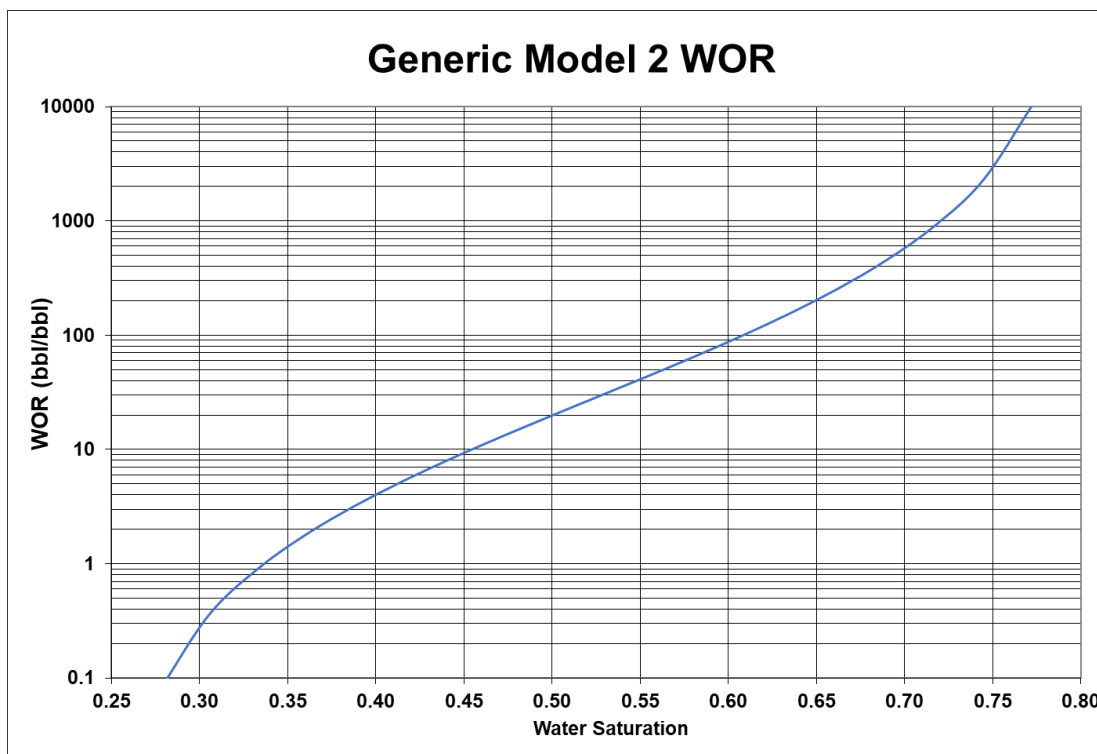


Figure IAT-8: Generic Simulation Model 2 WOR – Water Saturation Relationship

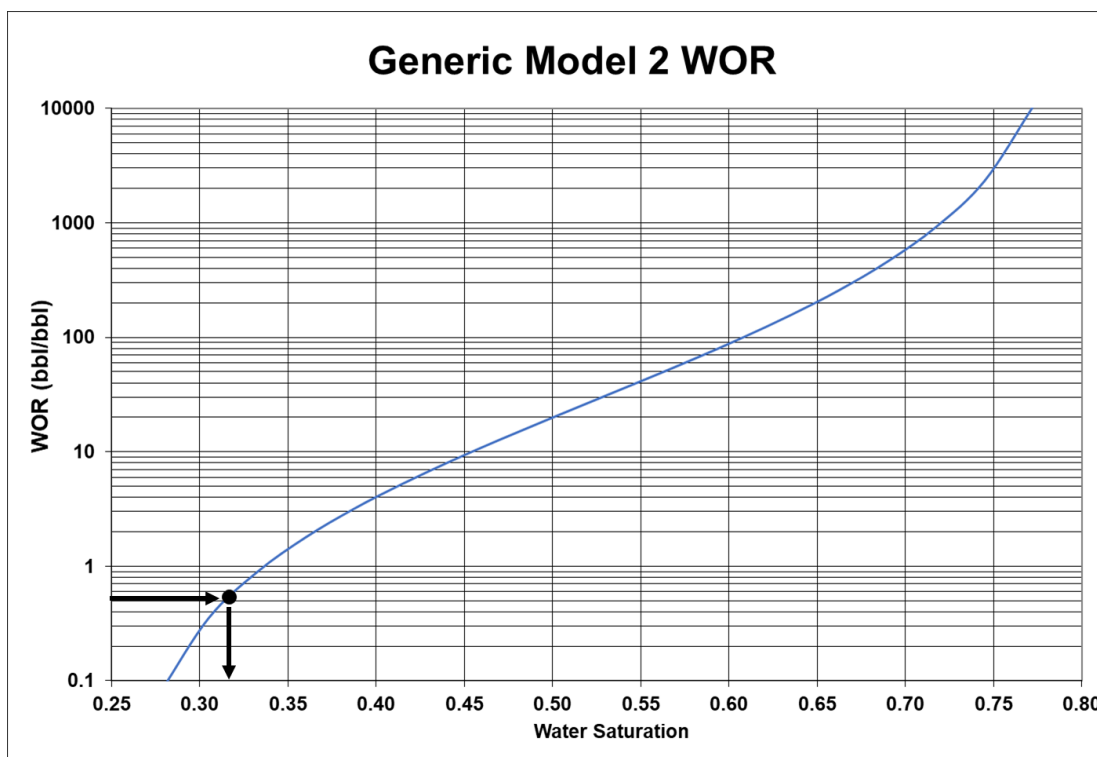


Figure IAT-9: Example for Calculation of  $S_w$  from WOR

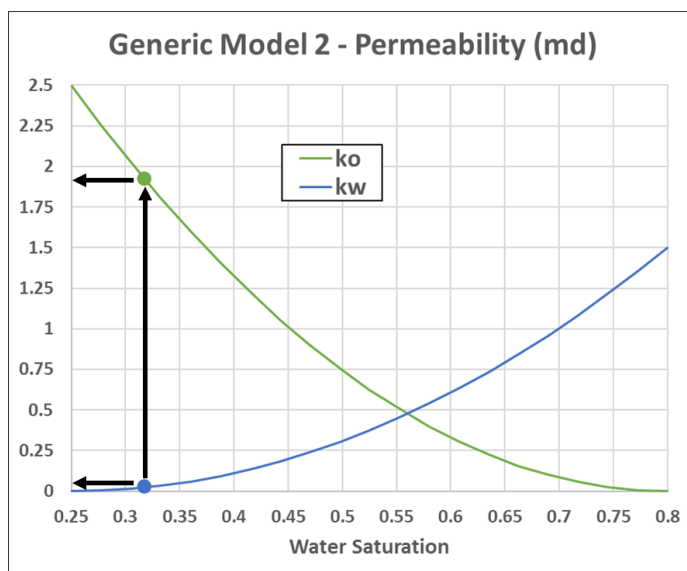


Figure IAT-10: Example for Calculation of Expected Permeabilities from  $S_w$

For Model 2, the interference analysis is presented in Figure IAT-11. The left-hand plots present the raw data showing that the production well's liquid rate (black curve) increased after the water injection began (blue curve). The right-hand plots present the injection well data time shifted by 320 days.

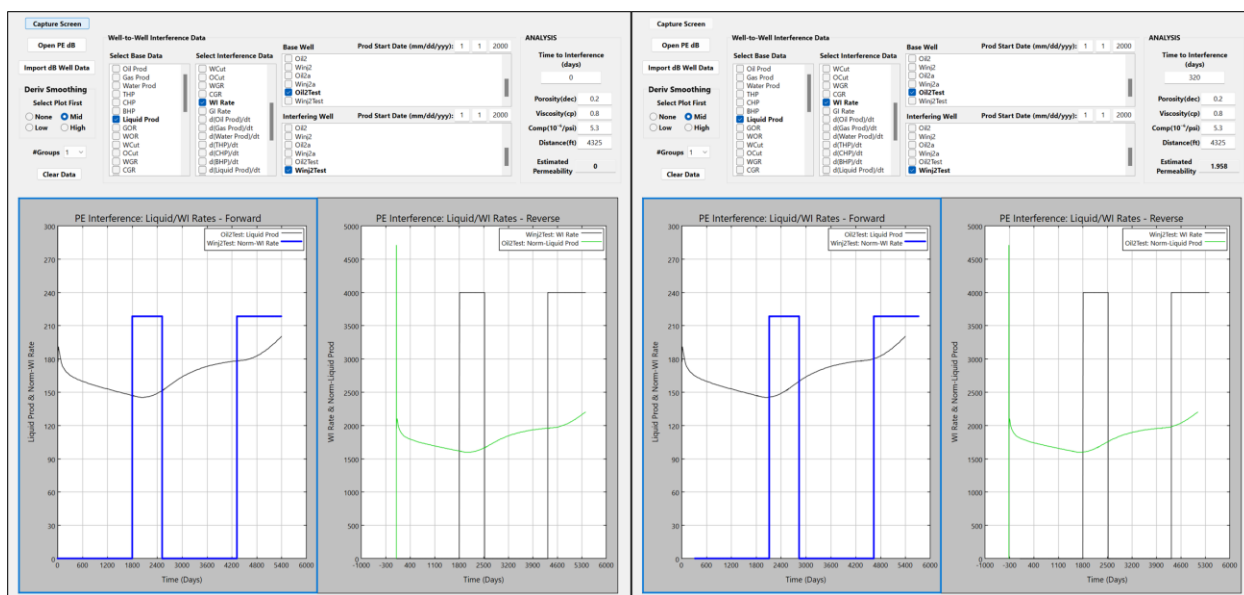


Figure IAT-11: Generic Simulation Model 2 Interference Analysis

The estimated interference effective permeability for Model 2 is 1.96md, or an equivalent  $k_{ro}$  of 0.77. The average inter-well  $S_w$  is estimated to be 32% from Figure IAT-12, which is similar to the average value extracted from the simulation model and the expected value calculated based on the well's WOR.

Model 2 results demonstrates the validity of well-to-well interference analysis for oil/water systems.

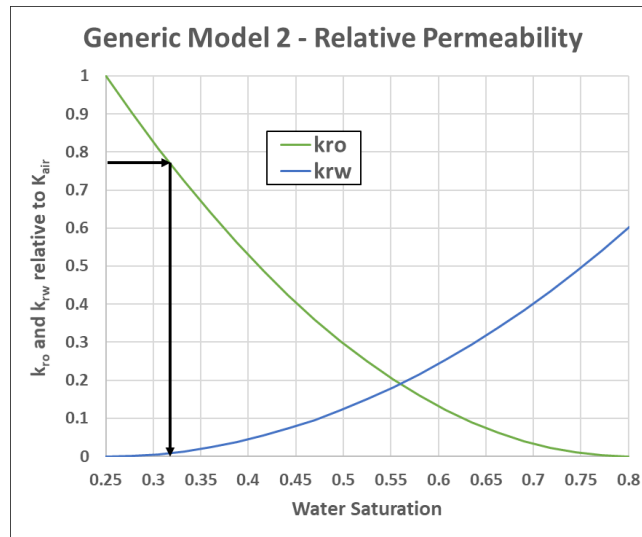


Figure IAT-12: Generic Simulation Model 2 Inter-Well Water Saturation of 32% for a  $k_{ro}$  of 0.77

## IAT.2 Interference Analysis

Data is imported from the PE Tools database for analysis. The Interference Analysis tool can plot and analyze up to two sets of data at the same time from the same well combination. Each analysis is comprised of two plots: a forward plot and a reverse plot. The assumption is that any communication that occurs in one direction will also occur in the reverse direction.

As an example, consider a producer – water injector pair of wells. To evaluate the interference effects of the injector on the BHP of the producer, BHP from the producer is selected as the base well and WI rate is chosen as the interference well (Figure IAT-13). The interference well data is labeled as 'Norm' data since the data is normalized to plot on the same scale as the base well.

Well-to-Well Interference Data		Select Base Well
<b>Select Base Data</b> <input type="checkbox"/> Oil Prod <input type="checkbox"/> Gas Prod <input type="checkbox"/> Water Prod <input type="checkbox"/> THP <input type="checkbox"/> CHP <input checked="" type="checkbox"/> <b>BHP</b> <input type="checkbox"/> Liquid Prod <input type="checkbox"/> GOR <input type="checkbox"/> WOR <input type="checkbox"/> WCut <input type="checkbox"/> OCut <input type="checkbox"/> WGR <input type="checkbox"/> CGR	<b>Select Interference Data</b> <input type="checkbox"/> WCut <input type="checkbox"/> OCut <input type="checkbox"/> WGR <input type="checkbox"/> CGR <input checked="" type="checkbox"/> <b>WI Rate</b> <input type="checkbox"/> GI Rate <input type="checkbox"/> d(Oil Prod)/dt <input type="checkbox"/> d(Gas Prod)/dt <input type="checkbox"/> d(Water Prod)/dt <input type="checkbox"/> d(THP)/dt <input type="checkbox"/> d(CHP)/dt <input type="checkbox"/> d(BHP)/dt <input type="checkbox"/> d(Liquid Prod)/dt	<input type="checkbox"/> Winj4-Smooth_7 <input checked="" type="checkbox"/> <b>Prod3-Smooth_7</b>
		<b>Select Interference Well</b> <input checked="" type="checkbox"/> <b>Winj4-Smooth_7</b> <input type="checkbox"/> Prod3-Smooth_7

Figure IAT-13: PE Interference Analysis Tool – Well Selection

The chosen data is plotted on the forward plot and set up so that the base well is static on the plot. A reverse plot is also set up where the interference well is made the base well (Figure IAT-14).

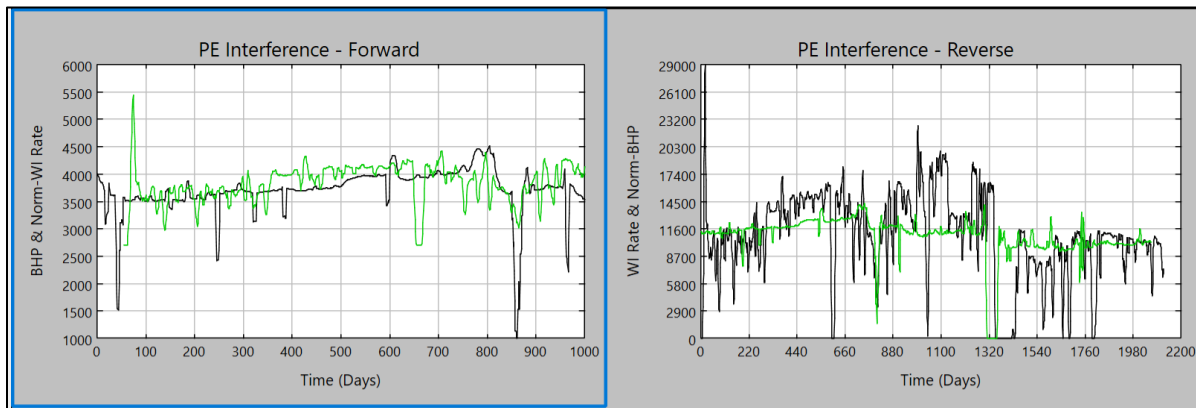


Figure IAT-14: PE Interference Analysis Tool – Analysis Plots Set #1

Optionally, a second set of data can be presented at the same time. In this example the second set of data was Liquid Rate and WI rate (Figure IAT-15).

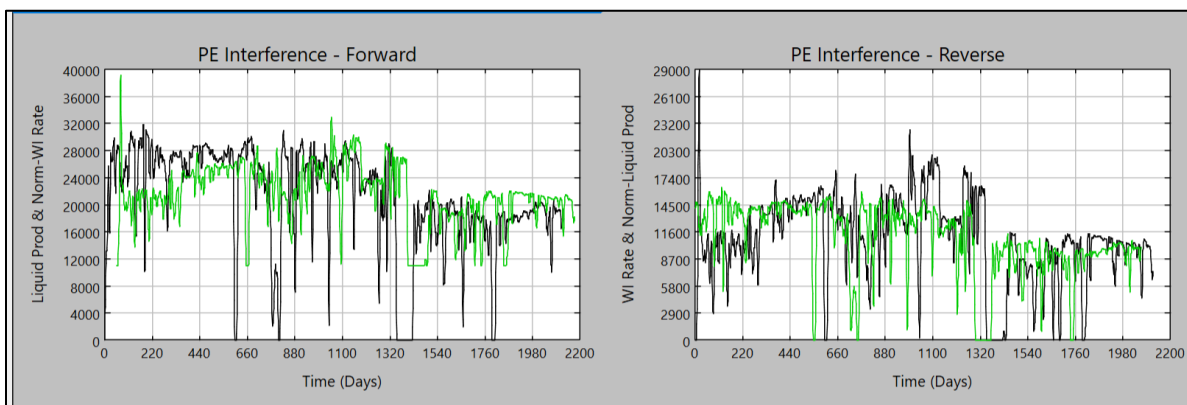


Figure IAT-15: PE Interference Analysis Tool – Analysis Plots Set #2

To evaluate the data, the interference well is manually shifted in time by entering the time shift in the 'Analysis' box (Figure IAT-16) until the response patterns are similar. When the forward and reverse plots show a similar response pattern, the interference time is assumed to be valid.

ANALYSIS	
Time to Interference (days)	<input type="text" value="55"/>
Porosity(dec)	<input type="text" value="0.24"/>
Viscosity(cp)	<input type="text" value="1.8"/>
Comp( $10^{-6}$ /psi)	<input type="text" value="15"/>
Distance(ft)	<input type="text" value="5500"/>
Estimated Permeability	<input type="text" value="140.778"/>

Figure IAT-16: PE Interference Analysis Tool – Analysis Plots

By entering the reservoir parameters into the analysis section, the well-to-well permeability will be calculated using the following radius of investigation equation (reference – Kuchuk, F.J., Radius of Investigation For Reserve Estimation From Pressure Transient Well Tests, SPE 120515, 2009).

$$\text{Perm} = 39.5 \text{ Porosity Viscosity Compressibility Distance}^2 / \text{Time}$$

Where Perm is in md, Porosity is in decimal, Viscosity is in cp, Compressibility is in  $\text{psi}^{-1}$ , Distance is in feet and time is in days.

### IAT.3 Control Panel

The control panel allows the individual graphs to be modified. There are general settings and plot-specific settings.

Figure IAT-17 shows the general settings for the plots.

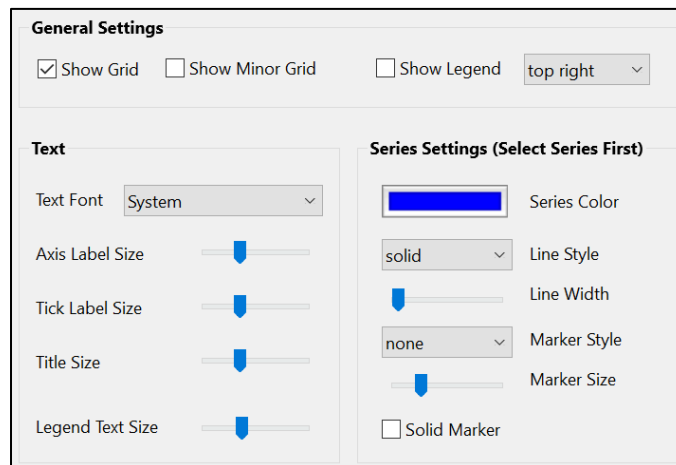


Figure IAT-17: PE Interference Analysis Tool – General Settings

It should be noted the Control Panel settings are stored with the actual plots so they do not have to be entered every time. To modify a series color, click and highlight that series first.

The plot-specific settings (Figure IAT-18) can be set for each plot by clicking and selecting the plot.

**Plot Group #1- Forward**

Title: PE Interference - Forward

y Label: BHP & Norm-WI Rate

Interfering Well: Y-Scaling Factor: 1.0

Interfering Well: Y-Shift: 0

x Axis y Axis

Minimum: 0 0

Maximum: 1000 10000

Reset X Reset Y

Figure IAT-18: PE Interference Analysis Tool – Plot Settings

The 'Interfering Well: Y-Scaling Factor' allows the interfering well data to be compressed or expanded on the graph and the 'Interfering Well: Y-shift' moves the interfering well data up or down. These parameters help to observe the interference effects.

The 'x-Axis' and 'y-Axis' parameters can be used to target a specific interval for in-depth analysis.

## PE Recovery Factor Essentials

Recovery Factor Essentials includes the 'Recovery Factor Analysis' tool (Figure 4-1) that is comprised of six models for determining recovery factor:

- Deterministic / Probabilistic Oil Recovery Factor
- Deterministic Gas Recovery Factor
- Unconventional Oil/Gas Recovery Factor
- Reservoir Complexity Index Oil Recovery Factor
- Empirical North Sea Recovery Factor (not included in tool)
- Artificial Neural Network Oil Model

## Recovery Factor Analysis Tool

The 'Recovery Factor Analysis' tool (Figure RFA-1) is comprised of six models for recovery factor:

- Deterministic / Probabilistic Oil Recovery Factor (Section RFA.1)
- Deterministic Gas Recovery Factor (Section RFA.2)
- Unconventional Oil/Gas Recovery Factor (Section RFA.3)
- Reservoir Complexity Index Oil Recovery Factor (Section RFA.4)
- Empirical North Sea Recovery Factor (not included in tool) (Section RFA.5)
- Artificial Neural Network Oil Model (Section RFA.6)

The screenshot displays the 'Recovery Factor Analysis - Version: 2022.0' software interface. It features a menu bar with options like 'Exit Program', 'Load PE Tools Model', 'Neural Network', 'Export MC Results to CSV File', 'Save Model to PE Tools dB', and 'Info'. Below the menu is a toolbar with buttons for 'Oilfield', 'Capture Screen', 'Open PE dB', and a search bar. The main workspace is divided into several panels:

- Deterministic / Probabilistic 'API' Oil Recovery Factor:** A table with columns P90, P50, and P10. Inputs include Initial Reservoir Pressure (Pi), Bubble Point Pressure (Pbp), Abandonment Pressure (Pab), Permeability (k), Porosity (phi), Initial Water Saturation (Sw), Reservoir Temperature (TR), Oil Gravity, Gas Gravity (G), Water Salinity, Boi, Bob, uoi, uob, uw, Solution Gas Drive (SGD) Oil RF, and Strong Water Drive/Flood (WD) Oil RF. A 'Seed (Random=-1)' field is set to 12345, and '# M-C Simulations' is 10000. A 'MC Simulation' button is present.
- Gas Recovery Factor:** Inputs for Gas Gravity (G), Initial Pressure (Pi), Abandon Pressure (Pab), Temperature (TR), Initial Sw, and Residual Gas (Sgr). A 'Reservoir System / RF' section includes a 'Recovery Factor' of 81.6% and a 'Suggested, Sgr' of 23.7%.
- Unconventional Gas Recovery Factor (Empirical):** Inputs for Initial Gas Resource in Place (100 Tscf) and Potential Gas RF (17.6%).
- Unconventional Oil Recovery Factor (Empirical):** Inputs for Initial Oil Resource in Place (100 Bbbls) and Potential Oil RF (4.6%).
- Oil Recovery Factor Based on Reservoir Complexity Index:** A section with four sub-panels: 'Structural Complexity', 'Oil Viscosity', 'OOIP Areal Density', and 'Perm Heterogeneity'. Each panel has radio button options for different geological and fluid properties. The 'Normalized Reservoir Complexity Index (RCI)' is 0.313, and the 'RCI-Based Oil RF' is 34.7%.
- Monte Carlo Results: Oil Recovery Factor:** A table showing results for P1, P10, P20, P30, P40, P50, P60, P70, P80, P90, P99, and EV across SGD and WD scenarios.

Figure RFA-1: PE<sup>2</sup> Essentials - Recovery Factor Analysis Tool



It should be noted that estimating recovery factors is not an exact science. It is based on empirical correlations and results should not be accepted as a final value. The purpose of the Recovery Factor Analysis Tool is to generate recovery factors using different techniques. It is up to the user to determine which value (if any) is most representative of the reservoir of interest.

### RFA.1 Deterministic/Probabilistic Oil RF

Entering values in the 'Deterministic / Probabilistic API Oil Recovery Factor' section (Figure RFA-2) will yield deterministic calculations of the oil recovery factors for solution gas drive and water drive reservoirs based on the 'API' equations. It is also possible to generate a probabilistic recovery factor profile using Monte Carlo simulation and the API oil RF equations.

Deterministic / Probabilistic 'API' Oil Recovery Factor				
	P90	P50	P10	
Initial Reservoir Pressure, Pi	3000	3500	4000	psi
Bubble Point Pressure, Pbp	2500	2600	2700	psi
Abandonment Pressure, Pab	1500	1750	2000	psi
Permeability, k	100	150	200	md
Porosity, phi	15	17	20	%
Initial Water Saturation, Sw	20	25	30	%
Reservoir Temperature, TR	175	180	185	°F
Oil Gravity	32	35	38	API
Gas Gravity, G	0.65	0.67	0.69	<>
Water Salinity	30000	35000	40000	ppm
Boi	1.253	1.294	1.34	bbl/bbl
Bob	1.26	1.306	1.359	bbl/bbl
μoi	0.9	0.701	0.564	cp
μob	0.857	0.64	0.493	cp
μw	0.381	0.373	0.366	cp
Solution Gas Drive (SGD) Oil RF	13.9	15.9	17.9	%
Water Drive (WD) Oil RF	45.6	45.9	46.2	%
Seed (Random=-1)	-1			
# M-C Simulations	10000			MC Simulation
<b>Monte Carlo Results: Oil Recovery Factor</b>				
	SGD	WD	SGD	WD
P1	18.15	52.32	P40	16.17 46.54
P10	17.19	49.26	P50	15.89 45.89
P20	16.78	48.13	P60	15.63 45.29
P30	16.45	47.26	P70	15.36 44.65
			P80	15.01 43.87
			P90	14.53 42.79
			P99	13.32 40.24
			EV	15.88 46

Figure RFA-2: Deterministic / Probabilistic Recovery Factor

#### RFA.1.1 Deterministic Oil Recovery Factor

The deterministic recovery factors are based on the API recovery factor equations as follows.

$$\text{SGD RF} = 41.815 (\phi(1 - S_w)/B_{ob})^{0.1611} (0.001k/\mu_{ob})^{0.0979} S_w^{0.3722} (P_{bp}/P_{ab})^{0.1744} \quad (\text{RFA-1})$$

$$\text{WD RF} = 54.898 (\phi(1 - S_w)/B_{oi})^{0.0422} (0.001k\mu_{wi}/\mu_{oi})^{0.077} S_w^{-0.1903} (P_i/P_{ab})^{-0.2159} \quad (\text{RFA-2})$$

Where: SGD RF is the solution gas drive recovery factor in %, WD RF is the water drive recovery factor in %,  $B_{ob}$  is oil  $B_o$  at the bubble point,  $B_{oi}$  is the oil  $B_o$  at the initial pressure,  $k$  is permeability in md,  $\mu_{ob}$  is oil viscosity at the bubble point,  $\mu_{oi}$  is oil viscosity at initial pressure,  $\mu_{wi}$  is water viscosity at initial pressure,  $P_{bp}$  is the bubble point pressure,  $P_{ab}$  is the abandonment pressure,  $P_i$  is the initial pressure,  $S_w$  is the initial water saturation in decimal and  $\phi$  is the porosity in decimal.

It should be noted that the WD RF does not represent the recovery for a waterflood. The WD RF correlation is for a natural water drive reservoir. Also, there is no specific API recovery factor equation for a gas drive reservoir.

As rules of thumb:

- The recovery factor for a solution gas drive, or depletion drive oil reservoir, is in the range of 5% to 20%
- The recovery factor for a gas cap drive oil reservoir is in the range of 10% to 30%
- The recovery factor for a water drive oil reservoir is in the range of 30% to 80%

An alternate approach for calculating ultimate oil recovery factor is to calculate the unit recovery factor in bbls/ac-ft and multiply by the area of reservoir, as follows.

For an undersaturated oil reservoir with  $P_i$  above  $P_b$ , unit recovery to the bubble point pressure of the depletion drive oil reservoir,  $N_{dep}$ , with no water drive is:

$$N_{dep} = 7758\phi (P_i - P_b) [C_o + C_r + S_w(C_o - C_w)] / [B_{oi} (1 + C_o(P_i - P_b))] \quad (\text{RFA-3})$$

For saturated oil, the unit recovery for a solution gas drive oil reservoir,  $N_{SGD}$ , with no water drive, is based on residual gas saturation as follows:

$$N_{SGD} = 7758\phi [(1 - S_w)/B_{oi} - (1 - S_w - S_{gr})/B_{oab}] \quad (\text{RFA-4})$$

$$S_{gr} = 0.625 - 1.3125\phi \quad (\text{RFA-5})$$

The unit recovery for a water drive oil reservoir,  $N_{WD}$ , is:

$$N_{WD} = 7758\phi [(1 - S_w)/B_{oi} - S_{or}/B_{oab}] \quad (\text{RFA-6})$$

Where:  $\phi$  is porosity in decimal,  $P_i$  is initial reservoir pressure in psi,  $P_b$  is bubble point pressure in psi,  $c_o$  is oil compressibility in  $\text{psi}^{-1}$ ,  $c_r$  is rock compressibility in  $\text{psi}^{-1}$ ,  $c_w$  is water compressibility in  $\text{psi}^{-1}$ ,  $B_{oi}$  is initial oil  $B_o$ ,  $S_w$  is initial water saturation in decimal,  $S_{gr}$  is residual gas saturation in decimal,  $B_{oab}$  is oil  $B_o$  at abandonment pressure  $S_{or}$  is residual oil saturation in decimal.

## RFA.1.2 Probabilistic Oil Recovery Factor

Probabilistic oil recovery factor is an optional calculation performed using Monte Carlo simulation on the API equations. The P90, P50, P10 normal distributions are used as input to the

simulation and the number of iterations are specified. The probabilistic recovery factor results for a solution gas drive and a water drive oil reservoir are presented. The 'Expected Value' based on the probabilistic results are also presented (Figure RFA-3).

Monte Carlo Results: Oil Recovery Factor								
	SGD	WD		SGD	WD		SGD	WD
P1	18.15	52.32	P40	16.17	46.54	P80	15.01	43.87
P10	17.19	49.26	P50	15.89	45.89	P90	14.53	42.79
P20	16.78	48.13	P60	15.63	45.29	P99	13.32	40.24
P30	16.45	47.26	P70	15.36	44.65	EV	15.88	46

Figure RFA-3: Probabilistic Oil Recovery Factor

For each iteration of the Monte Carlo simulator, the fluid properties are re-calculated based on the randomly sampled pressure. This ensures that all parameters that make up the API equations are converted to probabilistic distributions.

To generate a new probabilistic simulation for the same input distribution (if Seed=-1), just click the 'MC Simulation' button again. The 'Seed' value is included so the same probabilistic results can be re-generated. By entering a specific seed value, the same random Gaussian distribution will be used for the simulation. Entering '-1' for the seed will generate random seed numbers so the results will be different for each simulation run. The default number of Monte Carlo simulations is 10,000. This results in a relatively smooth probabilistic distribution curve.

## RFA.2 Deterministic Gas RF

The deterministic recovery factor for a gas reservoir is based on material balance calculations. For a volumetric gas reservoir, recovery factor is dependent on abandonment pressure (Figure RFA-4).

**Gas Recovery Factor**

Gas Gravity, G  <> Temperature, TR  °F  
Initial Pressure, Pi  psi Initial Sw  %  
Abandon Pressure, Pab  psi Residual Gas, Sgr  %

**Reservoir System / RF**

Recovery Factor  %  
Suggested, Sgr  %

☐ Volumetric Gas  
☒ Limited Water Drive  
☐ Strong Water Drive

Figure RFA-4: Deterministic Gas Recovery Factor

If a water drive is present, gas recovery will be reduced because of residual, or bypassed, gas. The gas recovery factor equations are as follows.

$$\text{Vol RF} = 100 (1 - B_{gi}/B_{gab}) = 100 (1 - P_{ab}Z_i/P_iZ_{ab}) \quad (\text{RFA-7})$$

$$\text{Limited WD RF} = 100 (S_g P_i/Z_i - S_{gr} P_{ab}/Z_{ab}) / (S_g P_i/Z_i) \quad (\text{RFA-8})$$

$$\text{Strong WD RF} = 100 (S_g - S_{gr}) / S_g \quad (\text{RFA-9})$$

$$\text{Suggested } S_{gr} = 0.6838 S_g^2 - 1.6831 S_g + 1.1525 \quad (\text{RFA-10})$$

Where: Vol RF is the volumetric gas recovery factor in %, Weak WD RF is the gas recovery factor for a reservoir with a limited water drive in %, Strong WD RF is the gas recovery factor for a reservoir with a strong water drive in %,  $P_{ab}$  is the abandonment pressure,  $P_i$  is the initial pressure,  $S_g$  is the initial gas saturation ( $1 - S_w$ ) in decimal,  $S_{gr}$  is residual gas saturation in decimal,  $B_{gab}$  is the gas formation factor at  $P_{ab}$ ,  $B_{gi}$  is the gas formation factor at  $P_i$ ,  $Z_i$  is the Z-factor at  $P_i$ , and  $Z_{ab}$  is Z-factor at  $P_{ab}$ . The 'Suggested  $S_{gr}$ ' is based on an EPCI correlation for  $S_{gr}$  in terms of initial  $S_g$  (Figure RFA-5).

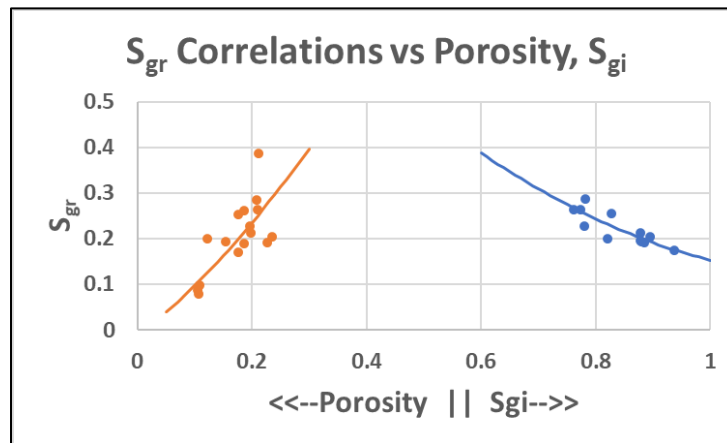


Figure RFA-5:  $S_{gr}$  Correlation

As rules of thumb:

- If a compressor is not installed,  $P_{ab}$  can be estimated at 100psi/1000ft of depth
- The recovery factor for a volumetric reservoir is in the range of 80% to 90%
- The recovery factor for a weak water drive reservoir is in the range of 70% to 80%
- The recovery factor for a strong water drive reservoir is in the range of 60% to 70%
- High permeability will tend to move recovery factor to the top of the range

No probabilistic calculations for gas recovery have been implemented in the PE<sup>2</sup> Essentials Recovery Factor Analysis tool.

### RFA.3 Unconventional Oil/Gas RF

For unconventional oil and gas reservoirs (Figure RFA-5), there are no industry standard published correlations for recovery factors. The correlations presented here were generated for use in PE<sup>2</sup> Essentials using public domain recovery data for unconventional reservoirs.

Unconventional Gas Recovery Factor (Speculative)	
Initial Gas Resource in Place	100 Tscf
Potential Gas RF	17.6 %
Potential Field IP	4900.4 mmscf
Unconventional Oil Recovery Factor (Speculative)	
Initial Oil Resource in Place	100 Bbbls
Potential Oil RF	4.6 %
Potential Field IP	767.6 mbopd

Figure RFA-6: Unconventional Oil/Gas Recovery Factor

For the unconventional empirical recovery factor, recovery data from a 2013 report published by the US EIA ([www.eia.gov/analysis/studies/worldshalegas/pdf/overview.pdf](http://www.eia.gov/analysis/studies/worldshalegas/pdf/overview.pdf)) was used to build the gas recovery correlations. The published data included in-place volumes and EUR volumes for 137 shale reservoirs in 41 countries.

Figure RFA-8 presents a plot of the gas in place versus EUR data for unconventional gas reservoirs and Figure RFA-9 presents the oil in place versus EUR data for unconventional oil reservoirs.

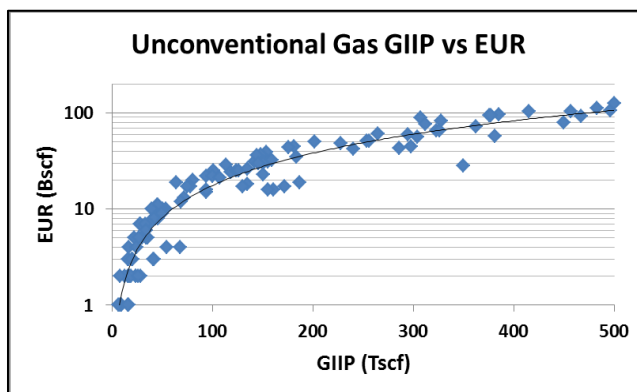


Figure RFA-8: Unconventional Gas GIIP vs EUR

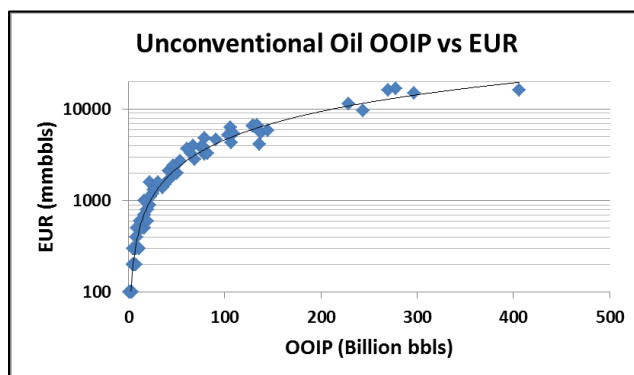


Figure RFA-9: Unconventional Oil OIIP vs EUR

The  $R^2$  for the gas plot is 0.9497 and the  $R^2$  for the oil plot is 0.9756. The trends apparent on these plots yielded the following correlation equations for the unconventional recovery factor.

$$\text{Gas RF} = 10.2798 \text{ GIIP}^{0.1169} \quad (\text{RFA-11})$$

$$\text{Oil RF} = 3.9581 \text{ OOIP}^{0.0329} \quad (\text{RFA-12})$$

Where: Gas RF and Oil RF are in %, GIIP is in Tscf and OOIP is in billion bbls.

The Recovery Factor Analysis tool also presents an estimate of 'Potential Field IP' for full development of an unconventional oil or gas field. Note – no assumption on well count is made for this estimate. These calculations were presented in an Oil and gas Journal article ([www.ogj.com/articles/print/vol-110/issue-12/exploration-development/evaluating-production-potential-of-mature-us-oil.html](http://www.ogj.com/articles/print/vol-110/issue-12/exploration-development/evaluating-production-potential-of-mature-us-oil.html)) and are as follows.

$$Q_g = 230 (\text{GasRF GIIP}/100)^{1.0664} \quad (\text{RFA-13})$$

$$Q_o = 260 (\text{OilRF OOIP}/100)^{0.7088} \quad (\text{RFA-14})$$

Where:  $Q_g$  is potential gas field IP in mmscf/d, GIIP is initial gas in place in Tscf, GasRF is calculated gas recovery factor in % (Equation 4-11),  $Q_o$  is potential oil field IP in mbopd, OOIP is initial oil in place in billion bbls and OilRF is calculated oil recovery factor in % (Equation RFA-12).

The 'Potential Field IP' is the potential production that may be achieved if the field was fully developed. No assumptions have been made concerning number of wells required to achieve this rate.

#### RFA.4 Reservoir Complexity Index Oil RF

Oil recovery factor based on Reservoir Complexity Index, RCI, is an EPCI enhancement to the work published by Wickens and Kelly (Wickens, L. M., Kelly, R., Rapid Assessment of Potential Recovery Factor: A New Correlation Demonstrated on UK and USA Fields, SPE134450, 2010). Wickens and Kelly used data from 24 UK North Sea fields in a linear correlation for RCI-RF with an applied weighting to maximize the  $R^2$  of the correlation. The database used by Wickens and Kelly was increased to include 43 Norwegian North Sea fields. The complete list of fields and their scores are presented in Table RFA-10.

The scores listed in Table RFA-10 were generated using the criteria in Table RFA-1.

Field	Scores				Total Score	Recovery Factor
	Structure	Viscosity	bbls/acre	k <sub>max</sub> /k <sub>min</sub>		
Arbroath	1	1	3	3	10	50.9
Arkwright	2	1	3	1	10	34.2
Auk	3	1	3	5	16	18
Balder	1	2	2	2	10	37.3
Borg	2	1	2	2	10	53.3
Borg N-V	2	1	3	2	11	61
BraeS	3	1	1	3	12	33
Brent	2	1	1	2	9	52.3
Bressay	1	5	1	1	14	25
Captain	2	3	2	1	13	32
Clair	5	2	1	1	16	14
Don	5	1	1	1	14	
Draugen	1	1	3	1	8	64.1
Ekofisk	2	1	1	2	9	46.6
Embla	4	1	1	2	13	27.3
Felt B Ang	3	2	1	2	13	38
Forties	1	1	1	2	7	57
Fram Vest	1	2	3	2	11	38.3
Fulmar	1	1	1	2	7	69
Glitne	2	2	3	2	13	37.6
Grane-OD	1	3	1	1	10	54.5
Gullfaks Cook	3	1	2	3	13	37.8
Gullfaks SF fm.	2	1	1	2	9	56.5
Gullfaks Sør SF fm.	5	1	3	2	17	9.1
Gyda	3	1	2	2	12	43.8
Heather	2	1	3	4	13	31
Heidrun Tilje&Åre	2	2	3	3	14	29.7
Hutton	2	2	2	1	11	35
HuttonNW	2	2	3	4	15	26
Jotun	2	2	2	2	12	41.6
Magnus	2	1	1	1	8	50
Mariner Heimdahl	3	4	1	1	16	14.2
Mariner Maureen	4	3	1	1	16	18.2
Maureen	1	1	2	2	8	55
Montrose	1	1	4	3	11	41
Ninian	3	1	2	2	12	46
Njord	3	2	3	3	16	20.5
Nome	2	1	2	2	10	55.7
Oseberg Ness	1	2	4	3	13	30
Oseberg Øst	3	2	3	3	16	30.7
Oseberg Sør	4	2	1	2	15	29.2
Rimfaks	2	1	2	3	11	37.2
Rob Roy Main	1	1	1	1	6	67
Rob Roy Supra	1	1	2	1	7	56
Smørbukk	2	1	2	3	11	33.2
Smørbukk Sør	2	1	2	3	11	36.4
Snorre Nord	2	1	2	2	10	40.6
Snorre TLP Lunde fm.	2	1	2	2	10	43
Snorre TLP SF fm.	2	1	2	2	10	44.3
Statfjord Brent	2	1	1	2	9	65.5
Statfjord IDS	4	1	4	3	17	19.1
Statfjord Nord	2	1	2	2	10	49.9
Statfjord Øst	2	1	2	2	10	55
Statfjord SF fm.	1	1	2	2	8	68.1
STUJ	3	1	2	2	12	25.4
Sygna	2	1	1	2	9	45.7
Thistle	2	1	1	3	10	49
Tordis	2	1	1	2	9	48.2
Tordis Øst	3	1	2	1	11	35.9
Troll Vest Hydro	1	2	4	1	11	34.9
Ula	1	1	1	4	9	51.1
Valhall	3	1	1	2	11	40.1
Veslefrikk	3	1	1	3	12	49
Vigdis	3	1	2	2	12	48.7
Visund	4	1	2	3	15	30.7
Yme	4	1	4	3	17	16.5

Table RFA-10: RCI Scores and Reported Recovery

Parameter	Score				
	1	2	3	4	5
Structure	No Faulting / Excellent Reservoir Quality / High Perm	Some Faulting / Some Isolated Fault Blocks / Good Perm	Highly Faulted / Major and Minor Faults	Highly Faulted / Naturally Fractured / Moderate Perm	Highly Discontinuous / Sealed Fault Blocks / Gas/Water Coning / Low Perm
Viscosity	Oil Viscosity < 1 cp	Oil Viscosity Between 1 cp and 10 cp	Oil Viscosity Between 10 cp and 100 cp	Oil Viscosity Between 100 cp and 1000 cp	Oil Viscosity > 1000 cp
bbls/acre	> 115,000 bbls/acre	Between 51,000 bbls/acre and 115,000 bbls/acre	Between 25,000 bbls/acre and 51,000 bbls/acre	Between 12,500 bbls/acre and 25,000 bbls/acre	< 12,500 bbls/acre
$k_{max}/k_{min}$	$1 < K_{max}/K_{min} < 10$ or Dykstra-Parsons: <0.6	$10 < K_{max}/K_{min} < 100$ or Dykstra-Parsons: 0.6 to 0.8	$100 < K_{max}/K_{min} < 1000$ or Dykstra-Parsons: 0.8 to 0.9	$1000 < K_{max}/K_{min} < 10000$ or Dykstra-Parsons: 0.9 to 1	$K_{max}/K_{min} > 10000$ or Dykstra-Parsons = 1

Table RFA-1: RCI Scoring Criteria

The scores were normalized, and a power correlation was used for the normalized RCI with exponent weighting to maximize the  $R^2$  of the normalized RCI-RF correlation. The resulting RCI-RF correlation is presented as Equation RFA-15.

$$RCI_{max} = 5^{StructExp} + 5^{VisExp} + 5^{AreaExp} + 5^{PermExp}$$

$$RCI_{calc} = StructScore^{StructExp} + ViscosityScore^{VisExp} + AreaScore^{AreaExp} + PermScore^{PermExp}$$

$$RCI_{norm} = RCI_{calc} / RCI_{max}$$

$$RF = 76.727 - 134.27 RCI_{norm} \quad (RFA-15)$$

Where: RF is oil recovery factor in %, the Scores are assigned based in the criteria presented in Table RFA-2 and the exponents were chosen to maximize the  $R^2$  of the correlation.

The calculated normalized RCI and RCI-based oil RF are presented as output (Figure RFA-11).

Oil Recovery Factor Based on Reservoir Complexity Index

**Structural Complexity**

- ☐ No Faulting / Excellent Reservoir Quality / High Perm
- ☒ Some Faulting / Some Isolated Fault Blocks / Good Perm
- ☐ Highly Faulted / Major and Minor Faults
- ☐ Highly Faulted / Naturally Fractured / Moderate Perm
- ☐ Highly Discontinuous / Sealed Fault Blocks / Gas/Water Coning / Low Perm

**Oil Viscosity**

- ☐ Oil Viscosity < 1 cp
- ☐ Oil Viscosity Between 1 cp and 10 cp
- ☒ Oil Viscosity Between 10 cp and 100 cp
- ☐ Oil Viscosity Between 100 cp and 1000 cp
- ☐ Oil Viscosity > 1000 cp

**OOIP Areal Density**

- ☐ > 115,000 bbls/acre
- ☒ Between 51,000 bbls/acre and 115,000 bbls/acre
- ☐ Between 25,000 bbls/acre and 51,000 bbls/acre
- ☐ Between 12,500 bbls/acre and 25,000 bbls/acre
- ☐ < 12,500 bbls/acre

**Perm Heterogeneity**

- ☒  $1 < K_{max}/K_{min} < 10$  or Dykstra-Parsons: <0.6
- ☐  $10 < K_{max}/K_{min} < 100$  or Dykstra-Parsons: 0.6 to 0.8
- ☐  $100 < K_{max}/K_{min} < 1000$  or Dykstra-Parsons: 0.8 to 0.9
- ☐  $1000 < K_{max}/K_{min} < 10000$  or Dykstra-Parsons: 0.9 to 1
- ☐  $K_{max}/K_{min} > 10000$  or Dykstra-Parsons = 1

Normalized Reservoir Complexity Index (RCI) 0.313
 RCI-Based Oil RF 34.7 %

Info

Figure RFA-11: RCI-based Oil Recovery Factor



### RFA.5 Alternative North Sea Oil RF

While investigating recovery factors, a number of analyses using regression were attempted for North Sea oil fields. Many correlations were examined including API, OOIP and kh (Figure RFA-12).

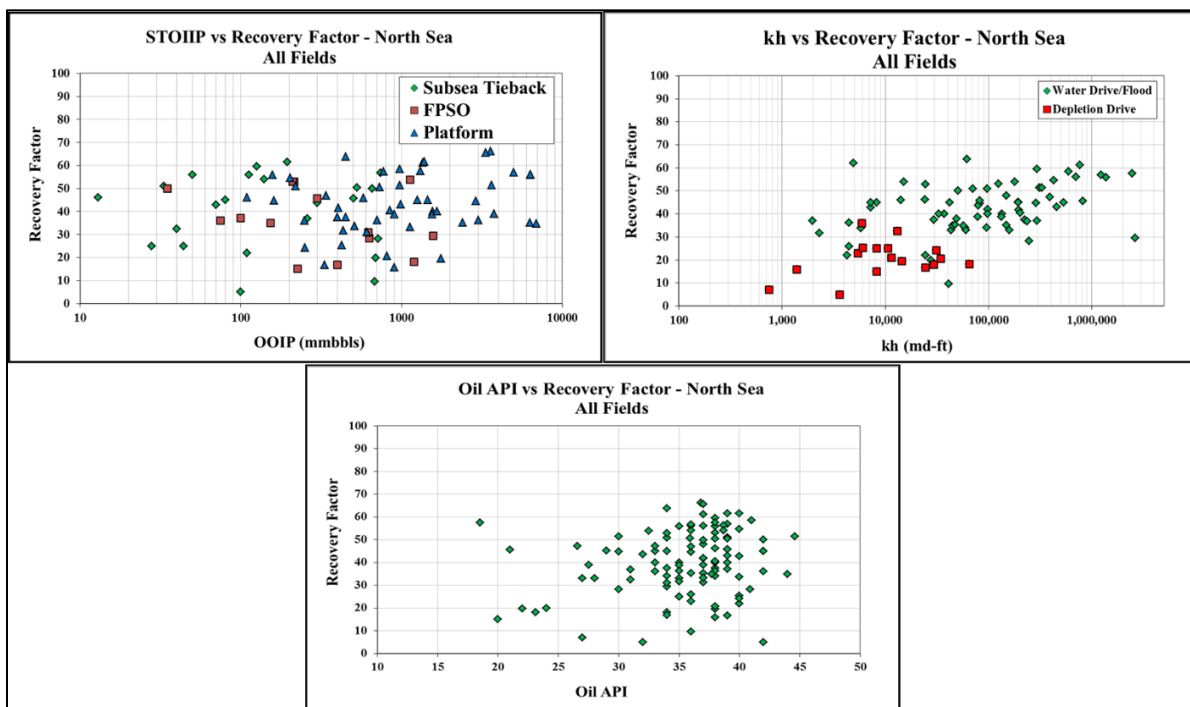


Figure RFA-12: Possible Correlation Plots for Oil Recovery Factor

The kh plot appeared to show a general semi-log correlation with RF. Assuming that the kh trend is valid, a high, mid, low correlation was generated for the data (Figure RFA-13).

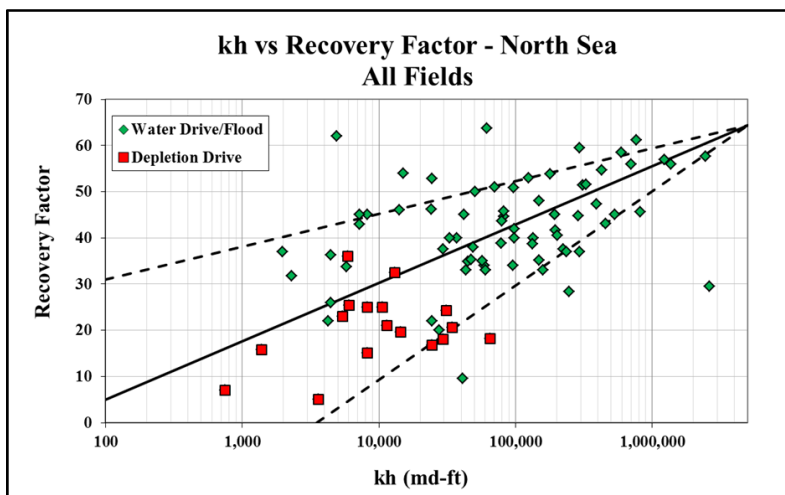


Figure RFA-13: Semi-log kh Correlation for Oil Recovery Factor

$$\text{High RF} = 7.029 \log(kh) + 16.815 \quad (\text{RFA-16})$$

$$\text{Mid RF} = 12.626 \log(kh) - 20.252 \quad (\text{RFA-17})$$

$$\text{Low RF} = 19.692 \log(kh) - 72.263 \quad (\text{RFA-18})$$

Based on the kh correlation plot, this correlation should be used only if kh is greater than ~5000md-ft.

Two other potential oil recovery factor correlations were generated as well, a kh/OOIP correlation (Figure RFA-14) and an api-kh/OOIP correlation (Figure RFA-15).

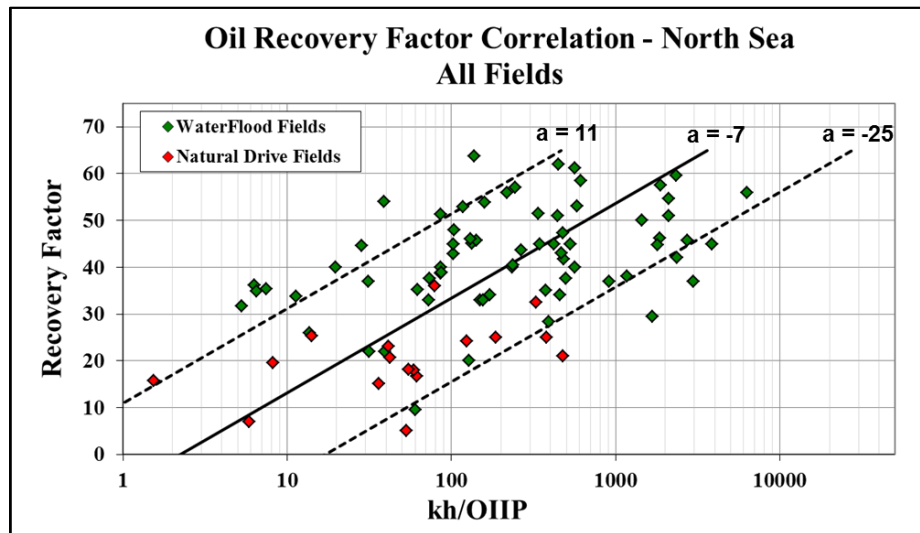


Figure RFA-14: Semi-log kh/OOIP Correlation for Oil Recovery Factor

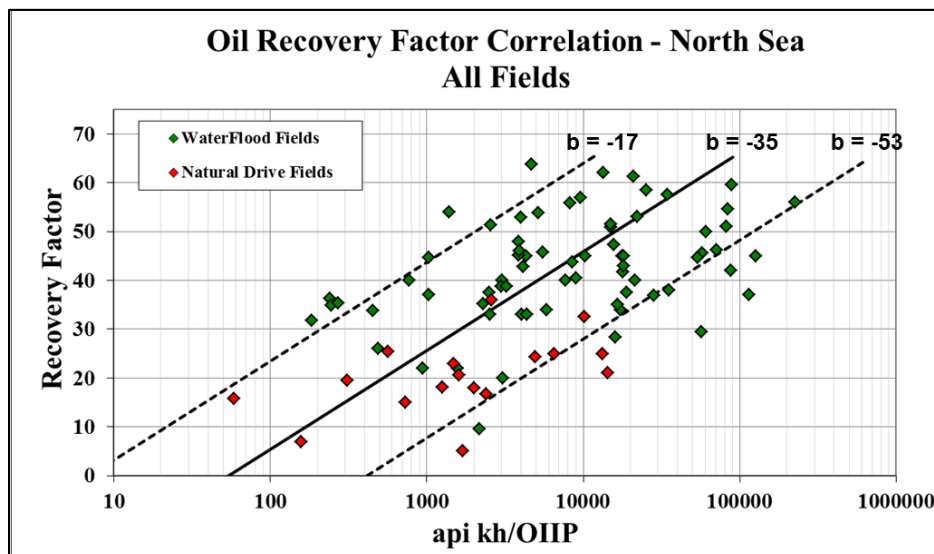


Figure RFA-15: Semi-log api-kh/OOIP Correlation for Oil Recovery Factor

The kh/OOIP and api-kh/OOIP plots appear to show a general semi-log correlation with RF. If the trends actually exist, a high, mid, low correlation was generated for the data as follows.

$$RF = 20.244 \log(kh/OOIP) + a \quad (RFA-19)$$

$$RF = 20.244 \log(api \text{ kh}/OOIP) + b \quad (RFA-20)$$

Where: a and b are listed on the plots and represent the high, mid, low constants.

These correlations (Figures RFA-13, RFA-14 and RFA-15) should only be used to estimate ranges of recovery.

As an example, assume a reservoir has a kh of 300md, 150ft of pay and contains 250mmbbls of 35°api oil. The correlating function for Figure RFA-12 is 6300 (api-md-ft/mmbbls). The resulting range of recovery factors is 59.9% / 41.9% / 23.9%.

It should be noted that there are no recovery factors above 65% in this data set. A calculated RF that exceeds 65% should be set at 65%.

## RFA.6 Artificial Neural Network (ANN) Oil RF Model

The ANN RF model is a new oil recovery model developed using an open source neural network model. There are a number of Neural Networks programs available that are based on the OpenNN system. Figure RFA-16 shows the inputs required for the PE<sup>2</sup> Essentials ANN Oil RF model. More information on the model was published in the March 2019 issue of World Oil.

ANN Oil Recovery Factor - Conventional Reservoir	
Oil In Place	10
Permeability	10
Net Oil Pay	50
Porosity	20
Oil API Gravity	35
Oil Viscosity	0.13

**ANN-Based Oil Recovery Factor**

32.8

**Run ANN Model**

ANN Model Range	
	Min Max
Oil In Place:	10 - 50000 mmbbls
Permeability:	1 - 5000 md
Net Pay:	10 - 1800 feet
Porosity:	5 - 35 %
Oil Gravity:	15 - 55 °API
Oil Viscosity:	0.1 - 88 cp
Oil RF:	4 - 78 %

Figure RFA-16: Artificial Neural Network Oil RF Model

### RFA.6.1 Introduction to Artificial Neural Networks (ANN)

Neural networks, a technique of machine learning, is a branch of artificial intelligence which attempts to model high-level data interactions by using complex architectures which perform multiple transformations.

The fundamental basis for neural network technology is the Universal Approximation Theorem ([http://en.wikipedia.org/wiki/Universal\\_approximation\\_theorem](http://en.wikipedia.org/wiki/Universal_approximation_theorem)). This theorem states that any continuous function that maps a set of real numbers to another set of real numbers can be approximated to some degree of accuracy by a feed-forward neural network with a single hidden layer and a finite number of hidden units (neurons or perceptrons) which contain non-linear transfer functions - Figure RFA-17. In almost all implementations of ANN's, the non-linear transfer function is a hyperbolic tangent (tanh).

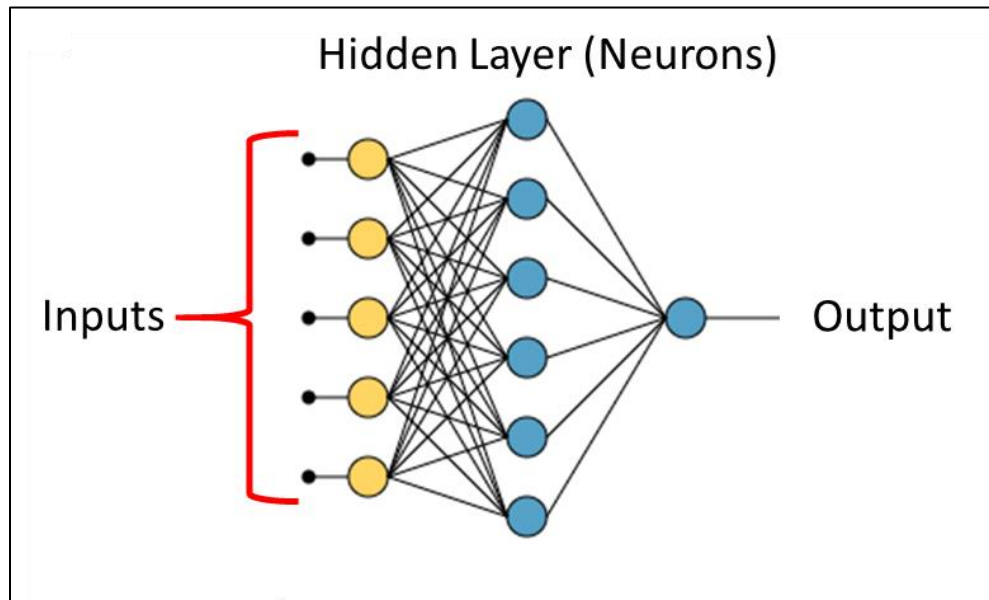


Figure RFA-17: Artificial Neural Network Model

Neural networks are particularly well-suited for modeling complex non-linear relationships which cannot be easily modeled by traditional linear regression methods, for example, oil recovery factors.

Full-featured ANN programs are normally combined with genetic algorithms, statistics/linear regression, and fuzzy logic to automatically find optimal or near-optimal solutions for the problem. For more information on these concepts refer to: [https://en.wikipedia.org/wiki/Genetic\\_algorithm](https://en.wikipedia.org/wiki/Genetic_algorithm) and [https://en.wikipedia.org/wiki/Fuzzy\\_logic](https://en.wikipedia.org/wiki/Fuzzy_logic).

ANN's may be a branch of artificial intelligence but they are basically high tech statistical calculators. As with all statistical analysis the results are completely dependant on how 'well-behaved' the input data is.

The author has successfully used ANN's in a number of implementations in the oil industry, for example, predicting IP30 (30-day IP), IP90 and IP365 for hydraulically fractured horizontal wells. This model could then be used to optimize well spacing and the hydraulic fracture programs of future horizontal wells.

### RFA.6.2 Building the ANN Oil RF Model

The validity of any ANN model is dependant on how well the system has been 'trained'. Normally a large dataset of well-behaved data is used for training and a different set of data is used as a blind test once the model is built. ANN systems will subdivide the training data set into a training set and a validating subset. This is not the same as using a set of blind test data. The validating subset is still part of the training subset.

Based on the API RF equations (Equation RFA.1 and RFA.2) and general reservoir engineering principals, the reservoir parameters used to build the ANN were: STOOIP, porosity, permeability, viscosity, Oil API and net pay. Although not the only parameters that impact recovery, these parameters are considered to be the major components impacting long-term recovery of oil from a reservoir. The final form used as input to the ANN were: Log(STOOIP), Log(kh), Log(viscosity), Log(phi-h) and Oil API. The logarithm of values was used to place the max/mins in a reasonable range and to pre-process the data prior to use in the ANN.

For the ANN Oil RF model, data from 264 sandstone/clastic reservoirs were used. A random subset of 46 reservoirs were removed from the data set to be used as a blind test. Of the remaining 218 reservoirs, 20% were used as validating data for training. Figure RFA-15 presents the available data for the sandstone reservoir data set.

It is obvious from Figure RFA-18 that the data has a large scatter. This is not unexpected when considering reservoir recovery factors. It is one of the problems with trying to generate a recovery factor correlation that is universally valid.

Nevertheless, each of the ANN inputs do tend to show a trend with respect to recovery factor. These trends will help the ANN system find an optimal solution.

It should be noted that the PE<sup>2</sup> Essentials ANN Oil RF Model continues to be developed as more data becomes available. The most current model was published in the March 2019 issue of World Oil.

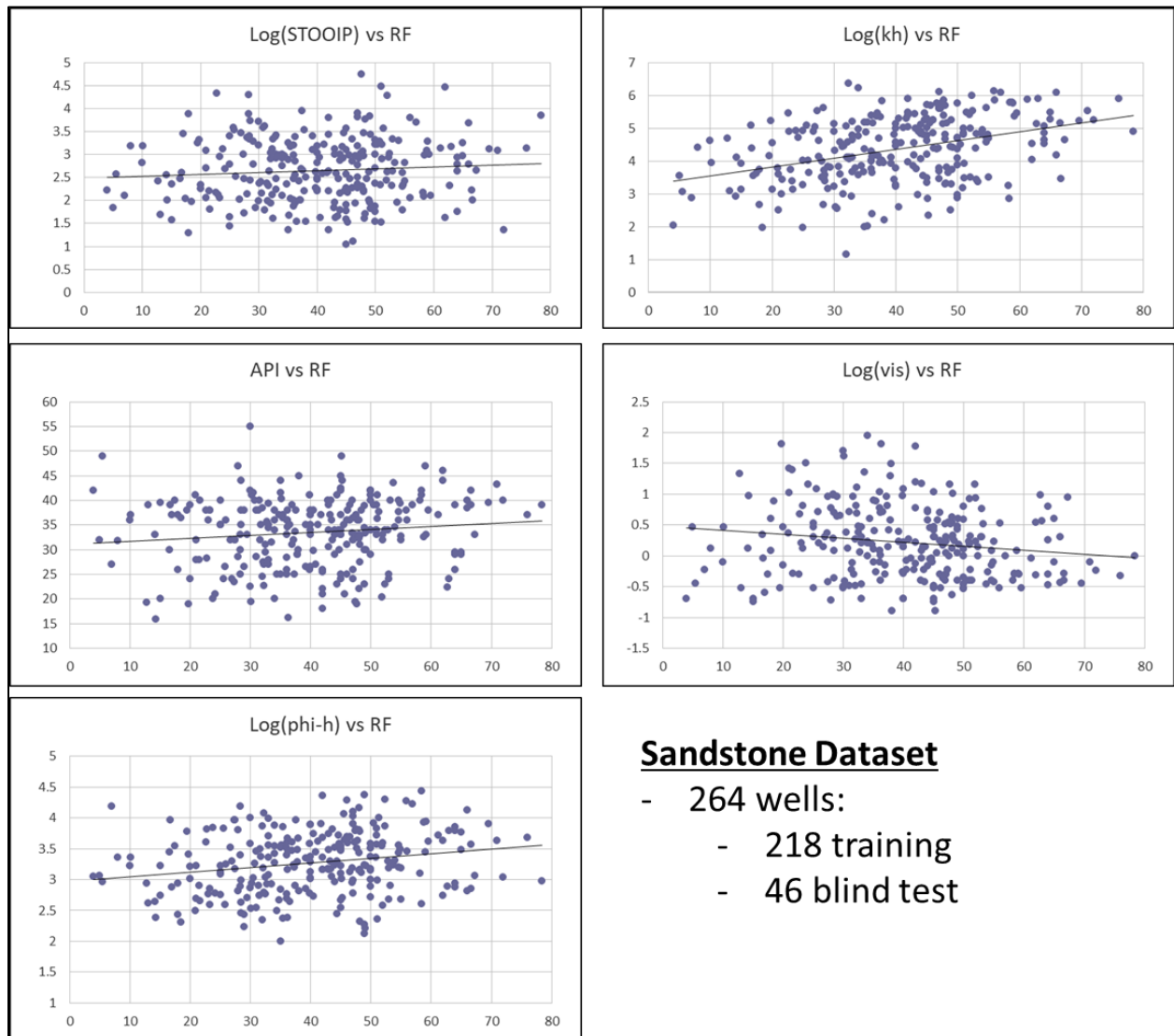


Figure RFA-18: Sandstone Data Set for ANN Oil RF Model

A second data set comprised of 38 carbonate/dolomite reservoirs was used to develop the ANN Oil RF model for carbonate reservoirs. A random subset of 5 reservoirs were removed from the data set to be used as a blind test.

Figure RFA-19 presents the available data for the carbonate reservoir data set.

It is obvious that the carbonate ANN model will not be as robust because of the small dataset.

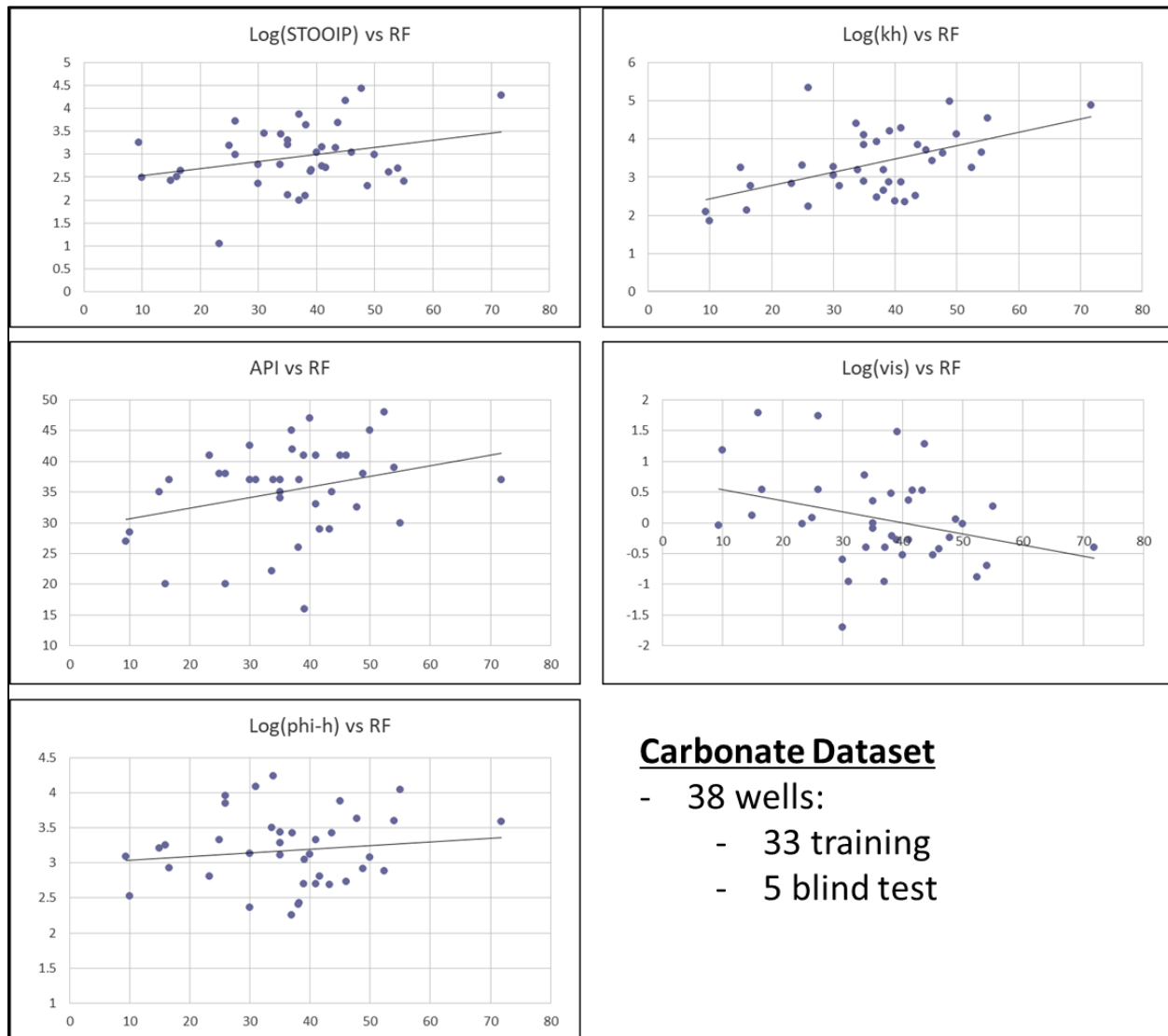


Figure RFA-19: Carbonate Data Set for ANN Model

The big unknown for ANN's is the number of neurons to include in the model. With well-behaved data, it may be possible to minimize the neurons so that they are less than or equal to the number of inputs to the model – 5 or 6 in this case.

It was found that using a small number of neurons could not handle the problem. Specifically, the lower the neuron count the less likely the ANN was able to model the high and low RF trends.

Figure RFA-20 shows the result, when 4 neurons were used in the ANN model. It was apparent that the ANN had trouble finding an optimum solution that would cover the entire range of RF's for the low neuron counts.

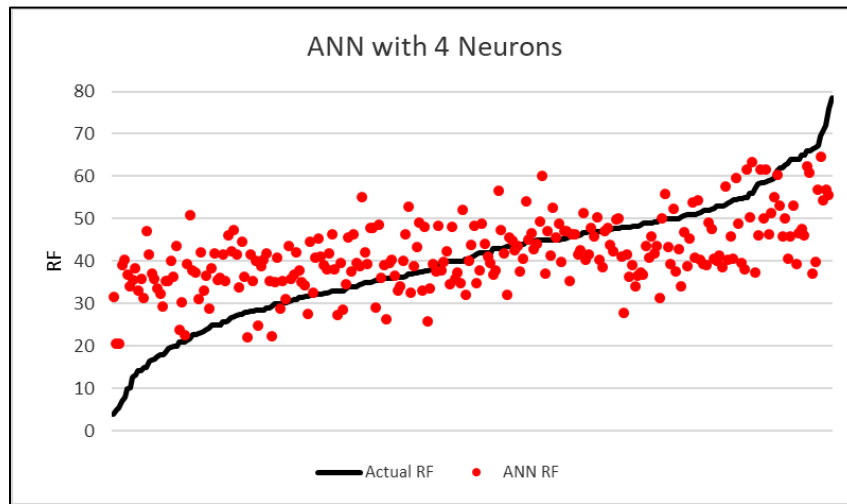


Figure RFA-20: ANN Model – 4 Neurons

Multiple models were built to try and find an optimum number of neurons that would yield an optimum solution that was valid over the entire range of RF's. Figure RFA-21 shows the  $R^2$  correlation for ANN's built using different numbers of neurons.

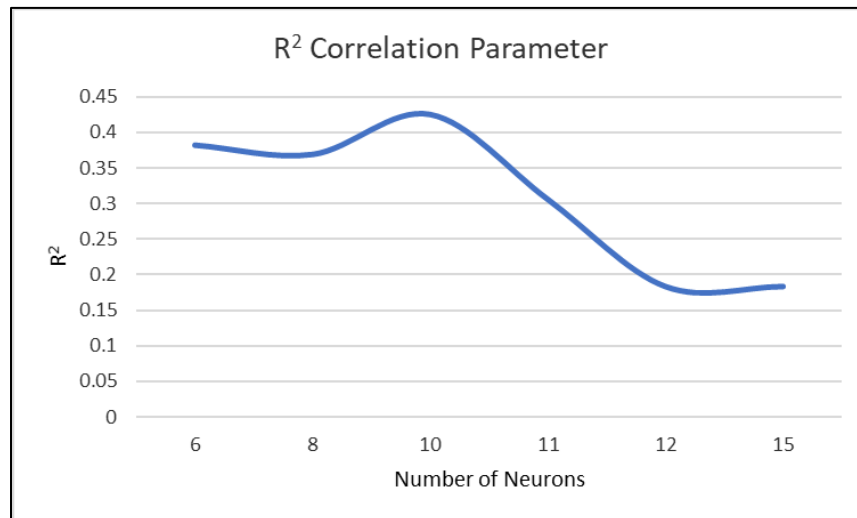


Figure RFA-21: ANN Model – Correlation Coefficients

From Figure RFA-21 there appears to be a maximum correlation coefficient for an ANN with 10 neurons.

Figure RFA-22 shows the result for an ANN trained with 10 neurons. Figure RFA-22 includes both the training data set and the blind test data set. There is still a scattered in the results but with the scatter in the input data, this was expected.



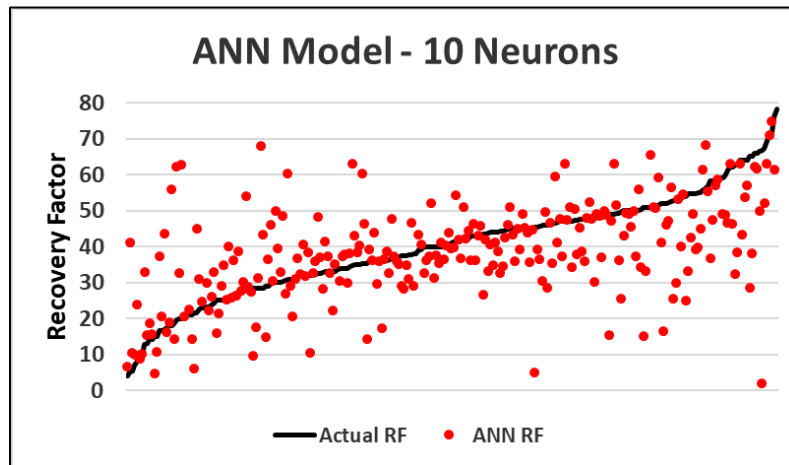


Figure RFA-22: ANN Model – 10 Neurons

As a final check, a second Neural Network program was used to build a second ANN with 10 neurons. Figure RFA-23 shows the two models. Both models are included in PE<sup>2</sup> Essentials.

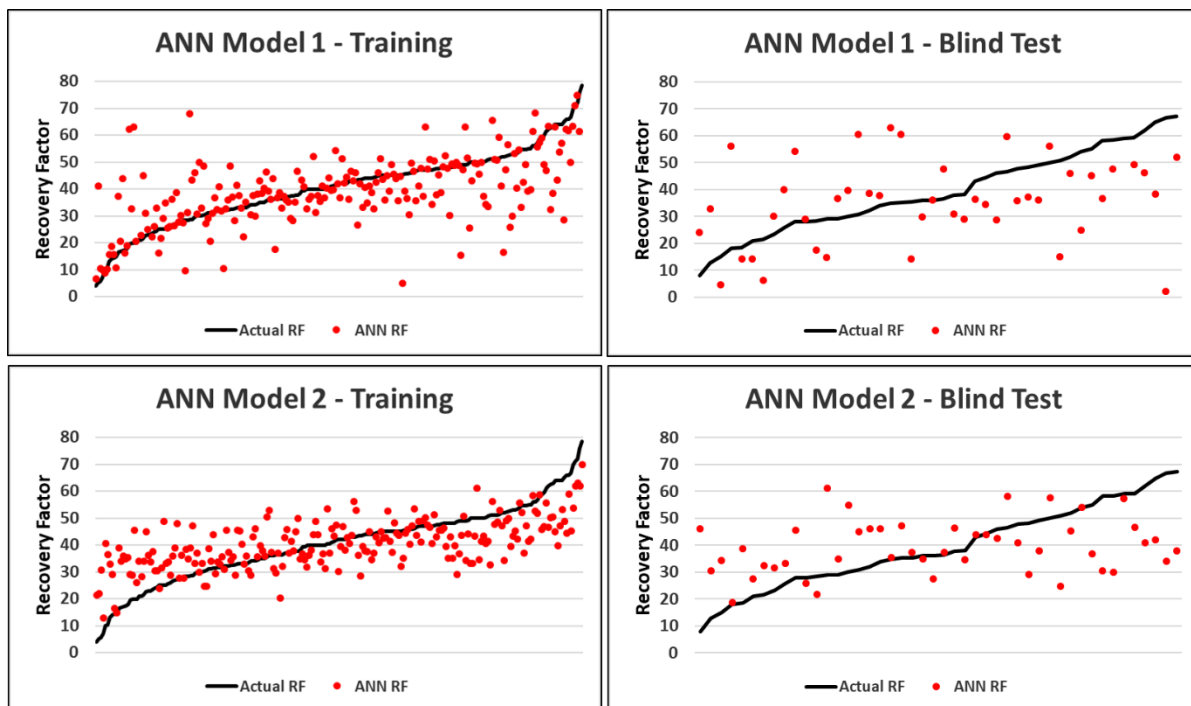


Figure RFA-23: ANN Oil RF Models – Sandstone Reservoirs

Model 2 appears to handle the blind test data better than Model 1, but Model 1 appears to model the high/low RF trends better than Model 2.

For carbonate reservoirs, 6 neurons were found to be optimum to model the RF's (Figure RFA-24).

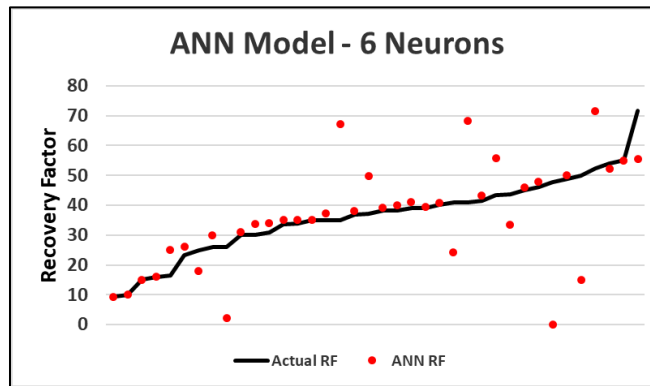


Figure RFA-24: ANN Oil RF Models – Carbonate Reservoirs

Because of the small dataset, the ANN model looks very good, but caution should be used when using the results from this model.

### RFA.6.3 ANN Oil RF Model – Sandstone Model

Figure RFA-25 summarizes the ANN Oil RF Model for sandstone reservoirs.

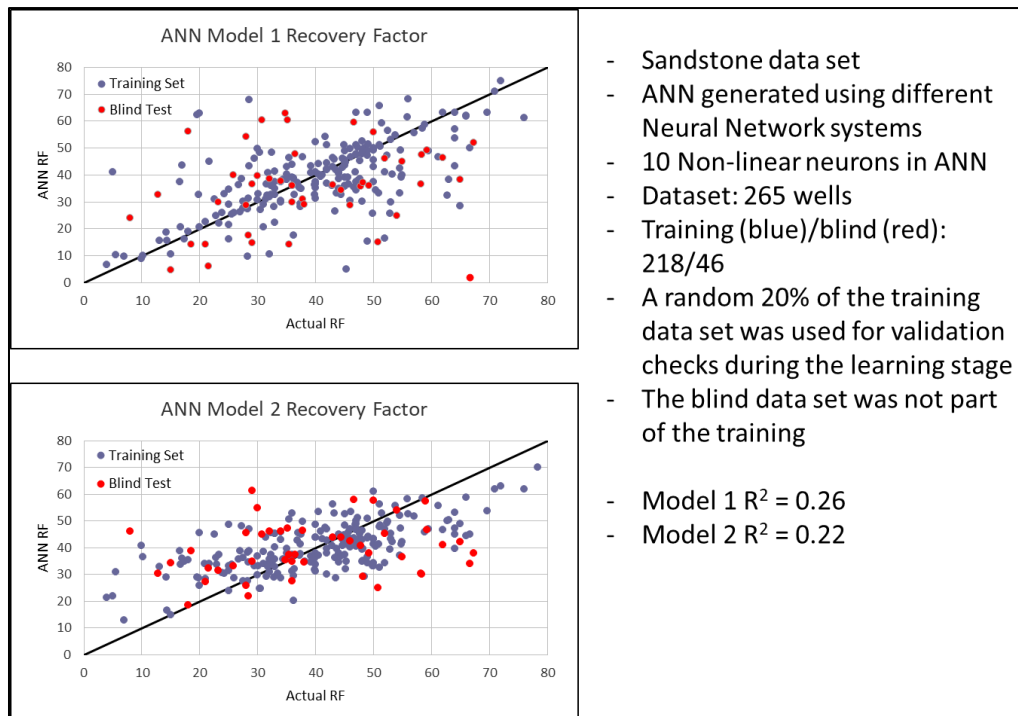


Figure RFA-25: PE<sup>2</sup> Essentials ANN Oil RF Models – Sandstone Reservoirs

The equation that represents the ANN model for sandstone reservoirs is presented below.

$$\begin{aligned}
 \text{Scaled\_Log\_OOIP} &= (\text{Log\_OOIP} - 2.65783) / 0.699151 \\
 \text{scaled\_log\_kh} &= (\text{log\_kh} - 4.41412) / 0.991662 \\
 \text{scaled\_API} &= (\text{API} - 33.5211) / 6.89976 \\
 \text{scaled\_log\_Viscosity} &= (\text{log\_Viscosity} - 0.186206) / 0.568663 \\
 \text{scaled\_Log\_Poro\_h} &= (\text{Log\_Poro\_h} - 3.30592) / 0.494583 \\
 \\
 a &= \text{Tanh}(-5.3314 - 0.653912 * \text{scaled\_Log\_OOIP} + 4.64736 * \text{scaled\_log\_kh} - \\
 &\quad 8.25336 * \text{scaled\_API} + 3.30679 * \text{scaled\_log\_Viscosity} + 3.32009 * \text{scaled\_Log\_Poro\_h}) \\
 \\
 b &= \text{Tanh}(-1.21679 + 1.47136 * \text{scaled\_Log\_OOIP} - 1.70876 * \text{scaled\_log\_kh} - \\
 &\quad 0.151557 * \text{scaled\_API} - 2.59019 * \text{scaled\_log\_Viscosity} + 1.19481 * \text{scaled\_Log\_Poro\_h}) \\
 \\
 c &= \text{Tanh}(-7.71927 - 2.77029 * \text{scaled\_Log\_OOIP} + 2.82045 * \text{scaled\_log\_kh} + \\
 &\quad 5.42809 * \text{scaled\_API} + 3.71707 * \text{scaled\_log\_Viscosity} + 1.47208 * \text{scaled\_Log\_Poro\_h}) \\
 \\
 d &= \text{Tanh}(-1.25949 + 2.11782 * \text{scaled\_Log\_OOIP} - 2.26974 * \text{scaled\_log\_kh} - \\
 &\quad 0.14775 * \text{scaled\_API} - 3.29086 * \text{scaled\_log\_Viscosity} + 1.21194 * \text{scaled\_Log\_Poro\_h}) \\
 \\
 e &= \text{Tanh}(1.55945 - 0.249741 * \text{scaled\_Log\_OOIP} + 0.564794 * \text{scaled\_log\_kh} - \\
 &\quad 0.328641 * \text{scaled\_API} - 0.0815263 * \text{scaled\_log\_Viscosity} - 0.248626 * \text{scaled\_Log\_Poro\_h}) \\
 \\
 f &= \text{Tanh}(-2.73454 + 0.763912 * \text{scaled\_Log\_OOIP} - 1.97289 * \text{scaled\_log\_kh} + \\
 &\quad 0.138494 * \text{scaled\_API} + 2.13543 * \text{scaled\_log\_Viscosity} - 1.59942 * \text{scaled\_Log\_Poro\_h}) \\
 \\
 g &= \text{Tanh}(-0.211486 + 0.754921 * \text{scaled\_Log\_OOIP} - 0.0672823 * \text{scaled\_log\_kh} + \\
 &\quad 0.84095 * \text{scaled\_API} - 0.0102544 * \text{scaled\_log\_Viscosity} - 0.949527 * \text{scaled\_Log\_Poro\_h}) \\
 \\
 h &= \text{Tanh}(-5.77792 + 0.160162 * \text{scaled\_Log\_OOIP} - 1.71346 * \text{scaled\_log\_kh} - \\
 &\quad 0.52399 * \text{scaled\_API} + 3.32055 * \text{scaled\_log\_Viscosity} - 2.28791 * \text{scaled\_Log\_Poro\_h}) \\
 \\
 i &= \text{Tanh}(1.05659 - 3.47005 * \text{scaled\_Log\_OOIP} - 0.586121 * \text{scaled\_log\_kh} - \\
 &\quad 1.2409 * \text{scaled\_API} + 0.64226 * \text{scaled\_log\_Viscosity} + 5.66334 * \text{scaled\_Log\_Poro\_h}) \\
 \\
 j &= \text{Tanh}(-4.67433 - 1.40063 * \text{scaled\_Log\_OOIP} + 3.41236 * \text{scaled\_log\_kh} - \\
 &\quad 3.79663 * \text{scaled\_API} + 0.081787 * \text{scaled\_log\_Viscosity} - 5.77076 * \text{scaled\_Log\_Poro\_h}) \\
 \\
 \text{scaled\_RF} &= -2.06301 + 0.271591 * a + 2.75565 * b + 0.397435 * c - 2.35473 * d + 3.00811 * e + \\
 &\quad 0.777111 * f + 0.976147 * g - 0.885672 * h + 0.406045 * i + 0.215362 * j \\
 \\
 \text{ANN\_RF} &= (0.5 * (\text{scaled\_RF} + 1.0) * (78.4 - 4) + 4) \quad (\text{RFA-21})
 \end{aligned}$$

Equation RFA-21 is the expression for ANN Model 1 in the PE<sup>2</sup> Essentials RF tool.

### RFA.6.4 ANN Oil RF Model – Carbonate Model

Figure RFA-26 summarizes the ANN Oil RF Model for carbonate reservoirs. The equation (Equation RFA-22) that represents the ANN model for carbonate reservoirs is presented below.

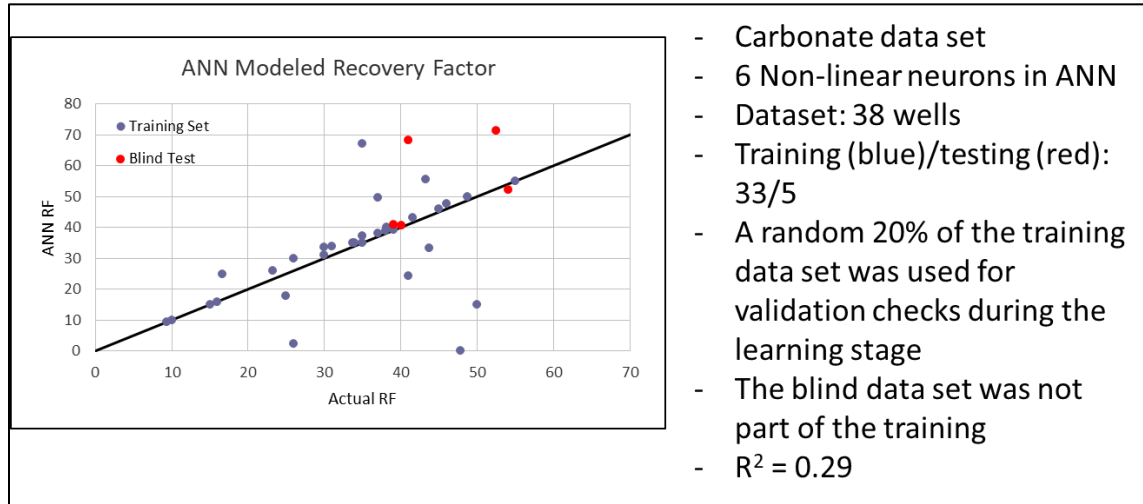


Figure RFA-26: PE<sup>2</sup> Essentials ANN Oil RF Models – Carbonate Reservoirs

$$\text{scaled\_Log\_OOIP} = (\text{Log\_OOIP} - 3.02819) / 0.636082$$

$$\text{scaled\_log\_kh} = (\text{log\_kh} - 3.40965) / 0.909265$$

$$\text{scaled\_API\_Gravity} = (\text{API} - 34.2652) / 7.58305$$

$$\text{scaled\_log\_Viscosity} = (\text{log\_Viscosity} - 0.101507) / 0.790694$$

$$\text{scaled\_Log\_Poro\_h} = (\text{Log\_Poro\_h} - 3.23401) / 0.523619$$

$$a = \text{Tanh}(-1.25222 + 4.32191 * \text{scaled\_Log\_OOIP} - 0.117155 * \text{scaled\_log\_kh} + 2.23329 * \text{scaled\_API\_Gravity} + 2.91222 * \text{scaled\_log\_Viscosity} - 5.90619 * \text{scaled\_Log\_Poro\_h})$$

$$b = \text{Tanh}(-1.98078 - 0.690941 * \text{scaled\_Log\_OOIP} + 3.41286 * \text{scaled\_log\_kh} - 3.52012 * \text{scaled\_API\_Gravity} - 6.97704 * \text{scaled\_log\_Viscosity} - 2.65092 * \text{scaled\_Log\_Poro\_h})$$

$$c = \text{Tanh}(2.44436 - 1.78361 * \text{scaled\_Log\_OOIP} - 3.22423 * \text{scaled\_log\_kh} + 1.56915 * \text{scaled\_API\_Gravity} + 1.10927 * \text{scaled\_log\_Viscosity} + 1.46621 * \text{scaled\_Log\_Poro\_h})$$

$$d = \text{Tanh}(-1.10494 - 2.3695 * \text{scaled\_Log\_OOIP} + 7.75508 * \text{scaled\_log\_kh} - 6.85185 * \text{scaled\_API\_Gravity} - 14.7533 * \text{scaled\_log\_Viscosity} - 6.9812 * \text{scaled\_Log\_Poro\_h})$$

$$e = \text{Tanh}(4.11763 - 0.223371 * \text{scaled\_Log\_OOIP} + 2.64977 * \text{scaled\_log\_kh} + 1.30149 * \text{scaled\_API\_Gravity} + 0.934554 * \text{scaled\_log\_Viscosity} + 0.961708 * \text{scaled\_Log\_Poro\_h})$$

$$f = \text{Tanh}(0.135445 - 2.61746 * \text{scaled\_Log\_OOIP} - 0.704636 * \text{scaled\_log\_kh} + 4.23633 * \text{scaled\_API\_Gravity} + 1.83716 * \text{scaled\_log\_Viscosity} - 1.18279 * \text{scaled\_Log\_Poro\_h})$$

$$\text{ANN\_RF} = 14.9587 + 16.6988 * a - 14.3414 * b + 8.04666 * c + 16.7378 * d + 17.123 * e - 12.9095 * f$$

(RFA-22)

## PE Asset Valuation Essentials

The Asset Valuation Essentials section contains the following:

- Basic Project Economics
- Comprehensive Asset Performance Evaluation

## Project Economics Analysis Tool

The PE<sup>2</sup> Essentials Basic Project Economics tool is a scoping economics model that can use either an imported forecast or forecasts generated by other PE<sup>2</sup> Essentials tools (Figure ECO-1).

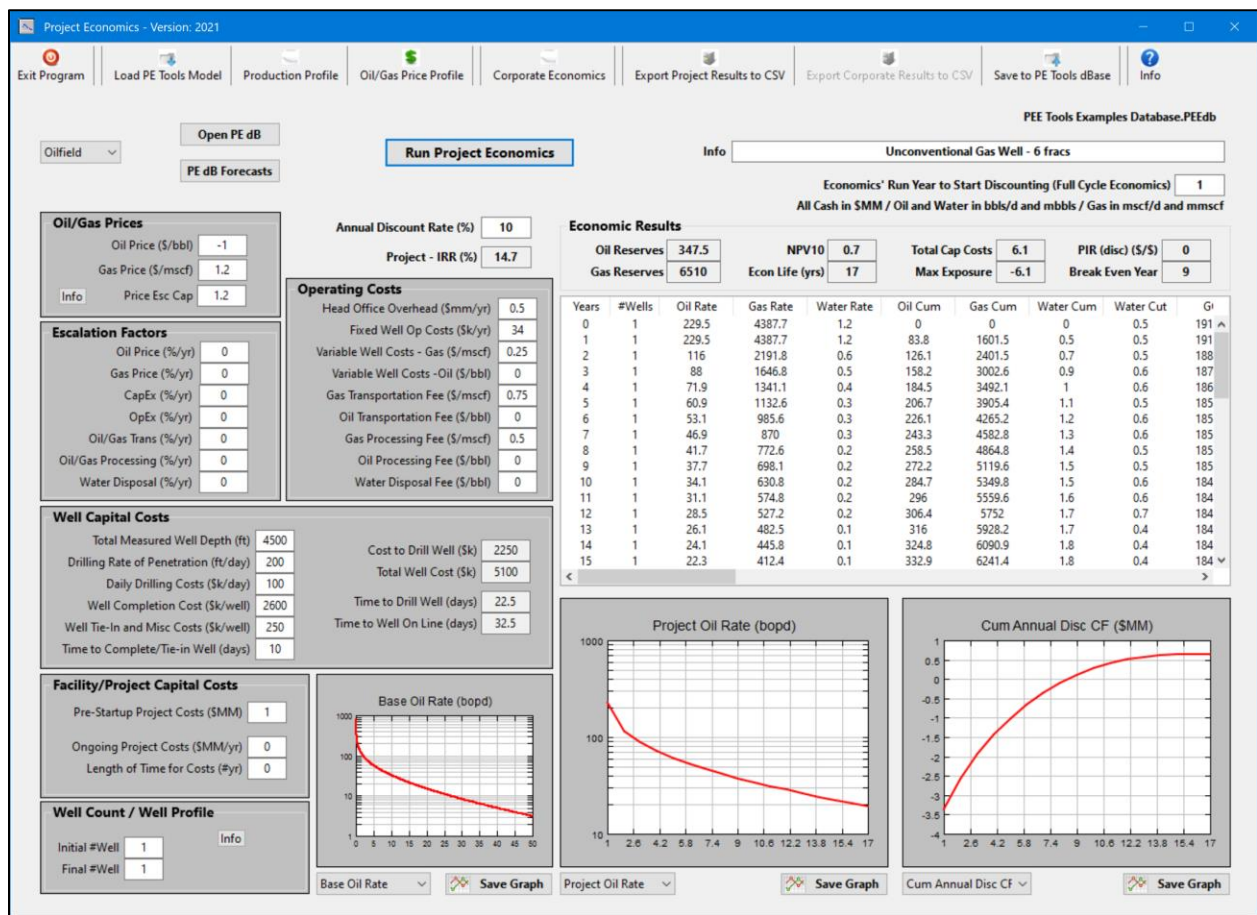


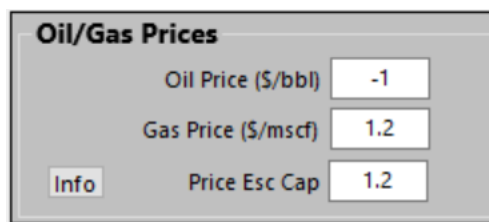
Figure ECO-1: PE<sup>2</sup> Essentials Basic Project Economics Tool

The tool generates before tax net present value (NPV) and can perform full-cycle and look-back economic analysis. This version has the option to perform simplified corporate economics. The Project Economics tool can be used to evaluate single or multi-well projects.

As a caveat, although this program has been built from fully debugged routines that have been used in the past, there are so many permutations and combinations possible with this model that it is difficult to test all combinations that may be used. If you end up with anomalous results that do not seem to make sense, send the information to the author for evaluation.

## ECO.1 Oil and Gas Prices

Oil and gas prices can be entered as a single value and then modified using the appropriate escalation factor (Figure ECO-2). Alternatively, an oil/gas price forecast can be loaded through the 'Oil/Gas Price Forecast' button on the main screen.



Oil/Gas Prices	
Oil Price (\$/bbl)	-1
Gas Price (\$/mscf)	1.2
Info Price Esc Cap	1.2

Figure ECO-2: Project Economics Tool – Oil/Gas Prices

To facilitate loading of historical oil and gas prices, an Excel spreadsheet ('Historical and Forecasted Oil and Gas Prices.xlsx') that includes oil and gas prices from January 1974 has been included in the "Example Input Files\Excel Files" directory. This file also includes a price forecast (2017+). To incorporate a different price forecast, modify the data in the 'Forecast Prices to 2028' spreadsheet.

After clicking the 'Oil/Gas Price Forecast' button, the Price Import screen will show the oil and gas prices currently stored with the model (Figure ECO-3). To change out these values, import the new data.

The oil and gas prices can be imported from an Excel file or loaded from a price deck saved in the PE Tools database ('Import Price Deck From PE Tools db'). If the price data is imported from an Excel file, the price deck can be saved to the PE Tools database.

When a price forecast file is loaded, the 'Oil Price (\$/bbls)' and 'Gas Price (\$/mscf)' on the main screen (Figure ECO-1) will be set to '-1'. To disable the loaded price forecast, enter a value for oil and/or gas price in the appropriate box. It is possible to disable just the gas price forecast or just the oil price forecast by entering the relevant price and leaving the other price as '-1'. The price forecast can be re-enabled by re-entering '-1' for the price.

Date	Time	\$/bbl	\$/mscf
Jan-2015	0	43.06	3.72
Feb-2015	0.085	44.35	4.46
Mar-2015	0.162	42.66	2.94
Apr-2015	0.247	49.3	2.23
May-2015	0.329	54.38	2.28
Jun-2015	0.414	55.88	2.27
Jul-2015	0.496	47.7	2.28
Aug-2015	0.581	39.98	2.34
Sep-2015	0.666	41.6	2.32
Oct-2015	0.748	42.33	2.21
Nov-2015	0.833	38.19	2.05
Dec-2015	0.915	32.26	1.99
Jan-2016	1	27.02	2.26
Feb-2016	1.085	25.51	1.98
Mar-2016	1.164	31.87	1.46
Apr-2016	1.249	35.59	1.42
May-2016	1.332	41.02	1.36
Jun-2016	1.416	43.96	1.65
Jul-2016	1.499	40.7	2.11
Aug-2016	1.584	40.46	2.14
Sep-2016	1.668	40.54	2.26
Oct-2016	1.751	45	2.33
Nov-2016	1.836	41.65	2.25
Dec-2016	1.918	45.5	2.8
Jan-2017	2.003	45.5	2.9
Feb-2017	2.088	48	2.9
Mar-2017	2.164	48	2.9

Figure ECO-3: Project Economics Tool – Oil/Gas Price Import

All oil and gas prices, whether a single value or imported, should be entered in today's currency. The oil and gas escalation factor (Section ECO.2) is used to convert to money-of-the-day. The 'Price Esc Cap' will place an upper limit on the price escalation. For example, if an oil price of \$45 is entered, or is the last value in the oil price forecast, and the escalation cap is set at 1.2 then oil price will escalate annually to a maximum of \$54 and then stay constant for the remainder of the forecast period.

Note that the oil/gas price forecast is saved with the model using 'Save Model' so the price forecast does not have to be re-entered.

## ECO.2 Escalation Factors

The cost of a number of operating and capital expense parameters can be escalated over time to take inflation into account (Figure ECO-4).

Escalation Factors	
Oil Price (%/yr)	0
Gas Price (%/yr)	0
CapEx (%/yr)	0
OpEx (%/yr)	0
Oil/Gas Trans (%/yr)	0
Oil/Gas Processing (%/yr)	0
Water Disposal (%/yr)	0

Figure ECO-4: Project Economics Tool – Escalation Factors



The following parameters can be escalated:

- Oil Price
- Gas Price
- Capital Costs:
  - Well Capital Costs
  - Facility / Project Capital Costs
- Operating Costs:
  - Head Office Overhead
  - Fixed Well Operating Costs
  - Variable Well Costs
- Oil/Gas Pipeline and Transportation Costs
- Oil/Gas Processing Costs
- Water Disposal Costs

The Annual Escalation Rates are entered in the 'Escalation Factors' section and costs are escalated using Equation ECO.1.

$$\text{EscFactor} = (1 + \text{EscRate}/100)^t \quad (\text{ECO.1})$$

Where: EscFactor is the annual escalation, EscRate is the escalation rate and t is the time in years.

### ECO.3 Discount Rate, Internal Rate of Return and Discount Year

The annual discount rate is entered into the model and the internal rate of return (IRR) is calculated during the economic forecast (Figure ECO-5). To facilitate full cycle, or look-back, analysis the year to start discounting can be set as shown in Figure ECO-6.

Annual Discount Rate (%)	10
Project - IRR (%)	98.8

Figure ECO-5: Project Economics Tool – Discount Rate and IRR

Economics' Run Year to Start Discounting (Full Cycle Economics)	1
---	---

Figure ECO-6: Project Economics Tool – Forecast Year to Start Discounting

Since the economic analysis assumes a '0' year start date, for full cycle economics the start of discounting will be at the end of the history.



To take the time value of money into account, all future revenue is converted to a common reference point in time. This is assumed to be the current year or the present (hence the term, 'present value'). This is achieved by discounting future net cash flow. Discounting converts a future sum of money into the equivalent of present-day cash.

The rate used for discounting future cash flow is called the discount factor and is entered into the model in the 'Annual Discount Rate' input box (Figure ECO-5). The annual discount factor is calculated at mid-year using Equation ECO.2.

$$\text{DiscFactor} = (1 + \text{DiscRate}/100)^{-(t - t_0 + 0.5)} \quad (\text{ECO.2})$$

Where: DiscFactor is the annual discount applied to the cash flow, DiscRate is the discount rate entered on the main sheet and t is the time in years, t<sub>0</sub> is the year to start discounting (defaults to year 1) and 0.5 specifies mid-year discounting.

The present value, PV, of a net cash flow, netCF, received at some future time, t, is given by Equation ECO.3.

$$\text{PV}_t = \text{netCF}_t \text{ DiscFactor}_t \quad (\text{ECO.3})$$

Where the subscript t is the time in years when the cash flow is received.

The net cash flow at a given time netCF<sub>t</sub> is calculated using Equation ECO.4.

$$\text{netCF}_t = \text{TotalNetRevenue} - \text{TotalOpCosts} - \text{TotalCapEx} \quad (\text{ECO.4})$$

Each revenue and cost stream has the appropriate escalation factors applied and then the discount factor is applied to generate the net present value.

The Internal Rate of Return, IRR, is the discount factor that will make the net present value, NPV, equal to zero. IRR is found by iterating on the annual discount factor until the NPV is 0.

## ECO.4 Operating, Capital and Sunk Costs

The operating costs and capital costs are entered in appropriate sections of the model (Figures ECO-7, ECO-8 and ECO-9).

Operating Costs	
Head Office Overhead (\$mm/yr)	0.5
Fixed Well Op Costs (\$k/yr)	34
Variable Well Costs - Gas (\$/mscf)	0.25
Variable Well Costs -Oil (\$/bbl)	0
Gas Transportation Fee (\$/mscf)	0.75
Oil Transportation Fee (\$/bbl)	0
Gas Processing Fee (\$/mscf)	0.5
Oil Processing Fee (\$/bbl)	0
Water Disposal Fee (\$/bbl)	0

Figure ECO-7: Project Economics Tool – Operating Costs

Well Capital Costs	
Total Measured Well Depth (ft)	4500
Drilling Rate of Penetration (ft/day)	200
Daily Drilling Costs (\$k/day)	100
Well Completion Cost (\$k/well)	2600
Well Tie-In and Misc Costs (\$k/well)	250
Time to Complete/Tie-in Well (days)	10
Cost to Drill Well (\$k)	2250
Total Well Cost (\$k)	5100
Time to Drill Well (days)	22.5
Time to Well On Line (days)	32.5

Figure ECO-8: Project Economics Tool – Well Capital Costs

Facility/Project Capital Costs	
Pre-Startup Project Costs (\$MM)	1
Ongoing Project Costs (\$MM/yr)	0
Length of Time for Costs (#yr)	0

Figure ECO-9: Project Economics Tool – Facility/Project Capital Costs

The costs are dependent on the forecast being generated. In terms of 'Well Capital Costs', if a multi-well forecast is being generated then the unit costs should be an average for the item. For example, not all wells would have a 'Total Measured Well depth' of 4500 feet. Instead this represents the average depth for all wells so the total cost for the multi-well project is valid.

For a multi-well development, it is assumed that the subsequent well will be drilled after the previous well is online. Total well costs will be escalated dependent on when the well is producing. The individual well total cost is calculated using Equation ECO.5.

$$\text{TotalWellCost} = (\text{DailyCost})(\text{WellMD})/\text{ROP} + \text{CompCost} + \text{TieInCost} \quad (\text{ECO.5})$$

Where: DailyCost is the daily drilling cost, WellMD is the measured depth of the well, ROP is the rate of penetration, CompCost is the cost to complete the well and TieInCost is the cost to tie-in the well, clean up the well and includes any other costs associated with the well.

The annual operating costs are escalated based on the escalation rates entered into the model.

$$\begin{aligned} \text{TotalOpCosts}_{\text{Esc}} = & (\text{HeadOffice})(\text{EscFactor}_{\text{OpEx}}) + \\ & (\text{FixedCost})(\text{EscFactor}_{\text{OpEx}}) + \\ & (\text{VariableCosts})(Q_g)(\text{ProdDays})(\text{EscFactor}_{\text{OpEx}}) + \\ & (\text{VariableCosts})(Q_o)(\text{ProdDays})(\text{EscFactor}_{\text{OpEx}}) + \quad (\text{ECO.6}) \\ & (\text{GasTransFee})(Q_g)(\text{ProdDays})(\text{EscFactor}_{\text{OilGasTrans}}) + \\ & (\text{OilTransFee})(Q_o)(\text{ProdDays})(\text{EscFactor}_{\text{OilGasTrans}}) + \\ & (\text{GasProcessFee})(Q_g)(\text{ProdDays})(\text{EscFactor}_{\text{OilGasProcess}}) + \\ & (\text{OilProcessFee})(Q_o)(\text{ProdDays})(\text{EscFactor}_{\text{OilGasProcess}}) + \\ & (\text{WaterProcessFee})(Q_w)(\text{ProdDays})(\text{EscFactor}_{\text{WaterProcess}}) \end{aligned}$$

The annual capital costs are also escalated based on the entered escalation rate. The cost for the initial wells (Section ECO.5) is considered to be sunk cost and is not escalated. Subsequent well costs are escalated based on when they are available.

$$\text{TotalCapCosts}_{\text{Esc}} = (\text{OngoingCapCosts})(\text{EscFactor}_{\text{CapEx}}) + (\text{TotalWellCost})(\text{EscFactor}_{\text{CapEx}}) \quad (\text{ECO.7})$$

All costs are discounted after escalation.

Sunk costs are not escalated or discounted and are calculated using Equation 9-8.

$$\text{SunkCapCosts} = \text{PreStartProjCosts} + (\text{TotalWellCost})(\# \text{InitialWells}) \quad (\text{ECO.8})$$

Note when using the preceding equations, caution must be used to ensure all terms are consistent, thousands\$ or millions\$.

## ECO.5 Well Count and Well Profile

Initial and final well counts are entered prior to the economic run (Figure ECO-10).

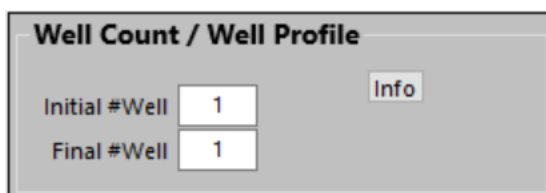


Figure ECO-10: Project Economics Tool – Well Count

A minimum initial well count of one well is required to run the economics. If the purpose of the run is to model a single well, the final count is set equal to the initial well count. If multiple wells are to be included, the final well count is set appropriately.

A base well profile is entered by clicking 'Load Well Profile' (Figure ECO-11). Production profiles can be imported from the PE Tools database; from Excel; or from a separate DCA database.

Refer to the information button on the Production Profile Import page for information concerning Excel formats. When importing from Excel, always make sure to check that the 'Units' and the 'Fluid Type' parameters are set properly before importing the data.

It is possible to import production data from an Excel spreadsheet; from a PE<sup>2</sup> Essentials PE Tools database, or a DCA database as shown in Figure ECO-11.

**Production Profile Import**

**Production Profile Import**  
☒ PE Tools db ☐ DCA Database  
☐ Excel File

**Fluid Type**  
☐ Oil  
☒ Gas

**Well Name/Info** Unconventional Gas Well - 6 fracs

**Excel Import Parameters**

	Column	Start Row	End Row
Time in Years			
Oil/Condensate Daily Rate			
Gas Daily Rate			
Water Daily Rate			
Cum Oil Volume			
Cum Gas Volume			
Cum Water Volume			

**Note: Gas in mscf/d and mmcf and Oil/Water in bbls/d and mbbls**

Years	bopd	mscf/d	bwpd	mbbls	mmcf	mbbls
Time	Qo	Qg	Qw	CumO	CumG	CumW
0	817.17	15000	4.41	0	0	0
0	817.17	15000	4.41	0.07	1.4	0
0	817.17	15000	4.41	0.16	2.9	0
0	817.17	15000	4.41	0.24	4.4	0
0	817.17	15000	4.41	0.32	5.9	0
0	817.17	15000	4.41	0.4	7.4	0
0	817.17	15000	4.41	0.48	8.9	0
0	817.17	15000	4.41	0.56	10.4	0
0	817.17	15000	4.41	0.65	11.9	0
0	817.17	15000	4.41	0.73	13.4	0
0	817.17	15000	4.41	0.81	14.9	0
0	817.17	15000	4.41	0.89	16.4	0
0	817.17	15000	4.41	0.97	17.9	0.01
0	817.17	15000	4.41	1.05	19.4	0.01
0	817.17	15000	4.41	1.14	20.9	0.01
0	812.45	14913.29	4.38	1.22	22.4	0.01
0	806.53	14804.63	4.35	1.3	23.8	0.01
0	799.63	14677.91	4.31	1.38	25.3	0.01
0	793.15	14558.98	4.28	1.46	26.8	0.01
0.01	787.2	14449.84	4.25	1.54	28.2	0.01
0.01	781.54	14345.9	4.22	1.61	29.7	0.01
0.01	777.22	13532.36	3.98	2.35	44	0.01
0.01	701.18	12870.91	3.78	3.05	57.6	0.02
0.01	673.56	12363.81	3.63	3.73	70.4	0.02
0.02	649.95	11930.5	3.51	4.38	82.8	0.02
0.02	628.98	11545.45	3.39	5	94.7	0.03
0.02	610.62	11208.44	3.29	5.62	106.3	0.03
0.04	527.75	9687.44	2.85	9.31	184.7	0.05

Figure ECO-11: Project Economics Tool – Import Production Forecast

If data is imported from an Excel file, the data can be saved to the PE Tools database with the 'Save to PE Tools db' button on the Production Profile Import page.

It should be noted that the production profile (Figure ECO-12) is saved with the economics model and does not need to be imported every time the Economics tool is loaded.

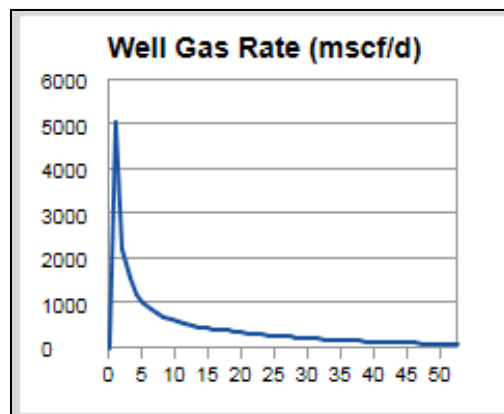


Figure ECO-12: Project Economics Tool – Imported Production Data

It is possible to read a standalone DCA database file and import forecasts or history+forecasts of one or more of the wells in the DCA database. When "DCA Database" is chosen for import a screen pops up to choose the well data to be imported (Figure ECO-13).

[illegible]

Figure ECO-13: Project Economics Tool – Import Production Forecast

When there is more than one well used in the forecast, it is possible to add variability to the well profiles by checking 'Vary Well Profiles' (Figure ECO-10). The first well will use the loaded production profile, but subsequent wells will use a profile that has been randomly modified by a factor between 0.75 and 1.25. Figure ECO-14 shows the single well profile (left) and a 5-well project profile (right) incorporating variable well rates.

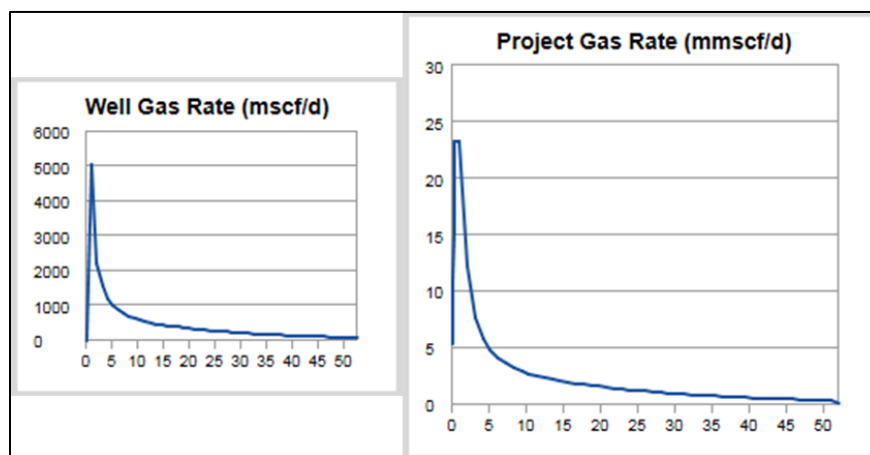


Figure ECO-14: Project Economics Tool – Multi- Well Production Data

## ECO.6 Economic Results

The net gas and oil/condensate prices are escalated prior to being discounted. This escalated price is then applied to the production stream to generate the revenue stream. Finally, costs are added, and discounts are applied to generate the net present value and corresponding plots for the total project are generated (Figures ECO-15 and ECO-16).

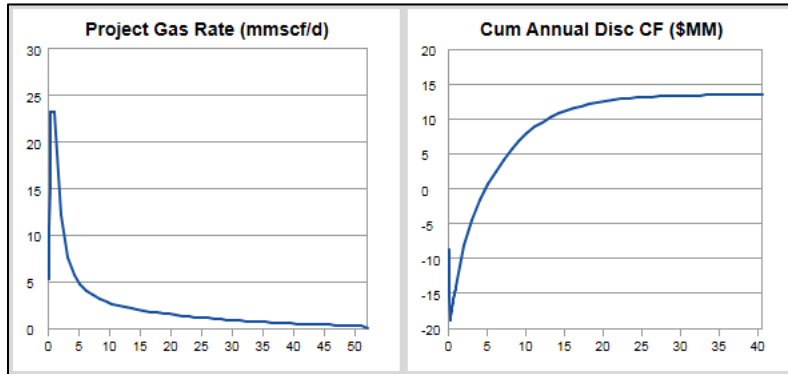


Figure ECO-15: Project Economics Tool – Plots of Economic Analysis

Economic Results									
Oil Reserves		2149	NPV		74.4	Total Cap Costs		26.5	PIR (disc) (\$/\$)
Gas Reserves		40063	Econ Life (yrs)		50	Max Exposure		-6.1	Break Even Year
									1
Years	#Wells	Oil Rate	Gas Rate	Water Rate	Oil Cum	Gas Cum	Water Cum	V	
0	5	873.1	16780.4	4.7	0	0	0		
1	5	873.1	16780.4	4.7	318.7	6124.8	1.7		
2	5	541.3	10184.2	2.9	516.3	9842.1	2.8		
3	5	406.7	7607.6	2.2	664.7	12618.9	3.6		
4	5	334.7	6233.1	1.8	786.9	14894	4.2		
5	5	286	5312.3	1.5	891.2	16833	4.8		
6	5	251.6	4665	1.4	983.1	18535.7	5.3		
7	5	224.6	4161.1	1.2	1065.1	20054.5	5.7		
8	5	201.8	3736.3	1.1	1138.8	21418.2	6.1		
9	5	184.2	3407.3	1	1206	22661.9	6.5		
10	5	168.3	3111.2	0.9	1267.4	23797.5	6.8		
11	5	155	2864.8	0.8	1324	24843.1	7.1		
12	5	143.5	2649.7	0.8	1376.4	25810.3	7.4		
13	5	132.7	2452.4	0.7	1424.8	26705.4	7.7		
14	5	123.7	2283.8	0.7	1470	27539	7.9		
15	5	115.5	2131.9	0.6	1512.1	28317.1	8.2		

Figure ECO-16: Project Economics Tool – Table of Economic Analysis

The economic equations are as follows:

$$\text{NetGasPrice}_{\text{esc}} = (\text{NetGasPrice})(\text{EscFactor}_{\text{gas}}) \quad (\text{ECO.10})$$

$$\text{NetOilPrice}_{\text{esc}} = (\text{NetOilPrice})(\text{EscFactor}_{\text{oil}}) \quad (\text{ECO.11})$$

$$\text{NetGasRevenue}_{\text{esc}} = (\text{NetGasPrice}_{\text{esc}})(Q_g)(\text{ProdDays}) \quad (\text{ECO.12})$$

$$\text{NetOilRevenue}_{\text{esc}} = (\text{NetOilPrice}_{\text{esc}})(Q_o)(\text{ProdDays}) \quad (\text{ECO.13})$$

$$\text{TotalNetRevenue}_{\text{esc}} = (\text{NetGasRevenue}_{\text{disc}})(\text{NetOilRevenue}_{\text{disc}}) \quad (\text{ECO.14})$$

$$\text{CashFlow}_{\text{esc}} = \text{TotalNetRevenue}_{\text{esc}} - \text{TotalOpCosts}_{\text{Esc}} - \text{TotalCapCosts}_{\text{Esc}} \quad (\text{ECO.15})$$

$$\text{CumCashFlow}_{\text{esc}} = \sum (\text{CashFlow}_{\text{esc}})_t - \text{SunkCapCosts} \quad (\text{ECO.16})$$

$$\text{CashFlow}_{\text{escDisc}} = (\text{CashFlow}_{\text{esc}})(\text{DiscFactor}_t) \quad (\text{ECO.17})$$

$$\text{CumCashFlow}_{\text{escDisc}} = \sum (\text{CashFlow}_{\text{escDisc}})_t - \text{SunkCapCosts} \quad (\text{ECO.18})$$

$$\text{NPV} = \text{CumCashFlow}_{\text{escDisc}} \quad (\text{ECO.19})$$

All cash flow calculations are presented on an annual basis except for the first year where the economics are presented on a monthly basis (Figure ECO-15) so the well start-ups can be observed when multi-well forecasts are made.

The reported economic parameters (Figure ECO-16) are as follows:

- 'NPV' is  $\text{CumCashFlow}_{\text{escDisc}}$
- 'Econ Life' is determined as the time when annual cash flow goes negative
- 'Total Cap Costs' is the total project capital costs
- 'Max Exposure' is maximum undiscounted cash required for the project
- 'PIR' is  $\text{NPV} / \text{Total Cap Costs}$
- 'Break Even Year' is the year when cumulative cash flow goes positive

## ECO.7 Corporate Economics

After the main project economics have been run, it is possible to run a corporate economic analysis of the project. Clicking the 'Corporate Economics' button opens up the corporate economics tool (Figure ECO-17).

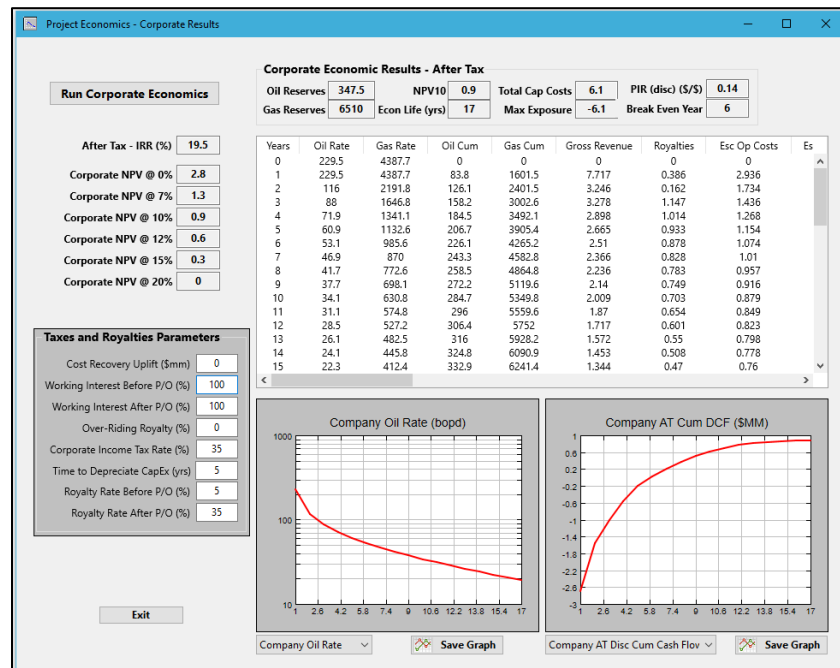


Figure ECO-17: Project Economics Tool – Corporate Economics

The Corporate Economics tool takes the cash flow forecast generated for the project and calculates before and after-tax economics for the company based on entered tax and royalty rates.

This tool includes input for the following parameters:

- Cost Recovery Uplift – when wells are drilled on penalty, the operator can recover an uplift portion of the well costs. As an example, if the penalty is 300% and the well costs \$5 million, then a cost recovery uplift of be \$10 million would be entered.
- Working Interest Before P/O – this is the company interest prior to payout of the capital costs.
- Working Interest After P/O – this is the company interest after payout of the capital costs.
- Over-Riding Royalty – This is the ORR that the company has to pay to a silent partner.
- Corporate Income Tax Rate – This is the corporate income tax rate.
- Time to Depreciate CapEx – This is the time over which the CapEx is depreciated for income tax purposes.
- Royalty Rate Before P/O – this is the government royalty rate prior to payout of the capital costs.
- Royalty Rate After P/O – this is the government royalty rate after payout of the capital costs.

After the corporate economics has been run, the results can be saved to a csv file by clicking the 'Save Company Results' button on the main screen. The 'Save Project Results' button will save the gross project economic analysis to a csv file.

## ECO.8 Project Economic Example – Marcellus

The final step in the analysis of the Marcellus well is to evaluate the full cycle economics of the P90, P50 and P10 forecasts. To generate the economics, Figure ECO-18 presents the cost for a Marcellus well (source: <http://ir.eqt.com>)

Marcellus Well Cost						
Lateral Length (Ft)	5,400	5,800	6,400	7,000	7,600	8,200
Fixed Costs (\$MM)	\$1.6	\$1.6	\$1.6	\$1.6	\$1.6	\$1.6
Variable drilling and completion (\$MM)	\$3.8	\$4.0	\$4.4	\$4.7	\$5.0	\$5.4
<b>Total</b>	<b>\$5.4</b>	<b>\$5.6</b>	<b>\$6.0</b>	<b>\$6.3</b>	<b>\$6.6</b>	<b>\$7.0</b>

Figure ECO-18: Project Economics Tool – Example Costs



Since this is a full cycle economic analysis the historical oil and gas prices from April 2014 were loaded into the Project Economics tool (Figure ECO-19).

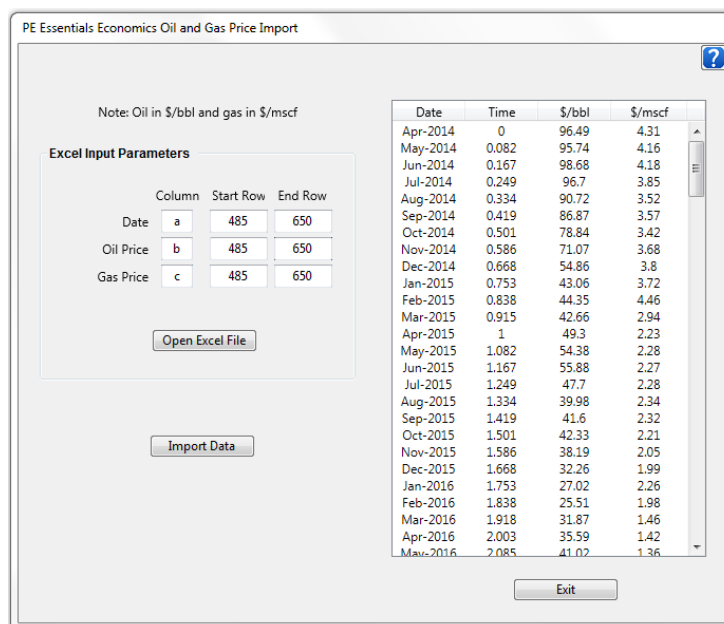


Figure ECO-19: Project Economics Tool – Price History/Forecast

The assumptions for this exercise are that the well was drilled in early 2014 and started production in April 2014. The well has 21 months of available history which ends at December 2015. To perform full cycle economics, no escalation on the realized prices to the end of 2016 was applied. Start of discounting was set at 2.75 years (23 months from April 2014).

The production forecasts, including the historical production, generated by the DCA and Monte Carlo DC Forecast programs are shown in Figure ECO-20 and were used to evaluate the full cycle economics of this Marcellus well.

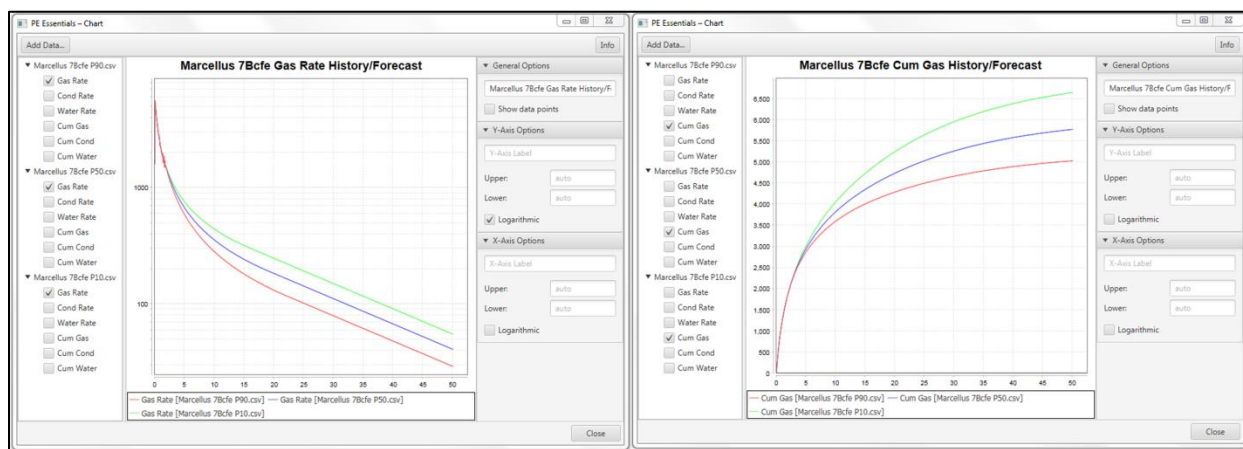


Figure Eco-20: Project Economics Tool – Marcellus Full Cycle Forecasts

The assumptions used to generate the full cycle economic analysis are as follows:

- Well capital costs were based on a 6400-foot lateral
- US\$6mm total well costs
- US\$0mm/yr head office
- US\$50k/yr fixed well costs
- US\$0.25/mscf variable costs
- US\$0.5/mscf transportation
- US\$0.5/mscf processing
- Production of the well was assumed to start April 2014
- Discounting applied after 2.75 years

After all the parameters were entered into the model (Figure ECO-21), each production forecast was imported (Figure ECO-22) and economics for each forecast was run.

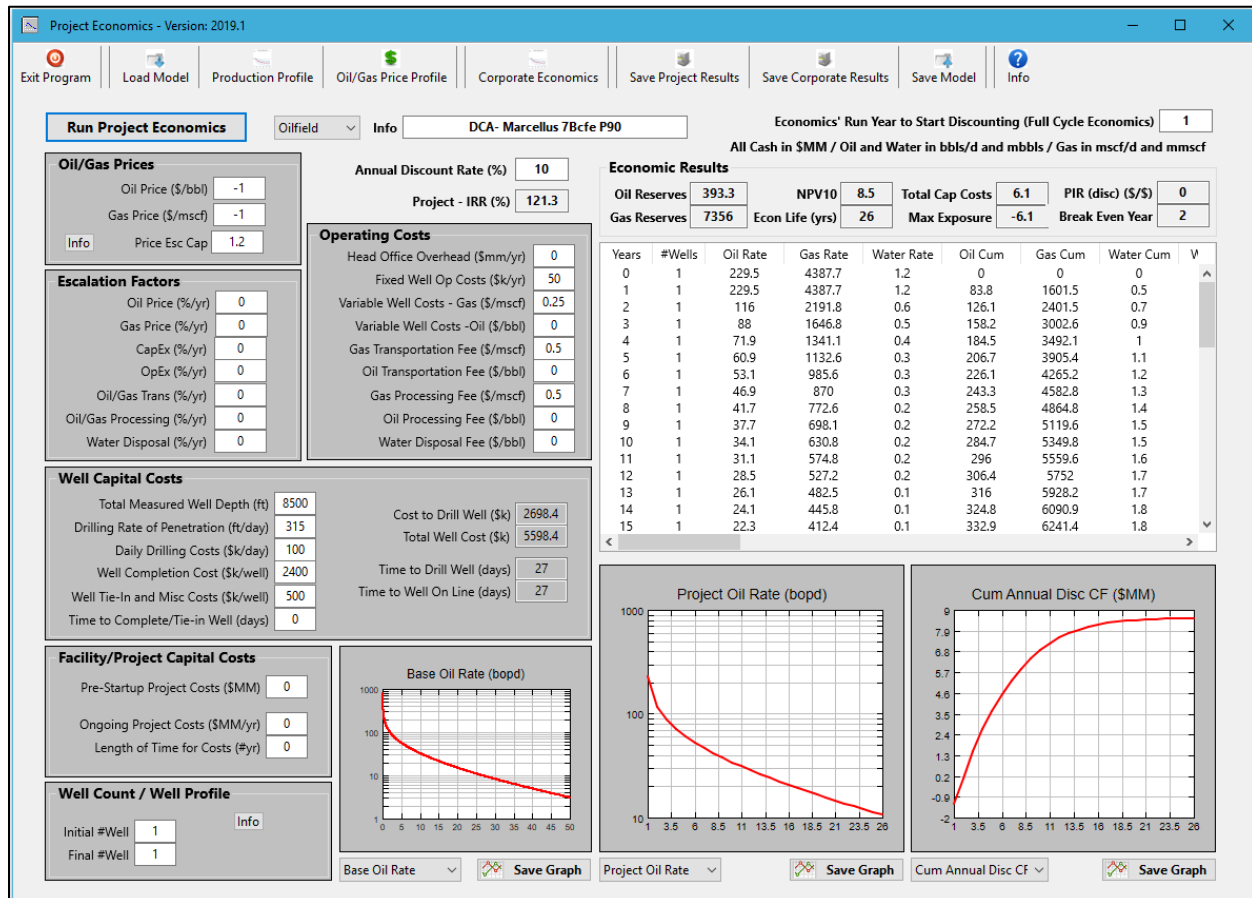


Figure ECO-21: Project Economics Tool – Marcellus Model: P50 Analysis

Figure ECO-22: Project Economics Tool – Marcellus Model: Import Forecasts

The full cycle economic results are presented in Figure ECO-23 and the IRR results are presented in Figure ECO-24.

From the economic analysis, it is obvious that for the assumed historical/forecast gas prices, the Marcellus economics are positive and show a 7-year to 10-year payback of costs.

Economic Results									
<b>P90</b>	Oil Reserves	0	NPV	0.9	Total Cap Costs	5.6	PIR (disc) (\$/\$)	0.16	
	Gas Reserves	4928							
			Econ Life (yrs)	42	Max Exposure	-5.6	Break Even Year	8	
Economic Results									
<b>P50</b>	Oil Reserves	0	NPV	1.5	Total Cap Costs	5.6	PIR (disc) (\$/\$)	0.26	
	Gas Reserves	5761							
			Econ Life (yrs)	49	Max Exposure	-5.6	Break Even Year	7	
Economic Results									
<b>P10</b>	Oil Reserves	0	NPV	2.1	Total Cap Costs	5.6	PIR (disc) (\$/\$)	0.37	
	Gas Reserves	6648							
			Econ Life (yrs)	50	Max Exposure	-5.6	Break Even Year	6	

Figure ECO-23: Project Economics Tool – Economic Results: Marcellus Model

<b>P90</b>	Project - IRR (%)	15.3
<b>P50</b>	Project - IRR (%)	18.1
<b>P10</b>	Project - IRR (%)	20.6

Figure ECO-24: Project Economics Tool – IRR Results: Marcellus Model

## Asset Economic Evaluation Tool

The PE<sup>2</sup> Essentials 'Asset Economic Evaluation' tool is a full-featured economics model used for comprehensive asset economic evaluation (CAEE) (Figure CEE-1).

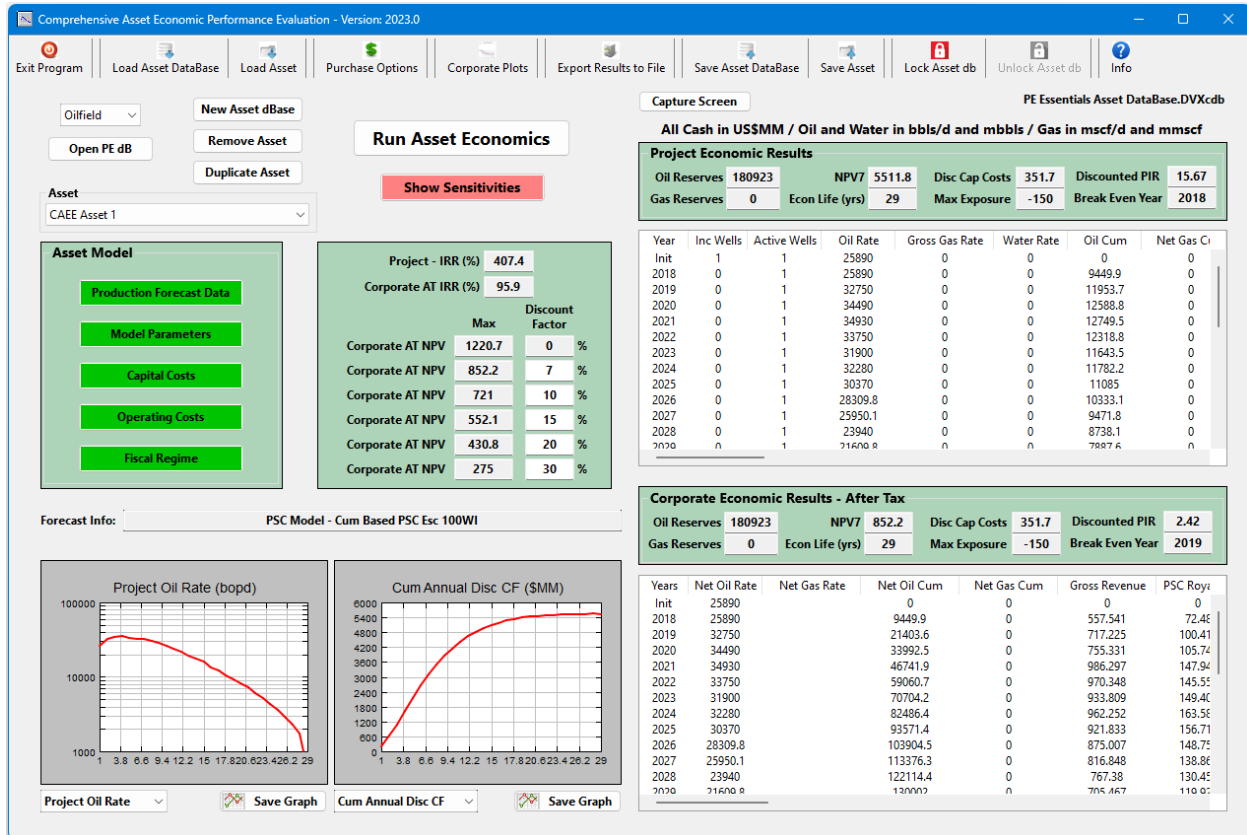


Figure CEE-1: PE<sup>2</sup> Essentials Comprehensive Asset Economic Evaluation Tool

The tool generates before- and after-tax net present value (NPV) and internal rate of return (IRR) for the asset and can perform full-cycle and look-back economic analysis. CAEE includes a number of generic fiscal regimes.

CAEE can perform single asset analysis and can combine single assets into a multi-asset database. This database can be password locked for read-only use for audit trail purposes. To add/modify the database, it has to be unlocked using the locking password. If a password is lost, a master password can be used to override the lost password.

The state of the database, locked or unlocked, can be determined by the state of the 'Lock db'/'UnLock db' buttons. If the the database is locked as read only, the 'UnLock db' button will be enabled and vice-versa. When individual assets are being evaluated, the 'Lock db' and 'UnLock db' buttons are disabled.

## CEE.1 CAEE Introduction

Petroleum economics (Asset Valuation) involves the application of the techniques of economic analysis at every stage in the development of oil and gas exploration and production projects.

The economics of oil and gas projects are affected by a range of factors, including:

- Level of knowledge about the oil or gas field (subsurface description and characterization, surface facilities, etc.)
- Location (onshore, offshore—shallow water, deep and ultra-deep water—), type and number of wells
- Market conditions (commodities prices, global supply and demand, worldwide E&P environment)
- Effect of tax/royalty systems, production sharing and service contracts and overall fiscal systems stability

By analyzing factors like these, Economists are able to assist in making investment decisions, such as deciding whether or not to drill an exploration well or whether or not to develop an oil/gas production project. They are crucial in the negotiations around Production Sharing Contracts and purchasing oil and gas properties. Economists are also involved in the assessment and management of the technical, economic and other risks associated with the different phases of an oil or gas projects.

Given the volatility in commodities (oil, gas, oil products) prices today, the economic evaluation of upstream oil and gas investments is essential. Business decisions involving asset acquisitions, lease-buy assessments, exploration drilling options, oil and gas field developments, equipment purchases, and fiscal negotiations all require detailed economic analysis. CAEE covers cash flow analysis, deriving and understanding economic indicators and detailed profitability and fiscal analysis.

CAEE provides detailed economic modelling using cash flow analysis and related sensitivity analysis, Spider diagrams and tornado plots. The tool currently includes two different fiscal systems commonly used in the oil & gas industry:

- Tax Royalty Contracts
- Production Sharing Contracts
- Service Contract

The benefits of economic evaluation of projects and thus of a thorough CAEE workflow are:

- Make investments decisions with greater confidence
- Standardize business processes across organization
- Improve the consistency of economic evaluation
- Incorporate risk assessment (by a thorough sensitivity analysis)
- Capture probabilistic analysis

Figure CEE-2 presents the workflow as implemented in the PE<sup>2</sup> Essentials CAEE tool.

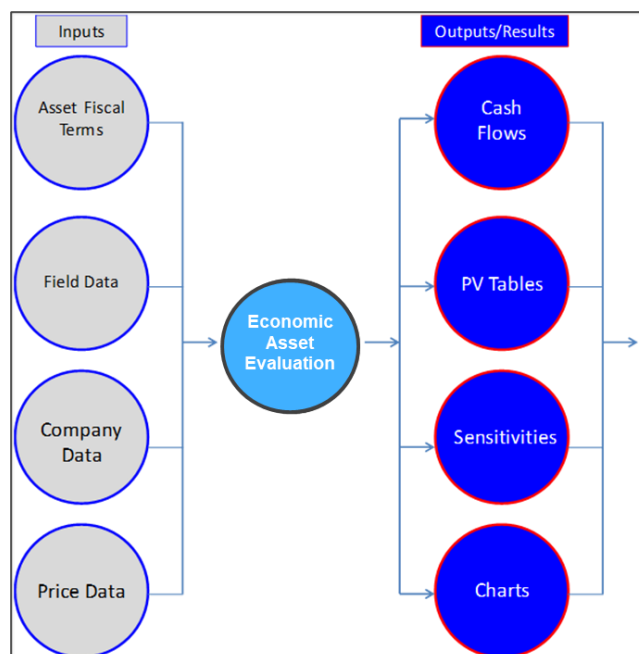


Figure CEE-2: PE<sup>2</sup> Essentials Asset Economic Evaluation - Workflow

## CEE.2 Fiscal Terms for E&P Projects

Fiscal terms (Figure CEE-3) for upstream investments refer to the agreement between a local government and an oil and gas exploration company to explore, develop and produce hydrocarbons.

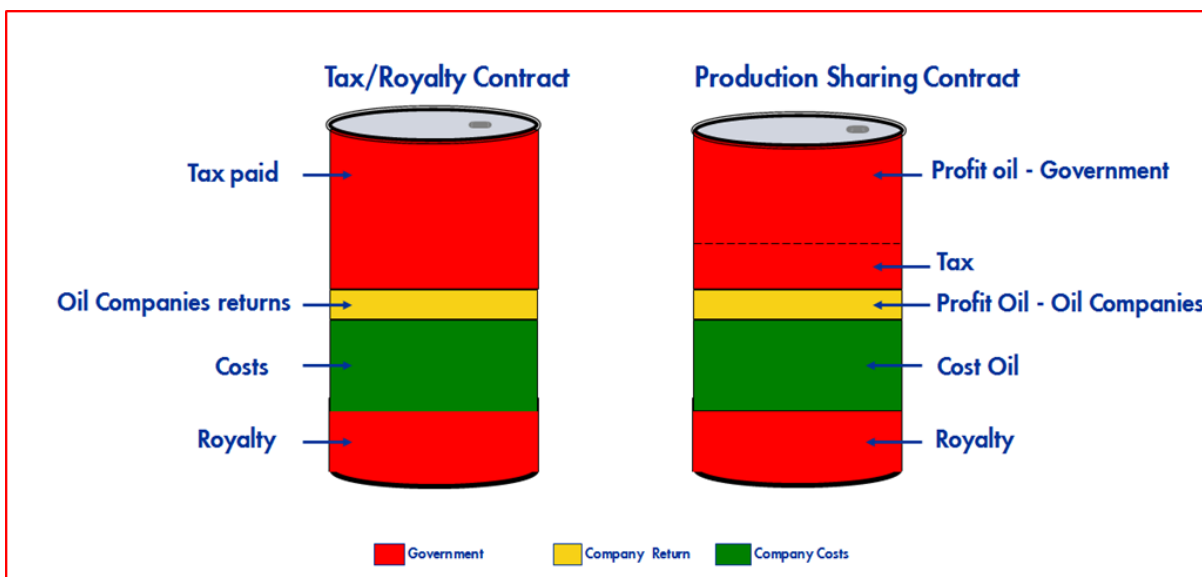


Figure CEE-3: Asset Economic Evaluation - Fiscal Regimes

The objective of a host government is to maximize wealth from its natural resources by encouraging appropriate levels of exploration and development activity. In order to accomplish this, governments must design fiscal systems to attract oil and gas companies. The objectives of the oil and gas companies are to build equity and maximize wealth by finding and producing oil and gas reserves at the lowest possible cost and highest possible profit margin.

In a competitive world, areas with the least favorable geology, the highest costs, and the lowest prices at the wellhead would offer the best fiscal terms, while areas with the best geology, the lowest costs, and the highest prices at the wellhead would offer the toughest fiscal terms.

The role of the host government is to design a fiscal system where exploration and development rights are acquired by those companies who place the highest value on these rights. Competitive bidding can help achieve this objective. In the absence of competition, efficiency must be designed into the fiscal terms.

Regardless of the fiscal system used, the bottom line is the economic issue of how costs are recovered, and profits divided. In order to accomplish this, fiscal systems are designed to:

- Provide a fair return to the state and to the industry
- Avoid undue speculation
- Have clarity and stability
- Limit undue administrative burden
- Provide flexibility
- Create healthy competition and market efficiency

The design of an efficient fiscal system must take into consideration the political and geological risks as well as the potential rewards. Detailed economic modeling using discounted cash flow analysis (as implemented in CAEE) is the best way to evaluate division of profits. Factors that limit a company's profits in a contract, such as cost recovery allowance, a government's right to back-in for an extra share of production, or an additional tax, can be modeled for the purposes of contract negotiation or project evaluation. Division of profits is commonly referred as contractor take or share and government take or share.

### **CEE.3 Tax and Royalty Contracts (TRC)**

To calculate the contractor's share in a tax and royalty contract, the first item to be deducted from the gross revenues from oil and gas production are the royalties. Gross revenues less royalty equals net revenue.

The next item are deductions, which include operating costs, depreciation, and amortization, and intangible drilling costs. These are deducted from net revenue to arrive at taxable income.

The third item is taxation. Revenue remaining after royalty and deductions is called taxable income. Taxable income might be taxed in two layers: provincial and federal (e.g. Canadian terms). The remaining revenue after taxation is the contractor's share of the revenue.



The diagram illustrates the calculation of Net Revenues and Taxable Income for an oil company, showing a step-by-step reduction from Gross Revenues.

**Gross Revenues (\$)** is calculated as **Production X Oil Price (\$)**.

**Net Revenues (\$)** is derived from Gross Revenues by subtracting **Royalty** (labeled as **Royalty in cash \$**).

**Taxable Income** is derived from Net Revenues by subtracting **Deductions: Assumed Costs**.

**Taxable Income** is further reduced by **Special Oil Tax** and **Income Tax** to arrive at the final **IOCs** (Income Before Tax).

**Production & Costs must be audited**

Figure CEE-4: Tax and Royalty Regimes (TRC/Concessions)

Royalties are regressive because they are levied on gross revenues. For less profitable ventures, the relative percentage of royalty increases. The further from gross revenues that taxes are levied, the more progressive the system becomes.

## CEE.4 Production Sharing Contracts (PSC)

In most contractual systems, the facilities put in place by the contractor within the host government domain become the property of the state either the moment they are landed in the country or upon startup or commissioning. Sometimes, the title to the assets or facilities does not pass to the government until the attendant costs have been recovered.

Contractual systems are divided into service contracts and production sharing contracts. The difference between them depends on whether or not the contractor receives compensation in cash or in kind (crude). Figure CEE-5 presents the PSC specifics.



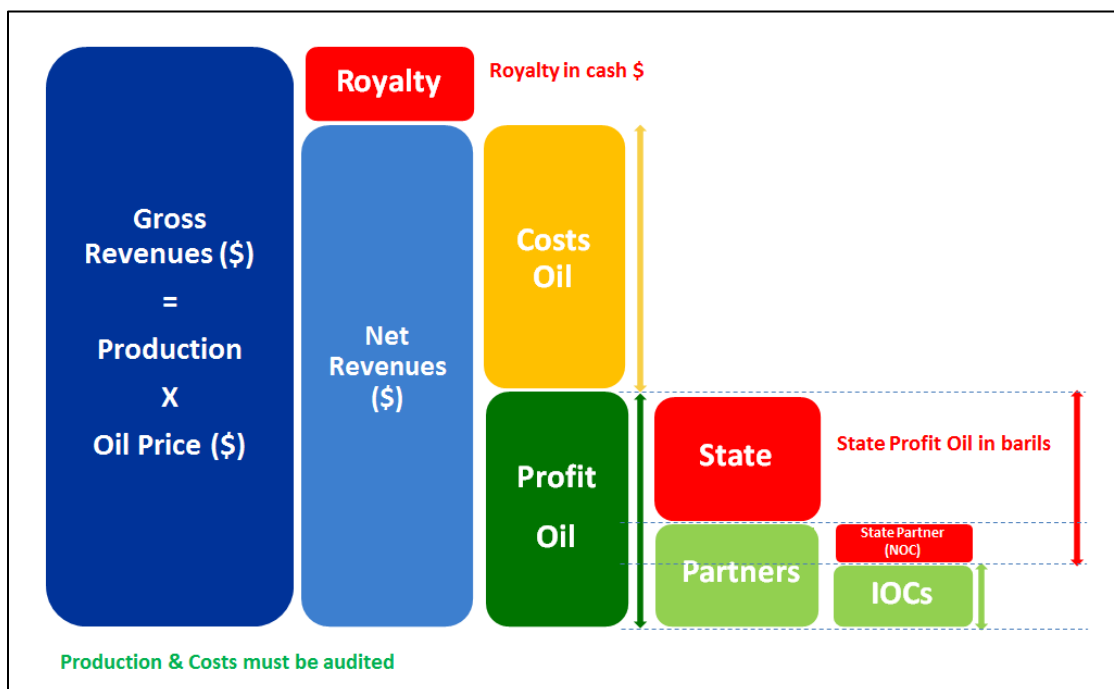


Figure CEE-5: Production Sharing Contracts (PSC)

Basic features of production sharing contracts are as follows:

- The title of the hydrocarbons remains with the host State/Government
- The State maintains management control and the contractor is responsible for the execution of petroleum operations in accordance to the terms of the contract
- The contractor is required to submit annual work programs and budgets for scrutiny and approval of the State/Government
- The contract is based on production sharing and not profit-sharing basis
- The contractor provides all financing and technology required for the operations and bears all risks of the project
- During the term of the contract, after allowance for up to a specified percentage of annual production for recovery of costs, the remaining production is split between the contractor and State/Government
- Equipment purchased and imported by the contractor becomes property of the State/Government (service company equipment and leased equipment are exempt from this stipulation)

### CEE.5 Service Contracts (SC)

A Service Contract is basically a PSC but the contractor gets paid a fee in term of xx\$ for every unit volume produced. As a result, refer to Section CEE.4 for more information.

## CEE.6 PSC/SC Advantage versus TRC

When evaluating fiscal terms (Figures CEE-4 and CEE-5), the focus is on division of profits – government share and contractors share. The most dramatic difference between the two fiscal regimes has to do with how much taxation is imposed.

PSC/SC terms can be more flexible. There may be more opportunities to come up with more balanced / attractive terms. For example, reduced income taxes paid within the PSC/SC instead of paying higher separate income taxes which can be >70%. Another possibility is negotiating a PSC/SC without royalties.

Under a PSC/SC, there is a higher net income after tax in the early years of production because of the built-in cost recovery mechanisms. With high cost recovery provisions, increased government share comes at a relatively later stage of production.

It is possible to obtain the same economic results under a variety of systems. The challenge is to make the most of the flexibility offered by a PSC/SC (i.e. negotiable points).

The PSC/SC is more likely to be a win-win situation. It has more balanced fiscal terms which yields an improved business climate.

## CEE.7 Ring Fencing

A ring fence is a protection-based transfer of assets from one destination to another, usually through the use of offshore accounting. A ring fence is meant to protect the assets from inclusion in an investor's calculable net worth or to lower tax consequences.

In project asset valuation, ring-fencing occurs when a portion of a company's assets or profits are financially separated without necessarily being operated as a separate entity. Reasons that governments use ring fencing include:

- Regulatory reasons,
- Creating asset protection schemes with respect to financing arrangements, or
- Segregating into separate income streams for taxation purposes (cost recovery, tax pools, etc.)

CAEE assumes that each asset has its own ring fence, so calculations are specific to that asset.

## CEE.8 Typical Project Life Cycle

Economics is a continuous activity. Figure CEE-6 schematically illustrates the cumulative cash flow for a typical E&P project over its life.

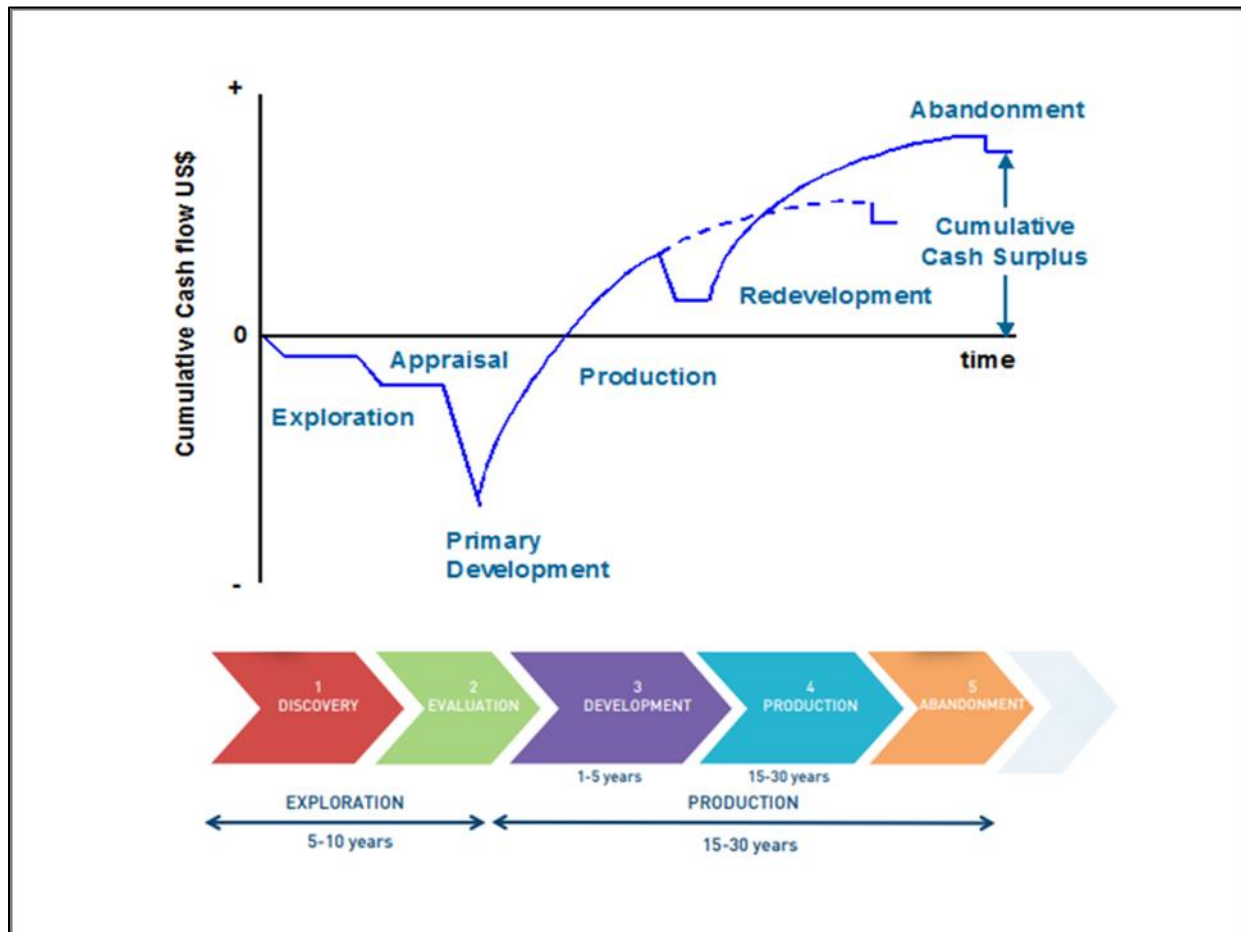


Figure CEE-6: Project Life Cycle

The first analysis normally concerns the exploration economics prior to any discovery. This may consist of the analysis of a completely new venture, a bid on an acreage block, a review of the prospects within currently held acreage, or the economics of a single prospect. The economic analysis is required not only for deciding whether or not to proceed to invest, but also to rank the opportunity with other opportunities. also, for currently held acreage the decision may be to divest.

Once economically recoverable quantities of oil/gas have been discovered within a prospect, economic analysis is required to decide whether further appraisal activities are desirable and, if so, economically justified. The purpose of these appraisal activities, such as the drilling of one or more appraisal wells or the acquisition of additional seismic data, is to reduce the uncertainty in the prospect to a sufficiently low level as to enable proper development decision to be taken.

Once appraisal activities have been completed, the next decision is whether or not to commit large funds to field development: The Final Investment Decision or FID. After the FID for field development has been taken, economic analysis is still required. Field Development Plans can be

changed, and these changes require economic analysis. In this context, for example, acceleration projects can be considered – investments to accelerate, but not necessarily increase, the recovery of the reserves – or EOR (Enhanced Oil Recovery) projects.

Performing a “postmortem” or look back economic analysis, after the end of a project, enables an evaluation of past investment decisions and to judge whether, in retrospect, the investment made the return envisaged at the time of the FID. It can be of great value in highlighting where consistent biases have been introduced in the past, with a view to avoiding these in the future. This post investment review is often carried out by an integrated team.

Towards the end of a field’s life it will be necessary to decide when and how to decommission (abandon) the project. Here again the economist will be required to analyze the alternatives.

Table CEE-1 presents general metrics to evaluate investment opportunities.

Category	Description	Pros	Cons
Net Present Value (NPV)	<ul style="list-style-type: none"> <li>The sum of all future cash flows from the investment minus the capital invested at time 0</li> <li>Discounted at a specific opportunity cost of capital over a defined economic life</li> </ul>	<ul style="list-style-type: none"> <li>Accounts for the time value of money</li> <li>Recognizes risk associated with the future cash flows</li> </ul>	<ul style="list-style-type: none"> <li>Only states whether a project is positive or negative</li> <li>Does not detail the capital investment required or the time required to become NPV positive</li> </ul>
Profit Investment Ratio (PIR)	<ul style="list-style-type: none"> <li>Is a ratio of the NPV of the future cash flows divided by the cost of the project</li> <li>Accept projects where the VIR is greater than 0</li> </ul>	<ul style="list-style-type: none"> <li>Accounts for the time value of money</li> <li>Valuable in a resource (Capital) limited environment since it determines the highest net present value dollar per dollar of initial outlay</li> <li>Measures the value creation efficiency of the portfolio</li> </ul>	<ul style="list-style-type: none"> <li>Does not consider actual cash flows which NPV does</li> <li>If capital is not constrained then NPV should be looked at before PIR</li> <li>Cannot add up</li> </ul>
Internal Rate of Return (IRR)	<ul style="list-style-type: none"> <li>Defined as the discount rate when the NPV of the cash flows equal 0</li> <li>Accept projects where the IRR is greater than the opportunity cost of capital</li> </ul>	<ul style="list-style-type: none"> <li>Accounts for the time value of money</li> </ul>	<ul style="list-style-type: none"> <li>Does not include the total value of the cash flows nor the original investment</li> <li>Cannot add up IRR's of multiple projects like you can with NPV</li> <li>May not work well for projects with complex cashflow</li> <li>Not adequate when investments have occurred in the past.</li> </ul>
Payout Time	<ul style="list-style-type: none"> <li>The number of years required for the cumulative forecasted cash flows to equal the initial investment</li> <li>Discounted cash flows should be used to account for the time value of money</li> </ul>	<ul style="list-style-type: none"> <li>Allows managers to understand how long it would take to recoup the cost</li> </ul>	<ul style="list-style-type: none"> <li>Ignores all cash flows that occur after the payout time is reached</li> <li>If discounted cash flows are not used, equal weight is given to all cash flows before the cut-off date</li> </ul>
UOC UDC UAC UTC UGT BEP	<ul style="list-style-type: none"> <li>Unit Operating Cost (\$/bbl)</li> <li>Unit Development Cost (\$/bbl)</li> <li>Unit Abandonment Cost (\$/bbl)</li> <li>Unit Technical Cost (\$/bbl)</li> <li>Unit Government Take (\$/bbl)</li> <li>All-in-Cost (\$/bbl) = UTC + UGT</li> <li>Break-Even-Price (\$/bbl)</li> </ul>	<ul style="list-style-type: none"> <li>Technical Costs: The total of capital and operating expenditure.</li> <li>All these indicators are a measure of the robustness of the project</li> <li>Indicators should be lower than oil price (\$/bbl), RT or MOD</li> <li>Indicators are independent of oil price</li> </ul>	<ul style="list-style-type: none"> <li>Ignores all other sources of income such as: tariffs paid, overriding royalty, entry/promote costs.</li> <li>Must be discounted to generate a full grid at different discount rates: 7%, 10%, 15% etc.</li> <li>All-in-Cost is mostly an accounting metrics rather than an economics metric: often shown in balance sheets</li> </ul>

Table CEE-1: Investment Metrics

## CEE.9 CAEE – Data Input

Figure CEE-7 shows the screen for entry of the general model parameters.

**Asset Model Parameters**

Asset Name:

Annual Discount Rate (%)  Start Year  Start Month (#)  Year to Start Discounting (Full Cycle Economics)

**Oil/Gas Prices**

Oil Price (US\$/bbl)   
 Gas Price (US\$/mscf)   
 Oil Price Differential (%)   
 Gas Price Premium (US\$)   
 View Oil/Gas Price Profile

**Escalation Factors**

Oil Price (%/yr)   
 Gas Price (%/yr)   
 CapEx (%/yr)   
 OpEx (%/yr)   
 Oil/Gas Trans (%/yr)   
 Oil/Gas Processing (%/yr)   
 Water Disposal (%/yr)   
 Note: Changing any of these parameters will reset the corresponding values in the

Import Price Data Import Esc Data

Save Price Data to PE Tools db

Save Esc Data to PE Tools db

Open PE dB

**Oil and Gas Price Forecast - Unescalated**

Date	Year	Oil: \$/bbl	Gas: \$/mscf
2018	1		
2019	2		
2020	3		
2021	4		
2022	5		
2023	6		
2024	7		
2025	8		
2026	9		
2027	10		
2028	11		
2029	12		
2030	13		
2031	14		
2032	15		
2033	16		
2034	17		
2035	18		
2036	19		
2037	20		
2038	21		
2039	22		
2040	23		
2041	24		
2042	25		
2043	26		
2044	27		
2045	28		
2046	29		
2047	30		
2048	31		
2049	32		
2050	33		
2051	34		
2052	35		

**Annual Escalation Factors**

Date	Oil Price	Gas Price	CapEx	OpEx	Trans	Process	Disposal
2018							
2019							
2020							
2021							
2022							
2023							
2024							
2025							
2026							
2027							
2028							
2029							
2030							
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2042							
2043							
2044							
2045							
2046							
2047							
2048							
2049							
2050							
2051							
2052							

Clear Table Clear Table Return

Figure CEE-7: Asset Economic Evaluation - Model Parameters

Data can be input manually; from the PE Tools database; or, from an Excel spreadsheet.

A file called “CAEE Input Data.xlsx” is included in the “Asset Evaluation Results File” directory. This file is used to import parameters into CAEE from a spreadsheet. It is imperative that the format of this file is not changed since CAEE assumes the data is available in a fixed location and format.

Using the data template ensures all the required data for CAEE is in the proper format and makes input into CAEE simple and straightforward. Selecting each section of the CAEE Model will have an option to read the data template file for importing of the appropriate data (Figure CEE-8). This is accessed with the appropriate ‘Import ...’ button.

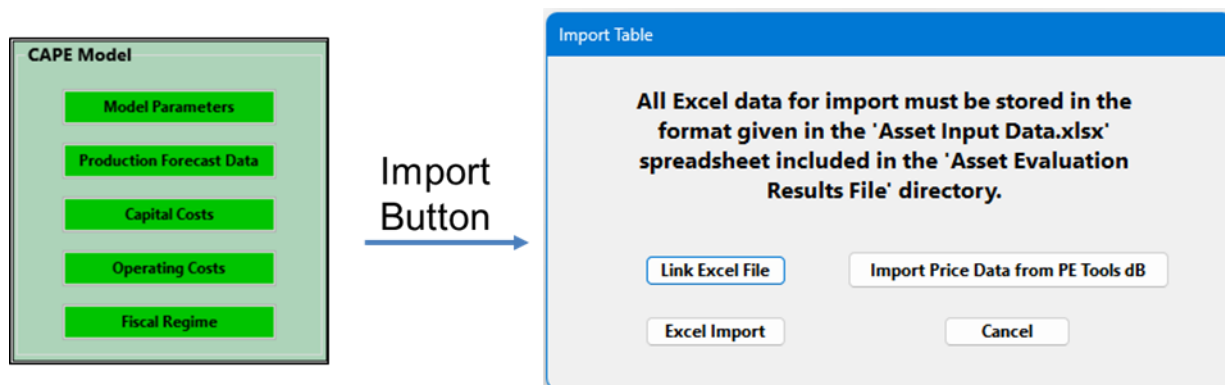


Figure CEE-8: Asset Economic Evaluation Data Input

The first time the Excel file is to be accessed, it must be linked to the CAEE tool using the 'Link Excel File' button. Following this the Excel data is read simply by clicking the 'Excel Import' button.

It is also possible to import data from the PE Tools database (Figure CEE-9). To do this, the CAEE Model data must have been stored to the PE Tools database from the appropriate CAEE Model screen. The available models will be listed, check the model and 'Load ...' the data.

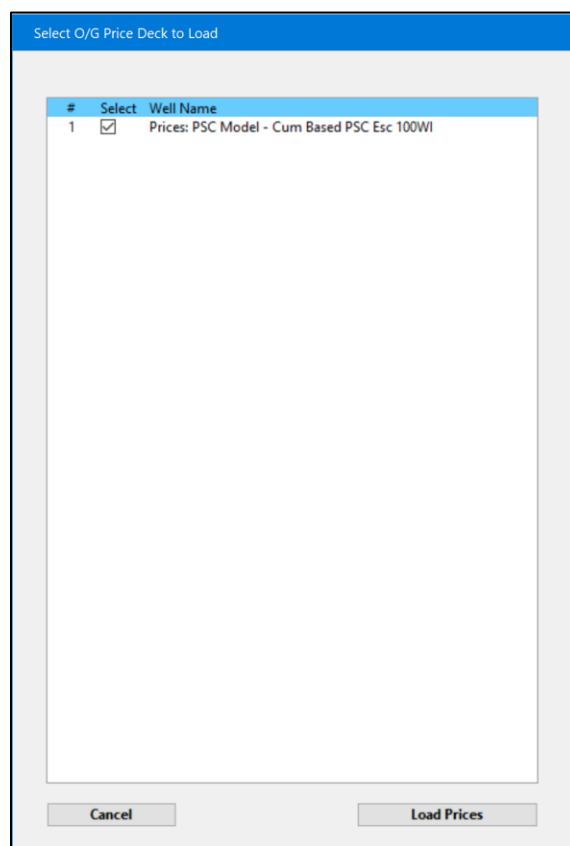


Figure CEE-9: Asset Economic Evaluation - PE Tools Database Data Input Option

## CEE.10 CAEE – Model Parameters

Figure CEE-10 shows the entry of the general model parameters.

**Asset Model Parameters**

Asset Name: CAEE Asset 1

Annual Discount Rate (%) 7 Start Year 2018 Year to Start Discounting (Full Cycle Economics) 2018

**Oil/Gas Prices**

Oil Price (US\$/bbl) -1  
Gas Price (US\$/mcf) -1

Oil Price Premium (US\$) 7  
Gas Price Premium (US\$) 0

**View Oil/Gas Price Profile**

**Escalation Factors**

Oil Price (%/yr) 0  
Gas Price (%/yr) 0  
CapEx (%/yr) 2  
OpEx (%/yr) 2  
Oil/Gas Trans (%/yr) 2  
Oil/Gas Processing (%/yr) 2  
Water Disposal (%/yr) 2

Note: Changing any of these parameters will reset the corresponding values in the

**Oil and Gas Price Forecast - Unescalated**

Date	Year	Oil: \$/bbl	Gas: \$/mcf
2018	1	52	3
2019	2	53	3.06
2020	3	53	3.12
2021	4	70.36	3.18
2022	5	71.77	3.25
2023	6	73.2	3.31
2024	7	74.67	3.38
2025	8	76.16	3.45
2026	9	77.68	3.51
2027	10	79.24	3.59
2028	11	80.82	3.66
2029	12	82.44	3.73
2030	13	84.09	3.8
2031	14	85.77	3.88
2032	15	87.48	3.96
2033	16	89.23	4.04
2034	17	91.02	4.12
2035	18	92.84	4.2
2036	19	94.7	4.28
2037	20	96.59	4.37
2038	21	98.52	4.46
2039	22	100.49	4.55
2040	23	102.5	4.64
2041	24	104.55	4.73
2042	25	106.64	4.83
2043	26	108.78	4.92
2044	27	110.95	5.02
2045	28	113.17	5.12
2046	29	115.43	5.22
2047	30	118.92	5.38
2048	31	123.73	5.6
2049	32	128.73	5.82
2050	33	133.93	6.06
2051	34	133.93	6.06
2052	35	133.93	6.06

**Annual Escalation Factors**

Date	Oil Price	Gas Price	CapEx	OpEx	Trans	Process	Disposal
2018	0	0	2	2	2	2	2
2019	0	0	2	2	2	2	2
2020	0	0	2	2	2	2	2
2021	0	0	2	2	2	2	2
2022	0	0	2	2	2	2	2
2023	0	0	2	2	2	2	2
2024	0	0	2	2	2	2	2
2025	0	0	2	2	2	2	2
2026	0	0	2	2	2	2	2
2027	0	0	2	2	2	2	2
2028	0	0	2	2	2	2	2
2029	0	0	2	2	2	2	2
2030	0	0	2	2	2	2	2
2031	0	0	2	2	2	2	2
2032	0	0	2	2	2	2	2
2033	0	0	2	2	2	2	2
2034	0	0	2	2	2	2	2
2035	0	0	2	2	2	2	2
2036	0	0	2	2	2	2	2
2037	0	0	2	2	2	2	2
2038	0	0	2	2	2	2	2
2039	0	0	2	2	2	2	2
2040	0	0	2	2	2	2	2
2041	0	0	2	2	2	2	2
2042	0	0	2	2	2	2	2
2043	0	0	2	2	2	2	2
2044	0	0	2	2	2	2	2
2045	0	0	2	2	2	2	2
2046	0	0	2	2	2	2	2
2047	0	0	2	2	2	2	2
2048	0	0	2	2	2	2	2
2049	0	0	2	2	2	2	2
2050	0	0	2	2	2	2	2
2051	0	0	2	2	2	2	2
2052	0	0	2	2	2	2	2

**Import Price Data** **Import Esc Data**

**Save Price Data to PE Tools db** **Save Esc Data to PE Tools db**

**Open PE dB**

**Clear Table** **Clear Table** **Return**

Figure CEE-10: Asset Economic Evaluation - Model Parameters

Oil and gas prices can be entered as a single value and then modified using the appropriate escalation factor. Alternatively, an oil/gas price forecast can be loaded through an Excel file using the “Import Price Data”. Note that oil and gas price forecasts are entered in \$US regardless of the currency used for analysis (refer to Section CEE.14).

It should be noted that all import tables function the same way. If a constant value is entered for a specific parameter, then the table is populated with that constant. All cells in the table can be edited so that specific values can be used for specific years. When a table is not made up of a constant value, the box containing the relevant value will display a “-1”. The “-1” indicates that the yearly data is variable.

The Model Parameters also includes the annual discount factor to be used for base NPV calculations as well as the “Start Year” which is the year the economic analysis begins – the actual



production data can start later than the start year. If a start month greater than 1 is entered, the cumulative production for the first year of production will be reduced. For look-back economics that includes production history, the start of discounting can start at a later date.

Finally, the Model Parameters sheet includes the “Asset Name”. The asset name is defaulted but can be changed to anything the user requires. Note, a “.” should not be used in the name and will be removed if entered in the Asset Name box.

### CEE.11 CAEE – Production Forecast Data

Figure CEE-11 shows the entry of production data.

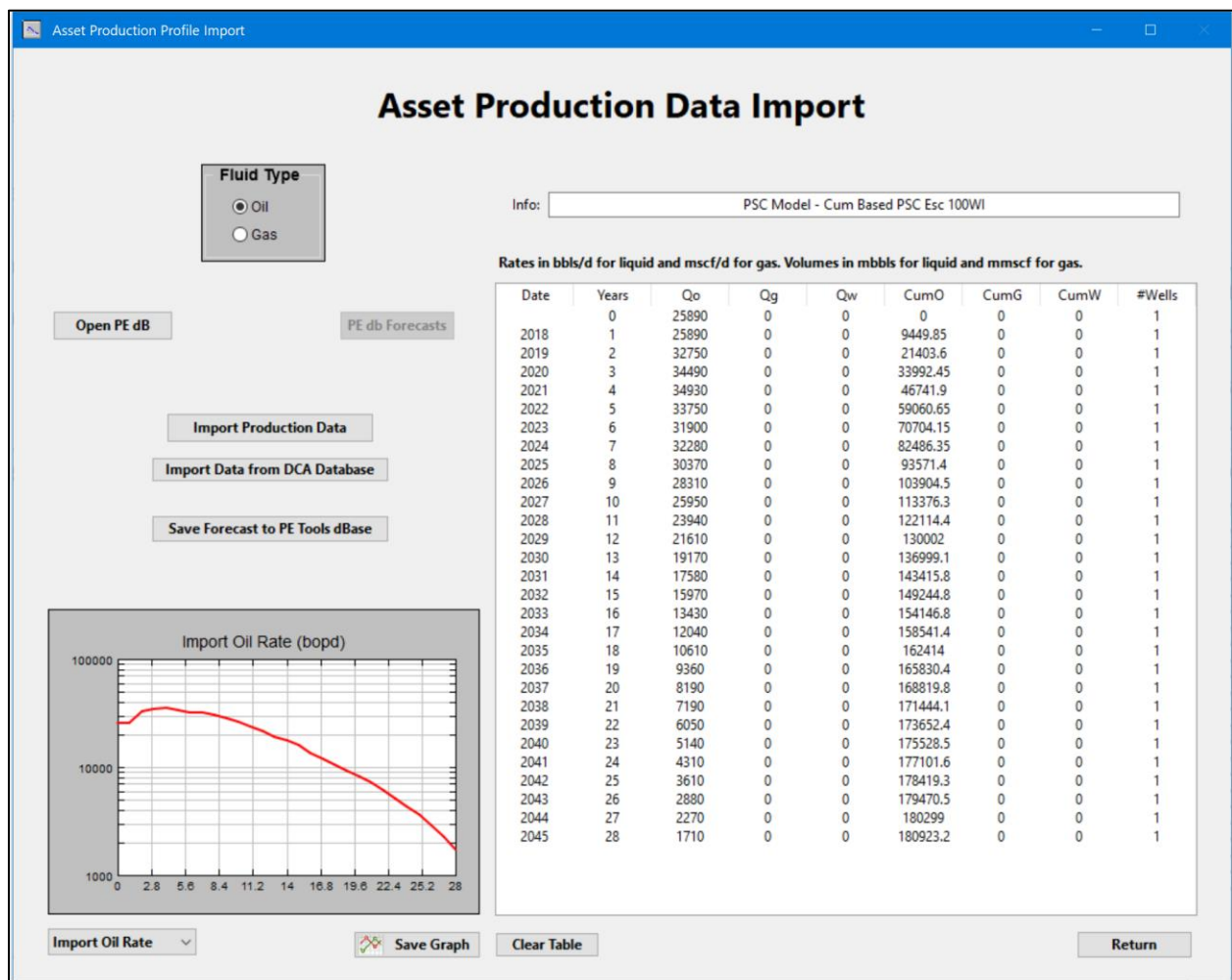


Figure CEE-11: Asset Economic Evaluation - Production Data



- PE<sup>2</sup> Essentials Unconventional Forecast Tool
- PE<sup>2</sup> Essentials Basic Reservoir Simulator Tool
- PE<sup>2</sup> Essentials StreamTube WaterFlood Tools
- PE<sup>2</sup> Essentials Misc/Immisc CO<sub>2</sub> WAG WF Tool
- PE<sup>2</sup> Essentials Gas Material Balance Tool
- PE<sup>2</sup> Essentials Oil Material Balance Tool
- PE<sup>2</sup> Essentials Decline Curve Analysis Tool
- PE<sup>2</sup> Essentials Monte Carlo DC Forecast Tool
- PE<sup>2</sup> Essentials Field Development Planning Tool

It is possible to read a separately stored DCA database file and import forecasts or history+forecasts of one or more of the assets in the DCA database (Figure CEE-12).

Figure CEE-12: Asset Economic Evaluation – Import DCA Production Forecast

When importing DCA assets, it is possible to delay the start-up of the asset as shown in Figure CEE-12.

From the Data Import screen, it is also possible to clear the CAEE database or delete the asset chosen on the main CAEE screen.

An asset can be easily duplicated by loading the asset, importing a new production forecast, modifying the asset name on the 'Asset Parameters' page and then saving the asset with the new forecast. The copied asset can then be imported into the CAEE database.

## CEE.12 CAEE – Capital Cost

Figure CEE-13 shows the screen for entry of capital cost data. Project capital costs are entered as unescalated costs.

Date	Project	Inc Well	Well Cost	Abandon
Init	150			
2019				
2020				
2021	27			
2022	27			
2023				
2024				
2025	20			
2026				
2027				
2028				
2029				
2030				
2031	15			
2032				
2033				
2034				
2035				
2036	15			
2037				
2038				
2039				
2040				
2041				
2042				
2043				
2044				
2045				
2046				
2047				
2048				

Figure CEE-13: Asset Economic Evaluation – Import Unescalated Capital Costs

Asset Capital Costs

## Asset Capital Costs - Unescalated

Well Count / Well Profile / Capital

Total Well Cost (US\$MM)

5

Initial #Well

1

Final #Well

16

Facility / Project / Capital Costs

Pre-Startup Costs (US\$MM)

150

Ongoing Costs (US\$MM/yr)

-1

Length of Time for Costs (#yr)

0

Abandonment Costs / Timing

Total Abandonment Costs (US\$MM)

184.7

Costs Spread Over How Many Years

5

Start Year for Expenditure

2027

Open PE dB

Import Cap Cost Data

Save Cap Costs to PE Tools db

Date	Project	Inc Well	Well Cost	Abandon
Init	150	1	6	
2019	0	0	0	0
2020	0	4	24	0
2021	27	2	12	0
2022	27	3	18	0
2023	0	0	0	0
2024	0	0	0	0
2025	20	3	18	0
2026	0	0	0	0
2027	0	0	0	36.94
2028	0	0	0	36.94
2029	0	0	0	36.94
2030	0	0	0	36.94
2031	15	3	18	36.94
2032	0	0	0	0
2033	0	0	0	0
2034	0	0	0	0
2035	0	0	0	0
2036	15	0	0	0
2037	0	0	0	0
2038	0	0	0	0
2039	0	0	0	0
2040	0	0	0	0
2041	0	0	0	0
2042	0	0	0	0
2043	0	0	0	0
2044	0	0	0	0
2045	0	0	0	0
2046	0	0	0	0
2047	0	0	0	0
2048	0	0	0	0

Clear Table

Return

Note that a '-1' in the input boxes indicates that the capital cost data was manually entered.

### CEE.13 CAEE – Operating Cost

Figure CEE-15 shows the entry of operating cost data. Operating costs are entered as unescalated costs.

Figure CEE-15: Asset Economic Evaluation – Import Operating Cost

Operating costs can be entered as a constant value and escalated by the escalation factors which is entered on the Model Parameters page, or they can be entered for each year in the forecast. When manual entry is used, the corresponding box is changed to “-1”

### CEE.14 CAEE – Fiscal Parameters

The required fiscal parameters are dependent on whether the “Taxes and Royalties Regime”, the “Production Sharing Contract” or the “Service Contract” is selected for the Fiscal Regime.

The Fiscal Parameters include an option to apply start-of-year, mid-year or year-end discounting. Figure CEE-16 presents an example of the impact on the economics for different discounting options.

Start of Year Discounting		Mid Year Discounting		Year End Discounting	
Project - IRR (%)	114.3	Project - IRR (%)	114.3	Project - IRR (%)	114.3
Corporate - IRR (%)	53.3	Corporate - IRR (%)	42.8	Corporate - IRR (%)	36.3
Corporate NPV @ 0%	1315.4	Corporate NPV @ 0%	1315.4	Corporate NPV @ 0%	1315.4
Corporate NPV @ 7%	882.4	Corporate NPV @ 7%	853	Corporate NPV @ 7%	824.7
Corporate NPV @ 10%	766	Corporate NPV @ 10%	730.4	Corporate NPV @ 10%	696.4
Corporate NPV @ 12%	702.7	Corporate NPV @ 12%	664	Corporate NPV @ 12%	627.4
Corporate NPV @ 15%	623.8	Corporate NPV @ 15%	581.7	Corporate NPV @ 15%	542.4
Corporate NPV @ 20%	523.5	Corporate NPV @ 20%	477.9	Corporate NPV @ 20%	436.2

Figure CEE-16: Asset Economic Evaluation – Sensitivity to Discounting

Figure CEE-17 shows the entry of fiscal parameters.

Figure CEE-17: Asset Economic Evaluation – Fiscal Parameters

For the PSC tax regime, if Oil Royalty and/or Government Share is calculated based on cumulative oil volume then the historical cumulative oil is entered in the 'Cum at Start of Forecast (MM)' box so that the proper percentage is used in the forecast. Note that the PSC "R-Factor" is defined as  $(\text{Total Revenue} - \text{Royalties}) / \text{Total Costs}$

The required currency is entered on this page as well. The built-in currencies are \$US, \$CDN, GBP and NOK. There is an option to add additional currencies in the drop-down menu. Any added currency will be stored with the model. Once the currency is chosen the conversion rates can be entered as a constant in the "Base Conv" box or entered on a yearly basis in the table.

It should be noted that, although CAEE will perform analysis in any currency, the oil and gas price forecast (Section CEE.10) must be entered in \$US. This was implemented based on the fact that most, if not all, public oil/gas price forecasts, and sales of oil and gas, are normally based on \$US.

## CEE.15 CAEE – Sensitivities and Analysis Results

Once all the parameters are entered, the analysis is performed by clicking “Run Model”. After performing the base analysis, a sensitivity analysis can be performed on production, CAEEEx, OpEx, oil price and gas price. Sensitivity is performed at +/-30% in increments of 5% (Figure CEE-18).

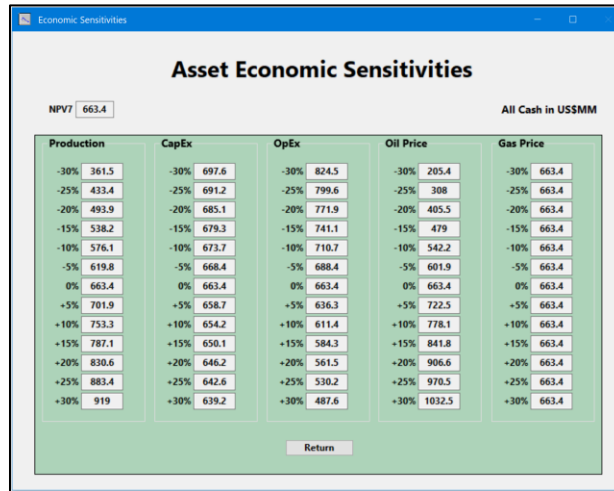


Figure CEE-18: Asset Economic Evaluation – Sensitivities

A table of project and corporate economic results as well as a table of NPV results are presented on the main page (Figure CEE-1).

Following analysis, it is possible to export the input/output results to an Excel file. CAEE uses three Excel templates located in the “Bin\PE Essentials CAEE Libs” directory called “TemplateSC.xlsx”, “TemplatePSC.xlsx” and “TemplateTRC.xlsx”.

The Excel file is generated by clicking “Export Results” on the main menu. This opens an export page (Figure CEE-19) which allows the generation of an Excel file or a csv report file.

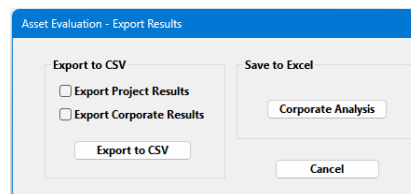


Figure CEE-19: Asset Economic Evaluation – Export Analysis Results

Checking “Save Corporate Results” and “Save to Excel File” will generate an Excel file containing the analysis results and plots as well as the input parameters used to generate the results. This file is saved in the “CAEE Results File” directory with a unique name so that many runs can be made and saved without overwriting the previous files.



The Excel file contains all the economic run data and input data and automatically generates tables and plots that are useful for viewing the results. Figures CEE-20 and CEE-21 show examples of the results and plots included in the Excel file.

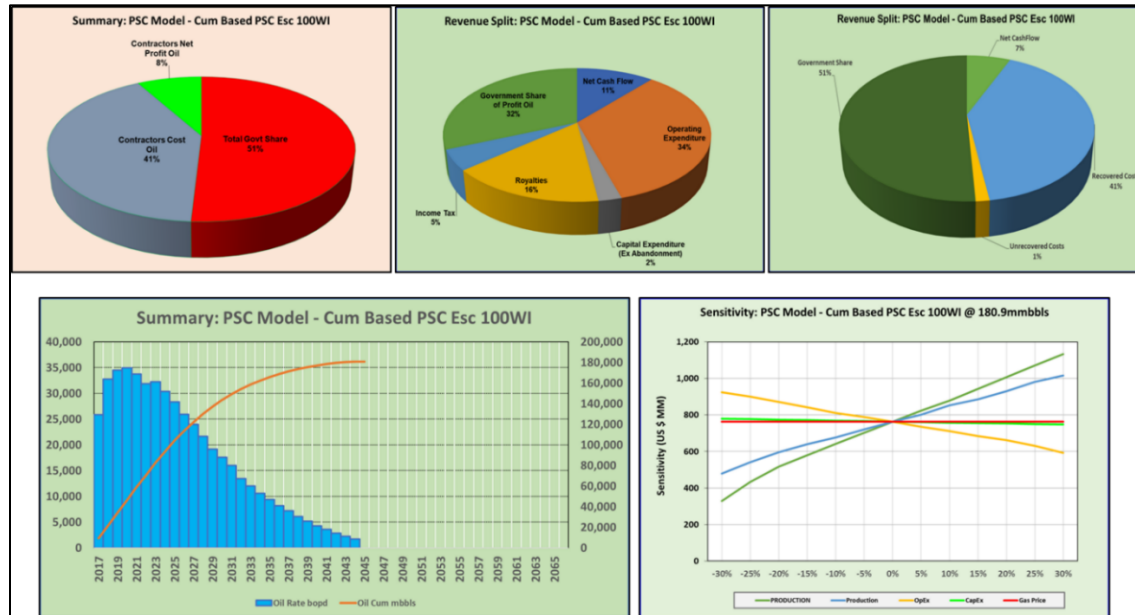


Figure CEE-20: Asset Economic Evaluation – Excel Results Plots

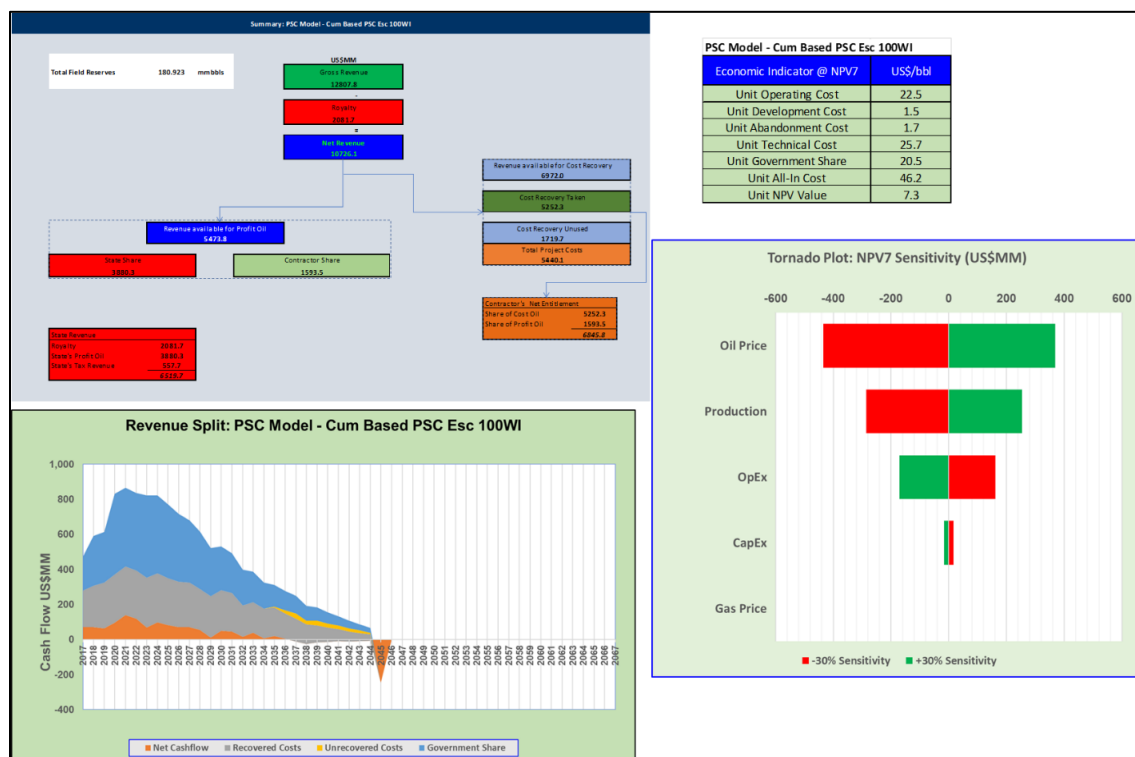


Figure CEE-21: Asset Economic Evaluation – Excel Results Tables/Plots

## CEE.16 CAEE – Purchase Options

The Asset Economic Evaluation tool includes an option to evaluate the value of purchasing an equity position in a company's working interest. This option is accessed by the clicking 'Purchase Options' on the main menu.

The target equity interest is entered in 'Equity Purchase (%)' and a range of 'Acquisition Cost' for the equity. The tool will plot the NPV at different discount rates (Figure CEE-22).

The IRR can also be plotted by clicking the 'Plot IRR' option (Figure CEE-23).

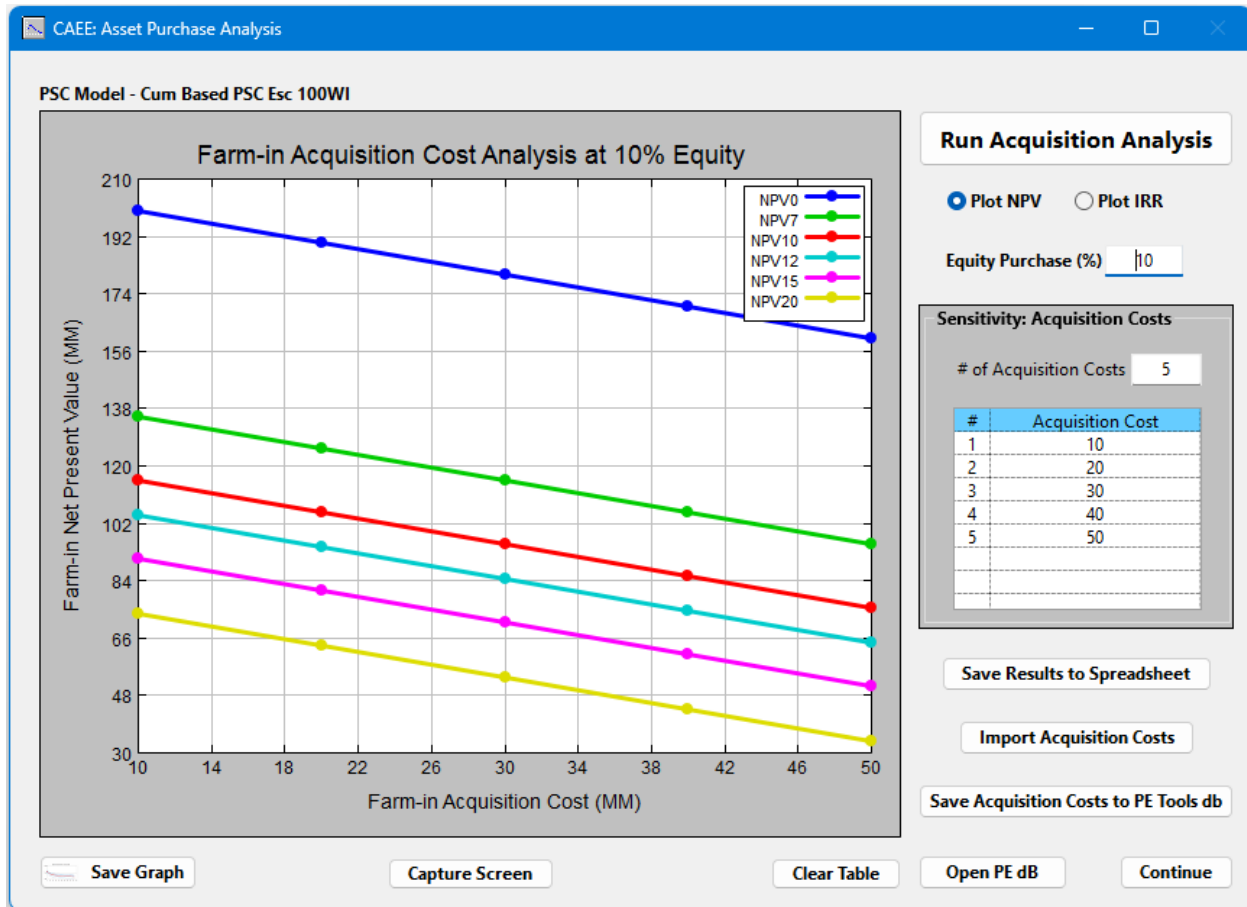


Figure CEE-22: Asset Economic Evaluation – Equity Purchase Options, NPV

After the analysis is completed, the results can be saved to a spreadsheet by clicking 'Save Results to Spreadsheet'. This file is saved in the 'Asset Evaluation Results File' directory with a unique name so that many runs can be made and saved without overwriting the previous run results.



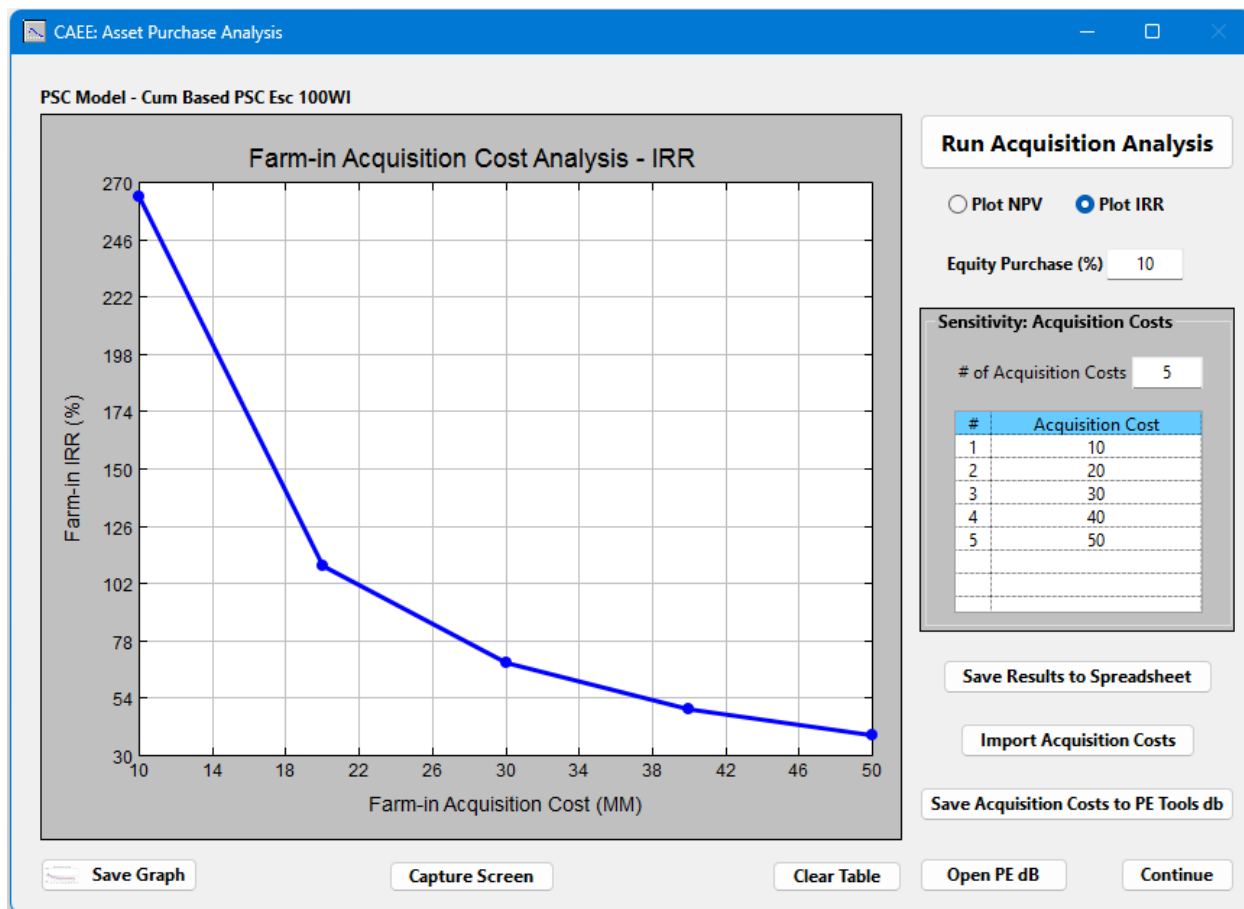


Figure CEE-23: Asset Economic Evaluation – Equity Purchase Options, IRR

## General Appendix

The Appendix contains the following sections:

- Appendix 1 – Conversion Factors
- Appendix 2 – Workflow Examples
  - W.1 – Granite Wash Well
  - W.2 – North Sea Recompletion
  - W.3 – Hydraulic Fracture Uplift
  - W.4 – Sequential Wells vs Pad Drilling
  - W-5 – Horizontal Frac/NoFrac Well Comparison
  - W-6 – Simulated Well Sensitivities
  - W-7 – Eagle Ford PDA Example
  - W-8 – CAPE: Marcellus 6-Well Pad
- Appendix 3 – Decline Curve Models and Diagnostic Formulations
- Appendix 4 – Concepts of Production Data Analysis

## Appendix 1 – Conversion Factors

Property	Conversion Factors				Output
	Input Units	Operator	Conversion Factor		Units
Area	ft <sup>2</sup>	*	2.29567E-05	=	acres
	acres	*	43560.17	=	ft <sup>2</sup>
	m <sup>2</sup>	*	0.000247104	=	acres
	acres	*	4046.87	=	m <sup>2</sup>
	m <sup>2</sup>	*	0.000001	=	km <sup>2</sup>
	km <sup>2</sup>	*	1000000	=	m <sup>2</sup>
	m <sup>2</sup>	*	0.0001	=	ha
	ha	*	10000	=	m <sup>2</sup>
	acres	*	0.404687	=	ha
	ha	*	2.47104	=	acres
In-Situ Gas Content	cc/gm	*	32.1958	=	scf/ton
	scf/ton	*	0.03106	=	cc/gm
	m <sup>3</sup> /t	*	32.1958	=	scf/ton
	scf/ton	*	0.03106	=	m <sup>3</sup> /t
Density (Density of Air = 1.222 kg/m <sup>3</sup> ) (Density of Water = 1000 kg/m <sup>3</sup> )	gm/cm	*	62.4280	=	lbm/ft <sup>3</sup>
	lbm/ft <sup>3</sup>	*	0.0160185	=	gm/cc
	kg/m <sup>3</sup>	*	0.062428	=	lbm/ft <sup>3</sup>
	lbm/ft <sup>3</sup>	*	16.01845	=	kg/m <sup>3</sup>
	Oil API	*	141.5 / (API+131.5)	=	Oil Specific Gravity
	Oil Specific Gravity	*	141.5/API - 131.5	=	Oil API
	Oil API	*	141.5/(API+131.5)*62.4	=	lbm/ft <sup>3</sup>
Condensate Gas Ratio	stb/Mscf	*	0.00561458	=	m <sup>3</sup> /m <sup>3</sup>
	m <sup>3</sup> /m <sup>3</sup>	*	178.1076	=	stb/Mscf
	stb/MMscf	*	5.61E-06	=	m <sup>3</sup> /m <sup>3</sup>
	m <sup>3</sup> /m <sup>3</sup>	*	178107.6	=	stb/MMscf
Gas Oil Ratio	scf/stb	*	0.1781076	=	m <sup>3</sup> /m <sup>3</sup>
	m <sup>3</sup> /m <sup>3</sup>	*	5.61458	=	scf/stb
Length	inch	*	2.54	=	cm
	cm	*	0.3937	=	inch
	inch	*	25.4	=	mm
	ft	*	0.3048	=	m
	m	*	3.2808	=	ft
Pressure	bar	*	14.5038	=	psi
	psi	*	0.0689474	=	bar
	bar	*	100	=	kPa
	kPa	*	0.01	=	bar
	psi	*	6.89476	=	kPa
	kPa	*	0.145038	=	psi
	psi	*	70.3077	=	g/cm <sup>2</sup>
	g/cm <sup>2</sup>	*	0.0142232	=	psi
Pressure Gradient	psi/ft	*	22.621	=	kPa/m
	kPa/m	*	0.044207	=	psi/ft
	psi/ft	*	3.28084	=	psi/m
	psi/m	*	0.3048	=	psi/ft
	psi/ft	*	0.006944	=	lb/ft <sup>3</sup>
	lb/ft <sup>3</sup>	*	144	=	psi/ft
	psi/ft	*	2306.682	=	kg/m <sup>3</sup>
	kg/m <sup>3</sup>	*	0.000433523	=	psi/ft
	psi/ft	*	2.306682	=	gm/cm <sup>3</sup>
	gm/cm <sup>3</sup>	*	0.433523	=	psi/ft
	psi/ft	*	19.23077	=	ppg
	ppg	*	0.052	=	psi/ft
Temperature	°C	*	(C * 9/5) + 32	=	°F
	°F	*	(F - 32) * 5/9	=	°C
	°K	*	1.8	=	°R
	°R	*	0.5555	=	°K
Volume	m <sup>3</sup>	*	35.3147	=	ft <sup>3</sup>
	ft <sup>3</sup>	*	0.0283168	=	m <sup>3</sup>
	m <sup>3</sup>	*	6.29	=	bbl
	bbl	*	0.158983	=	m <sup>3</sup>
	ft <sup>3</sup>	*	0.178107	=	bbl
	bbl	*	5.6146	=	ft <sup>3</sup>
	L	*	0.00629	=	bbl
	bbl	*	158.9825	=	L
Weight	1lb	*	0.4536	=	kg
	kg	*	2.2046	=	lb
	lb	*	0.000453593	=	metric t
	metric t	*	2204.62	=	lb
	metric t	*	0.9072	=	short ton
	metric t	*	1.016	=	long ton
	short t	*	0.8929	=	long ton

Property Variable	Conversion Factors				Output Units
	Input Units	Operator	Conversion Factor		
Crude Oil	barrels	*	0.1364	=	tonnes (metric)
	barrels	*	159	=	m <sup>3</sup>
	barrels	*	42	=	US gallons
	US gallons	*	0.00325	=	tonnes (metric)
	US gallons	*	0.003785	=	m <sup>3</sup>
	US gallons	*	0.02381	=	barrels
	barrels/day	*	49.8	=	tonnes/year
Natural Gas and LNG	10 <sup>9</sup> sm <sup>3</sup>	*	35.3147	=	Bscf
	10 <sup>9</sup> sm <sup>3</sup>	*	0.9	=	Million Tonnes Oil Equivalent
	10 <sup>9</sup> sm <sup>3</sup>	*	0.74	=	Million Tonnes LNG
	10 <sup>9</sup> sm <sup>3</sup>	*	35.7	=	TBTU
	10 <sup>9</sup> sm <sup>3</sup>	*	6.6	=	MBOE
	Bscf	*	0.028317	=	10 <sup>9</sup> sm <sup>3</sup>
	Bscf	*	0.025	=	Million Tonnes Oil Equivalent
	Bscf	*	0.021	=	Million Tonnes LNG
	Bscf	*	1.01	=	TBTU
	Bscf	*	0.19	=	MBOE
	Million Tonnes Oil Equivalent	*	1.11	=	10 <sup>9</sup> sm <sup>3</sup>
	Million Tonnes Oil Equivalent	*	39.2	=	Bscf
	Million Tonnes Oil Equivalent	*	0.82	=	Million Tonnes LNG
	Million Tonnes Oil Equivalent	*	39.7	=	TBTU
	Million Tonnes Oil Equivalent	*	7.33	=	MBOE
	Million Tonnes LNG	*	1.36	=	10 <sup>9</sup> sm <sup>3</sup>
	Million Tonnes LNG	*	48	=	Bscf
	Million Tonnes LNG	*	1.22	=	Million Tonnes Oil Equivalent
	Million Tonnes LNG	*	48.6	=	TBTU
	Million Tonnes LNG	*	8.97	=	MBOE
	TBTU	*	0.028	=	10 <sup>9</sup> sm <sup>3</sup>
	TBTU	*	0.99	=	Bscf
	TBTU	*	0.025	=	Million Tonnes Oil Equivalent
	TBTU	*	0.021	=	Million Tonnes LNG
	TBTU	*	0.18	=	MBOE
	MBOE	*	0.15	=	10 <sup>9</sup> sm <sup>3</sup>
	MBOE	*	5.35	=	Bscf
	MBOE	*	0.14	=	Million Tonnes Oil Equivalent
	MBOE	*	0.11	=	Million Tonnes LNG
	MBOE	*	5.41	=	TBTU
Energy	kilocalorie (kcal)	*	4.187	=	kJ
	Kcal	*	3.968	=	BTU
	kJ	*	0.23883	=	kcal
	kJ	*	0.948	=	BTU
	BTU	*	0.25202	=	kcal
	BTU	*	1.05485	=	kJ
	1 kilowatt-hour (kWh)	*	860	=	kcal
	kWh	*	3600	=	kJ
	kWh	*	3412	=	BTU
	kcal	*	0.001162791	=	kWh
	kJ	*	0.00277778	=	kWh
	BTU	*	0.00293083	=	kWh
Power	hp	*	0.7457	=	kW
	kW	*	1.341	=	hp
Miscellaneous	acre-ft	*	1233.48	=	m <sup>3</sup>
	BTU/ft <sup>2</sup> -°F	*	0.5797	=	W/m <sup>2</sup> -°K
	BTU/ft <sup>2</sup> -°F	*	14.911	=	kJ/m <sup>2</sup> -°K
	BTU/lb-°F	*	0.23885	=	kJ/kg-°K
	BTU/scf	*	0.037334	=	MJ/sm <sup>3</sup>
	cp (gas)	*	0.001	=	μPa.s
	in <sup>2</sup>	*	6.4516	=	cm <sup>2</sup>
	lbf	*	4.44822	=	N
	lbm	*	0.453592	=	kg
	miles	*	1.609	=	km
	miles <sup>2</sup>	*	2.58999	=	km <sup>2</sup>
	Section	*	640	=	Acres
	Section	*	258.999	=	ha
	ton	*	0.90748	=	tonne

## Appendix 2 – Workflow Examples

### W.1 Granite Wash Well

The following information is excerpted from <http://www.naturalgasintel.com/granitewashinfo>.

The Granite Wash is a liquids-rich tight sand ~160 miles long and ~30 miles wide and covering parts of Western Oklahoma and the Texas Panhandle (Figures W.1-1 and W.1-2).

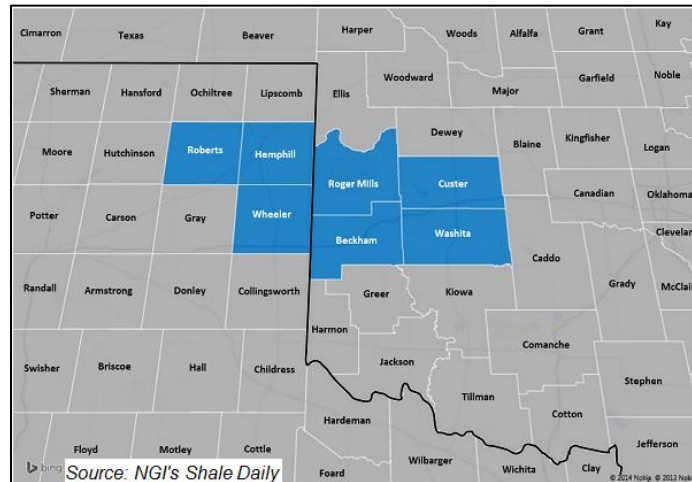


Figure W.1-1: Granite Wash Counties in Oklahoma and Texas

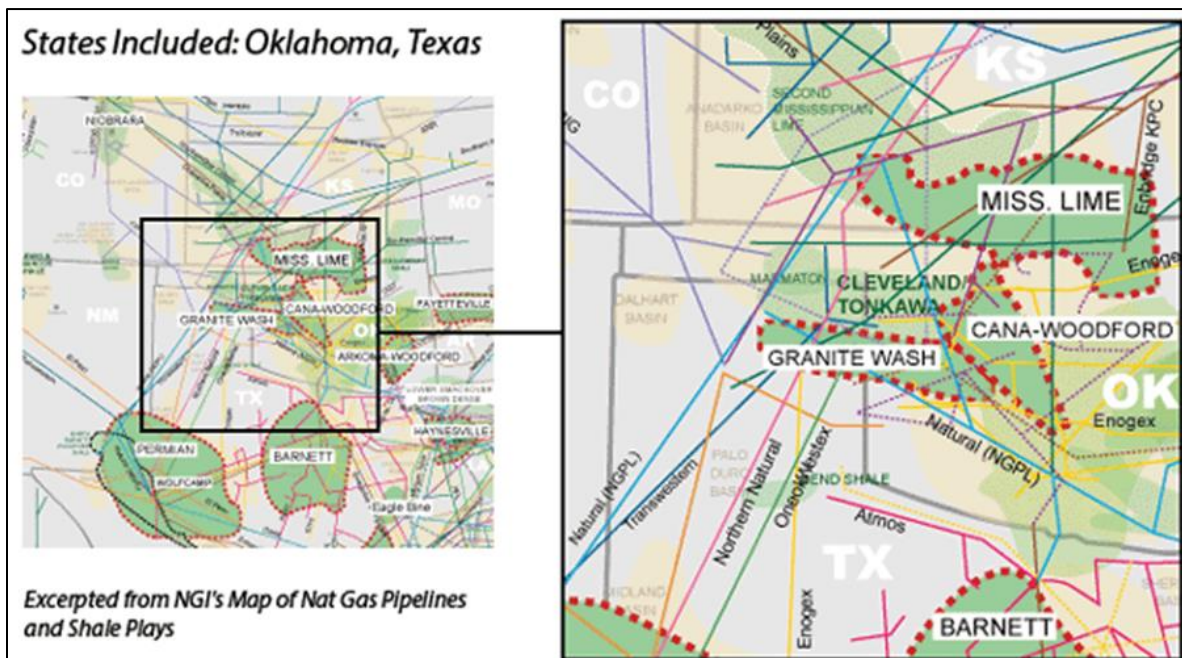


Figure W.1-2: Granite Wash Location

The Granite Wash is one of the deeper unconventional formations in North America, lying at depths between 10,000'-14,500' and is made up of a number of layered zones. These zones are listed as "A", "B", etc., as shown in Figure W.1-3. Gas in the Granite Wash tends to be liquids-rich, with natural gas liquids and condensate typically accounting for 30-40% of well production.

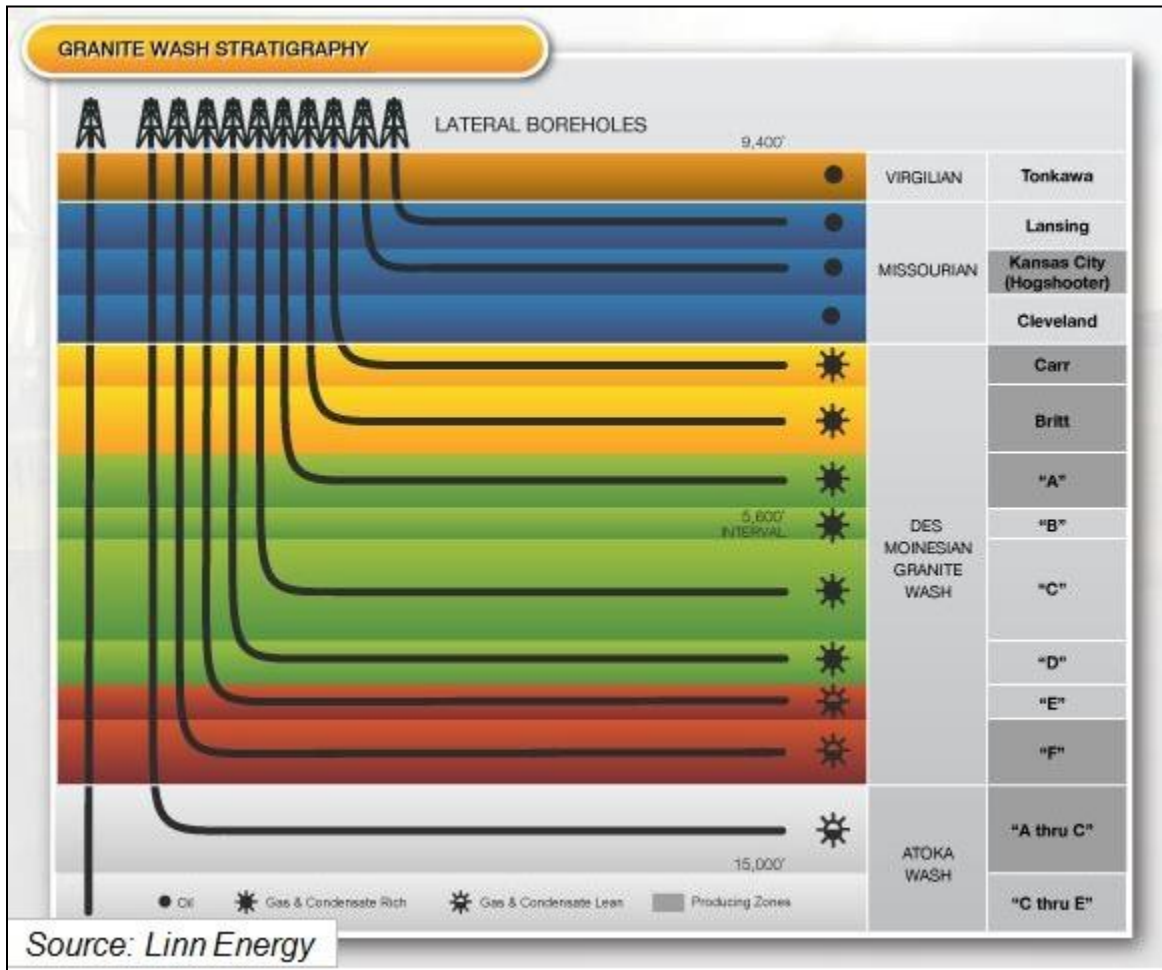


Figure W.1-3: Granite Wash Stratigraphy

The Granite Wash reportedly had 8.8 Tscf of technically recoverable natural gas as of January 1, 2013, according to the Energy Information Administration.

The purpose of this example is to evaluate the full cycle, as well as the point forward, economics of a horizontal well completed in the Granite Wash and place on production in April 2010.

### W.1.1 GW-01 Well

Data from a hydraulically fractured horizontal Granite Wash well, GW-01, (Figure W.1-4) has been evaluated using the PE<sup>2</sup> Essentials software. The Excel file, 'GW-01.xlsx' contains the production data from this well ("Workflow - Granite Wash Example").

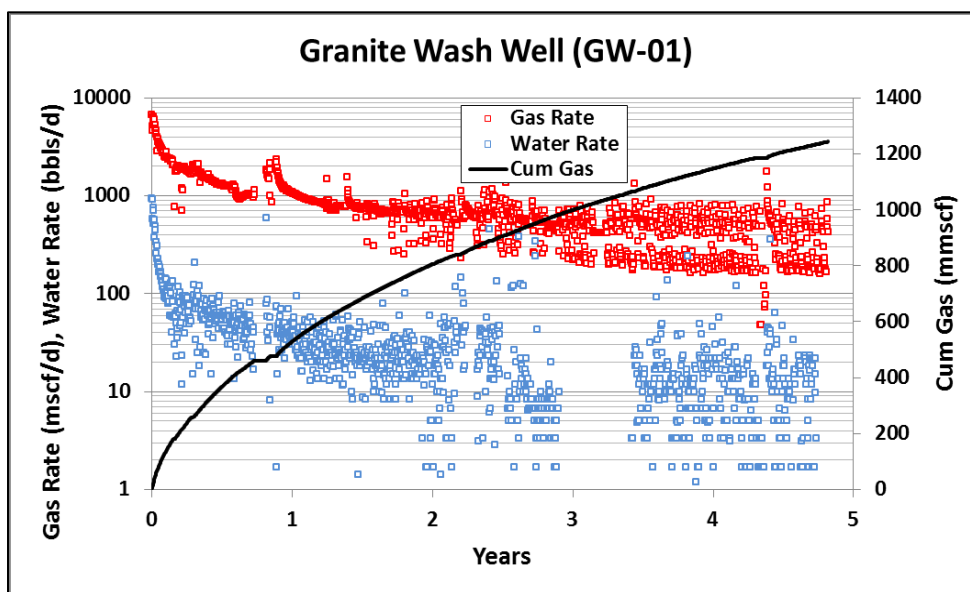


Figure W.1-4: Granite Wash Well (GW-01) Daily Production Data

Because of the scatter in the daily data, the data was averaged over a 1-week interval (Figure W.1-5) and this averaged data was used for analysis.

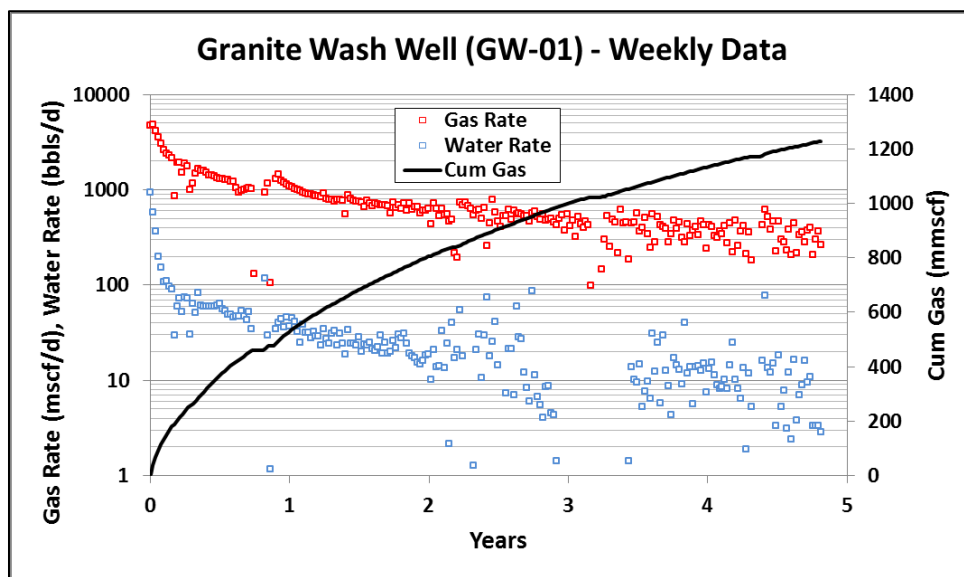


Figure W.1-5: Granite Wash Well (GW-01) Weekly Production data

Figure W.1-6 is the wellbore and completion diagrams for this horizontal well.

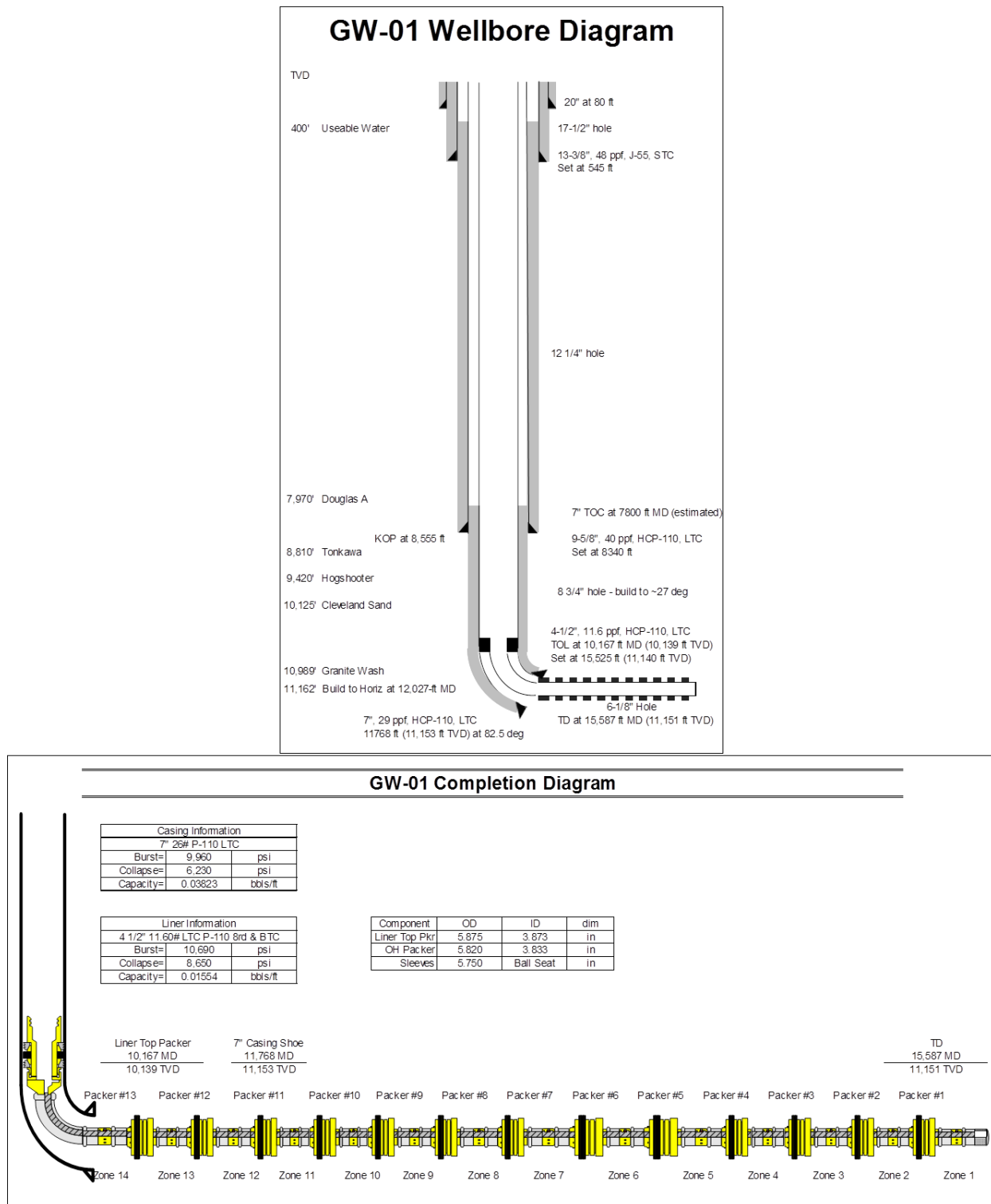


Figure W.1-6: GW-01 Wellbore and Completion Diagrams



Figure W.1-7 shows the wellbore trajectory for the GW-01 horizontal well showing the hydraulically fractured intervals.

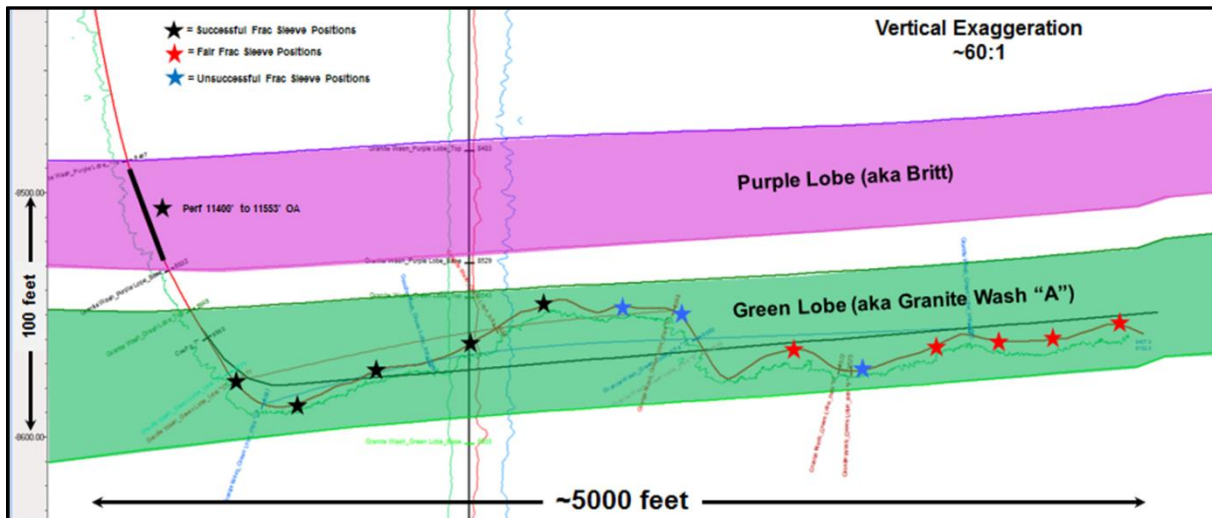


Figure W.1-7: GW-01 Wellbore Trajectory

## W.1.2 Gas Analysis

Figure W.1-8 indicates that the gas CGR has an average value of 16.4 bbls/mmscf.

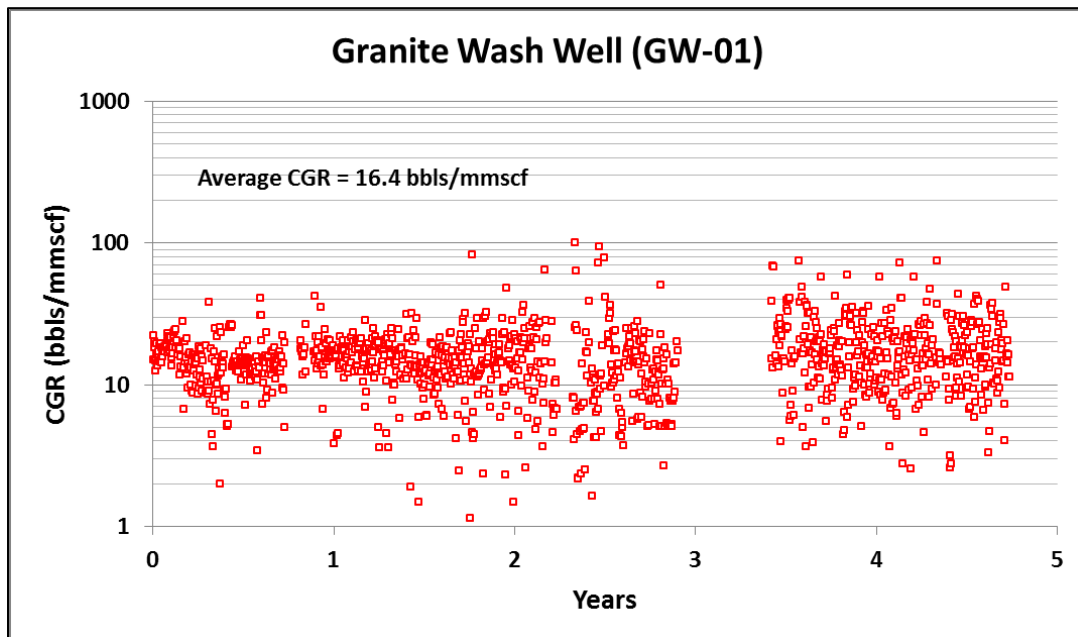


Figure W.1-8: GW-01 - Condensate-Gas ratio

Figure W.1-9 lists the components measured on a surface sample (ref: 590 psi and 80°F).

COMPONENTS	MOL %
Carbon Dioxide	0.843
Nitrogen	0.632
Methane	86.236
Ethane	7.148
Propane	2.754
iso-Butane	0.510
n-Butane	0.848
iso-Pentane	0.305
n-Pentane	0.355
Hexane + H2S	0.369
	100.000

Figure W.1-9: GW-01 Laboratory Gas Analysis

The GW-01 laboratory gas analysis (SG=0.668, BTU=1133) was used as a starting point for history matching the raw gas components to yield an average CGR of ~16.4 bbls/mmcsf, using the PVT model in the 'Unconventional Forecast' Tool. Figure W.1-10 presents the final estimation of raw gas properties for the GW-01 well.

Gas Properties Input

Sales Streams			
	Gas	Liquid	
H2S - mol%	0		Gas MW 20.98
N2 - mol%	0.63	0.65	Raw Gas G 0.7244
CO2 - mol%	0.84	0.87	Gas Pc (psi) 662
C1 - mol%	81.41	84.16	Gas Tc (°R) 392.5
C2 - mol%	9.33	9.64	Sales Gas G 0.6609
C3 - mol%	4.99	3.87	GHV (btu/scf) 1144
iC4 - mol%	0.59	0.3	Shrinkage (%) 4.7
nC4 - mol%	0.97	0.5	Propane-C3 (bbls/mmcsf) 8.1
iC5 - mol%	0.35	0	Butane-C4 (bbls/mmcsf) 5.9
nC5 - mol%	0.31	0	CGR-C5+ (bbls/mmcsf) 16.5
C6 - mol%	0.2	0	Condensate Density (°API) 77.3
C7Plus - mol%	0.38	0	Water (bbls/mmcsf) tba
Σ Comps	100	100	Dew Point Pressure (psi) 2355.1
C7Plus MW	215		
C7Plus SG	0.772		

Generate Gas Components Return

Figure W.1-10: GW-01 Estimated Raw Gas Analysis

These gas properties were used for analysis.

Prior to proceeding with a history match, the flowing THP data must be converted to BHP for matching.

A wellbore model was built (Figure W.1-11) and the THP data was imported and converted to BHP (Figure W.1-12). The BHP data was then transferred to the 'GW-01.xlsx' file for import into the history matching tool.

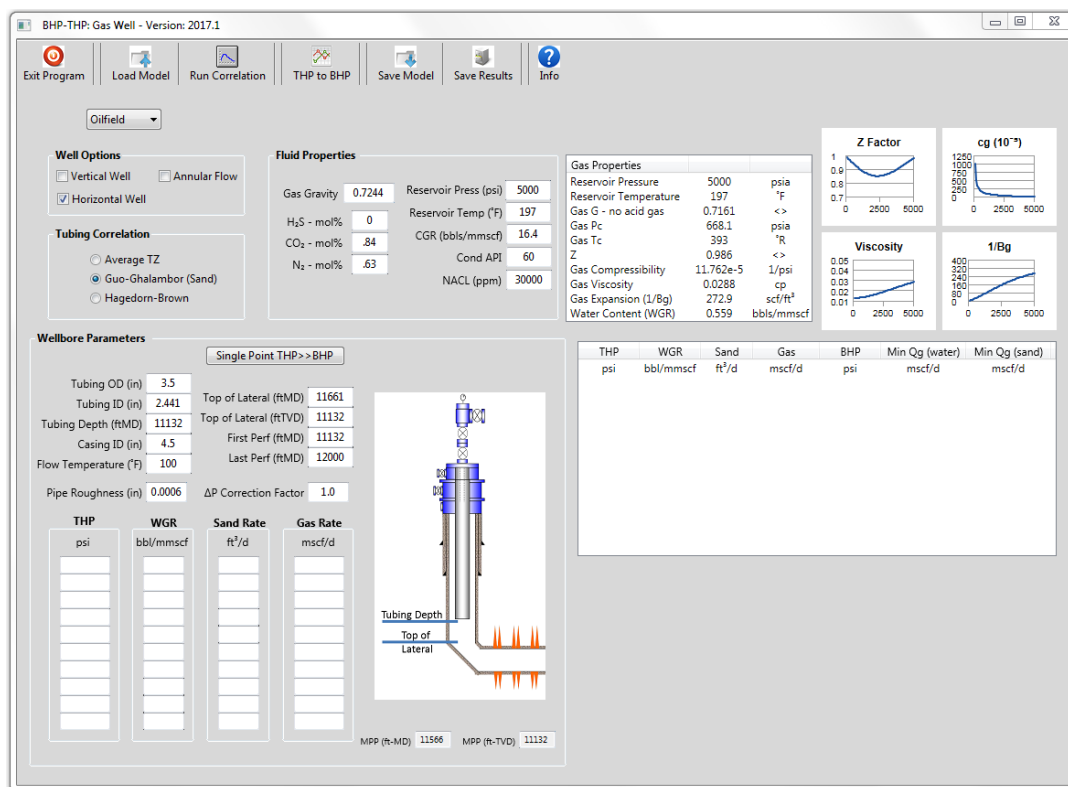


Figure W.1-11: GW-01 Wellbore Model

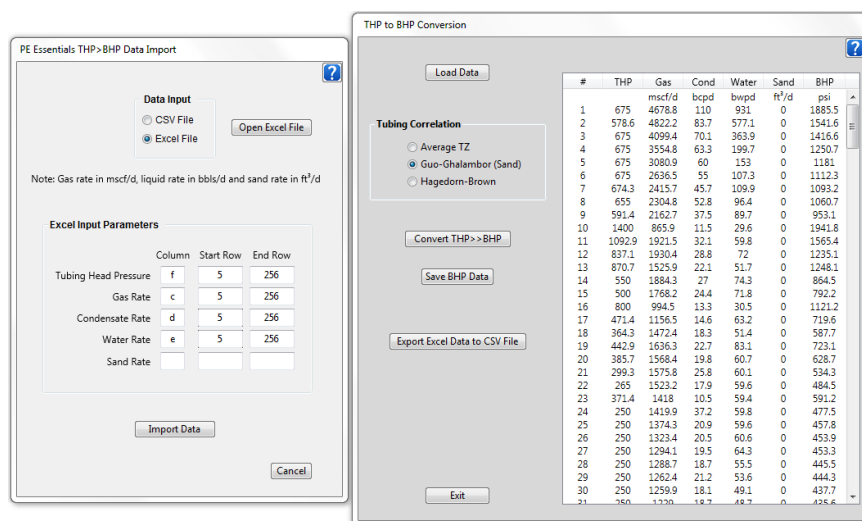


Figure W.1-12: GW-01 THP to BHP

### W.1.3 Production History Match

Using the 'Unconventional Forecast' tool, the production data was history matched in order to estimate reservoir parameters. For this exercise, the 7-day averaged data was used.

The Numerical Model was used to generate the initial history match. The base model that was built for this reservoir is 'PE\_Essentials\_Unconventional\_GW-01\_Base.dvx' located in the "Workflow - Granite Wash Example\Unconventional" directory.

The weekly averaged historical production data was imported into the History Match model (Figure W.1-13). A preliminary history match was performed using the analytical model (Figure W.1.14).

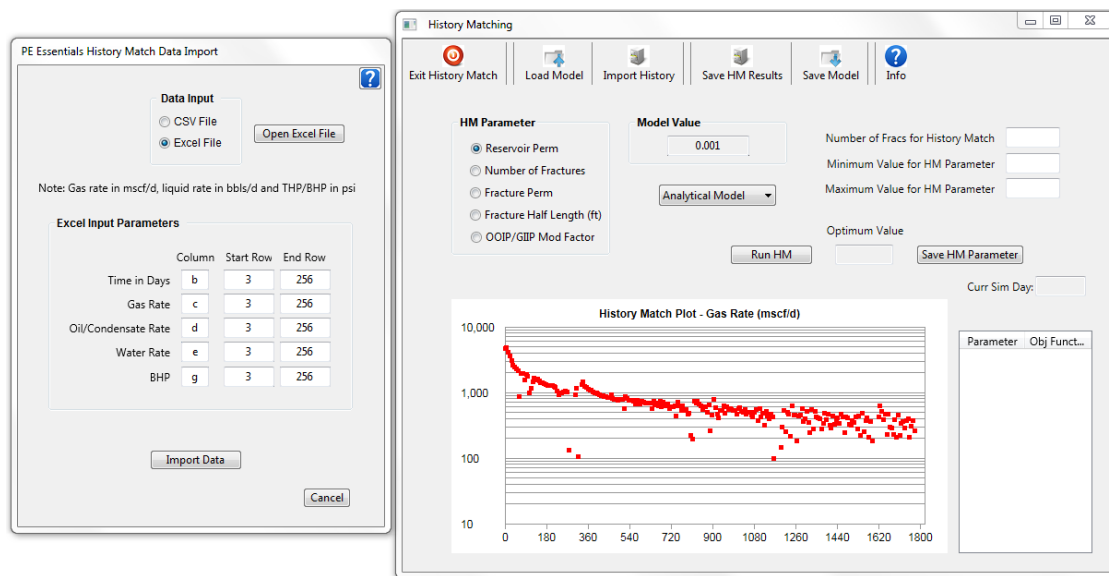


Figure W.1-13: GW-01 Import of Production History

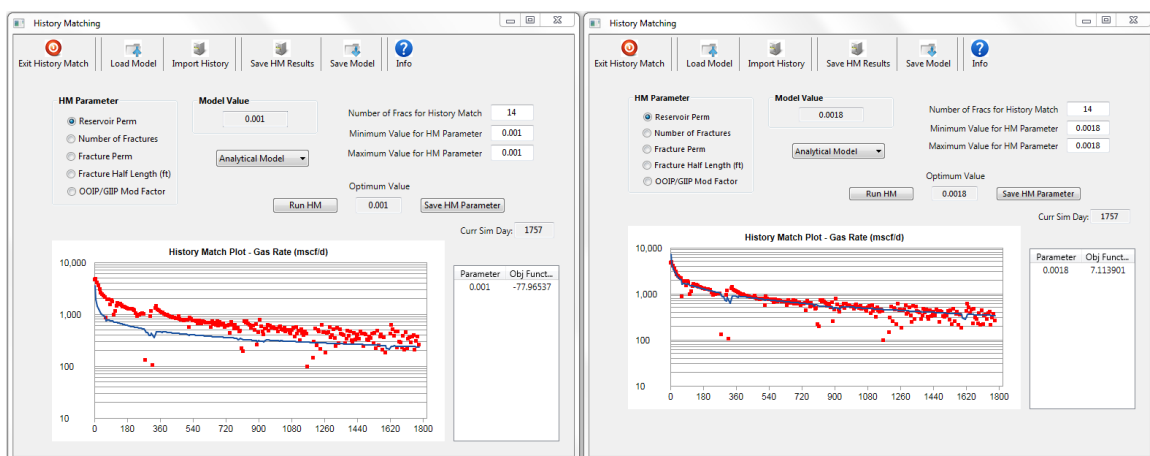


Figure W.1-14: GW-01 Unmatched and Matched History, Analytical Model

The history match shown in Figure W.1-14 (right) is an acceptable match. But, since a numerical model more rigorously models the reservoir, it is preferred for long term forecasting and as a result the numerical model was history match as well.

Note that history matching with the numerical model is time consuming and may or may not yield a more accurate solution. As is the case for all history matching; there are different solutions that appear to be equally valid. The final history match, by any technique, is not necessarily the most accurate solution, but it is sufficient to match the historical data.

The parameters obtained from the match using the analytical model were refined in the numerical model and the comparison of the analytical (left) and the numerical (right) history match results are presented in Figure W.1-15.

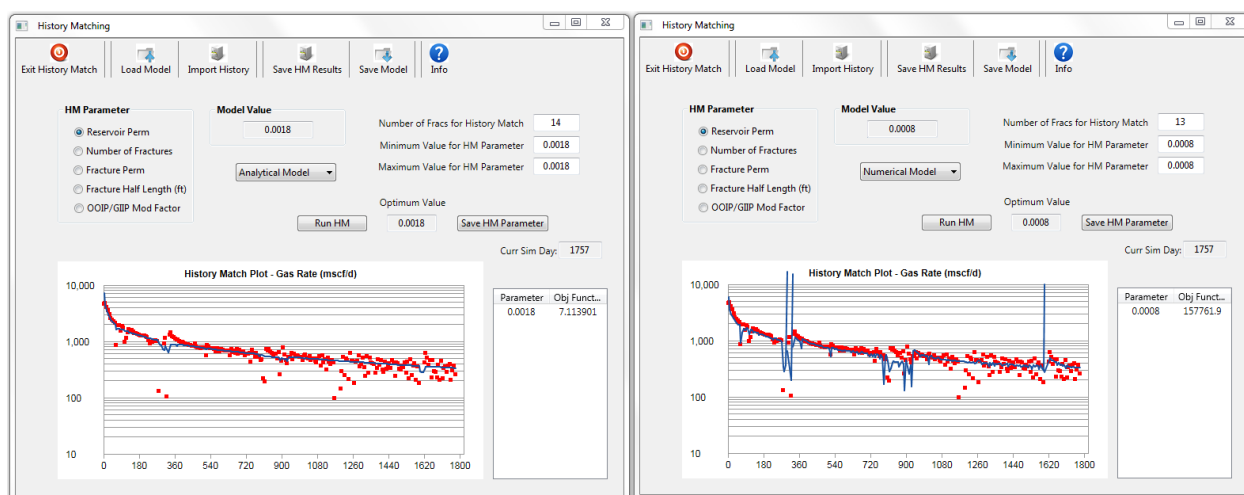


Figure W.1-15: GW-01 Production History Match – Analytical and Numerical Models

The numerical history match model is saved as 'PE\_Essentials\_Unconventional\_GW-01\_NumericalMatch.dvx' and this model will be used for long term forecasting. The main difference between the analytical and the numerical history match models is that the numerical model has a slightly lower permeability than the analytical model.

Figure W.1-16 presents the final history matched reservoir parameters; Figure W.1-17 presents the final hydraulic fracture parameters generated for the history match; and Figure W.1-18 presents the well parameters. These figures include the analytical model match parameters as well for comparison.

**Gas Reservoir Properties**

Average Perm (md)	0.0018	Initial Gas In Place (Bscf)	2.989
Average Pay (ft)	50	Sales Gas In Place (Bscf)	2.848
Average Sw	0.2	Condensate In Place (mmbbls)	49.3
Average Porosity	0.055	Initial Bg (ft <sup>3</sup> /scf)	0.00369
Res Temperature (°F)	197	Initial Gas Viscosity (cp)	0.02901
Reservoir Pressure (psi)	5000	Initial Gas Z Factor	0.99025
Reservoir Length (ft)	5000	Initial cg (10 <sup>-4</sup> /psi)	1.17
Reservoir Width (ft)	1000		
Reservoir Well radius (in)	4		

Area (Acres) 114.8

Return

**Gas Reservoir Properties**

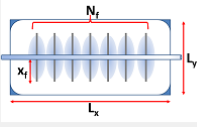
Average Perm (md)	0.0008	Initial Gas In Place (Bscf)	2.716
Average Pay (ft)	50	Sales Gas In Place (Bscf)	2.588
Average Sw	0.2	Condensate In Place (mmbbls)	44.8
Average Porosity	0.05	Initial Bg (ft <sup>3</sup> /scf)	0.00369
Res Temperature (°F)	197	Initial Gas Viscosity (cp)	0.02899
Reservoir Pressure (psi)	5000	Initial Gas Z Factor	0.99069
Reservoir Length (ft)	5000	Initial cg (10 <sup>-4</sup> /psi)	1.18
Reservoir Width (ft)	1000		
Reservoir Well radius (in)	4		

Area (Acres) 114.8

Return

Figure W.1-16: GW-01 History Match – Reservoir Parameters (Left-Analytical, Right-Numerical)

**Frac Parameters**

Effective Fracture Half Length, xf (ft)	200	
Propped Fracture Width (in)	0.1	
Effective Fracture Permeability (md)	600	
MIN Number of Fractures to Model	14	
MAX Number of Fractures to Model	14	
Dimensionless Fracture Conductivity, FCD	13.89	
<input type="checkbox"/> Include Frac Water Flowback		
Import Frac Parameters		
Return		

**Frac Parameters**

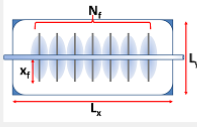
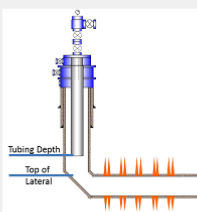
Effective Fracture Half Length, xf (ft)	150	
Propped Fracture Width (in)	0.1	
Effective Fracture Permeability (md)	600	
Number of Fractures to Simulate	13	
Dimensionless Fracture Conductivity, FCD	41.67	
Import Frac Parameters		
Return		

Figure W.1-17: GW-01 History Match – Fracture Parameters (Left-Analytical, Right-Numerical)

**Wellbore Properties**

Measured Depth to Top of Lateral (ft)	11661	
True Vertical Depth to Top of Lateral (ft)	11132	
Lateral Length (ft)	5000	
Tubing ID (in)	2.441	
Depth of Tubing (ft)	11132	
Casing ID (in)	4.5	
Tubing Correlation	Average TZ	
Return		

**Wellbore Properties**

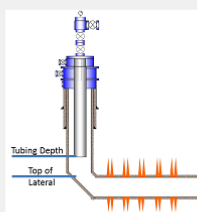
Measured Depth to Top of Lateral (ft)	11661	
True Vertical Depth to Top of Lateral (ft)	11132	
Lateral Length (ft)	5000	
Tubing ID (in)	2.441	
Depth of Tubing (ft)	11132	
Casing ID (in)	4.5	
Tubing Correlation	Average TZ	
Return		

Figure W.1-18: GW-01 – Wellbore Parameters (Left-Analytical, Right-Numerical)

Figures W.1-19 and W.1-20 present the forecast results using the history match parameters from the numerical model.

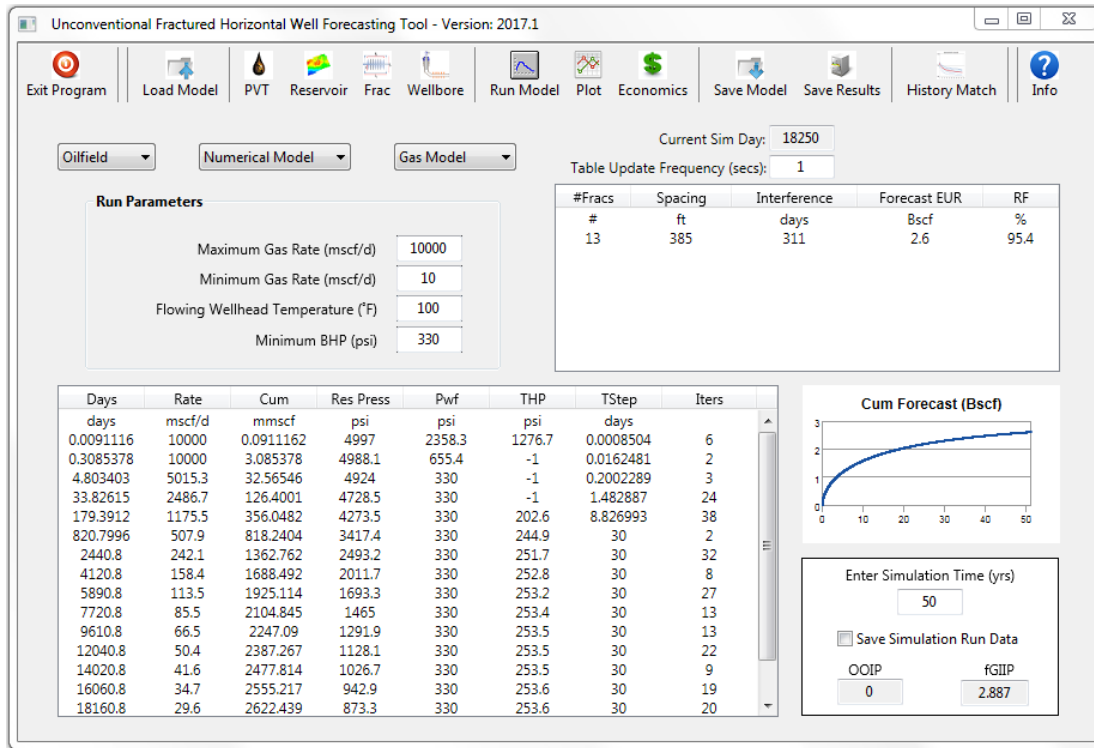


Figure W.1-19: GW-01 – Unconventional Forecast

Based on initialization of the numerical simulator, GIIP was calculated to be 2.887 Bscf and 50-year recovery factor was calculated to be 95.4%. It should be noted that the history data file used for plotting on Figure W.1-20 was generated with the PE<sup>2</sup> Essentials DCA tool.

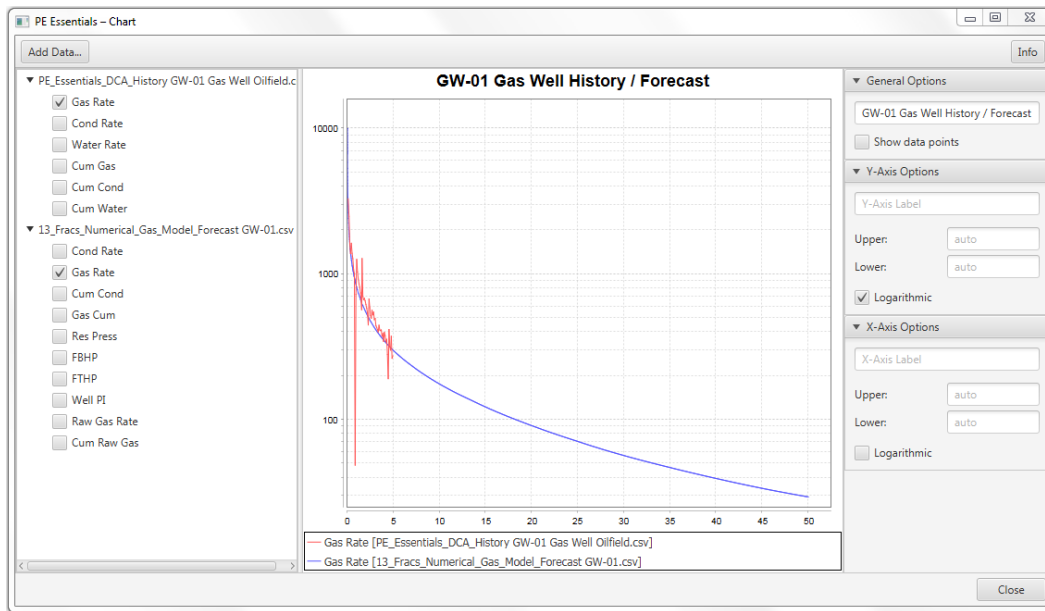


Figure W.1-20: GW-01 – Unconventional Gas Rate Forecast

### W.1.4 Monte Carlo Volumetrics: Gas Volume

Using the 'Monte Carlo Volumetrics' tool with the reservoir parameters presented in Section W.1.3, a Monte Carlo simulation was run to estimate gas volume for P90, P50, P10 and expected value (EV) cases (Figure W.1-21). The expected value for GIIP is 2.74 Tscf with an expected recovery of 2.55 Tscf (RF = 93.1%) for this well.

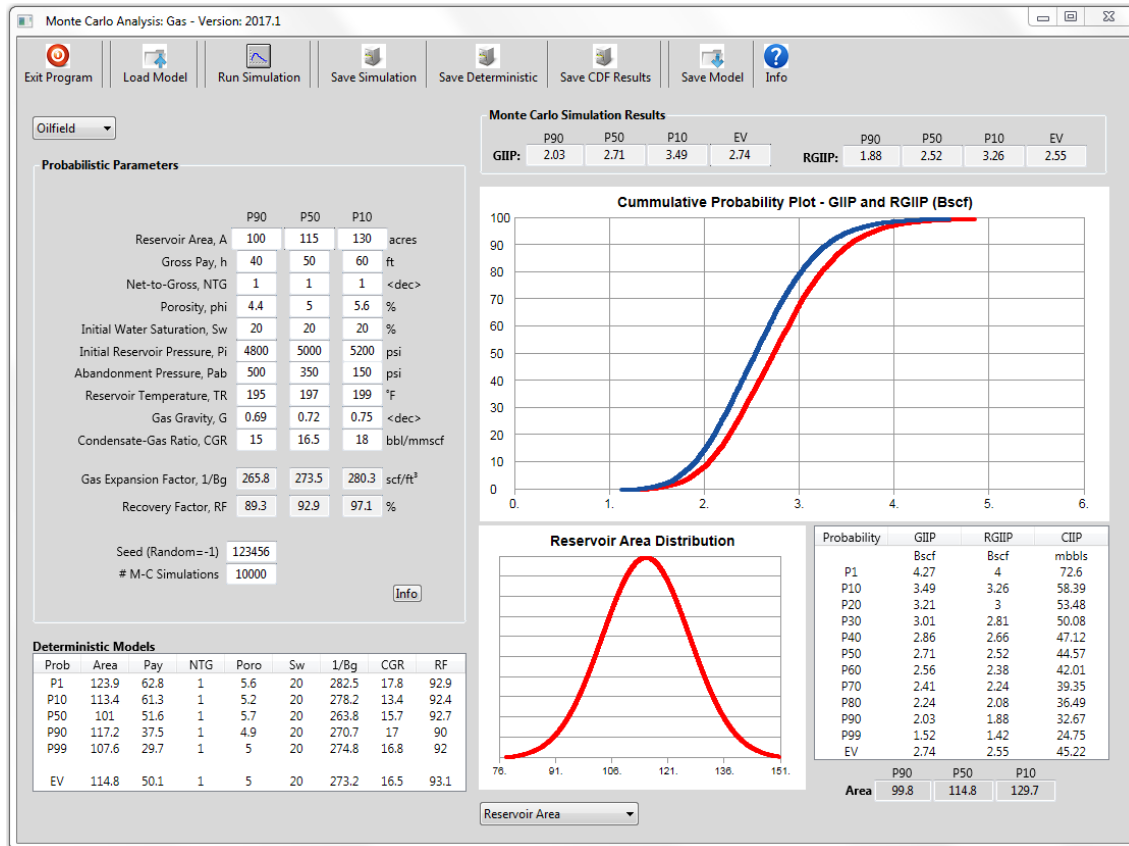


Figure W.1-21: GW-01 – Monte Carlo Gas Volumetrics

The results of this analysis were used to direct a 'Monte Carlo DC Forecast' analysis.

### W.1.5 Decline Curve Analysis

Using the 'Decline Curve Analysis' tool, the DCA parameters were determined using the average weekly gas production rates (Figure W.1-22).

It is possible to generate different solutions for the DCA parameters depending on the low/high ranges and 'X Range' entered for the analysis. This analysis was generated based on the assumption that the GW-01 well will exhibit a 'Super Hyperbolic' decline which is common for unconventional reservoirs.



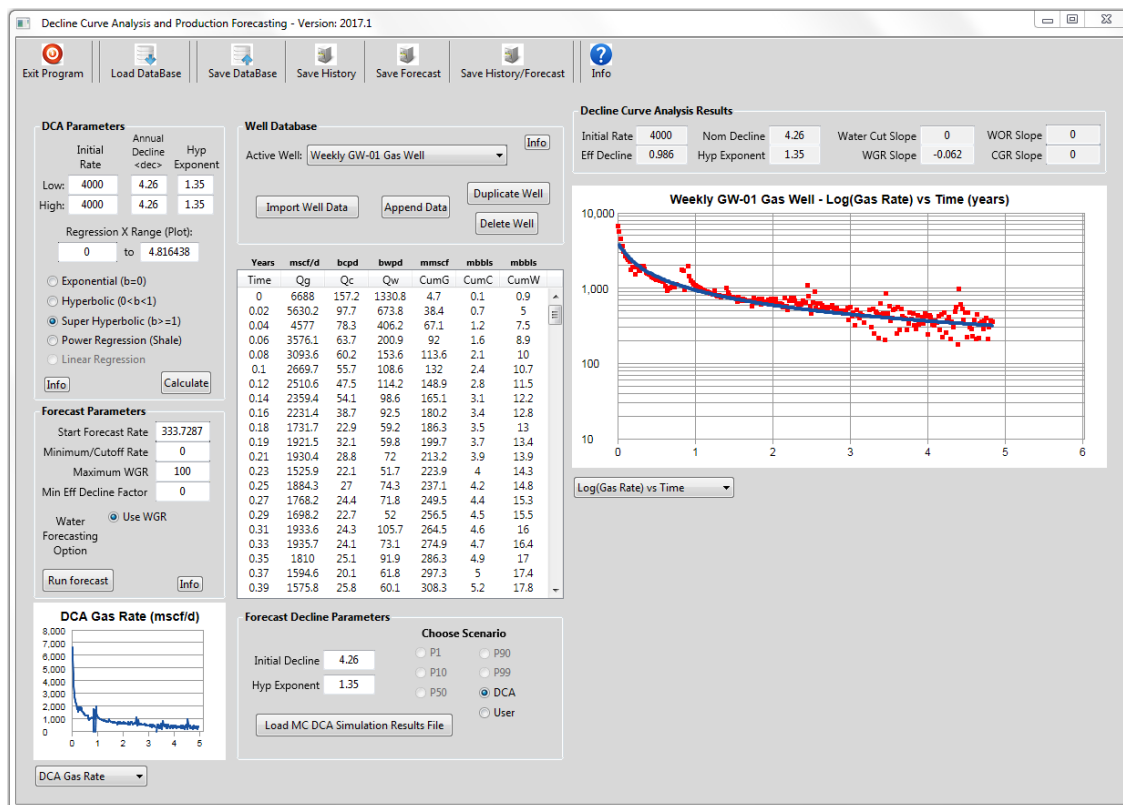


Figure W.1-22: GW-01 – DCA Using Weekly Averaged Rates

Figure W.1-23 shows that DCA using the daily and monthly rates yields results that are similar to the weekly rate DCA. The difficulty with using the daily rates is that, since the data is very scattered, a proper analysis is difficult to determine.

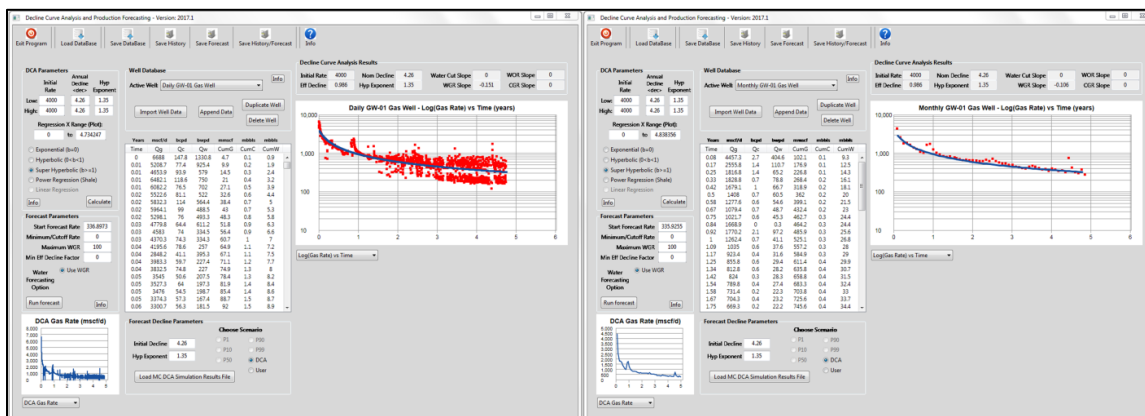


Figure W.1-23: GW-01 – DCA Using Daily and Monthly Rates

Figure W.1-24 presents the supplementary DCA plots for the weekly data analysis.

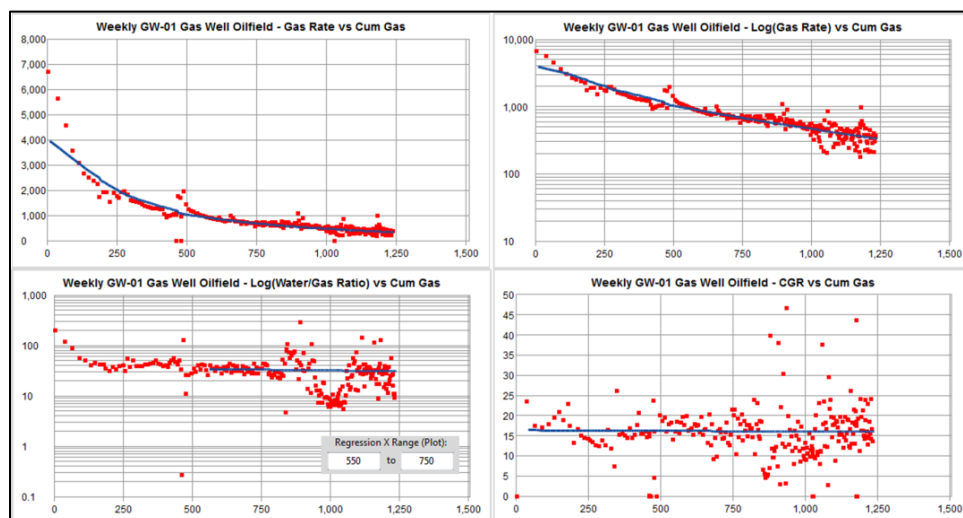


Figure W.1-24: GW-01 – Supplementary DCA Plots (Weekly Data)

The DCA results were entered as P50 in the 'Monte Carlo DC Forecast' tool. Ranges for P10/P90 were entered and history data, which was generated from the DCA tool using 'Save History', was imported to generate probabilistic forecasts (Figure W.1-25).

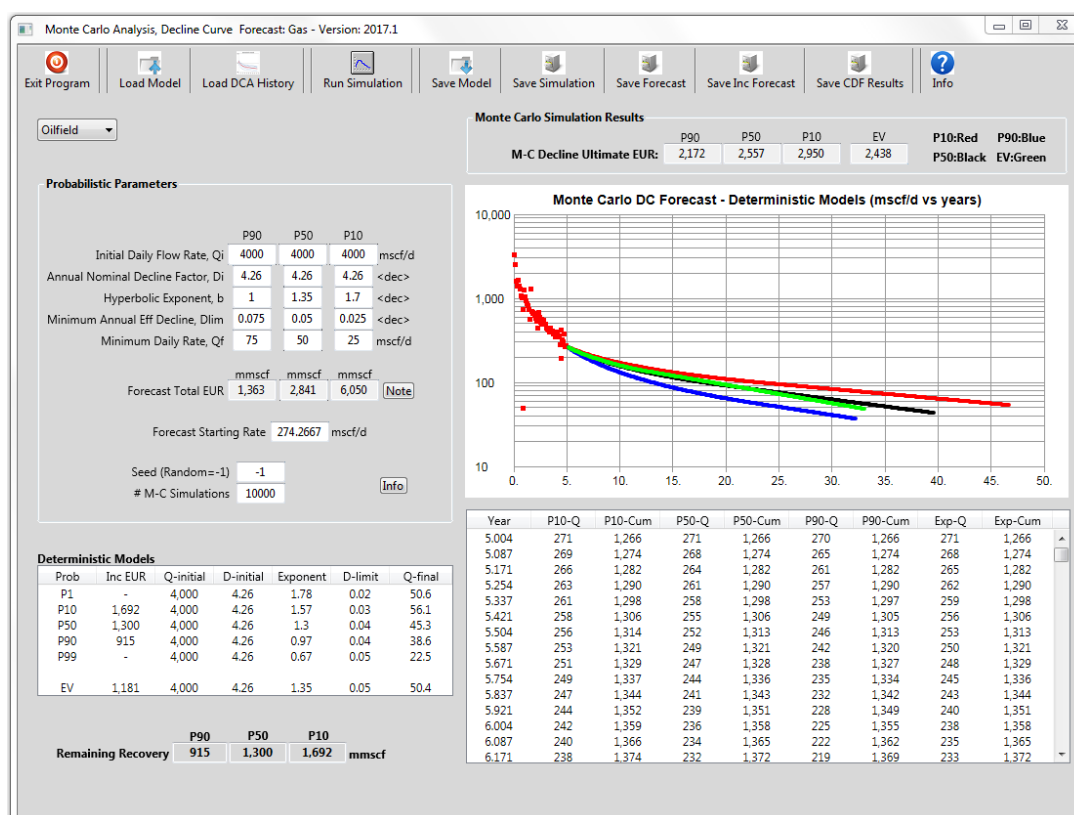


Figure W.1-25: GW-01 – Monte Carlo DC Parameter Generation and Forecast

It is possible to generate a number of different solutions for the Monte Carlo DC parameters depending on whether or not a constant 'seed' is used (refer to Section 2.4). This analysis represents just one realization for the P90/P50/P10/EV decline parameters.

In order to generate consistent results, the 'Initial Daily Flow Rate' and 'Annual Nominal Decline Factor' were entered as constant values. This will limit the Monte Carlo analysis to generation of  $b$ ,  $D_{lim}$  and  $Q_f$  values. After generating the DC parameters, they can be saved by clicking 'Save Simulation'. This will store the different realizations which can then be imported into the 'Decline Curve Analysis' tool to generate the deterministic DC forecasts.

The Monte Carlo simulation can also be performed without importing history (Figure W.1-26).

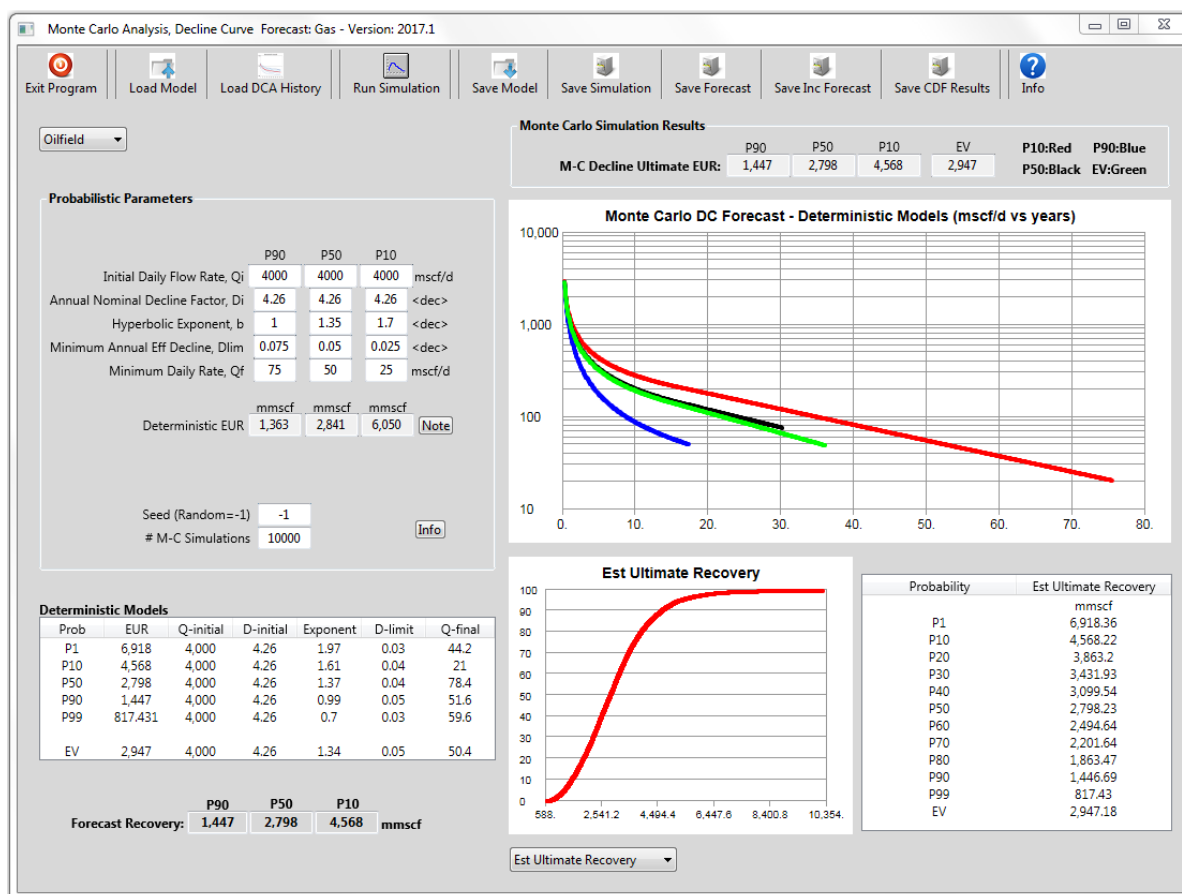


Figure W.1-26: GW-01 – Monte Carlo DC Parameter and Forecast Generation

The advantage of using the 'Decline Curve Analysis' tool to generate the deterministic DCA forecasts is that the water and condensate rates will also be generated for economics analysis purposes.

The Monte Carlo parameters were imported into the 'Decline Curve Analysis' tool and the different forecasts were generated with the results shown in Figure W.1-27.

Note that in order to save all the forecasts in the DCA database, copies of the base well (weekly data) were generated for each realization. All forecasts were saved to CSV files.

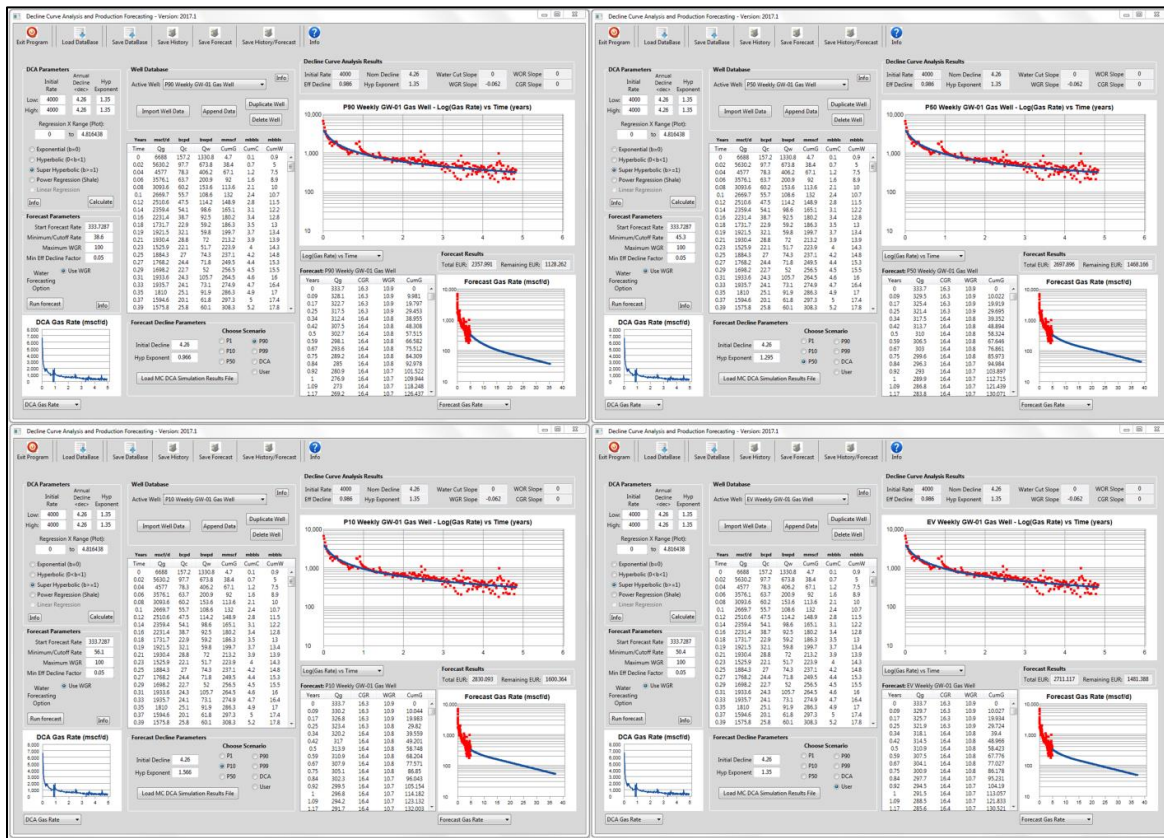


Figure W.1-27: GW-01 – DCA Forecasts for P90/P50/P10/EV

Figure W.1-28 presents the remaining gas rate and cum gas forecasts and Figure W.1-29 presents the full cycle well forecasts for the GW-01 well.

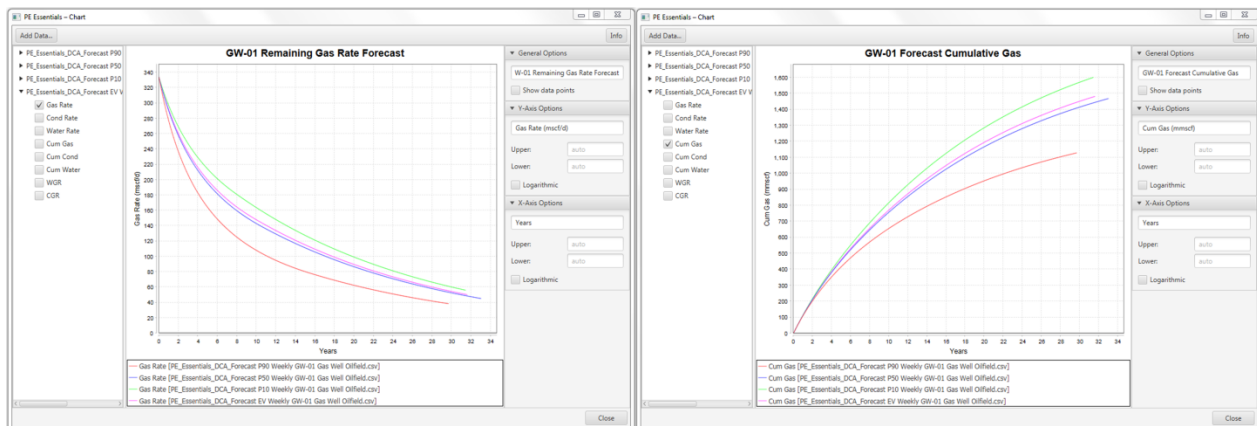


Figure W.1-28: GW-01 – Comparative Remaining Forecasts for P90/P50/P10/EV

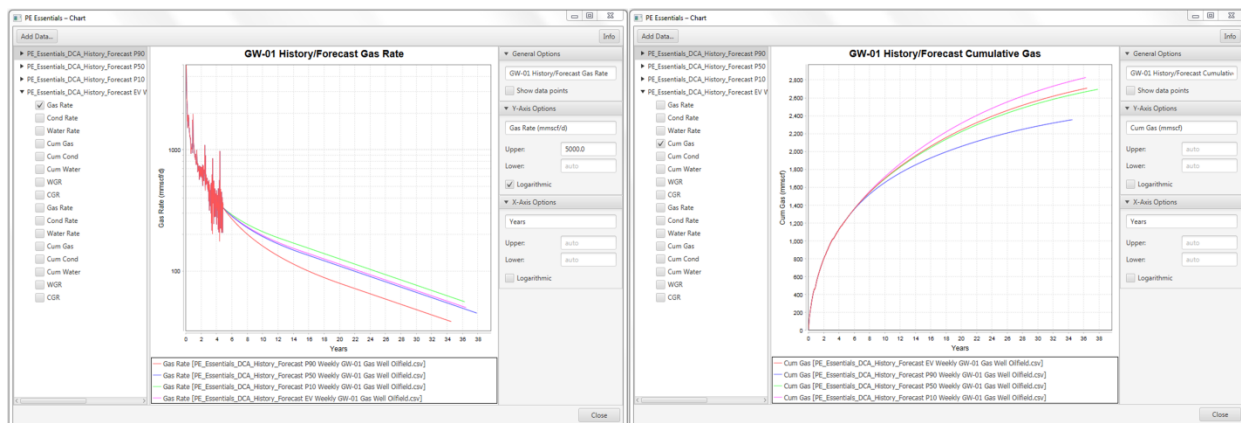


Figure W.1-29: GW-01 – Comparative Full Cycle Forecasts for P90/P50/P10/EV

The forecasts yielded the following results:

P90: Total EUR = 2358 mmscf  
Remaining Gas = 1128 mmscf

P50: Total EUR = 2698 mmscf  
Remaining Gas = 1488 mmscf

P10: Total EUR = 2830 mmscf  
Remaining Gas = 1600 mmscf

EV: Total EUR = 2711 mmscf  
Remaining Gas = 1481 mmscf

These forecasts were then imported into the 'Scoping Economics' tool to evaluate the full cycle economics of the well as well as the current economics for the well.

### W.1.6 Scoping Economics

The 'Scoping Economics' tool was used to evaluate the economic value of the GW-01 well in terms of the remaining value of the well and the full-cycle economics of the well (look-back evaluation).

In order to perform full cycle economics, the historical gas and oil prices are required. The Excel file, 'Historical and Forecasted Oil and Gas Prices.xlsx', located in the "Example Input Files\Excel Files" directory was used to import historical prices from August 2008 as well as import a price forecast. Figure W.1-30 shows the gas prices used for the remaining value (Forecast Gas Price) and the full cycle (Historical / Forecast Gas Price) economic analysis.



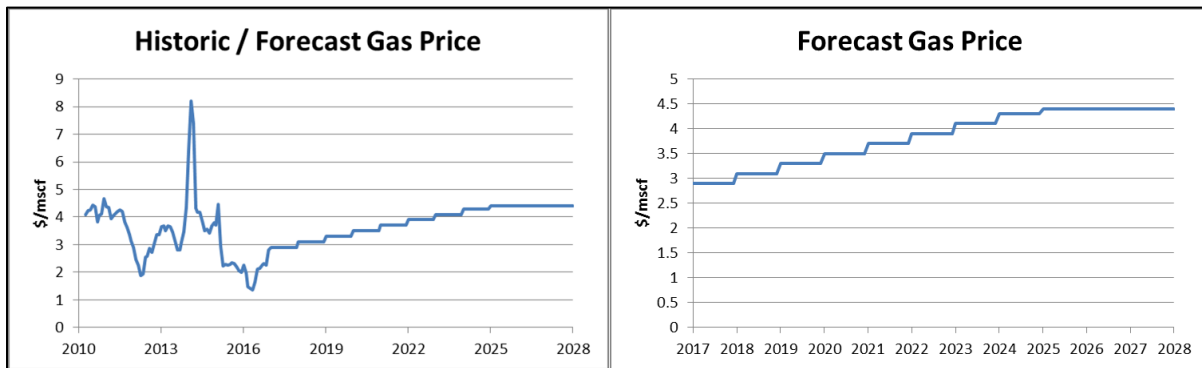


Figure W.1-30: GW-01 – Gas Price Data

The assumptions used for the point-forward economic run are: overhead cost for the well is \$100k/year; variable well cost is \$0.76/mscf; gas transportation fee is \$0.50/mscf; and water disposal cost is \$0.25/bbl. For full-cycle economics, a 2010 well completion cost of \$4.5mm was assumed. No escalations were applied for either forecast.

Figure W.1-31 shows the import screens for the oil and gas price forecasts. The spreadsheet was “Historical and Forecasted Oil and Gas Prices.xlsx” and the left sheet is the import for the incremental forecast, or point forward, economics and the right sheet is for the look back, or full cycle, economics.

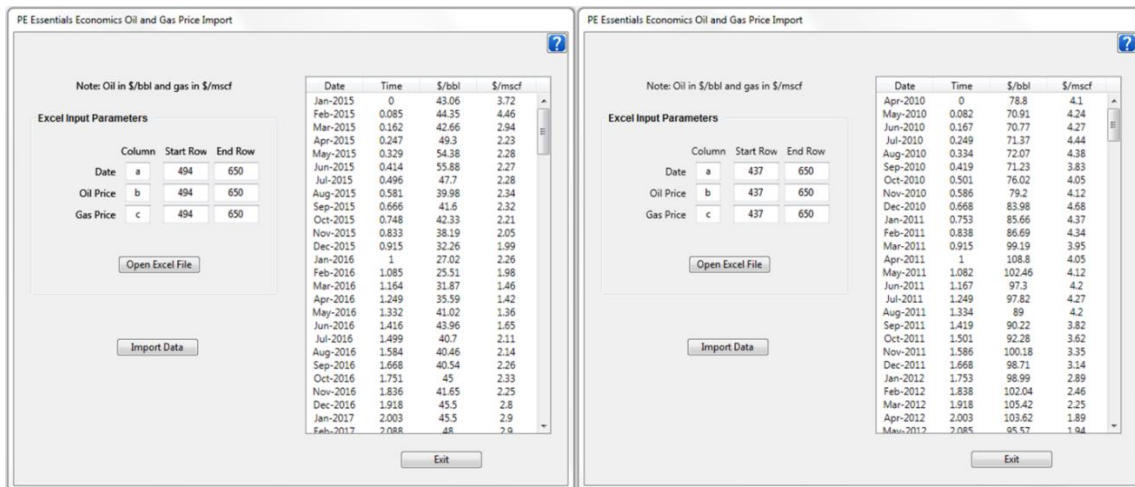


Figure W.1-31: GW-01 – Oil/Gas Price History/Forecast

Note that discounting for the full cycle economics starts after 6.75 years which is equivalent to January 2017 and 2 years for the incremental forecast. The discounting is delayed in the incremental forecast since it starts in January 2015 (end of history is December 2014).

Figures W.1-32 and W.1-33 show the incremental economic runs and Figures W.1-34 and W.1-35 shows the full cycle economic runs.

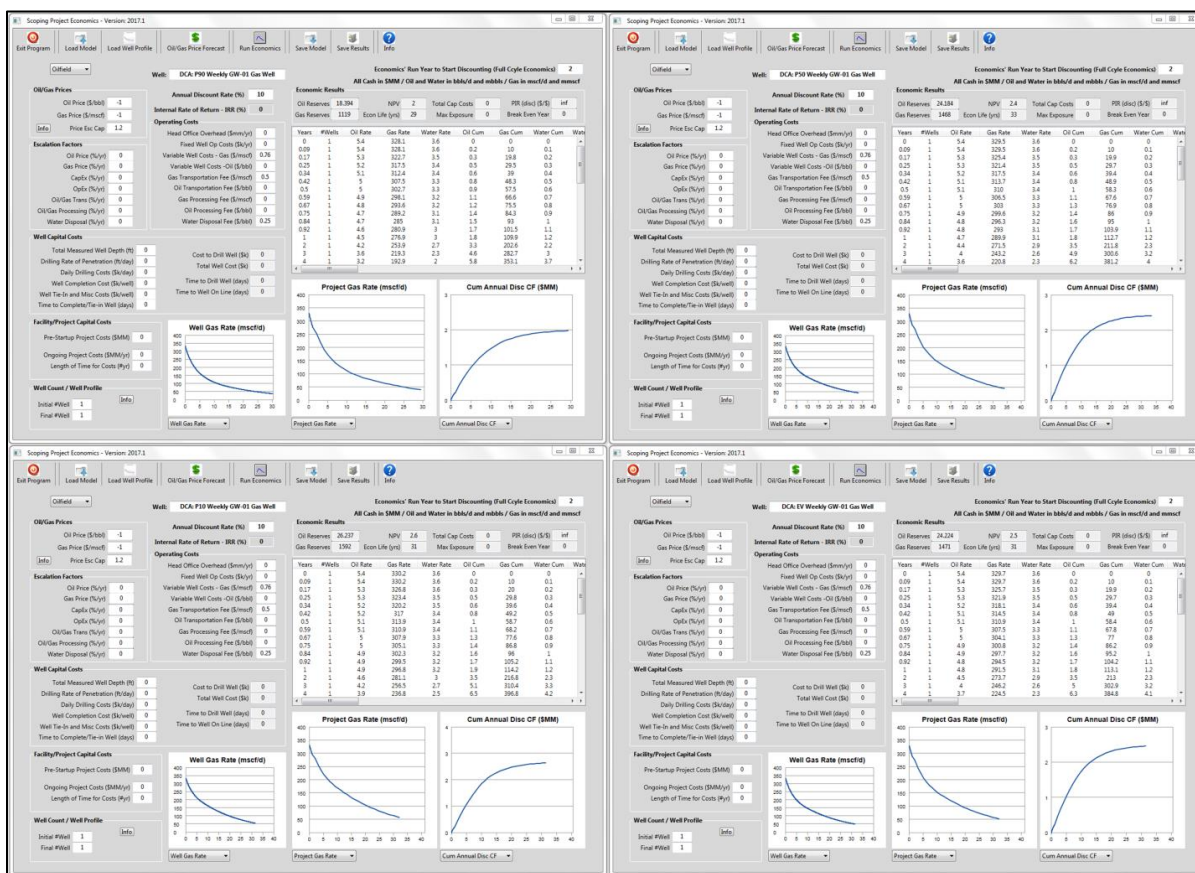


Figure W.1-32: GW-01 – Point Forward Economic Runs

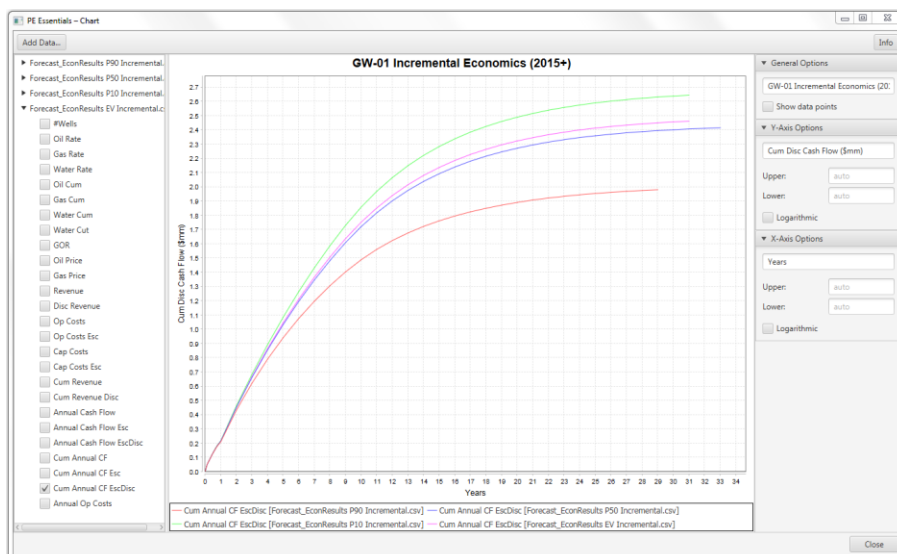


Figure W.1-33: GW-01 – Point Forward Discounted Cum Cash Flows

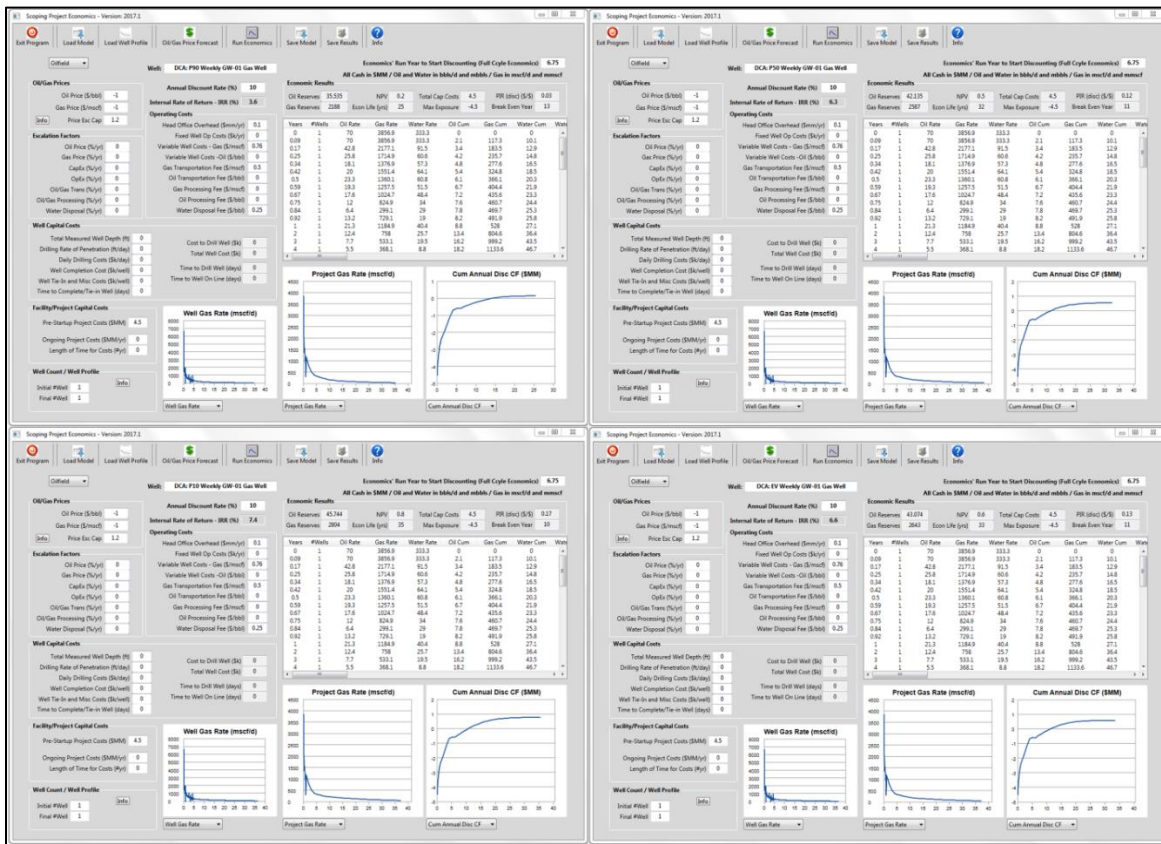


Figure W.1-34: GW-01 – Look Back (Full Cycle) Economic Runs

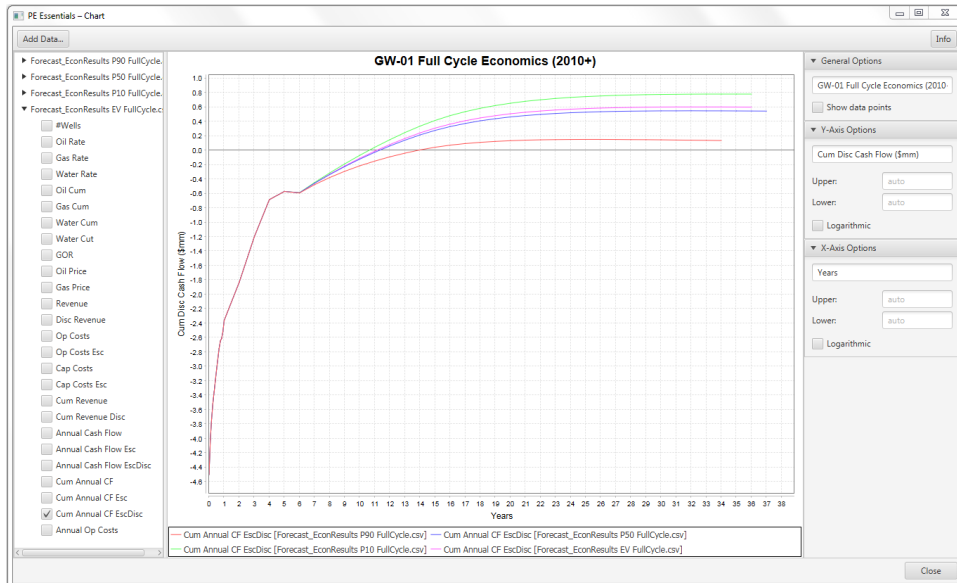


Figure W.1-35: GW-01 – Point Forward Discounted Cum Cash Flow



As is the case for most wells, the point forward economics of the GW-01 well is robust with an NPV of \$2.4mm at the P50 level. Since the GW-01 well was placed on production in 2010, during a period of low gas prices, look back economics (P50) yields an IRR of 6% and a payout of 11 years (2021).

Under 2017 economic conditions, this well may not be economic – current well costs for a Granite Wash well are in the \$7 - \$8 million range and gas price forecasts remain low.

### W.1.7 Material Balance Type Curve Generation

The 'Gas Material Balance' tool can be used to generate type curves for a given well or area. In most cases, especially for unconventional reservoirs, depleting reservoir pressure is not known. Without reservoir pressure, it is still possible to build a multi-tank model to history match the production characteristics of the well using the 'Low Perm Material Balance' tool.

There is no reservoir pressure data available for GW-01 so only cumulative production is available for analysis (Refer to Figure W.1-36).

PE Essentials Material Balance Historical Data Import

**Data Input**

☐ CSV File ☒ Excel File

Note: Gas volume in mmscf, reservoir pressure in psi

**Excel Input Parameters**

	Column	Start Row	End Row
Days	a	5	256
Incremental Production	e	5	256
Reservoir pressure	c	5	256

Days	Cum G...	Res Pre...
1	4.67882	4944.441
7	38.43414	0
14	67.12995	0
21	92.01372	0
28	113.5802	0
35	132.0357	0
42	148.9456	0
49	165.0792	0
56	180.2181	0
63	186.2791	0
70	199.7293	0
77	213.2422	0
84	223.9236	0
91	237.1137	0
98	249.4909	0
105	256.4527	0
112	264.5482	0
119	274.8552	0
126	286.3092	0
133	297.2881	0
140	308.3187	0
147	316.9999	0

Figure W.1-36: GW-01 – Multi-Tank Gas MB Model Import Production Data

The multi-tank GW-01 model is comprised of a 0.5 Bscf tank communicating with a 6 Bscf tank.

Figure W.1-37 shows the parameters used to build a multi-tank material balance model of the GW-01 well. The reservoir and well parameters were obtained from the data presented in Section W.1.3. Figure W.1.38 shows the history match of the production data.

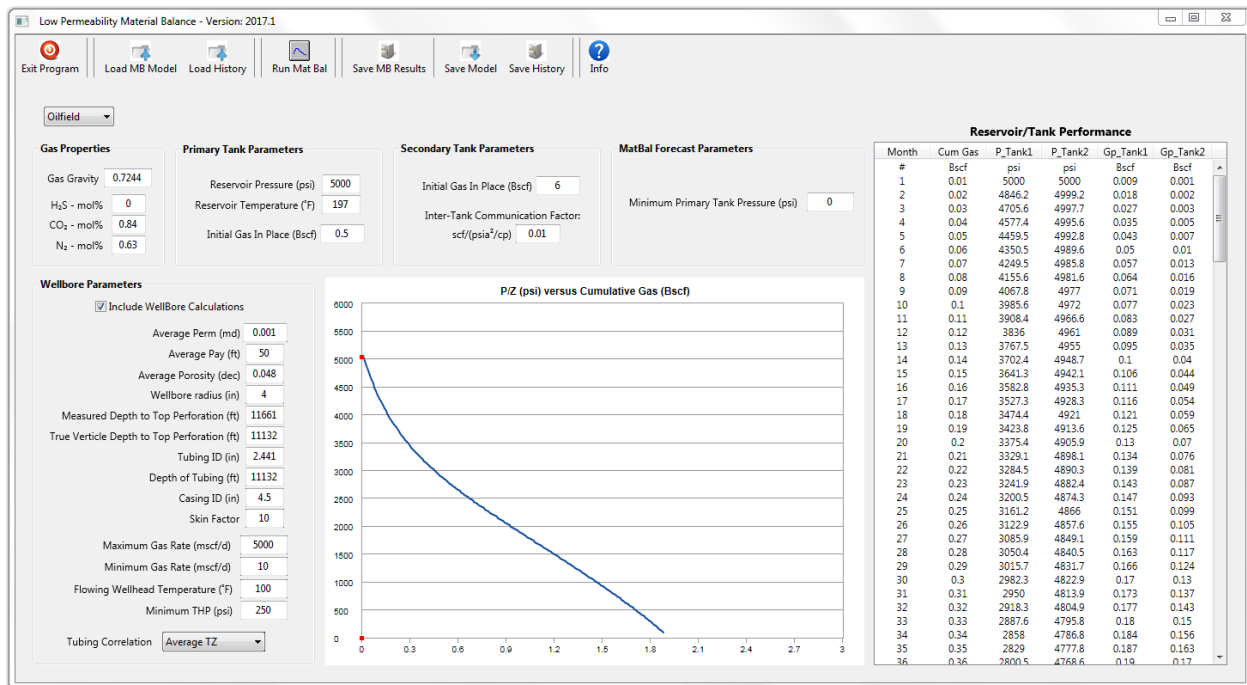


Figure W.1-37: GW-01 – Multi-Tank Gas Material Balance Model

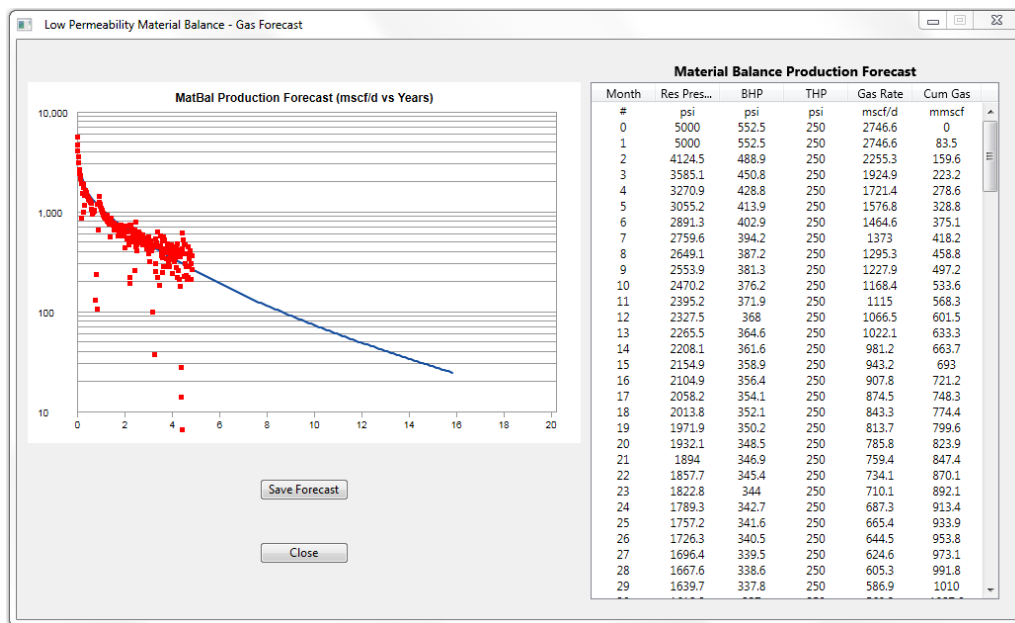


Figure W.1-38: GW-01 – Multi-Tank MB Gas Model Production History Match / Forecast

To use this multi-tank model as a forecast generator for a future well, the well and tank parameters can be modified, and a new forecast is generated using the future well parameters.

## W.2 North Sea Well Recompletion

A North Sea well stopped producing because of wellbore issues and will require a workover costing \$5mm to return the well to production. The well is a late field life well and produces with a high water cut. The problem is to determine if it is economically justifiable to perform the workover.

Figure W.2-1 shows the historical production from the well prior to shut-in.

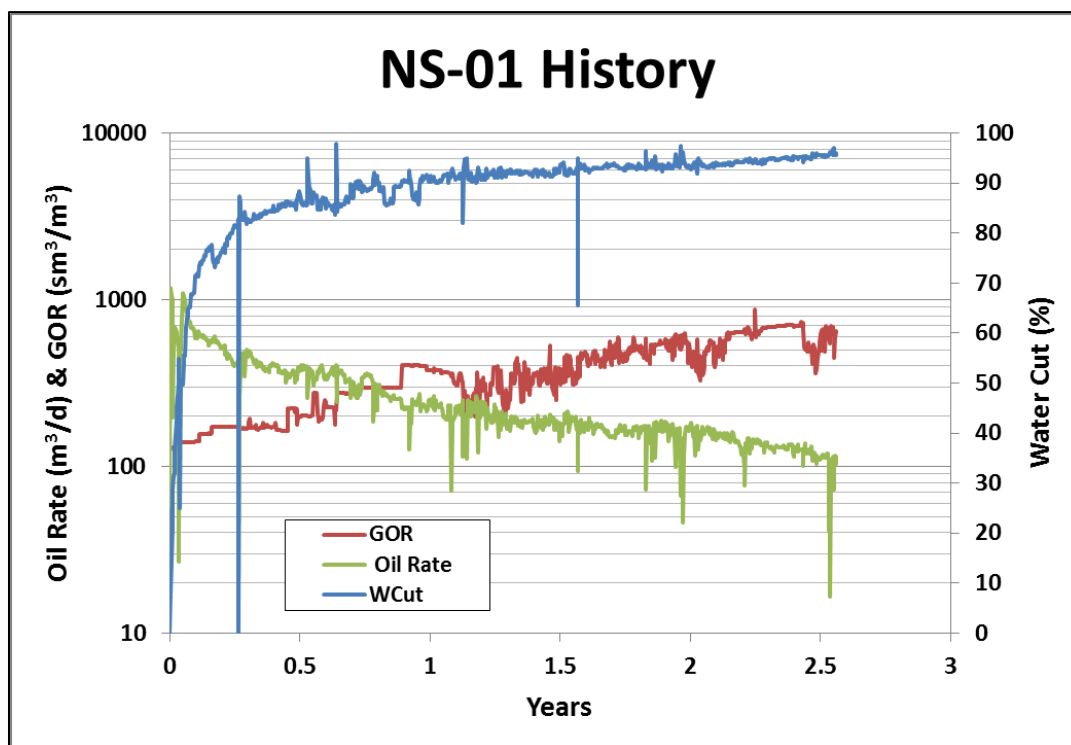


Figure W.2-1: NS-01 – Production History

The economic parameters for this analysis are as follows:

- Well workover cost: US\$5mm
- Well overhead: US\$2mm/yr
- Fixed well costs: US\$250k/yr
- Variable well costs: US\$31.45/m<sup>3</sup> (\$5/bbl)
- Transportation costs: US\$12.58/m<sup>3</sup> (\$2/bbl)
- Water disposal (injection costs): US\$3.15/m<sup>3</sup> (\$0.5/bbl)
- Gas processing fee: 0 (flared)
- Annual discount rate: 10%
- No price escalation

## W.2.1 Decline Curve Analysis

Using the 'Decline Curve Analysis' tool, the DCA parameters were determined for the daily oil production rates (Figure W.2-2 and Figure W.2-3).

PE Essentials DCA Data Import

Units: ☐ Oilfield ☒ Metric Data Input: ☐ CSV File ☒ Excel File Fluid Type: ☒ Oil ☐ Gas

Note: Gas volume in 10<sup>3</sup>sm<sup>3</sup> and Oil/Water volume in m<sup>3</sup>

Well Name/Info: NS-01 Oil Well

Excel Input Parameters

	Column	Start Row	End Row
Interval Calendar Days	c	4	975
Oil/Condensate Volume	d	4	975
Gas Volume	e	4	975
Water Volume	f	4	975
Producing Hours in Interval	g	4	975

Buttons: Import Data, Save to Database, Open Excel File, Exit

Years	m <sup>3</sup> /d	10 <sup>3</sup> m <sup>3</sup> /d	m <sup>3</sup> /d	10 <sup>3</sup> m <sup>3</sup>	10 <sup>3</sup> sm <sup>3</sup>	10 <sup>3</sup> m <sup>3</sup>
Time	Qo	Qg	Qw	CumO	CumG	CumW
0	57.6	7.2	0	0	0	0
0.01	1185.4	153.8	101	1.2	0.2	0.1
0.01	1049.3	135.1	179	2.2	0.3	0.3
0.01	1013.1	131.6	274	3.2	0.4	0.6
0.01	893.3	116	332.9	3.8	0.5	0.8
0.02	196.6	25.7	79.3	3.9	0.5	0.8
0.02	511	66.4	233	4.4	0.6	1
0.02	663.7	86.2	311	5	0.7	1.3
0.02	682.9	88.7	399	5.7	0.7	1.7
0.03	669.1	86.8	444	6.4	0.8	2.2
0.03	626.3	87.7	470	7	0.9	2.6
0.03	605.5	84.8	501	7.6	1	3.1
0.04	572.6	80.2	518	8.2	1.1	3.7
0.04	503	70.4	508	8.7	1.2	4.2
0.04	461	64.5	469.6	8.9	1.2	4.4
0.04	26.8	3.8	28	8.9	1.2	4.4
0.05	48.1	6.7	58.6	9	1.2	4.4
0.05	471	65.9	157.7	9.4	1.2	4.6
0.05	504.8	70.7	515	9.9	1.3	5.1
0.05	559.9	78.4	573	10.4	1.4	5.7
0.06	765.2	107.1	763	11.2	1.5	6.4
0.06	1096	153.4	1083	12.3	1.7	7.5
0.06	1055.5	147.7	1225	13.4	1.8	8.7
0.07	1024.9	143.5	1282	14.4	1.9	10
0.07	1013	141.8	1266	15.4	2.1	11.3
0.07	873.8	122.3	1374	16.3	2.2	12.6
0.07	869.3	121.7	1354	17.1	2.3	14
0.08	811.4	113.6	1381	17.9	2.4	15.4

Figure W.2-2: NS-01 – Import Production Data

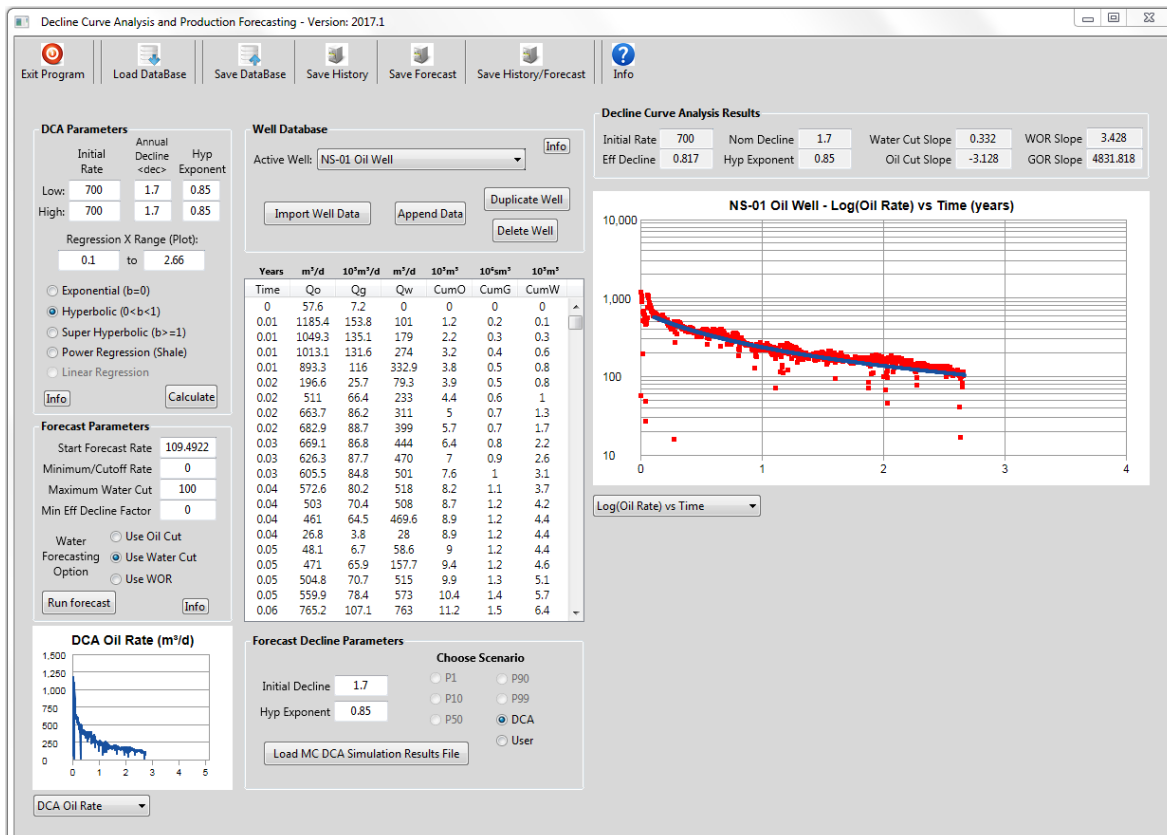


Figure W.2-3: NS-01 – Decline Curve Analysis

A high hyperbolic exponent was expected for this analysis since water injection was occurring at a reported voidage replacement ratio of 1.0.

The supplementary plots for this analysis are presented in Figure W.2-4.

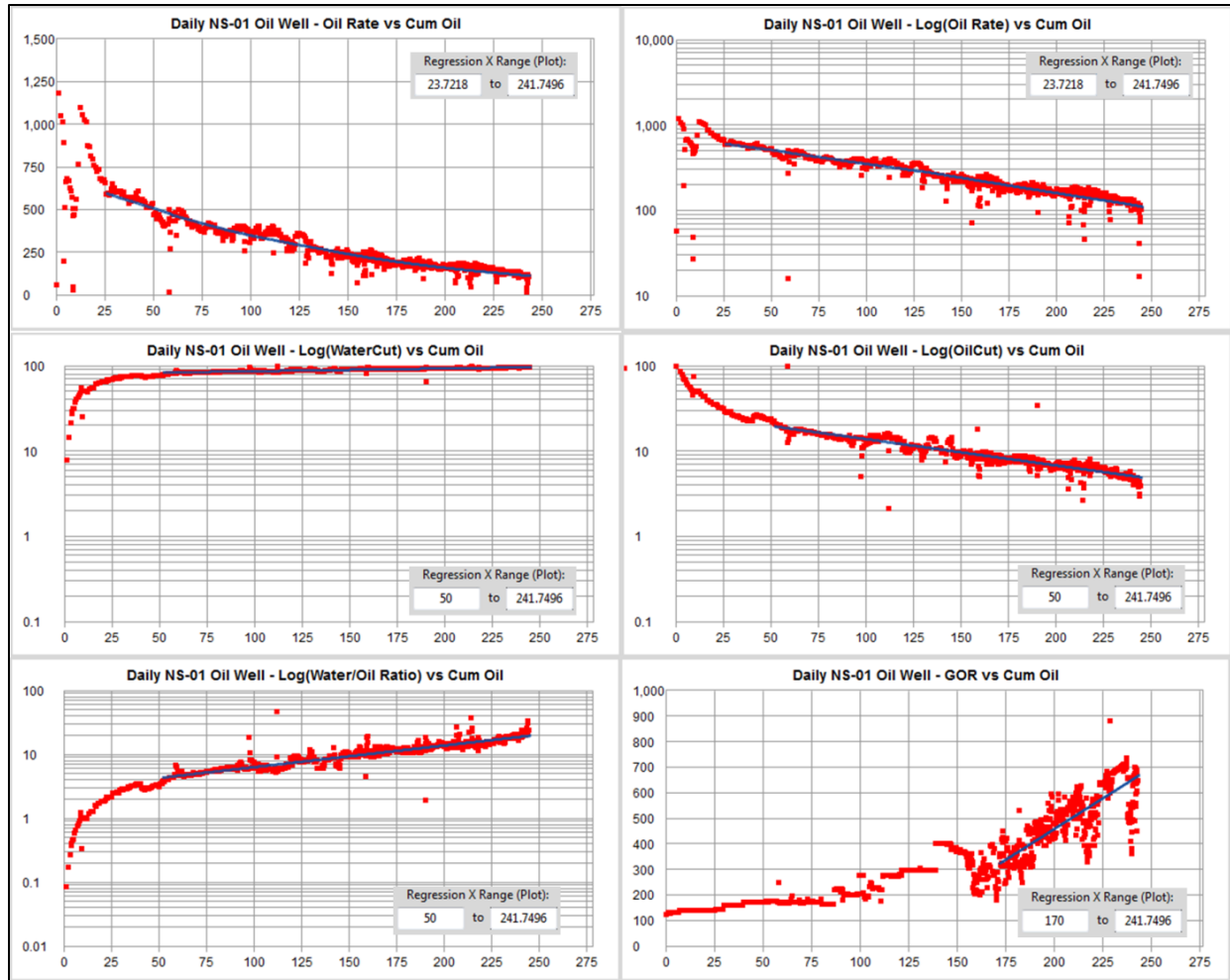


Figure W.2-4: NS-01 – Decline Curve Analysis – Supplementary Plots

The 'Monte Carlo DC Forecast' tool was used to generate P10/P50/P90/EV parameters for use in the DCA tool (Figure W.2-5). A constant seed value was entered so the results could be regenerated in the future.

The DCA results were used for the P50 input parameters.

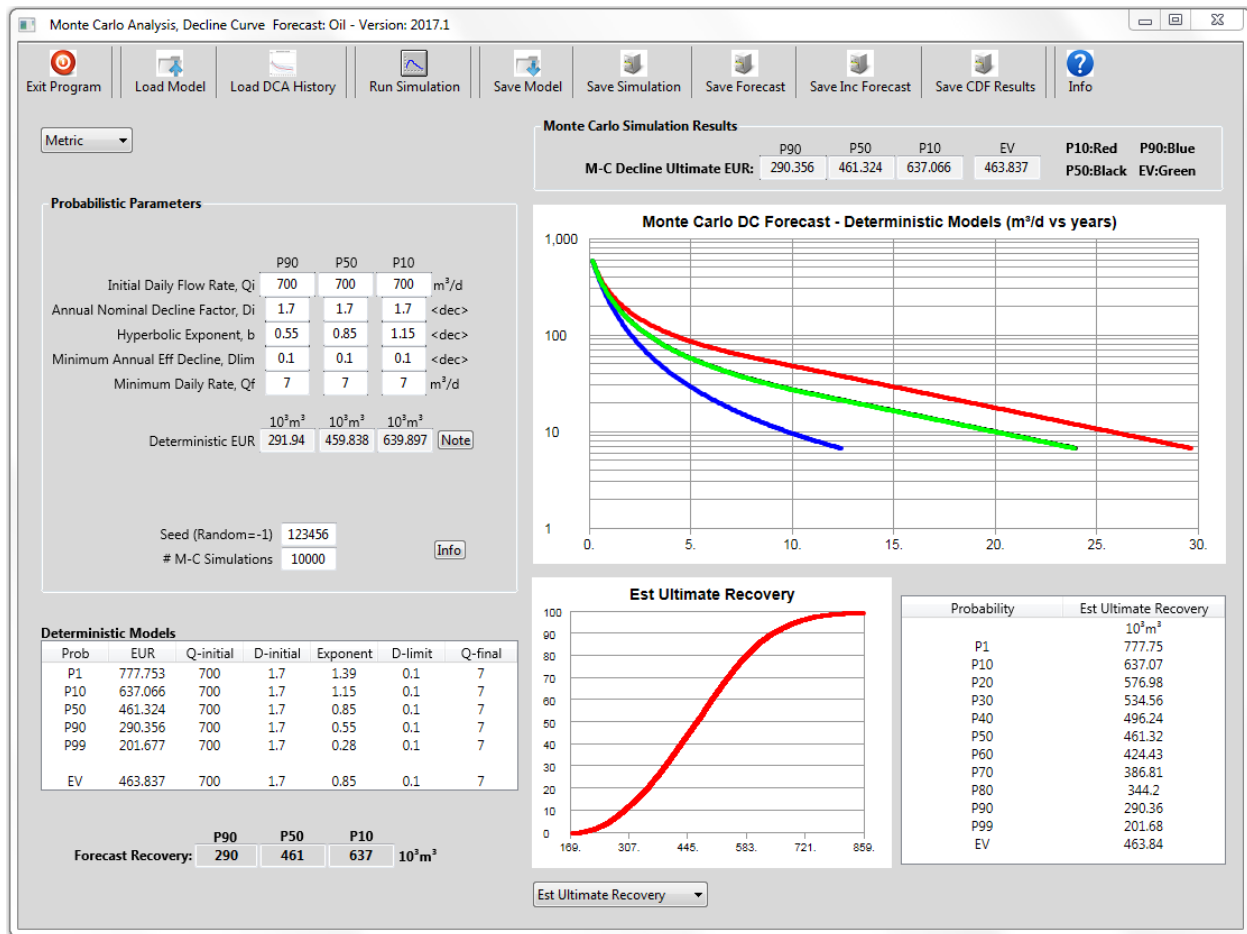


Figure W.2-5: NS-01 – Monte Carlo DC Simulation Results

Figure W.2-6 presents the Monte Carlo DC simulation results.

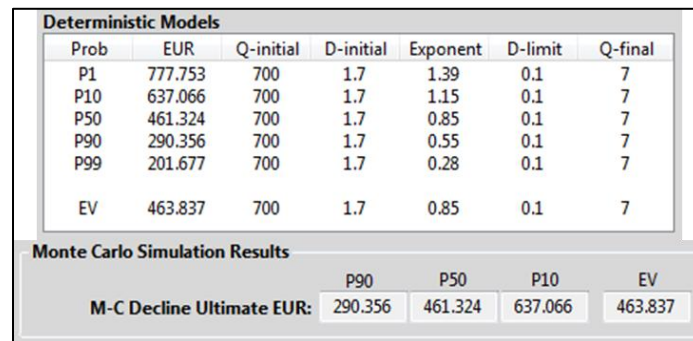


Figure W.2-6: NS-01 – Monte Carlo DC Simulation Results

The Monte Carlo DC results were transferred to the DCA tool and forecasts were generated. To generate the water production forecast, the 'Use WOR' option was implemented. The oil cut option could also have been used. Figure W.2-7 is a comparison of the oil rate, cumulative oil, GOR and water cut forecast results for the NS-01 well and Figure W.2-8 presents the final volumes.

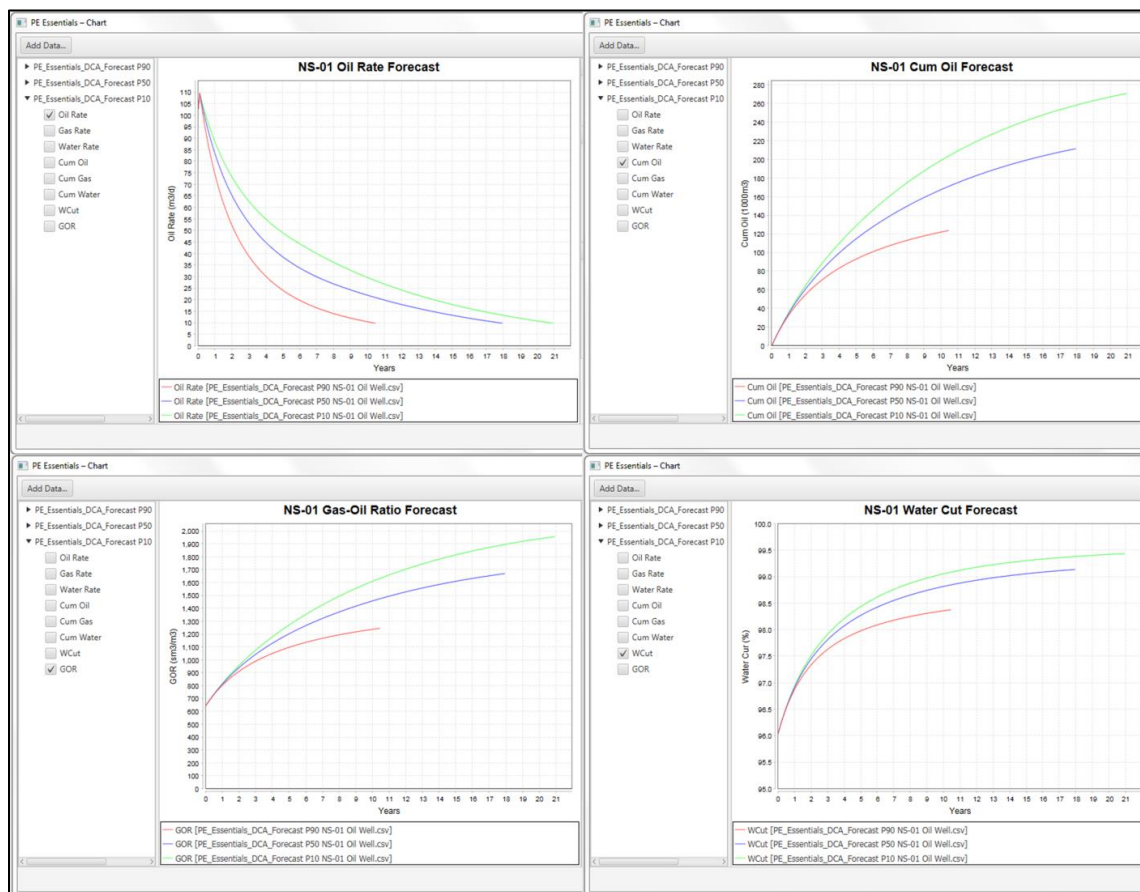


Figure W.2-7: NS-01 – Forecast Results

P10	<b>Forecast Results</b>	
	Total EUR: 512.435	Remaining EUR: 270.685
P50	<b>Forecast Results</b>	
	Total EUR: 453.181	Remaining EUR: 211.432
P90	<b>Forecast Results</b>	
	Total EUR: 365.409	Remaining EUR: 123.659

Figure W.2-8: NS-01 – Volumetric Results



## W.2.2 Scoping Economics

Using the economic parameters and the DCA forecasts, the 'Scoping Economics' tool was used to evaluate the viability of the workover. Figure W.2-9 presents the economic runs for each case and includes a plot of the oil and gas price forecast used in the analysis.

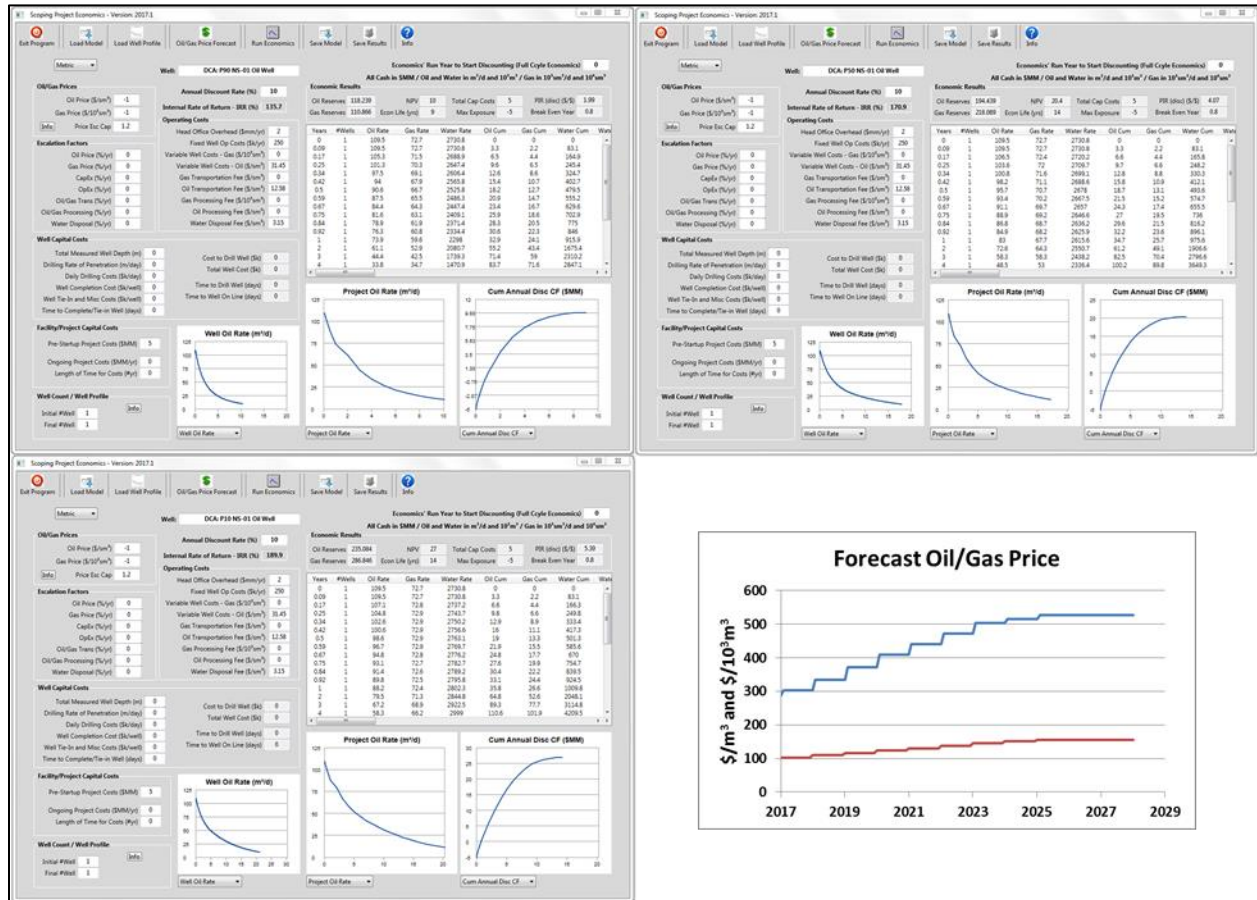


Figure W.2-9: NS-01 – Economic Evaluation

NPV (at 10%) are as follows:

- P90: US\$10.0mm
- P50: US\$20.4mm
- P10: US\$27.0mm

Remaining economic reserves are:

- P90:  $118.2 \times 10^3 \text{ m}^3$
- P50:  $194.4 \times 10^3 \text{ m}^3$
- P10:  $235.1 \times 10^3 \text{ m}^3$



Economics are based on the assumption that the well will be shut in as soon as the annual cash flow goes negative (Figure W.2-10).

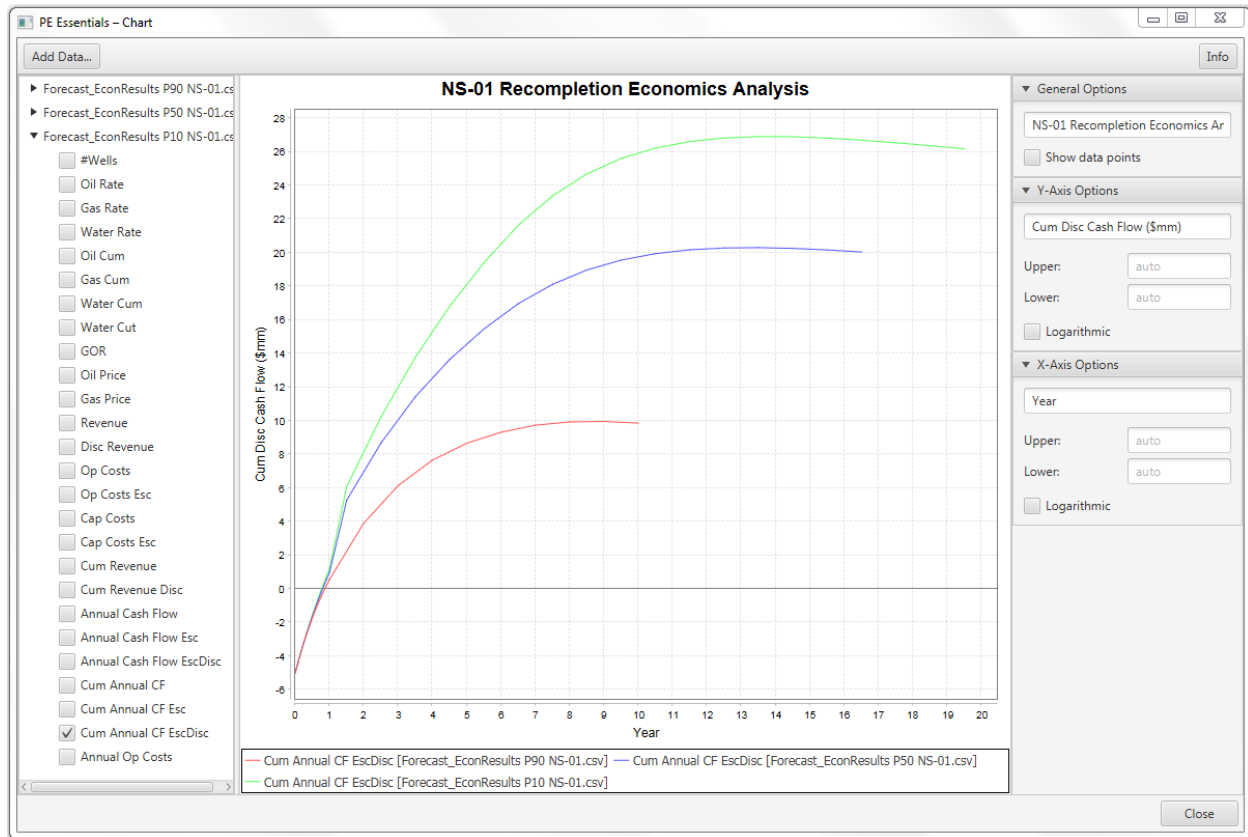


Figure W.2-10: NS-01 – Discounted Annual Cash Flow

Time to payout the recompletion costs are:

- P90: 10 months
- P50: 10 months
- P10: 9 months

Based on all the parameters included in this analysis, the economics for the recompletion of the NS-01 well are very robust. The recompletion of this well should proceed.

### W.3 Hydraulic Fracture Uplift

A single stage simulation model of a horizontal well (500 ft stage by 1000 ft well spacing) was built using the 'PE<sup>2</sup> Essentials Basic Reservoir Simulator'. A base 10-year forecast was generated then a hydraulic fracture was added to the model. Another 10-year forecast was generated and the economics of fracturing the well was evaluated.

The simulator files are 'PE\_Essentials\_BasicReservoirSimulator\_Base Horizontal Gas Well.dvx' and 'PE\_Essentials\_BasicReservoirSimulator\_Horizontal Gas Well, 1-Fracture.dvx' and are located in the "Workflow - Hydraulic Fracture Uplift\Simulator" directory.

The economic file is 'PE\_Essentials\_Economics FractureUplift.dvx' and is located in the "Workflow - Hydraulic Fracture Uplift\Economics" directory. The 2016+ oil and gas price forecast was imported from the 'Historical and Forecasted Oil and Gas Prices.xlsx' file located in the "Example Input Files\Excel Files" directory.

The model grid is 15 x 19 x 3 with x-gridding that includes a 2 ft block in the center of the grid for fracture placement (Figure W.3-1).

**Grid Properties**

**Grid Dimensions**

Number of x-grids: 15  
Number of y-grids: 19  
Number of z-grids: 3  
Reservoir Depth: 7000 ft

Dipping Reservoir ☐ 0 Degrees  
Info

Enter Faults (x/y)  
Enter Barriers (z)  
Mod X/Y Perm  
Inactivate Cells

Reset X Grid  
Reset Y Grid  
Reset Z Grid

Export Grid Properties

**X Grid Block Sizes**

Start	End	dx (ft)
1	to 2	= 75
3	to 3	= 50
4	to 4	= 25
5	to 5	= 15
6	to 6	= 6
7	to 7	= 3
8	to 8	= 2
9	to 9	= 3
10	to 10	= 6
11	to 11	= 15
12	to 12	= 25
13	to 13	= 50
14	to 15	= 75

**Y Grid Block Sizes**

Start	End	dy (ft)
1	to 1	= 150
2	to 7	= 50
8	to 12	= 20
13	to 18	= 50
19	to 19	= 150

**Z Grid Block Sizes and Layer Average Properties**

Start	End	dz (ft)	Porosity	kx	ky	kz
1	to 1	= 145	0.06	0.01	0.01	0.01
2	to 2	= 10	0.06	0.01	0.01	0.01
3	to 3	= 145	0.06	0.01	0.01	0.01

**Apply Gaussian Variability to Average Layer Properties**

Seed: -1  
+/-% for Gaussian Distribution: 25  
Apply/Remove Gaussian Variability: ☐ ☐ ☐ ☐

Store Data

Figure W.3-1: Model Grid – Single Stage Hydraulic Fracture

To place a hydraulic fracture in the well, the permeability in the grids from (8, 5) to (8, 15) was increased to 5 md (Figure W.3-2). This is equivalent to a fracture permeability of 480md assuming that the fracture width is 0.25". This is calculated by  $kh = k_f W_f$  where  $k$  is 5md,  $h$  is 2ft and  $W_f$  is 0.25" (0.0208ft).

Modify X/Y Permeability



Number of X/Y Perm Mods (max=10)

	X or Y dir	Start I	End I	Start J	End J	Start K	End K	Value
Perm Mod 1	X	8	8	5	15	1	3	5
Perm Mod 2	Y	8	8	5	15	1	3	5

Figure W.3-2: Hydraulic Fracture Input Parameters

The reservoir parameters, fluid parameters, relative permeability and wellbore parameters are presented in Figures W.3-3 to W.3-6.

Gas Reservoir Properties

Average Perm (md)	<input type="text" value="0.01"/>	Area (Acres)	<input type="text" value="11.5"/>
Average Pay (ft)	<input type="text" value="300"/>	Initial Bg (ft <sup>3</sup> /scf)	<input type="text" value="0.0040436"/>
Average Sw	<input type="text" value="0.2"/>	Initial Gas Viscosity (cp)	<input type="text" value="0.0281"/>
Average Porosity	<input type="text" value="0.06"/>	Initial Gas Z Factor	<input type="text" value="0.8877083"/>
Reservoir Length (ft)	<input type="text" value="500"/>	Initial cg (10 <sup>-4</sup> /psi)	<input type="text" value="1.83"/>
Reservoir Width (ft)	<input type="text" value="1000"/>		
Res Temperature (°F)	<input type="text" value="160"/>		
Reservoir Pressure (psi)	<input type="text" value="3850"/>		
Reservoir Well radius (in)	<input type="text" value="4"/>		
Ref Pressure Depth (ft)	<input type="text" value="7300"/>		

Figure W.3-3: Reservoir Parameters

**Gas Properties Input**

**Sales Streams**

		Gas	Liquid
H2S - mol%	0	0.49	0
N2 - mol%	0.47	1.88	0
CO2 - mol%	1.81	88.65	0
C1 - mol%	85.18	5.66	0
C2 - mol%	5.44	2.42	19.82
C3 - mol%	3.1	0.26	6.39
iC4 - mol%	0.5	0.63	15.6
nC4 - mol%	1.22	0	7.63
iC5 - mol%	0.3	0	10.43
nC5 - mol%	0.41	0	6.87
C6 - mol%	0.27	0	33.25
C7Plus - mol%	1.3	0	
$\Sigma$ Comps	100	100	100
C7Plus MW	300		

Gas MW 23.24  
 Raw Gas G 0.8024  
 Gas Pc (psi) 661.6  
 Gas Tc (°R) 385.4  
 Sales Gas G 0.638  
 GHV (btu/scf) 1086  
 Shrinkage (%) 6.2  
 Liquids (bbls/mmcf) 62.6  
 Liquid Density (°API) 60.5  
 Water (bbls/mmcf) tba

Generate Gas Components      Store Data

Figure W.3-4: Gas PVT Parameters

**Gas/Water Relative Permeability**

**Kr Exponents**

Gas Ng (G/W) 2  
 Water Nw (G/W) 2

Initial Sw 0.2  
 Krg at Sw 1  
 Residual Gas Saturation in Water, Sgr 0.1  
 Krw at Sgr 0.6  
 Pc at Sw 0  
 G/W Capillary Pressure Exponent, npg 0.5

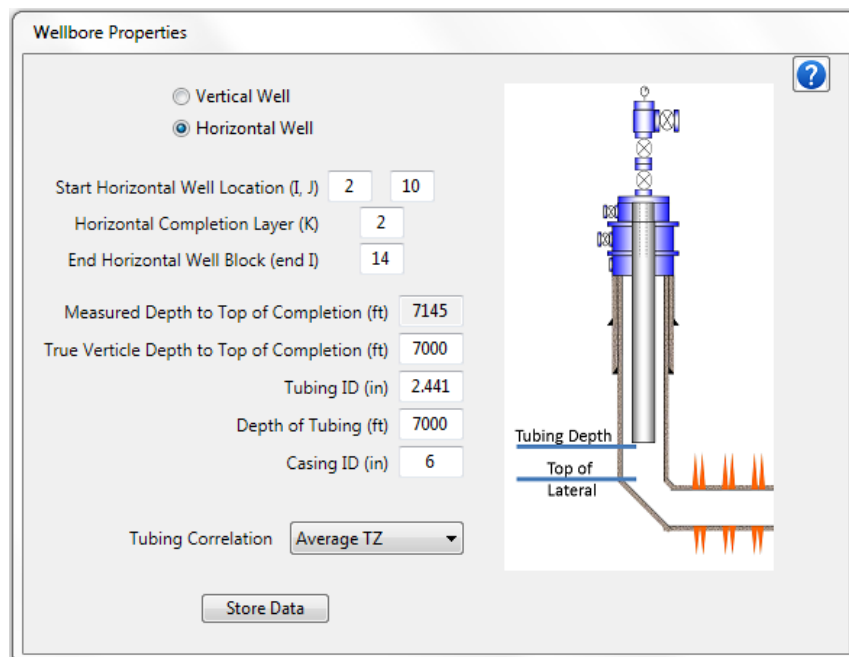
**Gas-Water Krg/Krw/Pcg**

Sw	Krg	Krw	Pcgw
0.2	1	0	0
0.235	0.9025	0.0015	0
0.27	0.81	0.006	0
0.305	0.7225	0.0135	0
0.34	0.64	0.024	0
0.375	0.5625	0.0375	0
0.41	0.49	0.054	0
0.445	0.4225	0.0735	0
0.48	0.36	0.096	0
0.515	0.3025	0.1215	0
0.55	0.25	0.15	0
0.585	0.2025	0.1815	0
0.62	0.16	0.216	0
0.655	0.1225	0.2535	0
0.69	0.09	0.294	0
0.725	0.0625	0.3375	0
0.76	0.04	0.384	0
0.795	0.0225	0.4335	0
0.83	0.01	0.486	0
0.865	0.0025	0.5415	0
0.9	0	0.6	0

**Krg/Krw vs Sw**

Default      Store Data

Figure W.3-5: Relative Permeability Parameters



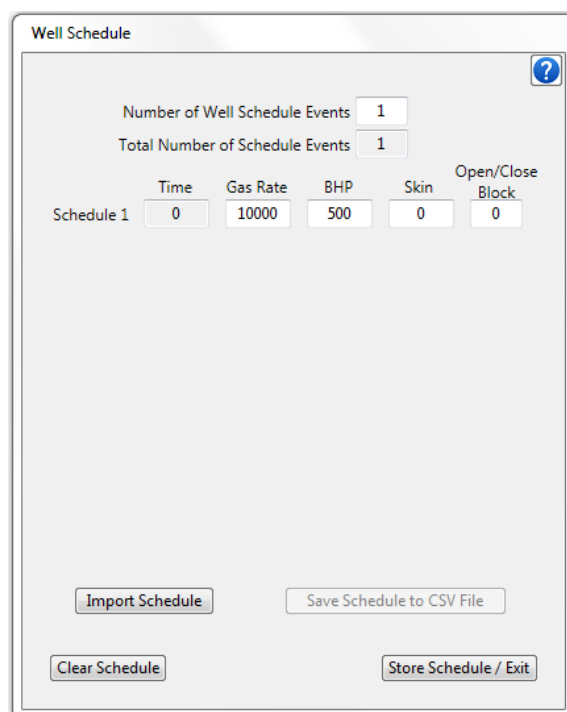
The Wellbore Properties dialog box contains the following fields and controls:

- ☐ Vertical Well
- ☒ Horizontal Well
- Start Horizontal Well Location (I, J): 2, 10
- Horizontal Completion Layer (K): 2
- End Horizontal Well Block (end I): 14
- Measured Depth to Top of Completion (ft): 7145
- True Vertical Depth to Top of Completion (ft): 7000
- Tubing ID (in): 2.441
- Depth of Tubing (ft): 7000
- Casing ID (in): 6
- Tubing Correlation: Average TZ (dropdown menu)
- Store Data button

A schematic diagram on the right shows a vertical wellbore with a horizontal lateral section at the bottom. Labels indicate 'Tubing Depth' and 'Top of Lateral'.

Figure W.3-6: Horizontal Wellbore Parameters

The lateral section of the well was placed in the center of the zone (layer 2). The entire lateral, except for block 1 and 15 were open to flow at a minimum BHP of 500 psi (Figure W.3-7).



The Well Schedule dialog box contains the following fields and controls:

- Number of Well Schedule Events: 1
- Total Number of Schedule Events: 1
- Table with 6 columns: Time, Gas Rate, BHP, Skin, Open/Close Block
- Table data for Schedule 1: Time: 0, Gas Rate: 10000, BHP: 500, Skin: 0, Open/Close Block: 0
- Buttons: Import Schedule, Save Schedule to CSV File, Clear Schedule, Store Schedule / Exit

Figure W.3-7: Well Schedule

The modeled fracture stage encompasses 11.5 acres and contains 1.7 Bscf of gas in place. Figure W.3-8 shows the production forecast for the unfractured and fractured cases.

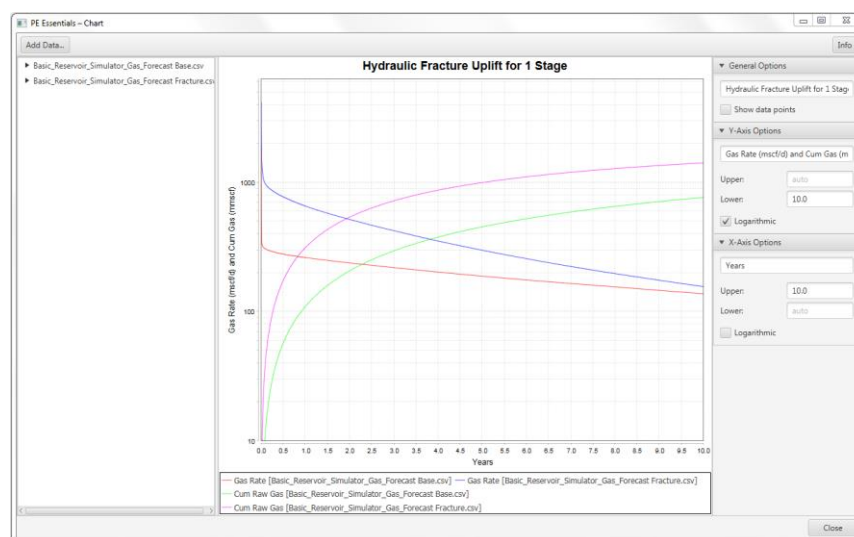


Figure W.3-8: Forecast Comparison – Unfractured vs Fractured

Two economic runs were made: unfractured (Figure W.3-9) and fractured Figure W.3-10).

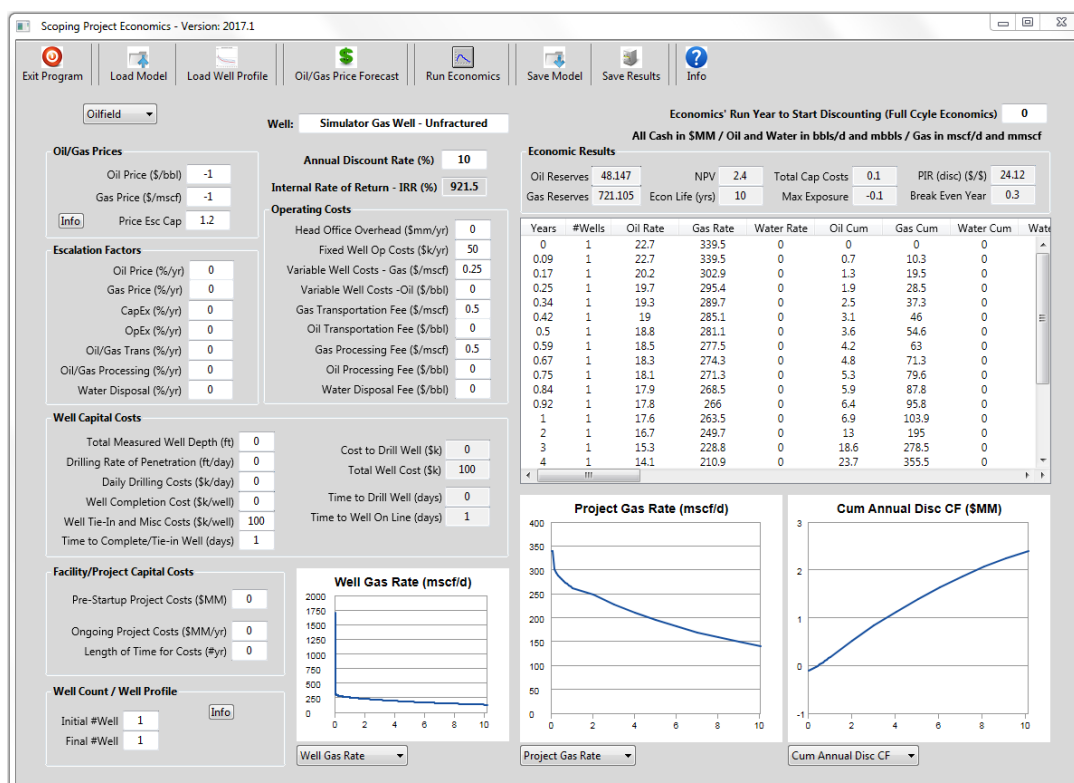


Figure W.3-9: Economic Analysis – Unfractured Case

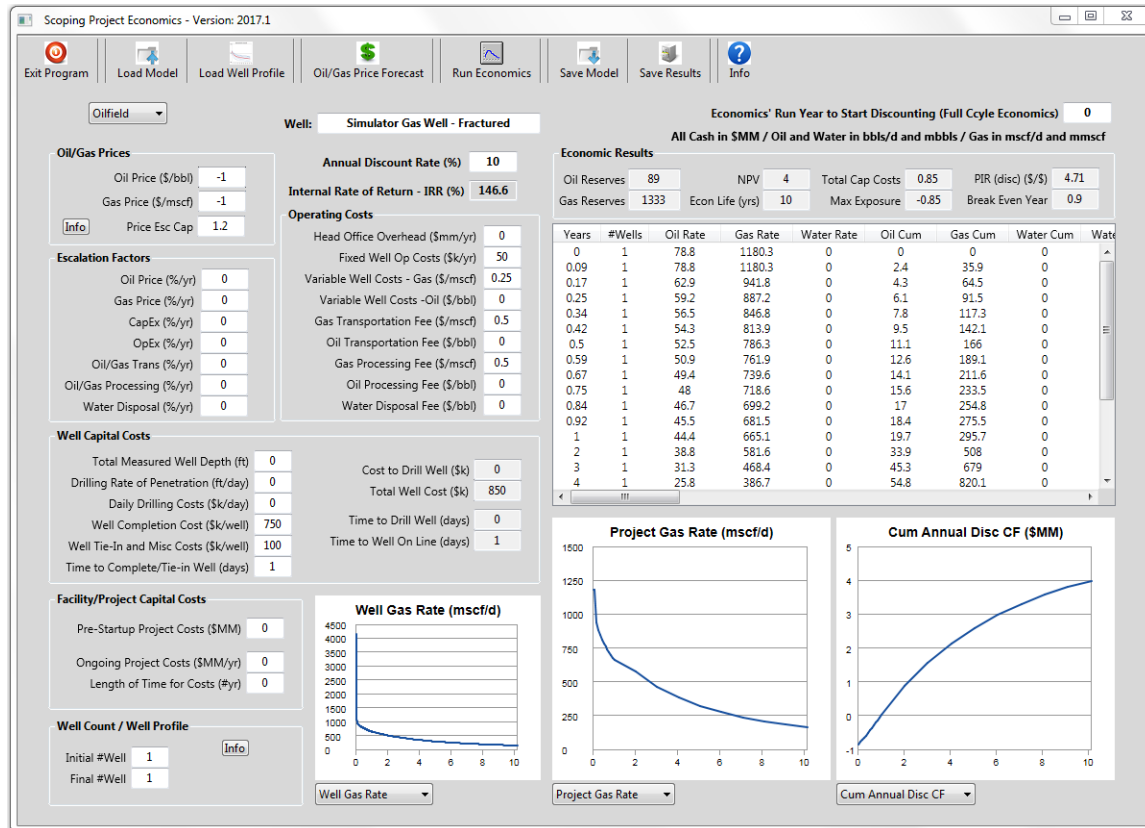


Figure W.3-10: Economic Analysis – Fractured Case

The incremental cost assumption for the fractured case is that the cost of a single hydraulic fracture stage would be \$750k. Both cases include \$100k for shared incremental costs for the completion and tie-in of the well.

A comparison of the economic results is shown in Figure W.3-11.

Unfractured	Economic Results								
	Oil Reserves	48.147		NPV	2.4	Total Cap Costs	0.1	PIR (disc) (\$/\$)	24.12
	Gas Reserves	721.105	Econ Life (yrs)	10	Max Exposure	-0.1	Break Even Year	0.3	
Fractured	Economic Results								
	Oil Reserves	89		NPV	4	Total Cap Costs	0.85	PIR (disc) (\$/\$)	4.71
	Gas Reserves	1333	Econ Life (yrs)	10	Max Exposure	-0.85	Break Even Year	0.9	

Figure W.3-11: Economic Results – Comparison

From this analysis, one hydraulic fracture stage will deliver an incremental 612 mmscf of gas over ten years; will take an additional 7 months to pay out the fracture costs; and delivers an extra \$1.6million of NPV.

## W.4 FDP: Sequential Wells vs Pad Drilling

Development of an unconventional oil field is going to be expanded with the addition of 24 wells. The operator has two rigs currently available and needs to decide whether to drill 4 pads with 6 wells on each pad or to sequentially drill each well.

For pad drilling, the two rigs would each drill one pad which is then placed on production and then the rigs would drill the third and fourth pads. In this scenario 12 wells would be placed on production initially, but up-front capital costs would be significant. For sequential drilling, the production rate would increase at a slower pace, but the up-front capital costs would be significantly reduced. To account for the delay in production start-up while the pads are being drilled a carrying cost of 5% will be added to the up-front capital cost.

For this example, the following assumptions were made:

- Statistical variations are included on the well performance parameters
- Facility costs are the same for either scenario
- Carrying costs for the pads is 5% of the capital to drill the first 2 pads
- Pad completion costs have a savings of 10% over sequential completions
- Additional \$50k/well to tie-in sequential wells to common facilities
- All other economic parameters are the same
- Facility uptime is a constant 95%
- No limits on maximum facility rate capacity
- Rig moves take 5 days for sequential drilling

### W.4.1 Production Type Curve

Using the 'Decline Curve Analysis' tool, the DCA parameters were determined for the production type curve which was available for the project (Figure W.4-1).

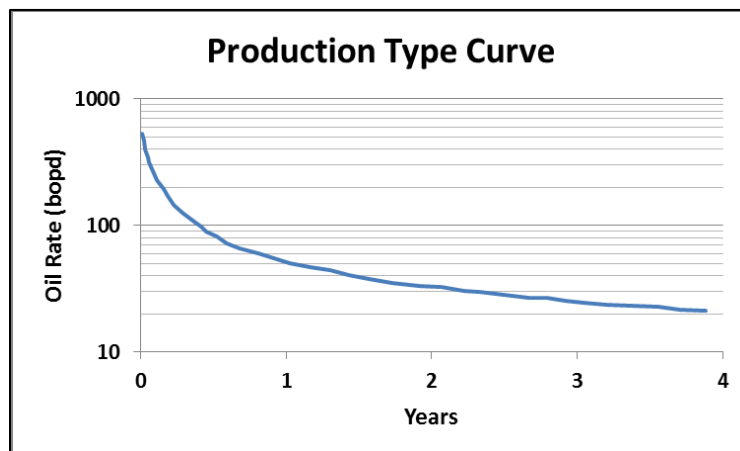


Figure W.4-1: Unconventional Oil – Production Type Curve



Figure W.4-2 shows the decline curve analysis results which were then imported into the Development Planning tool (Figure W.4-3) to generate the normalized type curve.

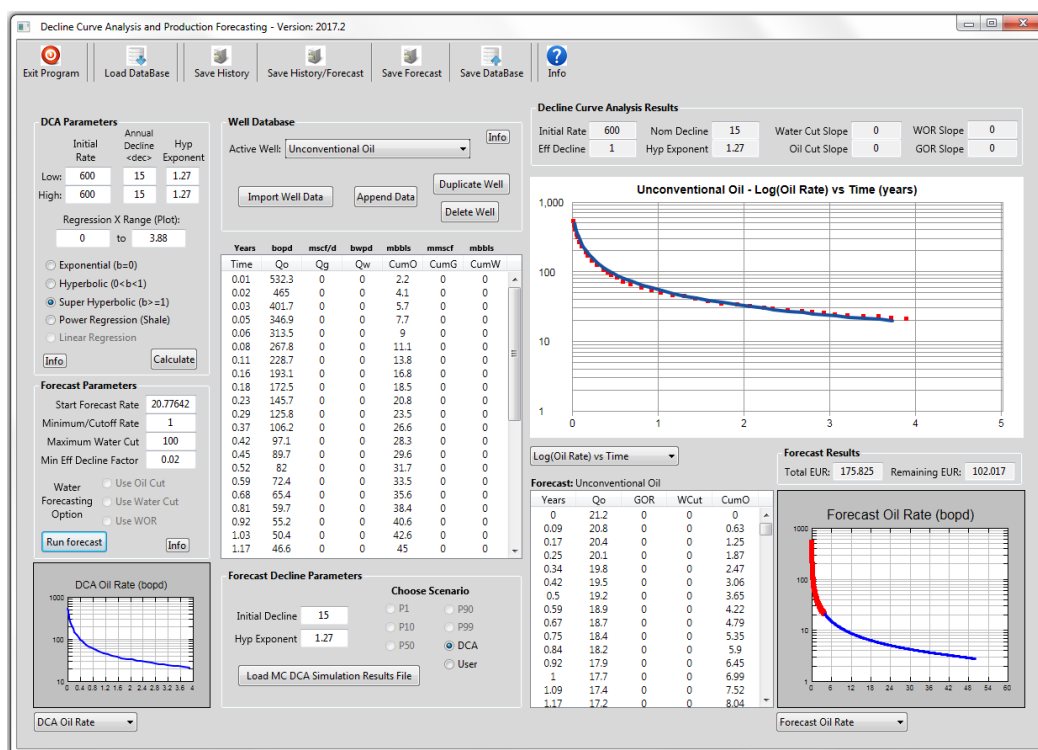


Figure W.4-2: Unconventional Oil – DCA Results

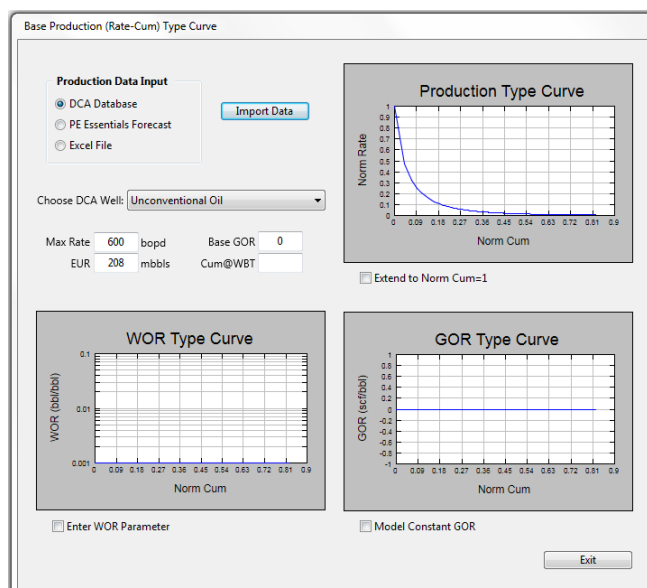


Figure W.4-3: Unconventional Oil – Type Curve

## W.4.2 Project Forecast

Figure W.4-4 shows the inputs to the Field Development Planning tool for the two scenarios.

Sequential Drilling	Pad Drilling
<b>Well Drilling and Completion Plan</b>	
Measured Well Depth (ft) 14000	Measured Well Depth (ft) 14000
Drilling Rate of Penetration (ft/day) 500	Drilling Rate of Penetration (ft/day) 500
Time to Complete/Tie-in Well (days) 5	Time to Complete/Tie-in Well (days) 0
<input type="checkbox"/> Pad Drilling: #Wells/Pad 1	<input checked="" type="checkbox"/> Pad Drilling: #Wells/Pad 6
Time to Drill Well (days) 28	Time to Drill Pad (days) 168
Time to Well On Line (days) 33	Time to Pad On Line (days) 168
<b>Rig Count / Well Count</b>	
Initial #Wells 1	Initial #Pads 2
Final #Wells 24	Final #Pads 4
Drilling Learning Rate 0 %	Drilling Learning Rate 0 %
Number of Rigs 2	Number of Rigs 2
<b>Facility Parameters</b>	
Maximum Oil Capacity 1000000 bopd	Maximum Oil Capacity 1000000 bopd
Maximum Gas Capacity 1000000 mscf/d	Maximum Gas Capacity 1000000 mscf/d
Minimum Capacity 10 bopd	Minimum Capacity 10 bopd
Start-up Month 1 (Jan = 1)	Start-up Month 1 (Jan = 1)
Start-up Year 2018	Start-up Year 2018
Average Facility Uptime 95 %	Average Facility Uptime 95 %

Figure W.4-4: Development Planning Tool – Sequential Drilling vs Pad Drilling

For both scenarios, the statistical variations were enabled for the production parameters. In both models, the Seed was set to be the same so the well productivity variations would be the same. Figure W.4-5 shows the statistical parameters used for both scenarios.

Type Curve and Productivity Distribution	
<b>Type Curve Parameters</b>	<b>Production Parameters</b>
Low Rate Factor .8	Low Perm Factor 1
Mid Rate Factor 1	Mid Perm Factor 1
High Rate Factor 1.2	High Perm Factor 1
Low Cum Factor .8	Low Pay Factor 1
Mid Cum Factor 1	Mid Pay Factor 1
High Cum Factor 1.2	High Pay Factor 1
Seed	
12345	
Exit	

Figure W.4-5: Development Planning Tool – Statistical Parameters

The forecasts are shown in Figure W.4-6 (sequential drilling) and Figure W.4-7 (pad drilling).

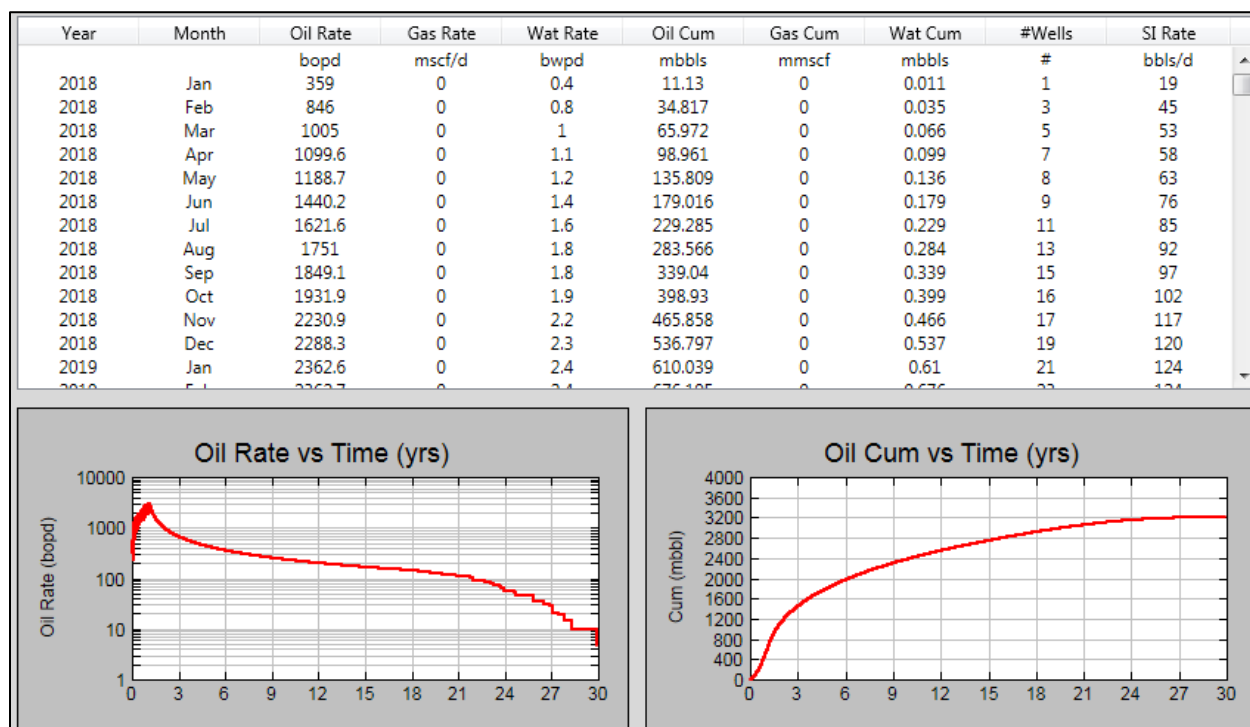


Figure W.4-6: Development Planning Tool – Sequential Drilling Forecast

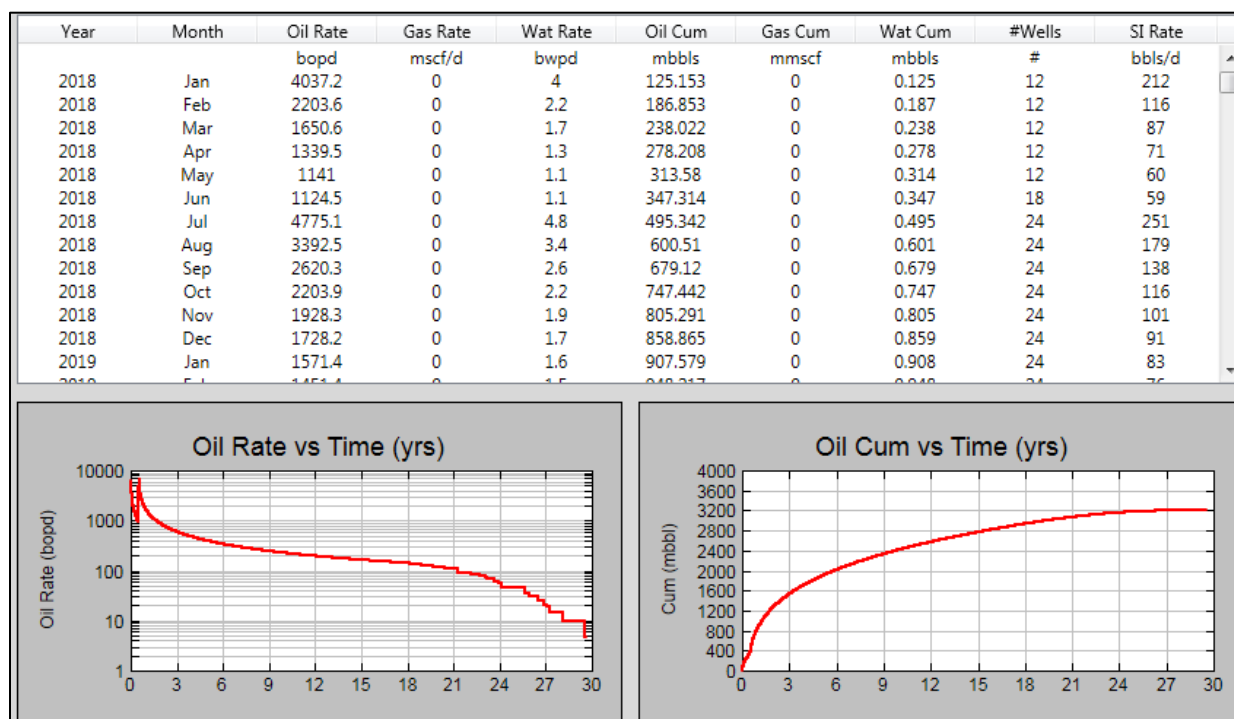


Figure W.4-7: Development Planning Tool – Pad Drilling Forecast

The forecast results are similar (Figure W.4-8) but the peak rates are significantly different.

Forecast Results			
Total OOIP (mbbls)	4943	Max Well Count	24
Final EUR (mbbls)	3215	Final Prod Wells	1
Peak Rate (bopd)	2965	Peak SI (bopd)	156
Peak Water (bwpd)	3	Forecast Years	29.9

Forecast Results			
Total OOIP (mbbls)	4943	Max Well Count	24
Final EUR (mbbls)	3215	Final Prod Wells	1
Peak Rate (bopd)	7992	Peak SI (bopd)	421
Peak Water (bwpd)	8	Forecast Years	29.6

Figure W.4-8: Development Planning Tool – Forecast Results (Top: Sequential, Bottom: Pad)

Figures W.4-8 and W.4-9 show that the main differences between the two scenarios are the peak oil rate (7992 bopd versus 2965 bopd), and the oil rate during the first year of production.

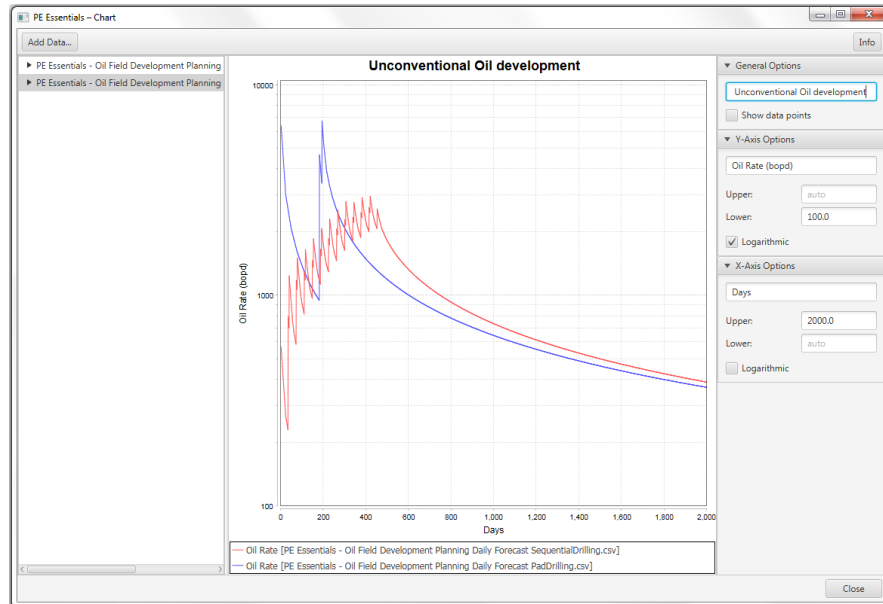


Figure W.4-9: Development Planning Tool – Forecast Comparison

The economic advantage of the rate acceleration that occurs with pad drilling may be offset by the carrying costs of the pad drilling capital.

### W.4.3 Project Economic Comparison

The economic difference between the two scenarios is assumed to be in the capital costs and the early rate profile. There should be cost savings associated with pad drilling and these are modeled as a 10% reduction in completion costs as shown in Figure W.4-10.

<b>Sequential Drilling</b>	<b>Well Capital Costs</b>			
	Total Measured Well Depth (ft)	14000	Cost to Drill Well (\$k)	1736
	Drilling Rate of Penetration (ft/day)	500	Total Well Cost (\$k)	2686
	Daily Drilling Costs (\$k/day)	62	Time to Drill Well (days)	28
	Well Completion Cost (\$k/well)	900	Time to Well On Line (days)	33
	Well Tie-In and Misc Costs (\$k/well)	50		
	Time to Complete/Tie-in Well (days)	5		
<b>Pad Drilling</b>	<b>Well Capital Costs</b>			
	Total Measured Well Depth (ft)	14000	Cost to Drill Well (\$k)	1736
	Drilling Rate of Penetration (ft/day)	500	Total Well Cost (\$k)	2546
	Daily Drilling Costs (\$k/day)	62	Time to Drill Well (days)	28
	Well Completion Cost (\$k/well)	810	Time to Well On Line (days)	28
	Well Tie-In and Misc Costs (\$k/well)	0		
	Time to Complete/Tie-in Well (days)	0		

Figure W.4-10: Scoping Economics Tool – Capital Comparison

The pad drilling economic model also included a 'Pre-Startup Project Cost' of \$1.527million which represents a 5% carrying cost on the \$30.552million required to pre-drill the first two pads (\$2.546million/well \* 12wells).

The economic analysis results (NPV10) of the two scenarios is presented in Figure W.4-11.

<b>Sequential Drilling</b>	<b>Economic Results</b>					
	Oil Reserves	3200	NPV	35.6	Total Cap Costs	64.46
	Gas Reserves	0	Econ Life (yrs)	27	Max Exposure	-19.42
					PIR (disc) (\$/\$)	0.55
					Break Even Year	4
<b>Pad Drilling</b>	<b>Economic Results</b>					
	Oil Reserves	3204	NPV	37.7	Total Cap Costs	62.63
	Gas Reserves	0	Econ Life (yrs)	27	Max Exposure	-37.18
					PIR (disc) (\$/\$)	0.6
					Break Even Year	3

Figure W.4-11: Scoping Economics Tool – Economic Comparison

Overall, the economics are similar: IRR for the sequential scenario is 27% and IRR for the pad scenario is 28.7%. One potentially significant difference between the two scenarios is that the pad drilling scenario has a 3-year payout of all its costs, including carrying costs, versus a 4-year payout for the sequential drilling scenario. This could be significant because of the rapid decline in oil rate evident from the type curve – the earlier payout would reduce the project risk.

For information purposes, Figure W.4-12 shows the economic run of the pad drilling scenario.

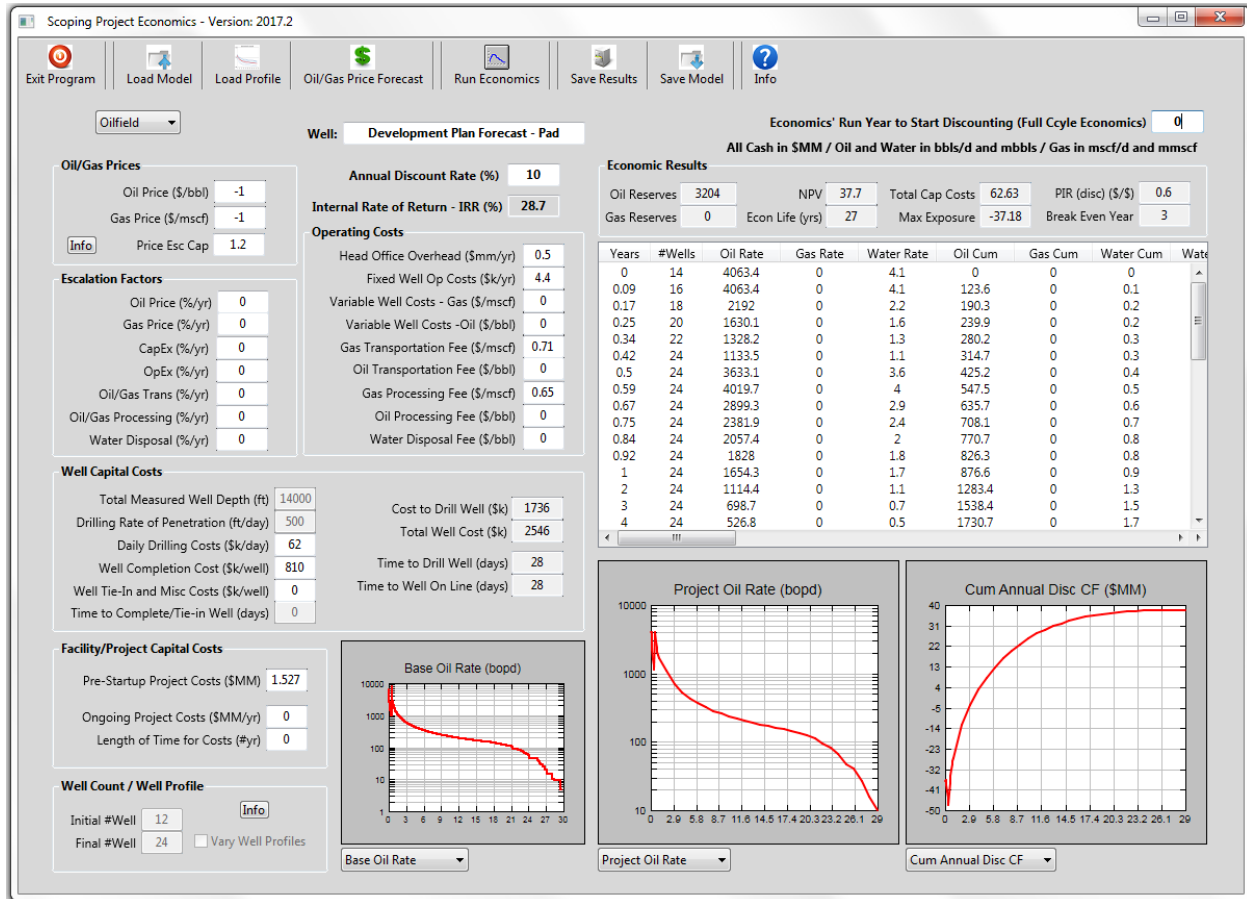


Figure W.4-12: Scoping Economics Tool – Economic Analysis of the Pad Drilling Scenario

All files used in this analysis are located in the “Workflow\Unconventional Oil Example” directory.

## W.5 Multi-Frac/NoFrac Gas Well

NOTE - The grid input limitations for the current version of the PE<sup>2</sup> Essentials Basic Reservoir Simulator will allow only 7 hydraulic fractures to be included in a model, assuming 1 grid block separating the fracture grid. This is not a limitation of the simulator but of the PE<sup>2</sup> Essentials input interface. This was designed because an IMPES simulator is not well suited to massive, complex models. It would be better to model a single fracture stage and upscale the results as done in the PE<sup>2</sup> Essentials Unconventional Forecast tool and as demonstrated in Appendix W.3. Nevertheless, as an exercise, a horizontal gas well containing 7 hydraulic fractures was built and forecast results were compared to an unfractured horizontal well.

For this exercise, the simulator files are located in the “Workflow - Multi-Frac Horizontal Well” directory. The two models have the same grid structure. ‘PE\_Essentials\_BasicReservoirSimulator\_No Fracs, k=0.007.dvx’ is the base model and ‘PE\_Essentials\_BasicReservoirSimulator\_7 Fracs, k=0.007 FCD=2.4, xf=300ft.dvx’ is the fractured well model. A fracture design model, ‘PE\_Essentials\_Hydraulic\_Fracture\_Analysis.dvx’, was used to determine fracture parameters.

The horizontal gas well model has a 29x19x1 grid (Figure W.5-1) with uniform permeability of 0.007md and porosity of 0.06.

**Grid Properties**

**Grid Dimensions**

Number of x-grids: 29  
 Number of y-grids: 19  
 Number of z-grids: 1  
 Reservoir Depth: 7000 ft

Dipping Reservoir ☐ 0 Degrees  
 Info

Enter Faults (x/y)  
 Enter Barriers (z)  
 Mod X/Y Perm  
 Inactivate Cells

Reset X Grid  
 Reset Y Grid  
 Reset Z Grid

Export Grid Properties

**X Grid Block Sizes**

Start	End	dx (ft)
1	to 2	= 250
3	to 3	= 2
4	to 6	= 100
7	to 7	= 2
8	to 10	= 100
11	to 11	= 2
12	to 14	= 100
15	to 15	= 2
16	to 18	= 100
19	to 19	= 2
20	to 22	= 100
23	to 23	= 2
24	to 26	= 100
27	to 27	= 2
28	to 29	= 250

**Y Grid Block Sizes**

Start	End	dy (ft)
1	to 1	= 150
2	to 7	= 50
8	to 12	= 20
13	to 18	= 50
19	to 19	= 150

**Z Grid Block Sizes and Layer Average Properties**

Start	End	dz (ft)	Porosity	kx	ky	kz
1	to 1	= 300	0.06	0.007	0.007	0.007

**Apply Gaussian Variability to Average Layer Properties**

Seed: -1

+/-% for Gaussian Distribution: Porosity: 25, kx: 25, ky: 25, kz: 25

Apply/Remove Gaussian Variability: ☐ ☐ ☐ ☐

Build Grid

Figure W.5-1: Basic Reservoir Simulator – Model Grid

The grid was set up with three grid blocks between the fracture grids.

The PE<sup>2</sup> Essentials ‘Hydraulic Fracture Design’ tool was used to evaluate fracture parameters for this model (Figure A2-5.2).

Figure W.5-2: Hydraulic Fracture Design – Multi-Frac Well

The fracture design indicated that for a fracture half length,  $x_f$ , of ~300ft, the optimum FCD would be 2.4. For IMPES stability, the model’s fracture grid width ( $dy$ ) was set to 2ft so the equivalent grid permeability for a 300ft model fracture would be 2.5md as calculated below.

$$k_f w_f = \text{FCD } k x_f$$

$$k_f = (2.4)(0.007)(300) / 2$$

$$k_f = 2.5\text{md}$$

Figure W.5-3 shows the input fracture parameters for the model.



**Modify X/Y Permeability**

Number of kx/ky Perm Mods (max=10)

	X,Y or XY	Start I	End I	Start J	End J	Start K	End K	Value
Perm Mod 1	xy	3	3	3	17	1	1	2.5
Perm Mod 2	xy	7	7	3	17	1	1	2.5
Perm Mod 3	xy	11	11	3	17	1	1	2.5
Perm Mod 4	xy	15	15	3	17	1	1	2.5
Perm Mod 5	xy	19	19	3	17	1	1	2.5
Perm Mod 6	xy	23	23	3	17	1	1	2.5
Perm Mod 7	xy	27	27	3	17	1	1	2.5

Figure W.5-3: Basic Reservoir Simulator – Model Fractures

Figure W.5-4 shows the x-y grid and Figure W.5-5 shows the permeability distribution for the multi-frac well.

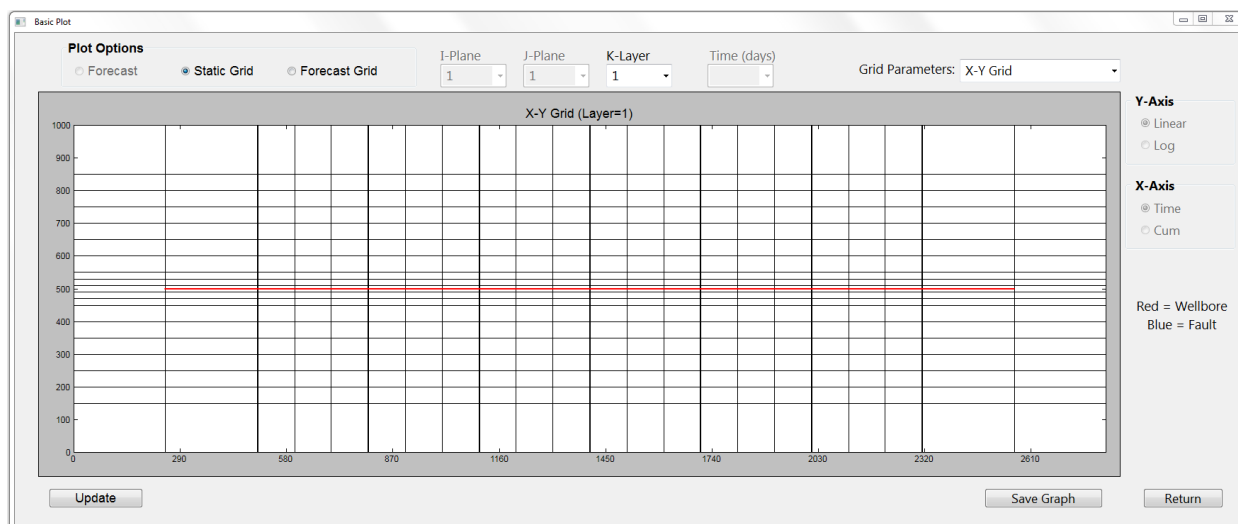


Figure W.5-4: Basic Reservoir Simulator – Model Grid

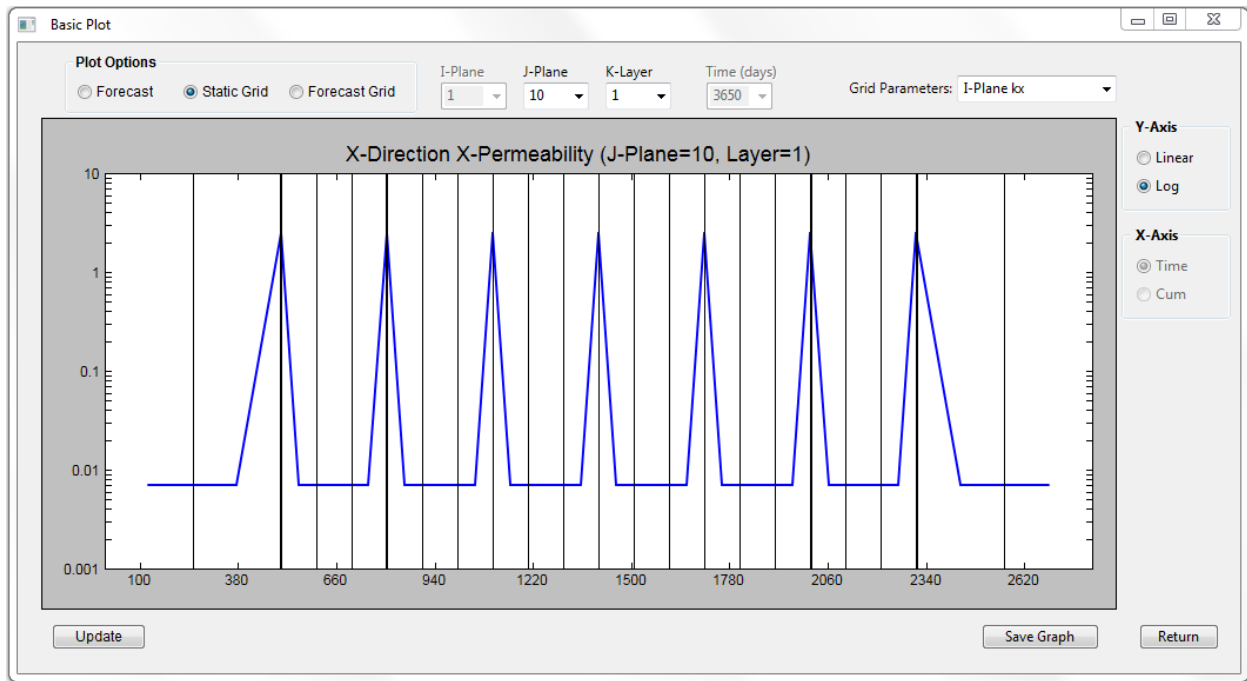


Figure W.5-5: Basic Reservoir Simulator – Fracture Model permeability

The reservoir parameters for the two models are the same except for the resulting average permeability (Figure W.5-6).

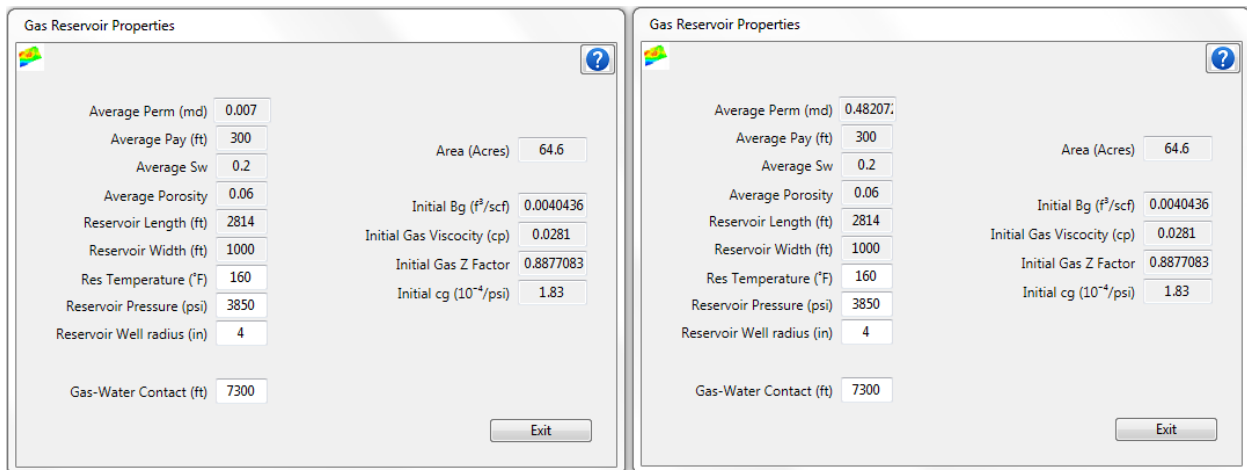


Figure W.5-6: Reservoir Parameters (Left: No Fracture, Right: Fractured)

The lateral section of the well was placed in the center of the layer (Figure W.5-7). The entire lateral, except for block 1 and 29 were open to flow at a minimum BHP of 500 psi (Figure W.5-8).

**Wellbore Properties**

☐ Vertical Well  
☒ Horizontal Well

Start Horizontal Well Location (I, J)    
 Horizontal Completion Layer (K)   
 End Horizontal Well Block (end I)

Measured Depth to Top of Completion (ft)   
 True Vertical Depth to Top of Completion (ft)   
 Tubing ID (in)   
 Depth of Tubing (ft)   
 Casing ID (in)

Tubing Correlation

The schematic diagram on the right shows a vertical wellbore with a horizontal lateral section at the bottom. Labels indicate 'Tubing Depth' and 'Top of Lateral'.

Figure W.5-7: Basic Reservoir Simulator – Well Model

**Well Schedule**

Number of Well Schedule Events   
 Total Number of Schedule Events

	Time	Gas Rate	BHP	Skin	Open/Close Block
Schedule 1	0	100000	500	0	0

Figure W.5-8: Basic Reservoir Simulator – Well Schedule

A 10-year forecast was generated for each model incorporating the 'Save Simulation Run Data' option for plotting with PE<sup>2</sup> Essentials Chart. The forecast results (Figures W.5-9 and W.5-10) indicate that the fractured well model recovered 82.3% of the gas in place versus 55.2% for the unfractured well model.

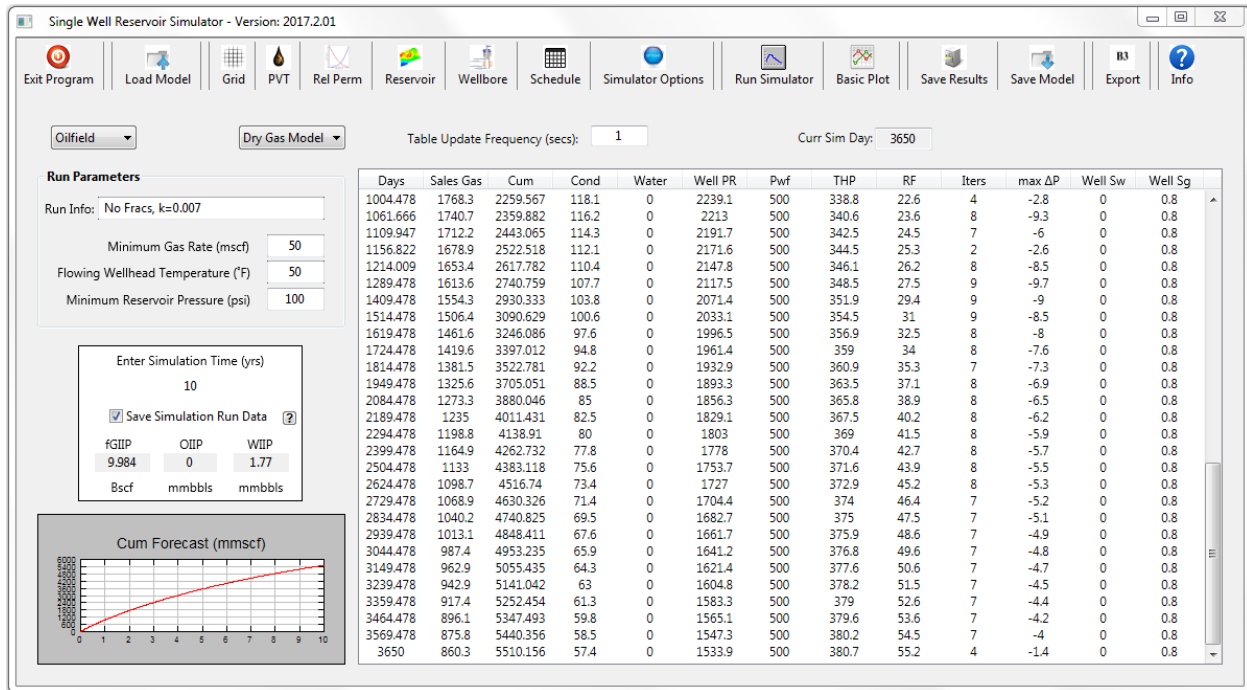


Figure W.5-9: Basic Reservoir Simulator – Non-Fractured Well Forecast

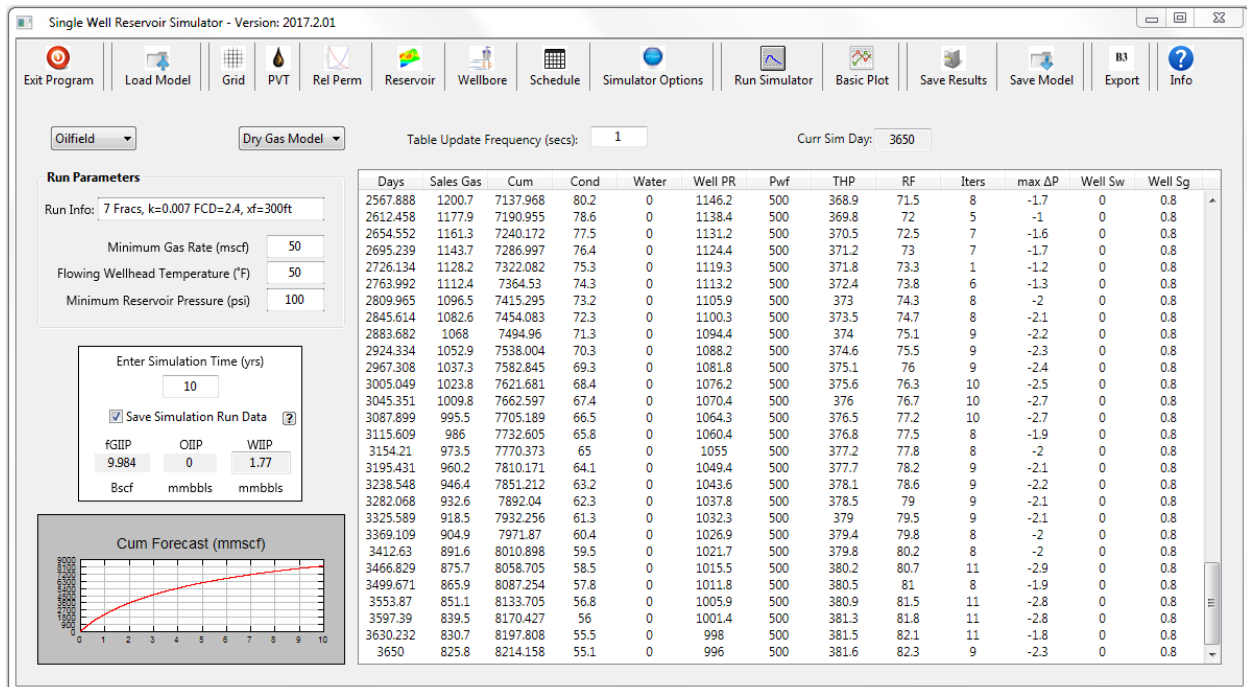


Figure W.5-10: Basic Reservoir Simulator – Fractured Well Forecast

Figures W.5-11 and W.5-12 show a comparison of the pressure profile along the wellbore at 102 days and at the end of the forecast, respectively. The top plot is for the unfractured well and the lower plot is for the fractured well.

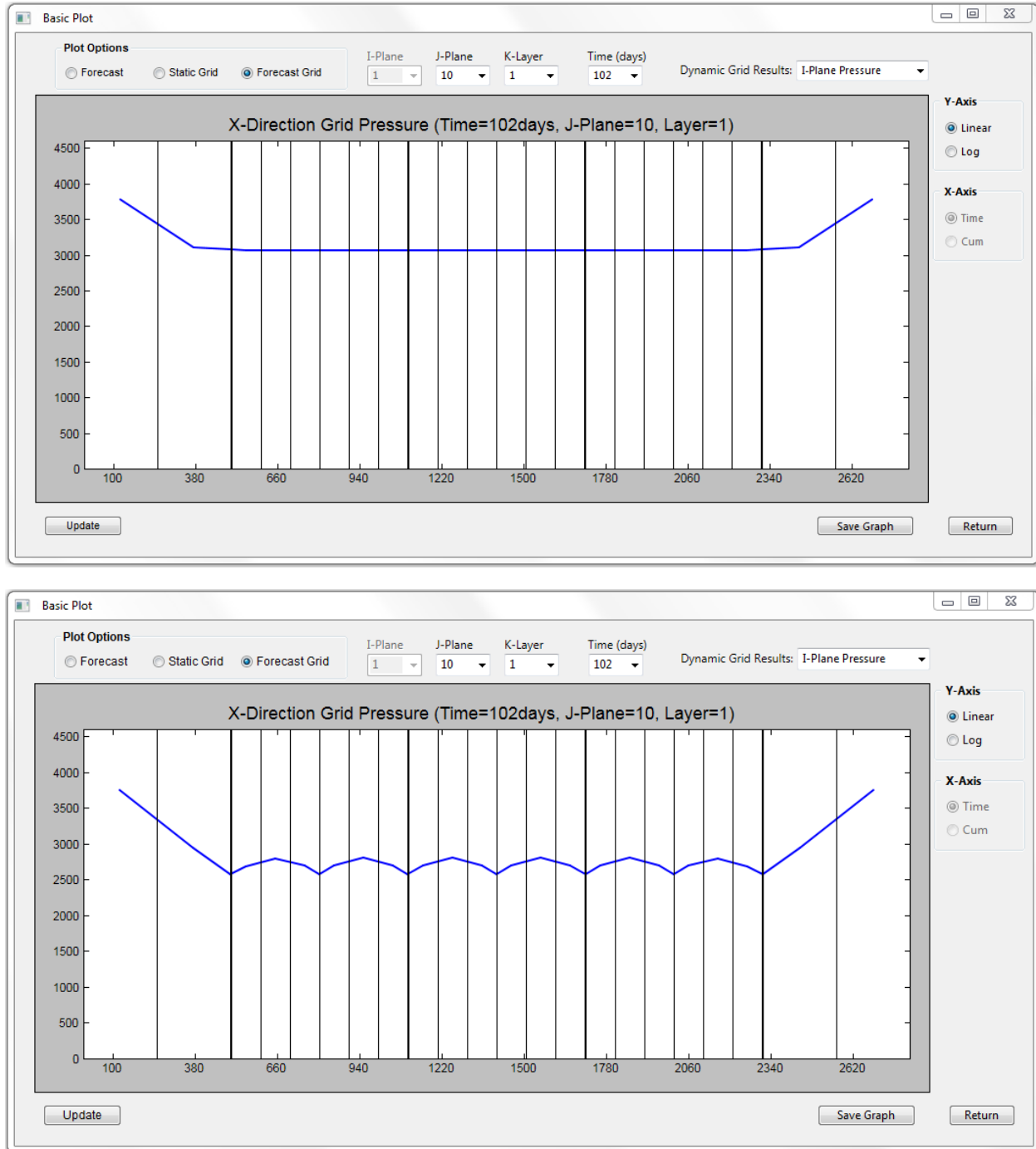


Figure W.5-11: Basic Reservoir Simulator – Wellbore Grid Pressure, 102 days

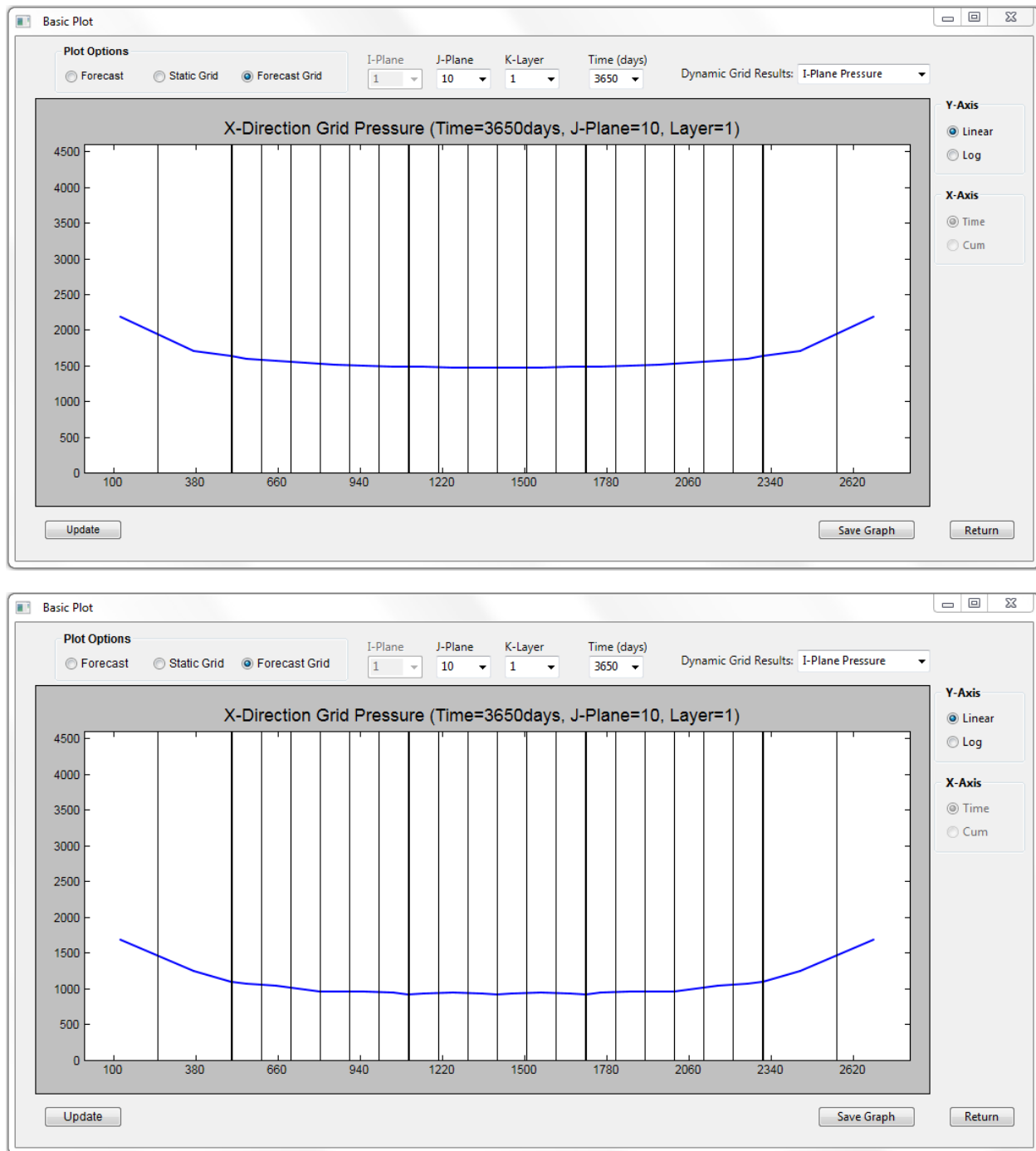


Figure W.5-12: Basic Reservoir Simulator – Wellbore Grid Pressure, 3650 days

Figure W.5-12 indicates that the reservoir grid pressure along the lateral at the end of the forecast was significantly less for the fractured well than for the unfractured well, as expected.

PE<sup>2</sup> Essentials Chart was used to compare the two forecasts. The run files were imported into Chart and the two forecasts plotted for comparison (Figure W.5-13).

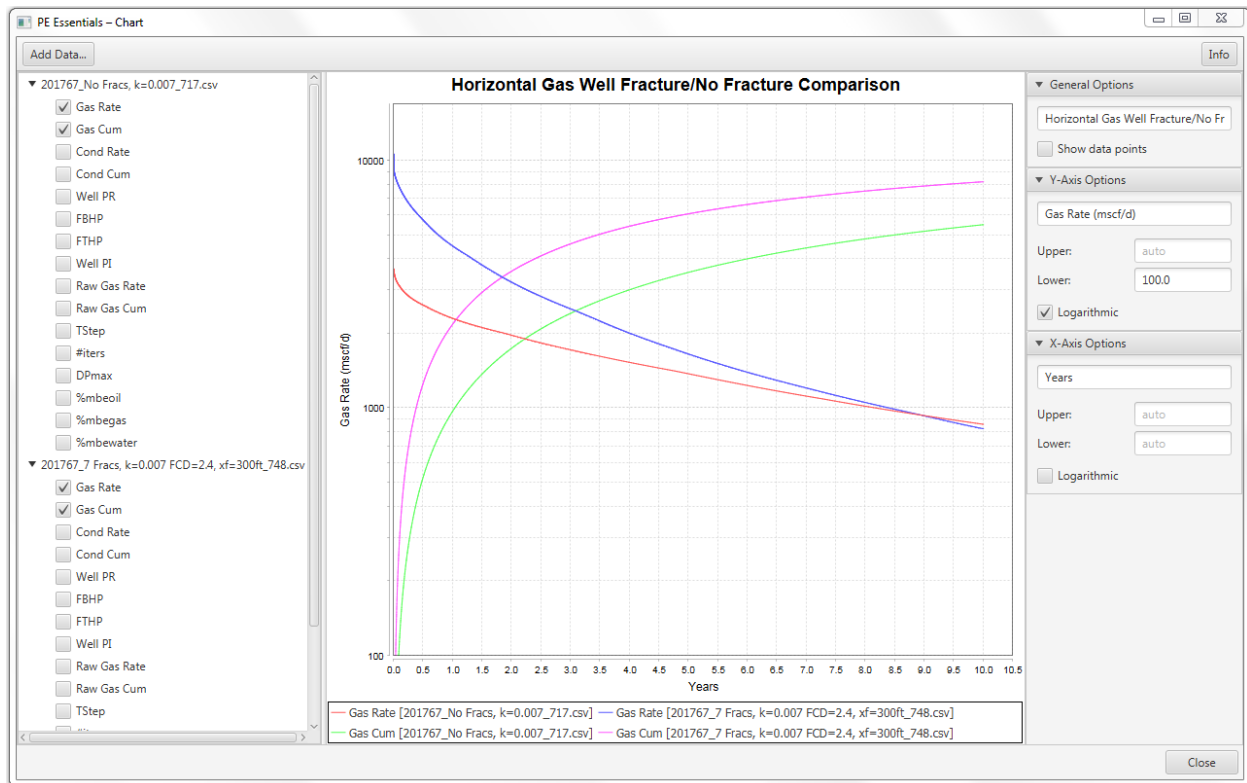


Figure W.5-13: Chart – Rate Comparison, Fractured vs Non-Fractured Well

Figure W.5-13 shows some of the rate acceleration component that is evident in all fractured wells. This is apparent by the gas rate for the fractured well falling below the gas rate for the unfractured well after 9 years of production.

## W.6 Single-Well Simulation Models

A single well simulation model can be used to look at a number of sensitivities associated with production performance and recovery characteristics of various parameters. This section presents a number of models and evaluates the sensitivity of one parameter for each model.

Except for GOC and OWC, all models have the same rock and fluid characteristics as shown in Figure W.6-1.

Figure W.6-1: General Reservoir and Fluid Parameters

The grids were set appropriately for each sensitivity case.

The models used in this section are included in the “Workflow - Single Well Sensitivity Models” directory.

### W.6.1 Vertical Oil Well – Drainage Area Sensitivity

The production performance of a vertical well was evaluated to evaluate the effects of drainage area. This type of study may be useful in the case of a new discovery with limited available data. A 15x15x5 pseudo-radial grid was built for an oil well in the center of the field. The well was completed in all five layers. There is no oil/water contact and the reservoir was initially above the bubble point pressure (no gas cap). This comparison varied only the drainage area from 160 acres to 640 acres (refer to Figures W.6-2 and W.6-3).



Grid Properties

**Grid Dimensions**

Number of x-grids: 15  
 Number of y-grids: 15  
 Number of z-grids: 5  
 Reservoir Depth: 5332 ft

Dipping Reservoir ☐ 0 Degrees

**X Grid Block Sizes**

Start	End	dx (ft)
1	to 2	= 230
3	to 3	= 350
4	to 4	= 250
5	to 5	= 150
6	to 6	= 70
7	to 7	= 30
8	to 8	= 20
9	to 9	= 30
10	to 10	= 70
11	to 11	= 150
12	to 12	= 250
13	to 13	= 350
14	to 15	= 230

**Y Grid Block Sizes**

Start	End	dy (ft)
1	to 2	= 230
3	to 3	= 350
4	to 4	= 250
5	to 5	= 150
6	to 6	= 70
7	to 7	= 30
8	to 8	= 20
9	to 9	= 30
10	to 10	= 70
11	to 11	= 150
12	to 12	= 250
13	to 13	= 350
14	to 15	= 230

**Z Grid Block Sizes and Layer Average Properties**

Start	End	dz (ft)	Porosity	kx	ky	kz
1	to 1	= 5	0.151	10	10	1
2	to 2	= 5	0.165	20	20	2
3	to 3	= 5	0.173	30	30	3
4	to 4	= 5	0.1591	17	15	1.5
5	to 5	= 5	0.182	35	18.2	1.82

**Apply Gaussian Variability to Average Layer Properties**

Seed: -1  
 +/-% for Gaussian Distribution: Porosity: 25, kx: 25, ky: 25, kz: 25  
 Apply/Remove Gaussian Variability: ☐ ☐ ☐ ☐

Figure W.6-2: Reservoir Grid – Vertical Oil Well, 160 Acre Drainage

Grid Properties

**Grid Dimensions**

Number of x-grids: 15  
 Number of y-grids: 15  
 Number of z-grids: 5  
 Reservoir Depth: 5332 ft

Dipping Reservoir ☐ 0 Degrees

**X Grid Block Sizes**

Start	End	dx (ft)
1	to 2	= 890
3	to 3	= 350
4	to 4	= 250
5	to 5	= 150
6	to 6	= 70
7	to 7	= 30
8	to 8	= 20
9	to 9	= 30
10	to 10	= 70
11	to 11	= 150
12	to 12	= 250
13	to 13	= 350
14	to 15	= 890

**Y Grid Block Sizes**

Start	End	dy (ft)
1	to 2	= 890
3	to 3	= 350
4	to 4	= 250
5	to 5	= 150
6	to 6	= 70
7	to 7	= 30
8	to 8	= 20
9	to 9	= 30
10	to 10	= 70
11	to 11	= 150
12	to 12	= 250
13	to 13	= 350
14	to 15	= 890

**Z Grid Block Sizes and Layer Average Properties**

Start	End	dz (ft)	Porosity	kx	ky	kz
1	to 1	= 5	0.151	10	10	1
2	to 2	= 5	0.165	20	20	2
3	to 3	= 5	0.173	30	30	3
4	to 4	= 5	0.1591	17	15	1.5
5	to 5	= 5	0.182	35	18.2	1.82

**Apply Gaussian Variability to Average Layer Properties**

Seed: -1  
 +/-% for Gaussian Distribution: Porosity: 25, kx: 25, ky: 25, kz: 25  
 Apply/Remove Gaussian Variability: ☐ ☐ ☐ ☐

Figure W.6-3: Reservoir Grid – Vertical Oil Well, 640 Acre Drainage

The vertical well location and well parameters are shown in Figure W.6-4

**Wellbore Properties**

☒ Vertical Well  
☐ Horizontal Well

Vertical Well Grid Location (I, J)

Top Completion Layer (K)

Bottom Completion Layer (K)

Measured Depth to Top of Completion (ft)

True Vertical Depth to Top of Completion (ft)

Tubing ID (in)

Depth of Tubing (ft)

Casing ID (in)

Tubing Correlation

**Diagram Labels:** Tubing Depth, Top Perf, Bot Perf, Total Depth

Figure W.6-4: Wellbore Parameters – Vertical Oil Well, Drainage Area Comparison

OIIP after initialization and the 10-year recovery for the two models are shown in Figure W.6-5.

**Run Parameters**

Run Info:

Minimum Oil Rate (bopd)

Flowing Wellhead Temperature (°F)

Minimum Reservoir Pressure (psi)

Enter Simulation Time (yrs)

☒ Save Simulation Run Data

fGIIP	OIIP	WIIP
0	3.359	1.123
Bscf	mmbbls	mmbbls

**Cum Forecast (mmbbls)**

**Run Parameters**

Run Info:

Minimum Oil Rate (bopd)

Flowing Wellhead Temperature (°F)

Minimum Reservoir Pressure (psi)

Enter Simulation Time (yrs)

☒ Save Simulation Run Data

fGIIP	OIIP	WIIP
0	13.435	4.492
Bscf	mmbbls	mmbbls

**Cum Forecast (mmbbls)**

Figure W.6-5: Vertical Well Model – Initialization and 10 Year Forecast

Figures W.6-6 presents a comparison of the forecasts for the two models. The middle curves on the graph show the GOR forecasts. As expected, the GOR for the smaller drainage area increases faster than for the larger drainage area because the reservoir pressure (upper two curves) falls faster for the smaller area.

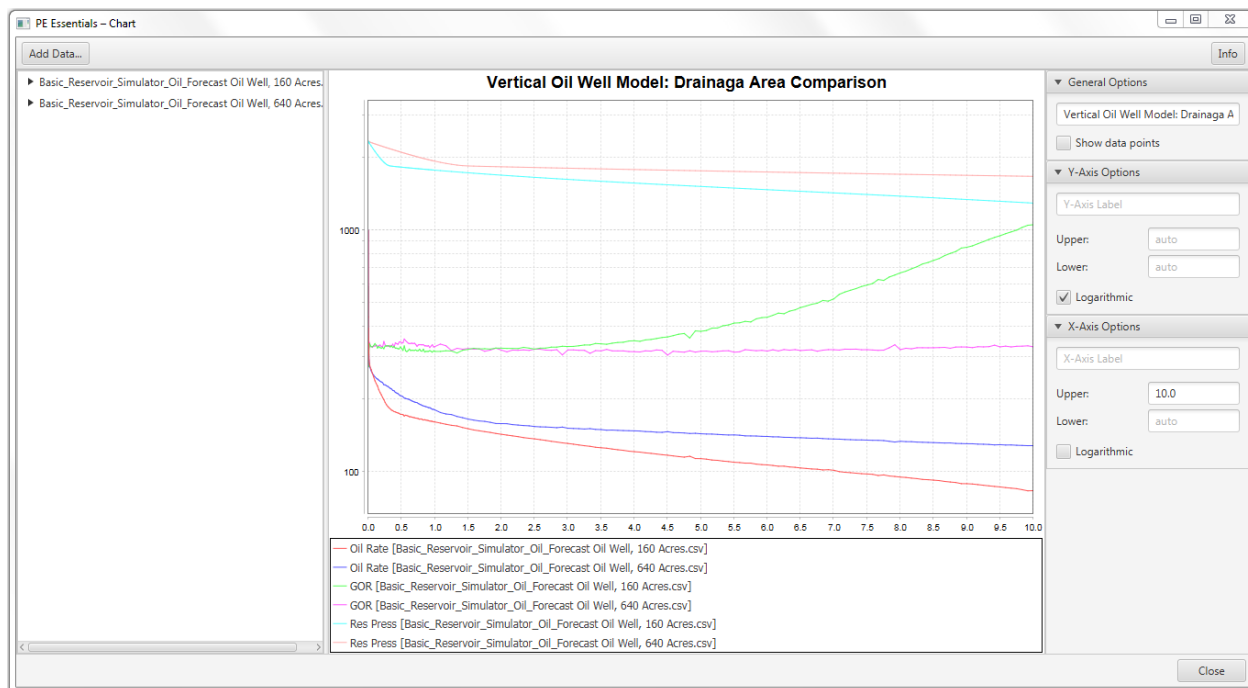


Figure W.6-6: Vertical Well Model – 10-Year Forecast (Reservoir Pressure, GOR, Oil Rate)

Although the larger drainage area allows for higher rates and slower decline in overall reservoir pressure. The recovery factor after 10 years was only 4.1% for the larger drainage area versus 7.6% for the smaller drainage area. This indicates that one oil well in a 640-acre drainage area may not be optimum for recovery.

### W.6.2 Vertical Oil Well – Water Coning/Completion Interval Comparison

An oil/water contact (OWC) at the top of the fourth layer was added to the 160 acres, vertical oil well model used in Section W.6.1 to evaluate the effect of different well completions.

This sensitivity compares the forecast for three cases; the well completed in the top three layers; the well completed in the top four layers; and the well completed in all five layers. The well's oil rate was set at 200 bopd for all cases and the recovery and well performances were compared.

For this case, the OIIP was 1.98 mmbbls and WIIP was 2.76 mmbbls. Figure W.6-7 shows the reservoir properties with the addition of the OWC.

**Oil Reservoir Properties**

Average Perm (md)	20.2415		
Average Pay (ft)	25	Area (Acres)	160
Average Sw	0.22		
Average Porosity	0.1660	Initial Bo (bbl/sbbl)	1.196
Reservoir Length (ft)	2640	Initial Oil Viscosity (cp)	1.63
Reservoir Width (ft)	2640	Solution GOR (scf/bbl)	354.0088
Res Temperature (°F)	123	Initial co (10 <sup>-5</sup> /psi)	0.886
Reservoir Pressure (psi)	2337	Water RSW (scf/sbbl)	11.82914
Reservoir Well radius (in)	4		
Bubble Point Pressure (psi)	1855		
Gas/Oil Contact (ft)	5330		
Oil/Water Contact (ft)	5347		

**Exit**

Figure W.6-7: Vertical Well Model – Addition of OWC at Top of Layer 4

Figure W.6-8 shows the well location in the grid for the case of the well completed in the top three oil bearing layers.



Figure W.6-8: Vertical Well Model with OWC – Well Location, Completion in Oil Layers

Figure W.6-9 presents the 10-year forecast results for oil rate and reservoir pressure and Figure W.6-10 presents the GOR and water cut.

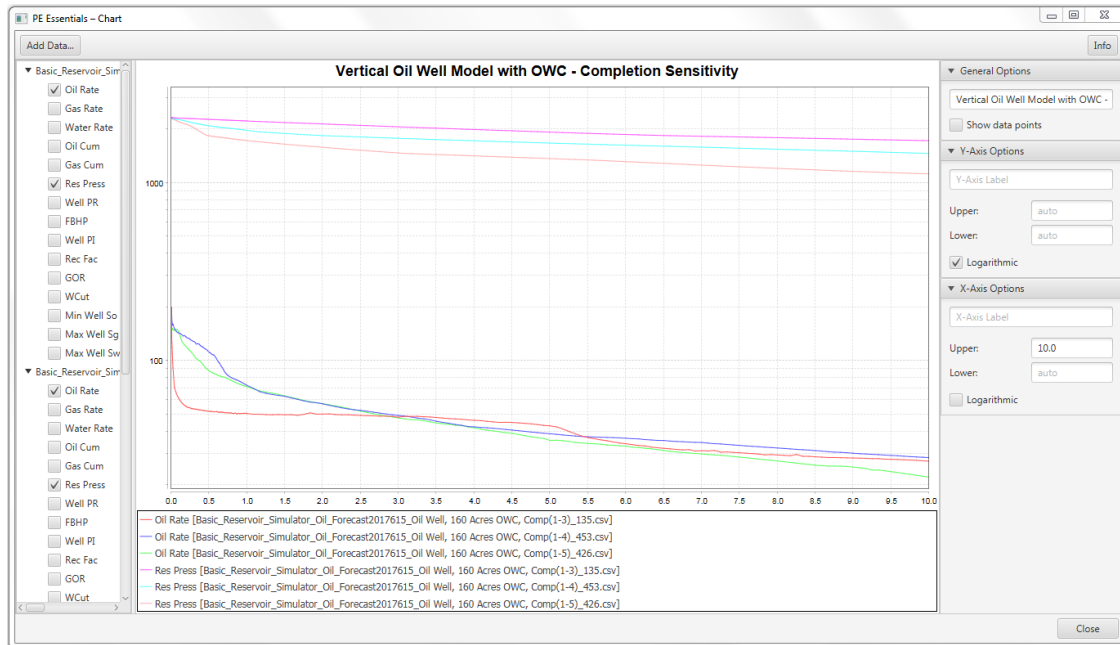


Figure W.6-9: Vertical Well Model with OWC – 10-Year Forecast (Reservoir Pressure, Oil Rate)

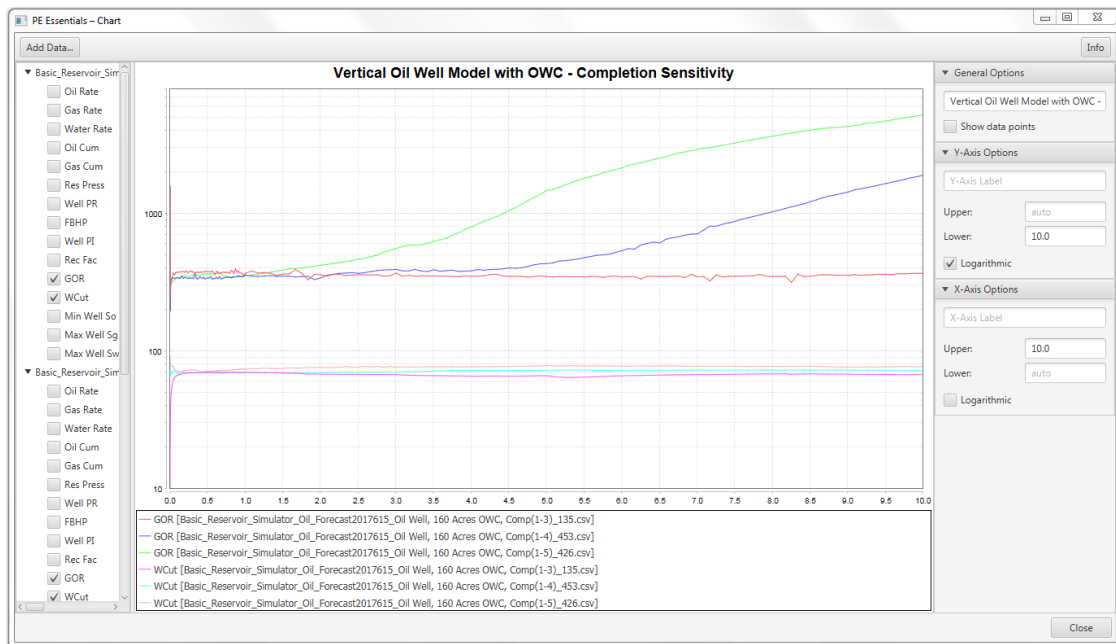


Figure W.6-10: Vertical Well Model with OWC – 10-Year Forecast (GOR and Water Cut)

Oil rate for the wells completed into the water layer are higher than oil rate for the well completed in just the oil layers. This is the result of slowing water encroachment into the oil layer by reducing pressure in the water zone. The GOR is highest in the well completed in all layers because of pressure depletion resulting from the higher fluid (oil+water) recovery.

Figures W.6-11 to W.6-13 show the water saturation after 10 years at the well location in layer 3 which is the lowermost oil bearing layer. Water encroachment is significantly reduced when the water layers are included in the completion.

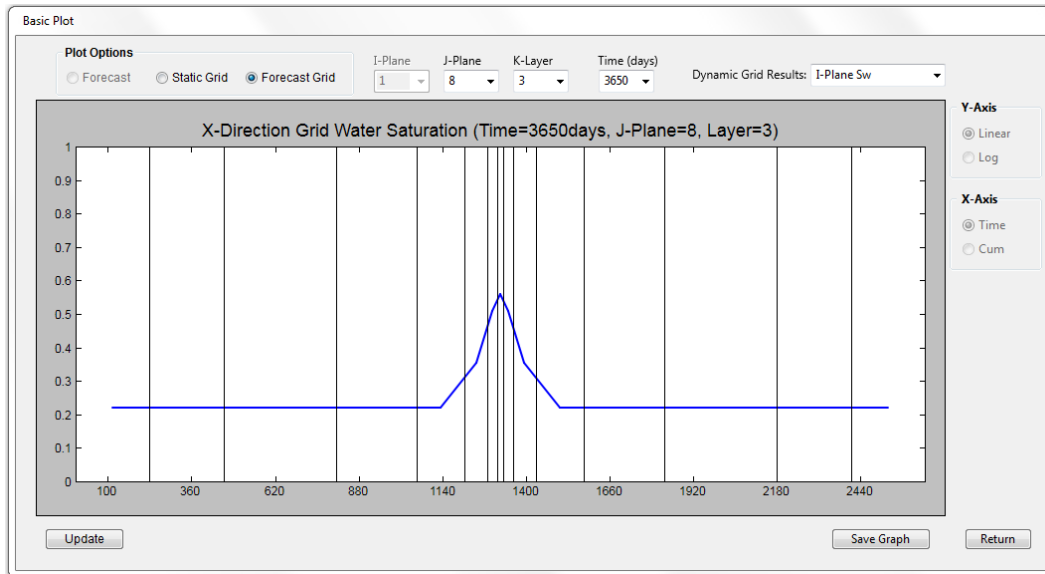


Figure W.6-11: Vertical Well Model with OWC – Water Saturation (Layer 1-3 Completion)

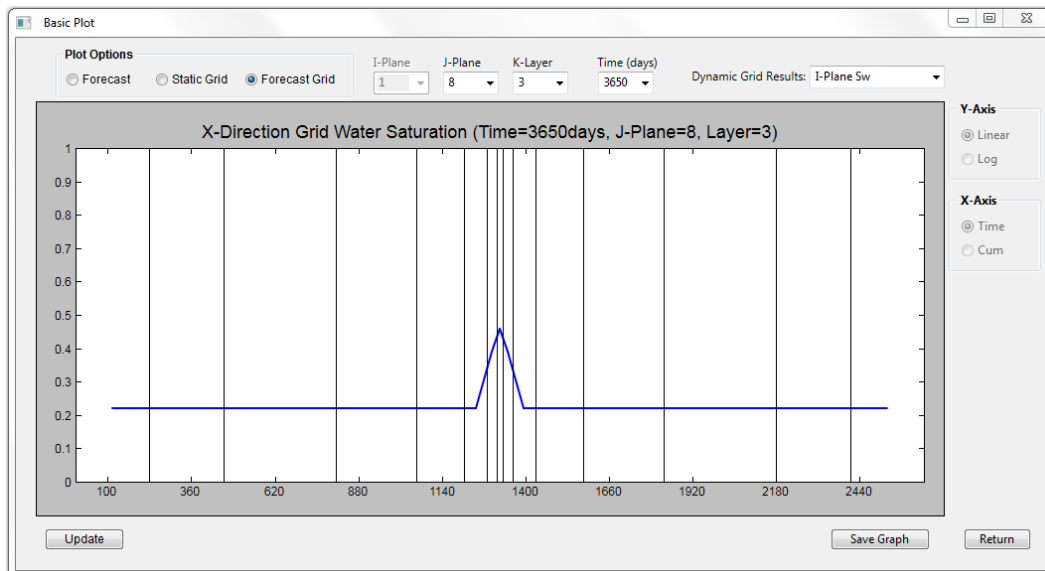


Figure W.6-12: Vertical Well Model with OWC – Water Saturation (Layer 1-4 Completion)

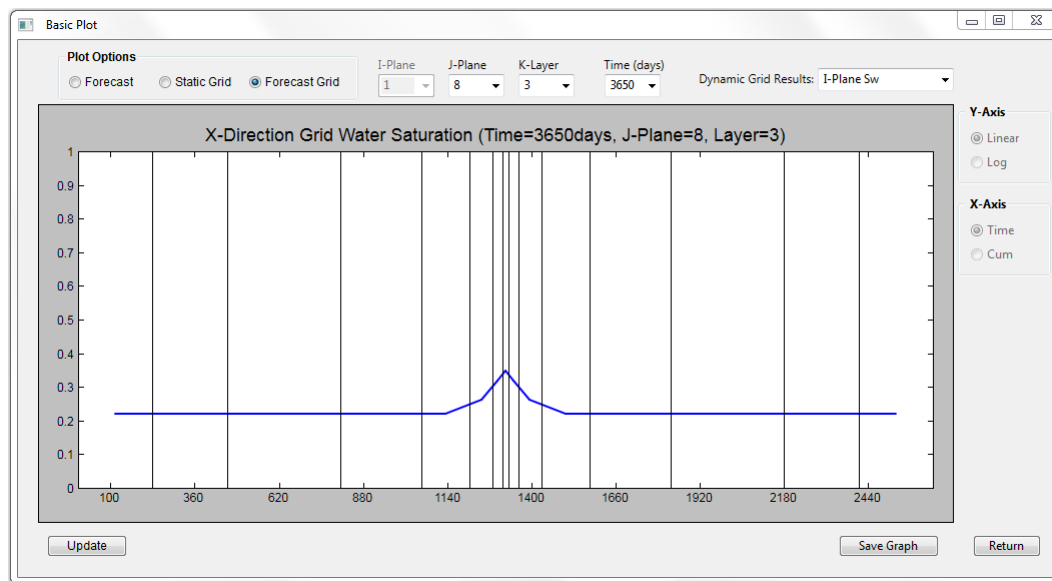


Figure W.6-13: Vertical Well Model with OWC – Water Saturation (Layer 1-5 Completion)

Other parameters such as the impact of vertical permeability and the impact of the relative permeability curves (end points and curvature), could also be evaluated with this model. The overall goal would be to optimize recovery with minimal water/gas coning. This sort of analysis can be important if production facilities have limited water handling capacity or if water disposal is costly.

### W.6.3 Horizontal Oil Well – Lateral Length Comparison

Production performance of a horizontal well can be compared to evaluate the effects of lateral length, zone thickness, vertical-to-horizontal permeability, and the position of the lateral in the pay interval, as well as vertical distance from an oil/water or gas/oil contact.

A simple grid (Figure W.6-14) was constructed to evaluate the impact of a number of lateral lengths. This model has grid dimensions of 21x21x5, with each cell 530ft by 530ft by 5ft in length, width, and thickness. The different wellbore models are shown in Figure W.6-15

**Grid Properties**

**Grid Dimensions**

Number of x-grids: 21

Number of y-grids: 21

Number of z-grids: 5

Reservoir Depth: 5332 ft

Dipping Reservoir: ☐ 0 Degrees

[Info](#)

[Enter Faults \(x/y\)](#)

[Enter Barriers \(z\)](#)

[Mod X/Y Perm](#)

[Inactivate Cells](#)

[Reset X Grid](#)

[Reset Y Grid](#)

[Reset Z Grid](#)

[Export Grid Properties](#)

**X Grid Block Sizes**

Start: 1 to End: 21 = dx (ft): 530

**Y Grid Block Sizes**

Start: 1 to End: 21 = dy (ft): 530

**Z Grid Block Sizes and Layer Average Properties**

Start	End	dz (ft)	Porosity	kx	ky	kz
1	to 1	= 5	0.151	10	10	1
2	to 2	= 5	0.165	20	20	2
3	to 3	= 5	0.173	30	30	3
4	to 4	= 5	0.1591	17	15	1.5
5	to 5	= 5	0.182	35	18.2	1.82

**Apply Gaussian Variability to Average Layer Properties**

Seed: -1

+/-% for Gaussian Distribution: Porosity: 25, kx: 25, ky: 25, kz: 25

Apply/Remove Gaussian Variability: ☐ ☐ ☐ ☐

[Build Grid](#)

Figure W.6-14: Reservoir Grid – Horizontal Oil Well, Lateral Length Comparison

**Wellbore Properties**

☐ Vertical Well

☒ Horizontal Well

Start Horizontal Well Location (I, J): 10 11

Horizontal Completion Layer (K): 2

End Horizontal Well Block (end I): 12

Measured Depth to Top of Completion (ft): 5337

True Vertical Depth to Top of Completion (ft): 5332

Tubing ID (in): 2.441

Depth of Tubing (ft): 5332

Casing ID (in): 6

Tubing Correlation: Hagedorn-Brown

[Exit](#)

**Wellbore Properties**

☐ Vertical Well

☒ Horizontal Well

Start Horizontal Well Location (I, J): 8 11

Horizontal Completion Layer (K): 2

End Horizontal Well Block (end I): 14

Measured Depth to Top of Completion (ft): 5337

True Vertical Depth to Top of Completion (ft): 5332

Tubing ID (in): 2.441

Depth of Tubing (ft): 5332

Casing ID (in): 6

Tubing Correlation: Hagedorn-Brown

[Exit](#)

**Wellbore Properties**

☐ Vertical Well

☒ Horizontal Well

Start Horizontal Well Location (I, J): 6 11

Horizontal Completion Layer (K): 2

End Horizontal Well Block (end I): 16

Measured Depth to Top of Completion (ft): 5337

True Vertical Depth to Top of Completion (ft): 5332

Tubing ID (in): 2.441

Depth of Tubing (ft): 5332

Casing ID (in): 6

Tubing Correlation: Hagedorn-Brown

[Exit](#)

Figure W.6-15: Wellbore Model – Horizontal Oil Well, Lateral Lengths: 1590ft, 3710ft, 5830ft

An oil-water contact (OWC) was placed at the top of the fourth layer and the well was placed in the center of the second layer. All laterals were centered in the grid model as shown in Figure W.6-16.



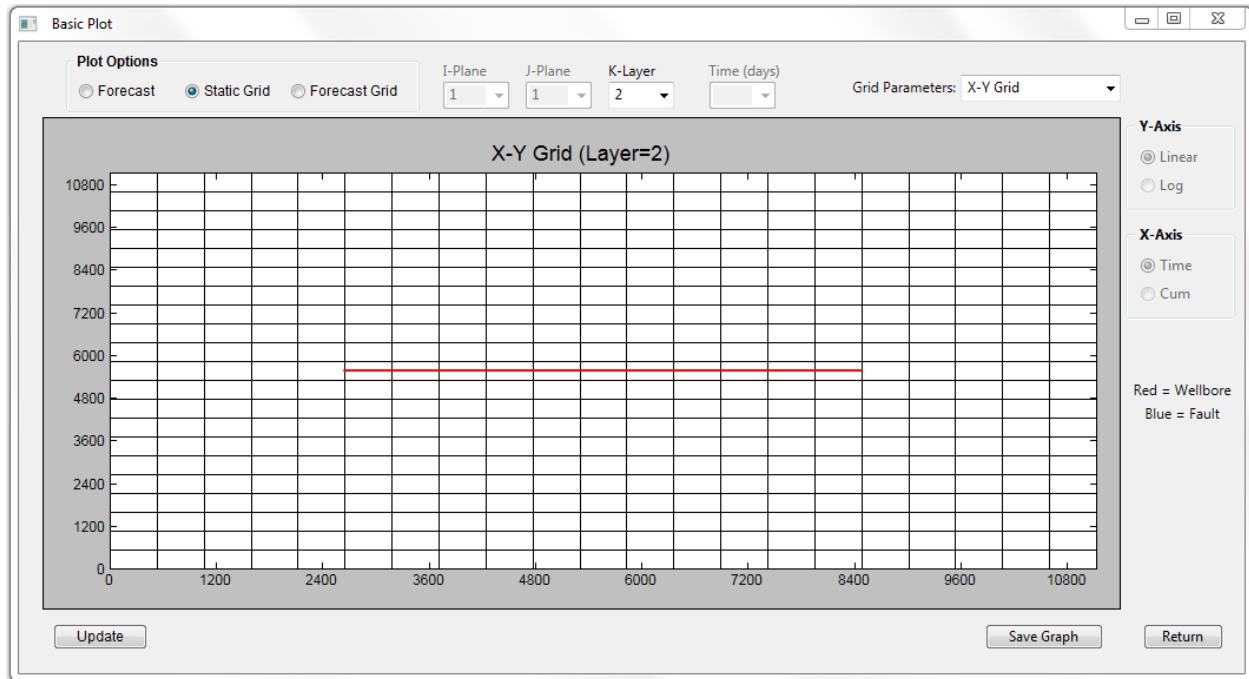


Figure W.6-16: Horizontal Oil Well – Location of the 5830ft Lateral

Figures W.6-17 to W.6-19 show the pressure profile along the lateral at the end of the 10-year forecast.

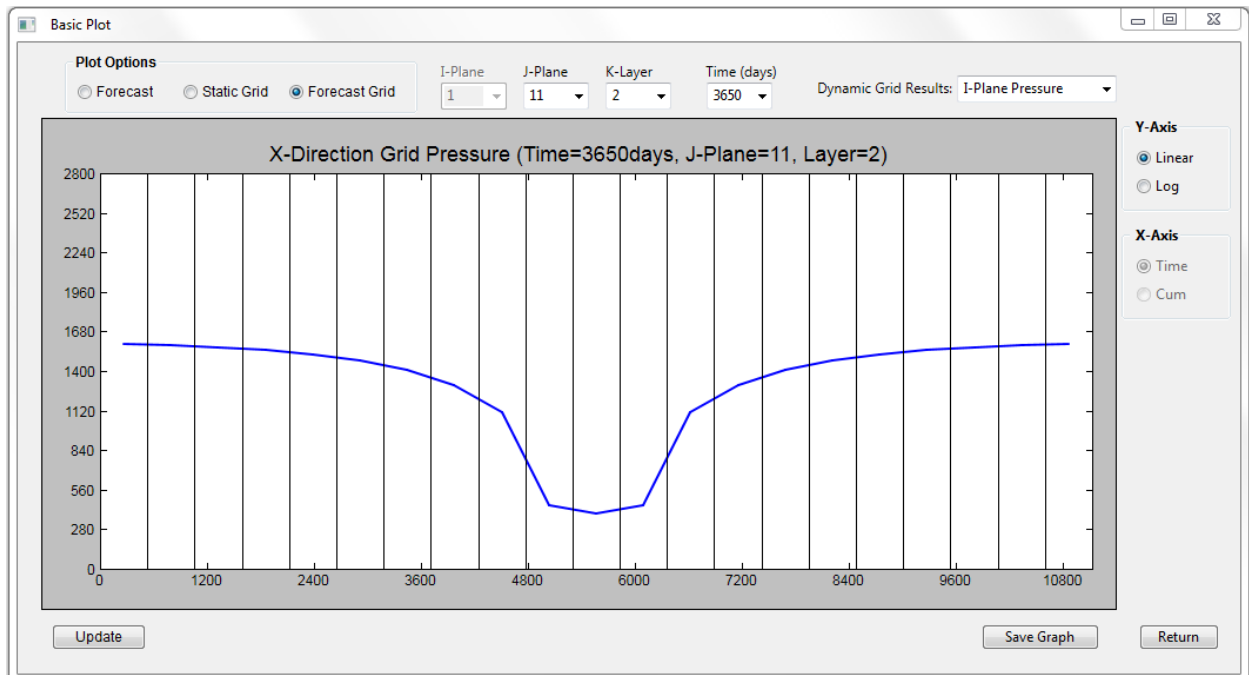


Figure W.6-17: Horizontal Oil Well – 10-Year Forecast, Pressure Along 1590ft Lateral

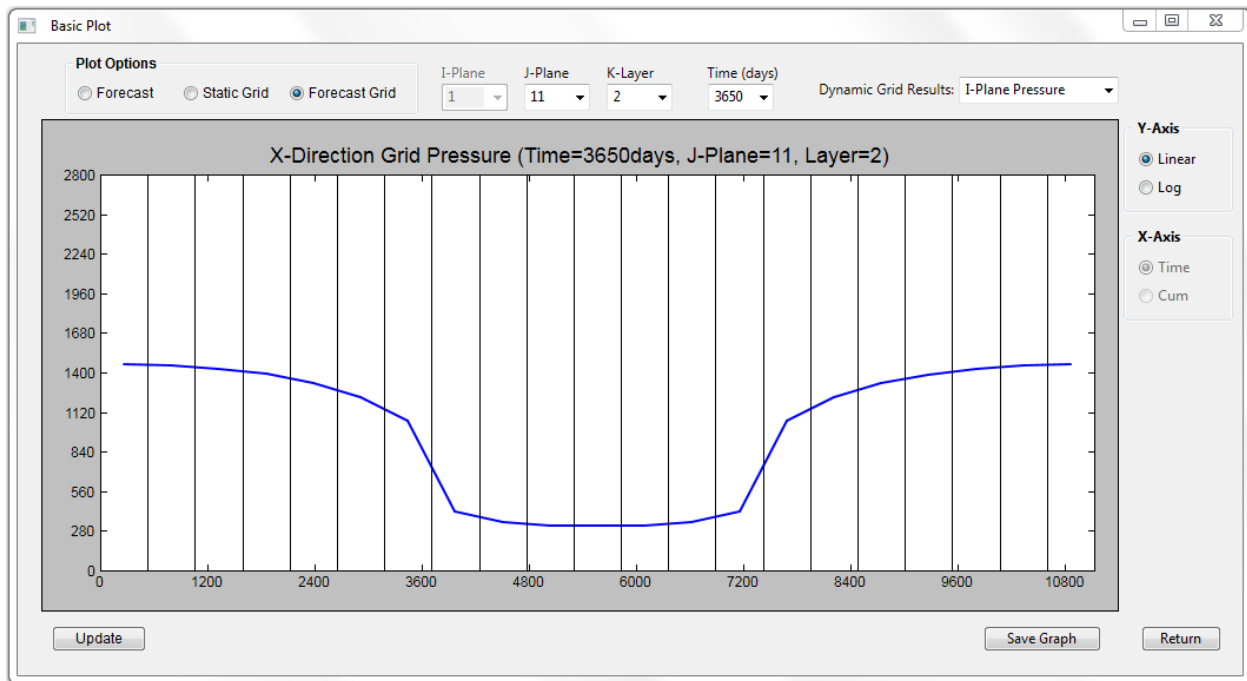


Figure W.6-18: Horizontal Oil Well – 10-Year Forecast, Pressure Along 3710ft Lateral

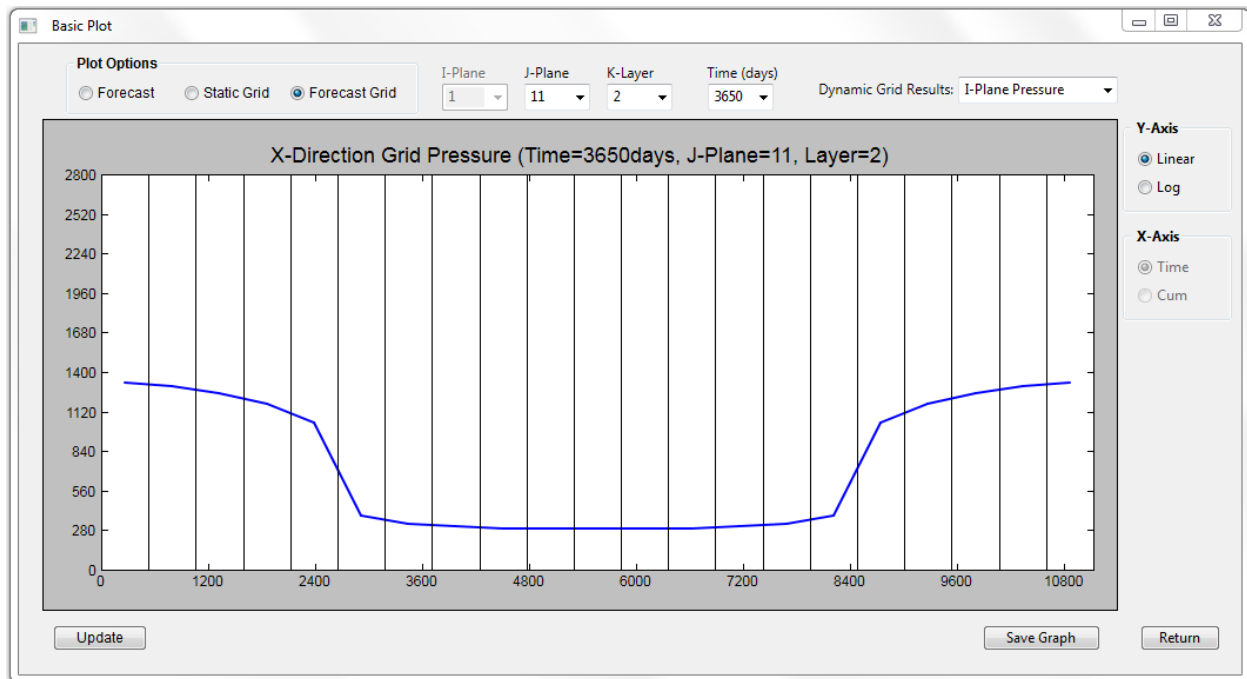


Figure W.6-19: Horizontal Oil Well – 10-Year Forecast, Pressure Along 5830ft Lateral

Figures W.6-20 to W.6-22 show the water saturation profile along the lateral at the end of the 10-year forecast. This quantifies the magnitude of the water encroachment into the well.

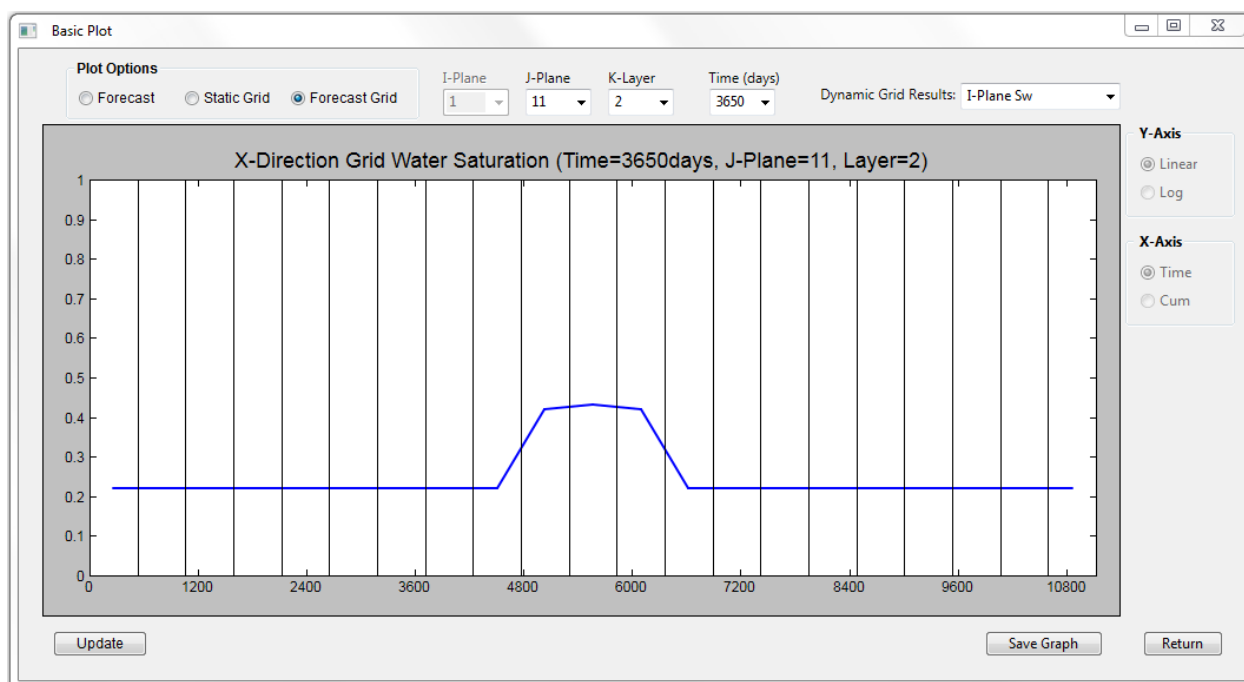


Figure W.6-20: Horizontal Oil Well – 10-Year Forecast, Water Saturation Along 1590ft Lateral

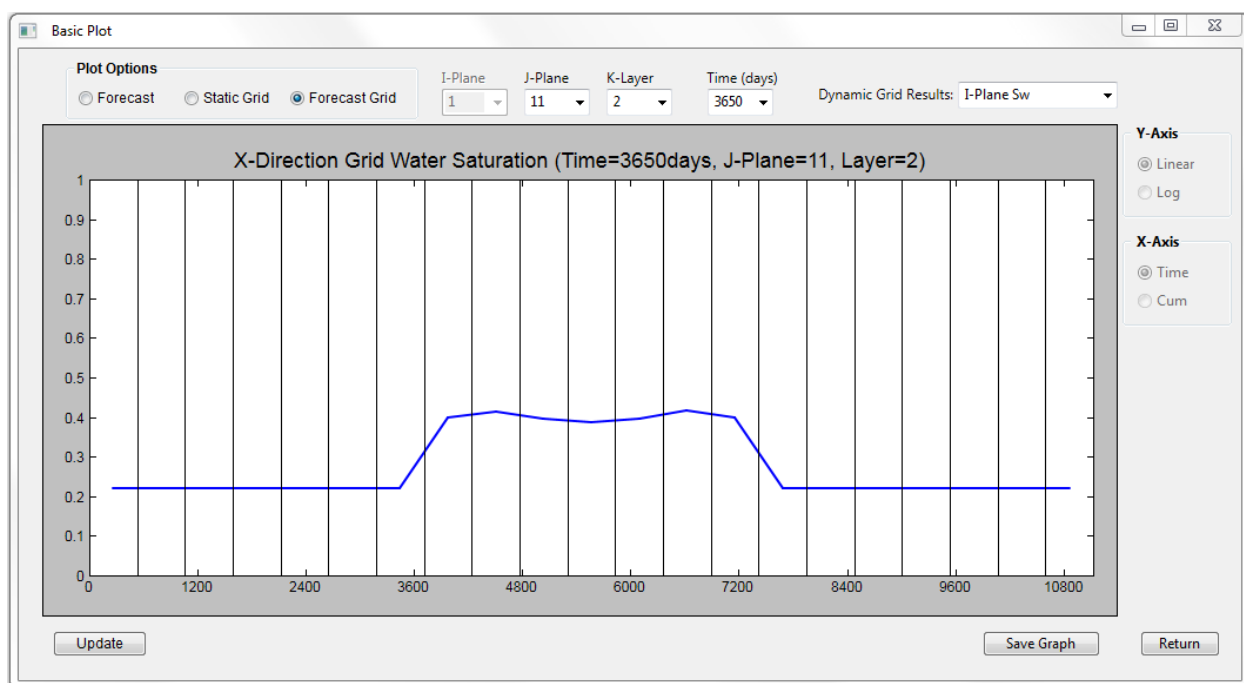


Figure W.6-21: Horizontal Oil Well – 10-Year Forecast, Water Saturation Along 3710ft Lateral

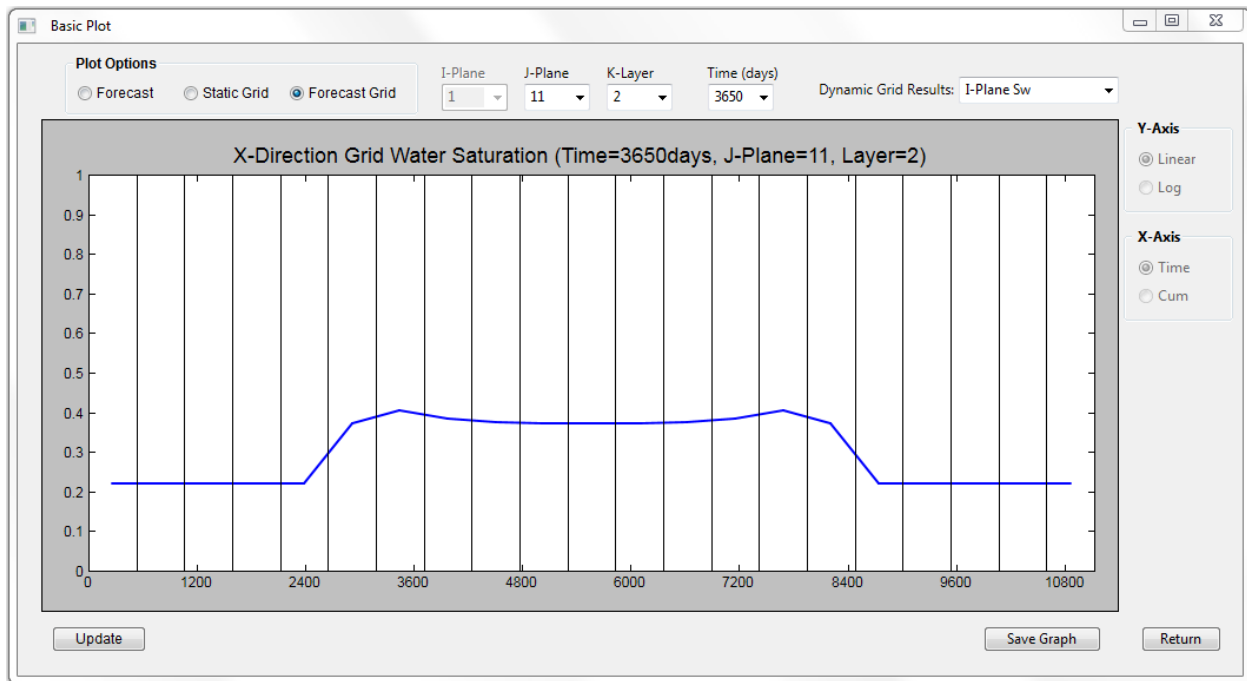


Figure W.6-22: Horizontal Oil Well – 10-Year Forecast, Water Saturation Along 5830ft Lateral

Figure W.6-23 shows the reservoir pressure and the oil rate performance for the different lateral lengths and Figure W.6-24 shows the GOR and Water Cut performance.

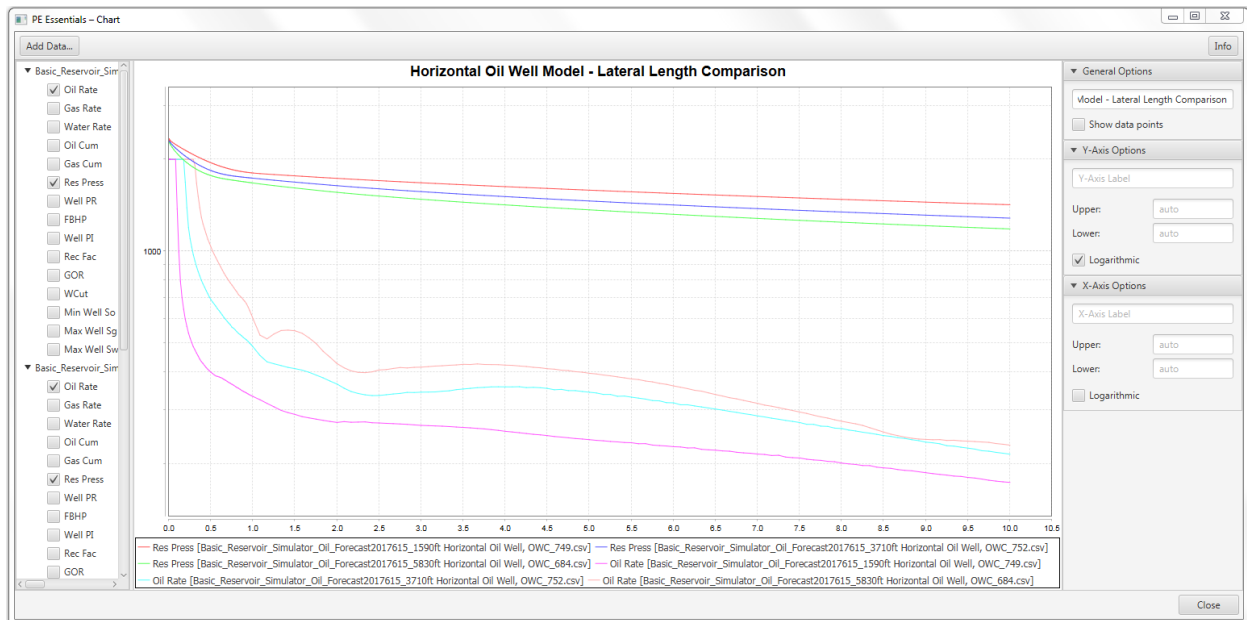


Figure W.6-23: Horizontal Oil Well – 10-Year Forecast (Reservoir Pressure, Oil Rate)

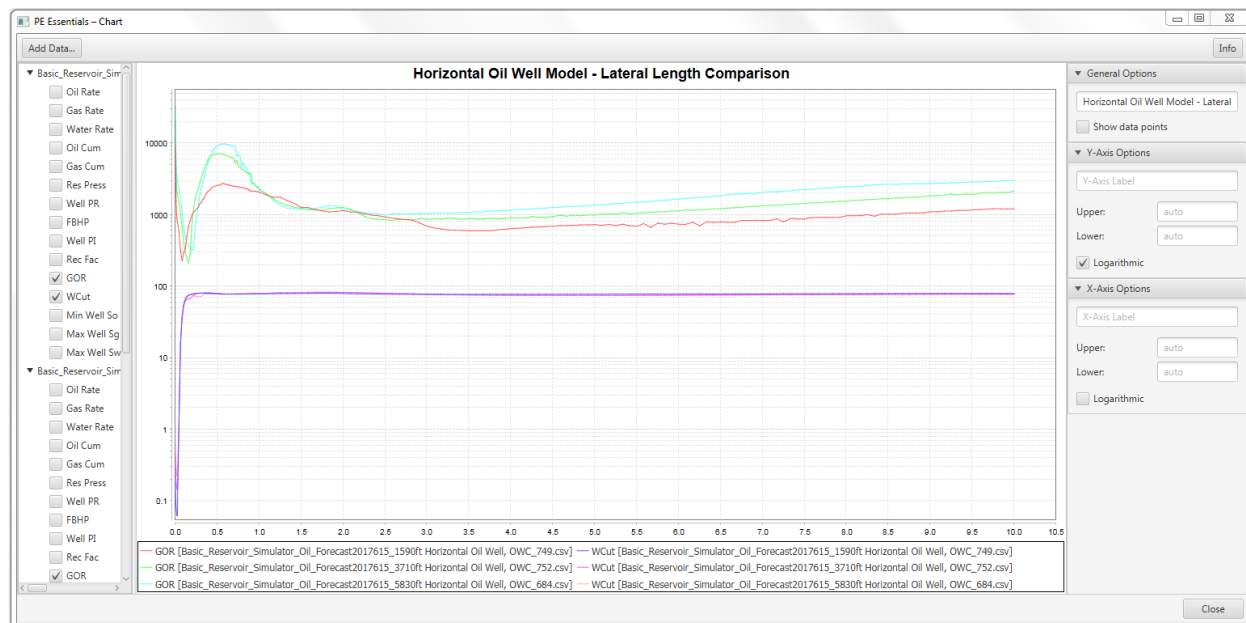


Figure W.6-24: Horizontal Oil Well – 10-Year Forecast (GOR, Water Cut)

The 10-year oil recovery was 2.8% for the 1590ft lateral, 3.9% for the 3710ft lateral and 4.7% for the 5830ft lateral. As expected, recovery increases as lateral length increases - all other factors remaining the same.

Water breakthrough and water cut responses were similar for all lateral lengths. GOR was slightly variable for the different lateral lengths and can be attributed to the higher reservoir pressure depletion for the longer laterals, resulting in higher recovery and pressure depletion.

The saturations in each layer at the end of the 10-year forecast for the 5830ft lateral are presented below. Figure W.6-25 shows the gas saturation in the top layer (above the wellbore) indicating the formation of a secondary gas cap. Figure W.6-26 shows the water saturation along the lateral indicating water encroachment into the well layer and Figure W.6-27 shows the water saturation below the lateral. Figure W.6-28 shows the oil saturation in the fourth layer, which was initially water saturated ( $S_w=100\%$ ), indicating the loss of oil into the aquifer because of pressure depletion and the formation of the secondary gas cap. Finally, Figure W.6-29 shows the oil saturation in the bottom layer.

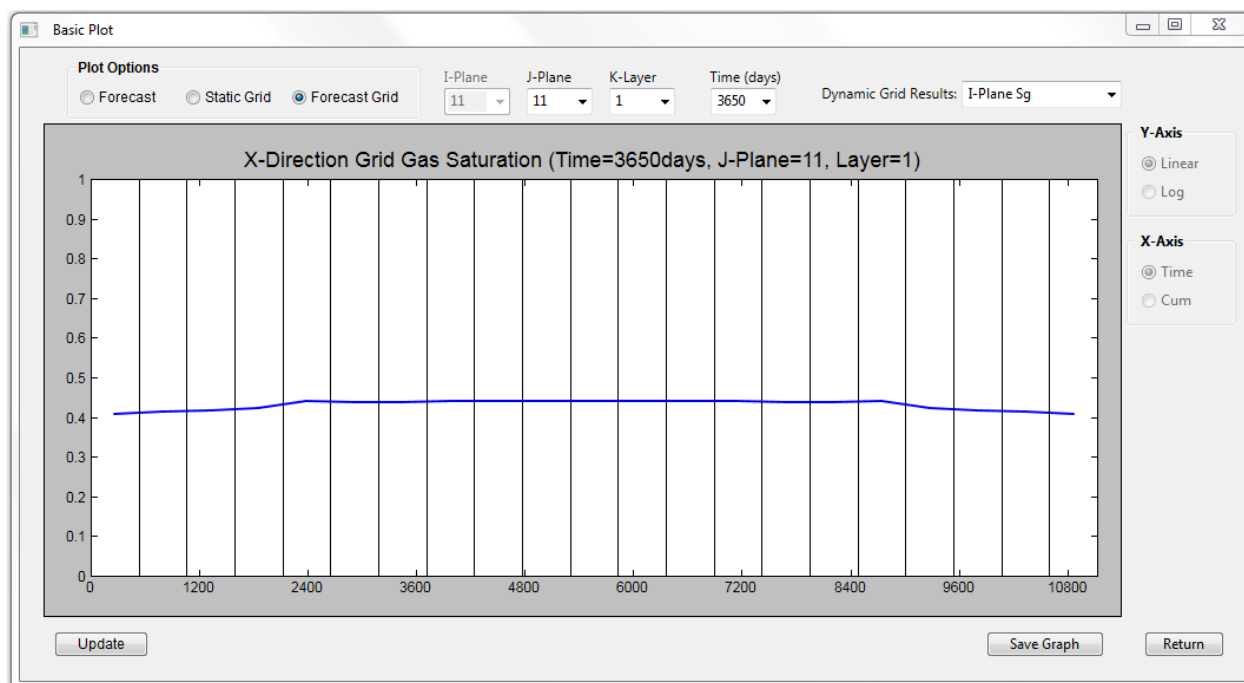


Figure W.6-25: Horizontal Oil Well – 10-Year Forecast, Gas Saturation, Layer 1 (Secondary Gas Cap)

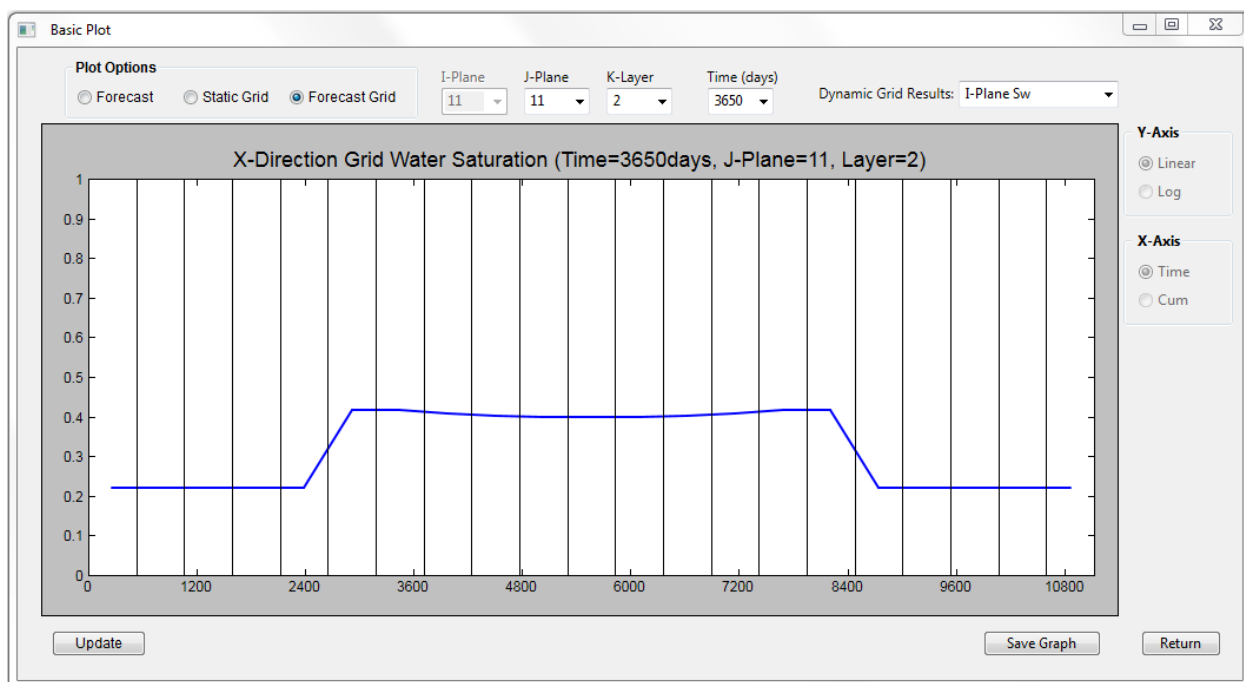


Figure W.6-26: Horizontal Oil Well – 10-Year Forecast, Water Saturation, Layer 2 (Water Encroachment)

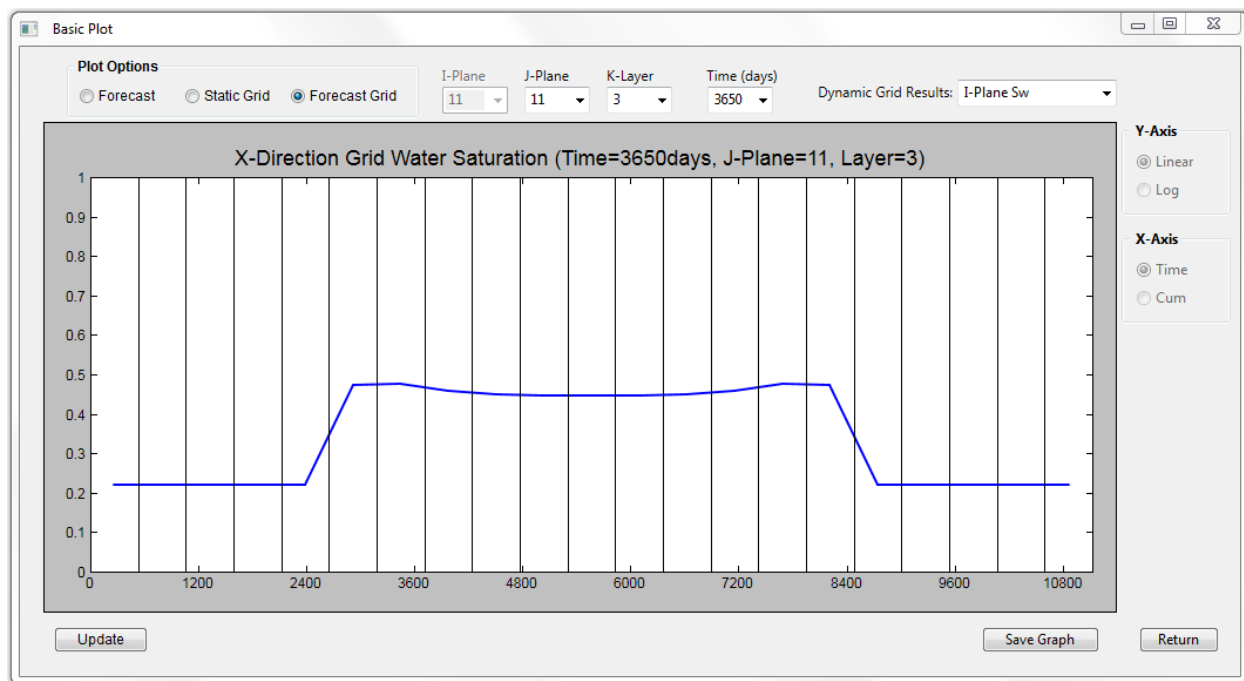


Figure W.6-27: Horizontal Oil Well – 10-Year Forecast, Water Saturation, Layer 3 (Water Encroachment)

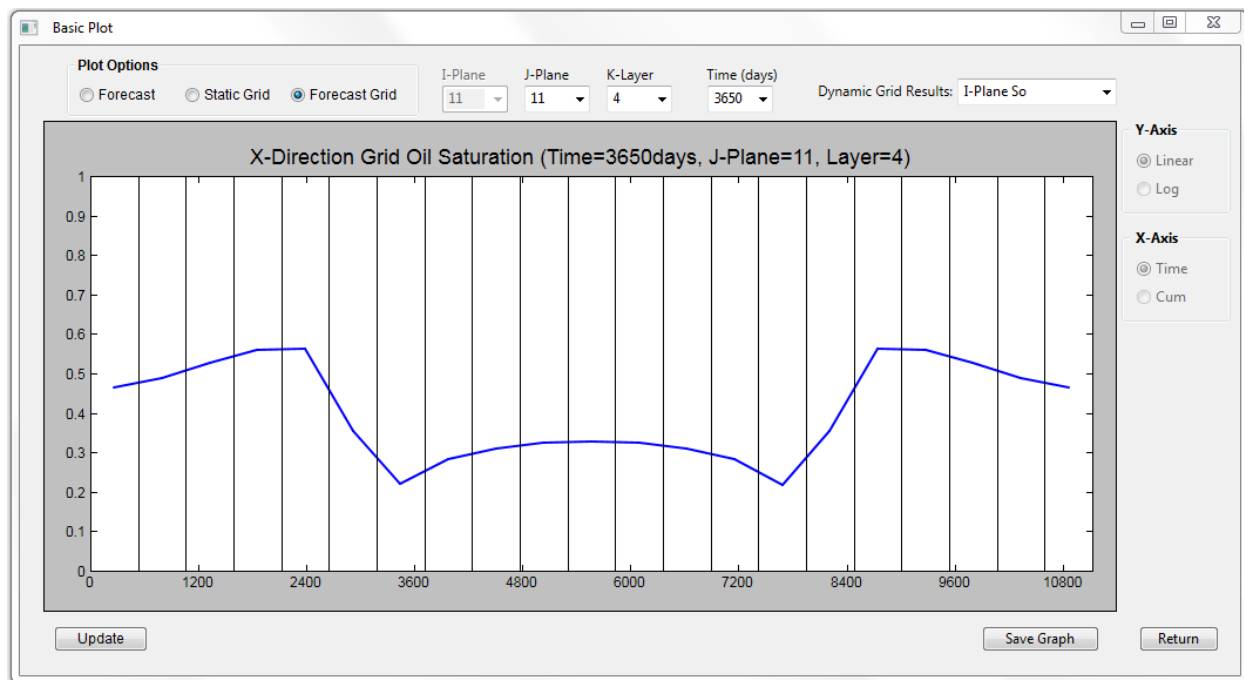


Figure W.6-28: Horizontal Oil Well – 10-Year Forecast, Oil Saturation, Layer 4 (Oil Movement into Water)

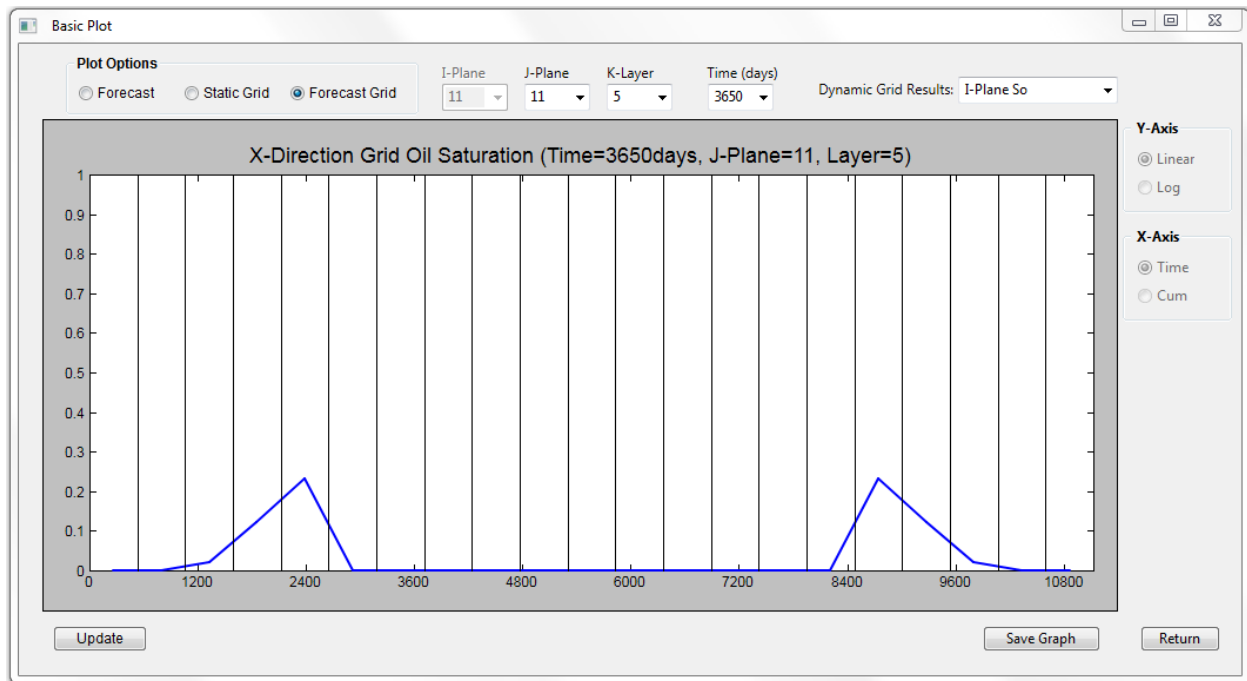


Figure W.6-29: Horizontal Oil Well – 10-Year Forecast, Oil Saturation, Layer 5 (Minor Oil Movement into Water)

Most of the oil movement into the aquifer could be stopped with water injection to maintain pressure in the reservoir.

#### W.6.4 Horizontal Oil Well – Fracture Spacing/Stage Size

The cost of completing a well with hydraulic fractures is dependent on the number of fracture stages placed in the well. The number of stages in a given lateral is a function of the size of each stage and the length of the lateral. A fracture stage can be a couple of hundred feet to as low as 50ft.

To evaluate the recovery sensitivity to the size of stages in a horizontal hydraulically fractured well, the well model presented in Section W.5 was converted to an oil well with no water or gas contacts and used for this analysis.

The model has a 29x19x1 grid with 7 hydraulic fractures. The fractures are placed so that there are 3 grid blocks between the fractures. For this analysis, the length of the fracture stage is determined by the total length of the three blocks between the fractures.

Seven models were used for this sensitivity analysis and are included in the “Workflow\Single Well Sensitivity Models” directory.



Table W.6-1-1 lists the parameters for the seven cases built for this analysis. The table also includes the 10-year recovery factor for each case.

Stage (ft)	OIIP (mbbls)	Lateral Length (ft)	10 Year Recovery Factor (%)
450	1102	3164	34.4
375	893	2564	35.0
300	736	2114	35.6
225	553	1589	36.5
150	370	1064	37.8
75	188	539	40.2
45	114	329	42.0

Table W.6-1: Sensitivity Cases – Fracture Stage Size

One impact of reducing the fracture spacing in an oil well is the resulting increase in GOR (Figure W.6-30). The increased GOR is the result of the increased drawdown in the reservoir as recovery is increased and reservoir pressure is reduced.

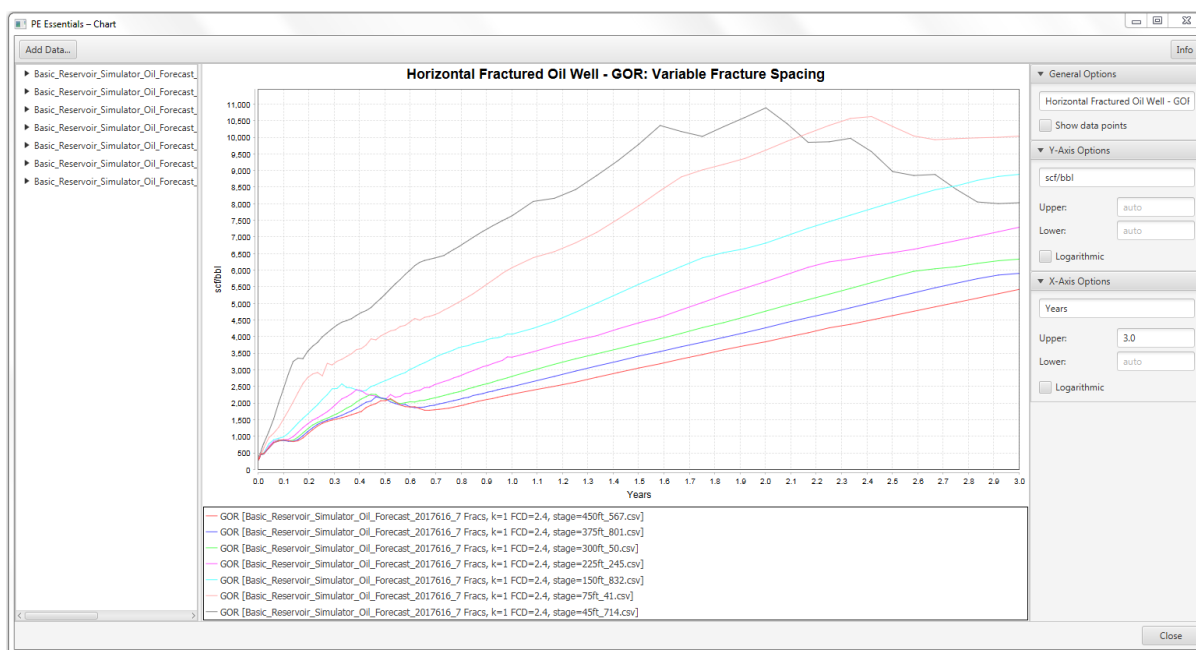


Figure W.6-30: Fracture Spacing – 10-Year Forecast, GOR

Figure W.6-31 presents a plot of the recovery as a function of fracture spacing and Figure W.6-32 presents a plot of the normalized recovery factors (normalized to the recovery factor value for a stage length of 225ft) as a function of fracture spacing.

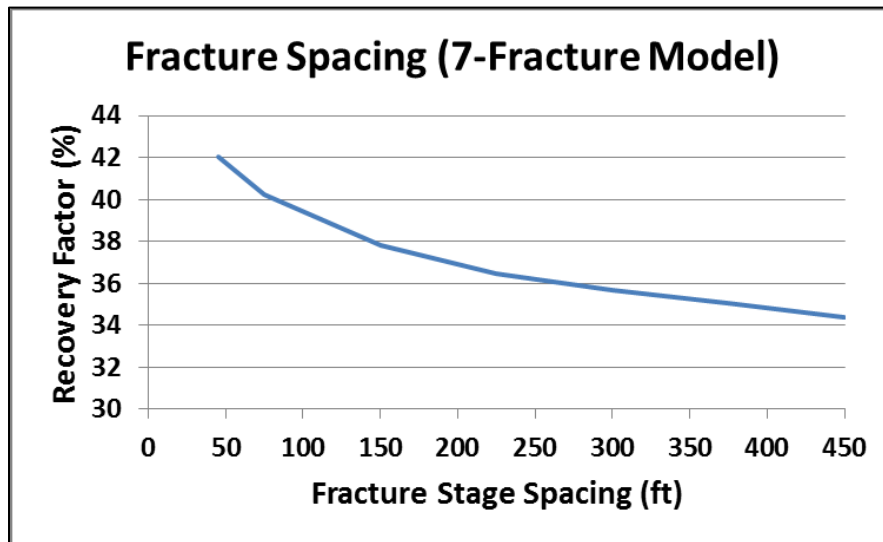


Figure W.6-31: Fracture Spacing – 10-Year Forecast, Recovery Factor

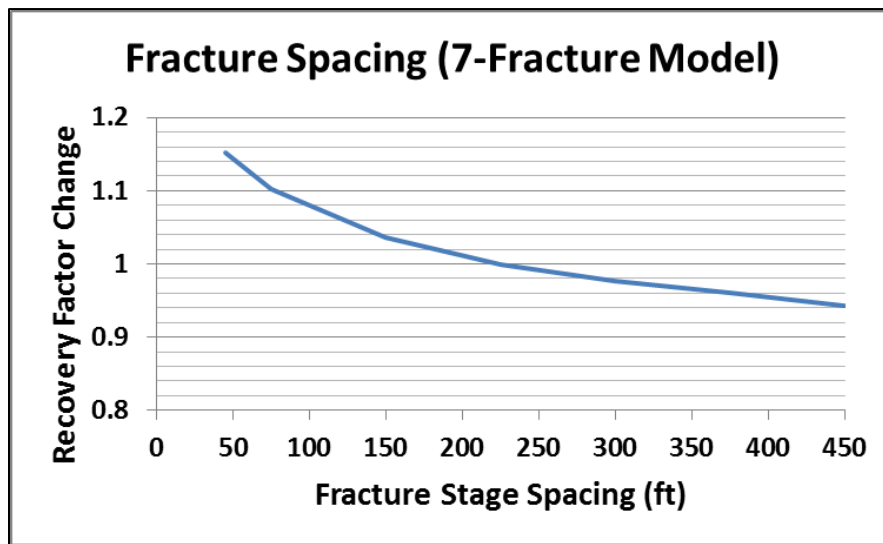


Figure W.6-32: Fracture Spacing – RF (Normalized to RF at 225ft)

Figure W.6-32 shows that, for this model, a stage size greater than 225ft does not significantly reduce recovery factor but reducing the stage size may significantly increase recovery factor. The economics of decreasing the fracture spacing, and increasing total number of stages in the well, has to be evaluated to determine the optimum fracture spacing (number of stages and stage size).

## W.7 PDA – Eagle Ford Example

Historical production data was available from an Eagle Ford tight oil well (refer to “Workflow - Eagle Ford Example” for input/output files).

One complexity for this well was that the well was initially produced through casing from July 31 to Aug. 6. Tubing was then run into the well and the well was returned to production. Although PE<sup>2</sup> Essentials Production Data Analysis includes an internal routine to convert THP/CHP to BHP, this complexity cannot be handled. In order to generate BHP, two PE<sup>2</sup> Essentials THP-BHP Oil Well models were constructed:

PE\_Essentials\_Oil\_THPBHP EagleFordCasingFlow.dvx (Figure W.7-1 and W.7-2)

PE\_Essentials\_Oil\_THPBHP EagleFordTubingFlow.dvx (Figure W.7-3 and W.7-4)

**BHP-THP: Oil Well - Version: 2018.2**

Exit Program Load Model Run Correlation THP to BHP Save Results Save Model Info

Oilfield

**Well Options**

☒ Vertical Well ☐ Annular Flow

☐ Horizontal Well

**Tubing Correlation**

☒ Hagedorn-Brown

**Fluid Properties**

Oil API 30 Reservoir Press (psi) 7000

Gas Gravity 0.8 Reservoir Temp (°F) 160

Sat Pressure (psi) 3000

Solution GOR (scf/bbl) 638.7

NACL (ppm) 35000

**Oil Properties**

Reservoir Pressure	7000	psia
Reservoir Temperature	160	°C
Gas Gravity	0.8	<>
Gas Pc	665	psia
Gas Tc	420	°R
Bubble Point Pressure	3000	psia
Solution GOR	638.7	scf/bbl
Oil Compressibility	0.564e-5	1/psi
Oil Viscosity	1.27	cp
Bo	1.2915	bbl/sbbl

**Wellbore Parameters**

Single Point THP >> BHP

Tubing OD (in) 6

Tubing ID (in) 6

Tubing Depth (ftMD) 8700

Casing ID (in) 6

Flow Temperature (°F) 75

Bottom Perf (ftMD) 8785

Top Perf (ftMD) 8700

Bottom Perf (ftTVD) 8785

Top Perf (ftTVD) 8700

Pipe Roughness (in) 0.0006

ΔP Correction Factor 1

**THP** psi

**WCut** %

**GOR** scf/bbl

**Oil Rate** bbls/d

MPP (ftMD) 8742.5 MPP (ftTVD) 8742.5

**THP** psi

**WCut** %

**GOR** scf/bbl

**Oil** mscf/d

**BHP** psi

Figure W.7-1: PE<sup>2</sup> Essentials THP-BHP Model – Casing Flow Model

Figure W.7-2: PE<sup>2</sup> Essentials THP-BHP Model – CHP to BHP Conversion

Figure W.7-3: PE<sup>2</sup> Essentials THP-BHP Model – Tubing Flow Model

**PE Essentials THP>BHP Data Import**

Data Input  
☐ CSV File  
☒ Excel File  
 Open Excel File

Note: Gas rate in mscf/d, liquid rate in bbls/d

Excel Input Parameters

	Column	Start Row	End Row
Tubing Head Pressure	c	84	307
Gas Rate	e	84	307
Oil Rate	d	84	307
Water Rate	f	84	307

Import Data  
 Save to CSV File  
 Continue

**THP to BHP Conversion**

Load Data

Tubing Correlation  
☒ Hagedorn-Brown

Convert THP>BHP  
 Save BHP Data  
 Export Excel Data to CSV File  
 Exit

#	THP	Gas mscf/d	Oil bopd	Water bwpd	BHP psi
1	3850	2632	82	51	5201.6
2	3750	3216	163	31	5131.9
3	3500	4264	150	17	4855.8
4	3350	4135	186	13	4706
5	3250	4063	210	19	4616.8
6	3200	3985	166	25	4531.5
7	3350	2726	73	7	4563.7
8	3250	3714	135	23	4552.3
9	3150	3674	158	31	4466.7
10	3100	3663	120	27	4374.7
11	3100	3649	84	29	4347.8
12	3050	3527	151	33	4346.4
13	3050	3378	93	46	4313.4
14	3000	3055	113	47	4267.4
15	2950	3315	113	28	4189.5
16	2800	3256	144	29	4042.7
17	2925	3195	144	35	4193
18	2900	3194	144	34	4163
19	2900	3196	124	52	4171.1
20	2900	3182	120	31	4138.9
21	2850	3090	125	31	4083.6
22	2800	3109	115	30	4016.6
23	2800	3057	123	34	4027.9
24	2800	3139	98	26	3997.2
25	2857	3256	70	13	4021
26	2775	3194	136	42	4023.7
27	2741	3080	121	29	3951.7
28	2717	2987	120	31	3924.1
29	2641	3459	130	36	3862.7
30	2617	3455	141	31	3837.4
31	3674	3630	120	40	3700.6

Figure W.7-4: PE<sup>2</sup> Essentials THP-BHP Model – THP to BHP Conversion

The BHP was merged into the production data and imported into PE<sup>2</sup> Essentials PDA (Figure W.7-5). The reservoir parameters and PVT parameters were entered (Figure W.7-6).

**Production Data Analysis - Version: 2018.2**

Exit Program Load PDA Database Export Data Save PDA Database Info

Info Production Data PVT Data Validation / Diagnostics Flow Regime Identification Flowing Material Balance Analysis Analytical Simulator Numerical Simulator

Base Well  
 Eagle Ford Example

Reservoir Parameters

Reservoir Pressure (psi) 7000  
 Reservoir Temp (°F) 160  
 Average Porosity (dec) 0.057  
 Average Perm (md) 1.8  
 Average Pay (ft) 50  
 Wellbore radius (in) 4

Gas Saturation (dec) 0  
 Oil Saturation (dec) 0.73  
 Water Saturation (dec) 0.27

Initial OIP (mmbbls) 0.465

AP/AOF Parameters  
☐ Use THP  
☐ Use CHP  
☒ Use BHP

☐ Use Pseudo Pressure  
 Copy Res Parameters to all Wells

Units  
☒ Oilfield  
☐ Metric

Data Import  
☒ Excel File  
☐ DCA db

Fluid Type  
☒ Oil  
☐ Gas

Clear dBase  
 Eagle Ford Example

Delete Well Duplicate Well

Excel Input Parameters

	Column	Start Row	End Row
Producing Days or Date	a	3	307
Cumulative Oil/Cond (bbls)	g	3	307
Cumulative Gas (mscf)	h	3	307
Cumulative Water (bbls)	i	3	307
Tubing Head Pressure (psi)	b	3	307
Casing Head Pressure (psi)	c	3	307
Bottomhole Pressure (psi)	l	3	307
Optional Uptime (hrs)			

Generate BHP  
 Reset Well BHP  
 Reset All BHP's

Import Data

Check-Raw Import Data / UnCheck-Analyzable Data  
☒ Show Rate ☐ Show Cum

Date	Days	Oil	Gas	Water	THP	CHP	BHP
31-Jul-12	1	42.99955	1119.988	554.9942	0	3857	6191.7
1-Aug-12	2.000012	53.58936	1410.983	537.9935	0	4075	6326.5
2-Aug-12	3.000012	58.99998	1608.999	429.9998	0	4179	6355.6
3-Aug-12	4.000012	73.99997	1805.999	340.9999	0	4288	6394.9
4-Aug-12	5.000012	72.99997	1933.999	291.9999	0	4300	6354.6
5-Aug-12	6.000012	92.99996	2254.999	240.9999	0	4300	6252.3
6-Aug-12	7.000012	88.99996	2201.999	205.9999	0	4275	6224.3
7-Aug-12	8.000012	44.99998	1330.999	110	0	4225	6410.8
8-Aug-12	9.000012	93.99996	2529.999	210.9999	0	4225	6078.7
9-Aug-12	10.00001	105	2432.999	130.9999	0	4225	6075.1
10-Aug-12	11.00001	139.9999	2561.999	161.9999	0	4150	5471.8
11-Aug-12	12.00001	98.99996	2608.999	158.9999	0	4067	5326.8
12-Aug-12	13.00001	34.09999	850.9996	51.69998	0	4217	6571
13-Aug-12	14.00001	53.99998	1249.999	80.99997	0	4192	6402.7
14-Aug-12	15.00001	0	0	0	0	0	0
15-Aug-12	16.00001	0	0	0	0	0	0
16-Aug-12	17.00001	0	0	0	0	0	0
17-Aug-12	18.00001	0	0	0	0	0	0
18-Aug-12	19.00001	62.99997	1844.999	55.99998	0	4200	6179.9
19-Aug-12	20.00001	59.99998	1530.999	53.99998	0	4329	6434.4
20-Aug-12	21.00001	127.9999	3081.999	120	0	4100	5322.3
21-Aug-12	22.00001	115	2866.999	101	0	4050	5258.6
22-Aug-12	23.00001	96.99996	2740.999	103	0	4000	5192.7
23-Aug-12	24.00001	120	2717.999	81.99997	0	3933	5126.8
24-Aug-12	25.00001	117	2714.999	82.99997	0	3904	5091.3
25-Aug-12	26.00001	124.9999	2700.999	80.99997	0	3850	5037.7
26-Aug-12	27.00001	121.9999	2710.999	73.99997	0	3810	4981.9
27-Aug-12	28.00001	128.9999	2714.999	71.99997	0	3894	5084.4
28-Aug-12	29.00001	121.9999	2618.999	68.99997	0	3900	5088.6
29-Aug-12	30.00001	117	2602.999	65.99997	0	3900	5081.2
30-Aug-12	31.00001	120	2604.999	66.99997	0	3875	5057
31-Aug-12	32.00001	107	2560.999	62.99997	0	3850	5012.4
1-Sep-12	33.00001	115	2562.999	63.99997	0	3800	4965.2
2-Sep-12	34.00001	111	2552.999	58.99998	0	3796	4952.2

Note: Rate in mscf/d, bbls/d and Pressure in psi  
 Edited data, Cum Reduction => 0.3

Figure W.7-5: PE<sup>2</sup> Essentials Production Data Analysis – Eagle Ford Example

Info	Production Data	PVT	Data Validation / Diagnostics	Flow Regime Identification	Flowing Material Balance Analysis	Analytical Simulator	Numerical Simulator
<div> <div> <b>Gas Properties</b> <p>Gas Gravity: 0.8</p> <p>H<sub>2</sub>S - mol%: 0</p> <p>CO<sub>2</sub> - mol%: 0</p> <p>N<sub>2</sub> - mol%: 0</p> <p>Cond/Gas Ratio (bbls/mmscf): 0</p> <p>Gas P<sub>c</sub> (psi): 665</p> <p>Gas T<sub>c</sub> (°R): 420</p> <p>Acid Free Gas G: 0.8</p> <p>Gas Viscosity (cp): 0.0436</p> <p>Gas Z Factor: 1.168</p> <p>Initial c<sub>g</sub> (10<sup>-5</sup>/psi): 4.655</p> </div> <div> <b>Oil Properties</b> <p>Oil/Cond API: 30</p> <p>Bubble Point Pressure (psi): 3000</p> <p>Separator Pressure (psi): 114.7</p> <p>Separator Temperature (°F): 60</p> <p>Corrected Gas G: 0.8</p> <p>Initial B<sub>o</sub> (rbbl/sbbl): 1.2915</p> <p>Oil Viscosity (cp): 1.27</p> <p>Solution GOR (scf/bbl): 638.7</p> <p>Initial c<sub>o</sub> (10<sup>-5</sup>/psi): 0.564</p> </div> <div> <b>Water/Rock Properties</b> <p>Salinity (ppm NaCl): 35000</p> <p>Initial B<sub>w</sub> (rbbl/sbbl): 1.0149</p> <p>Water Viscosity (cp): 0.433</p> <p>Solution GWR (scf/bbl): 15.97</p> <p>Initial c<sub>w</sub> (10<sup>-5</sup>/psi): 0.275</p> <p>Initial c<sub>r</sub> (10<sup>-5</sup>/psi): 0.625</p> <p>Initial c<sub>e</sub> (10<sup>-5</sup>/psi): 1.111</p> </div> </div> <p>Copy PVT Properties to all Wells</p>							

Figure W.7-6: PE<sup>2</sup> Essentials Production Data Analysis – PVT Data

The PDA tool will automatically remove the zero rates for analysis purposes. To further improve the analysis, the rate spikes were removed from the data (Figure W.7-7).

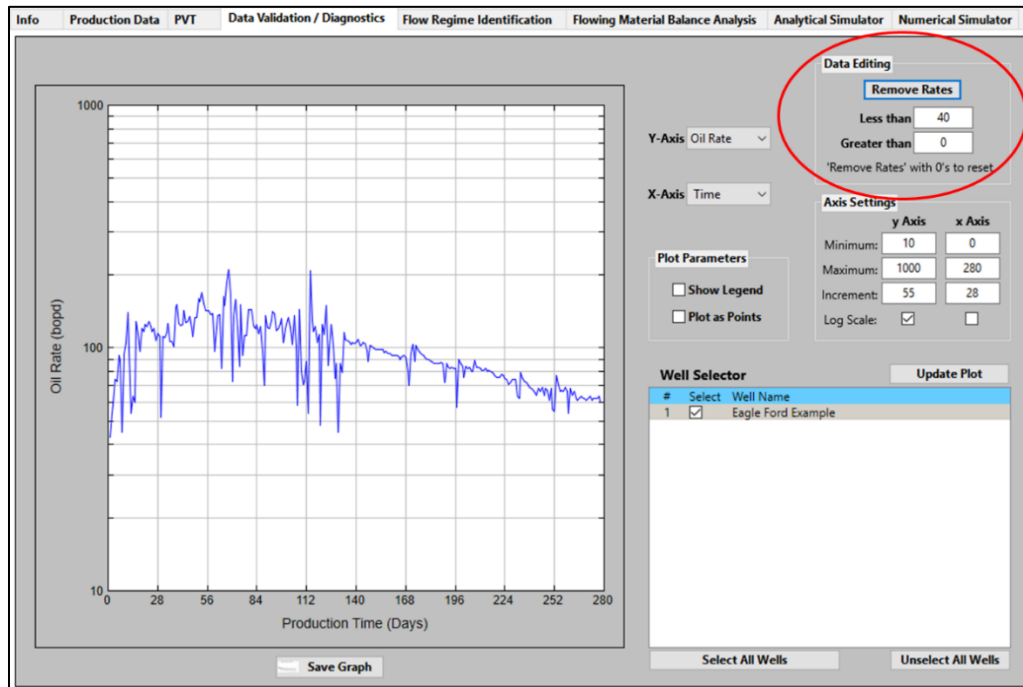


Figure W.7-7: PE<sup>2</sup> Essentials Production Data Analysis – Data Edit: Remove Rate Spikes

The existence of boundary-dominated flow was confirmed by placing a unit-slope line on the data plot on the “Flow Regime Identification” sheet (Figure W.7-8). This confirms that flowing material balance, simulation and conventional decline curve analyses are possible with this data set.

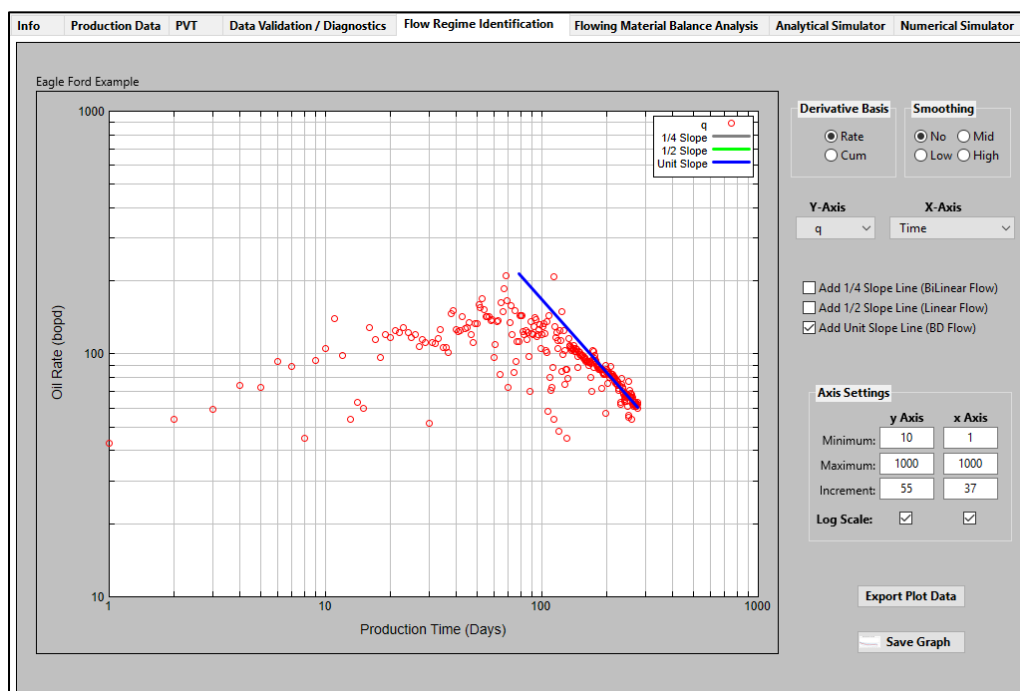


Figure W.7-8: PE<sup>2</sup> Essentials Production Data Analysis – Flow Regime Identification

There are many more plots available in the “Flow Regime Identification” sheet that can be used to confirm the existence of bilinear, linear and boundary dominated flow (BDF).

### W.7.1 Flowing Material Balance – Eagle Ford Example

Since BDF was confirmed to exist, a flowing material balance was performed on the data. It should be noted that flowing P/Z and flowing PI is available for FMB of a gas well. These parameters are not available for the oil FMB because oil production is a much more complex process to model (Refer to Section 8.5.9).

A caveat when performing oil FMB, it is very important to load the proper material balance model to estimate declining reservoir pressure. For a gas well, the default straight-line material balance model will work since the gas recovery process is normally a straight-line P/Z process which extrapolates to initial gas in place. For oil reservoirs, the material balance is a complex process of depletion, gas and water drives and as a result, the default straight-line material balance model will not be valid so an appropriate material balance model should be loaded.

Figure W.7-9 shows the FMB analysis using an imported depletion drive material balance model generated with the PE<sup>2</sup> Essentials Oil Material Balance tool (Oil\_Material\_Balance Results Depletion Drive EagleFord.csv). Resulting oil in place was 586 mbbls.

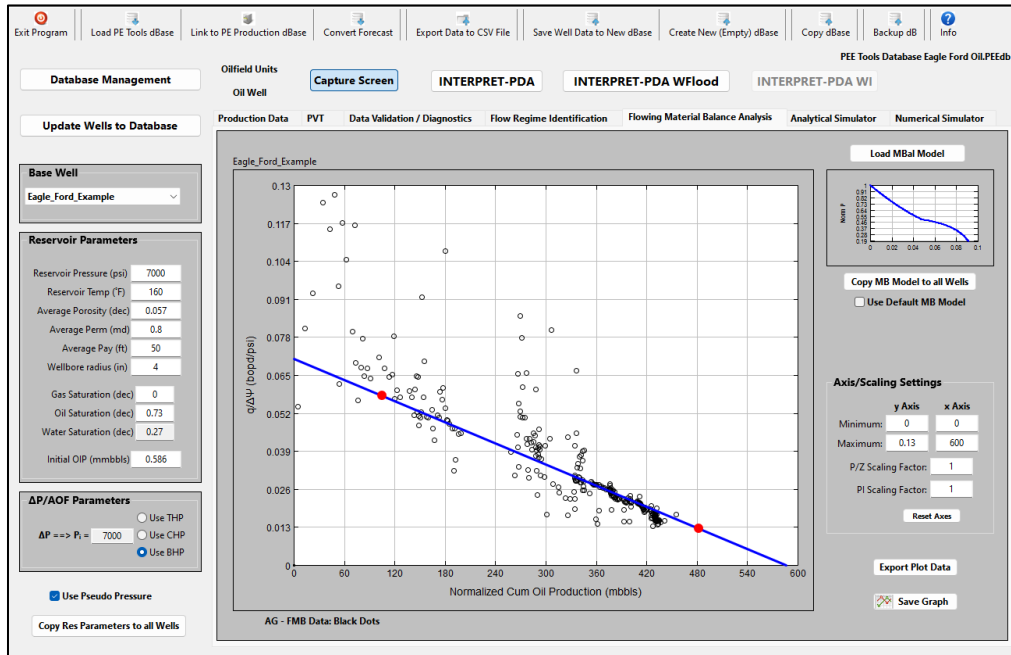


Figure W.7-9: PE<sup>2</sup> Essentials Production Data Analysis – Flow Material Balance Analysis

It should be noted that oil pseudo pressure was used for analysis. This gives a more rigorous solution taking varying oil properties into account. Figure W.7-10 presents the analysis using pressure. The result is a lower oil in place (499 mbbls). Section W.7.2 evaluates the difference.

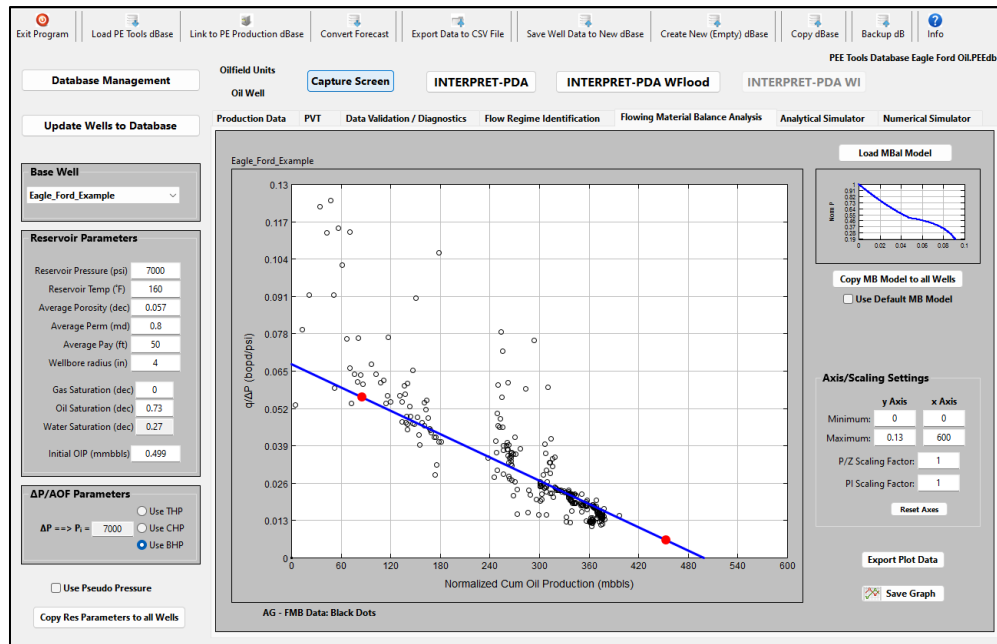




Figure W.7-10: PE<sup>2</sup> Essentials Production Data Analysis – FMB – Pressure Based

### W.7.2 Analytical Simulation – Eagle Ford Example

Since BDF was confirmed to exist and an oil in place was determined, the analytical simulator was used to determine the remaining reservoir parameters for this Eagle Ford well. Figure W.7-11 shows the simulation results using the FMB pseudo pressure analysis results.

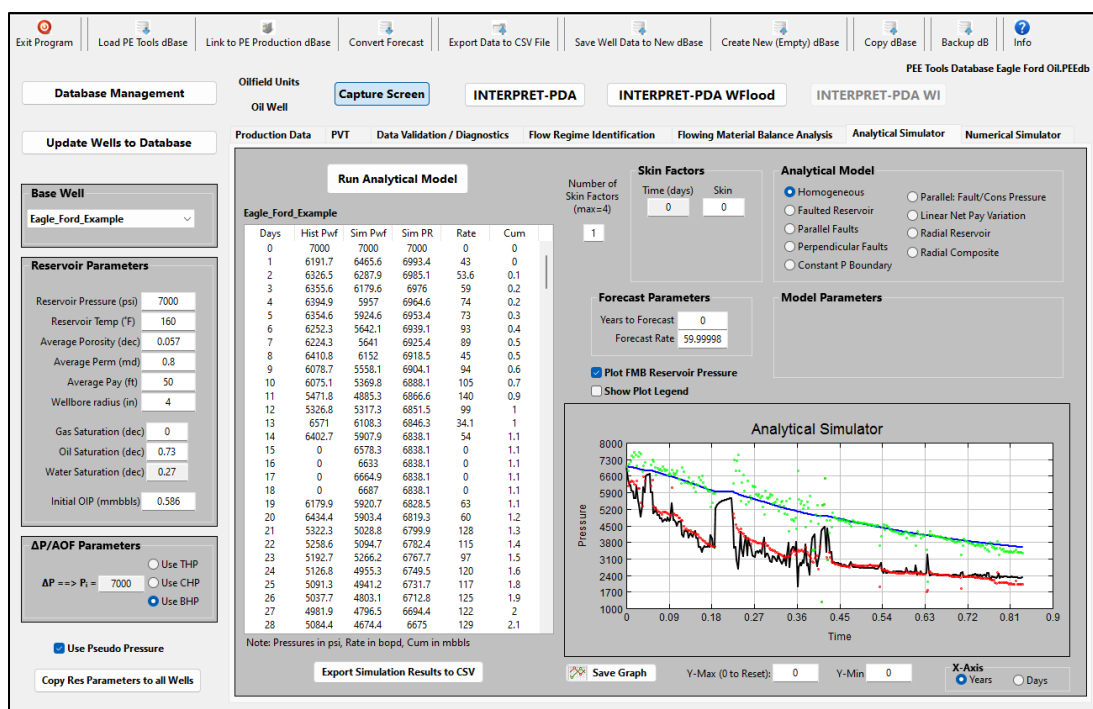
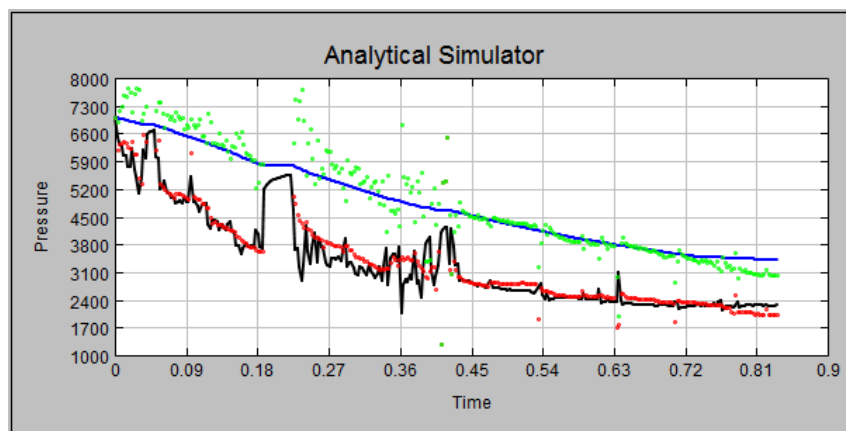
Figure W.7-11: PE<sup>2</sup> Essentials Production Data Analysis – Analytical Simulation, 578 mbbls Case

Figure W.7-12 presents the simulation results for 465 mbbls. Note that it would still be possible to match the historical pressures by increasing the permeability to 1.0 md from 0.8 md.

Figure W.7-12: PE<sup>2</sup> Essentials Production Data Analysis – Analytical Simulation, 465 mbbls Case

## W.7.3 Numerical Simulation – Eagle Ford Example

With the estimated reservoir parameters resulting from the analytical simulation a PE<sup>2</sup> Essentials Basic Reservoir Simulator well model was built to confirm the analytical simulator results, fine-tune the reservoir parameters, and generate a forecast for the well. Figure W.7-13 shows the parameters used to build the simulation model and Figure W.7-14 is the simulation run.

**Database Management**

**Oilfield Units**

**Update Wells to Database**

**Base Well**  
Eagle\_Ford\_Example

**Reservoir Parameters**

Reservoir Pressure (psi)	7000
Reservoir Temp (°F)	160
Average Porosity (dec)	0.057
Average Perm (md)	0.8
Average Pay (ft)	50
Wellbore radius (in)	4
Gas Saturation (dec)	0
Oil Saturation (dec)	0.73
Water Saturation (dec)	0.27
Initial OIP (mmbbls)	0.586

**ΔP/AOF Parameters**

Use THP ☐ Use CHP ☐ Use BHP ☒

ΔP =  $\Rightarrow$  P<sub>i</sub> = 7000

☒ Use Pseudo Pressure

Copy Res Parameters to all Wells

**Numerical Model**

Depth to Top Reservoir (ft)	8700
Reservoir Length (ft)	6037
Reservoir Width/Well Spacing (ft)	450
Tubing ID (in)	1.992
Number of Hydraulic Fractures	15
Fracture Half Length (ft)	150

Reset Reservoir Area

**Basic Reservoir Simulator**

☐ Vertical Well ☒ Horizontal Well

Build PE Basic Reservoir Simulator Model

☐ Build Single Fracture Stage Model

**Unconventional Forecast**

☒ Horizontal Well

Build PE Unconventional Forecast Model

**Industry Simulator - Single Vertical Well Model**

Build Simulator Well Model

Export Schedule File

☒ Rate Control ☐ BHP Control ☐ THP Control

**Estimated Numerical Model Parameters**

Area of Simulation Model (Acres)	62.4
Initial Oil in Place (mmbbls)	0.588
Free+Sol'n Gas in Place (Bscf)	0.949
Initial Water in Place (mmbbls)	0.367

Figure W.7-13: PE<sup>2</sup> Essentials Production Data Analysis – Numerical Simulation Model Build

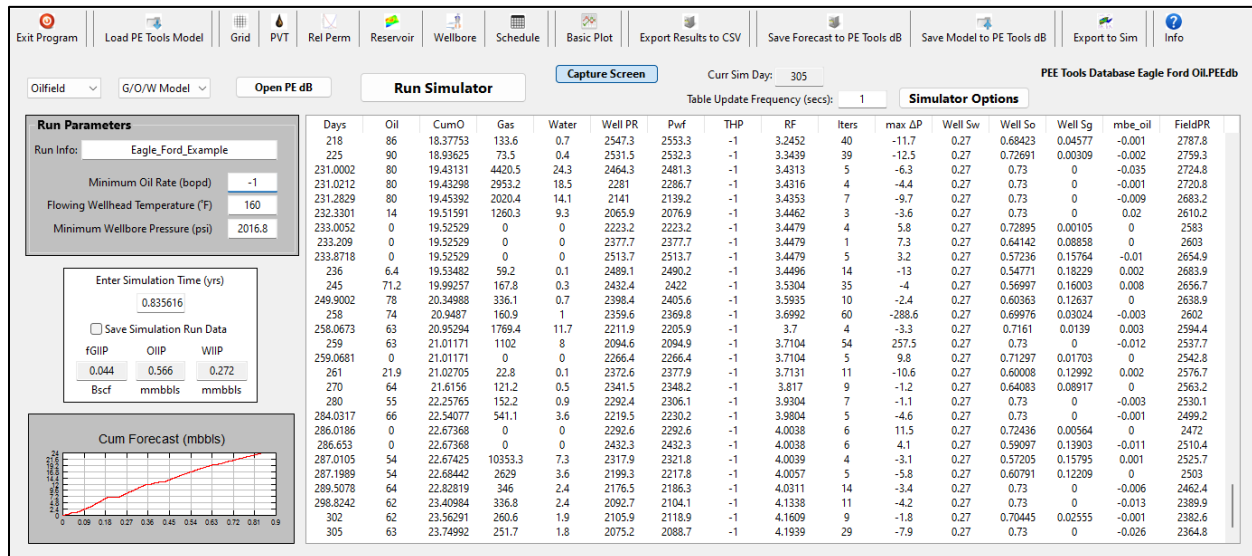


Figure W.7-14: PE<sup>2</sup> Essentials Basic Reservoir Simulator – Eagle Ford

### W.7.4 Decline Curve Analysis – Eagle Ford Example

Since boundary dominated flow was evident from the PDA, the data was exported to a DCA database file and loaded into the PE<sup>2</sup> Essentials Decline Curve Analysis tool (Figure W.7-15).

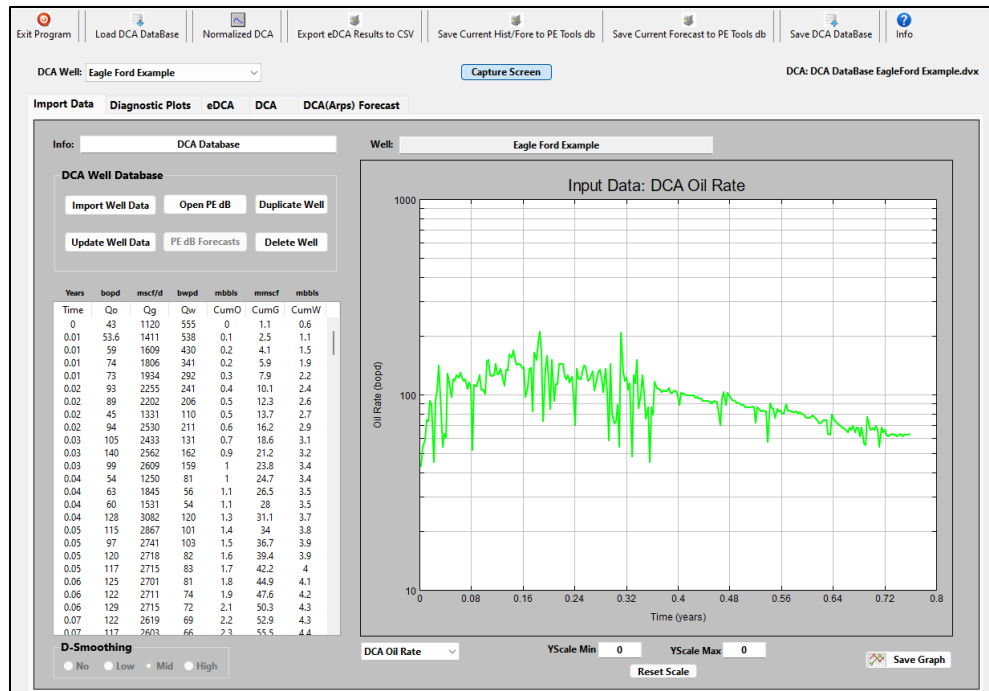


Figure W.7-15: PE Decline Curve Analysis – Eagle Ford

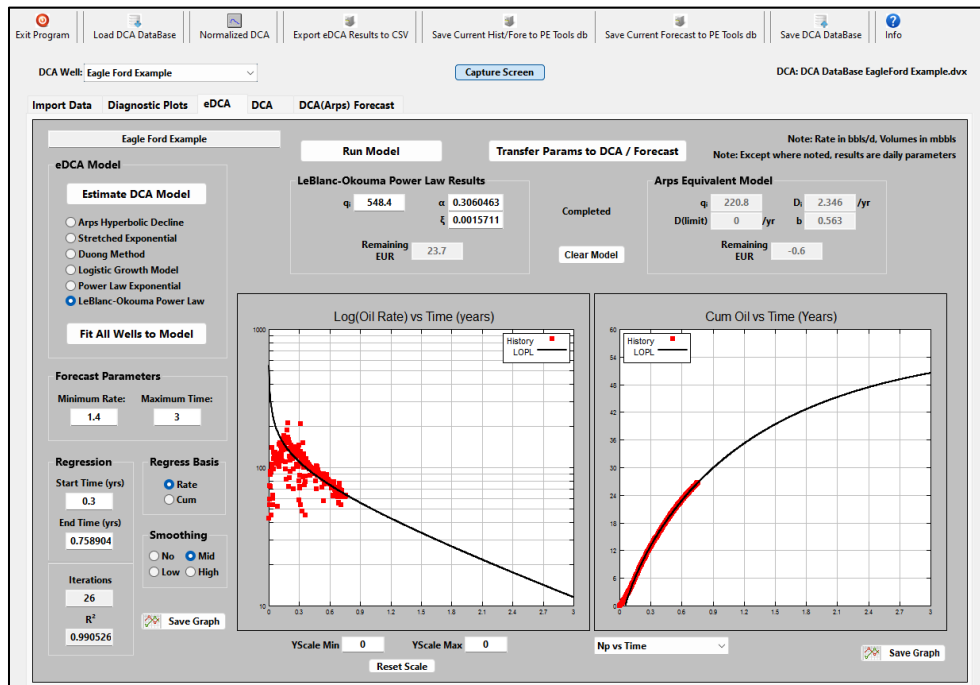


Figure W.7-16: PE Decline Curve Analysis – eDCA, Eagle Ford

The eDCA tool was used to evaluate the Eagle Ford data (Figure W.7-16). The LOPL model was used with a regression start time of 0.3 yrs to restrict the analysis to the BDF period, and a total production period of 3 years. After the model is generated, the parameters are transferred to the other tabs by clicking the 'Transfer Parameters to DCA / Forecast' button.

It is also possible to refine the match using the sliders on the 'DCA' tab. To do this enter a low and high value in the parameters box and then move the sliders until the match is acceptable. Figure W.7-17 shows the final match. If the model was modified, clicking the 'Save to eDCA & Forecast' button will transfer the parameters to the other tabs.

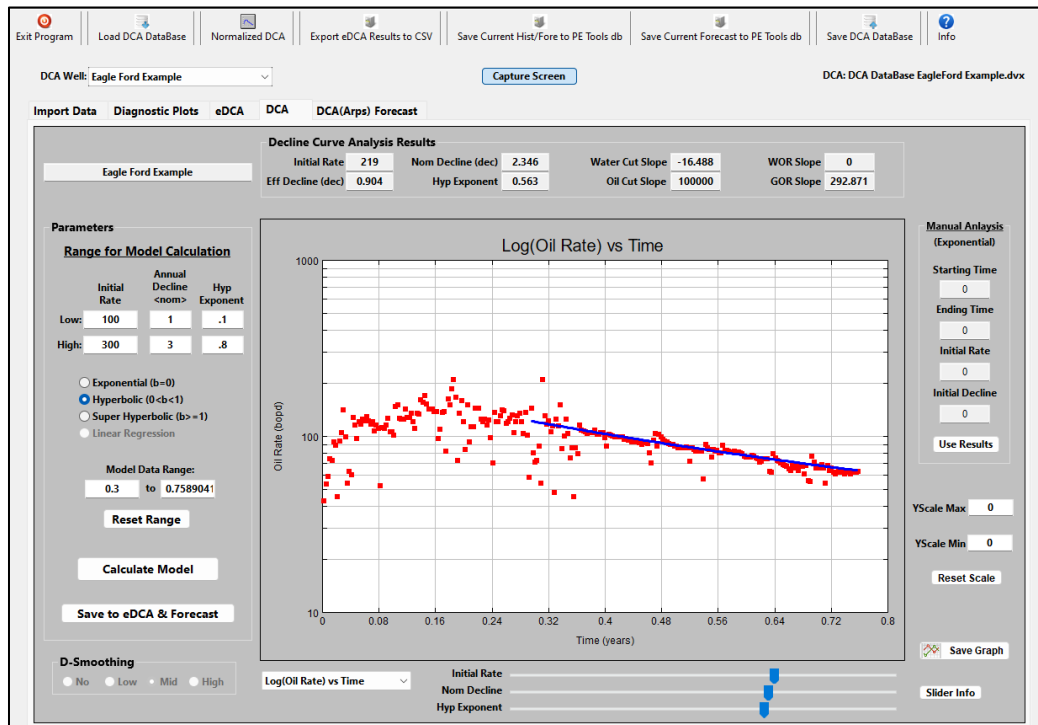


Figure W.7-17: PE Decline Curve Analysis – eDCA, Eagle Ford, Slider-Based Match

From this tab, the water cut and GOR trends are estimated (Figure W.7-18) and a forecast was generated (Figure W.7-19).

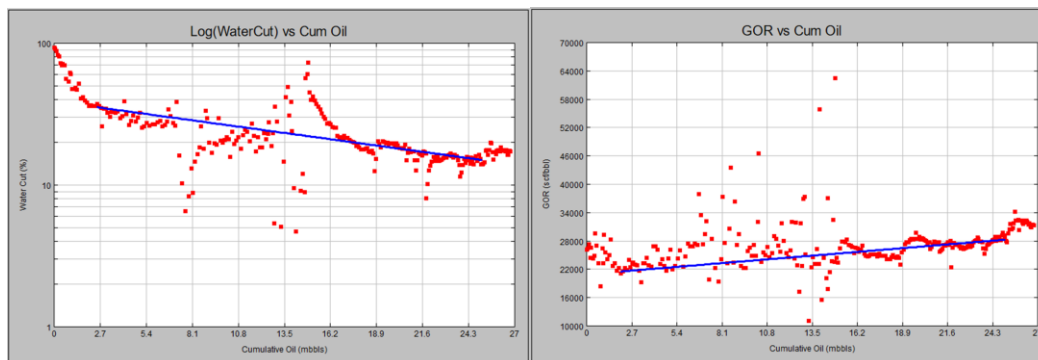


Figure W.7-18: PE Decline Curve Analysis – Water Cut and GOR Trends

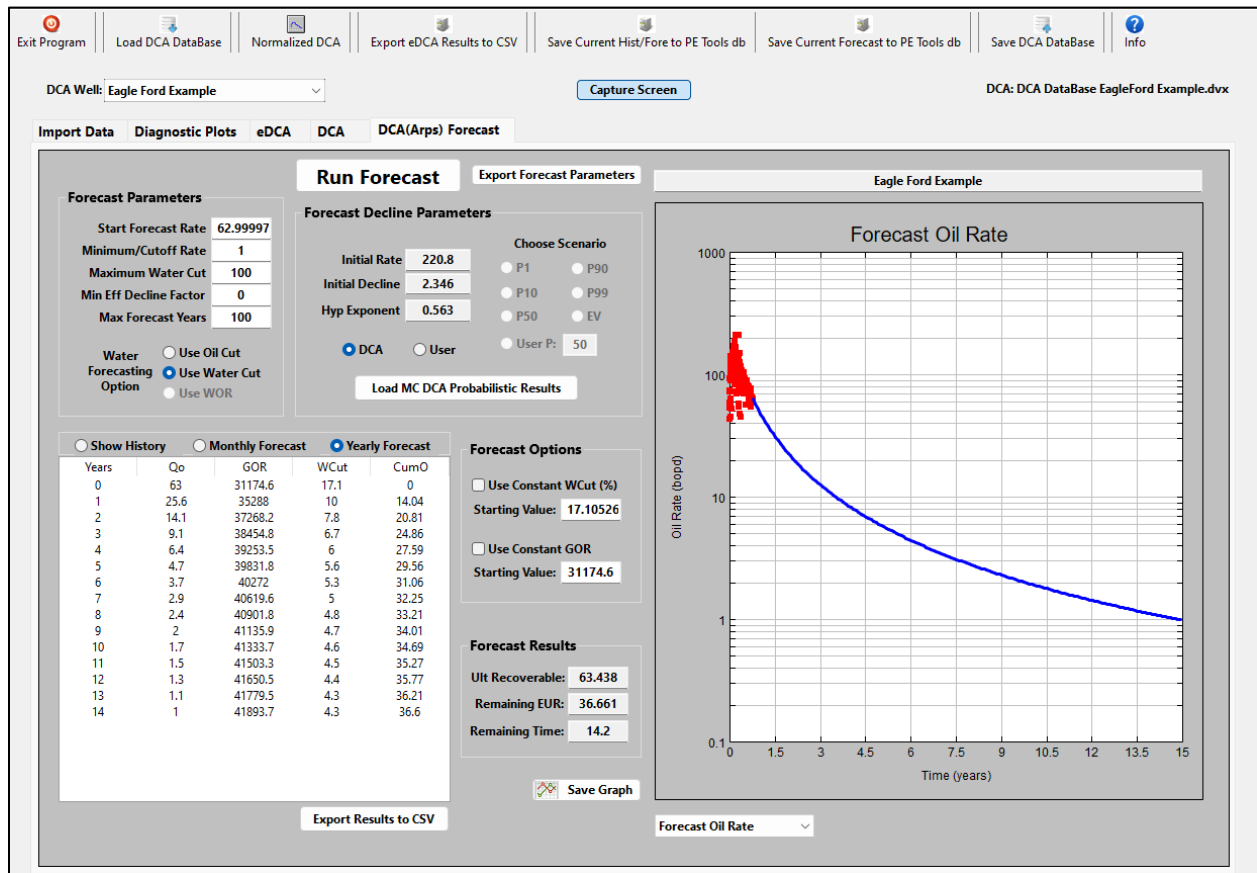


Figure W.7-19: PE Decline Curve Analysis – DCA Forecast

From the DCA forecast, the ultimate oil recovery is forecast to be 63.4 mbbls (10.6%) with a remaining recovery, to a minimum of 1 bopd, of 36.7 mbbls. Over 14.2 years

At this point the data could be exported for Monte Carlo forecasting or additional forecasting and economic analysis could be performed.

## W.8 Asset Evaluation – 6-Well Pad

The proposed plan is to produce the Marcellus by drilling two 6-well production pads. The question to be answered: is it better to drill the two pads simultaneously with two rigs or sequentially with one rig. A pad cannot be placed on production until all 6 wells are completed and tied into the facilities.

### W.8.1 Marcellus Historical Wells - DCA

In order to base the economics on real Marcellus data, a DCA database containing 12 Marcellus wells was built for this project. The DCA database containing the base data is located in the “Workflow - Marcellus Pads” directory and is called “PE\_Essentials\_DCA\_DataBase Marcellus.dvx”.

The first step is to perform a DCA on the historical data and generate a forecast for each well. The Marcellus-11 well in the database was used to demonstrate the steps used for this example.

Since the entire history will be used as a “forecast” for the CAPE analysis, eDCA was used to determine the Arps parameters for the entire history plus a 10-year forecast. Figure W.8-1 shows the first step: calculate the LOPL parameters for a 10-year history/forecast.

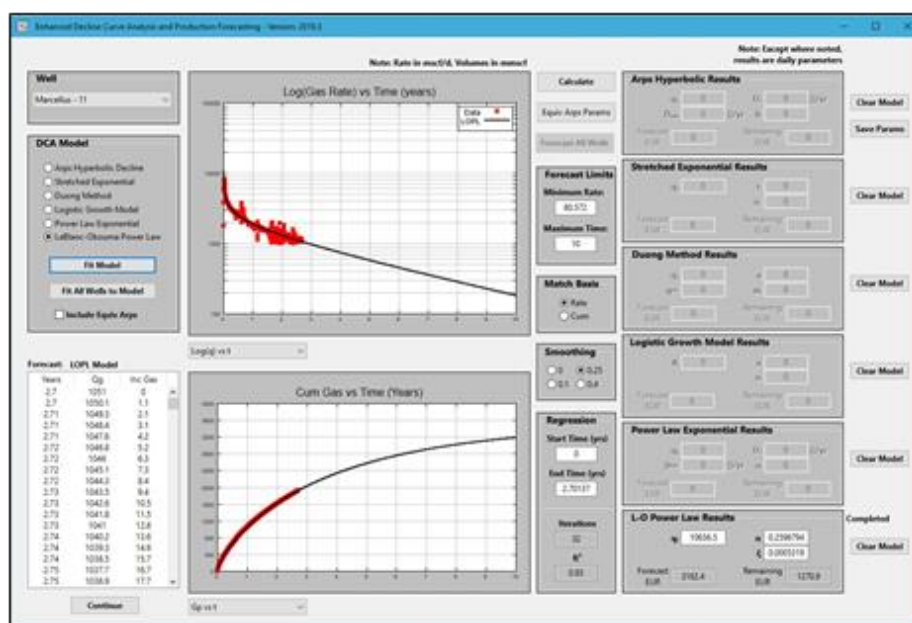


Figure W.8-1: eDCA – Marcellus-11: LOPL Analysis

The next step is to fit an Arps model to the data (Figure W.8-2) and then modify the Dlim until the history/forecast matches the LOPL model results.



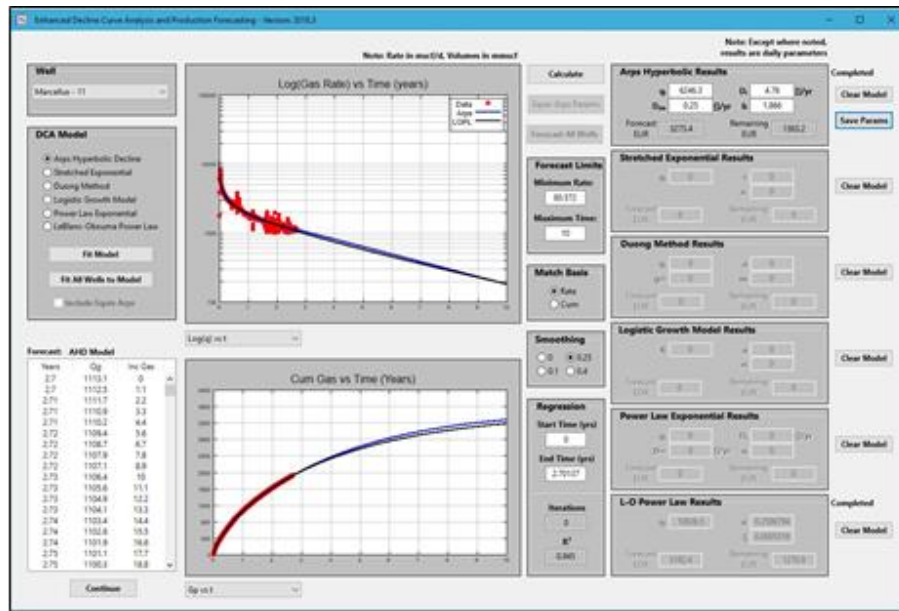


Figure W.8-2: eDCA – Marcellus-11: Arps Analysis and Match

The results are then transferred to the main DCA page by clicking “Save Params” and a forecast is generated by clicking “Run Forecast” (Figure W.8-3) on the main DCA page.

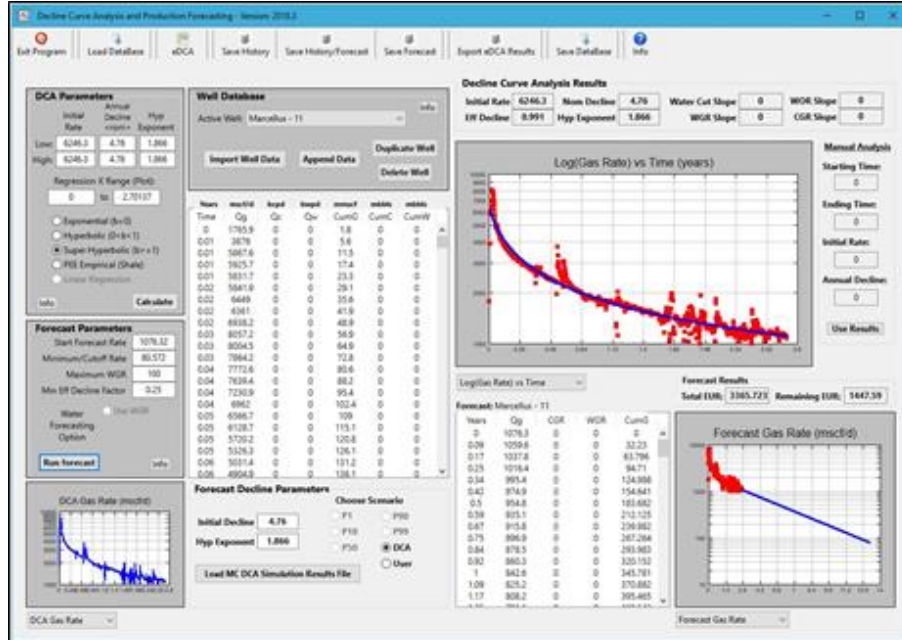


Figure W.8-3: eDCA – Marcellus-11: Generate Forecast for CAPE

This was done for all 12 Marcellus wells in the database and the results are stored in the “PE\_Essentials\_DCA\_DataBase Marcellus Inter.dvx” file for import into the Asset Evaluation tool.



	Model	$Q_i$	$D_i$	$b$	$D_{lim}$
Marcellus - 1	Arps	8059.2	2.433	1.023	1.1
Marcellus - 2	Arps	9591.3	1.42	0.287	1.2
Marcellus - 3	Arps	8789.7	4.643	1.869	0.28
Marcellus - 4	Arps	4006.1	0.498	0.037	0.000
Marcellus - 5	Arps	3268.8	1.274	0.655	0.55
Marcellus - 6	Arps	3977.7	0.869	0.128	0.68
Marcellus - 7	Arps	8667.1	3.51	1.065	0.4
Marcellus - 8	Arps	3784.6	0.718	1.205	0.3
Marcellus - 10	Arps	13904.2	50.729	3.051	0.15
Marcellus - 11	Arps	6246.3	4.76	1.866	0.25
Marcellus - 12	Arps	5218.5	1.491	0.921	0.6
Marcellus - 13	Arps	5043.3	1.96	1.441	0.45

	Model	$Q$	$\alpha$	$\xi$
Marcellus - 1	LOPL	8995.7	0.07244	0.00274
Marcellus - 2	LOPL	9274.6	0.00010	0.00328
Marcellus - 3	LOPL	14181.2	0.24365	0.00060
Marcellus - 4	LOPL	4915	0.04508	0.00123
Marcellus - 5	LOPL	5309.9	0.15587	0.00131
Marcellus - 6	LOPL	7518.6	0.15659	0.00161
Marcellus - 7	LOPL	20040.7	0.32949	0.00088
Marcellus - 8	LOPL	4196.8	0.05380	0.00077
Marcellus - 10	LOPL	14178.1	0.26827	0.00021
Marcellus - 11	LOPL	10636.5	0.25968	0.00053
Marcellus - 12	LOPL	5621	0.06876	0.00152
Marcellus - 13	LOPL	6045.2	0.11121	0.00112

## W.8.2 Marcellus Pad Production – Asset Evaluation Import Parameters

[illegible]

*epci.*

For this example, the second pad is available immediately, 5.5 months (~27 days/well) after production start-up or delayed to 1 year after production start-up. The drilling of the second pad was modeled by delaying the availability of the second group of 6 wells as shown in Figure W.8-5. Figure W.8-5 compares the three production profiles that were evaluated: no delay for second pad; 5.5-month delay for second pad, and 1-year delay for second pad.

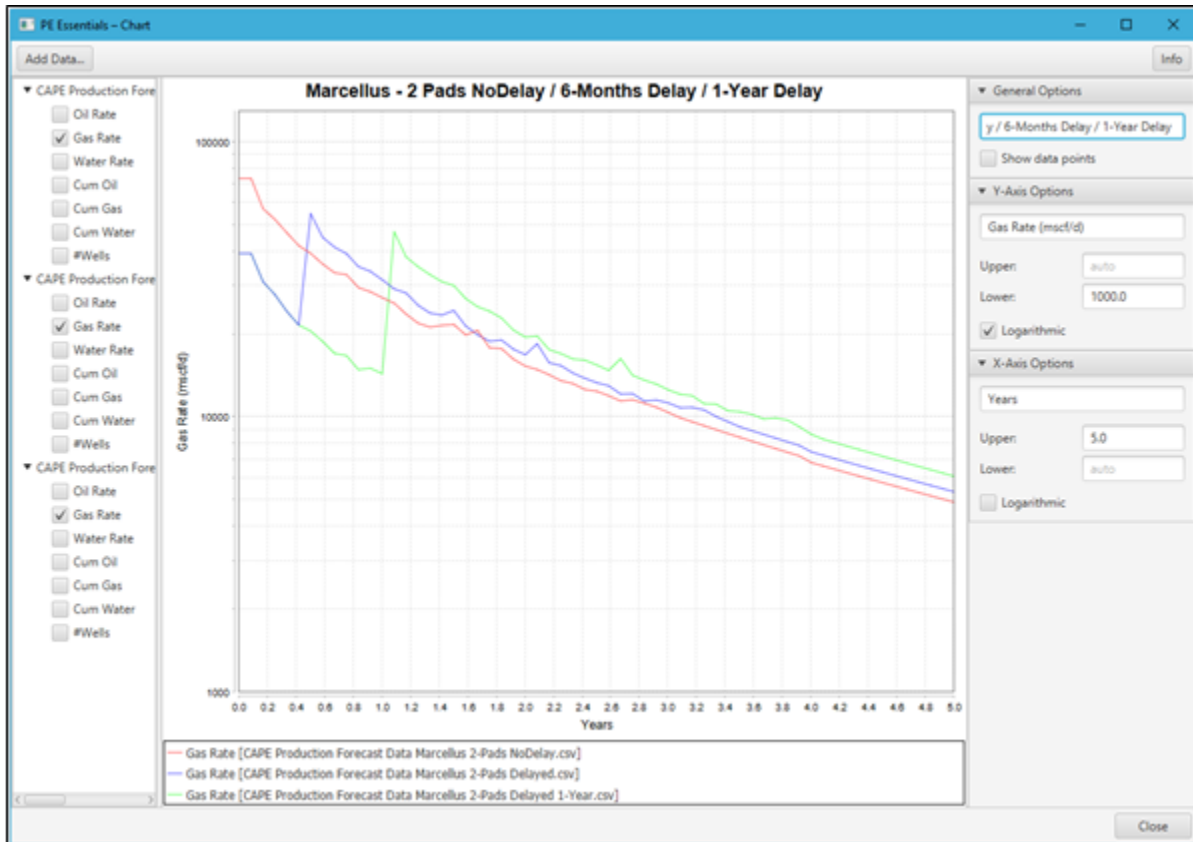


Figure W.8-5: Asset Evaluation – Comparison of Marcellus Forecast

In both delay cases, the capital for the second pad is spent in the first year but the production availability is different.

The economic data used for these sensitivity cases for the Marcellus development were similar to the economic data presented in Section W4. The following figures – Figure W.8-6, Figure W.8-7, Figure W.8-8, Figure W.8-9 – present the input data used for this analysis.

Note – the TRC fiscal regime was used with an assumed gas royalty rate of 18% and a corporate income tax rate of 35%.

The oil and gas price forecast was imported from the “Historical and Forecasted Oil and Gas Prices.xlsx” spreadsheet located in the “Example Input Files\Excel Files” directory

**CAPE Model Parameters**

Asset Name: Marcellus 2 Pads NoDelay

Annual Discount Rate (%) 30

Forecast Start Year 2018

Forecast Start Month (#) 1

Year to Start Discounting (Full Cycle Economics) 1

**Oil/Gas Prices**

Oil Price (US\$/bbl) 0

Gas Price (US\$/mcf) 0

Oil Price Differential (%) 0

Gas Price Premium (US\$/mcf) 0

Import Oil/Gas Price Profile

**Escalation Factors**

Oil Price (%/yr) 0

Gas Price (%/yr) 0

CapEx (%/yr) 0

OpEx (%/yr) 0

Oil/Gas Trans (%/yr) 0

Oil/Gas Processing (%/yr) 0

Water Disposal (%/yr) 0

Note: Changing any of these parameters will reset the corresponding values in the table

Return

Import O/G Table

Import Esc Table

**Oil and Gas Price Forecast - Unescalated**

Date	Year	Oil \$/bbl	Gas \$/mcf
2018	1	52.58	3.1
2019	2	58.5	3.3
2020	3	64.45	3.5
2021	4	69.17	3.68
2022	5	74.17	3.88
2023	6	79.17	4.08
2024	7	81.67	4.28
2025	8	83.38	4.39
2026	9	83.65	4.4
2027	10	83.65	4.4
2028	11	83.65	4.4
2029	12	83.65	4.4
2030	13	83.65	4.4
2031	14	83.65	4.4
2032	15	83.65	4.4
2033	16	83.65	4.4
2034	17	83.65	4.4
2035	18	83.65	4.4
2036	19	83.65	4.4
2037	20	83.65	4.4
2038	21	83.65	4.4
2039	22	83.65	4.4
2040	23	83.65	4.4
2041	24	83.65	4.4
2042	25	83.65	4.4
2043	26	83.65	4.4
2044	27	83.65	4.4
2045	28	83.65	4.4
2046	29	83.65	4.4
2047	30	83.65	4.4
2048	31	83.65	4.4

**Annual Escalation Factors**

Date	Oil Price	Gas Price	CapEx	OpEx	Trans	Process	Disposal
2018	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0
2034	0	0	0	0	0	0	0
2035	0	0	0	0	0	0	0
2036	0	0	0	0	0	0	0
2037	0	0	0	0	0	0	0
2038	0	0	0	0	0	0	0
2039	0	0	0	0	0	0	0
2040	0	0	0	0	0	0	0
2041	0	0	0	0	0	0	0
2042	0	0	0	0	0	0	0
2043	0	0	0	0	0	0	0
2044	0	0	0	0	0	0	0
2045	0	0	0	0	0	0	0
2046	0	0	0	0	0	0	0
2047	0	0	0	0	0	0	0
2048	0	0	0	0	0	0	0

Figure W.8-6: Asset Evaluation – Marcellus: Model Parameters

**CAPE Capital Costs**

**CAPE Capital Costs - Unescalated**

**Well Count / Well Profile / Capital**

Total Well Cost (US\$MM) 0

Time to Well On Line (days) -1

Initial #Well 12

Final #Well 12

Info

Vary Well Profiles

**Facility / Project / Capital Costs**

Pre-Startup Costs (US\$MM) 67.2

Ongoing Costs (US\$MM/yr) 0

Length of Time for Costs (#yr) 0

**Abandonment Costs / Timing**

Total Abandonment Costs (US\$MM) 0

Costs Spread Over How Many Years 1

Start Year for Expenditure 2018

Return

Import Table

Date	Project	Inc Well	Well Cost	Abandon
Init	67.2	12	0	
2018	0	0	0	0
2019	0	0	0	0
2020	0	0	0	0
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	0	0	0	0
2028	0	0	0	0
2029	0	0	0	0
2030	0	0	0	0
2031	0	0	0	0
2032	0	0	0	0
2033	0	0	0	0
2034	0	0	0	0
2035	0	0	0	0
2036	0	0	0	0
2037	0	0	0	0
2038	0	0	0	0
2039	0	0	0	0
2040	0	0	0	0
2041	0	0	0	0
2042	0	0	0	0
2043	0	0	0	0
2044	0	0	0	0
2045	0	0	0	0
2046	0	0	0	0

Figure W.8-7(a): Asset Evaluation – Marcellus: Capital Costs and Pad Timing, No Delay

**CAPE Capital Costs - Unescalated**

**Well Count / Well Profile / Capital**

Total Well Cost (US\$MM)

Time to Well On Line (days)

Initial #Well  Info

Final #Well  ☐ Vary Well Profiles

**Facility / Project / Capital Costs**

Pre-Startup Costs (US\$MM)

Ongoing Costs (US\$MM/yr)

Length of Time for Costs (#yr)

**Abandonment Costs / Timing**

Total Abandonment Costs (US\$MM)

Costs Spread Over How Many Years

Start Year for Expenditure

Date	Project	Inc Well	Well Cost	Abandon
Init	33.6	6	0	
2018	33.6	6	0	0
2019	0	0	0	0
2020	0	0	0	0
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	0	0	0	0
2028	0	0	0	0
2029	0	0	0	0
2030	0	0	0	0
2031	0	0	0	0
2032	0	0	0	0
2033	0	0	0	0
2034	0	0	0	0
2035	0	0	0	0
2036	0	0	0	0
2037	0	0	0	0
2038	0	0	0	0
2039	0	0	0	0
2040	0	0	0	0
2041	0	0	0	0
2042	0	0	0	0
2043	0	0	0	0
2044	0	0	0	0
2045	0	0	0	0
2046	0	0	0	0

Figure W.8-7(b): Asset Evaluation – Marcellus: Capital Costs and Pad Timing, 5.5 Month Delay

**CAPE Capital Costs - Unescalated**

**Well Count / Well Profile / Capital**

Total Well Cost (US\$MM)

Time to Well On Line (days)

Initial #Well  Info

Final #Well  ☐ Vary Well Profiles

**Facility / Project / Capital Costs**

Pre-Startup Costs (US\$MM)

Ongoing Costs (US\$MM/yr)

Length of Time for Costs (#yr)

**Abandonment Costs / Timing**

Total Abandonment Costs (US\$MM)

Costs Spread Over How Many Years

Start Year for Expenditure

Date	Project	Inc Well	Well Cost	Abandon
Init	33.6	6	0	
2018	33.6	0	0	0
2019	0	6	0	0
2020	0	0	0	0
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	0	0	0	0
2028	0	0	0	0
2029	0	0	0	0
2030	0	0	0	0
2031	0	0	0	0
2032	0	0	0	0
2033	0	0	0	0
2034	0	0	0	0
2035	0	0	0	0
2036	0	0	0	0
2037	0	0	0	0
2038	0	0	0	0
2039	0	0	0	0
2040	0	0	0	0
2041	0	0	0	0
2042	0	0	0	0
2043	0	0	0	0
2044	0	0	0	0
2045	0	0	0	0
2046	0	0	0	0

Figure W.8-7(c): Asset Evaluation – Marcellus: Capital Costs and Pad Timing, 1-Year Delay

**CAPE Operating Costs**

### CAPE Operating Costs - Unescalated

**Operating Costs**

Field Management (US\$MM/yr)

Fixed Op Costs/Active Well (US\$/yr)

Variable Well Costs - Gas (US\$/mscf)

Variable Well Costs - Oil (US\$/bbl)

Gas Transportation Fee (US\$/mscf)

Oil Transportation Fee (US\$/bbl)

Gas Processing Fee (US\$/mscf)

Oil Processing Fee (US\$/bbl)

Water Disposal Fee (US\$/bbl)

Other Fixed Op Costs (US\$MM/yr)

Note: Changing any of these parameters will reset the corresponding values in the table

Date	Field	Fixed	Var-Oil	Var-Gas	Gas-Trans	Oil-Trans	Gas Proc	Oil Proc	Wat Dis	Other
2018	0	50	0	0.25	0.5	0	0.5	0	0	0
2019	0	50	0	0.25	0.5	0	0.5	0	0	0
2020	0	50	0	0.25	0.5	0	0.5	0	0	0
2021	0	50	0	0.25	0.5	0	0.5	0	0	0
2022	0	50	0	0.25	0.5	0	0.5	0	0	0
2023	0	50	0	0.25	0.5	0	0.5	0	0	0
2024	0	50	0	0.25	0.5	0	0.5	0	0	0
2025	0	50	0	0.25	0.5	0	0.5	0	0	0
2026	0	50	0	0.25	0.5	0	0.5	0	0	0
2027	0	50	0	0.25	0.5	0	0.5	0	0	0
2028	0	50	0	0.25	0.5	0	0.5	0	0	0
2029	0	50	0	0.25	0.5	0	0.5	0	0	0
2030	0	50	0	0.25	0.5	0	0.5	0	0	0
2031	0	50	0	0.25	0.5	0	0.5	0	0	0
2032	0	50	0	0.25	0.5	0	0.5	0	0	0
2033	0	50	0	0.25	0.5	0	0.5	0	0	0
2034	0	50	0	0.25	0.5	0	0.5	0	0	0
2035	0	50	0	0.25	0.5	0	0.5	0	0	0
2036	0	50	0	0.25	0.5	0	0.5	0	0	0
2037	0	50	0	0.25	0.5	0	0.5	0	0	0
2038	0	50	0	0.25	0.5	0	0.5	0	0	0
2039	0	50	0	0.25	0.5	0	0.5	0	0	0
2040	0	50	0	0.25	0.5	0	0.5	0	0	0
2041	0	50	0	0.25	0.5	0	0.5	0	0	0
2042	0	50	0	0.25	0.5	0	0.5	0	0	0

Figure W.8-8: Asset Evaluation – Marcellus: Operating Costs

**CAPE Fiscal Parameters**

### CAPE Fiscal Terms

Currency:

Base Conv:  =US\$

**Fiscal Regime**

☒ Taxes and Royalties Regime

☐ Production Sharing Contract

**Taxes and Royalty Parameters**

Cost Recovery Uplift (US\$MM)

Working Interest Before P/O (%)

Working Interest After P/O (%)

Time to Depreciate CapEx (yrs)

Corporate Income Tax Rate (%)

Oil Royalty Rate Before P/O (%)

Oil Royalty Rate After P/O (%)

Gas Royalty Rate Before P/O (%)

Gas Royalty Rate After P/O (%)

**PSC Parameters**

**PSC Oil/Gas Royalty**

# of Cum Oil Intervals:

#	Max Cum (MM)	Royalty (%)
1	0	0
2	0	0
3	0	0
4	0	0
5	0	0

Gas Royalty Rate (%)

Cost Oil Ceiling (%)

Corporate Income Tax Rate (%)

Time to Depreciate CapEx (yrs)

Company Net Working Interest (%)

**Gov't Share of Profit Oil**

☐ Cum Based Profit Oil Split

☐ Rate Based Profit Oil Split

☐ R-Factor Based Profit Oil Split

# of Cum Oil Intervals:

#	Max Cum (MM)	Gov Share (%)
1	0	0
2	0	0
3	0	0
4	0	0
5	0	0

**Date** **Conv Rate**

2018	1
2019	1
2020	1
2021	1
2022	1
2023	1
2024	1
2025	1
2026	1
2027	1
2028	1
2029	1
2030	1
2031	1
2032	1
2033	1
2034	1
2035	1
2036	1
2037	1
2038	1
2039	1
2040	1
2041	1
2042	1
2043	1
2044	1
2045	1
2046	1

Figure W.8-9: Asset Evaluation – Marcellus: Fiscal Terms



### W.8.3 Marcellus Pad Comparison – Asset Evaluation Results

The analysis results for the three scenarios are presented in Figures W.8-10 and W.8-11.

Asset	Asset	Asset
Marcellus 2 Pads NoDelay	Marcellus 2 Pads Delayed	Marcellus 2 Pads Delayed 1 Y
Project - IRR (%) 6	Project - IRR (%) 6.1	Project - IRR (%) 6.3
Corporate - IRR (%) 1000	Corporate - IRR (%) 30.3	Corporate - IRR (%) 27.6
Corporate NPV @ 0% 49.7	Corporate NPV @ 0% 17.8	Corporate NPV @ 0% 20.3
Corporate NPV @ 7% 42.4	Corporate NPV @ 7% 10.9	Corporate NPV @ 7% 12.1
Corporate NPV @ 10% 40	Corporate NPV @ 10% 8.7	Corporate NPV @ 10% 9.5
Corporate NPV @ 12% 38.5	Corporate NPV @ 12% 7.4	Corporate NPV @ 12% 7.9
Corporate NPV @ 15% 36.6	Corporate NPV @ 15% 5.7	Corporate NPV @ 15% 5.9
Corporate NPV @ 20% 33.8	Corporate NPV @ 20% 3.4	Corporate NPV @ 20% 3.1

Figure W.8-10: Asset Evaluation – Marcellus: NPV Results

	Corporate Economic Results - After Tax					
No Delay	Oil Reserves	0	NPV10	40	Disc Cap Costs	67.2
	Gas Reserves	37262	Econ Life (yrs)	12	Max Exposure	-67.2
5.5 Month Delay	Oil Reserves	0	NPV10	8.7	Disc Cap Costs	65.6
	Gas Reserves	37123	Econ Life (yrs)	12	Max Exposure	-33.6
1 Year Delay	Oil Reserves	0	NPV10	9.5	Disc Cap Costs	65.6
	Gas Reserves	36921	Econ Life (yrs)	12	Max Exposure	-33.6
					Discounted PIR	0.59
					Break Even Year	2018
					Discounted PIR	0.13
					Break Even Year	2021
					Discounted PIR	0.14
					Break Even Year	2021

Figure W.8-11: Asset Evaluation – Marcellus: Economic Results

From the analysis, the simultaneous production of both pads has higher economic value. A large part of this is the rate acceleration resulting from having 12 wells available at the start of production.

If a delay is required, delaying for 1-year appears to have slightly better economics because of more efficient use of the tax pools by the delayed pad, but this could just be the result of yearly averaging in the calculations.

## W.9 Hydrate Protection Requirement

A gas well is produced through a pipeline to a central surface facility and then exported. The PE Nodal tool can be used to generate the different pressures in the system if actual pressure-temperature values are unknown.

The following is given for this example:

Bottomhole Pressure / Temperature: 2500 psi / 120 F

Wellhead Pressure / Temperature: 1750 psi / 80F

Pipeline Outlet Pressure / Temperature: 1500 psi / 70F

Central Manifold Export Pressure / Temperature: 900 psi / 65F

Separator Pressure / Temperature: 500 psi / 45F

### W.9.1 Hydrate Formation Curves

The PE Essentials Hydrate Tool was used to generate the pressure-temperature hydrate curves for 0% methanol (Figure W.9-1), 10% methanol (Figure W.9-2), and 20% methanol (Figure W.9-3) and the csv files were exported for each case. The example model included in PE Essentials was used to generate the hydrate curves.

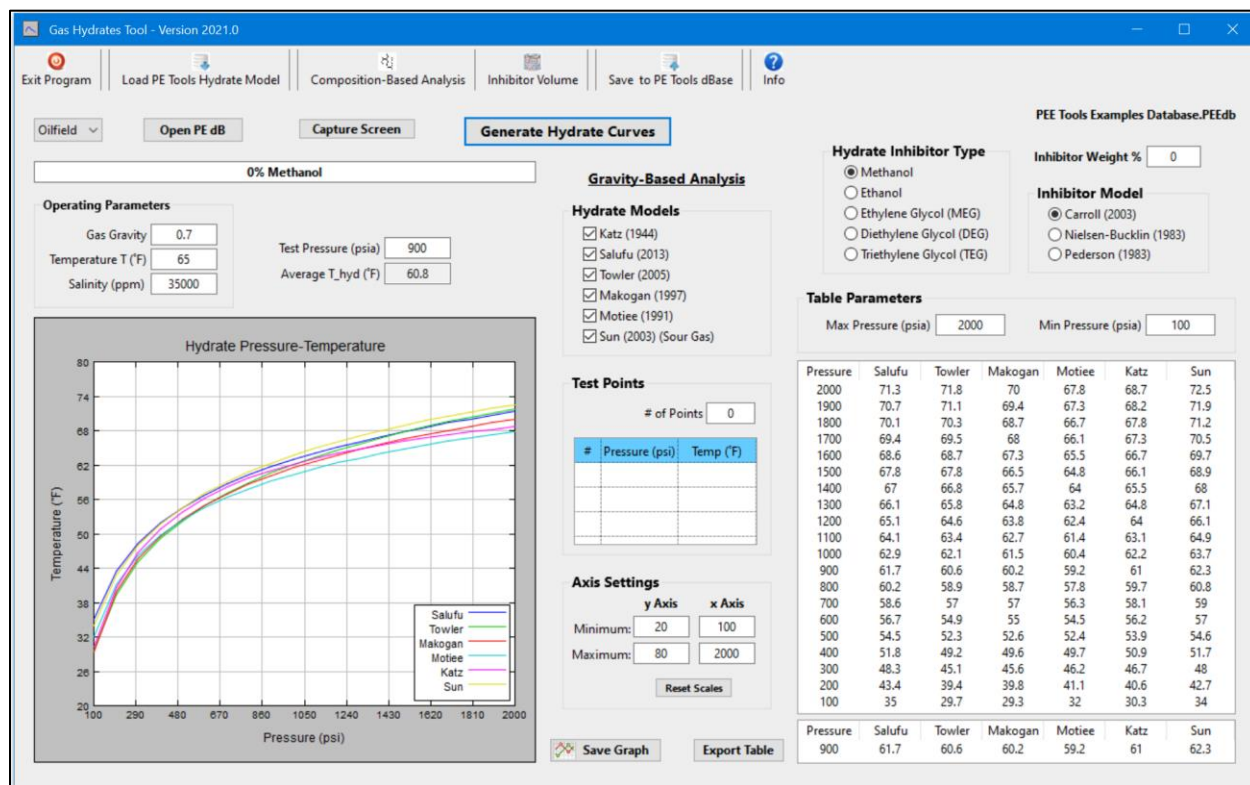


Figure W.9-1: Generation of Hydrate Curves for 0% Methanol

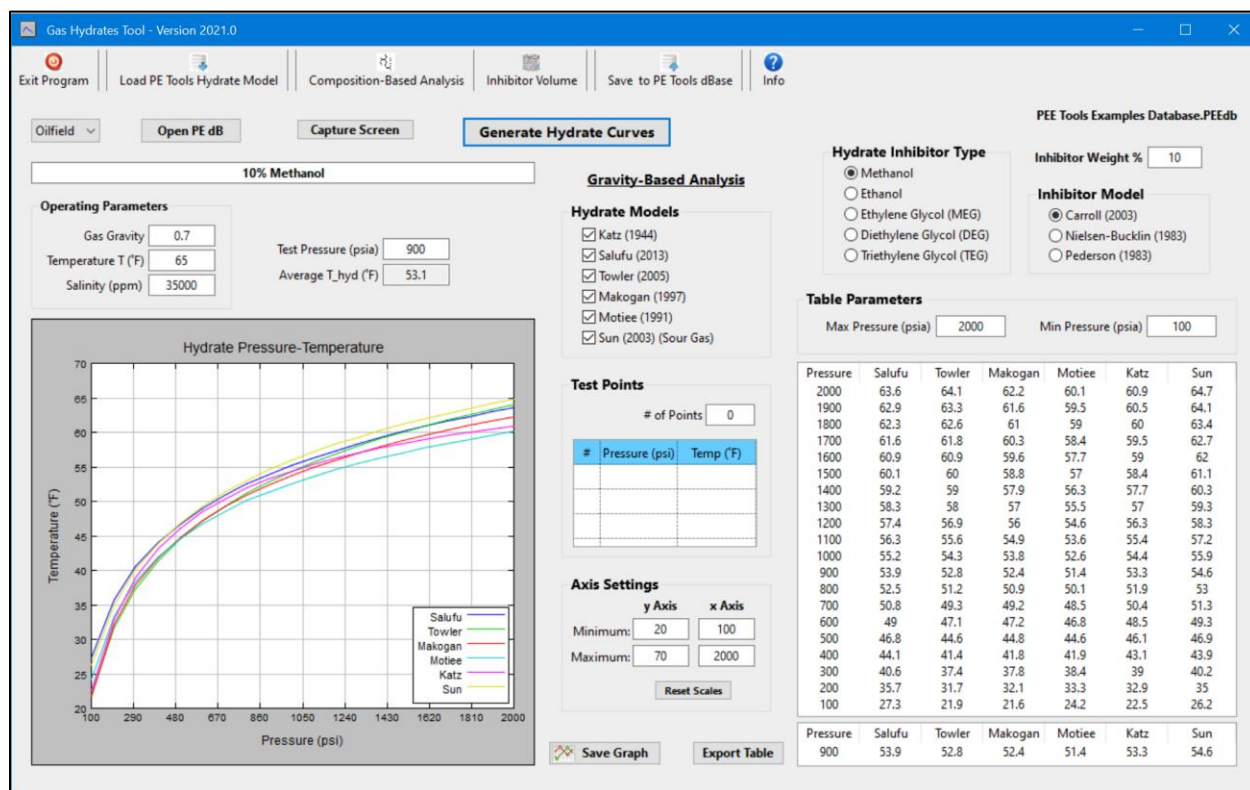


Figure W.9-2: Generation of Hydrate Curves for 10% Methanol

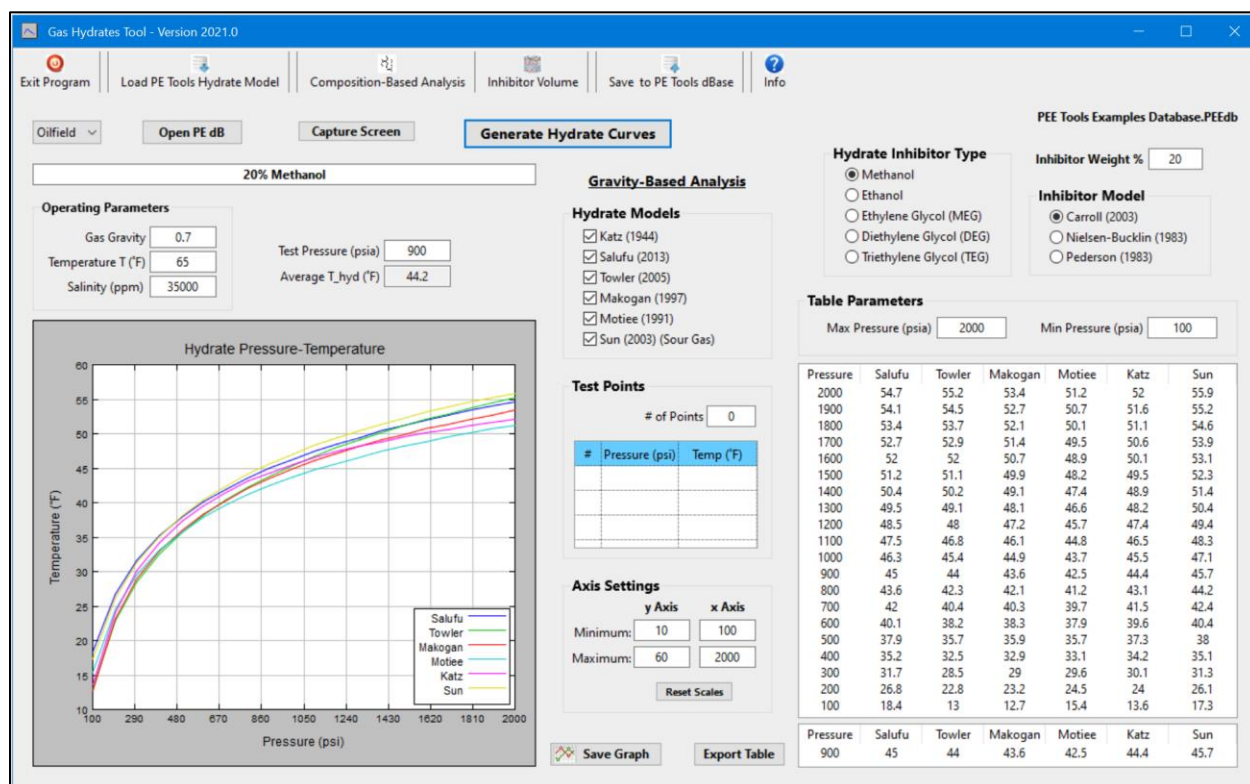


Figure W.9-3: Generation of Hydrate Curves for 20% Methanol



## W.9.2 Graphical Analysis

The PE Essentials Graph Tool was used to evaluate the requirement for methanol to protect the production from hydrates. To plot the analysis, the production pressure/temperature data was copied to a csv file in a format similar to the Hydrate tool's csv plots.

Figure W.9-4 shows the format to the hydrate tool files and Figure W.9-5 presents the csv file built for the production data.

```
PE Essentials Gravity-Based Gas Hydrate Curves, Oilfield
0% Methanol, Gas Gravity = 0.7
Pressure, Salufu, Towler, Makogan, Motiee, Katz, Sun
psi, F, F, F, F, F, F
100,35.01931,29.67332,29.34309,31.99687,30.26245,33.95603
200,43.42109,39.42412,39.82294,41.09241,40.64451,42.7271
300,48.33581,45.12797,45.59785,46.18923,46.73575,47.95869
400,51.82286,49.17491,49.55772,49.70532,50.85931,51.70525
500,54.52763,52.31397,52.55728,52.37535,53.89049,54.62478
600,56.73759,54.87877,54.9643,54.5198,56.2402,57.01467
700,58.60608,57.04727,56.97013,56.30685,58.13083,59.03534
800,60.22464,58.92571,58.68684,57.83558,59.69494,60.78344
900,61.65231,60.58262,60.18557,59.16914,61.01716,62.32179
1000,62.92941,62.06477,61.51426,60.35024,62.15445,63.69359
1100,64.08468,63.40554,62.70671,61.40907,63.14677,64.92983
1200,65.13936,64.62957,63.78764,62.36773,64.02305,66.05352
1300,66.10958,65.75556,64.77563,63.24291,64.80485,67.08224
1400,67.00785,66.79807,65.68504,64.04745,65.50857,68.02968
1500,67.84413,67.76862,66.52714,64.79151,66.14696,68.90678
1600,68.62642,68.67651,67.31098,65.48319,66.7301,69.72237
1700,69.36126,69.52935,68.04391,66.12912,67.26605,70.48371
1800,70.05409,70.33342,68.73196,66.73474,67.76135,71.19684
1900,70.70945,71.09401,69.3802,67.30458,68.22137,71.86681
2000,71.33118,71.81557,69.99286,67.84248,68.65057,72.49793
```

Figure W.9-4: Hydrate Tool CSV File

```
PE Essentials Gravity-Based Gas Hydrate Curves, Oilfield
Bottomhole-to-Export
Pressure, Salufu, Towler, Makogan, Motiee, Katz, Sun
psi, F, F, F, F, F, F
500,45,45,45,45,45,45
900,65,65,65,65,65,65
1500,70,70,70,70,70,70
1750,80,80,80,80,80,80
2500,120,120,120,102,120,120
```

Figure W.9-5: Production Data CSV File

The key to the production data csv file is the layout and the first line in the file has to be the same as the first line in the Hydrate Tool's csv file. The first line is used to confirm that compatible files are being loaded.

All the csv files were then loaded into PE Graph (Figure W.9-6) and the analysis plot was built (Figure W.9-7).

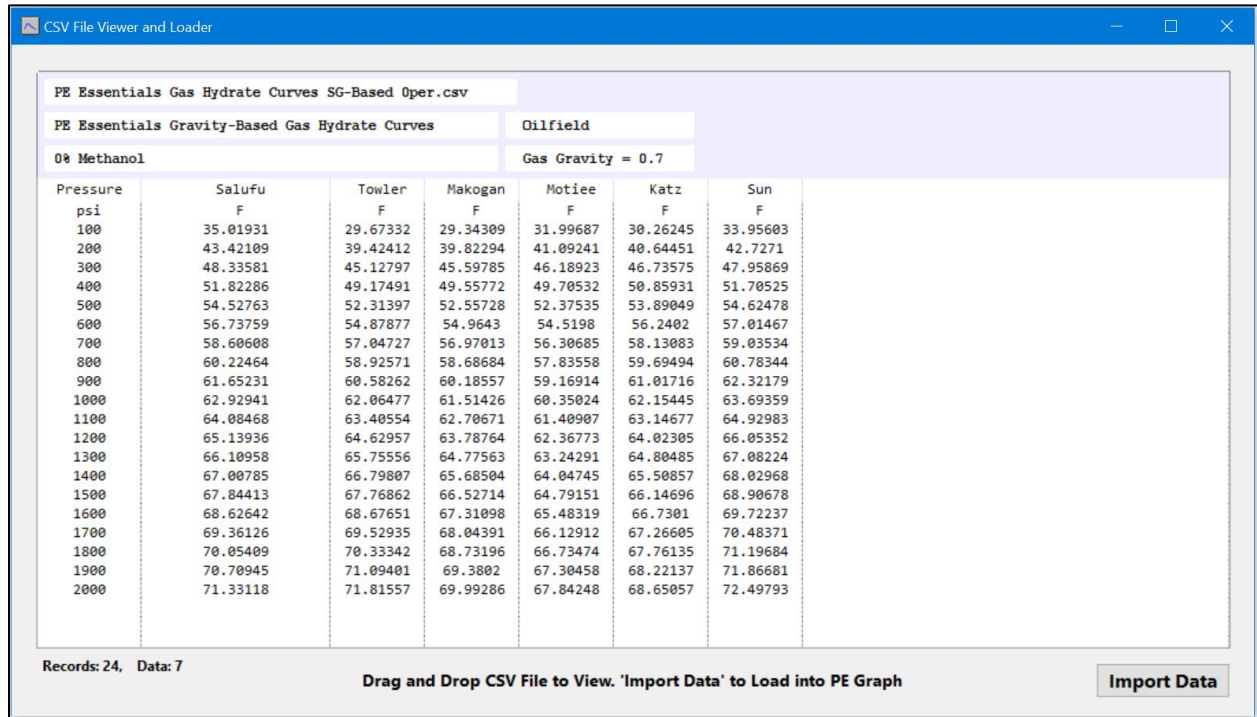


Figure W.9-6: PE Graph - Import of csv File

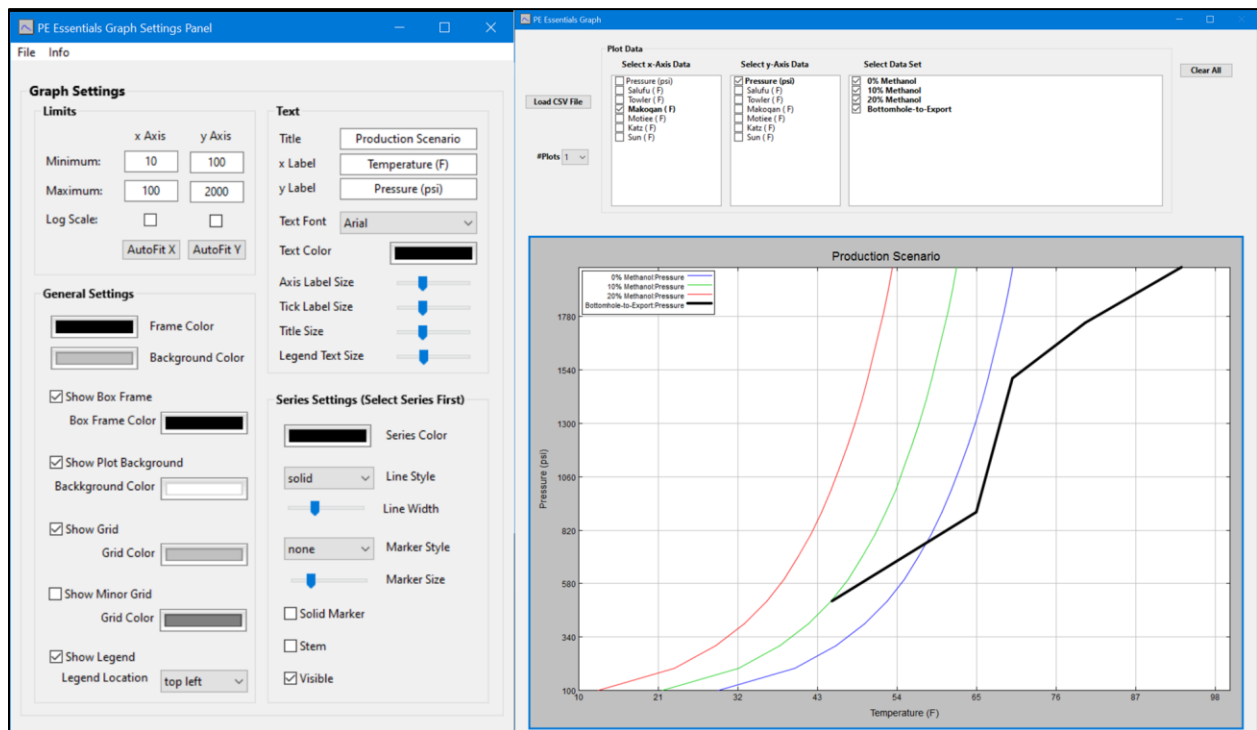


Figure W.9-7: PE Graph – Plot Generation

Figure W.9-8 shows the production scenario in terms of pressure/temperature.

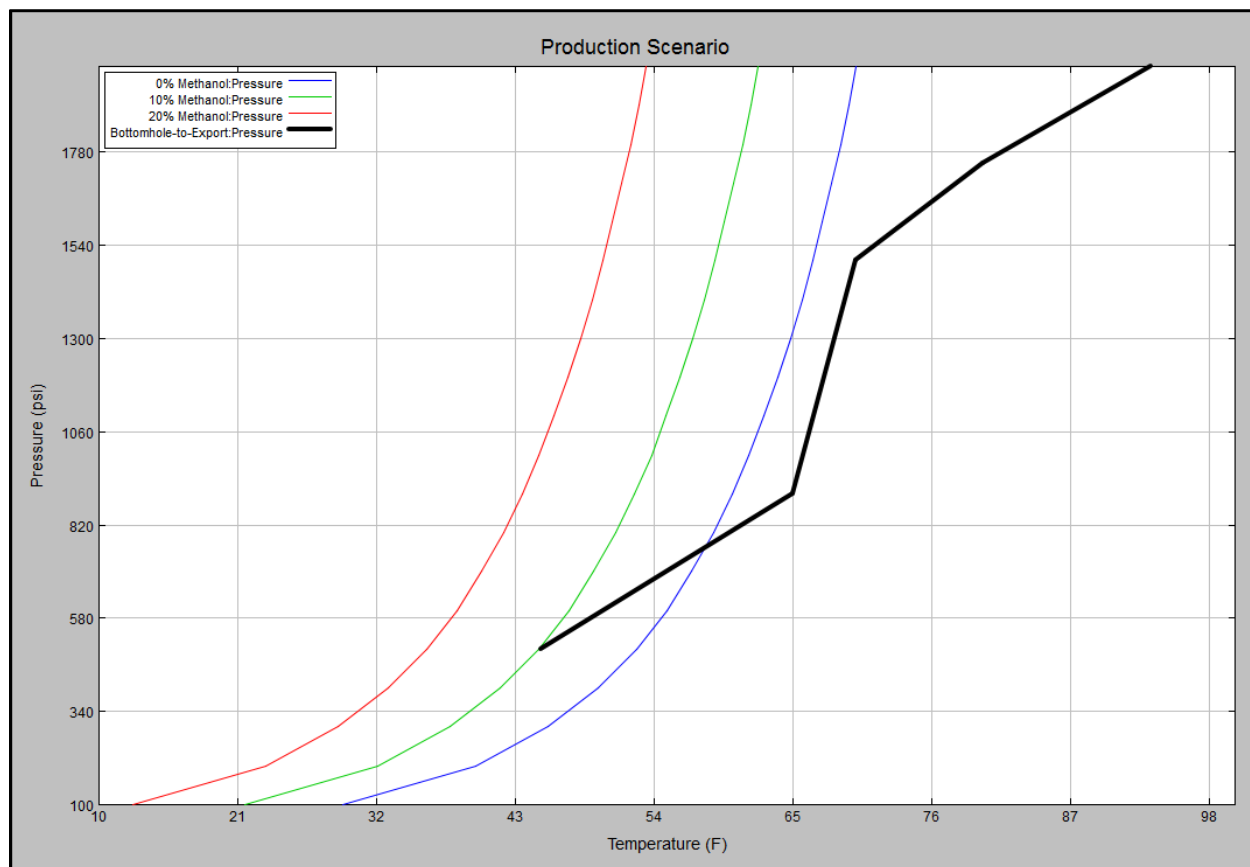


Figure W.9-8: PE Graph – Hydrate Evaluation

From Figure W.9-8, there is a risk of hydrates when pressure falls below 800 psi. This occurs between the central manifold and the separator. Based on the analysis, a methanol solution of  $\leq 10\%$  injected after the central manifold would protect this system from hydrate formation.