Objective of CONFIGURATION Screens

Criteria that determine which screens are listed in the Screen Wizard are defined in two steps: (1) selecting the WEM program, and (2) entering data in the CONFIGURATION group of screens.

Effect of WEM Program

You select a program by clicking "Program" in the WEM Input Window menu bar and selecting the desired program in the dropdown list. Selecting a program determines which of the 3 system components (i.e. fluid model, outflow model and inflow model) are included in the well model. For example, the Gradient program does not require inflow data; therefore, these input screens are excluded.

Selecting a program type also determines which sensitivity screen is included in the Screen Wizard. For example, a Nodal sensitivity screen is very different from a Gradient sensitivity screen.

Effect of Configuration Input

The input screens listed in the CONFIGURATION group depends upon which WEM Program has been selected in the dropdown menu under "Program" on the WEM Input Window menu bar. The general function of the screens listed in the CONFIGURATION group is to define well and data attributes so that a comprehensive list of input screens in the BASE CASE group can be assembled. The CONFIGURATION screens in order are as follows:

Input Screens – Appears in the Screen Wizard for all programs *except* when the Group 3 Programs (e.g. Batch Run & Multi-well Hydraulic Tables) have been selected.

Wellbore / Flowline – Appears in the Screen Wizard for all programs *except* when the Batch Run program has been selected.

Reservoir / Completion – Appears in the Screen Wizard for all programs *except* when the PVT Program, the Flowline Program, and the Group 3 Programs have been selected.

Perforating Options – Appears in the Screen Wizard *only* when Perforating Design program has been selected.

ESP Design Options – Appears in the Screen Wizard *only* when the ESP Design program has been selected.

Laterals – Appears in the Screen Wizard *only* when the when the Multi-Laterals Completion box has been checked ☑ in the Wellbore/Flowline Configuration screen.

Input Screens

Wizard Configuration Index Tab

The Wizard Configuration index tab contains 3 data groups titled "Static Temperature", "Deviation", and "Add Screens to List". Each data group contains radio buttons (⦿) or selection boxes that activate options by placing a check mark in the corresponding box (☑). The respective function of each data group is:

- "Static Temperature" : Define whether simple or detailed geothermal temperature data are to be entered
- "Deviation" : Define whether well deviation input is entered directly from processed or raw directional survey data
- "Add Screens to List" : Define whether the program selects default correlations or screens are added where the user selects correlations. Also, the screens added provide a facility to tune correlations to measured data.

Static Temperature

The Static Temperature data input group contains radio buttons that determine the type of input required to describe the geothermal temperature profile.

⦿ Use Surface and Reservoir Temps

The option labeled "Use Surface and Reservoir Temps" generates a linear static ground temperature profile between the reservoir and wellhead. When you select an offshore platform model in the Reference Depths index tab, the program includes surface temperatures for the platform, water level and sea floor. Linear profiles are used between these points. This model is generally sufficient for most applications.

◉ Enter Geothermal Profile

When a more detailed temperature profile is required for your well model, select the "Enter Geothermal Profile" option. In this case you can enter water and geothermal temperatures as a function of depth.

Deviation

You select whether the well is vertical or deviated in te Wellbore/Flowline configuration screen. The Deviation data input group in this screen contains radio buttons that determine the type of input required to describe the deviation profile of a deviated wellbore. When the well is vertical, this input selection has no affect on the Screen Wizard.

◉ Use Deviation Profile (MD/TVD only)

The option labeled "Use Deviation Profile (MD/TVD only)" is used when the well directional survey has previously been converted to measured depths and true vertical depths. You can enter these depths in a table provided by WEM or you can import the information directly from a text file.

◉ Use Full Directional Survey

The option labeled "Use Full Directional Survey" is used when you want to describe the full 3 dimensional aspects of the well profile (i.e. measured depth, inclination angle and azimuth). Usually, you import this data directly from the directional survey. Then WEM converts the information to measured depth, true vertical depth and North/East offsets using one of 3 calculation methods.

Add Screens to List

The "Add Screens to List" data input group provides options for including input screens used to select and refine well model correlations.

If an option check box is not checked (□), the WEM program *automatically selects* default correlations and option settings for the corresponding model.

However, if an option check box is checked (☑), the WEM program *does not select* a default correlation and a screen is added to the Screen Wizard where you implement your selection and/or tune the selected correlation.

☑ Tune PVT

A check mark in the Tune PVT box adds a PVT correlation screen to the Screen Wizard in the PVT group of screens under the BASE CASE branch. When multiple correlations are available, this screen provides the means for selecting a specific method that is suitable for your application. You can enter measured PVT data when this option is enabled. Regression coefficients are calculated that adjust correlation predictions to match the PVT data.

If the Tune PVT option is OFF (not checked) the program selects default correlations that are reasonable for most applications. In addition, all regression coefficients are set to the default value (either 1.0 or 0.0). Default correlations are listed below depending on fluid type.

Default Black Oil Correlations

Solution Gas-Oil Ratio:	Vasquez
Oil Formation Volume Factor:	Vasquez
Oil Viscosity:	Robinson
Oil-Water Mixture Viscosity:	Volumetric Average
Gas-Water Solubility:	Insoluble

Default Gas Correlations

Gas Compressibility:	Standing/Katz
Gas Viscosity:	Lee
Condensate Dropout:	Eilert

Pressure Drop

☑ Flowline

A check mark in the box labeled "Flowline" adds the screen "Pressure Drop" to the Screen Wizard list in the WELLBORE group of screens under the BASE CASE branch. Of course, this appears in the Wizard only when a flowline is included in the well model. In this screen, you select the pressure drop correlation used for horizontal flow, vertical up flow, angle that delineates between horizontal & vertical up, and set the downhill pressure recovery option. There is an advanced correlation option provided that is seldom required for modeling flowline pressure drops.

If the "Flowline" box is left unchecked, the program uses defaults that are reasonable for most applications. The default angle to switch from a pipeline to vertical up correlation is 15 degrees from horizontal and the downhill pressure recovery option is ON. The pressure drop correlations are listed below depending on fluid type.

Default Black Oil Correlations

Pipeline (near horizontal) Flow: Beggs & Brill

Vertical Up Flow: Mobil-Shell, if licensed

OLGAS, if licensed & Mobil-Shell not licensed Otherwise, Hagedorn-Brown.

Vertical Down Flow: Homogeneous

Default Gas Correlations

Horizontal Flow: Beggs & Brill

Vertical Up Flow: OLGAS, if licensed Otherwise, Gray

Vertical Down Flow: Homogeneous

☑ Wellbore

A check mark in the box labeled "Wellbore" adds the screen "Pressure Drop" to the Screen Wizard list in the WELLBORE group of screens under the BASE CASE branch. This screen provides an option for you to select the pressure drop correlation used in the wellbore and to fine-tune the predictive results to match measured bottom hole pressures. In addition you can toggle an option for using the Beggs/Brill deviation correction, and switch to the Beggs/Brill flow correlation at high deviation angles from vertical. When this latter option is ON, you enter the angle when the flow correlation switches from vertical up to horizontal flow.

If the "Wellbore" box is left unchecked, the program uses default option settings and selects a default correlation. The Beggs/Brill deviation correction defaults to ON and the option to switch to Beggs/Brill flow correlation at high deviation angles defaults to ON. The angle to switch from a vertical up to horizontal correlation is 75 degrees from vertical. The default pressure drop correlations are listed below depending on fluid type.

Default Black Oil Correlations (Producing Wells)

Mobil-Shell, if licensed

OLGAS, if licensed & Mobil-Shell not licensed

Otherwise, Hagedorn-Brown.

Default Gas Correlations (Producing Wells)

OLGAS, if licensed

Otherwise, Gray

Default Water or Gas (Injecting Wells)

Homogeneous

Temperature Model

☑ Flowline

A check mark in the box labeled "Flowline" adds the screen "Temperature Model" to the Screen Wizard list in the FLOWLINE group of screens under the BASE CASE branch. Of course, this appears in the Wizard only when a flowline is included in the well model. In this screen, you enter the heat transfer coefficient profile and ambient temperature profile.

If the "Flowline" box is left unchecked, the program uses defaults that are reasonable for some applications. The default heat transfer coefficient is 1.5 Btu/hr-ft2-oF (8.52 W/m2-oC) and the ambient temperature is 80 oF (26.66 oC).

☑ Wellbore

A check mark in the box labeled "Wellbore" adds the screen "Temperature Model" to the Screen Wizard list in the WELLBORE group of screens under the BASE CASE branch. In this screen, you enter the heat transfer coefficient profile and ambient temperature profile. You also have the option of calculating a heat transfer coefficient that matches a measured flowing well temperature.

If the "Wellbore" box is left unchecked, the program uses defaults that are reasonable for most applications. The default heat transfer coefficient (U) for oil wells is 2.292 Btu/hr-ft2-oF (13.015 W/m2-oC) and for gas wells is 3.33 Btu/hr-ft2-oF (18.91 W/m2-oC). These default U factors are not theoretically derived but represent averages of tuned U factors determined from matching numerous flowing wellhead temperatures.

Reference Depths Index Tab

Two data groups define the input options for program reference depths. The function of each respective group is:

- Define the well model's zero reference depth, and
- Define whether reservoir depth values are input as measured (MD) or true vertical (TVD).

Zero Reference Depth

This data input group defines the reference depth datum as either the wellhead or the Kelly rig bushing. If the Kelly bushing option is selected, all actual lengths in the well are corrected back to the wellhead for calculation purposes. The reference depth has no influence on the Flowline profile.

◉ Wellhead

When this radio button is selected, depths are measured with respect to the wellhead.

◉ Kelly Bushing

When this radio button is selected, depths are measured with respect to the Kelly Bushing. Actual lengths in the wellbore are determined from the input of the distance between the Kelly bushing and wellhead. Installations are treated differently depending on location of the well. Three options are provided:

◉ Onshore

In this case, the wellhead is essentially at ground level. This option requires only the distance between the Kelly bushing and wellhead.

◉ Platform

In this case, the wellhead is located on the platform and the wellbore includes the piping conduit from the sea floor to the platform. This option requires the distance between the Kelly bushing and wellhead, distance from the Kelly bushing to the mean sea level and water depth.

◉ Subsea

In this case, the wellhead is located on the sea floor and a flowline is used to connect the wellhead to the producing platform. This option requires the distance from the Kelly bushing to mean sea level and water depth.

The depths required to define each of these cases are input in the RKB/Tsurf screen located in the WELL PROFILE group of screens under the BASE CASE branch.

Reservoir Depth

Most depths in the program are entered as measured depths; however, reservoir depths can be entered as either true vertical or measured depths.

One exception is for horizontal wells. Since the horizontal well may not penetrate the entire formation, a deviation profile may not be available that permits the conversion from measured depth to true vertical depth. In this case, this option defaults to True Vertical.

◉ Measured

Enter the depth to the top and bottom of the reservoir as measured depth.

◉ True Vertical

Enter the depth to the top and bottom of the reservoir as true vertical depth.

Wellbore/Flowline

Overview

The Wellbore/Flowline configuration screen provides choices for configuring the flow system that connects the bottom of a well to the end-point of the flowline. The Screen Wizard inserts appropriate input screens in the BASE CASE branch to accommodate the input for the various options selected.

Wellbore Fluid Type

The "Wellbore Fluid Type" data field provides a dropdown list with 6 selections: Black Oil, Dry Gas, Gas Condensate, Water, Compositional Oil, Compositional Gas.

Black Oil

The black oil model is a mixture of 2 hydrocarbon pseudo-components: oil and gas. When the oil and gas mixture is at sufficiently high pressure, the system exists as a single-phase liquid. Lowering the pressure at constant temperature eventually causes gas to break out of solution at a pressure referred to as the bubble point pressure. Continued reduction of the pressure causes increasing amounts of gas to be liberated. When the incremental change in dissolved gas for an incremental change in pressure is relatively constant, the black oil model is appropriate. When viewing a phase envelope for this type of fluid, the quality lines in a phase envelope are fairly evenly spaced.

Black oils are characterized as having initial producing gas-oil ratios of 2000 scf/bbl or less and a stock tank oil gravity below 45o API. The stock tank oil is very dark, indicating the presence of heavy hydrocarbons, often, black, sometimes with a greenish cast, or brown. The oil formation volume factor is usually 2.0 res bbl/stb or less. If a laboratory analysis is available, the composition of the heptanes plus is usually higher than 30 percent.

Water is a third component that can be added to the black oil mixture. This component is treated as immiscible with an option to adjust the predictions for gas-water solubility. Emulsion mixtures of oil and water can also be modeled.

Dry Gas

The dry gas model contains a single gas pseudo-component that does not condense liquid hydrocarbons as it moves from the reservoir to the surface. Therefore, the composition of the surface gas is equal to the composition of the gas in the reservoir.

Water can be produced with the dry gas model. When liquid water is present, the gas phase is saturated with water vapor. As the pressure and temperature change in the well, water condenses from the gas phase or vaporizes from the liquid water phase to maintain the gas phase in a saturated state.

Gas Condensate

The gas condensate model is a mixture of 2 pseudo-components: oil and gas. When the oil and gas mixture is at sufficiently high pressure, the system exists as a single-phase gas. Lowering the pressure at constant temperature eventually causes oil droplets to form at a pressure referred to as the dew point pressure. Continued reduction of the pressure causes increasing amounts of oil to form, a process referred to as retrograde condensation. The liquid dropout continues to increase until at some pressure the trend reverses and the oil phase begins to re-vaporize.

Of course, the gas-liquid phase behavior is actually a complex, multi-component calculation where the concentration of each component in each phase is adjusted to achieve phase equilibrium. Consequently, the composition of the gas and liquid phases both vary with pressure and temperature. With the gas condensate model, the oil gravity is held constant but the gas gravity is adjusted for the amount of condensate in the vapor state. Thus, the model accounts for the difference between the composition of the surface gas and reservoir gas.

Water can be produced with the gas condensate model. When liquid water is present, the gas phase is saturated with water vapor. As the pressure and temperature change in the well, water condenses from the gas phase or vaporizes from the liquid water phase to maintain the gas phase in a saturated state.

Water

The water model is intended for waterflood and water disposal wells. When a source well for a waterflood is modeled, a gas phase can be modeled. In this case, the gas and water phases are treated as completely immiscible.

Compositional Oil/Compositional Gas

The compositional model is primarily intended for, but not limited to, volatile oils and retrograde condensates. The mole percent of each component, as determined in a laboratory analysis, is entered that usually includes methane, ethane, propane, butane, pentane and hexane. In many cases, the hexane is a pseudo-component that includes hexane and all heavier components or the pseudo-component might be comprised of heptanes and all heavier components. Usually, increasing the number of components beyond C10+ is unwarranted.

The Peng-Robinson equation of state (ESO) with the volume shift factor is used to determine the phase equilibrium of the system. The component concentrations in both the gas and liquid phases are determined along with the density, enthalpy and entropy.

The Peng-Robinson EOS is the same for both the Compositional Oil and Gas models.

The selection of wellbore fluid type determines the PVT screen added to the Screen Wizard and the selection of inflow models in the Reservoir/Completion configuration screen. There are other procedures in the general WEM program that utilize the definition of whether the produced fluid is an oil or gas. For example, the IPR models for the two phases are different. The oil IPR is based on the oil pseudo-pressure where gas breaks out of solution as the pressure decreases. On the other hand, the gas IPR is based on the gas pseudo-pressure. Another example is flow rate units. When using English (field) units, the oil/water and gas models produce output in flow rate units of bbls/d and MMscf/d, respectively.

When you select a fluid type in the Wellbore/Flowline configuration screen, you define the PVT model used in the wellbore. If your model is comprised of a single reservoir, the reservoir is forced to use the same fluid type defined for the wellbore.

When the model contains a multi-layered reservoir completion, each reservoir is permitted an individual fluid type designation where at least one of the reservoirs must match the fluid type in the Wellbore/Flowline configuration screen. Also, in this case, when the wellbore fluid type is defined as "Black Oil" and the "Tune PVT" option is turned on in the Input Screen, the program adds a black oil correlation screen entitled "Mixed Flow Black Oil Correlations". This screen defines what correlations are used when two black oil streams are mixed that might be based on different correlations.

Flowline

☑ Include Flowline Model

The flowing pressure at the wellhead is equal to the downstream set point pressure, e.g. separator pressure, plus the pressure losses that occur due to flow through the flowline and any restrictions installed between the separator and wellhead. When analyzing well flow, you usually are only concerned with the relationship between wellhead pressure and rate. The wellhead choke is adjusted to achieve the target wellhead pressure. Therefore, the flowline model option is often not turned on.

However, when a wellhead choke is not installed, such as in a gas lift well or subsea completion, the flowline usually becomes an integral component of the well flow analysis. For example, an undersized flowline dramatically reduces the flow rate obtained from a well. In these cases, the "Include Flowline Model" option should be turned on.

When you intend to determine the choke size for a particular flow rate, the pressure immediately downstream of the choke is required. If the pressure drop in the flowline between the separator and choke is appreciable, the "Include Flowline Model" must be turned on to calculate the choke downstream pressure.

☑ Choke

For a producing system, when you enable the "Choke" option in the "Flowline" data group, a choke is installed at the discharge end of the flowline. You enter the downstream pressure, usually the separator pressure, and the choke diameter. The program calculates the pressure losses through the choke and through the flowline, that, when added to the separator pressure, determines the flowing wellhead pressure.

For an injecting system, the choke is installed at the inlet end of the flowline. Given an upstream separator pressure and choke diameter, the program calculates the pressure drop through the choke and through the flowline, that, when subtracted from the separator pressure determines the flowing wellhead pressure.

You cannot simultaneously enable both the Choke and Compressor options.

☑ Parallel Lines

The "Parallel Lines" option constructs multiple flowlines between the wellhead and discharge end of the flowline, usually at the separator. The wellhead connects into a manifold that feeds each of the parallel lines. All of the parallel lines run the entire distance to a manifold at the end of the flowline. This manifold feeds a pipe that connects to the separator, upstream of a choke or compressor, depending on the configuration.

You can define any number of parallel lines in the model. The elevation profile, ambient temperature profile, heat transfer coefficient profile, diameter profile and roughness profile are all common to each of the lines.

☑ Compressor

Flowline compressors can be modeled for producing gas systems only. A model for injecting systems is currently not available.

The compressor is installed at the discharge end of the flowline. Two compressor calculation options are provided. One option operates the compressor at a fixed suction pressure and fixed discharge pressure. In this case, the program calculates the pressure losses in the flowline at each flow rate to determine the flowing wellhead pressure. Well performance is computed at the wellhead pressure and the compressor model calculates horsepower required for that flow rate. In this case, the compressor model does not affect well flow.

The second option operates the compressor at a specified maximum horsepower and discharge pressure to calculate compressor suction pressure for each flow rate. The program then calculates the pressure losses in the flowline to convert the suction pressure to flowing wellhead pressure and subsequently down the wellbore to flowing bottomhole pressure. A solution point (e.g. flow rate where the inlfow and outflow systems are in balance) is the maximum rate obtainable for the specified compressor horsepower.

You cannot simultaneously enable both the Compressor and Choke options.

Wellbore

Flow Direction

You setup the flow direction in the well using one of the two following two radio buttons.

◉ Production

The radio button labeled "Production" is selected for upflow. When this flow direction is selected the performance curve for the reservoir/completion is labeled as the inflow curve and the performance curve for the tubing/flowline is labeled as the outflow curve.

◉ Injection

The radio button labeled "Injection" is selected for downflow. When this flow direction is selected the performance curve for the reservoir/completion is labeled as the ouflow curve and the performance curve for the tubing/flowline is labeled as the inflow curve. The Injection radio button is active only when the selected fluid type is water, gas, or compositional gas.

Well Profile

⊙ Vertical

When measured depths in the wellbore are essentially equal to true vertical depths, select the radio button labeled "Vertical. The deviation screen is removed from the Screen Wizard list and the slope of the wellbore defaults to zero degrees from vertical.

⊙ Deviated

When the slope of the wellbore deviates from vertical, select the radio button labeled "Deviated". In this case, the Screen Wizard adds an input screen for defining either the deviation profile or directional survey, depending on how the input option is selected in the Configuration screen labeled "Input Screens".

Wellhead Equipment

☑ Choke

When you enable the "Choke" option in the "Wellhead Equipment" data group, a choke is installed at the wellhead.

For a producing system, when a flowline is not installed, you enter the downstream pressure, usually the separator pressure, and the choke diameter. Alternatively, you can install a flowline whereby the program calculates the pressure losses through the flowline to determine the flowing pressure downstream of the wellhead choke. Based on the downstream pressure and choke diameter, the program calculates the wellhead pressure for each flow rate.

For an injecting system, when a flowline is not installed, you enter the upstream pressure and upstream temperature. Alternatively, you can install a flowline whereby the program calculates the pressure and temperature losses through the flowline to determine the flowing pressure and temperature upstream of the wellhead choke. Based on the upstream pressure and temperature and choke diameter, the program calculates the wellhead pressure for each flow rate.

You cannot simultaneously enable both the Choke and Compressor options.

☑ Compressor

Wellhead compressors can be modeled for producing gas systems only. A model for injecting systems is currently not allowed.

The compressor is installed at the wellhead, assuming no pressure losses occur between the wellhead and compressor suction. When a flowline is not installed, you specify the compressor discharge pressure. Alternatively, you can install a flowline whereby the program calculates the pressure losses through the flowline to determine the flowing pressure downstream of the compressor.

Two compressor calculation options are provided. One option operates the compressor at a fixed suction pressure, compressing gas to the discharge pressure that is either specified or calculated as described above. Compressor suction pressure and wellhead pressure are assumed equal. Well performance is computed at the fixed wellhead pressure and the program calculates horsepower required for each flow rate. The compressor model does not affect well flow rate. Also, when a flowline model is included, the compressor horsepower required is affected but not the well flow rate.

The second option operates the compressor at a specified maximum horsepower, compressing gas to the discharge pressure that is either specified or calculated as described above. The compressor model computes compressor suction pressure required for each flow rate. The program sets flowing wellhead pressure equal to suction pressure and then calculates the pressure losses in the wellbore to convert the flowing wellhead pressure to flowing bottomhole pressure. A solution point (e.g. flow rate where the inflow and outflow systems are in balance) is the maximum rate obtainable for the specified compressor horsepower.

You cannot simultaneously enable both the Compressor and Choke options.

Wellbore Completion

The standard wellbore completion for the program is with both casing and tubing installed in the well. If the reservoir completion requires a cased hole (i.e. natural perforations, inside casing gravel pack, natural perf + gravel pack, frac pack and hydraulic fracture), then the casing is extended to a depth at least equal to the midpoint of the reservoir. In this case, an annular flow area extends from the bottom of the tubing to the surface. For an open hole completion, a borehole profile screen is added where the diameter profile is described from the bottom of the casing to at least the midpoint of the reservoir.

A slimhole completion is modeled by stopping the casing at a depth above the reservoir and extending the tubing at least equal to the midpoint of then reservoir. In this case, the tubing is assumed cemented in the ground from the bottom of the casing to the bottom of the tubing. Therefore, the completion type must be one of the cased hole types (i.e. natural perforations, inside casing gravel pack, natural perf + gravel pack, frac pack and hydraulic fracture). The annular area then extends from the bottom of the casing to the surface.

A slimhole model with an open hole completion is not permitted. In this case, you must stop the tubing at the bottom of the actual casing and then extend a reduced casing size to the bottom of the actual cemented tubing. The borehole profile is then used to extend the casing to reservoir depth.

Other completion options are configured using the check boxes below.

☑ Monobore

Check the "Monobore" option when the primary production conduit is the production casing string cemented from the surface to the producing interval. Tubing is not installed and the Tubing screen is removed from the Screen Wizard. Therefore, with this option there is no annular cross-sectional area for flow unless you install coiled tubing.

Use the following radio buttons to determine which database is used to define the size of pipe in the Casing screen. In either case, the pipe is stored as a casing string for the purposes of the calculations.

⊙ Casing

Select the "Casing" radio button if the monobore pipe is a typical casing size, usually equal or larger than 4-1/2 inches (114 mm).

⊙ Tubing

Select the "Tubing" radio button if the monobore pipe is a typical tubing size, usually less than 4-1/2 inches (114 mm). However, larger tubing sizes (up to 9-5/8" or 244 mm) are stored in the tubing database.

☑ Coiled Tubing

Check the "Coiled Tubing" check box to install coiled tubing in the well.

⊙ Coaxial

The "Coaxial" radio button installs the coiled tubing inside the tubing string or; in the case of a monobore, the coiled tubing is installed inside the casing. This is the only option provided except when the well is gas lifted.

⊙ Non-Coaxial

The "Non-coaxial" radio button installs the coiled tubing external to the tubing string so that the tubing and coiled tubing run down the well side by side. Lift gas is injected down the coil tubing string with production up the tubing string.

☑ Downhole Equipment

Click on the check box to enable a Downhole Equipment screen for installing downhole restrictions, sliding sleeves, safety valves and control valves. Data entries for these pieces of equipment are also provided on this screen.

Gravel pack screens are automatically added for all gravel packed completions. When this screen is enabled, data entries for the gravel pack screens are included on this dialog. Otherwise, a separate Gravel Pack data entry screen is added.

☑ Multi-Lateral Completion

Check the "Multi-Lateral Completion" check box when one or more laterals are drilled and completed off of the parent wellbore. Each lateral must produce from a separate reservoir. The purpose of this check box is to incorporate the hydraulic calculations for downhole branching systems. The junction where each lateral branch is connected to the wellbore is defined and the corresponding hardware screens are added to the Screen Wizard: Borehole, Casing and Tubing screens.

When laterals are completed in a single reservoir that branch off of a horizontal well completion, an inflow performance model is provided for some configurations. This reservoir specific lateral model does not require you to check the "Multi-Lateral Completion" check box. Pipe flow hydraulics for this lateral configuration is not considered.

Wellhead Flow Connection

Select the radio button that describes the flow path at the wellhead. This flow path is maintained from the surface to the first downhole flow device that causes the flow to crossover to a different flow area. If there are no downhole flow devices installed, the wellhead flow path is maintained in the same flow area to the bottom of the well.

⊙ Tubing

Tubing flow is flow in the smallest pipe installed in the well. In normal cases (i.e. both "Monobore" and "Coiled Tubing" check boxes OFF), the flow path is through the production tubing.

For a monobore completion, the flow path is through the casing.

In either of the above cases, when coaxial coil tubing is installed, production is through the coil tubing string.

⊙ Annulus

Annular flow is flow in the annulus between the outside diameter (OD) of the smallest pipe and the inside diameter (ID) of the next larger pipe size installed in the well. In normal cases (i.e. both "Monobore" and "Coiled Tubing" check boxes are OFF), the flow path is through the annulus between the production tubing and casing. When coaxial coil tubing is installed inside the tubing, annular flow is through the OD of the coil tubing and ID of the tubing string.

For a monobore completion, annular flow is not possible unless coaxial coil tubing is installed. In this case, production is through the annulus between the OD of the coil tubing and ID of the casing string.

⊙ Combined (Tubing/Annulus)

Combined flow is simultaneous flow through both the tubing and annulus. These flow areas correspond to those described in the two radio buttons above. At some downhole depth, the flow splits into the tubing and annular flow areas. At this depth the pressure of the two streams are equal. You can set the wellhead pressure for both the annulus and tubing, independently; thereby, defining individual pressure drops across each flow path. The flow split between the annulus and tubing is determined so that the pressure drop across each flow path matches the specified pressure drop.

The point of the flow split cannot be deeper than the shallowest reservoir. A sliding sleeve installed in the tubing above this depth defines the depth where the flow split occurs. If a sliding sleeve is not installed, flow is assumed to split at the bottom of the tubing string but not deeper than the midpoint of the top reservoir.

Combined Flow Choke Location

When a wellhead choke is installed by checking the "Choke" check box located in the "Wellhead Equipment" data group, and the "Combined (Tubing/Annulus)" flow option is checked in the "Wellhead Flow Connection" data group, the radio button options in this data group are enabled.

Tubing flow and annular flow leave the wellhead through separate pipes and connect into a common manifold. The mixed flow then exits the manifold through a single line. You can install a single choke, located according to the radio button selected below.

⊙ Tubing

Install the wellhead choke in the pipe between the tubing and manifold.

⊙ Annulus

Install the wellhead choke in the pipe between the annulus and manifold.

⊙ Combined

Install the wellhead choke in the pipe exiting the manifold.

Artificial Lift

Input in the combo box labeled "Artificial Lift" determines the source of energy supplied to the produced fluid in order for it to reach the surface. For oil and water wells, the drop down list contains four (4) options. These are:

> **Natural Flow:** When there is no artificial lift installed in the well, production is from the natural energy stored in the reservoir. No additional input screens are required.
>
> **Gas Lift:** Continuous flow gas lift is the process of continually injecting gas down the well annulus (production up the tubing) or injecting gas down the tubing (production up the annulus) and into the producing stream as deep as possible in the well. The addition of high-pressure gas reduces the density of the fluid column and increases the flow rate.
>
> **ESP:** Electric Submersible Pumps (ESP) transforms electric power into pump impeller rpm. The rotating impellers transfer their motion to the fluid. The fluid is then sent to a diffuser where the kinetic energy is converted into increased fluid pressure. Repeating this process through a number of stages permits production at very low flowing bottomhole pressures.
>
> **Jet Pump:** Jet pumps circulate a power fluid. A surface pump increases the pressure of the power fluid that is then injected downhole. The high pressure fluid enters the jet pump and flows through a nozzle that transforms pressure energy into kinetic energy. The produced fluid and power fluid mix in the throat of the pump where some of the kinetic energy of the power fluid is transferred to the produced fluid. The mixture then flows into a diffuser where the kinetic energy is converted to pressure.

For gas wells, the drop down list contains two (2) options. These are:

> **Natural Flow:** When there is no artificial lift installed in the well, production is from the natural energy stored in the reservoir. No additional input screens are required.
>
> **Gas Lift:** Continuous flow gas lift is the process of continually injecting gas down the well annulus (production up the tubing) or injecting gas down the tubing (production up the annulus) and into the producing stream as deep as possible in the well. The addition of high-pressure gas increases the velocity of the fluid column and lifts accumulated liquid from the well. The reduced flowing

bottomhole pressure increases the flow rate.

Reservoir / Completion

Introduction

The Reservoir/Completion configuration screen is used to configure one or more reservoirs that are traversed by the wellbore. A reservoir is defined as a drainage volume with independent PVT and independent static pressure. Therefore, the inflow performance of each reservoir is entirely independent with the exception of wellbore crossflow effects.

Use the [Add Before] and [Add After] buttons to add reservoirs to your model. When you add a reservoir, a row is added to the table and an entire data structure is added to your WEM file to hold the PVT and reservoir information. Up to 50 separate reservoirs can be defined, although simulation time is dependent on the number of reservoirs modeled. Use the [Delete Res] button to remove a reservoir from your model. When you use this button, all data entered for that reservoir is lost. Alternatively, use the Status column to temporarily shut-in the reservoir.

Reservoir/Completion Table

Name

Enter the name of the reservoir. For a single reservoir model, this name is appended to screen names that are associated with input for the reservoir. These include the PVT screens and Reservoir/Completion screens listed under the BASE CASE group of screens. When multiple reservoirs are defined (non tabular input), a PVT branch for each reservoir is created and a reservoir/completion branch for each reservoir is created. Then the screens are listed in the branch without the reservoir name appended to the screen name. When multiple reservoirs are defined (tabular input), each table includes a column (first column in the table) that displays the reservoir name.

Fluid Type

This column is used to define the type of fluid produced from the reservoir. If your model is a single reservoir, this column is automatically set equal to the fluid type defined in the Wellbore/Flowline configuration screen. In this case, you must return to the Wellbore/Flowline configuration to edit this entry.

When you create a multi-layered reservoir model, each reservoir can produce an independent fluid type. However, WEM does not have a mechanism for mixing empirical PVT models with compositional data so you are limited to one type or the other. If the Wellbore/Flowline fluid type is empirical, then all reservoirs must be empirical. The converse is true for compositional PVT.

Black Oil

The black oil model is a mixture of 2 hydrocarbon pseudo-components: oil and gas. When the oil and gas mixture is at sufficiently high pressure, the system exists as a single-phase liquid. Lowering the pressure at constant temperature eventually causes gas to break out of solution at a pressure referred to as the bubble point pressure. Continued reduction of the pressure causes increasing amounts of gas to be liberated. When the incremental change in dissolved gas for an incremental change in pressure is relatively constant, the black oil model is appropriate, that is when viewing a phase envelope, the quality lines are fairly evenly spaced.

Black oils are characterized as having initial producing gas-oil ratios of 2000 scf/bbl or less and a stock tank oil gravity below 45o API. The stock tank oil is very dark, indicating the presence of heavy hydrocarbons, often, black, sometimes with a greenish cast, or brown. The oil formation volume factor is usually 2.0 res bbl/stb or less. If a laboratory analysis is available, the composition of the heptanes plus is usually higher than 30 percent.

Water is a third component that can be added to the black oil mixture. This component is treated as immiscible with an option to adjust the predictions for gas-water solubility. Emulsion mixtures of oil and water can also be modeled.

Dry Gas

The dry gas model contains a single pseudo-component (gas) that does not condense liquid hydrocarbons as it moves from the reservoir to the surface. Therefore, the composition of the surface gas is equal to the composition of the gas in the reservoir.

Water can be produced with the dry gas model. When liquid water is present, the gas phase is saturated with water vapor. As the pressure and temperature change in the well, water condenses from the gas phase or vaporizes from the liquid water phase to maintain the gas phase in a saturated state.

Gas Condensate

The gas condensate model is a mixture of 2 pseudo-components: oil and gas. When the oil and gas mixture is at sufficiently high pressure, the system exists as a single-phase gas. Lowering the pressure at constant temperature eventually causes oil droplets to form at a pressure referred to as the dew point pressure. Continued reduction of the pressure causes increasing amounts of oil to form, a process referred to as retrograde condensation. The liquid dropout continues to increase until at some pressure the trend reverses and the oil phase begins to re-vaporize.

Of course, the gas-liquid phase behavior is actually a complex, multi-component calculation where the concentration of each component in each phase is adjusted to achieve phase equilibrium. Consequently, the composition of the gas and liquid phases both vary with pressure and temperature. With the gas condensate model, the oil gravity is held constant but the gas gravity is adjusted for the amount of condensate in the vapor state. Thus, the model accounts for the difference between the composition of the surface gas and reservoir gas.

Water can be produced with the gas condensate model. When liquid water is present, the gas phase is saturated with water vapor. As the pressure and temperature change in the well, water condenses from the gas phase or vaporizes from the liquid water phase to maintain the gas phase in a saturated state.

Water

The water model is intended for waterflood and water disposal wells. When a source well for a waterflood is modeled, a gas phase can be modeled. In this case, the gas and water phases are treated as completely immiscible.

Compositional Oil/Compositional Gas

The compositional model is primarily intended for, but not limited to, volatile oils and retrograde condensates. The mole percent of each component, as determined in a laboratory analysis, is entered that usually includes methane, ethane, propane, butane, pentane and hexane. In many cases, the hexane is a pseudo-component that includes hexane and all heavier components or the pseudo-component might be comprised of heptanes and all heavier components. Usually, increasing the number of components beyond C10+ is unwarranted.

The Peng-Robinson equation of state (ESO) with the volume shift factor is used to determine the phase equilibrium of the system. The component concentrations in both the gas and liquid phases are determined along with the density, enthalpy and entropy.

The Peng-Robinson EOS is the same for both the Compositional Oil and Gas models.

Completion Type

Completion type describes the method used to establish flow communication between the reservoir and the wellbore. Eight completion types, grouped as either cased hole or open hole, are contained in the drop down list.

When the production casing or liner is cemented in to a depth below the bottom of the reservoir; or in the case of a slimhole, tubing extends below the casing bottom and is cemented in to a depth below the bottom of the reservoir, then the pipe and cement must be perforated to establish communication with the reservoir. Four completion types are provided for cased holes where the quality of the perforations affect well flow: (1) Natural Perfs, (2) InCsg Gravel Pack, (3) NatPerfs + Gravel Pack and (4) Frac Pack. A fifth type of completion for a cased hole is the Hydraulic fracture where the characteristics of the perforations are not included in the well performance analysis.

When the producing interval is not completed with cemented pipe, the wellbore is directly open to flow from the reservoir. Three types of completions are provided: (1) Open Hole, (2) Open Hole Gravel Pack, (3) Open Hole Slotted Liner.

Natural Perfs: A naturally perforated completion (Natural Perf) is one where the perforation tunnel is created in a consolidated reservoir rock and is essentially not altered or destroyed by flow. If the reservoir rock is sandstone, an acid treatment may remove some or all of the perforation and/or drilling damage, but the perforation tunnel generally remains intact. On the other hand, large acid treatments in carbonate reservoirs can destroy the characteristics of the perforation tunnel.

Flow from the reservoir converges to the perforation tunnels, re-aligning the flow direction so that the produced fluid essentially flows radially into the perforation. The pressure drop associated with flow convergence and pressure drop across damage surrounding the perforation comprise the impediment to flow due to perforations. Flow through the inside of the perforation tunnel into the wellbore is assumed to have a negligible pressure drop.

InCsg Gravel Pack: The inside casing gravel pack completion applies to unconsolidated sands where perforation tunnels created in the formation rock are destroyed during the completion process. Underbalance perforating or perforation washing flow a small volume of formation sand into the wellbore forming a cavity between the cement and formation. Sand control is achieved by placing a granular sand filter in the void between the formation and cement sheath, filling the perforation tunnels and filling the annular space between the casing and a wire-wrapped screen.

With an inside casing gravel pack completion, radial flow in the formation converges to linear flow through tunnels between the outside of the cement sheath and inside casing wall. Flow disperses when the fluid enters the annular region and resumes near radial flow. Linear flow through the tunnels is often a source of significant pressure drop while in comparison; pressure drop in the annulus is insignificant.

A pressure drop occurs across the slotted liner or wire-wrapped screen. However, in normal cases, the magnitude of this pressure drop is small, particularly for a wire-wrapped screen, and is not included in the WEM gravel pack model. When the liner or screen becomes plugged, the pressure drop increases as flow in the annulus becomes linear and impingement velocities on the screen increase to the point that erosion occurs.

NatPerfs + Gravel Pack: A natural perforation with gravel pack is a combination of the two completions described above. The formation rock is semi-consolidated where the perforations are assumed to remain intact in the reservoir but are gravel packed to prohibit sand from being produced to the surface. As a result the skin is a combination of both skins.

Open Hole: An open hole completion is one where the production casing is set in the cap rock above or just into the top pay. Then, the pay zone is drilled; and the bottom of the hole is left uncased. This type of completion is used where formations are relatively strong and stable, especially in hard rocks and fractured carbonates.

Open Hole Gravel Pack: When an open hole completion is subject to possible mobilization due to flow, a gravel pack can be installed. Sand control is achieved by placing a granular sand filter in the annular space between an unconsolidated formation wall and a slotted liner. Successful sand control requires the gravel slurry to be circulated into place; and then, setting a packer or closing a circulation tool to hold the gravel against the formation face.

Hydraulic Fracture: A hydraulic fracture completion is one where a vertical fracture is created in the formation and propped open with a fracture proppant. Natural perforations are created to establish communication with the reservoir. A fracture fluid is injected in the well and the pressure increased beyond the formation breakdown pressure. A slurry carrying a proppant is squeezed into the fracture after the fracture is created. Once the completion is completed, there is no fracture proppant left in the wellbore or perforation tunnels.

The fracture model provides a means of predicting the inflow performance of a reservoir following a hydraulic fracture. The inflow performance can be used to provide a preliminary screening for a fracture design. The fracture models in the program are also very useful for evaluating post fracture test data. A transient model is provided for matching well performance data obtained during flush production, while another model is provided for pseudo-steady state well performance.

Frac Pack: The frac pack completion is comprised of an inside casing gravel pack with a relatively short, highly conductive fracture. Sand control is achieved by placing a granular sand filter in the fracture, in the void between the formation and cement sheath, filling the perforation tunnels and filling the annular space between the casing and a wire-wrapped screen. Radial flow in the formation converges to linear flow through the fracture and into the gravel filled manifold surrounding the well's cement sheath. The program assumes a "halo" manifold where flow from the fracture is dispersed 360o around the wellbore. Flow then enters the perforating tunnels between the outside of the cement sheath and inside casing wall. If you suspect that the "halo" is not fully created during the fracturing process, flow to some of the perforating tunnels is restricted, then reduce the shot density accordingly. Flow disperses when the fluid enters the annular region and resumes near radial flow.

Unperforated Casing: The unperforated casing option is used primarily for utilization in the DynaField program. This program connects the well performance program to a material balance program and time steps through the producing life of a completed reservoir. When the time is determined that the economic limits are reached for the currently producing reservoir, the program shuts-in the open zone and completes the well in the next scheduled reservoir.

Open Hole Slotted Liner: This completion type is identical to the open hole completion with the inclusion of the slotted liner. The slotted liner is only used for determining the flow area in the wellbore. The program does not model the pressure drop across the slotted liner.

Status

Two settings are provided for Status: "Open" or "Shut-in" (the third setting, "Squeezed Perfs", is equivalent to "Shut-in"). In most cases, a single reservoir is defined and the Status must be set to "Open", otherwise, you could not run a well performance. However, when multiple reservoirs are defined, some reservoirs can be shut-in as long as at least one reservoir remains Open. For example, you could determine one reservoir is acting as a thief zone that, if shut-in, would increase total flow rate. When the producing reservoir pressures decrease sufficiently, the shut-in reservoir can be re-opened. Using the Shut-in status retains the reservoir data in your WEM file whereas using the {Delete Res] button destroys the data.

Inflow Model

This column defines the method used for modeling inflow performance from the reservoir. Click on the button, denoted by the symbol **[…]**, located in the Inflow Model column of the table. A dialog is displayed providing a variety of options with either a theoretical or empirical basis. Each inflow model uses a different set of input data. Therefore, specific screens are added to the Screen Wizard in the BASE CASE branch to facilitate entering data associated with the selected inflow model.

Inflow Models

Overview

The inflow model you select determines the relationship between flowing bottomhole pressure and rate. When the well is comprised of a multi-layered reservoir system, each reservoir is assigned an inflow model that need not be the same as any other reservoir. An input screen for each reservoir is added to the Screen Wizard. The input screens are configured for the data required for the selected inflow model.

The Inflow Model screen contains two types of models that are arranged in two data groups labeled "Theoretical IPR" and "Empirical IPR". Theoretical IPR's are principally based on Darcy's law for three (3) flow geometries induced by one of the following well completions: radial (vertical well), horizontal well and vertical hydraulic fracture. If you elect to use one of the theoretical IPR's, detailed reservoir characterization data must be available (i.e. permeability, net pay, etc.). Situations that dictate the use of a theoretical IPR are:

- **Test data are not available**. In this case you need detailed completion information (completion damage, gun performance, etc) to predict the pressure drop across the completion. Often, you are sensitizing on these parameters to develop a completion strategy.
- **Test data are available and you intend to analyze completion efficiency**. The theoretical IPR allows you to break the total drawdown into formation pressure drop and completion pressure drop. Here, reservoir parameters determine the formation pressure drop and the difference between measured total drawdown and formation pressure drop determines the completion pressure drop.

Empirical IPR's are equations based on coefficients that are determined from measured flowing test data. As such, these IPR's model the total pressure drop and do not provide a means to distinguish between the formation and completion pressure drop components. Situations where the use of an empirical IPR is required are:

- **Reservoir permeability and net pay are not available**. In this case you must obtain flowing test data. This provides you a model capable of analyzing the effects of decreasing reservoir pressure, increasing water cut, tubing size, wellhead pressure, or any other parameter not associated with completion efficiency.

Theoretical IPR

This data input group has radio buttons for Radial Flow, Horizontal Flow, and Fracture Model. Click "on" your choice of the theoretical IPR. If any one of these buttons is "on"; then, the Empirical IPR choices must be ignored ("off"). A brief explanation of each of the Theoretical IPRs follows.

☑ Transient

When a static drainage volume first begins to produce, only fluid occupying a thin cylindrical reservoir volume adjacent to the wellbore becomes mobile. The pressure in the wellbore decreases, reflecting the losses due to the flow through reservoir rock in the thin cylindrical volume. With increasing time, the flow disturbance moves radially outward, increasing the size of the reservoir with flowing fluid. The pressure in the wellbore drops corresponding to the radius of the affected reservoir. The flow disturbance continues moving out radially until the boundary of a circular reservoir is reached. The time period between the start of flow and when the flow disturbance reaches this boundary is called "infinite acting". Once the disturbance has reached the boundary, then as time progresses, and as more fluids are withdrawn from the reservoir, the average reservoir pressure starts decreasing with time when there is no flow across the drainage boundary. This is called pseudo-steady state.

The two flow periods, infinite acting and pseudo-steady state, describe flow periods sufficiently accurate for circular or square reservoirs. However, in the case of rectangular reservoirs, the flow disturbance encounters the closest boundary first and the most distant boundary last. The time to reach the first boundary is called the end of the infinite acting time and the time to reach the most distant boundary is the beginning of the pseudo-steady state period. The time period between these two extremes is called transition flow.

The most common application of well performance analysis involves pseudo-steady state flow. In these cases, leave the "Transient" check box OFF. Then both the Radial flow model and the Fracture model are based on a circular reservoir. Shape factors are used to account for reduced productivity caused by irregularly shaped reservoirs. The horizontal well IPR is based on a rectangular reservoir and definition of well position.

When you want to analyze the transient behavior or a well, turn the "Transient" check box ON. Then all three of the flow models are based on a rectangular reservoir with a defined well position.

⊙ Radial Flow

The IPR can be viewed as a composite of pressure losses in the reservoir and completion. The IPR derived from basic principles for idealized flow through porous rock is referred to as the "Ideal IPR". An "Open Hole IPR" can also be constructed, where differences between Ideal and Open Hole IPR's reflect non-ideal flow behavior in the formation. When the pressure drop across the perforations/gravel pack is added to the reservoir pressure drop, the resulting curve is the Actual or Total IPR. Characterizing the pressure drop in three parts facilitates each component being analyzed independently. In this manner, various completion design options or workover scenarios can be investigated, each of which involve changing one or more of the component pressure drops.

Note: *Rate-dependent effects are included as a deviation from idealized Darcy's law. If you base idealized flow on Forcheimer's relation, then formation turbulence would be included in the Ideal IPR.*

As noted, the ideal Radial flow model is based on Darcy's law (Ref. 14), integrated over a cylindrical reservoir (constant thickness and homogenous properties) with a well positioned at the center, thereby establishing radial flow to the well. Pressure-dependent fluid properties for both oil and gas wells are treated by means of pseudo-pressure functions (Ref. 19, pgs. 141 & 166). In the case of oil wells, when flowing pressure falls below the bubble point pressure, gas breaking out of solution reduces oil permeability and is treated analytically using "typical" gas-oil relative permeability curves incorporated with the oil pseudo-pressure function. This effect plus gas compressibility introduces non-linearity to the classical single phase, incompressible solution of Darcy's law. [Condensate dropout in gas reservoirs has not yet been incorporated in the flow model].

Any deviation from the ideal flow model is accounted for by means of skin. In WEM, a theoretical skin can be calculated based on user-supplied descriptions of the reservoir rock matrix, the reservoir's fluid properties and the completion geometry. In this method, skins are calculated for each of the components contributing to the overall skin, including shape factor skin, formation damage skin, partial completion skin, slant hole skin, perforation skin and a rate-dependent skin, herein referred to as turbulence.

On the other hand, the Radial flow model can be tuned to match observed well performance. You can input up to 10 flowing test points and have the program perform a regression analysis to determine both a skin and turbulence coefficient. Alternatively, you can input the skin and turbulence coefficient directly.

<u>Application Summary</u>- Use this IPR model anytime you design new completions or evaluate existing completions. The model is also useful when modeling inflow for a well where test data are not available for determining empirical IPR coefficients. A description of the reservoir is required to predict inflow characteristics and the model is applicable for any fluid type.

⊙ Horizontal Well

The physical description of the horizontal well is described in an input screen separate from the reservoir description. Click on this radio button to model a horizontal well and completion. Then, the WEM wizard places a Horizontal Well – Sand Name topic line in the BASE CASE – RESERVOIR/COMPLETION wizard outline.

⊙ Fracture Model

This radio button is not active unless the current reservoir (layer) has Hydraulic Fracture entered in the Completion Type column data input field on the Reservoir / Completion screen. Click on the Fracture Model radio button if you are modeling (evaluating an IPR) a well completed with an open hole or casing perf frac job. The fracture model provides a means of predicting the inflow performance of a reservoir following a hydraulic fracture. The inflow performance can be used to provide a preliminary screening for a fracture design. The fracture models in the program are also very useful for evaluating post fracture test data. Two transient models are provided for matching well performance data obtained during flush production, while the third model is intended for steady state well performance.

Once the Fracture Model is tuned to the well performance data, accurate IPR curves can be generated. These curves can then be used for evaluating other well performance problems such as liquid loading, artificial lift installation, etc. *Click on the "green jump words" for discussion of the Fracture Models.*

Overview

There are five oil and gas well inflow correlations in WEM. The inflow correlation names are as follows:

Vogel	Fetkovich	Linear PI
Jones (Mod)	Jones.	

One radio button can be "on" (selected), if no Theoretical IPR choices are "on" (selected). A brief discussion of each is below.

Click on the following titles [green jump buttons] to open a more complete discussion.

Vogel

Vogel's inflow relation (Ref. 39) is based on 100% oil flow. Water inflow is handled using a straight line IPR based on the water to oil ratio (Kw/Ko) entered in WEM. A gross liquid IPR is constructed by combining the oil and water inflow models.

Fetkovich

The back pressure equation developed originally by Rawlins/Schellhardt (Ref. 33) for gas wells and later for oil wells by Fetkovich is based on empirical data obtained from multi-rate flow tests (Ref. 16). The model assimilates well test data entered by the user to generate a linear curve of flow rate versus delta-p-squared on a log-log plot. The slope of the line drawn is given by "1/n", and the x-axis intercept is given by "C".

Linear PI

The simplest and most widely used oil or water IPR equation assumes that inflow into a well is proportional to the pressure differential between the reservoir and the wellbore. The linear relationship can be substantiated from theoretical arguments for a single, incompressible fluid, such as occurs in an undersaturated reservoir. However, extensive field observation verifies that the straight line IPR approach provides the accuracy needed for well performance calculations in situations that exceed the theoretical basis including: high water cuts, limited drawdowns, highly damaged wells and low gas/liquid ratios. As such, the straight line IPR finds application in a wide variety of practical engineering studies. As in the case of Vogel's relationship, this model requires only a single data point of rate and its associated pressure with a static reservoir pressure in order to generate the inflow relationship.

Jones (modified)

The Modified Jones inflow relation is based on the radial flow equation (Ref. 37). However, the coefficients in the Radial flow model that are functions of reservoir geometry, rock properties and completion configuration are lumped into two empirical coefficients: A, which multiplies the linear rate term, and B, which multiplies the quadratic rate term. The pressure differentials are expressed as pseudo pressures, which deviates from the original Jones equations.

Jones

The Jones inflow relation is based on the radial flow equation (Ref. Beggs). However, the coefficients in the Radial flow model that are functions of reservoir geometry, rock properties and completion configuration are lumped into two empirical coefficients: A, which multiplies the linear rate term; and B, which multiplies the quadratic rate term. The pressure differentials are expressed as pressure differential for oil wells and difference in pressure squared for gas wells.

Perforating Options

Overview

The Perforating Options topic is placed by WEM in the CONFIGURATION section of the wizard outline screen only when Perf Design in the main menu bar Program dropdown menu is checked.

The function of this screen is to provide you with the option of using the tubing performance curves (outflow) in the evaluation of perforating options. If TPC is not included; then, the IPR (inflow) curve is used to evaluate the performance of several perforating guns.

A click on the Perforating Options topic on the wizard outline enables the Perforating Options screen. A check box is labeled, Include TPC in Perf Design. Click the box to place a 4 mark in it if you want to use tubing performance curves (TPC) in the evaluation of the perforations.

A click on Gun Database will jump to Gun Database Help.

ESP Design Options

Overview

The ESP Design Options line is placed by WEM in the CONFIGURATION section of the wizard outline screen only when ESP Design in the main menu bar Program dropdown menu is checked.

The purpose of this screen is to allow you to either specify a design rate for the pump, or to have WEM calculate an IPR curve. Completion, reservoir data, and inflow performance is not needed to make a ESP design if the design rate is specified.

A click on the topic enables the ESP Design Options screen containing a Design Rate data input group. The data input group has two radio buttons labeled User Entered Rate, and Calculate from IPR.

User Entered Rate

Click the User Entered Rate if you want to specify the design rate. When this radio button is "on", WEM will not allow input of well inflow performance data. The ESP design will not be matched to the well's IPR.

Calculate from IPR

Click the Calculate from IPR if you want to calculate a design rate from an IPR based upon reservoir data. Then, the ESP Design program will calculate a pump to match the well's IPR.

Laterals

Introduction

The function of the Laterals screen is to assign the previously defined reservoirs to lateral boreholes, identify the type of lateral borehole connection to the parent borehole, and indicate if each reservoir is open or shut-in. The completion in a lateral borehole can be either vertical or horizontal.

WEM will calculate inflow performance of each reservoir in the same manner as done for single reservoir completions. Then, the inflow from each lateral will mix in the parent borehole at the appropriate junction. The individual lateral flow and the combined flow pressure loss is calculated by WEM

Overview

The Laterals wizard CONFIGURATION screen is available only when the Multi-Laterals Completion box has been checked [4] on the Wellbore/Flowline CONFIGURATION screen.

The data input screen named Laterals contains a data input group named Laterals Connections. This data input screen has an open data field on the left for describing the Parent Wellbore. The data field on the right side will contain the name of each of the reservoirs that have been entered previously on the

Reservoir/Completion wizard screen. The [Add] and [Remove] buttons below the Parent Wellbore field are used to add lateral connections (junctions) to the Parent Wellbore. The lateral junction must be created before a reservoir can added to the Parent at a junction.

There are [Add] and [Remove] buttons between the Parent Wellbore data field and the Reservoir names data field Use these buttons to add reservoirs to a particular lateral connection

Lateral Connection data input group

Parent Wellbore

Overview

The Parent Wellbore data field is used to add and describe each Lateral Connection. This is done with the five buttons, the Junction Type list box, and the Lateral Status box that is located below the Parent Wellbore data field. The five buttons are named [Add], [Remove], Rename], [Move Up], and [Move Up].

Add

A click on the [Add] button opens a Lateral Name dialog box. Type a name in the space provided and click [OK]. Suggested names are Sand A, or Lateral Depth 5000' for example.

Remove

To remove a lateral, click on a lateral name in the Parent Wellbore data field to highlight it; and click on [Remove]. A safety dialog box will ask you to confirm your removal.

Rename

To rename a lateral, click on a lateral name in the Parent Wellbore data field to highlight it; and click on [Rename]. A dialog box will open and contains a data field in which to type the new name. A click on [OK] with insert the new name in place of the old name.

Move Up

A click on the [Move Up] button will move a highlight up to the next lateral connection

Move Down

A click on the [Move Down] button will move a highlight down to the next lateral connection

Connection Type and Status

Overview

The Connection Type and Status are active only when a Lateral Connection is highlighted. The Connection Type data input field contains a list of seven types of lateral connections. The list is opened with a click on the [t] arrow. The types of lateral connections are as follows:

`

Lev 1:	Open and Unsupported
Lev 2:	Parent cased & cemented / lateral open
Lev 3:	Parent cased & cemented / lateral cased, not cemented
Lev 4:	Parent & lateral cased and cemented
Lev 5:	Pressure integrity – mechanical
Lev 6:	Pressure integrity – casing
Lev 6s:	Downhole splitter

Designate the type of lateral connection each time a lateral is created and named.

Lateral Status

The Lateral Status data input field presents a list of Open, or Shut-in. The list is opened with a click on the [t] arrow. Highlight one to set the status of each laterally connected reservoir.