IHS Markit™

Energy Upstream

Harmony Enterprise™ 2018.3 Help – PDF

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About Harmony Enterprise™ 2018.3

These topics highlight key content in Harmony Enterprise™ to get you started:

About Harmony

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- User permissions in local folders

Tip: For hands-on practice with Harmony Enterprise, browse to the Examples folder (the default directory is C:\Users\Public\Public Documents\Harmony Shared\Harmony Enterprise 2018.3

How to...

- Connect to your data source
- Get well data into Harmony Enterprise
- Preview well data
- Analyze wells
- View results
- Export data
- Use workflows

Reference Material

- Analysis method theory
- Calculations & correlations
- General concepts
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Overview

After installing Harmony Enterprise™ and launching the application, the License Type dialog opens. In this dialog box, you select between two versions: multi-user capable and single-user capable. (This dialog box only opens the first time you select your license type.)

The multi-user version is classified as the full version. You can have up to 100,000 wells in each project. All analysis work is centralized for better access, and multiple engineers can share one common project. In addition, you can import data once, which reduces the risk of duplicating wells and analyses.

The SE license is the single-user version of Harmony Enterprise, and has some restrictions.

You can manage up to 5,000 wells with a local database (.hldb) file. However, you cannot:

- import from or merge local databases
- connect to a SQL database (multi-user database)
- perform scheduled imports
- have role-based security

If you try to import a file that has more than 5,000 wells, or where the file total plus the existing well count exceeds 5,000, wells are imported up to the limit, and then a warning message is displayed in the Status Window.

Active directory

Microsoft's active directory provides a variety of directory-based identity-related services. Harmony Enterprise pulls information from active directory for Status Window messaging, role-based security, and group assignments.

Note: Your database administrator (DBA) adds active-directory groups via the SQL Server Management Studio.

Important considerations

When DBAs set permissions, these items need to be considered:

- Individual permissions supercede group permissions. For example, if you have permission to import data and the group you are assigned to does not, you are still able to import data.

- Groups at the same level in the hierarchy, roll up / concatenate permissions. For example, if you belong to group ABC with import rights but no delete rights, and also belong to group 123 with delete rights, you have both import and delete rights.

- By default, individuals in a group receive all the same permissions as those set at the group level.

- If you remove all of the roles for an individual, they inherit the default roles. In order to have an individual inherit group permissions, you have to delete the user's login name.

Note: At this time, we support active directory groups that contain individuals, not other active directory groups.

User permissions in local folders

Harmony Enterprise saves and uses data in local folders throughout various processes while you work. If you do not have "write" permission to these folders, it can interfere with normal operations and negatively impact your projects. On startup, Harmony Enterprise checks for write access to the required paths. Ensure you are able to write to these locations for optimal use of Harmony Enterprise.

Logging directory: \Users\<username>\AppData\Local\IHS_Inc\

This directory is used to store a running log file for Harmony Enterprise, including many software and database transactions. This log file is *not* the same as the Status Window log file.

"My documents" directories:

- \documents\fast
- \documents\fast\Core
- \documents\fast\Core_Attributes
- \documents\fast\AdvPropsCMDLL_GlobalImport
- \documents\fast\AdvPropsCMDLL_GasProperties
- \documents\fast\AdvPropsCMDLL_OilProperties
- \documents\fast\AdvPropsCMDLL_WaterProperties
- \documents\fast\AdvPropsCMDLL_GeoMechanical
- \documents\fast\AdvPropsCMDLL_RelativePermeability
- \documents\fast\HarmonyAnalysis
- \documents\fast\ImportData\ProductionEditor
- \documents\fast\EnterData\ProductionEditor
- \documents\fast\Database Connection
- \documents\fast\HarmonyEnterprise
- \documents\fast\HarmonyEnterprise 20XX.X\ScheduledImportLogs

Licensing

Harmony Enterprise is licensed on a per-module basis. A license for a given module grants you access to a set of analysis methods and features. For each module, there are two types of licenses available: standalone and network. At least one license is required to connect to a Harmony Enterprise database.

A standalone license is installed on your local machine. For information on standalone licensing, see activating / deactivating licenses.

A network license is installed on a network server and Harmony Enterprise must request a seat from the network server. If you want to work offline, a network license can be checked out as a commuter, and is accounted for in the network license seat count. After you are finished working offline, you can check your commuter in, and release the seat. For information on setting up network licensing, see the IHS Markit Installation Guide and License Manager help (both links open in a new window / tab).

The Harmony Enterprise startup screen has a license icon for each module that indicates whether or not you have been granted a seat. For example, a green Harmony Forecast™ icon means that you have access to the Forecast module, while a grayed-out icon indicates that you do not have access. Clicking the **Forecast** icon (or **Reservoir** icon) opens the Licensing dialog box.

IHS Harmony Forecast™   IHS Harmony Forecast™
(Not Licensed)   (Active License -- Server)
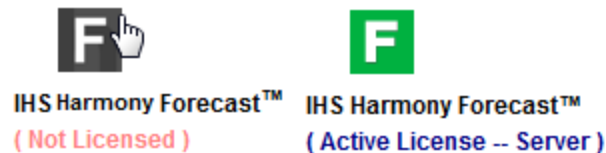
Activating / deactivating licenses

For standalone licensing, you only need to install Harmony Enterprise.

To set up a network licensing system, you need to install the License Service on your server and the License Manager on one or more machines with connectivity to the server. For more information (including activation / deactivation information), see the IHS Markit Installation Guide (opens in a new window / tab).

Activating / deactivating standalone licenses
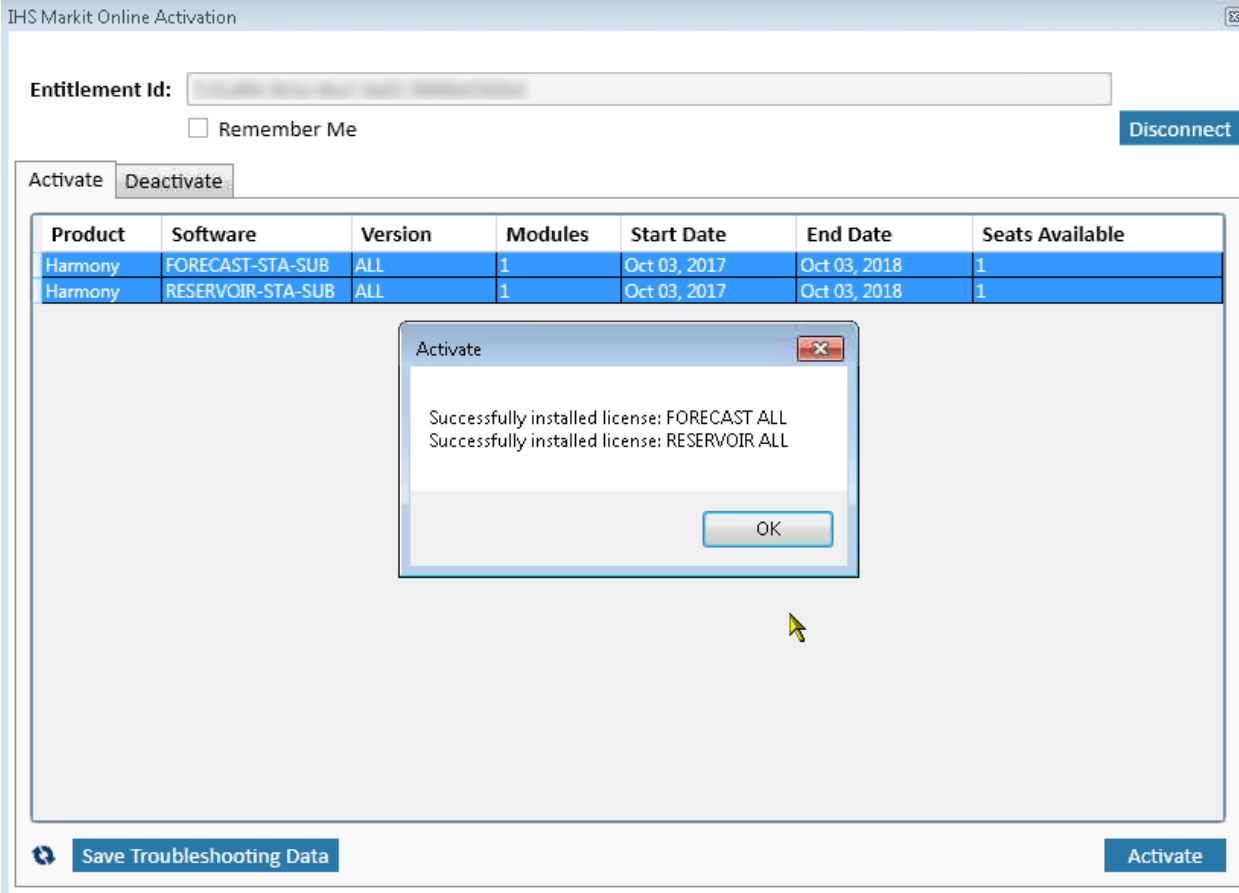
To activate or deactivate standalone licenses:

1. Open your EMS - Entitlement Certificate email and copy your entitlement ID (EID).

2. Start Harmony Enterprise.

3. Open the Licensing dialog box by clicking either the **Forecast** or **Reservoir** icons in the startup screen.
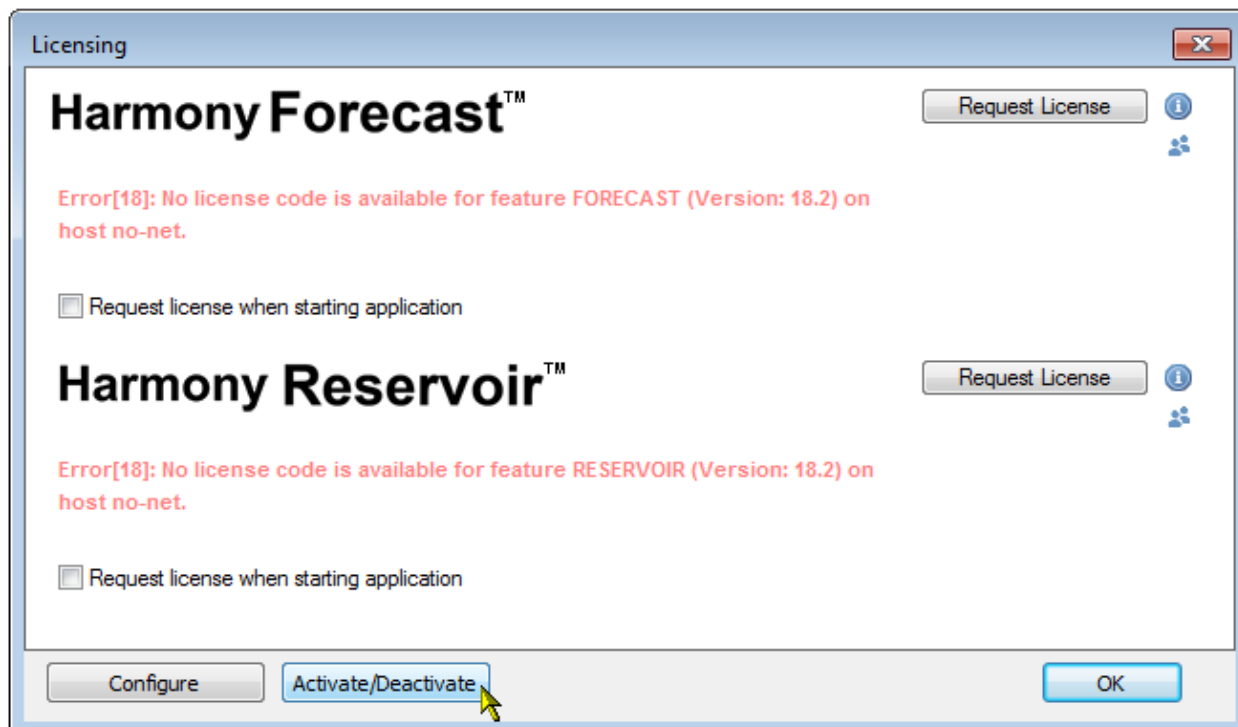
4. Click the **Activate / Deactivate** button.

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5. Paste your EID (from the email) in the **Entitlement Id** field and click **Connect**.

6. To activate licenses, in the Activate tab, select the products you want to use and click the **Activate** button.

Your licenses are now active.

Note: You can also queue up renewed licenses as soon as you have received your new entitlement email. There is no need to remove your current license, or to wait until your current license expires.

7. To deactivate licenses, in the Deactivate tab, select the products you want to deactivate and click the **Deactivate** button.

The products are now displayed in the Activate tab and can be activated on a new machine.

When the deactivation process completes, a dialog box opens indicating whether the process was successful or not. If the network experiences an interruption during the deactivation, a "Complete Partial Deactivation" button may appear. When the network is restored, clicking this button cleans up any artifacts caused by the interruption, and then the button disappears.

Licensing dialog box

This dialog box enables you to configure standalone or network licensing.

Standalone licensing
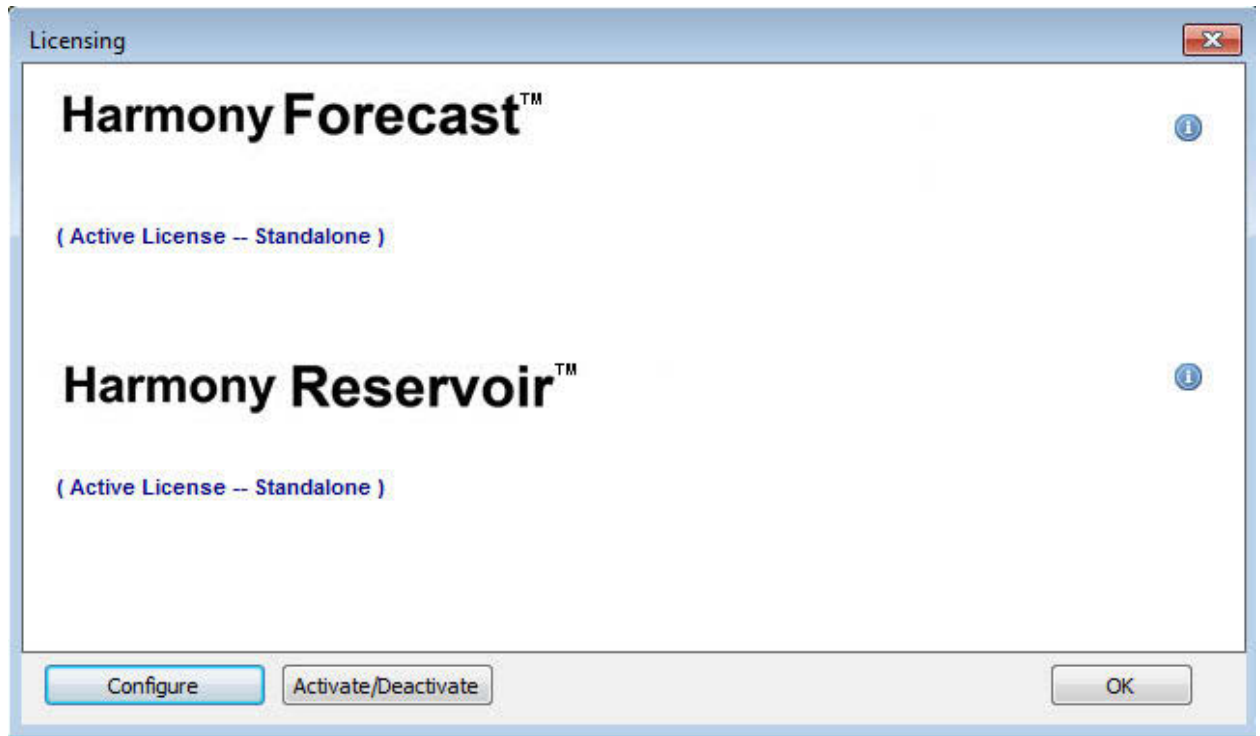
Active License -- Standalone — indicates that your license is ready for use.
Note that if your license is not active, errors are displayed for troubleshooting purposes.

ⓘ **Information** icon — opens the License Information dialog box.

Configure — opens the Licensing Settings dialog box where you can configure your licensing (for example, you can install or uninstall a license that has already been activated).

Activate / Deactivate — opens the IHS Markit Online Activation dialog box where you can activate and deactivate your licenses. For more information, see activating / deactivating licenses.

Network licensing
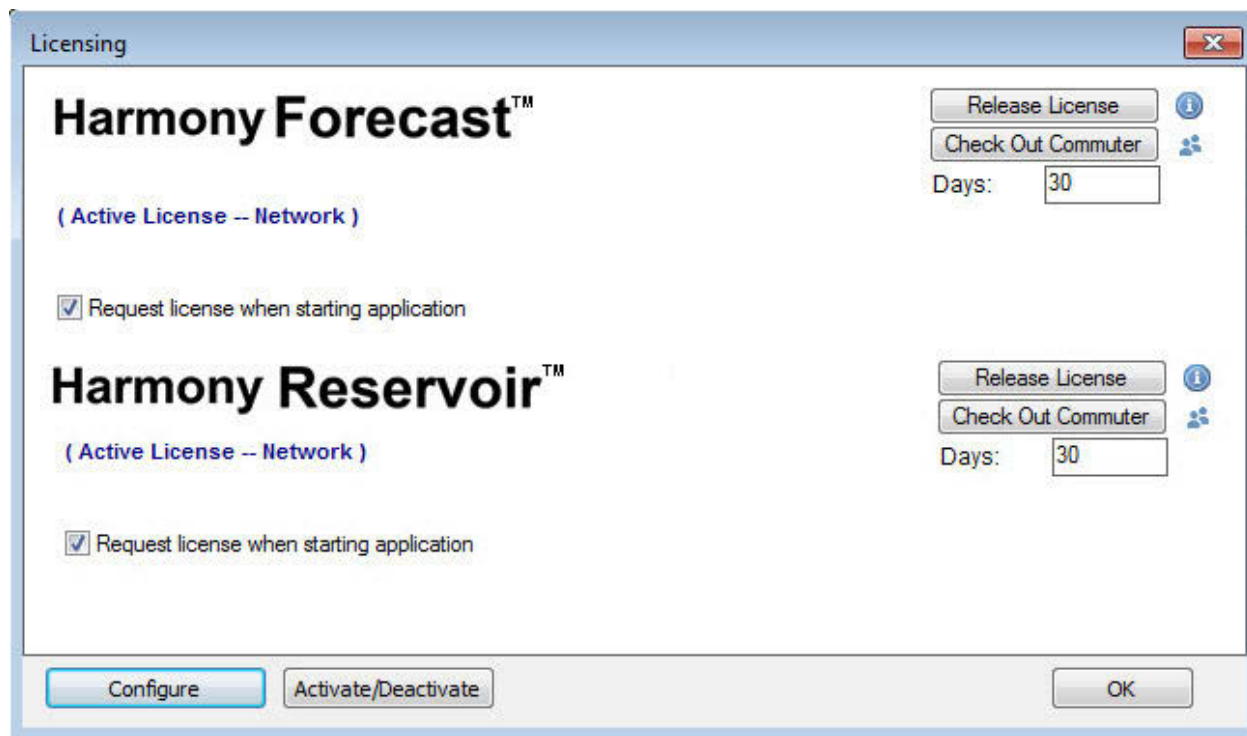
Active License -- Network — indicates that your license is ready for use.
Note that if your license is not active, errors are displayed for troubleshooting purposes.

Request license when starting application checkbox — click this checkbox to automatically request your seat when Harmony Enterprise opens. If you click this checkbox before you have a network seat, a seat is requested.
Note that this checkbox may be hidden by your administrator.

Release License button —releases your network seat. This button is only visible if you use a network license seat, and this button is only enabled if more than one seat is used, because Harmony Enterprise requires at least one seat to be used.

Note: A network license has a specific number of network seats, each of which allow one instance of Harmony Enterprise to run. In addition, a network seat can be commuted, which enables you to work offline.

Request License button — requests a network seat.
Note that this button is only visible if you do not have a network license seat.

Check Out Commuter button — enables you to work offline by commuting a network seat. (This button is only visible if you have not checked out a commuter.)

Days field — use this field to set the number of days your commuter can exist offline. By default, you can check out the commuter for a maximum of 90 days. Note that this field is only visible when the Check Out Commuter button is displayed.

Check In Commuter button — click this button when you are finished working offline to check your commuter back in. (This button is only visible if you have checked out a commuter.)

ⓘ **Information** icon — opens the License Information dialog box.

👥 **Current Users** icon — opens the Current Users dialog box, which lists all current users, machine names, start dates, and if users' licenses are commuters. (Commuter licenses enable you to work offline.) This list of current users can be useful if you are trying to track down a seat that could be made available. If the Commuter column lists "Yes", the user is likely away from the office.
Note that this icon may be hidden by your administrator.

Configure — opens the Licensing Settings dialog box where you can configure your licensing (for example, you can set the name of your network license server).

Activate / Deactivate — opens the IHS Markit Online Activation dialog box where you can activate and deactivate your licenses.

You need at least one license to run Harmony Enterprise; as a result, if only one license is active, the Release License option is grayed-out.

License Information dialog box

This dialog box is accessible from the Licensing dialog box.
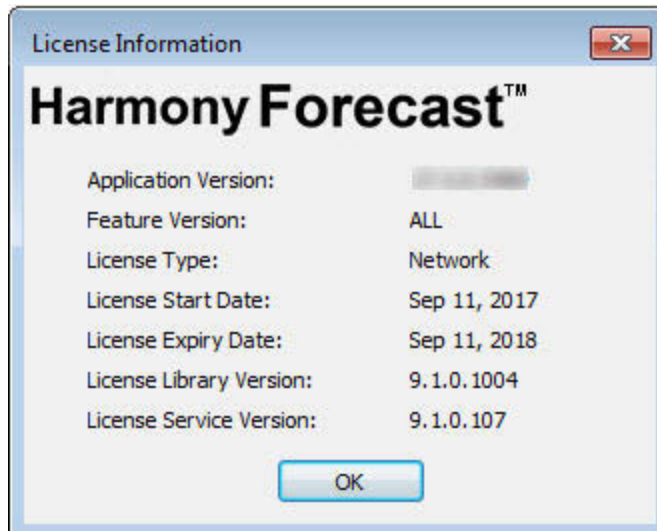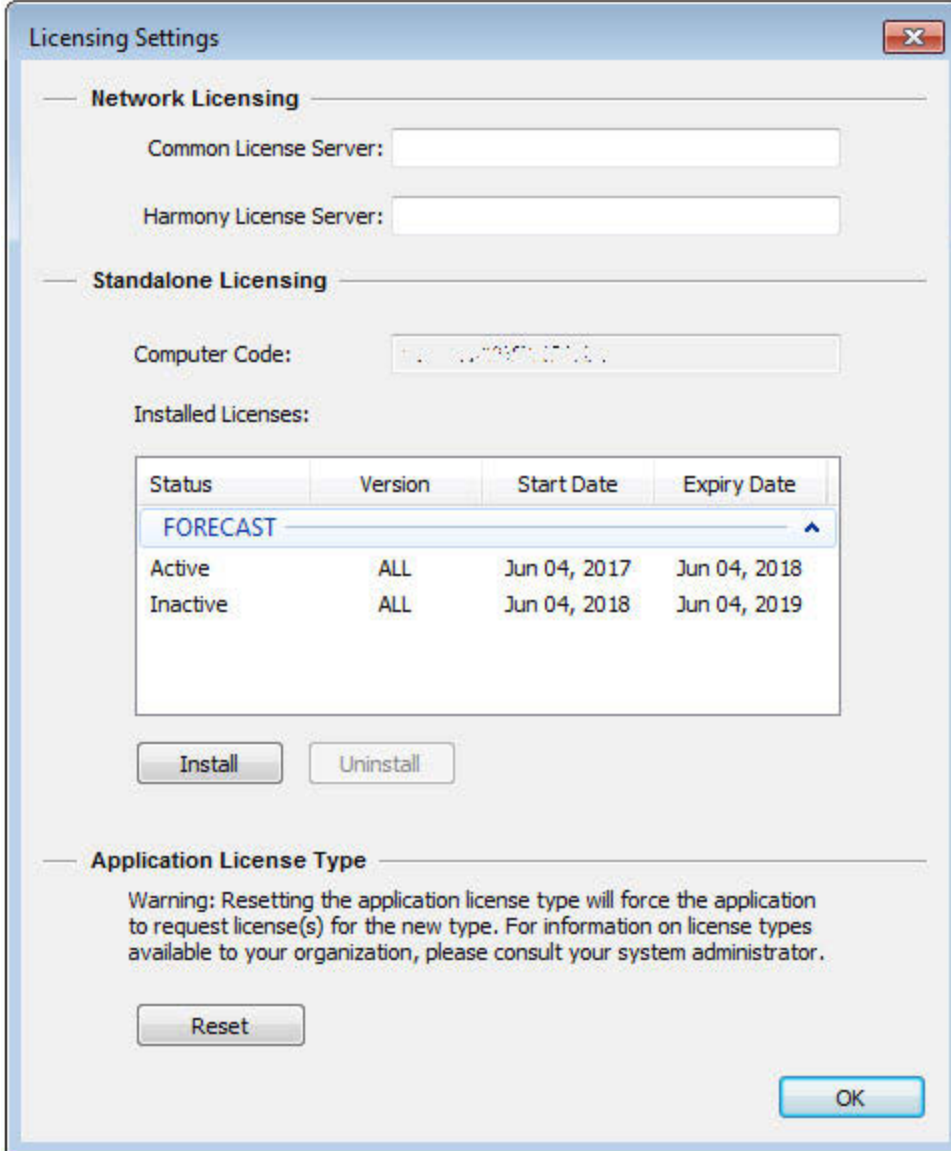
At the top, the name of your licensed module is displayed. Beneath this, the following information is displayed:

- **Application Version** — the build number for Harmony Enterprise

- **Feature Version** — indicates whether or not a license is version locked. A version of ALL indicates that a license is *not* version locked and can use any version of Harmony Enterprise compatible with the Gemalto licensing system.
  Version locked licenses (for example, perpetual licenses) have a version number, and can use all versions of Harmony Enterprise compatible with the Gemalto licensing system up to and including the version number specified.

- **License Type** — indicates a network or standalone license

- **License Start Date** — the first day the license can be used

- **License Expiry Date** — the last day the license can be used

- **License Library Version** — the build number for the license library

- **License Service Version** — the build number for the license server (only visible for network systems)

Licensing Settings dialog box

This dialog box is accessible from the Licensing dialog box.

Network Licensing

    Use this section to specify the location of your network license server. If you are hosting all of your IHS Markit network licenses (for applications using the Gemalto licensing system) on the same server, use the Common License Server field. If you have separate servers for Harmony Enterprise and other IHS Markit applications, use the Harmony License Server field.

Note: If you fill in both fields, the Harmony License Server field takes precedence.

Standalone Licensing

Computer Code field — this is the hardware footprint for your computer. It is only required if you need to activate a license using the customer portal. For computers with internet access, see activating / deactivating licenses.

Installed Licenses — lists all of the standalone licenses currently activated. This section shows active licenses, as well as inactive licenses (expired or future licenses that are queued up).

Install button — click this button to install standalone licensing that you have activated using the customer portal.

Uninstall button — if you want to uninstall standalone licensing on your local computer, click this button. Note that standalone licenses that are uninstalled with this button are not available for activation on other computers. If you want to move a standalone license to another computer, it must first be deactivated, and then activated on the new computer. For more information, see activating / deactivating licenses.

Application License Type

Reset button — if you have purchased the full version of Harmony Enterprise and want to switch from SE, click the Reset button. For more information, see overview.

IHS Markit Online Activation dialog box

This dialog box is accessible from the Licensing dialog box and displays content after you connect to the Entitlement Management System (EMS). Click the **Activate** tab to activate products from the list, and click the **Deactivate** tab to deactivate products from the list. For more information, see activating / deactivating licenses.

Entitlement Id — enter the entitlement ID (sent to you via email) and click **Connect**. This enables you to activate licenses or deactivate / move licenses from one machine to another.

Remember Me — if you click this checkbox, your entitlement ID is saved, so that you can quickly reconnect to the EMS

Activate tab — lists the products you can activate

Deactivate tab — lists the products you can deactivate

 Refresh icon — click this icon to refresh the product list in the table

Save Troubleshooting Data button — if you do not see the products you want in the list, Customer Care may ask you to click this button to generate a text file for troubleshooting purposes. If you need assistance, please contact us. Note that this button only applies to the Activate tab.

Activate / Deactivate button — click this button to activate or deactivate products

How to...

These key procedures are essential to using Harmony Enterprise:

- Connect to your data source
- Get well data into Harmony Enterprise
- Preview well data
- Analyze wells
- View results
- Export data
- Use workflows
- Work offline

Connect to your data source

Prior to connecting to your data source, you need to set up your database (SQL Server Express 2012 / 2014 / 2016, or SQL Server Enterprise 2012 / 2014 / 2016). This is a prerequisite for Harmony Enterprise.

When you launch Harmony Enterprise, the startup screen opens.

To connect to your data source:

1. Click **Connect to** and select from these options:

   - **SQL database** — for Harmony Enterprise (full version). Opens the Select Data Source dialog box.

   - **Existing .hldb file** — Browse to your existing local database file.

   - **New .hldb file** — Create an empty project to bring wells into.

2. In the Select Data Source dialog box, there are two ways to connect to an existing data source. Use option 1 or option 2.

   - **Option 1:** configure your data source through the Data Source Manager, and then connect to that data source.

   - **Option 2:** if you have a .dsn file that points to a particular data source, you can connect using the .dsn file.
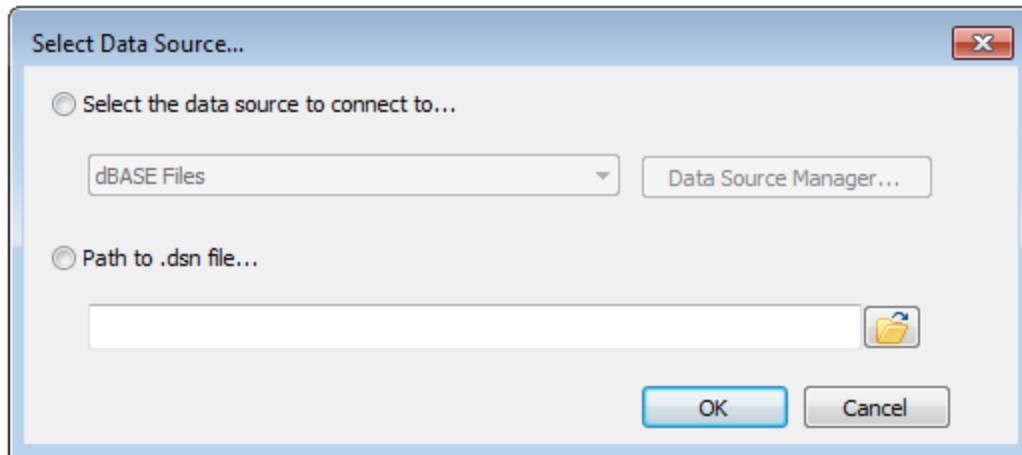
Connecting using the Data Source Manager

Harmony Enterprise requires a data source that uses the SQL server native client 11.0 driver.

To connect to your data source using the Data Source Manager:

1. In the Select Data Source dialog box, click **Select the data source to connect to**.

2. To provide information on how to connect to your data source, click **Data Source Manager**. Select **SQL Server Client 11.0** when creating your DSN.

   The ODBC Data Source Administrator dialog box opens.

3. Click the **System DSN** tab (*not* the User DSN tab), and then click the **Add** button to create a new data source.
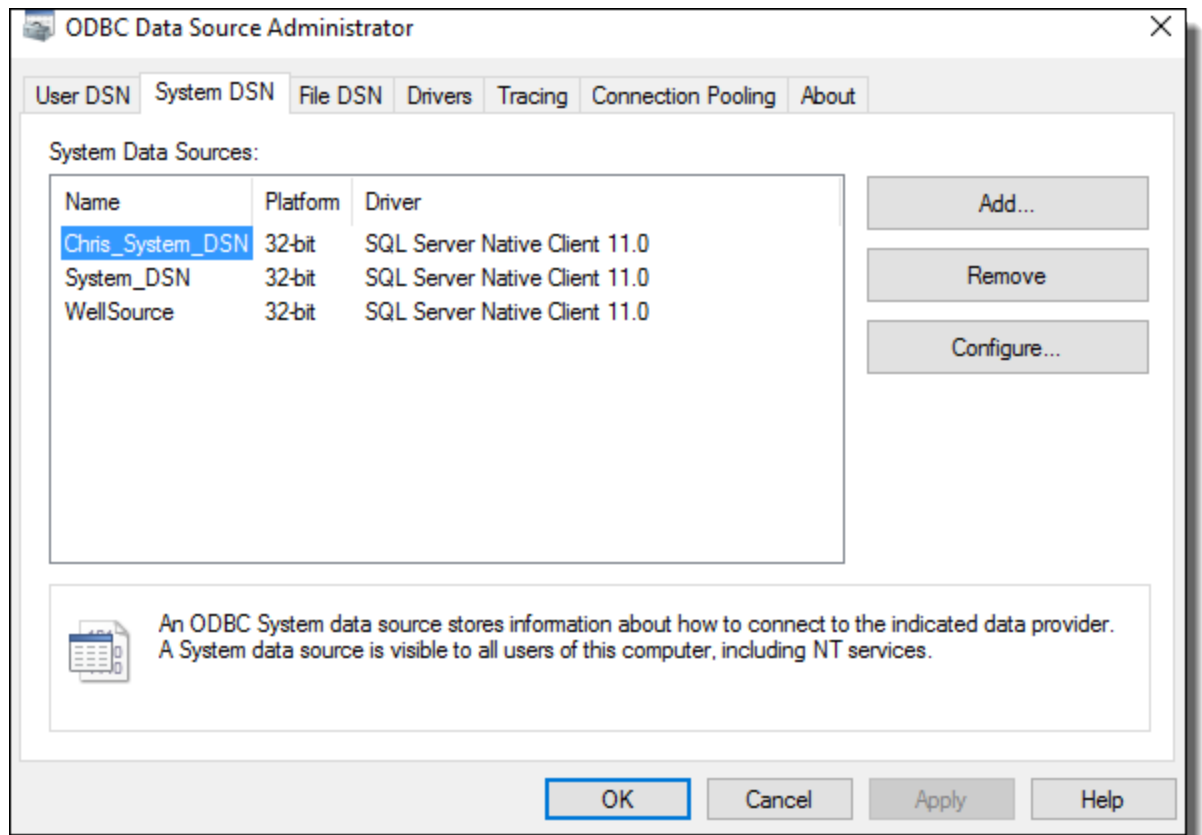
4. Select **SQL Server Native Client 11.0** from the list of drivers and click **Finish**.

   The Create a New Data Source to SQL Server dialog box opens.

5. Type a name for your data source, select the server you want to connect to from the drop-down list, and click **Next**.
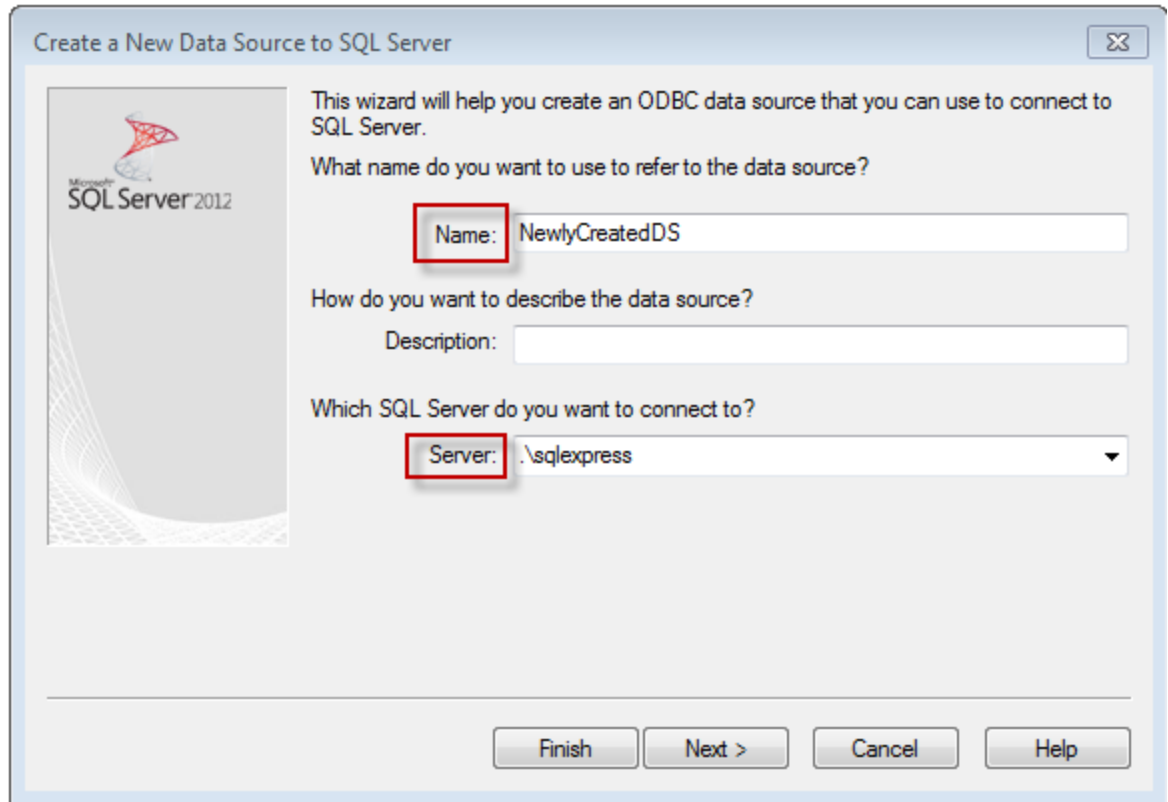
6. Click **Next** two more times. Then, select the database you want to connect to from the drop-down list.
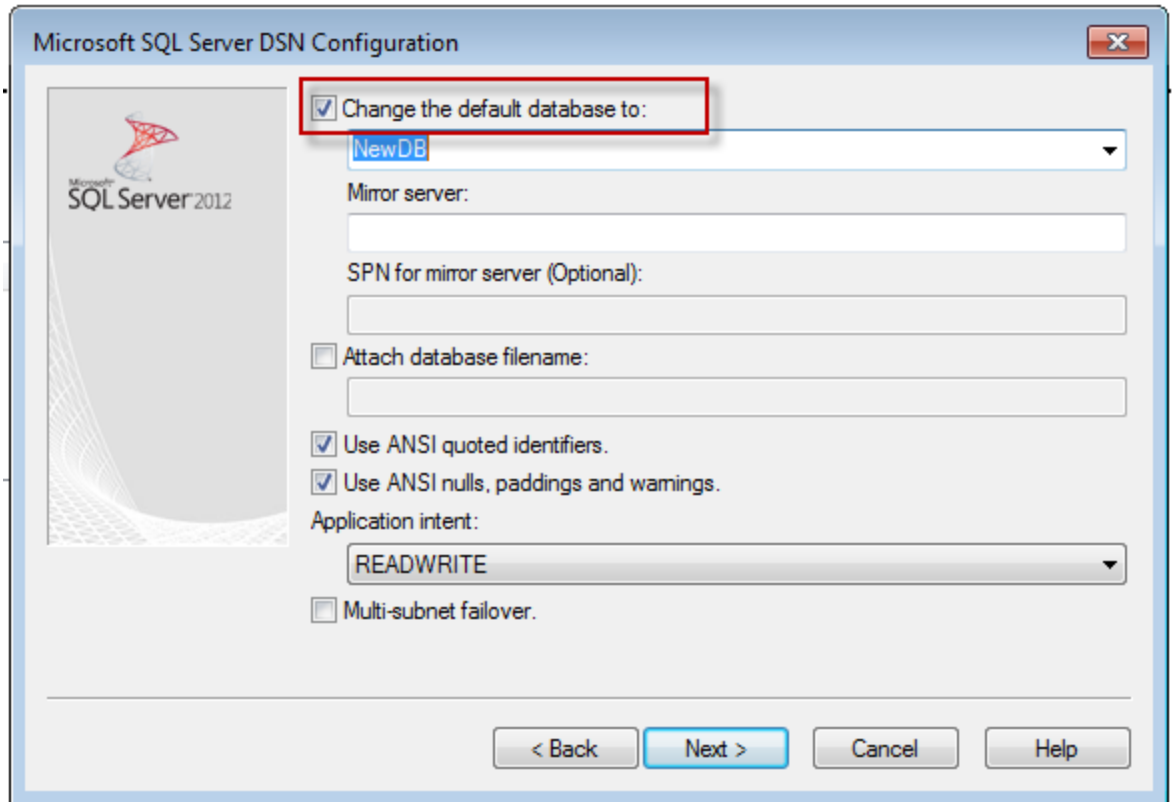
7. Click **Next** and then **Finish**. Close the ODBC Data Source Administrator dialog box.

8. Select your data source from the drop-down list and click **OK**.
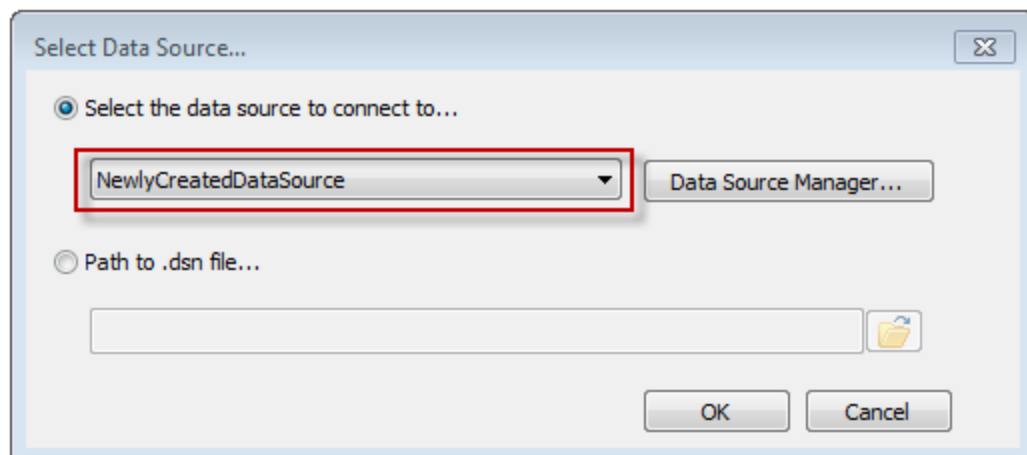
Your newly added data source is added to the drop-down list.

Connecting using a .dsn file

The .dsn file is a file that describes the data source, and it can be created by a database administrator.

To connect to your data source using a .dsn file:

1. In the Select Data Source dialog box, click **Path to .dsn file**.
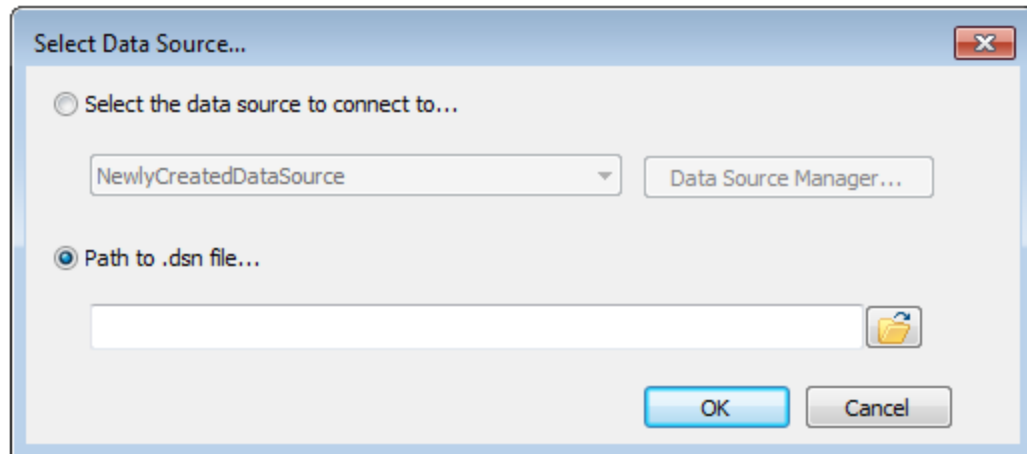
2. Type the full path to the .dsn file, or navigate to the file by clicking the **Browse** icon ( ).

> **Note:** By default, clicking the Browse icon ( ) opens the Documents folder. However, you can change this default location by setting a new default path with the **HARMONYDSN** environment variable.

Get well data into Harmony Enterprise

To get well data into Harmony Enterprise, you can:

- import well data from a file

- import well data from a database

- import / update from IHS:

  - import from Enerdeq or information hub direct connect (IHDC)

  - import from PowerTools

- import from Harmony

- import from an .hldb file

Note: If you are updating a well that has been locked by another user (for example, Well1 is in the process of being merged with an existing Well1), this merged well cannot be imported into Harmony Enterprise while there is a lock in place.

To verify that import settings are set as you want, see the Importing node in the Options dialog box.

Harmony Enterprise example files

Harmony Enterprise example files are saved within this directory:

Windows 7, 8, 10: C:\Users\Public\Public Documents\Harmony Shared\Harmony Enterprise 2018.3.

Tip: For hands-on practice with Harmony Enterprise, browse to the Examples folder (the default directory is C:\Users\Public\Public Documents\Harmony Shared\Harmony Enterprise 2018.3). In this directory, there are several different files that can be imported into your Harmony Enterprise project, including Merak (*.mer), LocalDB (*.hldb), and Harmony (*.harmony) example files.

Import well data from a file

With Harmony Enterprise, you can import plain-content files, such as .csv, .txt, and .xlsx, along with the following file types:

File Type	File Extension	Sources
Merak Note that you can import injection tubing pressure and it is displayed as Tubing Pressure in the Production editor.	.mer	Geoscout
Dwight dmp2	.dp2, .dmp2	IHS
Value Navigator (ValNav)	.vna	Accumap (IHS Accumap can save files in a ValNav format. Note that Harmony Enterprise cannot import .xml files from ValNav.)
Lasser Data	.prn	Lasser Data
Aries	.axp	Aries (IHS Accumap can save files in an Aries format.)
Geo Webworks	.mxp	Geo Webworks
298 98c	.98c	IHS
Recorder	.rec	

Plain-content files

To import well data from plain content .rec file types:

1. Click the **Import** icon () in the main toolbar and select **File**.

   Or, you can click the **Import** menu and select **File**.

2. Browse to your file and click **Open**.

3. In the Import Data Type dialog box, select either **Production** or **Attributes**.

   The Import Data dialog box opens.

4. Assign column headers by clicking the drop-down arrows at the top of each column.

Note: You must assign a Time and Date Time column (when using Production data), and a Well Identifier and a second column (when using Attribute data).

The Import Data utility assigns start and end rows to the dataset. The start row (the first entry populated in Harmony Enterprise's production or attributes table) is indicated by two arrows pointing down in the far left column. The end row (the last entry populated in Harmony Enterprise's production or attributes table) is indicated by two arrows pointing upwards in the far left column.

5. Verify that the correct rows are assigned as the start and end rows, and modify if necessary.

   To modify a row, right-click the row and select **Set Start Row** or **Set End Row**.
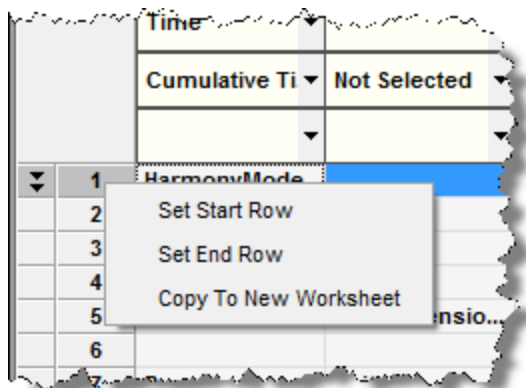
6. After you have assigned your column headings, click **OK**.

   The Select Worksheets to Import dialog box opens.
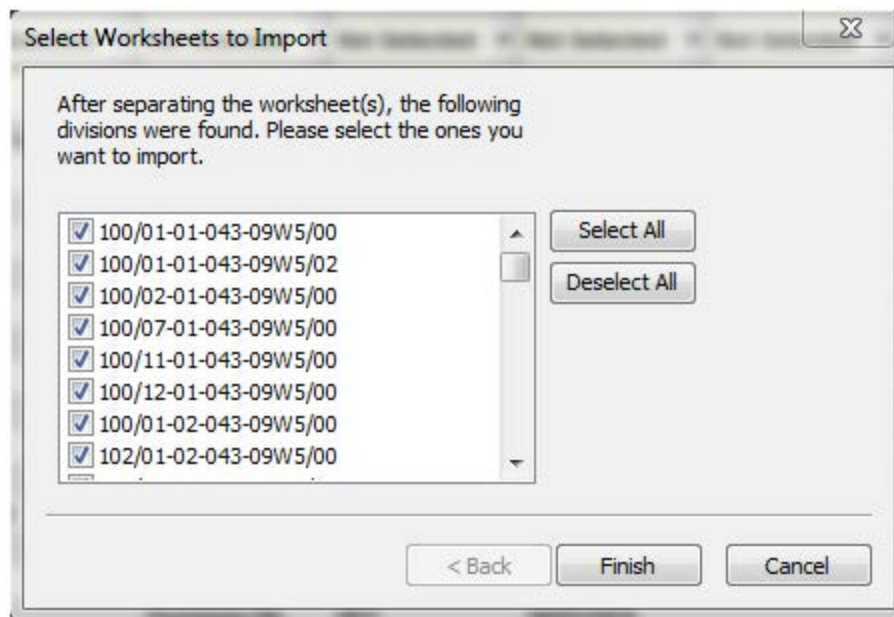
7. Click the checkboxes for the entities you want to import, and click **Finish**.

    Harmony Enterprise imports the well data. After the import process is complete, the new wells are listed in the Entity Viewer - Hierarchy pane. (If you imported the wells as a group, they are displayed as a new custom group in the Entity Viewer - Custom pane.)

Other files

To import well data from the other supported file types:

1. Click the **Import** icon (   ) in the main toolbar and select **File**.

    Or, you can click the **Import** menu and select **File**.

2. Browse to your file and click **Open**.

Note: The import behavior for an incoming file, which contains well information about wells that are already in the database, is determined by the settings in the Options dialog box, under the Importing node.

Import well data from a database

By importing well data from your company's database, you can import well production and reservoir data into a Harmony Enterprise project. You can also import data from any open database compliant (ODBC) database.

Harmony Enterprise uses the Database Connection Wizard to facilitate importing well production and attributes, along with wellbore, fluid, and reservoir properties from your company's proprietary database into the Harmony Enterprise database.

Important: The Database Connection Wizard reads the data from your company's database, but does not write to it. Therefore, there is no danger that Harmony Enterprise can corrupt your database.

If you would like to view a video of the import database wizard, see connecting to a database to import data in Harmony Enterprise (opens a YouTube video in a new window).

To import well and production data from your database:

1. Click the **Import** icon ( ) in the main toolbar and select **Database Connection**.

   The Import Database Wizard opens.

2. In the Import Database - Harmony dialog box, read the welcome message and click **Next**.

3. In the Specify Connection Settings dialog box:

   - to create a new database connection, click **New Connection**.

   - to edit an existing database connection, select the connection, then click **Edit**.

   - to use an existing connection, select the connection, then click **Next**. Proceed to step 9.

   - to delete an existing connection, select the connection, then click **Delete**, **Yes**.

   - to copy an existing connection, select the connection, then click **Duplicate**. This copies the existing database mappings in a connection to a new connection.

   - *(not applicable to SE licenses)* review your scheduled well updates (daily, weekly, or monthly). For more information, see scheduling well updates.

4. In the Set Up Connection Settings dialog box, type / edit your connection name.

Your connection name, data source, connection credentials, and schema are saved for this database connection and can be used by others. Your user name and password are saved on a per-user basis.

5. Click **Access File** and browse to your Microsoft Access database (.mdb, .accdb files). Or, click **Data Sources** and select your data source from the drop-down list, or click **Add New**. For more information, see connect to your data source.

   If you have a schema set up in your database, specify its name in the Schema field. For more information, ask your database administrator (DBA).

6. In the Specify Mapping dialog box (only applies to new database connections), select your initial mapping configuration (that is, Aries, IHS Views, Custom Mapping, Legacy Schema Mapping); click **Next**.

   - **Aries** — We have provided a mapping based on the standard tables and columns available in an Aries database. Mapping is preconfigured for the default Aries data model.

   - **IHS Markit Views** — If your DBA or other database support has already created a view in your database to map its content to Harmony Enterprise, select this option. Mapping comes from the SQL views or queries built within the data source.

   - **Custom Mapping** —You can manually map the tables and columns in your database to recognized Harmony Enterprise data in the next part of the wizard.

   - **Legacy Schema Mapping** — If you have a schema .csv file from Harmony, you can use this to import from your database.

7. In the Assign Mapping dialog box, set your initial mapping, or resolve any errors in the existing mapping, by clicking the **Source View / Table** cell, and selecting from the drop-down list. If you select a blank value, this column is not imported.

8. To set your units, first resolve any errors in the right pane by clicking the **Source Column Name** cell, and selecting from the drop-down list. Then, click the **Units** cell, and select from the drop-down list. Click **Next**. (Errors are displayed in red text and warnings are displayed in orange text.)

   Your source tables, source columns, and unit mappings are saved for this database connection, and are available for any user who connects to this source through the same Harmony Enterprise database.

   Note: If you try and map a column that is already mapped, an error message is displayed at the bottom of the dialog box.

9. In the Set Up Filters dialog box, click **Add** to create a filter to restrict which wells are imported. If you do not enter any filters and click **Next**, all wells in the data source can be viewed and imported.

10. In the Filter a Column dialog box, select your filter from the **Filter Column** drop-down list, and then type / paste your values (lowercase or uppercase — filtering is case *insensitive*), or select from the checkboxes. Click **OK**; then click **Next**.

    The validation of your filtering values is handled in the next step of the wizard, and your filters are saved for your database connection (not shared with others).

11. In the Select Wells to Import dialog box, a tree structure must first be created to view available wells. To build a tree structure, click the **Tree Hierarchy** icon ( ) and select attributes. By default, all wells are selected. To exclude wells from import, click the checkboxes to deselect them. To see a preview of the production data, click the well's *name*. Click **Import**.

    The wells you selected for import are saved for your database connection.

12. When importing data with an irregular frequency (for example, Well Test data or synthetic data with a logarithmic time track), or all shut-in periods reported, click the **Continuous Time Track** checkbox. For more information, see continuous time track.

13. When importing an Aries file, the Select Analyses to Import dialog box opens where you can select the decline curves you want to import. Click **Next**.

14. In the Import Options dialog box, options are displayed for updating the data of existing wells, recalculating sandface pressures, and scheduling well updates. To override the global settings on a one-time basis, select your data options from the drop-down lists. For more information on these options, see updating data (set in the Options dialog box). To automatically import data, see scheduling well updates.

15. Click **Finish**.

    The database wizard remembers your last database connection, and it is automatically selected the next time you run the wizard.

Import / update from Enerdeq or IHDC

You can import / update data well production data and directional survey data from IHS:

- Enerdeq (opens the Enerdeq web page in a new window) provides access to US well and lease production data.

- The Canadian Hub or IHDC (Information Hub Direct Connect) provides access to Canadian well production data. Note that wells must have DLS or NTS naming.

To import or update from IHS:

1. Click the **Import** icon ( ) in the main toolbar and select **Enerdeq / IHDC**.

2. Select IHS Enerdeq (**US**) or IHDC (**Canada**).

   Your options vary depending on your country.

3. Enter your IHS Enerdeq or IHDC credentials.

   The dialog box options are now enabled.
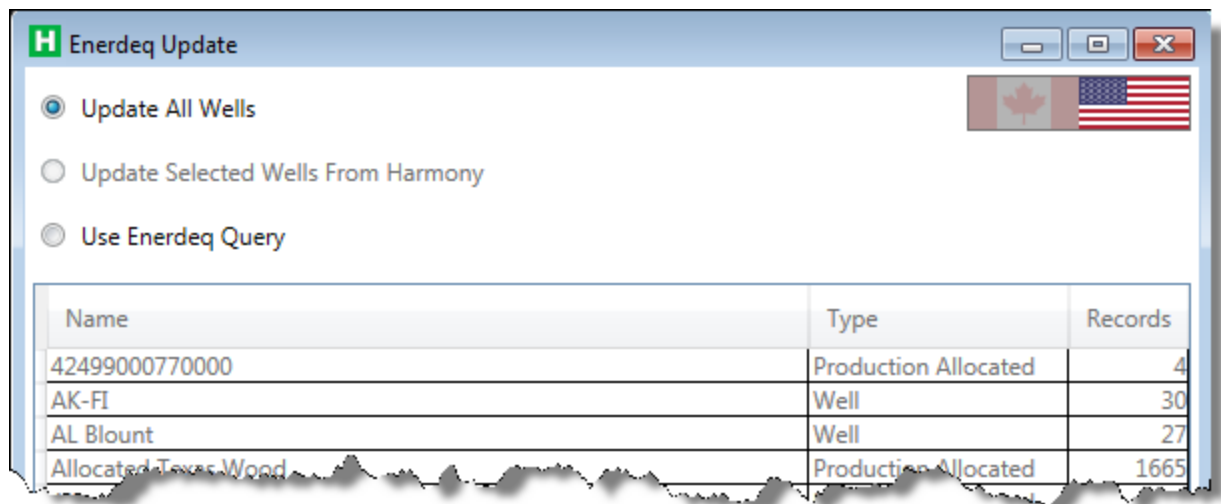
4. To update your wells from Enerdeq, click **Update All Wells**.

   If you have multiple wells that are mapped to existing wells, the Link Imported Wells to Existing Wells dialog box opens.

5. If you selected wells in Harmony Enterprise before selecting **From Enerdeq / IHDC**, the Update Select Wells from Harmony option is enabled. Click **Update**.
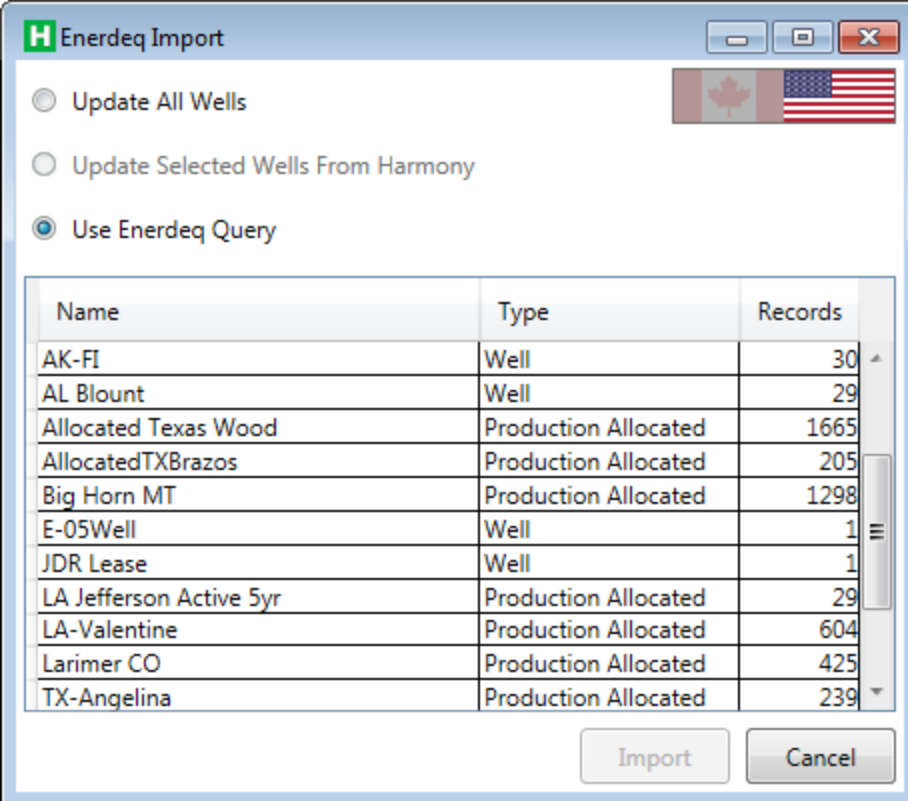
The wells in Enerdeq are updated with your Harmony Enterprise data.

6. (US only) To import wells / production data from API numbers obtained by running an Enerdeq query, click **Use Enerdeq Query** and then click **Import**.

Or, double-click a row in the table.

Enerdeq queries (US only)

In the Enerdeq Update dialog box (see above), selecting the **Use Enerdeq Query** option displays queries currently saved in your Enerdeq account. Note that unallocated production is not imported — unallocated queries are not displayed in the table.

This table shows the query type (allocated production or well), and lists the number of records that the query currently returns. (The table can be sorted by clicking the column headers.) If you have set your import option to combine records with the same API (some wells have multiple production IDs), the number of wells imported to Harmony may differ from the number of records listed in the table.

Import from PowerTools

If you have US well production with reservoir and economic analyses in PowerTools, you can import this data into Harmony Enterprise as long as you have access to these files:

- Access database file (.mdb) — this Microsoft database file must be from PowerTools 9.3 or later.

- cache folder (with .98c files) — each .98c file represents a single well's data.

Note: Decline analyses in PowerTools are imported with a maximum b value of five. In addition, imported files do not include economics or Field Direct data.

To import from PowerTools:

1. Click the **Import** menu and select **PowerTools**.

   Or, in the main toolbar, click the **Import** icon (   ), and select **PowerTools** (   ).

   The PowerTools File Import dialog box opens.

2. Browse to your .mdb PowerTools file.

3. *(Optional)* Browse to the folder where your .98c cache files reside.

   Note: If your cache files are stored elsewhere, you can import this data later via an Enerdeq update. Make sure that your .98c files match your .mdb file, so that the production data is synchronized.

4. Click the **Import** button.

   If there are no .98c files that match the .mdb file, the .mdb file imports its data, and then a dialog box opens stating that none of the .98c files were imported.

Note: If you have missing static pressures in your PowerTools project (Access database file) or .98c file, your material balance is not brought over.

Import Harmony data

When you import a project from Harmony, you bring in the following data:

- All supported well attributes, properties, wellbore configurations, and production datasets.

- Hierarchy structure and custom groups.

- All supported worksheets and analysis types on wells and groups:

  - Declines

  - Typewells

  - Ratio analyses

  - Forecast / consolidation forecasts

  - Custom worksheets

- Reference dates

- Filters

- Filtered-out data points for all rate-transient analyses (RTAs)

- Sets of points selected for best-fitting within individual analyses

- Injection tubing pressure — displayed as Tubing Pressure in the Production editor

Tip: For wells with multiple deviation surveys, the first-populated survey is imported. For wells with multiple temperature profiles, the last-populated temperature profile is imported.

Any data and analyses that are not currently shown in Harmony are not imported. Custom groups in Harmony are imported into the shared groups tab (Entity Viewer - Custom) in Harmony Enterprise. Incoming production data, properties, attributes, or analyses, are appended, discarded, overwritten, or merged, for wells and groups that exist in both projects, based on your settings in the Options dialog box under the Importing Data section.

Note: We recommend that you review your updating data settings prior to importing from Harmony. You can also manually merge an imported well to an existing well by selecting the **Imported Well Linking** option in the Options dialog box under the Importing Data section. For additional information, see the Link Imported Wells to Existing Wells dialog box.

You can import .harmony files for Harmony 2014v1 and later. (Earlier versions have to be manually upgraded to 2014v1 or later first.)

To import from Harmony:

1. Click the **Import** menu and select **.Harmony file**.

   Or, you can click the **Import** icon () and select **.Harmony file**.

2. Browse to your .harmony file and click **OK**.

   Your Harmony project can now be used in Harmony Enterprise.

Import from an .hldb file

You can extract entities from your Harmony Enterprise database into a local database, including custom datasets, custom attributes, analyses, forecasts, wellbore configurations, and deviation surveys. Then, you can import extracted information into either a standalone database, or an existing database. Whether or not information is overwritten, appended, or merged into the existing database, is dictated by the Options dialog box. Wellbore configurations are only imported, if the original wellbore configuration is empty.

Note: With an SE license, you can extract entities to an .hldb file, but you cannot import entities from an .hldb file.

To export data from Harmony Enterprise and import the exported entities:

1. Open the Harmony project that has the entities you want to export. Select these entities in the Entity Viewer (Hierarchy or Custom).

2. Click the **Export** icon ( ) in the main toolbar and select **To .hldb file**, and save your file.

3. To import the exported entities, do one of the following:

    - To open the entities into an existing database, open the Harmony project that you want to import the exported wells to. Click the **Import** icon ( ) and select **.hldb file**. Browse to your .hldb file and click **Open**.

        Your imported entities are brought into your existing database from the entities you exported.

    - To open the entities in a standalone database, click **Connect to, Existing .hldb file** from the Harmony startup screen, browse to your .hldb file, and click **Open**.

        Your imported entities are brought into a standalone database from the entities you exported.

Custom groups

If you import an .hldb file with a custom group that has the same name and ID as one found in the database, the custom group is merged in the database.

If you import an .hldb file with a custom group that has the same name but a different ID from one in the database, a new custom group is created with a filename appended by a numeric (for example, <custom_group>(1), <custom_group>(2), etc).

Preview well data

When you click various tabs, a different subset of information is displayed in the main pane for the selections in the Entity Viewer (Hierarchy or Custom). The geographic information system (GIS) tab displays the location of the entities on a world map, if the location attribute fields are populated, while the Attributes tab displays the meta-data associated with the selected entities. Datasets associated with the selected entities can be viewed from the Diagnostics tab.

The following examples describe how you can preview wells, or groups of wells, on these tabs: GIS, Attributes, and Diagnostics.

GIS well preview

To preview a well in the GIS tab:

1. Select the well in the Entity Viewer (Hierarchy or Custom).

2. Right-click the well and select **Go to**.
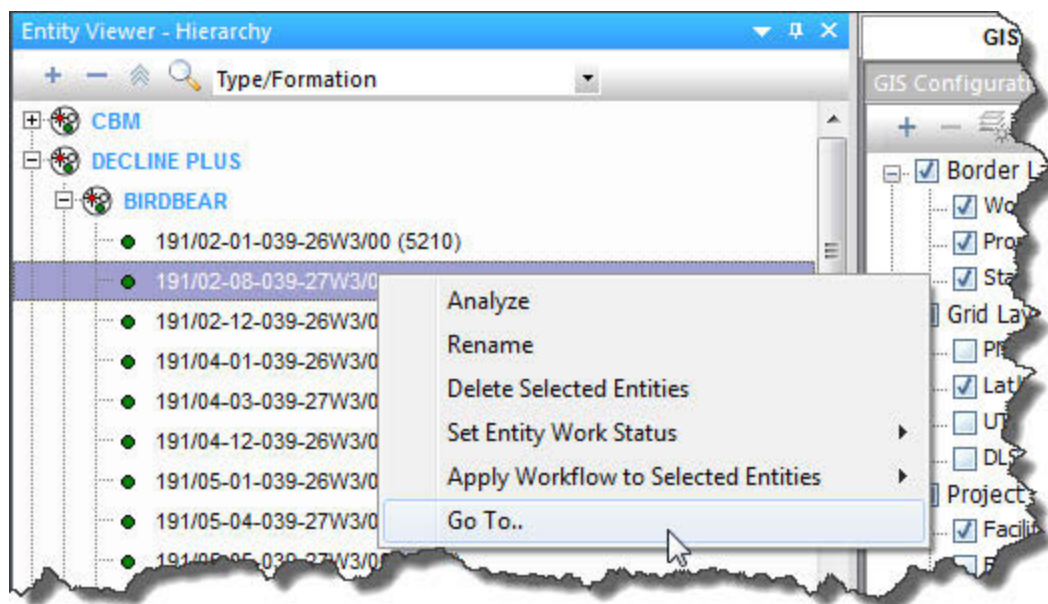
The GIS zooms in towards the selected well and highlights it.

Note: Entities that do not have values recorded for their location attributes are not displayed in the GIS.
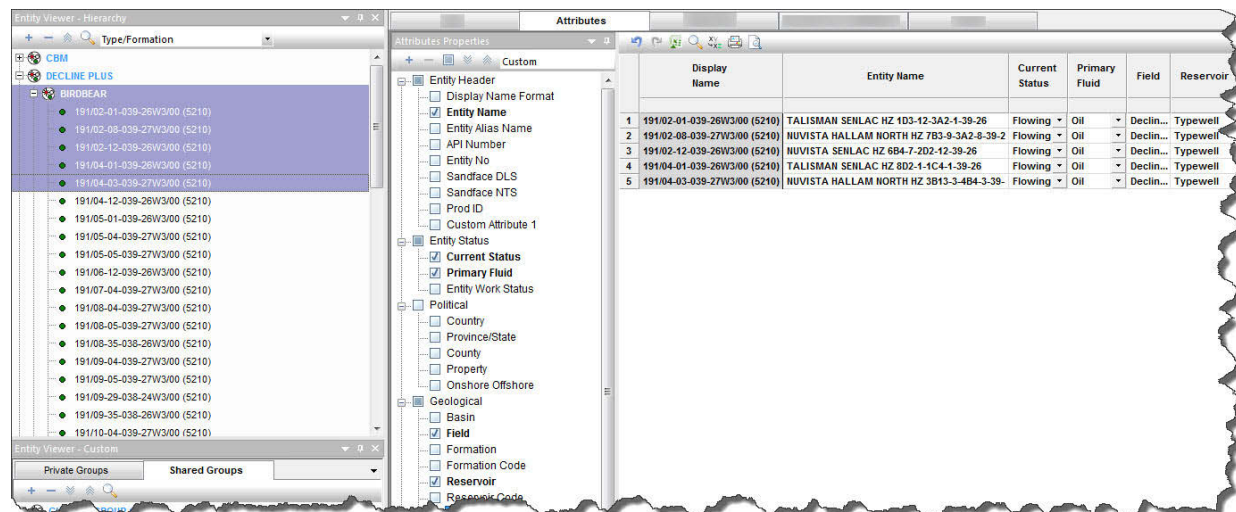
Attributes well preview

To preview well attributes:

1. Select the well (or multiple wells) in the Entity Viewer (Hierarchy or Custom).

2. Click the **Attributes** tab.

   By default, the auto template displays the following attributes: Display name, Entity Name, API Number, Entity No, Current Status, Primary Fluid, Country, Province / State, Field, Reservoir, and Unit.

3. Select the attributes you want to view from the Attributes Properties tree structure by clicking the checkboxes next to the attribute. (Selecting a category displays all of the attributes in the category.)

Note: Attributes are not displayed for groups; therefore, a selection that includes both groups and wells only displays the well attribute data.

Diagnostics well preview

To preview well production data:

1. Select the wells and/or groups in the Entity Viewer (Hierarchy or Custom).

2. Click the **Diagnostics** tab.

   By default, the auto template selects the gas, oil, and water-rate datasets, if they are populated, and plots them.

3. Select the datasets you want to view in the Data Viewer Properties tree structure by clicking the checkboxes next to the dataset.
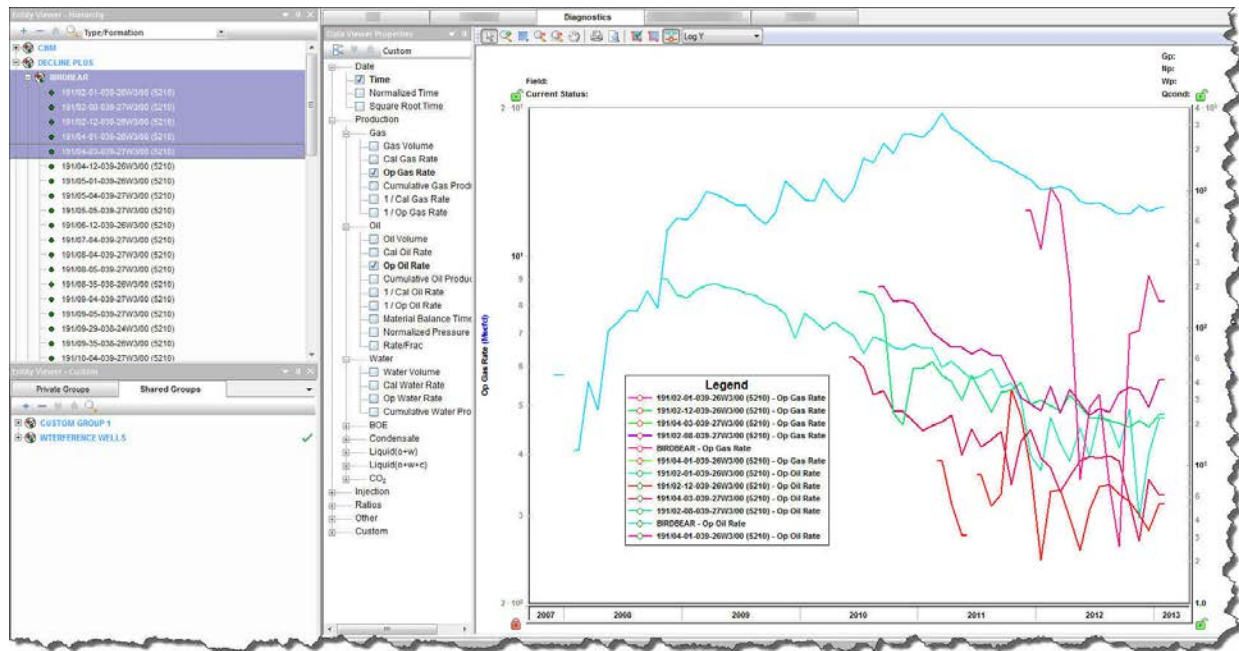
Note: Selecting a group displays the aggregate production data of the constituent wells in the group, while selecting multiple wells displays the production data of the individual wells.

Analyze well data

In order to analyze well data in Harmony Enterprise, you need to select an entity (for example, a well, scenario, or group), and then click the Analysis tab.

Selecting an entity for analysis

To select an entity for analysis, follow the steps in the table below.

Location	Method of Selecting	Notes
Entity Viewer (Hierarchy or Custom)	▪ Click an entity (well or group) name. ▪ Click the **Analysis** tab.	You can select any entity that exists in the viewer.
GIS map	▪ Click an entity on the map. ▪ Click the **Analysis** tab.	You can only select a well from the GIS map.
Analysis tab	▪ Click the **Analysis** tab ▪ Click an entity in the Entity Viewer (Hierarchy or Custom)	You can select any entity that exists in the viewer.

After you have selected an entity for analysis, that entity is locked until you select another entity. In other words, the lock is released when you click another entity. If another user tries to open the same entity for analysis while the lock is in place, a message is displayed in the main pane and the Status Window. There is no way to force the release of the well, but the username with the locked well is displayed in the Status Window.

Note: The editors are also locked when you are performing an analysis.

Analyzing an entity

To analyze an entity:

1. Select an entity for analysis.

   The New Worksheet tab opens. Or, if one or more worksheets exist, one of these opens.

2. Add a gas decline worksheet. (You must add a worksheet before you can analyze an entity.)
   Click a worksheet image, and if applicable, select a worksheet type from the submenu.
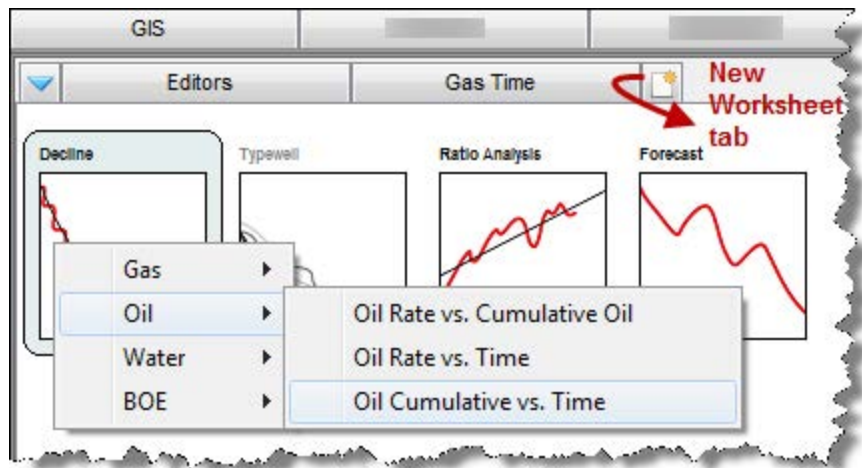
The worksheet is added.

3. Add an analysis by clicking the **+** icon on the Analysis Manager toolbar and selecting an analysis type. A decline analysis is shown as an example.
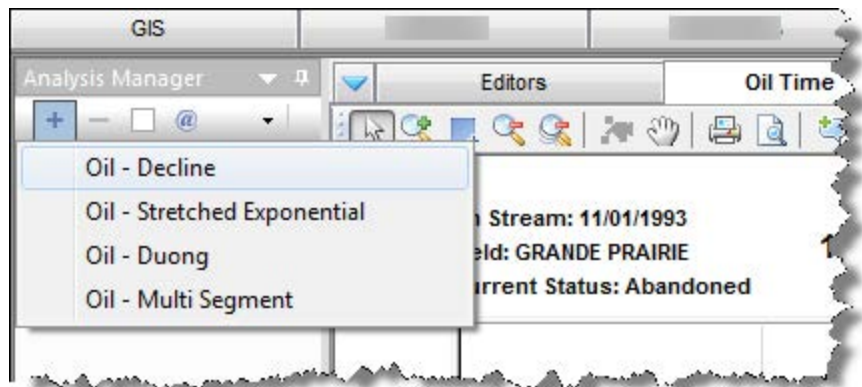
The analysis is added to your worksheet. For more information on analyses, see analysis types.

Analyzing a condensate decline analysis

To analyze a condensate decline analysis:

1. Select an entity for analysis.

   The New Worksheet tab opens. Or, if there is an analysis already an analysis in place, the existing analysis opens.

2. Add a gas worksheet.

Note: For more information, see <u>analyzing an entity</u>.

3. Click the **Plot Selection** tab and do the following:

- click the **Deselect All Series** icon ( ).

- select your x- and y-axis (either **Cumulative Cond Production** on the x-axis, or **Time** on the x-axis and **Cal Cond Rate** and/or **Op Cond Rate** on the y-axis)
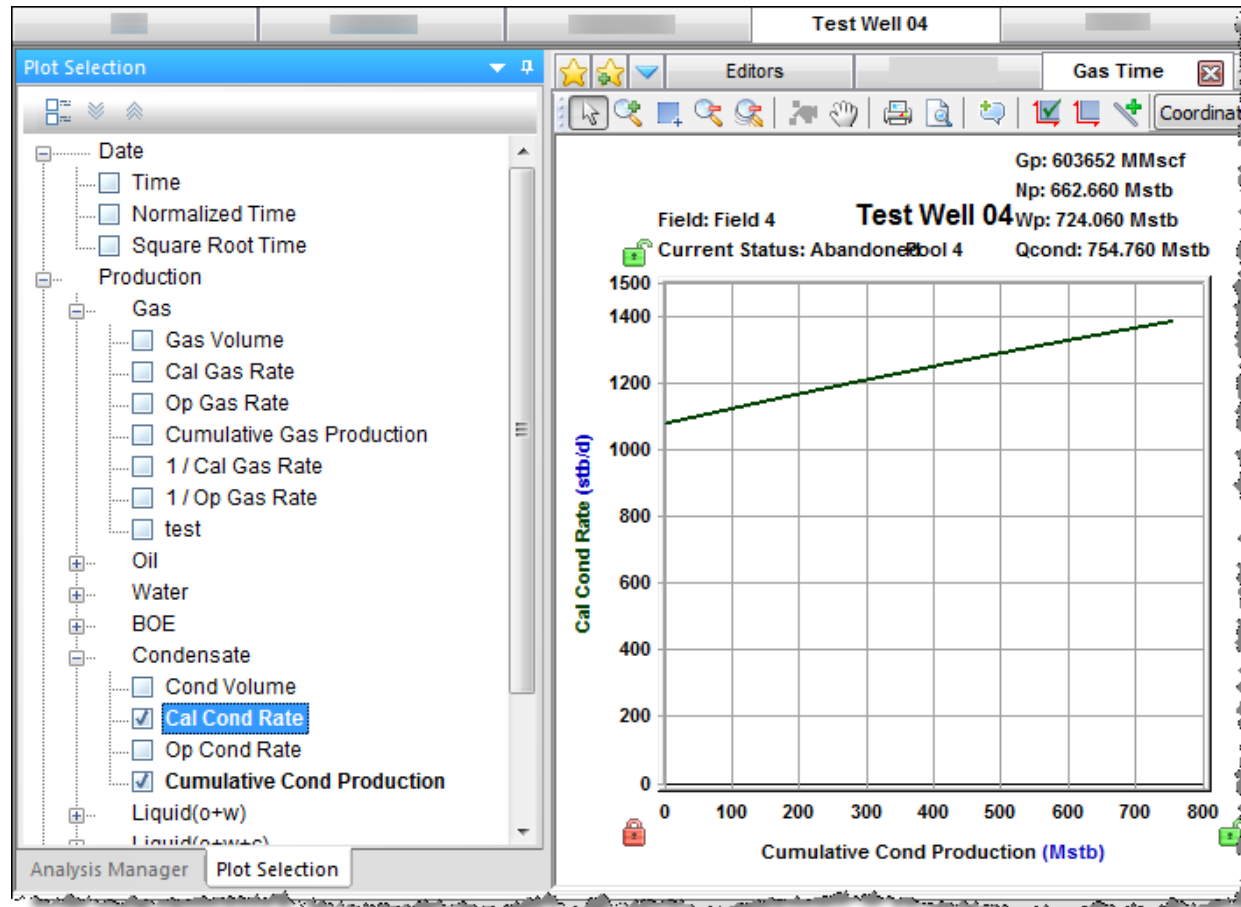
4. Click the **Analysis Manager** tab; click the **+** icon and select a condensate analysis.
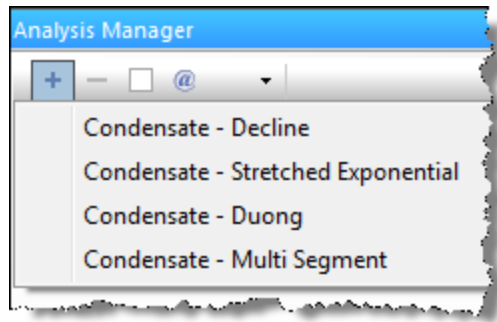
The analysis is added to your worksheet.
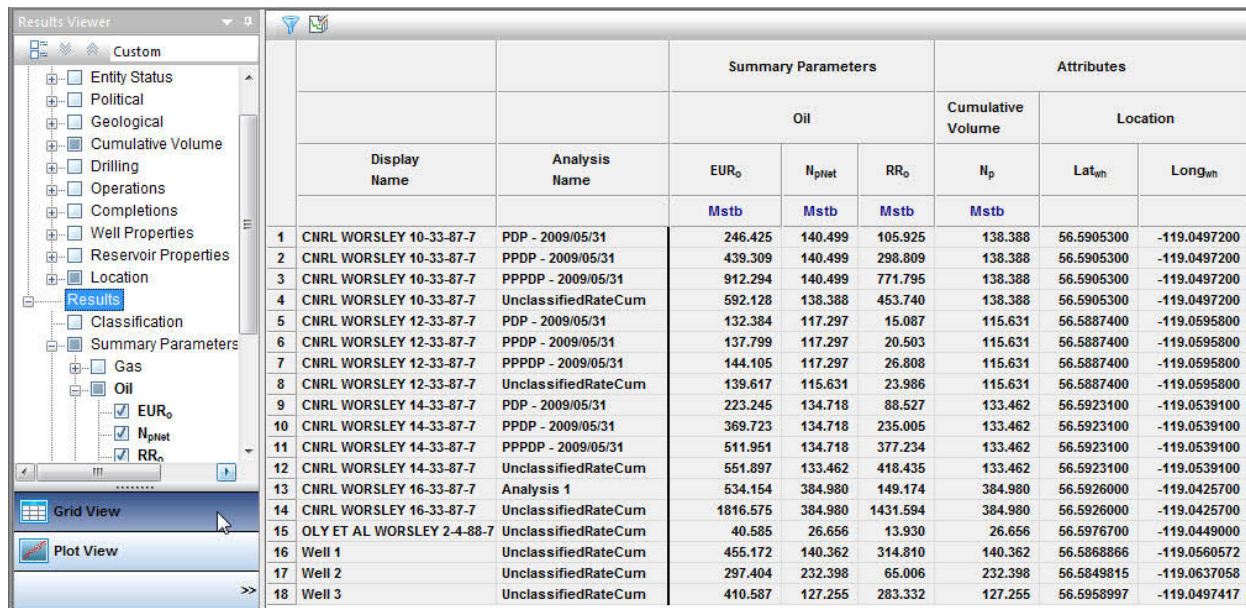
View results

After you perform an analysis, you can view the results of multiple analyses from one or more wells on the Results tab. These results can be viewed in a tabular format using the grid view, or graphically in a cross plot using the plot view. Well attributes can also be displayed in conjunction with the analysis results in both views.

Grid view

To view your results in grid view:

1. Select one or more wells or groups from the Entity Viewer (Hierarchy or Custom pane), or the GIS tab, and then click the **Results** tab.

2. Click the **Grid View** navigation button at the bottom of the Result Viewer pane.

3. Select the parameters you want to display by selecting the appropriate checkboxes in the Results Viewer pane (tree structure).

Plot view

To view your results in plot view:

1. Select one or more wells or groups from the Entity Viewer (Hierarchy or Custom pane), or the GIS tab, and then click the **Results** tab.

2. Click the **Plot View** navigation button at the bottom of the Result Viewer pane.

3. Select the parameters you want to display by selecting the appropriate checkboxes in the Results Viewer pane (tree structure).
   Or, you can drag-and-drop the parameters to the plot.
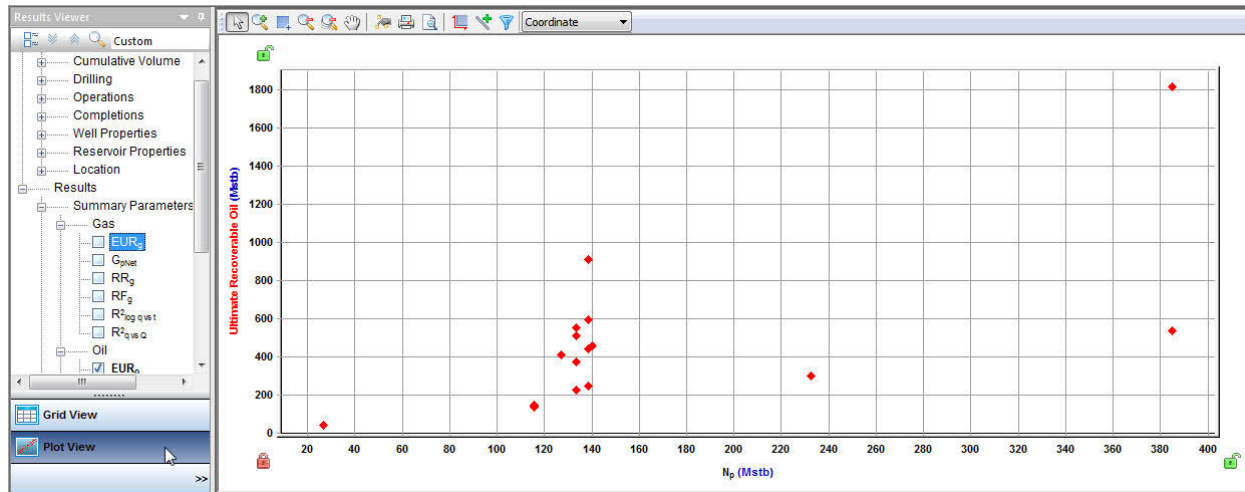
Export data

You can export these data types using an export wizard:

- Production data

- Forecasts

- Decline parameters

In addition, you can export wells and well-and-analysis pairs for use in Piper$^{®}$ by using the Piper Export wizard.

Export production data

Exporting production data includes all the datasets in the Production editor.

To export production data:

1. Click the **Export** icon ( ) in the main toolbar and select **Production Data, Forecasts, or Decline Analyses**.

    The export wizard opens.
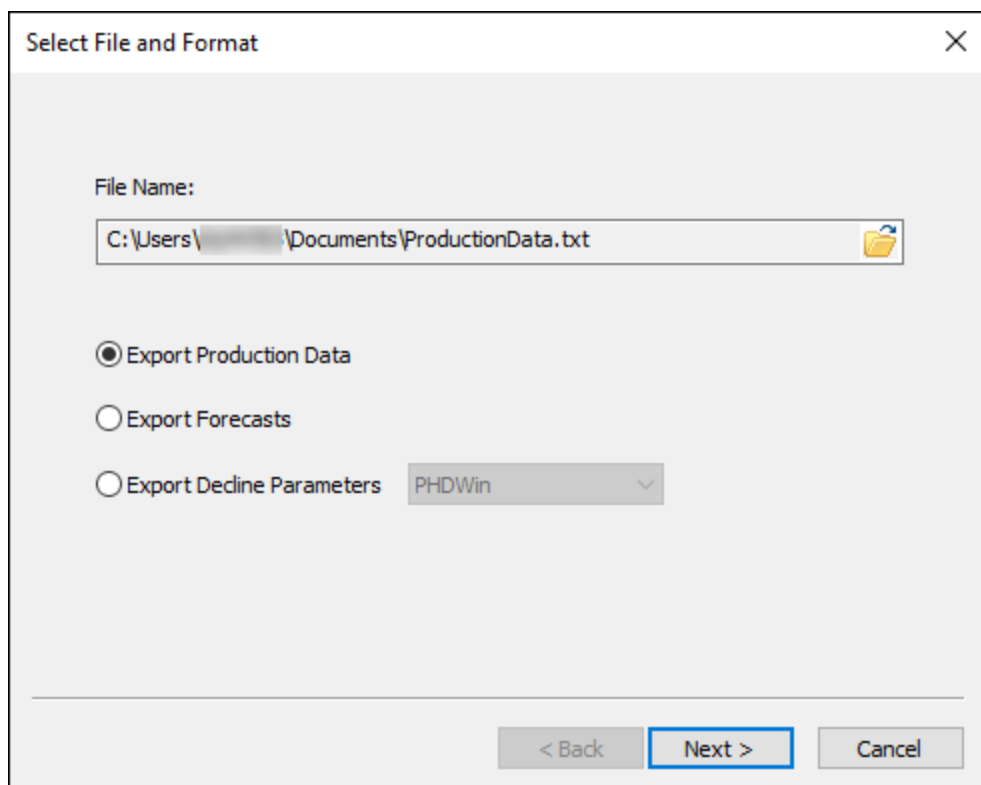
2. In the Select File and Format dialog box, browse to the location where your text file is to be saved. Click **Export Production Data** and then click **Next**.

3. In the Select Entities dialog box, select the entities you want to export from the three tabs: Hierarchy, Shared Groups, and Private Groups. Click **Next**. Note that you can search for entities by name by clicking the **Search** icon.

4. In the Select Output Data dialog box, click the checkboxes for the attributes and fluid rates / volumes you want to export. Click **Next**.

5. In the Export Preview dialog box, apply the sampling rate you want to export the data in. To re-sample the data to be daily, monthly, or yearly, click the **D**, **M**,or **Y** icons. To maintain the original sampling rate of the data, click the actual (**A**) icon.

6. Review your selections, and then click **Finish**. Note that the export can be customized as follows:

   - The format for the date columns (and the units and precision for numeric columns) can be changed by right-clicking the green column headers.

   - The order of the columns can be customized by dragging-and-dropping the column headers.

Note: Custom datasets are not included when you export your production data.

Export forecasts

These forecasts can be exported:

- Decline

- Multi-segment decline

- Water-oil ratio (WOR) total fluid forecast

- Oil cut total fluid forecast

- Ratio forecast

- Custom forecast

- Forecast consolidation

- Hybrid model forecasts

- Analytical model forecasts

- Unconventional reservoir forecasts

- Typecurve forecasts

To export forecasts:

1. Click the **Export** icon ( ) in the main toolbar and select **Production Data, Forecasts, or Decline Analyses**.

   The export wizard opens.

2. In the Select File and Format dialog box, browse to the location where your text file is to be saved. Click **Export Forecasts** and click **Next**.

3. In the Select Entities dialog box, select the entities you want to export from the three tabs: Hierarchy, Shared Groups, and Private Groups. Click **Next**. Note that you can search for entities by name by clicking the **Search** icon.

4. In the Select Analyses dialog box, click the checkboxes for the analyses (including consolidations) you want to export, and then click **Next**.

5. In the Select Attributes dialog box, click the checkboxes for the attributes and fluid rates / volumes you want to export. Clicking the **Include Historical Data** checkbox appends the historical production from the entity to each forecast until the forecast start date (this does not apply to declines from typewell worksheets). Click **Next**.

6. In the Export Preview dialog box, review your selections, and then click **Finish**. Note that the export can be customized as follows:

- The format for the date columns, and the units and precision for numeric columns, can be changed by right-clicking the green column headers.

- The order of the columns can be customized by dragging-and-dropping the column headers.

The file is saved with a message in the <u>Status Window</u> and the wizard closes.

Export decline parameters

These decline parameter formats can be exported:

- Aries

- Decline parameters (Mosaic, other)

- PHDWin

- Energy Navigator

Note: You can set a classification for your data in the Analysis Manager.

To export decline parameters:

1. Click the **Export** icon ( ) in the main toolbar and select **Production Data, Forecasts, or Decline Analyses**.

   The export wizard opens.

2. In the Select File and Format dialog box, browse to the location where your file is to be saved. Click **Export Decline Parameters** and select your export format, and then click **Next**.

   - **Aries** — exports gas, oil, water, and condensate decline analyses. Includes decline analyses at the entity, hierarchy, or custom-group level. Includes Decline and Multi-Segment analyses. The output format is a .txt file.

   - **Energy Navigator** — only exports reserve-classified gas and oil decline analyses. Includes decline analyses at the entity and hierarchy level. Includes Decline and Multi-Segment analyses. The output format is an .xml file.

   - **PHDWin** — exports gas, oil, water, and condensate decline analyses. Includes decline analyses at the entity, hierarchy, or custom-group level. Includes Decline and Multi-Segment analyses. The output format is a .csv file.

   - **MOSAIC** — exports decline and multi-segment decline analyses in a MOSAIC format. Includes decline analyses at the entity, hierarchy, or custom-group level. Exports decline parameters in a generic format to a .xlsx file. Files exported using this option can be imported to Entero MOSAIC (version 2015.5 and later).

   If you try to export a linked analysis containing any invalid analysis types, it does not export.

3. In the Select Entities dialog box, select the entities you want to export from the three tabs: Hierarchy, Shared Groups, and Private Groups. Click **Next**. Note that you can search for entities by name by clicking the **Search** icon.

4. In the Select Analyses dialog box, click the checkboxes for the analyses (including con-solidations) you want to export, and then click **Next**.

The file is saved with a message in the Status Window and the wizard closes.

Export a file for use in Piper®

You can export wells for building and calibration purposes, and well-and-analysis pairs for forecasting purposes.

To export a .hmy2pip file from Harmony Enterprise to use in Piper:

1. Click the **Export** icon ( ) in the main toolbar and select **To Piper**.

   The Piper export wizard opens.

2. In the Welcome dialog box, read the message and click **Next**.

3. In the Piper Export | Export Type dialog box, click **Building and Calibration** or **Forecasting**. Note that you must calibrate your data prior to forecasting.

   If you select **Building and Calibration**, the following data is exported: well locations, attributes, as well as rates and pressures on the effective / calibration date.

   If you select **Forecasting**, analytical wells are exported with their paired analytical analysis / model. Each well is paired with an analysis.

4. Browse to the location where your .hmy2pip file is to be saved. Click **Next**

5. In the Piper Export | Select Entities dialog box, select the wells you want to export in one of the tabs (Hierarchy, Shared Groups, or Private Groups). Note that you do not see the Private Groups tab if you are using an .hldb file.

6. *(For Building and Calibration)* Click **Export**.

7. *(For Forecasting)* Click **Next**.

8. *(For Forecasting)* In the Piper Export | Analyses Selection dialog box, select the analyses you want to export. Click **Next**.

9. *(For Forecasting)* If more than one analysis has been paired with a well, the Piper Export | Well-Analysis Pairing Conflicts dialog box opens.
   For each well with a conflict, select an analysis or exclude the well from the export by selecting from the drop-down list. Click **Next**.

10. *(For Forecasting)* In the Piper Export | Preview dialog box, review your well-and-analysis pairings. If no corrections are needed, click **Export**.
    If you need to make corrections, click **Back** to return to the previous dialog box.

The Piper Export | Summary dialog box opens, which outlines what happened with the export. If you want additional information, click the **View export log file** link. For more information, see the example export logs.

Piper requires tubing data, so if a well in Harmony Enterprise is using a casing flow path, when the well is exported, the casing internal diameter is saved into the tubing internal diameter field in the .hmy2pip file. When imported into Piper, the well has a tubing flow path, where the tubing internal diameter is equal to the casing internal diameter in the Harmony project.

Note: Gas lift data requirements in Harmony Enterprise are different than gas lift requirements in Piper. If a well in Harmony Enterprise has a Gas Lift flow path, when imported into Piper, the well has a tubing flow path. You must set the gas lift flow path with required gas lift data inputs in Piper's Wellbore Descriptions editor. For more information, see modeling wellbores (opens the Piper help in a new window).

11. Click **Done**.

Important: If sandface pressures are not calculated in Harmony Enterprise, they are calculated for the Piper export. These calculations are not written to the Harmony Enterprise project database.

Use workflows

A workflow is a collection of worksheets and analyses that can be applied to an entity as a set. Using a workflow eliminates the need to create the same worksheets and analyses for every entity with similar characteristics. Workflows also maintain worksheet and analysis customizations (for example, names, colors, axis ranges, etc.).

Note: When an entity is selected for analysis, it is locked, so you are not able to apply a workflow to this entity while the lock is in place.

These items apply to workflows:

- create a workflow
- modify a workflow
- apply a workflow
- Create Workflow dialog box

You can *rename* or *remove* a workflow by clicking the **Launch Workflow** icon ( ) and then right-clicking the workflow.

The following analyses cannot be included in workflows because they require user input in order to be created:

- ratio forecasts
- WOR / oil cut fluid forecasts
- consolidations
- custom forecasts

Create a workflow

To create a workflow:

1. Select an entity and click the **Analysis** tab. Create the worksheets and analyses to be included in the workflow, including any customizations for the plot.

   Note: If a custom dataset does not exist when a template is applied, the dataset is not added to the plot.

2. Click the **Create Workflow** icon ( ) on the main pane's toolbar.

   The Create Workflow dialog box opens.

3. Click **New** and type a name for your workflow; click **OK**.

4. Click **Save**.

   Your workflow is saved and can be viewed by clicking the **Launch Workflow** icon ( ) on the main pane's toolbar.
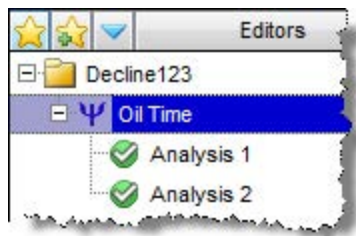
Modify a workflow

To modify a workflow:

1. Select an entity for analysis (or group), and create or modify the worksheets and analyses you want to include in the new version of the workflow.

2. Click the **Create Workflow** icon () on the main pane's toolbar.

   The Create Workflow dialog box opens.

3. Select the workflow name you want to replace in the **Workflow** drop-down list.

4. Click **Save**.

Apply a workflow

After you create a workflow, you can apply it to entities and groups.

To apply a workflow:

1. Select one or more entities in the Entity Viewer (Hierarchy or Custom).

2. Right-click and select **Apply Workflow to Selected Entities**; then select a workflow.
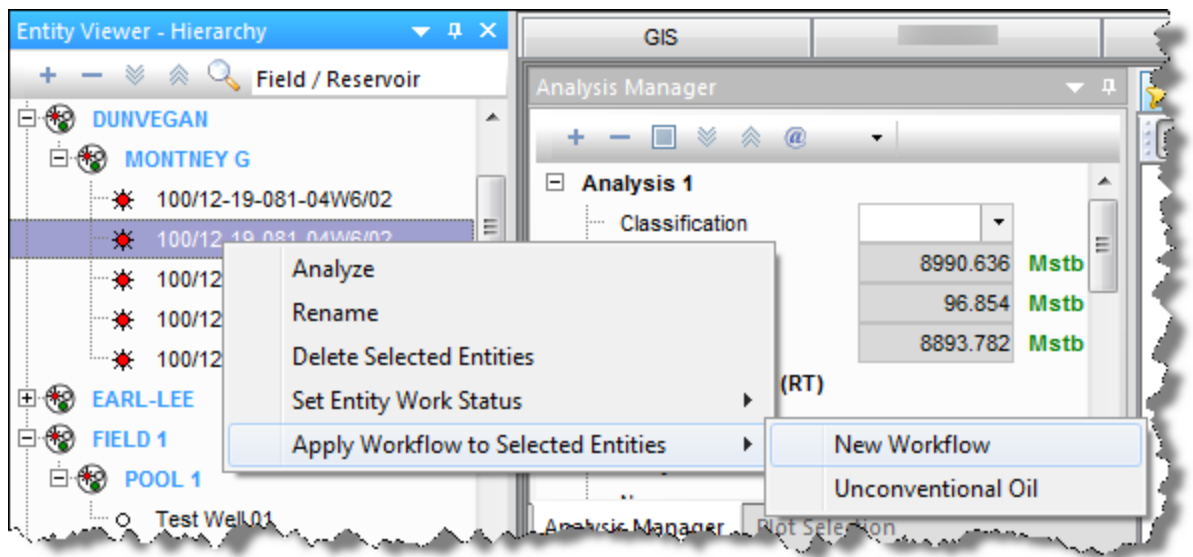
Note: If you right-click a selection when no workflows exist, (No Workflows Exist) is displayed in the context menu. Also, if you attempt to apply a workflow to an empty group, an error message opens stating that workflows cannot be applied to groups that do not contain any wells.

Alternatively, you can select an entity for analysis (or group), and then click the **Launch Workflow** icon (⭐) on the main pane's toolbar. Then either double-click the workflow, or click the blue arrow to the right of the workflow.
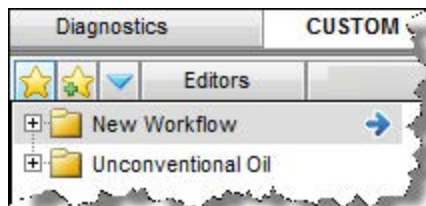
A dialog box opens where you confirm your intention to apply the workflow.
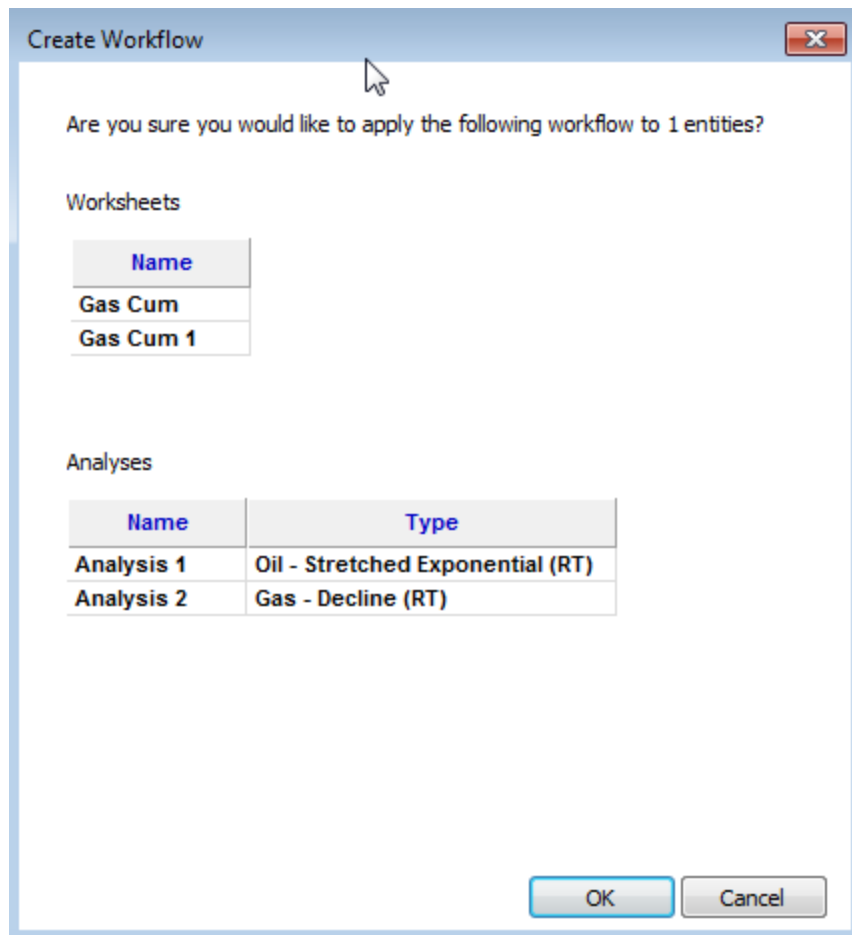
The Status Window displays messages for the following:

- If your workflow is applied to the entities you selected.

- If your workflow could not be applied to all of the entities.

- If there are any analysis errors (for example, the data could not be "best fit").

Create Workflow dialog box

This dialog box is commonly used when you <u>create</u> or <u>modify a workflow</u>.

- **Workflow** drop-down list — select your previously created workflow from the drop-down list. If you have not created a workflow, this list is blank.

- **New** button — opens the Workflow Name dialog box where you type a name for your workflow.

- **Worksheets** — click the checkboxes to select or deselect the worksheets for your workflow.

- **Lock Scaling** — keeps the x- and y-axis scale from the worksheet you are applying to your workflow.

- **Analyses** — click the checkboxes to select or deselect the analyses for your workflow.

Work offline

If you want to perform some work outside of the database (for example, if you want to test some analyses without modifying the existing work in your current project database), then you can export wells, scenarios, or groups into a separate project. This work can remain in a separate project, or you can import this data back into the source project later.

Exporting entities from a Harmony Enterprise database is a process that creates an .hldb file from the entities using Microsoft SQL LocalDB. You can connect to the .hldb file with Harmony Enterprise, as long as the LocalDB is installed on your computer. Or, you can import the .hldb file into a Harmony Enterprise SQL database (*not* applicable to SE licenses). You can transfer wells from one database to another, work on a subset of wells offline, or send your work to technical support.

To export wells, you must have Microsoft SQL LocalDB 2012 or later. For your convenience, Microsoft SQL LocalDB 2014 is included in the Harmony Enterprise installation.

Exporting entities

To export entities from a database:

1. Select the entities you want to export in the Entity Viewer (Hierarchy or Custom pane).

2. Click the **Export** icon ( ) in the main toolbar and select **To .hldb file**.

3. Specify a filename and save your .hldb file.
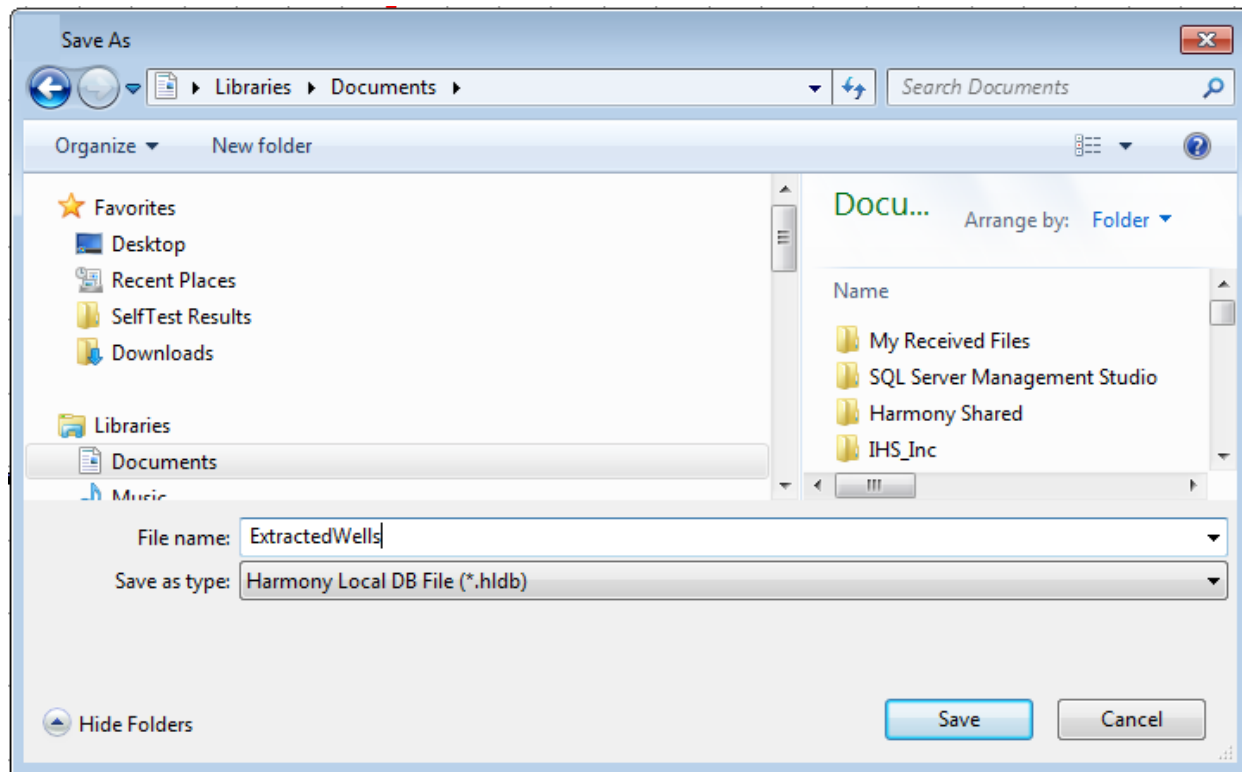
Connecting to an .hldb file

To connect to an .hldb file that was exported from Harmony Enterprise (by you or another user):

1. Click **Connect to**, **Existing .hldb file** in the Harmony Enterprise startup screen (opens when you launch Harmony Enterprise).

2. Browse to the location of the .hldb file and click **Open**.

   Your exported wells are now treated as a new Harmony Enterprise database, and any changes you make in Harmony Enterprise are saved in the .hldb file.

Tip: When you connect to a local database, private groups (in the Entity Viewer - Custom) are converted to shared groups.

Importing / merging an .hldb file into a database

Note: This functionality does *not* apply to SE licenses.

To import wells from your .hldb file back into the source database, or a new database:

1. Open Harmony Enterprise.

2. Click the **Import** icon ( ) in the main toolbar, and select **To .hldb file**.

   If you are importing back into the source database, your changes are automatically merged with the original wells (this cannot be unlinked). Analyses with the same name are always overwritten, while production and attribute data is controlled by your settings in the Options dialog box. Any new analyses are appended. Any analyses that exist in the original database, but not in the exported database, remain unchanged.

   If you are importing to a different database, you can merge your changes to existing wells, or import your changes as new wells (see importing well data from a file).

With a Harmony Enterprise license, you can import an .hldb into a full SQL project database, or you can import into another .hldb. If the source database contains the same wells as the imported .hldb, then a merge process occurs.

Analysis types

After you have added a worksheet, you can create an analysis. Harmony Enterprise supports the following analysis types:

With a Forecast license	With a Reservoir license
Decline analyses: Decline (Arps decline) Multi-segment Stretched exponential Duong Typewell (the above decline analyses can be added to the typewell worksheet) Material Balance analyses Volumetrics analyses Ratio analyses: WOR (water-oil ratio) Oil cut Production forecasts: WOR / oil cut forecast Ratio forecast Custom forecast Forecast consolidation	Typecurve FMB URM Analytical model Hybrid model Probabilistic Multi-well model
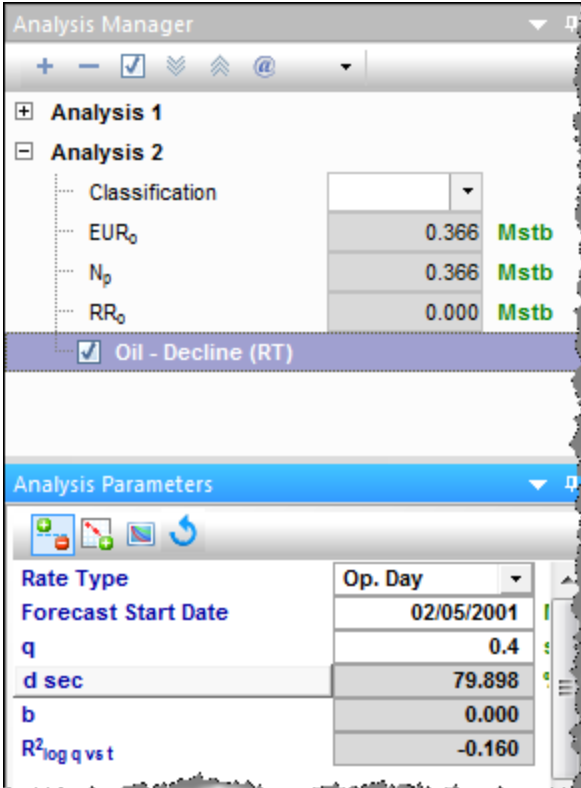
Decline analysis

The decline analysis uses the conventional Arps' decline method and generates forecasts of future production rates, and the estimated ultimate recovery (EUR) of reserves. For additional information on theory and concepts, see decline analysis theory. When you add a decline analysis (see analyzing an entity), Harmony Enterprise automatically selects the best subset of your data (90% of your data points) for an initial best fit.

Note: This analysis works with your Harmony Forecast™ license.

Analysis Parameters pane

After you add your decline analysis, the selected analysis (highlighted in purple) has its detailed parameters displayed in the Analysis Parameters pane located below the Analysis Manager pane (the default setting).

Harmony Enterprise automatically fits (best fits) your decline curve based on:

- recent trends.

- rate data. It is able to handle shut-ins, and exclude these data points from the best fit.

- If you have anomalies in your data, a local outlier factor algorithm is used to determine which data points are considered outliers to be excluded from the initial best fit.

In order for the auto-fit algorithm to work, at least six months of data is required. If there is not enough data, all of the data points are selected, and a decline curve is generated based on the data that is available. Harmony Enterprise automatically selects the best subset of your data for an initial best fit.

In this pane, you can specify / view the following settings and parameters:
(The parameters that are displayed depend on if the analysis was created on a rate-time (RT) or rate-cumulative (RC) production plot.)

- **Rate Type** — select calendar rate (**Cal. Day**) or operator rate (**Op. Day**) from the drop-down list. For more information, see rate type.

- **Forecast Start Date** — the decline curve in Harmony Enterprise includes a "best fit" of historical data followed by a forecast section. The Forecast Start Date (FSD), high-lighted by a small green triangle, defines the beginning of the forecast. For more inform-ation, see forecast start date.

- **q** — the production rate at the *FSD*.

- **d $_{sec}$** — the effective decline rate at the *FSD*. It can be toggled to d_{tan}, or a nominal decline rate.

- **b** — the decline exponent at the *FSD*.

- **R^2** — an indication of the precision of the history match. It is reported as $R^2_{log\,q\,vs\,t}$ on a rate-time (RT) plot, and $R^2_{q\,vs\,Q}$ on a rate-cumulative (RC) production plot.

Rate type

The rate type can be either calendar rate or operated rate, which you can select from the drop-down list at the top of Analysis Parameters pane. However, you first need to select the rate type you want from the Plot Selection tab, which is located next to the Analysis Manager tab (by default).
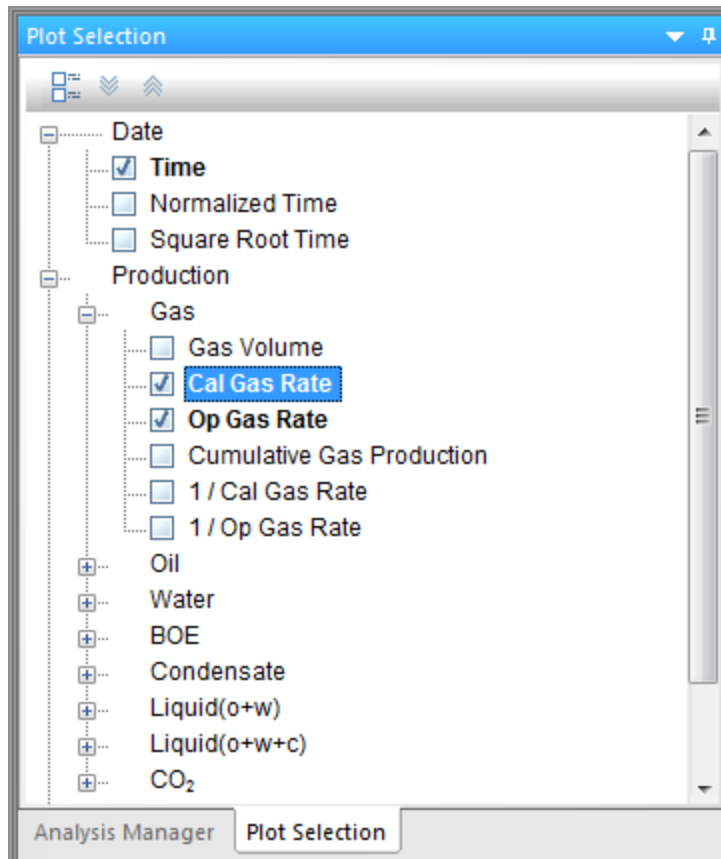
Note that if you select both the *calendar rate* (for example, *Cal Gas Rate*) and *operated rate* (for example, *Op Gas Rate*), they appear as separate axes on your plot. After you select the rate type to place your decline analysis on, the decline curve is placed on that rate history. The decline parameters do not change, but the precision of your match, indicated by R^2, does consequently change. Also, the point selection tool for best-fitting ( ) is only active on the selected axis.

Forecast start date

The forecast start date (FSD) defaults to the last data point in the production history (or the active reference date, if it is set to an earlier time). However, you can change this date, which updates the corresponding rate (q), effective decline rate (d_{sec}), and the decline exponent (b) reported below that date.

Multiple segments

You can add multiple segments (see analysis parameters toolbar) to your decline analysis, and under each segment, you can change parameters and the calculation method for that segment.

Under each segment's tab, you can specify / view the following parameters:

- **Calc Method** — select the decline parameters you want to enter as inputs, and the parameters to be calculated by Harmony Enterprise. For more information, see decline calculation methods.

- **Start Date** — sets the onset of the decline in a segment. For the first segment, it is defined by the time of the historical (best fit) portion when the decline curve begins.

  - In each best fit of production data, the *Start Date* defaults to the first selected point, and is highlighted by a small blue square. By default, Harmony Enterprise selects the last 50% of the data for curve-fitting, but you can change this percentage by clicking the **Point Selection Tool** icon ( ).

- **q_i** — the initial production rate and is reported / specified at the *Start Date*.

- **$d_{i\,sec}$** — the initial effective decline rate and is reported / specified at the *Start Date*. You can toggle this parameter to show either $d_{i\,tan}$ or a_i (nominal decline rate).

- **Δt** — the duration of the decline segment.

- **q_f** — the final forecast rate (abandonment rate), and is initialized from the settings defined in the Options dialog box (see decline options). However, you can manually modify this rate by entering a new value. When a decline is added to a group, the abandonment rate uses the value in the Options dialog box multiplied by the number of producing wells.

- **b** — the decline component. The initially reported *b* value results from the best fit of the selected historical data to a hyperbolic decline, unless a fixed b value is defined in the Options dialog box.

  - The *b* value can be automatically updated each time you change the historical portion of the fit, if you have the yellow lock icon ( ) open. If this icon is in a locked position ( ), your b value is locked and changing the selected history does not impact the reported b value.

Analysis Parameters toolbar

The Analysis Parameters toolbar has the following key icons:

- **Show / Hide Results Line** — shows (default setting) or hides the dashed line on the plot that represents the abandonment rate for the decline analysis and the d_{lim} transition.

- **Add / Remove Segment** — adds a new segment to the end of the existing decline forecast, or removes the last segment. When you add a new segment, this is how Harmony Enterprise *initializes* that segment:

  - **Nominal decline rate (a)** — the beginning of the new segment and the end of preceding segment are equal.

  - **q_i** of the new segment is set to q_f of the preceding segment.

  - The **b** value of the new segment is the same as that of the preceding segment, and a duration of *60 months* is initially applied.

- **Fit Decline to Forecast and Selected Production Points**· — clears your historical data selections (the decline "best fit") and uses the data points for the forecast you select. Any additional points you manually select are included in the "best fit" as well. If you select None from the drop-down list, your forecast data is not included in best fits.

  Tip: This option works on these forecast types: stretched, Duong, WOR total fluid, custom, ratio, typecurve, analytical, hybrid, and the unconventional reservoir model. When best-fitting data, you can control when the b value (slope) should be minimized. For more information, see b value minimization in the Options dialog box.

- **Reinitialize Segment** — for reinitialization of a segment, you can select one of the following options from the drop-down menu:

  - **Reinitialize Segment** — the *nominal decline rate (a)* at the beginning of a new segment and end of its preceding segment are set to be equal to

ensure there is a smooth transition between the two segments. Also, q_i of the new segment, and q_f of the preceding segment, are set to be equal. If you have more than two segments, this reinitialization rule applies to all of the segments.

- **Reinitialize Segment q_i** — only the q_i of new segments, and the q_f of their preceding segments, are set to be equal to attach the segments together.

- **Reset decline to initial state** — resets the plot to the default best fit (initial auto fit). Note that if you changed the dlim Exp field in the Options dialog box, clicking this icon resets the plot to the current value in this field.

Decline calculation methods

After you have created your decline analysis, you can modify the parameters by entering new values. As the parameters are changed, calculated values and the forecast line on the plot are updated. To change which parameters are specified, you can change your *calc method*.

The table below lists which values are specified (denoted by S), and which are calculated (denoted by C), in different calc methods. For special parameters or calc methods, some parameters are marked as not applicable (n/a).

Calc Method	qi	Δt	di	b	qf	Qf	dlim
Δt | Qf	S	C	S	S	S	C	n/a
Δt | di	S	C	C	S	S	S	n/a
Δt | qf	S	C	S	S	C	S	n/a
qf | Qf	S	S	S	S	C	C	n/a
di | Qf	S	S	C	S	S	C	n/a
di | qf	S	S	C	S	C	S	n/a
di | b	S	S	C	C	S	S	n/a
Fixed Rate	S	S	n/a	n/a	n/a	C	n/a
dlim - Δt | Qf	S	C	S	S	S	C	S
dlim - qf | Qf	S	S	S	S	C	C	S

dlim - Δt | qf	S	C	S	S	C	S	S
Inclining Rate	S	C	S	n/a	S	C	n/a

- **Fixed rate** — this calculation method can be used to create a constant rate forecast. When you switch to this *calc method*, the previous q_i and Δt are maintained. These are the only parameters that can be changed for this forecast type.

- **d$_{lim}$** — when a decline forecast has a b value greater than 0, the decline rate (or slope at a given point on the curve) decreases through time. The decline rate can become very small, resulting in a very long forecast and sometimes an unreasonable EUR. The d_{lim} calc method provides a way to limit this by setting a minimum decline rate (d_{lim}). After this minimum decline rate is reached, the forecast proceeds with a b of 0 (a constant decline rate, or exponential decline), and a vertical dashed-green line displays the transition between the two decline regimes.

  - The limiting effective decline rate can be toggled between exponential ($d_{lim\ exp}$) and hyperbolic ($d_{lim\ hyp}$). This defines whether the nominal decline rate (at the time of transition from the hyperbolic decline to the exponential decline) should be calculated using the b value of the hyperbolic, or exponential decline regimes.

- **Inclining rate** — this method can be used to create a segment with an increasing rate. The b value is forced to remain at 0. The q_i, d, and q_f are specified. By default, when you switch to this calc method, the q_i is maintained, and the d_i is converted to a negative value (an inclining rate rather than a declining rate). A q_f is initially calculated to set the Δt to 60 months.

Line manipulation

Line manipulations are initiated by clicking (sometimes while pressing the **Ctrl** or **Shift** keys) the line itself, or one of the manipulation points for a given segment (start date, forecast start date, or end date). You can cancel your line manipulation by pressing the **Esc** key. Specific line manipulations are described below.

Tip: Any time you see "click", this means to left-click your mouse. Right-click actions are specifically mentioned.
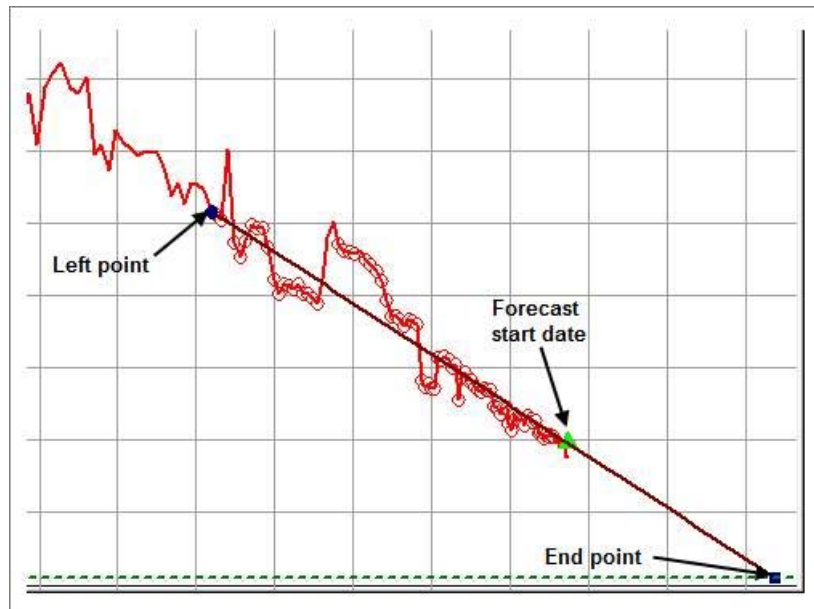
Left point: any historical point (The selection between the left point and th[e] FSD is not included in the forecast; it i[s] only used to show historical production.)
Forecast start date (FSD): the middle point of the line
End point: the expected ultimate recovery

- **Forecast Start Date, FSD** (indicated by a green triangle on the decline line)

  - **Click, grab-and-drag** — maintains the shape of the decline line and the *b* and *d* values. Enables vertical shifting of the decline line, which results in changes to *q* and q_i.
    - The segments after the segment containing the FSD are also affected because they are shifting in time / cumulative production.

  - **Shift key** — pressing the **Shift** key while dragging enables you to position the *FSD* along the decline curve, while maintaining the shape of the decline. This changes your Q_f (only on a rate-time Decline worksheet).
    - Positioning of the FSD beyond the historical production is restricted on a rate-cumulative (RC) production decline.

  - **Ctrl key** — pressing the **Ctrl** key while dragging enables horizontal shifting (translation) of the decline with time. This impacts the FSD in time on a rate-time (RT) plot, but the decline parameters remain unchanged.
    - If the *FSD* is located on the second segment, pressing the **Ctrl** key results in behavior similar to "click, grab-and-drag" on the second segment.

- **Start Date** (indicated by a blue circle)

- **Click, grab-and-drag** — moves the decline line vertically to change the q_i of the segment. However, it does not change the *start date* or *FSD*. The shape of the decline (b and d) line is preserved.
  - Both q_i and q for the segment being manipulated get modified, and all segments following this segment are shifted in time / cumulative production, accordingly.

- **Shift key** — pressing the **Shift** key while dragging extends your forecast back into the historical production. The *start date*, q_i, and d_i change, but the b value is not impacted.
  - This Shift-key functionality does not apply to a *secondary* segment.

- **Ctrl key** — pressing the **Ctrl** key while dragging translates the curve along the x-axis. The *start date*, *FSD*, and forecast *end date* advance in time for the first segment.
  - This Ctrl-key functionality does not apply to a *secondary* segment.

- **End Date** (indicated by a blue square)

  - **Click, grab-and-drag** — enables you to move the *end date* in time, anchoring to the start date and maintaining the q_f. The b value is maintained, but d_i is updated. If the FSD is contained within the segment, then q and d update as well.

  - **Shift key** — pressing the **Shift** key while dragging extends your forecast forward in time, and decreases your final rate (q_f). Your final Q_f increases, but none of the decline parameters change.

  - **Ctrl key** — visually similar to the grab-and-drag functionality for the end date, but the b value can change with the Ctrl-key functionality.

- **Any point on the forecast decline curve** (activated when the decline segment turns orange)

  - **Click, grab-and-drag** — If the segment contains the FSD, that segment is anchored to the *FSD* and rotates around while the b value and q_f are maintained.
    - On a segment that does not contain FSD, the decline is anchored to the *start date* of the segment.
    - If you accidentally place the FSD at the end date of a segment, the

decline is anchored to the *end date* of the segment.

- **Ctrl key** — the curvature of the line (the *b* value) changes.

Decline-line customization

You can customize the width and color of your decline line / curve by right-clicking it.
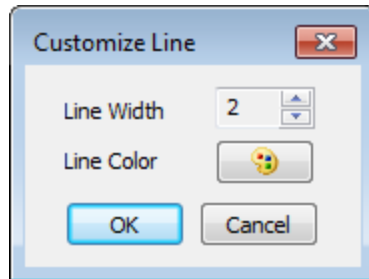
After you customize your decline line / curve, the modifications are saved and applied to every worksheet that displays this decline.

Multi-segment decline analysis

You can add a multi-segment decline analysis to a decline worksheet (see analyzing an entity).

Note: This analysis works with your Harmony Forecast™ license.

When you add a multi-segment decline analysis to your worksheet, Harmony Enterprise initializes your analysis with a two-segment decline analysis, based on the initialization settings specified in the Options dialog box. You can add as many decline segments as you want to the first two segments, by clicking the **Add Segment** icon on the Analysis Parameters toolbar.

Note: Segments can only be added or removed after the first two (fixed) segments, and these segments follow the Arps' decline analysis.

Multi-segment decline analyses have these properties:

- The *first segment's* decline starts at either the *initial production date*, or the date corresponding to the historical *peak rate*, based on your multi-segment decline options.

- The *nominal decline rate* (a) at the end of the *first segment* is equivalent to the *nominal decline rate* at the beginning of the *second segment*, in order to enforce a smooth transition between these two segments.

- The q_i (initial production rate) of the *second segment* is set to the q_f (final production rate) of the *first segment*.

- After you add a *secondary segment* (to these two initial segments), q_i of the *secondary segment* is set to the q_f of the preceding segment. Also, the *nominal decline rate* (a) at the beginning of the new segment and end of the preceding segment are set to be equal. For information on how a new segment is initialized, see decline initialization.

    - For a new segment, you can specify your calc method, but the default method is q_f / Q_f. This method enables you to enter the initial rate (q_i), initial effective decline rate (d_i), b value, and time; the calc method calculates the final rate (q_f), and cumulative production (Q_f).

    - The *b* value defaults to the value from the preceding segment, and a duration of *60 months* is initially applied.

Analysis Parameters pane

For a description of general parameters and options, see the decline: Analysis Parameters pane and decline: Analysis Parameters toolbar.

The differences between multi-segment and Arps' decline analyses are described below.

- For the initial (segment #1 and segment #2) decline segments, a calc method cannot be specified.

- You can choose for your b value to be manually *input*, or selected from a custom attribute, under the **b Method** drop-down list.

- You can modify the constraints for your first decline segment under segment 1. For additional information, see constraints.

- For the second segment, you cannot specify a calc method, but you can define a limiting decline rate (both exponential and hyperbolic) by toggling $d_{lim\ exp}$ / $d_{lim\ hyp}$ and entering a value.

Line manipulation

Most of the line manipulation from the decline analysis is the same. However, some of the functionality is slightly different for the initial and secondary segments of your decline.

1. Since the initial decline rate at the beginning of the second segment is forced to be equivalent to the decline rate at the end of the first segment, you cannot use the *Ctrl key* to change the curvature, and hence the *b* value of the second segment. However, you can still use this functionality on any other secondary segment.

2. For the purpose of maintaining a smooth transition between the two segments, you cannot "click, grab-and-drag" the second segment and tilt your decline.

Line manipulations are initiated by clicking (sometimes while pressing the **Ctrl** or **Shift** keys) the line itself, or one of the manipulation points for a given segment (start date, forecast start date, or end date). You can cancel your line manipulation by pressing the **Esc** key.

Tip: Any time you see "click", this means to left-click your mouse. Right-click actions are specifically mentioned.

- **Forecast Start Date, (FSD)** (indicated by a green triangle on the decline line)

  - **Click, grab-and-drag** — moves the FSD along the decline curve, but does not change the decline itself. The *FSD* and consequently the production rate (q), and the effective decline rate (d_{sec}) are updated.
    - If you position the *FSD* anywhere beyond the historical production data on a rate-time plot, it simulates a shut-in. Note that you cannot locate the *FSD* beyond the historical production data on a rate-cumulative plot.
    - If you move the *FSD* to the first segment and then grab-and-drag, the decline line shifts vertically when you move your mouse up and down. The shape of the decline (b and d) is preserved, and q and q_i get updated.

  - **Shift key** — the effect of the Shift key on FSD depends on where the FSD is located:
    - If the *FSD* is located in the *second segment* (the default position), pressing the **Shift** key results in behavior similar to "click, grab-and-drag".
    - If you move the *FSD* to the *first segment* of the decline, pressing the **Shift** key enables you to move the FSD along the decline curve.

  - **Ctrl key** — if the *FSD* is located in the *second segment*, pressing the **Ctrl** key results in behavior similar to "click, grab-and-drag". However, if FSD is on the *first segment*, pressing the **Ctrl** key enables you to translate the decline in time.

- **Start Date** (indicated by a blue circle)

  - For any segment excluding the second segment, all three line functions (1. click, grab-and drag, 2. Shift key, 3. Ctrl key) behave the same as the default "click, grab-and-drag" behavior for the Start Date.

  - For the *Start Date* of the *second segment*, all three line functions behave the same and enable you to reposition the point along the decline curve. The Start Date adjusts the transition point by setting the time constraint to the current position and clearing the other constraints.

- **End Date** (indicated by a blue square)

  - For the *first segment* and *second segment*, all three line functions behave the same. They extend your forecast forward in time and decrease your abandonment rate (q_f). The final cumulative production (Q_f) increases, but none of the decline parameters change.

- For any additional segments, line functions performed on the end date behave the same as the default end-date line functions.

- **Any point on the forecast decline curve** (activated when the decline segment turns orange)

  - All line functions remain the same as the default "any point" line functions, when you adjust the *first segment* or any *added segments*.

  - You cannot manipulate the *second segment*.

Note: To customize your decline line, see decline-line customization.

Stretched exponential decline analysis

The stretched exponential decline method is a variation of the traditional Arps method, but is better suited for unconventional reservoirs due to its bounded nature. For more information, see stretched exponential decline theory.

Note: This analysis works with your Harmony Forecast™ license.

Analysis Parameters pane

After you add your decline analysis (see analyzing an entity), the selected analysis (highlighted in purple) has its detailed parameters displayed in the Analysis Parameters pane located below the Analysis Manager pane (the default setting).

In this pane, you can specify / view the following settings and parameters:

(The parameters that are displayed depend on if the analysis was created on a rate-time (RT) or rate-cumulative (RC) production plot.)

- **Rate Type** — select calendar rate (**Cal. Day**) or operator rate (**Op. Day**) from the drop-down list. For more information, see decline analysis: rate type.

- **Calc Method** — select the method by which the decline analysis is calculated (for example, Δt or q_f) from the drop-down list.

- **Start Date** — the end of production data and the date of the forecast start, represented by the middle point of the analysis line.

- q_i — the initial gas / oil production rate for the forecast.

- Q_i — the cumulative production at the start of the forecast.

- Δt — the duration of the decline segment.

- q_o — a stretched exponential q_o term. (The initial rate at the start of production. Not to be confused with q_i, which is the initial rate at the start of the forecast.)

- **n** — a stretched exponential n term; it must be between 0 and 1.

- **τ** — a stretched exponential t term; it must be positive.

- q_f — the gas / oil production rate at the end of the forecast.

- **End Date** — the date the forecast ends.

- ΔQ — the cumulative production that occurs during the forecast period.

- Q_f — the cumulative production at the end of the forecast — expected ultimate recovery (EUR).

- **EUR_0 Infinite** — the EUR if the abandonment rate = 0.

- **R^2** — an indication of the precision of the history match. It is reported as $R^2_{\log q \, vs \, t}$ on a rate-time (RT) plot, and $R_{2 q \, vs \, Q}$ on a rate-cumulative (RC) production plot.

Analysis Parameters toolbar

The Analysis Parameters toolbar has the following icon:

Show / Hide Results Line — shows (default setting) or hides the dashed-green line on the plot that represents the abandonment for the stretched decline analysis..

Line manipulation

Line manipulations are initiated by clicking (sometimes while pressing the **Ctrl** or **Shift** keys) the line itself, or one of the manipulation points for a given segment (start date, forecast start date, or end date). You can cancel your line manipulation by pressing the **Esc** key. Specific line manipulations are described below:

Tip: Any time you see "click", this means to left-click your mouse. Right-click actions are specifically mentioned.

- **Start Date** (indicated by a blue circle)

  - **Click, grab-and-drag** — moves the decline line vertically to change the q_i of the segment. However, it does not change the *start date* or *Forecast Start Date (FSD)*. The shape of the decline (*b* and *d*) line is preserved.
  - Both q_i and q for the segment being manipulated get modified, and all segments following this segment are shifted in time / cumulative production, accordingly.

  - **Shift key** — pressing the **Shift** key while dragging extends your forecast back into the historical production. The *start date*, q_i, and d_i change, but the *b* value is not impacted.
  - This Shift-key functionality does not apply to a *secondary* segment.

  - **Ctrl key** — pressing the **Ctrl** key while dragging translates the curve along the x-axis. The *start date*, *FSD*, and forecast *end date* advance in time for the first segment.
  - This Ctrl-key functionality does not apply to a *secondary* segment.

- **End Date** (indicated by a blue square)

  - **Click, grab-and-drag** — enables you to move the *end date* in time, anchoring to the start date and maintaining the q_f. The *b* value is maintained, but d_i is updated. If the FSD is contained within the segment, then q and d update as well.

  - **Shift key** — pressing the **Shift** key while dragging extends your forecast forward in time, and decreases your final rate (q_f). Your final Q_f increases, but none of the decline parameters change.

  - **Ctrl key** — visually similar to the grab-and-drag functionality for the end date, but the b value can change with the Ctrl-key functionality.

- **Any point on the forecast decline curve** (activated when the decline segment turns orange)

  - **Click, grab-and-drag** — If the segment contains the FSD, that segment is anchored to the *FSD* and rotates around while the *b* value and q_f are maintained.
  - On a segment that does not contain FSD, the decline is anchored to the *start date* of the segment.
  - If you accidentally place the FSD at the end date of a segment, the decline is anchored to the *end date* of the segment.

  - **Ctrl key** — the curvature of the line (the *b* value) changes.

To customize your line, right-click it. For more information, see <u>decline-line customization</u>.

Duong decline analysis

The Duong analysis was developed specifically for unconventional reservoirs with very low permeability. For more information, see Duong decline theory.

Note: This analysis works with your Harmony Forecast™ license.

Analysis Parameters pane

After you add your decline analysis (see analyzing an entity), the selected analysis (highlighted in purple) has its detailed parameters displayed in the Analysis Parameters pane located below the Analysis Manager pane (the default setting).

In this pane, you can specify / view the following settings and parameters:

(The parameters that are displayed depend on if the analysis was created on a rate-time (RT) or rate-cumulative (RC) production plot.)

- **Rate Type** — select calendar rate (**Cal. Day**) or operator rate (**Op. Day**) from the drop-down list. For more information, see decline analysis: rate type.

- **Calc Method** — select the method by which the decline analysis is calculated (for example, Δt or q_f) from the drop-down list.

- **Start Date** — the end of production data and the date of the forecast start, represented by the middle point of the analysis line.

- q_i — the initial gas / oil production rate for the forecast.

- Δt — the duration of the decline segment.

- $t_{(a,m)}$ — the time function based on the coefficients a and m.

- t_{max} — the time at which the maximum flow rate occurs.

- a — the straight-line intercept of a log(q/N) vs. log(t) plot.

- m — the negative of a straight-line slope of a log(q/N) vs. log(t) plot.

- q_t — rate.

- Q_t — cumulative.

- q_1 — the rate at day one estimated from the slope of a plot of q vs. $t_{(a,m)}$.

- q_∞ — the rate at infinite time estimated from the intercept of a plot of q vs. $t_{(a,m)}$.

- q_f — the gas / oil production rate at the end of the forecast.

- q_{max} — the maximum flow rate.

- **End Date** — the date the forecast ends.

- Q_f — the cumulative production at the end of the forecast — expected ultimate recovery (EUR).

- R^2 — an indication of the precision of the history match. It is reported as $R^2_{\log q \, vs \, t}$ on a rate-time (RT) plot, and $R_{2q \, vs \, Q}$ on a rate-cumulative (RC) production plot.

Analysis Parameters toolbar

The Analysis Parameters toolbar has the following icon:

Show / Hide Results Line — shows (default setting) or hides the dashed-green line on the plot that represents the abandonment for the stretched decline analysis..

Line manipulation

Line manipulations are initiated by clicking (sometimes while pressing the **Ctrl** or **Shift** keys) the line itself, or one of the manipulation points for a given segment (start date, forecast start date, or end date). You can cancel your line manipulation by pressing the **Esc** key. Specific line manipulations are described below:

Tip: Any time you see "click", this means to left-click your mouse. Right-click actions are specifically mentioned.

- **Start Date** (indicated by a blue circle)

- **Click, grab-and-drag** — moves the decline line vertically to change the q_i of the segment. However, it does not change the *start date* or *Forecast Start Date (FSD)*. The shape of the decline (b and d) line is preserved.
  - Both q_i and q for the segment being manipulated get modified, and all segments following this segment are shifted in time / cumulative production, accordingly.

- **Shift key** — pressing the **Shift** key while dragging extends your forecast back into the historical production. The *start date*, q_i, and d_i change, but the b value is not impacted.
  - This Shift-key functionality does not apply to a *secondary* segment.

- **Ctrl key** — pressing the **Ctrl** key while dragging translates the curve along the x-axis. The *start date*, *FSD*, and forecast *end date* advance in time for the first segment.
  - This Ctrl-key functionality does not apply to a *secondary* segment.

- **End Date** (indicated by a blue square)

  - **Click, grab-and-drag** — enables you to move the *end date* in time, anchoring to the start date and maintaining the q_f. The b value is maintained, but d_i is updated. If the FSD is contained within the segment, then q and d update as well.

  - **Shift key** — pressing the **Shift** key while dragging extends your forecast forward in time, and decreases your final rate (q_f). Your final Q_f increases, but none of the decline parameters change.

  - **Ctrl key** — visually similar to the grab-and-drag functionality for the end date, but the b value can change with the Ctrl-key functionality.

- **Any point on the forecast decline curve** (activated when the decline segment turns orange)

  - **Click, grab-and-drag** — If the segment contains the FSD, that segment is anchored to the *FSD* and rotates around while the b value and q_f are maintained.
    - On a segment that does not contain FSD, the decline is anchored to the *start date* of the segment.
    - If you accidentally place the FSD at the end date of a segment, the decline is anchored to the *end date* of the segment.

  - **Ctrl key** — the curvature of the line (the b value) changes.

To customize your line, right-click it. For more information, see decline-line customization.

Material Balance analysis

The material balance analysis is an interpretation method used to determine original fluids-in-place (OFIP) based on production and static pressure data. For more information, see material balance theory.

Note: This analysis works with your Harmony Forecast™ license.

Harmony Enterprise supports gas material balance (GMB).

Gas material balance

With the gas material balance (GMB) analysis, you can select: **Pressure-Function vs. Cumulative Gas** or **Pressure vs. Time** for a single well, or a group of wells.

The analysis line for GMB determines the original gas-in-place (OGIP). The expected ultimate recovery (EUR) can be determined using a recovery factor (RF) or abandonment pressure (P_{ab}). Note that the default calculation for EUR is the Auto option. For more information, see the Analysis Parameters pane below.

> **Tip:** On a p/Z plot, the analysis trend is linear, and the line can be manipulated manually, or by changing the point selection for the best fit. On a Pressure vs. Time plot, the analysis is not a linear trend, and the only way to manipulate the analysis is through point selection.

Single well analysis

The well's static pressures are displayed as a letter. For a single-well analysis, the same letter is used for all pressures.
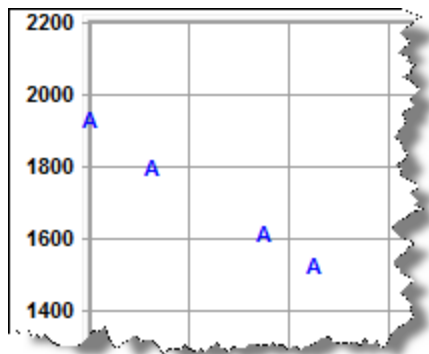
Group well analysis

When a group is analyzed, each well is represented by a different letter.
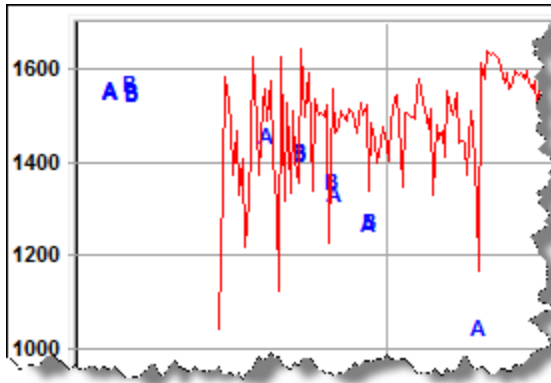
In addition, there is a Material Balance Wells tab / pane where you can select various wells.
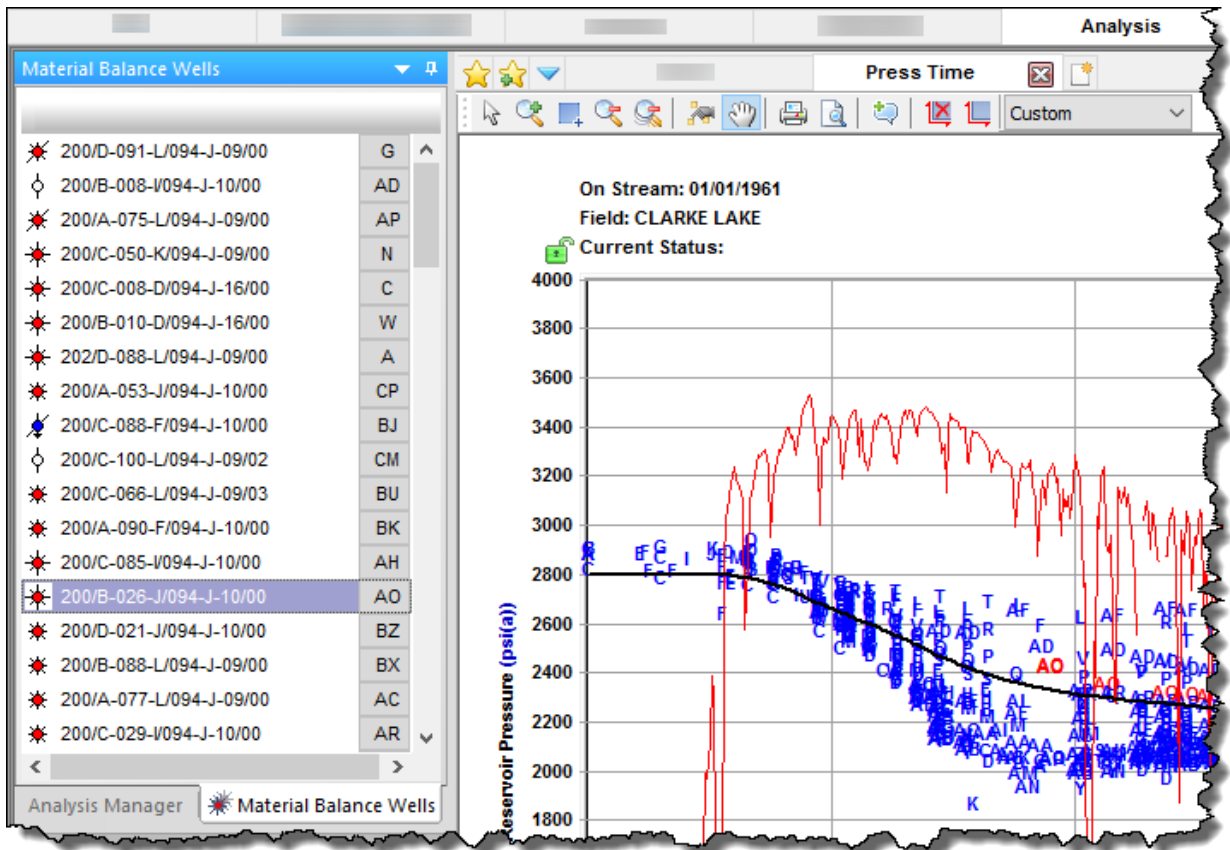
As you hover over various wells in the main pane, their analysis line and well letter is displayed in bold.

Context menus

Right-clicking a well in the Material Balance Wells pane lists these options:

- **Duplicate Selected into Shared Custom Group** — copies the selected entities into the shared custom group you select from the submenu.

- **Duplicate Selected into Private Custom Group** — copies the selected entities into the private custom group you select from the submenu.

- **Move Selected into Shared Custom Group** — moves the selected entities into the shared custom group you select from the submenu.

- **Move Selected into Private Custom Group** — moves the selected entities into the private custom group you select from the submenu.

For more information, see shared and private custom groups.

Analysis Parameters pane

This pane has the following items that you can adjust:

- **Lock p_i** — select Yes or No.

- **p_i** — type your initial reservoir pressure.

- **Abd Calc** — select from the drop-down list:

  - **Auto** — estimates the depth by dividing the initial pressure by the water gradient (0.433 psi/ft). The abandonment pressure is then 35 psi plus 35 psi for every 1,000 ft of depth.

  - **Specify P_{ab}** — you can specify a final reservoir pressure that is used to calculate the corresponding production at this pressure and the recovery factor for gas (RF_g).

  - **Specify RF** — you can specify a percentage of the original gas in-place (OGIP) from the analysis, and the corresponding abandonment pressure is calculated.

  - **None** — RF and P_{ab} are left blank; therefore, expected ultimate recovery (EUR) and remaining recoverable (RR) are not calculated.

Toolbar

The Analysis Parameters toolbar has the following icons:

- **Show / Hide Abandonment Line** — toggle this line on or off. This line represents the abandonment pressure in terms of p/Z or p/Z**, and the expected ultimate recoverable reserves.

- **View data for the current analysis and adjust data point selection** — opens the Material Balance Data Point Selection dialog box where you can view, print, preview, and export your data to a .csv file.

- **Open advanced options for this analysis** (if applicable) — applies to advanced GMB analyses, but in some cases, these options can be applied to non-advanced GMB analyses. Opens the Advanced Material Balance Options dialog box where you can adjust four areas of your GMB: producing reservoir, geopressured, water drive, and connected reservoir.

- **Show GMB diagnostics grid** — opens the Material Balance Data dialog box where you can view, print, preview, and export your calculated and synthetic data to a .csv file.

GMB plots and parameters
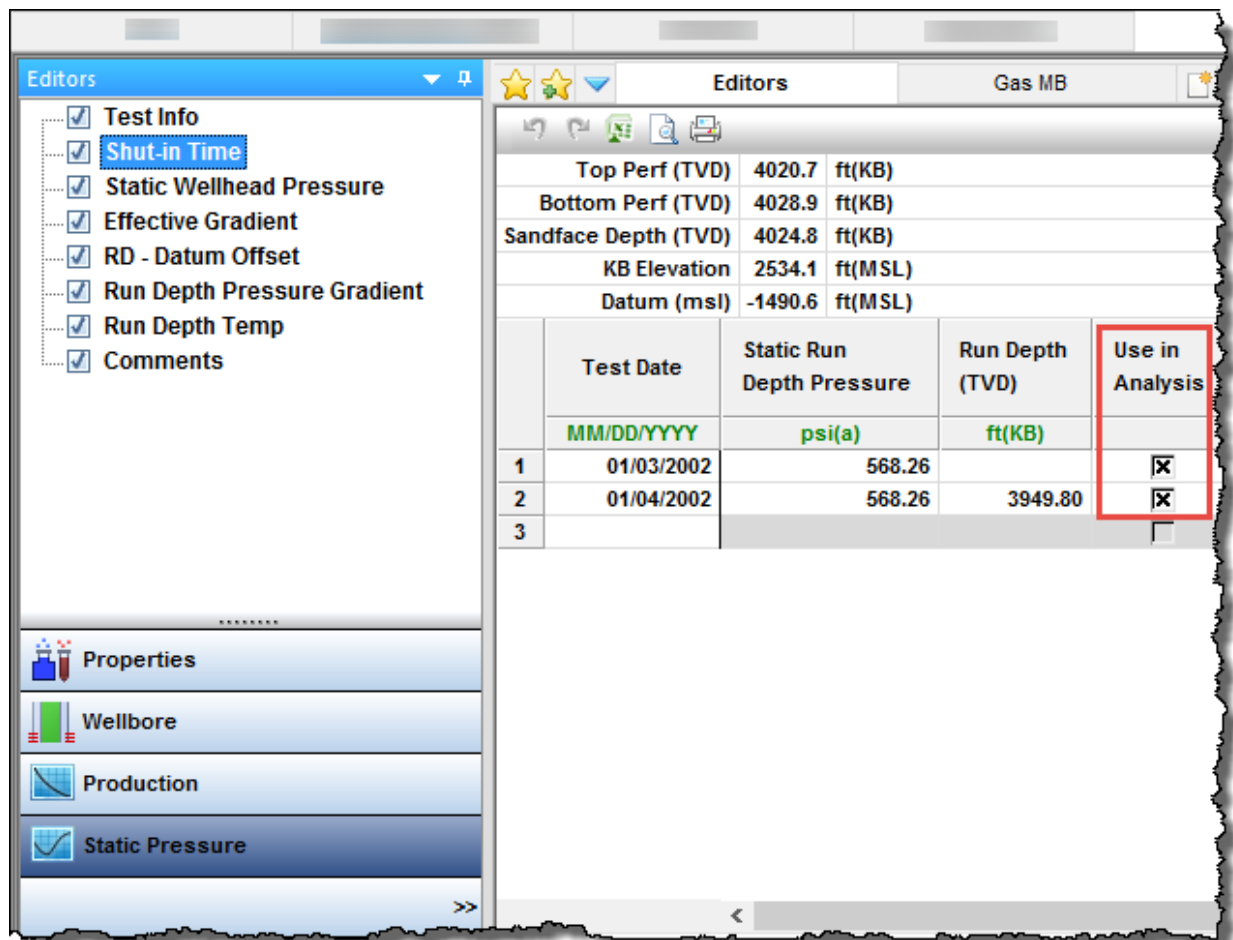
Gas material balance (GMB) analyses can use a pressure function vs. cumulative gas, or pressure vs. time.

The pressure function depends on the type of analysis:

- GMB uses p/Z

- Advanced GMB uses p/Z** (including aquifer effects, but excluding desorption effects)

In order for data to be displayed on the worksheet, the well or group being analyzed must have at least one static pressure value in the Static Pressure editor. Gas gravity, or gas composition and reservoir temperature must be provided in the Properties editor.

Data points in the plot can be turned on or off by selecting / deselecting checkboxes in the **Use in Analysis** column of the Static Pressure editor.

Advanced GMB

You can add an advanced gas material balance (GMB) analysis to an existing GMB worksheet by clicking the **Open advanced options** (⚙) icon in the Analysis Parameter pane's toolbar.

Or, you can add an advanced GMB analysis to a new worksheet by clicking the **Add an analysis** (+) icon in the Analysis Manager's toolbar and selecting **Gas - Advanced Material Balance**.

In both cases, the Advanced Material Balance Options dialog box opens.

Select the options you want to use:

- **Geopressured** — this model does not have parameters in the GMB worksheet. In the Properties editor in the Geomechanical node, a correlation for formation compressibility can be set. This is what is used with the geopressured model to account for formation compressibility in the analysis. The additional reservoir properties that are required for the correlation are initial pressure and porosity.

- **Water Drive** — these models have parameters in the Advanced Material Balance Options dialog box to match the analysis.

- **Connected Reservoir** — these models have parameters in the Advanced Material Balance Options dialog box to match the analysis.

For the water drive and connection reservoir models, the Pressure vs. Time worksheet is often easier to use for matching the analysis. First, match the initial decline trend using the standard GMB analysis, then add the water drive or connected reservoir advanced model. Start the parameters with a low connected aquifer / gas reservoir, then increase the transfer coefficient to a region where the pressure data is very sensitive to a changing transfer coefficient. The transfer coefficient is used to match the initial pressure support trend, and the connected volume is used to match later pressure data. You may need to manipulate one parameter and then the other, back and forth, until you are satisfied with the match. Because two parameters are used in a single equation for the match, the solution is not unique. It is better to stick with a smaller connected volume, unless other indications of a large connected volume (geology, etc.) are present.

Volumetrics analysis

The volumetrics analysis is used to estimate the original hydrocarbon fluid volume in a reservoir. This analysis requires knowledge of reservoir rock properties, as well as fluid saturations and properties. A volumetric analysis can be conducted at any point in the production history, but it is most often used early in the life of the reservoir. For more information, see volumetrics theory.

Note: This analysis works with your Harmony Forecast™ license.

Toolbars

For information on the primary toolbar (and context menu), see the Analysis Manager.

The secondary toolbar is located in the analysis tab and includes the following important icon:

Defaults — copies parameters from the Properties editor.

For information on common icons, see plot toolbars.

Parameters

Enter (or edit) the parameters in the worksheet. As values are calculated, the summary values in the Analysis Manager are also populated.

- **Reservoir Properties** — these parameters are pre-populated from the Properties editor. However, you can amend parameters to see how variation in reservoir properties affects results. To re-populate all of the parameters from the Properties editor, click the **Defaults** icon ( ).
  To re-populate a specific parameter from the Properties editor, click the **Defaults and Limits** button ( ) to the right of the parameter.

- **Oil / Gas Properties** — these parameters are pre-populated from the Properties editor, but you can change some of them. Volumetric calculations use the properties specified in the volumetric analyses.

- **Formation Volume Factor** — you can enter a formation volume factor (B_{gi} or B_{oi}), or click the checkbox to let Harmony Enterprise automatically calculate this value.

- **Adsorption** (intended for shale gas) — you can enter adsorption values to calculate $OGIP_A$. (The default values are those set in the Adsorption section of the Properties editor.)

- **Volume Parameters** — Since reservoir area, rock volume, pore volume, and hydro-carbon pore volume are all linked to each other, OFIP can be calculated based on any of these inputs. Click the option ⊙ for the parameter you want to enter.

  You can also set Dimensions (reservoir length x_e and reservoir width y_e). In this case, the reservoir area is calculated based on given dimensions, and this area is used to calculate the remaining volume parameters.

  Or, you can calculate OFIP based on the RF and EUR, by clicking the EUR option ⊙ .

- In a gas analysis, a surface loss parameter (SL) is available. When SL is entered, the Sales EUR parameter is calculated (if EUR_g exists).

Note: The gas volume analysis has different parameters depending on whether the well is a dry / wet gas well, or a liquid-rich gas well. In the case of a liquid-rich gas well, a volumetric analysis calculates and displays $OGIP_d$ (original dry gas-in-place), as well as $OGIP_r$ (original recombined gas-in-place). Additionally, OCIP (original condensate-in place) is calculated. When displaying volumetric analysis results in the Results Viewer, gas summary parameters (OGIP, EUR_g, Gp_{Net}, RR_g, and RF_g) are displayed in terms of dry gas, *not* in terms of recombined gas. For more information on calculations for liquid-rich gas wells, see volumetrics theory.

WOR analysis

The water-oil ratio (WOR) analysis is an empirical method for trending water and oil production. For additional information on theory and concepts, see WOR forecasting theory. When a WOR analysis is added, it is initialized using a best fit.

Note: This analysis works with your Harmony Forecast™ license.

Analysis Parameters pane

A WOR analysis can be added or displayed in an open worksheet while Cumulative Oil is on the x-axis, and at least one of the following is on the y-axis: WOR, WOR+1, or Water Cut. After you add a WOR analysis (see analyzing an entity), the selected analysis has its detailed parameters displayed in the Analysis Parameters pane.
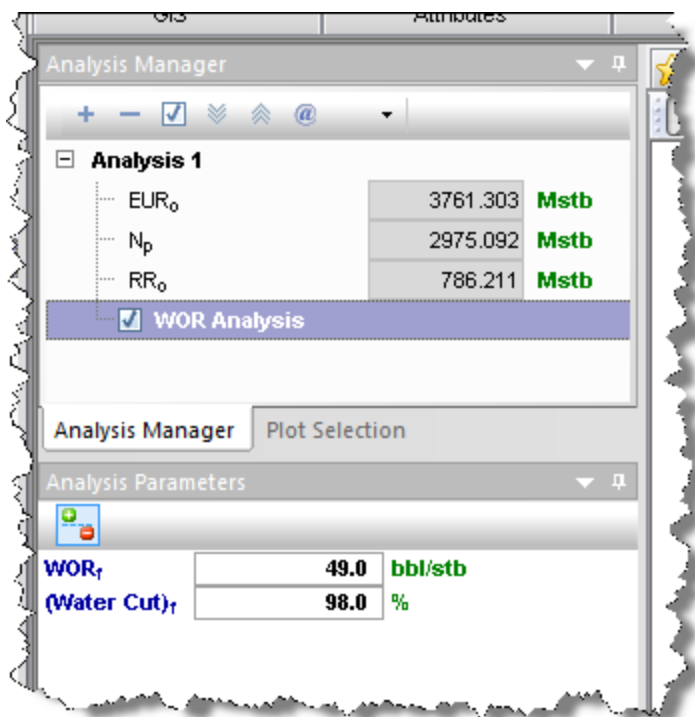
In this pane, you can specify / view the following parameters:

- **WOR_f** — the final / abandonment water-oil ratio. It is initialized from the settings defined in the Options dialog box (see WOR options). This value is calculated when **(Water Cut)$_f$** is specified, and this value must be in the range $(0, \infty)$.

- **(Water Cut)$_f$** — the final / abandonment water cut. It is initialized from the settings defined in the Options dialog box (see WOR options). This value is calculated when **WOR$_f$** is specified, and the value must be in the range (0, 100).

Analysis Parameters toolbar

The Analysis Parameters toolbar has the following icon:

Show / Hide Results Line — shows (default setting) or hides the dashed-green line on the plot that represents the abandonment for the WOR analysis. It is initialized from the settings defined in the Options dialog box (see <u>WOR options</u>).

Line manipulation

Line manipulations are initiated by clicking-and-dragging:

- **Line** — changes the slope of the trend line about the manipulation point.

- **Manipulation point** (   ) — translates the line vertically or horizontally while maintaining the slope.

Analysis line customization

To change the line width and color of your analysis line, right-click the WOR analysis line and select **Customize Line**.
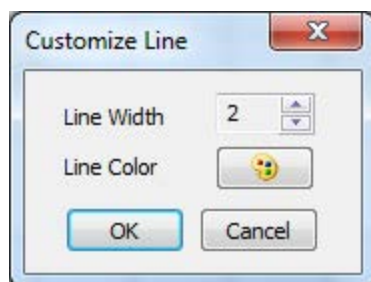
After you customize your line, the modifications are saved and applied to every worksheet that displays this analysis.

WOR options

WOR analysis options are accessed by clicking the **Options** icon (   ) on the main toolbar, or by clicking the **Tools** menu and selecting **Options**. In the Options dialog box, click **Water Oil Ratio**

under the User Settings>>Analysis node.
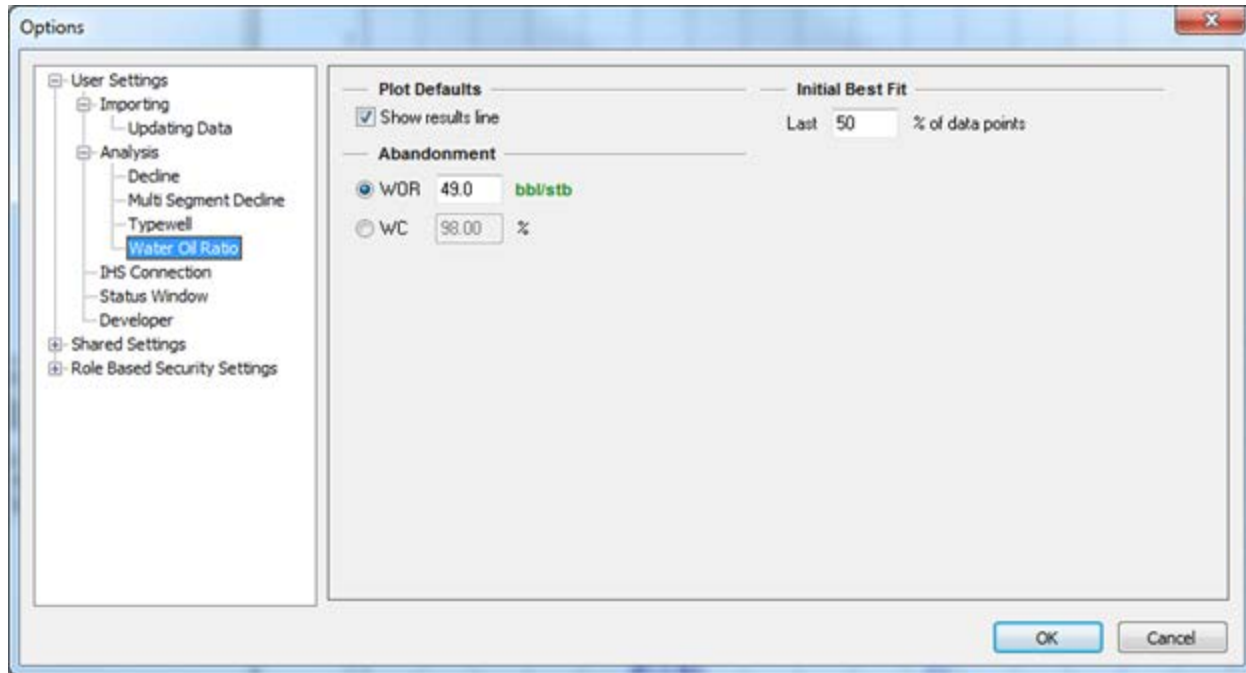
You can set the parameters that initialize water-oil ratio (WOR) analyses in Harmony Enterprise. These inputs can be overridden with each analysis, and the Options dialog box inputs are only used when the analysis is created. The WOR parameters and settings are as follows:

- **Show results line** — shows / hides the green-dashed line for abandonment on your plot.

- **WOR** — sets the abandonment WOR. Harmony Enterprise uses 49 bbl/stb as the default.

- **WC** — sets the abandonment water cut (WC). Harmony Enterprise uses 98% as the default.

- **Initial Best Fit** — specifies the percentage of your historical data that you want to be included in the initial best fit.

Oil cut analysis

The oil cut analysis is an empirical method for trending water and oil production. When an oil cut analysis is added, it is initialized using a best fit. Since time is on the x-axis, an EUR is not determined.

Note: This analysis works with your Harmony Forecast™ license.

Analysis Parameters pane

An oil cut analysis can be added / displayed on an open worksheet while time is on the x-axis, and oil cut is on the y-axis. After you add an oil cut analysis (see analyzing an entity), the selected analysis has its detailed parameters displayed in the Analysis Parameters pane.
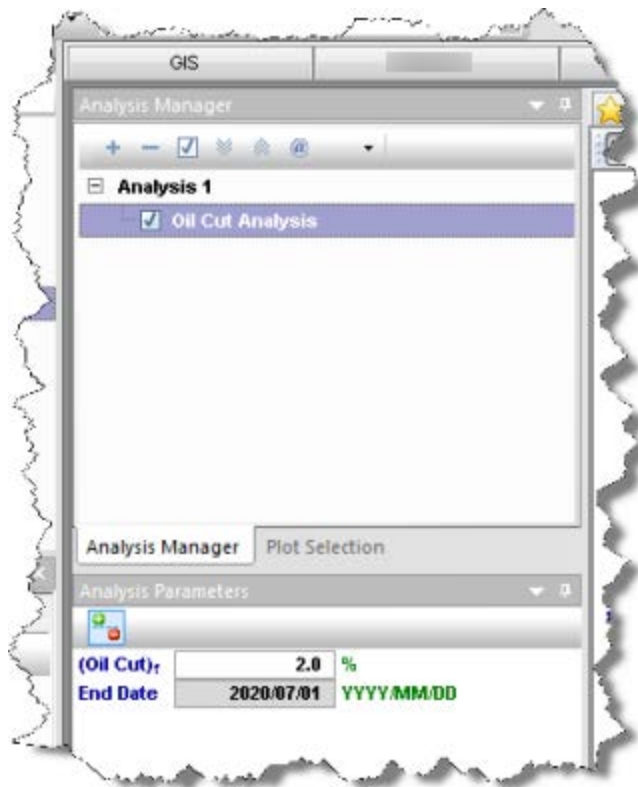
In this pane, you can specify / view the following parameters:

- **(Oil Cut)$_f$** — the final / abandonment oil cut. Initialized as 100-WC from the WC value defined in the Options dialog box (under the Water Oil Ratio node). The value must be in the range (0, 100).

- **End Date** — the corresponding date at the oil cut abandonment value.

Analysis Parameters toolbar

The Analysis Parameters toolbar has the following icon:

Show / Hide Results Line — shows (default setting) or hides the dashed-green line on the plot that represents the abandonment for the oil cut analysis. It is initialized from the settings defined in the Options dialog box, under the Water Oil Ratio node.

Line manipulation

Line manipulations are initiated by clicking-and-dragging:

- **Line** — changes the slope of the trend line about the manipulation point.

- **Manipulation point** ( ) — translates the line vertically or horizontally while maintaining the slope.

Analysis line customization

You can customize your analysis line's width and color by right-clicking and selecting **Customize Line**.
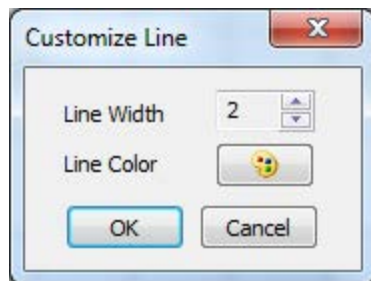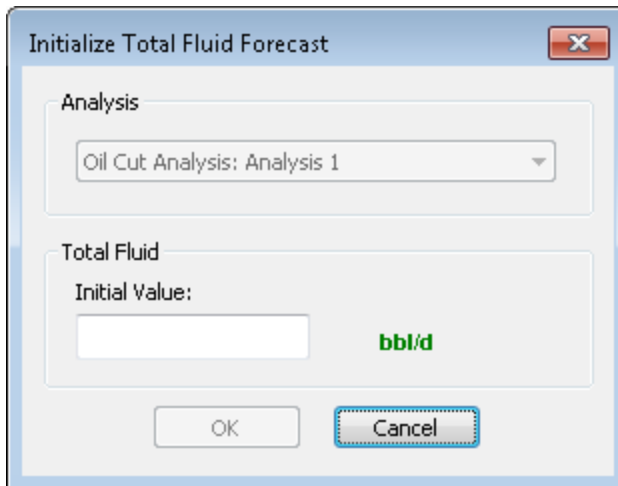
Your modifications are saved and applied to every worksheet that displays this analysis.

WOR / oil cut forecast

By associating a water-oil ratio (WOR) / oil cut forecast (total fluid forecast) with a WOR or oil cut analysis, Harmony Enterprise calculates oil and water forecasts that update as the WOR / oil cut analysis is modified.

Note: This forecast works with your Harmony Forecast™ license.

You can add this analysis by selecting a WOR or Oil Cut analysis while on a Forecast worksheet, or by selecting **WOR / Oil Cut Forecast** from the Analysis Manager after clicking the **+** icon. Using either method opens the Initialize Total Fluid Forecast dialog box.

- **Analysis** — select the WOR or oil cut analysis to be used with the total fluid forecast.
- **Total Fluid Initial Value** — the specified value is a constant to initialize the total fluid forecast ($q_o + q_w$). The total fluid rate can be defined through time by entering values in the $q_{Liquid(o+w)}$ column in the Forecast worksheet.

Clicking **OK** after providing the required inputs, adds an oil and water forecast with the specified analysis, starting at the end of historical production.

Analysis Parameters pane

After you add a WOR / Oil Cut Forecast, selecting the oil or water forecast displays its detailed parameters in the Analysis Parameters pane.
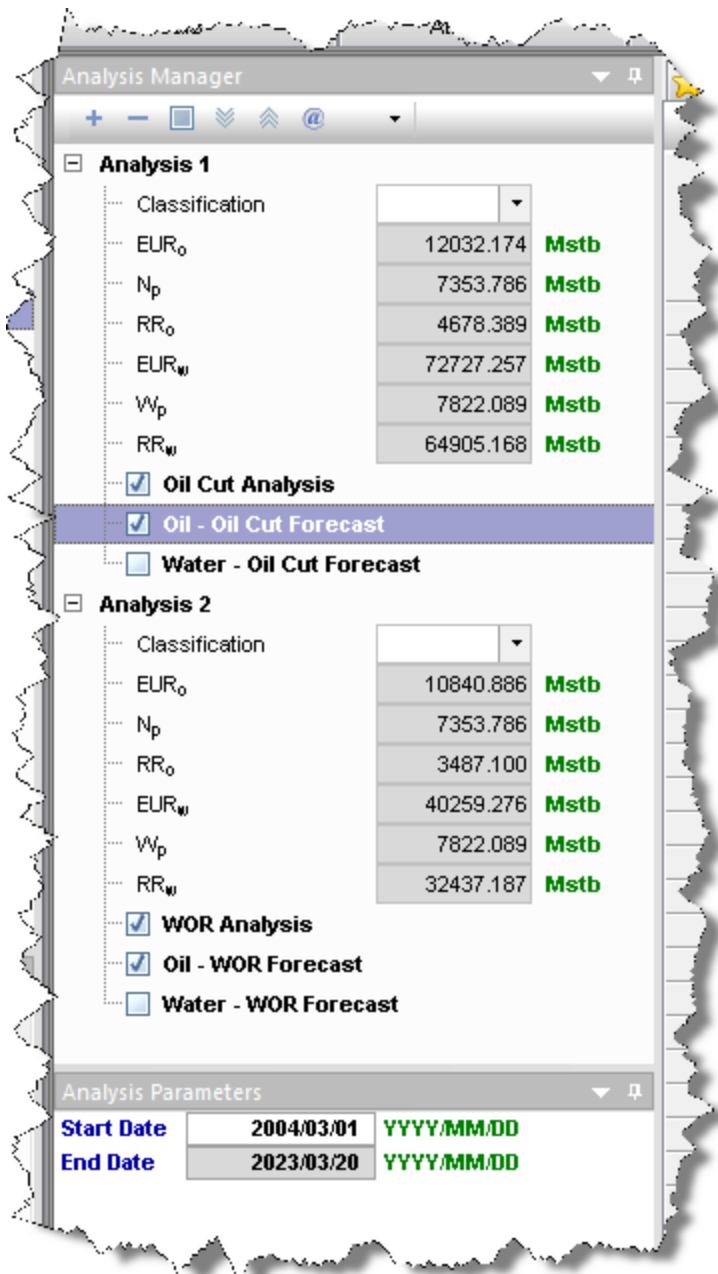
In this pane, you can specify / view the following parameters:
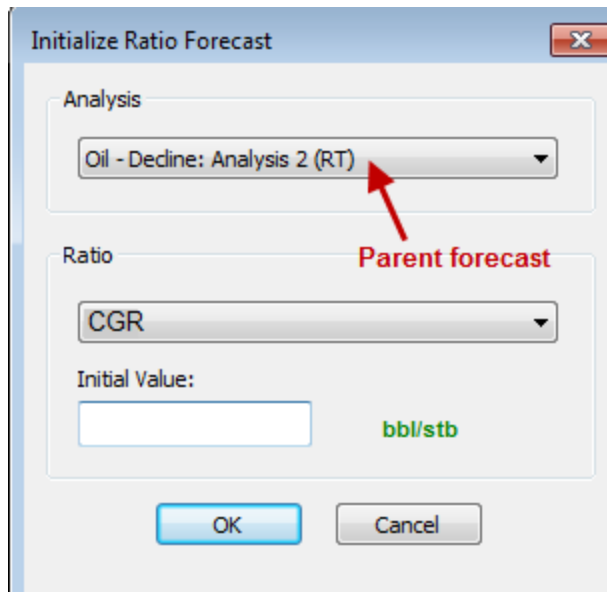
- **Start Date** — the start of the total fluid forecast. It is initialized as the end of historical production. Specifying a value beyond the end of production does not adjust the trend of the associated WOR / Oil Cut analysis.

- **End Date** — the date at abandonment controlled by the associated WOR / Oil Cut analysis (WOR_f, $(Water\ Cut)_f$, or $(Oil\ Cut)_f$).

Ratio forecast

Ratio forecasts are used to keep your forecasts synchronized. As a prerequisite, you must have an existing forecast, and you can only add ratio forecasts to analyses that are forecasts.

Note: This forecast works with your Harmony Forecast™ license.

After you open your existing forecast, you can add a ratio forecast (see analyzing an entity) and initialize this forecast.

The ratio forecast is a child forecast, so if you update, move, or delete the parent forecast, the child is updated automatically. Note that the child forecast does not affect the parent.

The initial value for the ratio forecast can be updated, but ranges (for example, the end date) are set at the parent level. If you extend the range of the parent forecast, the ratio forecast automatically extends its initial value to match the new end date. If you truncate the range of the parent forecast, the unnecessary rows in the ratio forecast are automatically deleted.

You can change your table resolution by clicking the **D** (day), **M** (month, the default setting), or **Y** (year) icons on the toolbar. For a description of common icons, see toolbars.

Custom forecast
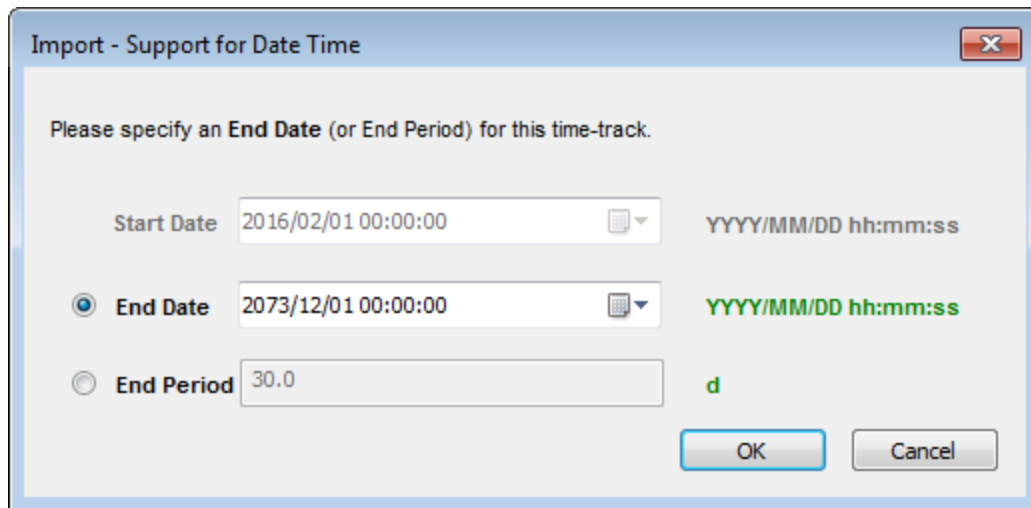
Custom forecasts are used to bring third-party forecasts into Harmony Enterprise.

Note: This forecast works with your Harmony Forecast™ license.

Custom forecasts are created by importing a third-party forecast (for example, Excel, IHS Piper) for various fluid types into a Forecast worksheet (see analyzing an entity). The files types we support are: .csv, .txt, or .xls /.xlsx.

Only one forecast can be brought in at a time and column headers must be assigned to the data to be imported in the Import Data dialog box, and either a Cumulative Time or Date Time must be specified.

If Date Time is used, the Start and End Dates are read from the import file. The End Date is one day after the last record in the import file for daily forecasts, and one month for monthly forecasts. The End Period can be used to extend the forecast past the final date in the import file by a specified number of days.

If Cumulative Time is used, a Start and End Date can be specified. If the host entity contains production data, the Start Date defaults to the end-of-production. If the host entity does not contain production data, the Start Date defaults to midnight of the current day on the machine that is running Harmony Enterprise.

Changing the Start Date changes the End Date, but changing the End Date results in the forecast being truncated or extended.

The End Period can be used to extend the forecast past the final date in the import file by a specified number of months.
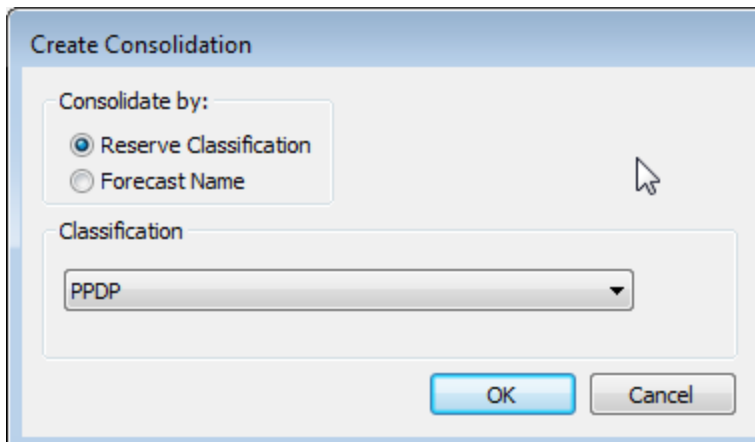
Forecast consolidation

A consolidation is a summation of forecasts from constituent wells (historical data is aggregated). This analysis type can only be created at the group level, and is used to sum up forecasts within the group. Therefore, when creating a forecast consolidation for a set of wells, it must be created from a hierarchical group, or from a custom group (excluding reserve classification consolidations).

Note: This forecast works with your Harmony Forecast™ license.

Note that classified consolidations have an additional field for the reference date.

When you add a forecast consolidation (see analyzing an entity), you can consolidate by reserve classification or forecast name.

- **Reserve Classification** — when selected, the Classification drop-down list is enabled. Note that classified consolidations only include classified forecasts with active reference dates.

- **Forecast Name** — when selected, the Name drop-down list is enabled.

- **Classification** — select your reserve classification from the drop-down list. There are two types of classified consolidations: proved (P) and total (T). There are nine P consolidations: PNP, PPNP, PPPNP, PDP, PPDP, PPPDP, PUD, PPUD, and PPPUD. The T consolidations are aggregates of the Ps, so TP = PNP + PDP + PUD. TPP = PPNP + PPDP + PPUD. TPPP = PPPNP + PPPDP + PPPUD. For more information on classifications, see reserve classification.

- **Name** — select your analysis from the drop-down list. Note that named classifications are case sensitive. For example, Analysis 1 and ANALYSIS 1 cannot appear in the same consolidation.

Note: Consolidations can be done on ratio forecasts, water-oil ratio (WOR) / oil cut forecasts, and custom forecasts. If forecasts do not have the same forecast start date (FSD), the consolidation begins at the earliest FSD, and historical production is used for wells whose FSD starts later. Note that you cannot edit consolidation plots or results because they are directly governed by the forecasts of the constituent wells of the group.

Typecurve analysis

With the typecurve worksheet, flowing pressures must be provided at the same frequency as rates in the Production editor (not required for a Fetkovich analysis), and reservoir / fluid parameters must be entered in the Properties editor. If this data is not provided, the typecurve worksheet remains accessible, but the data is not displayed on the plot.

Note: This analysis works with your Harmony Reservoir™ license.

When creating a typecurve worksheet, select your fluid type, model, and then method (for example, Gas, Fracture, Blasingame).

If you analyze a group of wells, you can change which well is displayed by selecting your well from the **Primary Well** drop-down list. Note that there is no interpretation for these well completion parameters: skin and fracture half length.

Models

Harmony Enterprise supports the following models:

- **Vertical** — a cylindrical reservoir with a vertical well in the center.

  - **Radial** — a cylindrical reservoir with a vertical well in the center.

  - **Water Drive** — a cylindrical reservoir with a concentrically cylindrical aquifer. This model is based on a radial composite model, with the outer region representing the aquifer, characterized by several different levels of aquifer mobility, relative to the reservoir. The mobility ratios range from zero (no aquifer) to 10 (effectively constant-pressure boundaries). The aquifer model assumes a water zone of infinite extent.

- **Vertical with Fracture** — a cylindrical or rectangular (Fetkovich) reservoir with an infinite conductivity fracture in the center.

  Finite Conductivity Fracture — a cylindrical reservoir with a finite conductivity fracture in the center.

- **Horizontal** — a square reservoir with a horizontal well in the center. There are actually nine different horizontal well models. Each model represents a different penetration ratio "$L_e/2x_e$"(ratio of effective wellbore length to reservoir length) and dimensionless wellbore radius "r_{wD}" (ratio of effective wellbore radius to effective wellbore length).

- **Hz Multifrac** — a horizontal reservoir with multiple vertical fractures.

Compound Linear — an infinite reservoir with a horizontal well and multiple hydraulic fractures (you must specify n_f and L_e).

Methods

Harmony Enterprise supports the following methods:

- Argarwal-Gardner
- Blasingame
- Compound Linear
- Fetkovich
- NPI
- Wattenbarger

Sub-tabs

There are three sub-tabs: plot, forecast, and tables.

Plot

The Plot sub-tab displays sets of typecurves that can be viewed together or separately depending on which checkboxes you click in the Plot Options section.

1. Normalized Rate
2. Integral
3. Raw Data Derivative
4. Derivative
5. Beta-Derivative (in the Fracture model)

The objective of the typecurve analysis is to move data over top of the family of typecurves (click the Reposition icon) until the data points match one of the typecurves as closely as possible. After you know which typecurve matches your data best, you can select the appropriate parameter from the **Parameter Value** drop-down list.

We recommend beginning the match with normalized rate data and typecurves. To add further confidence in the match, use the derivative, integral and derivative, or cumulative production (Fetkovich) options to provide a more unique analysis.

Note: When one of the typecurve sets is disabled, both the data points and associated typecurves are removed from the plot.

Toolbar

This toolbar has the following unique icons:

- **Tools to Select Data Points for Filtering** — opens an additional toolbar with point-selection options.

  Tip: Selection of filtered-out (disabled) points is shared between all typecurve, unconventional reservoir, and FMB analyses for the same fluid type. In addition, these selections are saved when you export to a local database, or import from a local database.

- **Reposition Data on Plot** — drag data across the screen.

- **Reset Plot Attributes** — resets your plot attributes to default settings.

- **Fully Automatic** — removes the outliers in your data by applying a median filter.

- **Enable / Disable Square Log-Log Plot** — when enabled, the current plot is made proportional for comparison purposes. Clicking the icon again disables this feature.

- **Single Annotation** — adds a single annotation to a specific point on your typecurve.

- **Linked Annotations** — synchronizes your annotation across your typecurve, FMB, unconventional reservoir, and data filter plots. For example, if you move your annotation on one plot using the keyboard arrow keys, the arrow is synchronized on the other plots.

- **Data Filter** — opens the Data Filter dialog box where you can select points to hide from typecurve matching.

- **Options** — opens the Typecurve Options dialog box where you can set your derivative options, typecurve settings, and rate options.

For information on common plot icons, see plot toolbars.

Forecast

The Forecast sub-tab displays your forecast: results, options, and constraints. You can send your plot to a comparison plot, by right-clicking it and selecting **Send Plot to Comparison Plot**. For

information on other options, see plot options.

The forecast toolbar has the same common icons described in plot toolbars.

Tables

The Tables sub-tab displays your forecast data in a tabular format.

Argarwal-Gardner typecurve method

The Agarwal-Gardner method (SPE 057916, 1998) is a practical tool that can estimate the gas (or oil) in-place, as well as reservoir permeability, skin effect, and fracture half-length (for hydraulically fractured wells). The accuracy of this method has been verified through numerical simulations. These modern decline typecurves represent advancement over Blasingame typecurves because a clearer distinction can be made between transient and boundary-dominated flow periods. This method also features curves containing derivative functions, similar to those used in the pressure transient literature, to aid in the matching process. The raw data derivative can also be used to assist in flow regime interpretation.

Note: For information on the Agarwal-Gardner typecurve theory and equations, see Agarwal-Gardner typecurve theory.

The Agarwal-Gardner typecurve method uses the following models:

- **Radial**

- **Fracture** (cylindrical)

- **Water Drive**

Boundary-dominated match

To obtain information about reserves and drainage areas, we recommend that you focus on the boundary-dominated (depletion) stems of the typecurves. These are located on the right-side of the plot, where each set of typecurves converges to a single line. The Agarwal-Gardner typecurve method does not require hyperbolic exponent values. Instead, the data is matched on the single depletion stem. As the data is moved about the plot, the OGIP / OOIP is continuously updated on the Analysis tab.

For gas reservoirs whose fluid properties are strongly a function of pressure, the data points appear to "stretch" and "contract" as they are moved around the screen. This is because of the pseudo-time effect. Harmony Enterprise recalculates gas properties at average reservoir pressures based on the calculated OGIP from the typecurve match. As the match is modified, OGIP, average reservoir pressure, and material balance pseudo-time are automatically recalculated, and the data points are repositioned accordingly.

Transient match

To obtain information about permeability and skin, we recommend that you focus on the transient stems of the typecurves. On the Agarwal-Gardner typecurve plot, these appear on the left-side of the

plot as a "fan" of different r_{eD} values for the radial and water-drive models, r_e / x_f values for the fracture model. Select the typecurve that best matches the data; this provides an associated r_{eD} (or r_e / x_f) value.

From the selection, Harmony Enterprise calculates:

- skin for a radial model.

- fracture half-length for a fracture model.

- mobility ratio and skin for a water-drive (transient) model.

Blasingame typecurve method

Blasingame represents the first of the modern typecurve methods (SPE 028688, 1994). It features pressure normalized rates, and introduces the concept of material balance time (that is, boundary-dominated superposition time) to generate fully analytical constant rate typecurves featuring a single depletion stem, regardless of the reservoir structure (shape and size) or drive mechanism. Blasingame analysis results include skin factor, formation permeability, in-place fluid volumes, and reservoir drainage area. The flow-rate integral and flow-rate integral derivative functions allow for more accurate decline typecurve matches than would be possible using flow-rate data alone. These integral functions also eliminate problems associated with the analysis of field production data with erratic production rate and sandface pressure behavior. The Blasingame method is particularly useful in the modeling of suspected elliptical drainage patterns and open-hole horizontal wells, which have transitioned into boundary-dominated flow.

Note: For information on the Blasingame typecurve theory and equations, see Blasingame type-curve theory.

The Blasingame typecurve method uses the following models:

- **Radial**

- **Fracture** (cylindrical)

- **Water Drive**

- **Horizontal**

- **Finite Conductivity Fracture** (cylindrical)

Boundary-dominated match

To obtain information about reserves and drainage area, we recommend that you focus on the boundary-dominated (depletion) stems of the typecurves. These are located on the right-side of the plot, where each set of typecurves converges to a single line. The Blasingame typecurve analysis does not require hyperbolic exponent values. Instead, the data is matched on the single depletion stem. As the data is moved about the plot, the OGIP / OOIP is continuously updated on the Analysis tab.

For gas reservoirs whose fluid properties are strongly a function of pressure, the data points appear to "stretch" and "contract", as they are moved around the screen. This is because of the pseudo-time effect. Harmony Enterprise recalculates gas properties at average reservoir pressures based on the calculated OGIP from the typecurve match. As the match is modified, OGIP, average reservoir pres-

sure, and material balance pseudo-time are automatically recalculated, and the data points are repositioned accordingly.

Transient match

To obtain information about permeability and skin, you should focus on the transient stems of the type-curves. On the Blasingame typecurve plot, these appear on the left-side of the plot as a "fan" of different r_{eD} values for the radial and water-drive models, r_e / x_f values for the fracture and finite conductivity fracture models, and L_D for the horizontal model. You can select the best matching typecurve, which provides an associated r_{eD} (or r_e / x_f, , L_D) value.

From the selection, Harmony Enterprise calculates:

- permeability and skin for the radial model.

- permeability and fracture half-length for the fracture model.

- mobility ratio, permeability, aquifer permeability, and skin for the water-drive (transient) model.

- vertical and horizontal permeability, and skin for the horizontal model.

- permeability, fracture half-length, and fracture-equivalent skin for the finite conductivity fracture model.

Compound linear typecurve method

Compound linear typecurves are useful for analyzing horizontal multifrac wells producing from tight gas or shale wells.

Note: For more information on Compound Linear typecurve theory and equations, see <u>compound linear typecurve theory</u>.

This method uses the horizontal multifrac model.
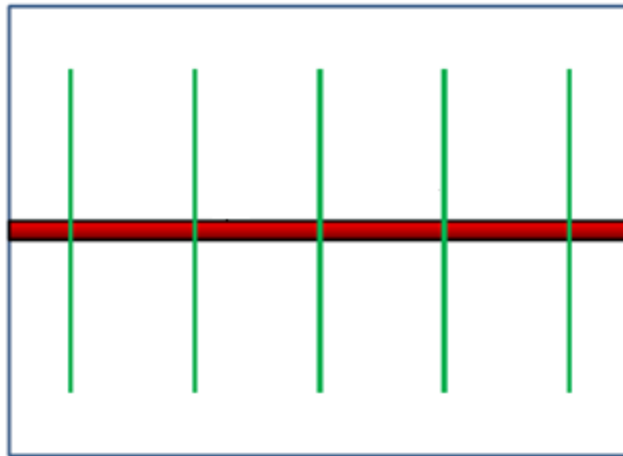
There are two sets of compound linear typecurves:

    1. Pressure-time — uses normalized pressures: the constant rate solution

    2. Rate-time — uses normalized rates: the reciprocal of the constant rate solution

Rate-time and pressure-time are reciprocals of one another, and simply plot the data on the typecurves differently.

Rate-time

Pressure-time
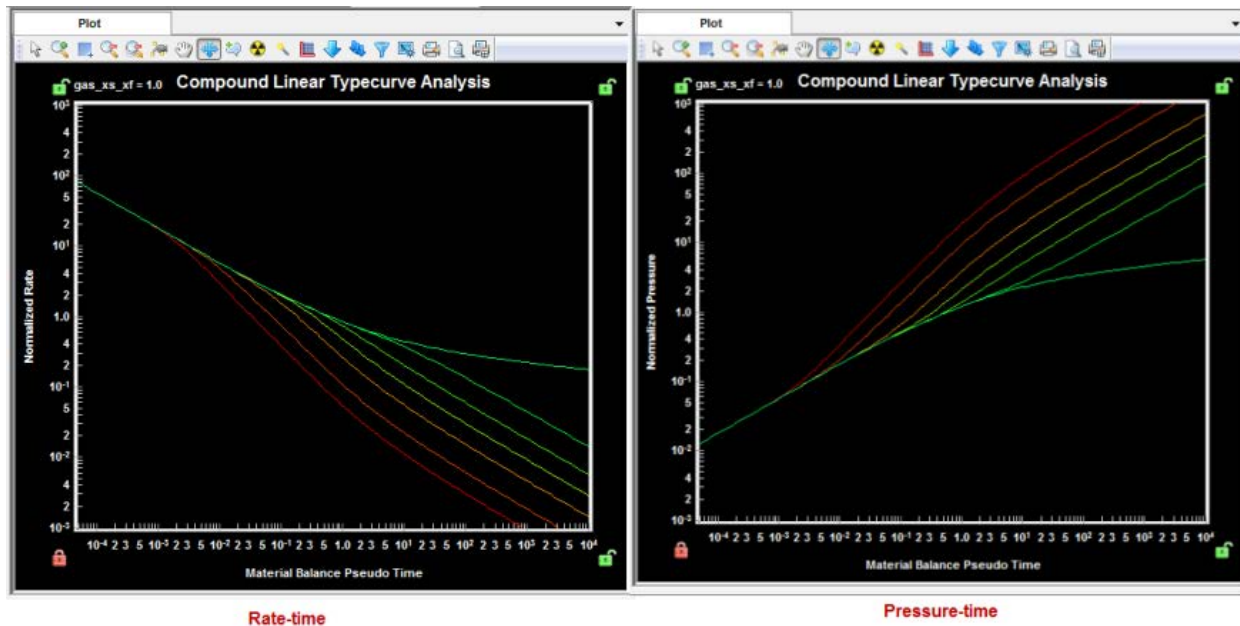
Boundary-dominated match

As the compound linear typecurves were developed using an infinitely large reservoir, there is no boundary-dominated flow stem. However, entering a value for either Ye or Area (A), will produce a dashed boundary-dominated flow line that intersects the selected typecurve.

 Note: A typecurve must be selected before the boundary-dominated line is plotted.

If boundaries have been reached, the production data deviates from the compound linear typecurve on to the boundary-dominated line.
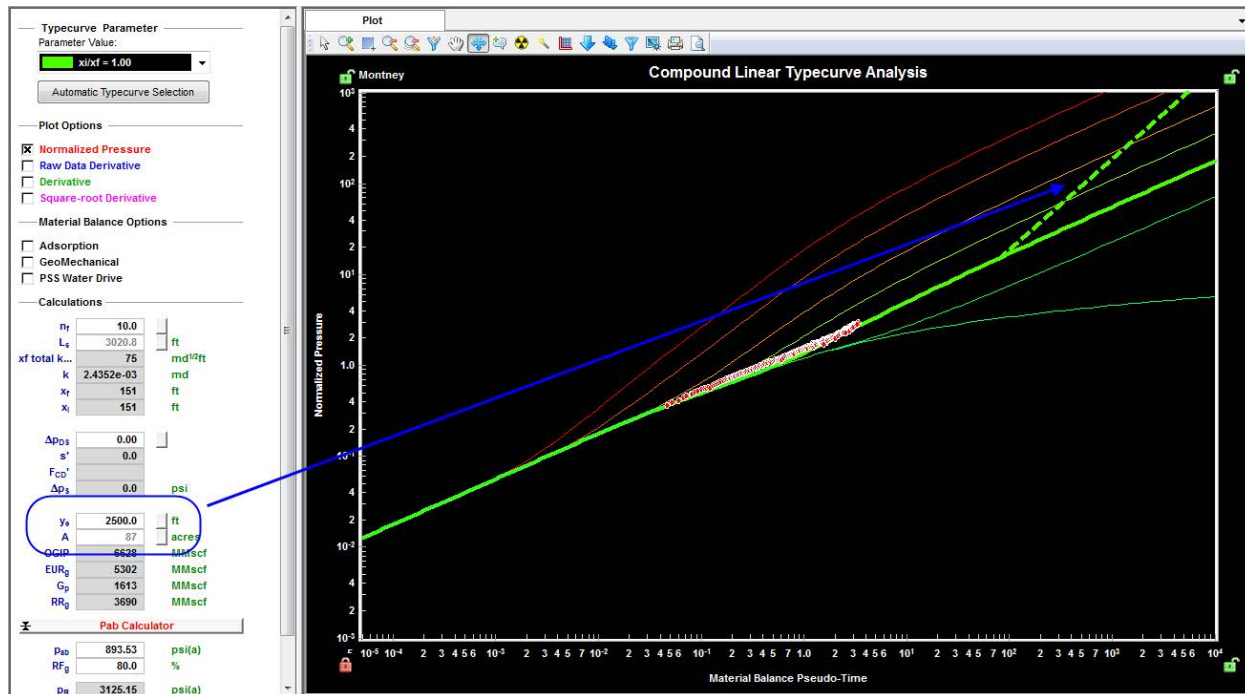
Transient match

Compound linear typecurves were developed for a horizontal, multifrac well in an infinite reservoir. The first half slope indicates linear flow into the fractures, while the second half slope indicates linear flow into the fractured region. The two half slopes are connected by a transition period. Most production data is expected to fall in the transition zone.
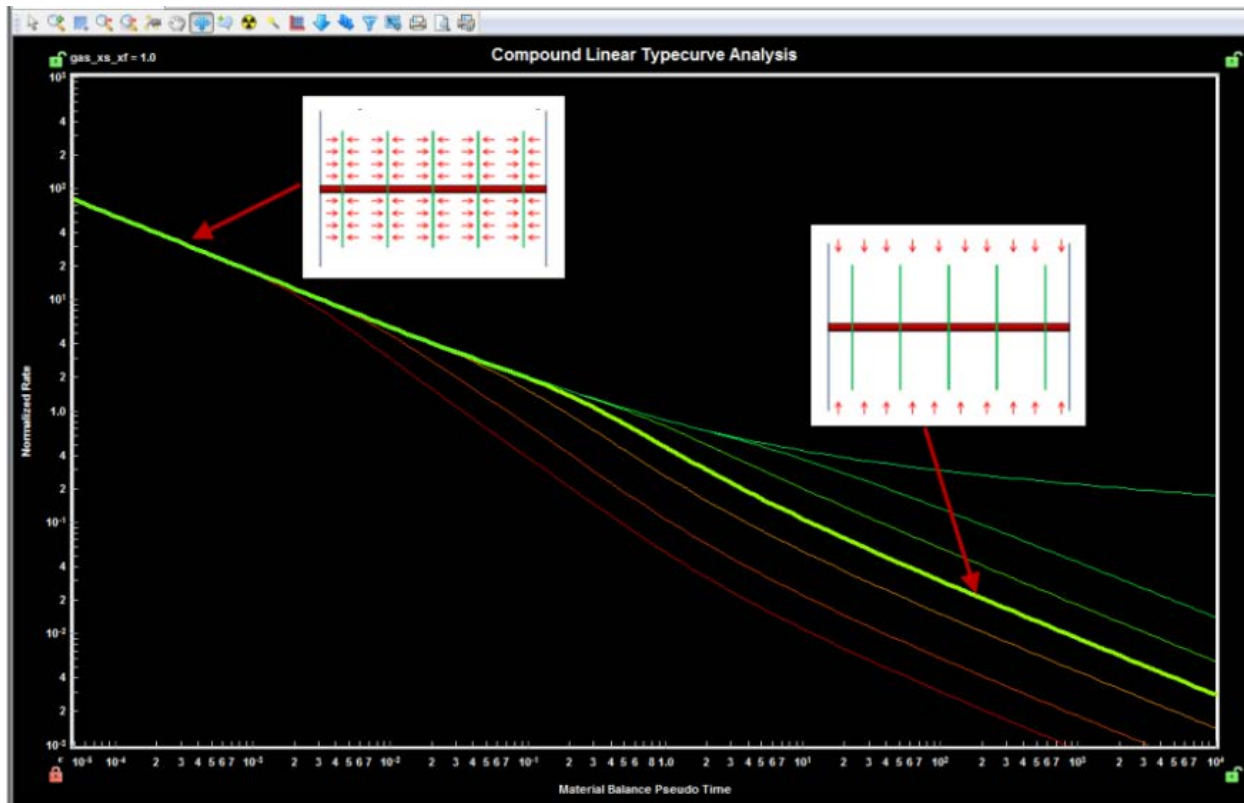
Selecting the "Square Root Derivative" plot displays the linear flow periods as flat lines, which may be helpful for matching data.
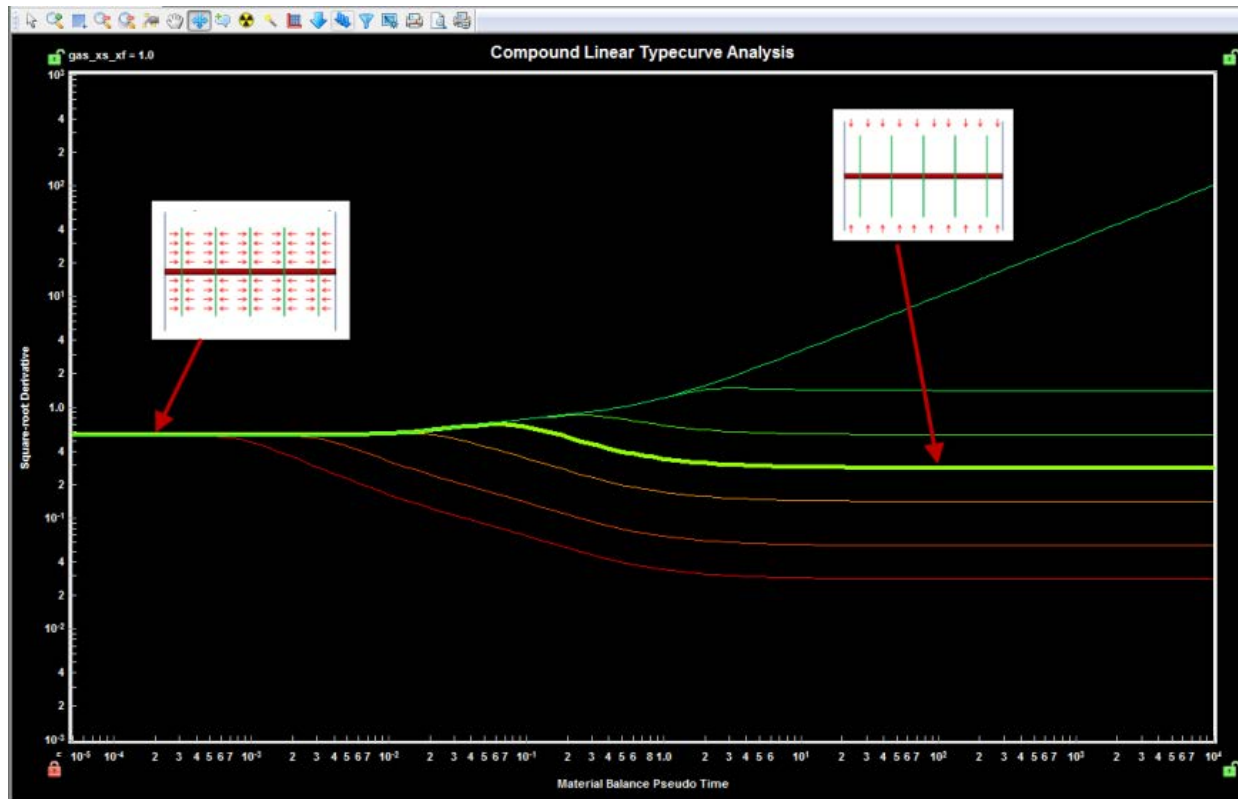
Matching data to a typecurve gives the xi / xf ratio. Entering a value for number of fractures (n_f) calculates the following values:

- Ls

- $x_f\sqrt{k_{SRV}}$

- x_f

- x_i

Note: Entering a value for Ls calculates n_f.

Skin

Generally, skin effects impact the first linear flow period, causing the data to deviate from the ideal typecurve.

To correct for skin effects on the Normalized Pressure or Rate curves:

1. Match the later part of the data to a typecurve.

2. Select the typecurve that matches the data most closely.

3. Enter the number of fractures (n_f) or Ls.
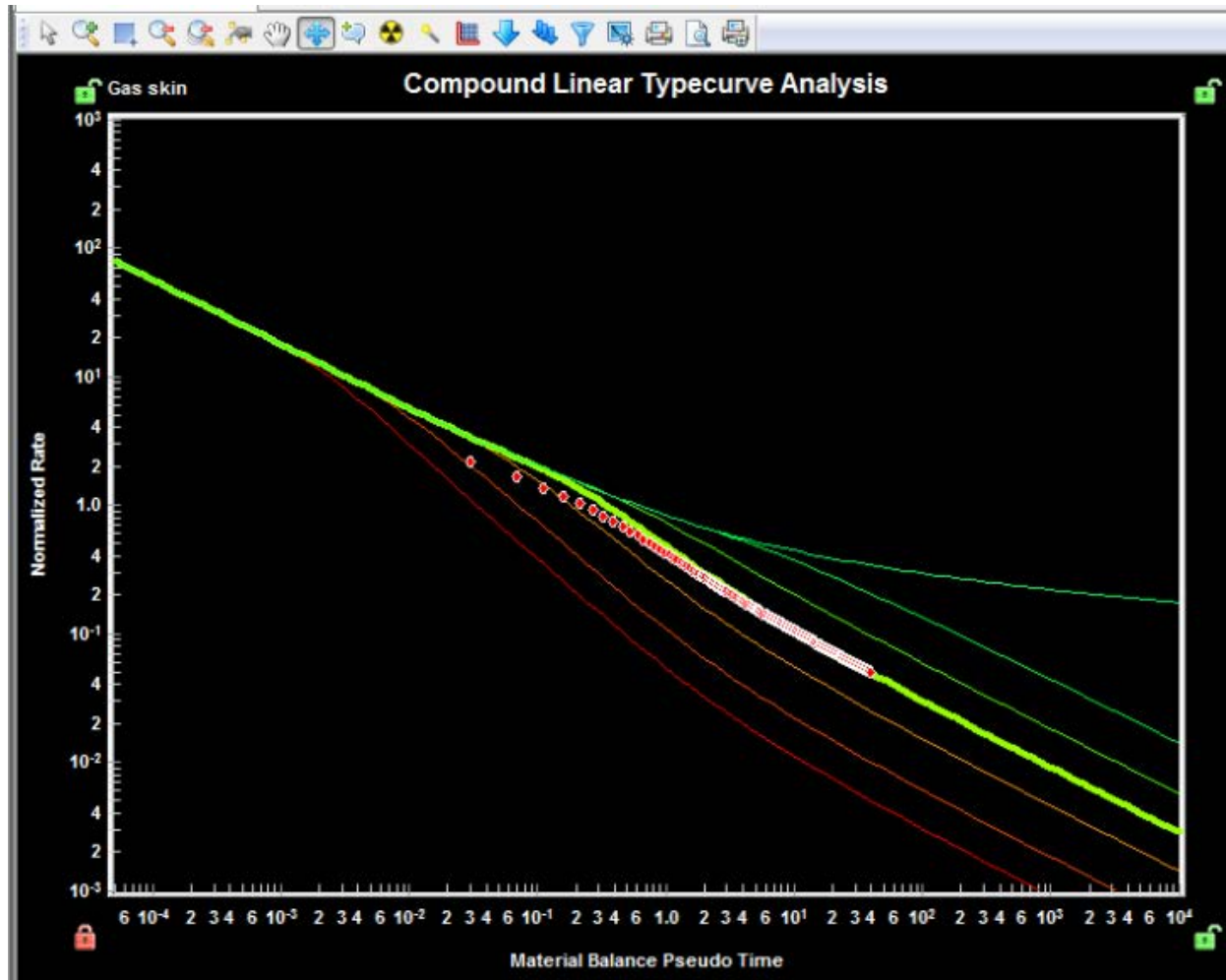
4. Right-click the plot and hold your mouse button. This highlights the data point closest to the top left corner for Rate-Time (bottom left for Pressure-Time), and the cursor changes to a triangle.
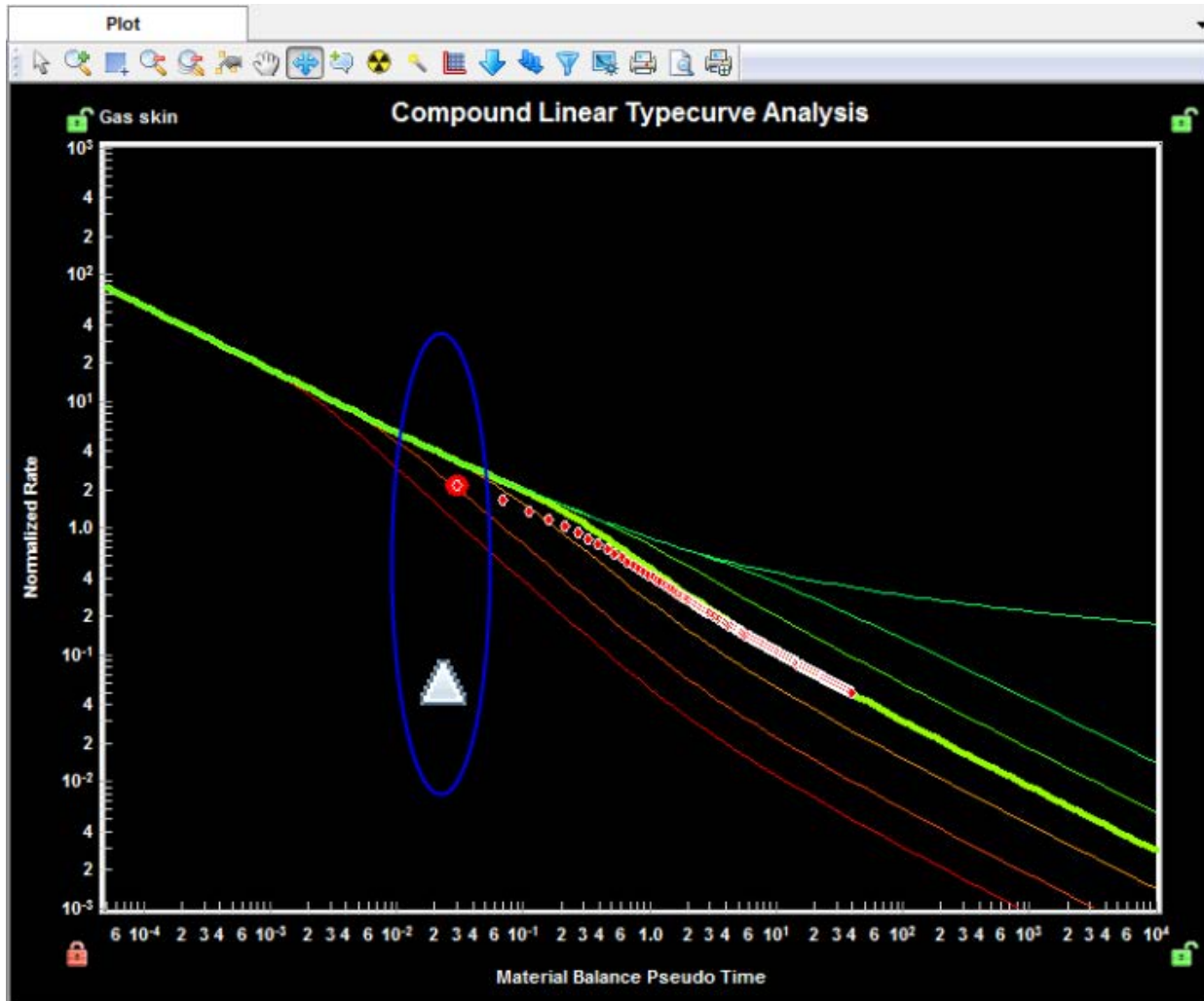
5. While continuing to hold the right-mouse button, move the cursor up or down until the early portion is matched on the typecurve.

Compound Linear Typecurve Analysis
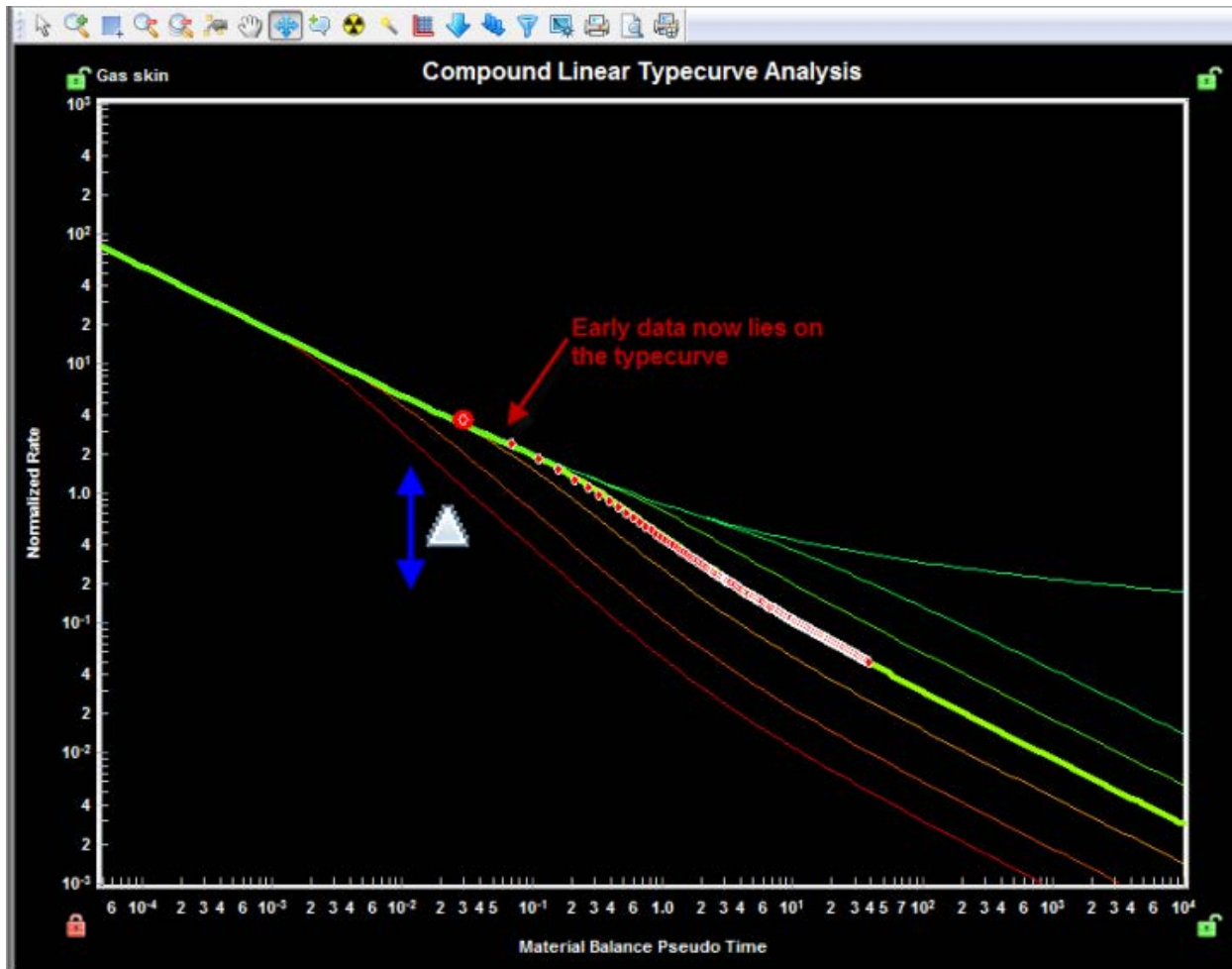
Moving the data in this manner populates the Δp_{DS} cell. This value is then used to convert the dimensionless pressure drop into an equivalent apparent skin, apparent fracture conductivity, and dimensional pressure drop.

For more details on the calculations, see compound linear typecurve theory.

Fetkovich typecurve method

The Fetkovich typecurve method (SPE 004629, 1980) was the first analysis method to use analytical typecurve matching for production data. It is a semi-analytical approach in that typecurves are generated from analytical solutions of transient (infinite) radial systems at constant flowing pressure, while the boundary-dominated flow period is defined using hyperbolic decline typecurves, originally developed by Arps. In addition to reserves, calculated from the depletion stem (b-value) match, this analysis provides diagnostic power through the determination of reservoir permeability and wellbore skin factor. Rate normalization (SPE 012179, 1984) has been included to account for changing operating conditions (that is, changes in flowing pressures) to more reliably determine permeability and skin. With reinitialization, you can analyze the transient production data signature of post-buildup production to diagnose permeability and skin. A clear advantage of this method over modern typecurve methods is that it does *not* plot data using superposition time functions, which may bias the interpretation. It remains a popular technique for the analysis of conventional vertical oil and gas wells. Fetkovich plots are even used to describe the behavior of unconventional well production data (for example, Bakken oil wells). The limitation of this technique is that the transient typecurves are restricted to radial flow systems, and the method does not directly calculate original-hydrocarbons-in-place (as is the case in modern methods); it is estimated through simple material balance.

Note: For information on the Fetkovich typecurve theory and equations, see Fetkovich typecurve theory.

The Fetkovich typecurve method uses the following models:

- **Radial**

- **Fracture** (rectangular)

Boundary-dominated match

To obtain information about reserves and drainage areas, we recommend that you focus on the boundary-dominated (depletion) stems of the typecurves. These are located to the right of where the Rate vs. Time and the Cumulative Production vs. Time typecurves intersect. Each of the depletion stems represents a different b value, identical to the b values used in the hyperbolic Arps analysis. After a b value has been selected, Harmony calculates recoverable reserves and expected ultimate recovery. If a sandface flowing pressure is specified on the Analysis tab, Harmony also calculates drainage area and original gas-in-place.

Transient match

To obtain information about permeability and skin, we recommend that you focus on the transient stems of the typecurves. These are located to the left of where the Rate vs. Time and the Cumulative Production vs. Time typecurves intersect. Each of the transient stems represents a different r_{eD} value. Once a r_{eD} value has been selected and a sandface flowing pressure is specified, Harmony calculates permeability and skin.

Time reinitialization

The fundamental assumption in a Fetkovich transient analysis is a constant sandface flowing pressure. Although an ideal case, this assumption is rarely representative of true operating conditions, particularly in early (transient) production. A well may be subject to shut-ins or operational changes during its life. When a well is shut in, or undergoes a change in operating conditions, the constant sandface flowing pressure assumption is no longer valid. When the well resumes production, a new additional transient effect is introduced to the wellbore. Additional transient effects in the wellbore are indicated by the green arrows in the screenshot below.
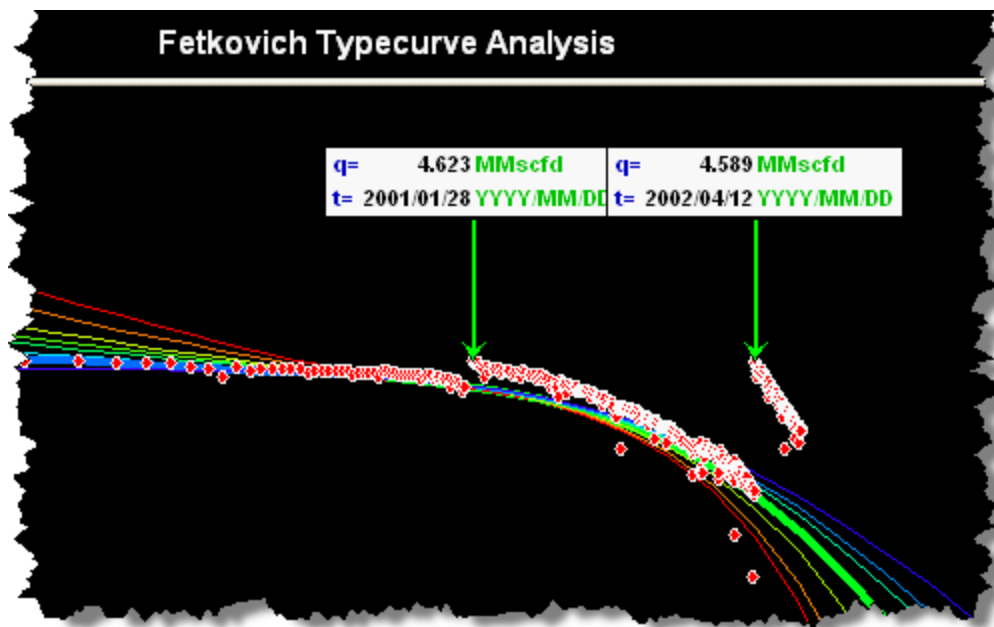
Fetkovich suggested a method called "time reinitialization" to analyze a dataset with multiple transient effects. This method resets the time at the start of each additional transient effect to zero, allowing you to specify additional transient effects on the typecurve plot. Once specified, the time associated with the first rate of each new transient flow period is reset to zero. As a result, the dataset is smoothed on the typecurve, allowing you to continue with the Fetkovich typecurve match.

To perform a Fetkovich time reinitialization:

1. Identify the beginning of each additional transient flow period either from Fetkovich or the Raw Data plot.

2. Click the **Add Reinitialization Arrow** icon (⬇) on the Fetkovich plot tool bar.

3. Click the data point representing the beginning of the additional transient flow period. The green reinitialization arrow is displayed at that point.
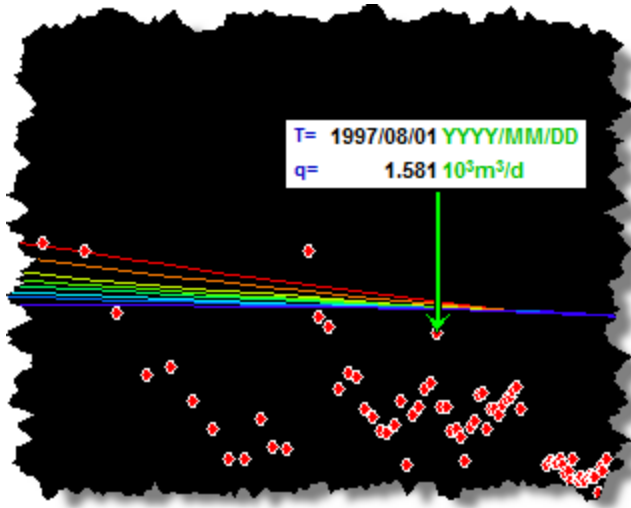
- Move the arrow left and right using the arrow keys on the keyboard.

- Remove the arrow by clicking the arrow's annotation box, and then pressing the **Delete** key on the keyboard.

Note: To create multiple additional transient periods, click the **Add Reinitialization Arrow** icon again, then repeat the process explained above. (The maximum number of additional transient periods permitted in Harmony is ten.)

4. Select the **Reinitialize** option under Material Balance Options in the parameters pane.
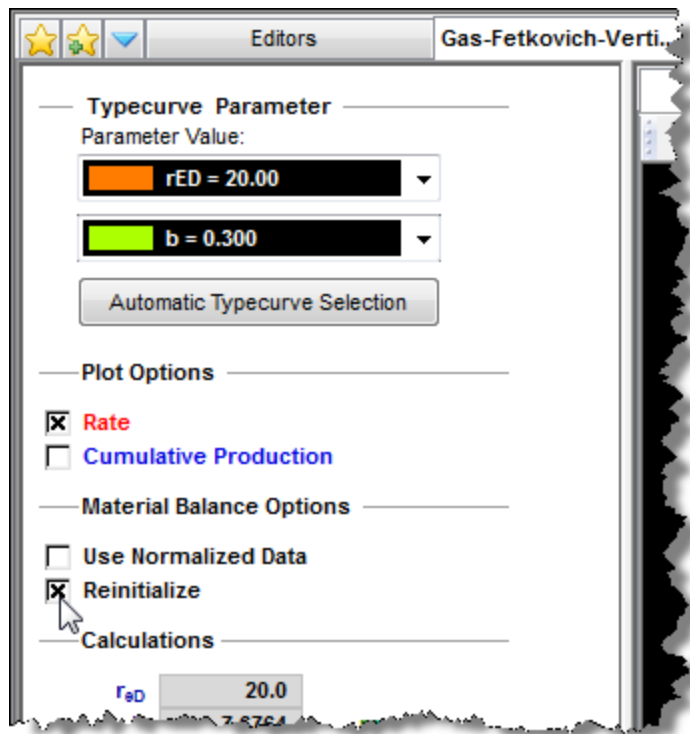
5. Continue with the Fetkovich typecurve matching method.

NPI typecurve method

Normalized pressure integral (NPI) typecurves are the inverse of Agarwal-Gardner typecurves. The NPI method is often preferred by those who come from a pressure transient analysis domain, and are accustomed to seeing log-log plots using normalized pressure, instead of normalized rates.

Note: For information on the NPI typecurve theory and equations, see NPI typecurve theory.

The NPI typecurve method uses the following models:

- **Radial**

- **Fracture** (cylindrical)

- **Water Drive**

Boundary-dominated match

To obtain information about reserves and drainage areas, we recommend that you focus on the boundary-dominated (depletion) stems of typecurves. These are located on the right-side of the plot, where each set of typecurves converge to a single line. The NPI typecurve method does not require hyperbolic exponent values. Instead, the data is matched on the single depletion stem. As the data is moved about the plot, the OGIP / OOIP is continuously updated on the Analysis tab.

For gas reservoirs whose fluid properties are strongly a function of pressure, the data points appear to "stretch" and "contract" as they are moved around the screen. This is because of the pseudo-time effect. Harmony Enterprise recalculates gas properties at average reservoir pressures based on the calculated OGIP from the typecurve match. As the match is modified, OGIP, average reservoir pressure, and material balance pseudo-time are automatically recalculated, and the data points are repositioned accordingly.

Transient match

To obtain information about permeability and skin, you should focus on the transient stems of the typecurves. On the NPI typecurve plot, these open on the left-side of the plot as a "fan" of different r_{eD} values for the radial and water-drive models, r_e / x_f values for the fracture model. You can select the best matching typecurve, which provides an associated r_{eD} (or r_e / x_f) value.

From the selection, Harmony Enterprise calculates:

- permeability and skin for the radial model.

- permeability and fracture half-length for the fracture model.

- mobility ratio, permeability, aquifer permeability, and skin for the water-drive (transient) model.

Wattenbarger typecurve method

Wattenbarger typecurves are used for analyzing linear flow. They are particularly useful in the analysis of shale gas wells, which tend to exhibit long-term linear flow followed by a transition towards boundary-dominated flow.

Note: For information on the Wattenbarger typecurve theory and equations, see Wattenbarger typecurve theory.

The Wattenbarger typecurve method uses the **Vertical with Fracture** (rectangular) model.

Boundary-dominated match

To obtain information about reserves and drainage areas, we recommend that you focus on the boundary-dominated (depletion) stems of typecurves. These are located on the right-side of the plot, where each set of typecurve converges to a single line. The Wattenbarger typecurve method does not require hyperbolic exponent values. Instead, the data is matched on the single depletion stem. As the data is moved about the plot, the OGIP / OOIP is continuously updated on the Analysis tab.

For gas reservoirs whose fluid properties are strongly a function of pressure, the data points appear to "stretch" and "contract", as they are moved around the screen. This is because of the pseudo-time effect. Harmony Enterprise recalculates gas properties at average reservoir pressures based on the calculated OGIP from the typecurve match. As the match is modified, OGIP, average reservoir pressure, and material balance pseudo-time are automatically recalculated, and the data points are repositioned accordingly.

Transient match

To obtain information about fracture half length, reservoir size, and well location in the reservoir, you should focus on the transient stems of typecurves. On the Wattenbarger typecurve plot, these appear on the left-side of the plot as different y_e / y_w values for the dimensionless channel model. You select the best fitting typecurve, which provides an associated y_e / y_w value.

From the selection and the permeability you define, Harmony Enterprise calculates:

- fracture half length
- reservoir width
- reservoir length
- well location

Data filter dialog box

This dialog box is commonly used when you click the filter data for an FMB, typecurve, or unconventional reservoir analysis.

This dialog box has the following important icons:

- **Tools to Select Data Points for Filtering** — opens an additional toolbar with point-selection options.

    - **spray gun** — selects points when you left-click, and deselects points when you right-click. The mouse wheel can be used to change the spread-tool's size.

    - **select all data points** — selects all the data points on the plot.

    - **deselect all data points** — deselects all the data points on the plot.

    - **lasso** — select points by clicking-and-dragging a shape around your data points. Deselect points by right-clicking-and-dragging a shape around the data points you do not want.

- **Fully Automatic** — select one of these options:

    - **Median Filter** — used to make data less noisy by deselecting data points that are far from the rest of the data (those points are likely to be outliers). Note that the dataset needs to have at least 20 points for this filter to be applicable.

- **Liquid Load Filter** — in some cases, flowing pressures are not measured at sandface; instead they are measured at the wellhead, and Harmony Enterprise calculates sandface pressures (see pressure loss calculations) based on given wellhead pressures in the wellbore editor. If the well is experiencing liquid loading, calculated sandface pressures may be inaccurate. Therefore, you may want to exclude corresponding data points from the analysis. With this filter, you can deselect data points where the well is experiencing liquid loading. For more information, see liquid lift calculations.

- **Saturated Filter** — used to identify the portion of the data where flowing pressure is below the bubble point pressure (oil and gas flowing in the reservoir). For more information, see saturated filter.

For information on common plot icons, see plot toolbars.

FMB analysis

You can use the flowing material balance (FMB) analysis as a practical technique to estimate hydro-carbons-in-place from production rates and pressures. It uses precisely the same principles as a classical material balance analysis, but requires no shut-in data. It is designed for wells that have reached boundary-dominated flow, but can also be used to identify minimum original gas / oil in place (OGIP / OOIP) in transient cases. For additional information, see FMB theory.

After an FMB analysis is created, data points are displayed on the plot. A portion of the data representing boundary-dominated flow should follow a straight line. Locate the analysis line that goes through the boundary-dominated (late) portion of the data. The original fluid in-place (OGIP, OOIP, or OWIP) is calculated based on the position of the analysis line.

Note: This analysis works with your Harmony Reservoir™ license.

If you analyze a group of wells, you can change which well is displayed by selecting your well from the **Primary Well** drop-down list. Note that there is no interpretation for these well completion parameters: skin and fracture half length.

Plot Options

Plot options define which datasets are displayed on the plot.

For Gas FMB:

- **AG FMB** — Agarwal-Gardner FMB plots normalized rate versus Normalized Cumulative Production. The underlying calculation is described in Agarwal-Gardner normalized rate.

- **Static Pressure Data** — if static pressures are available, you can use this data as an independent confirmation of the OGIP:

    - in single-phase mode (when the **Multiphase (Pseudo-Pressure)** option is deselected) — Static p/Z** is plotted against Cumulative Gas production. A straight line drawn through this data defines OGIP. Estimates of OGIP based on flowing pressures and static pressures should be consistent.

    - in multiphase mode (when the **Multiphase (Pseudo-Pressure)** option is selected) — static pressure is plotted against date. If the estimate of OGIP is correct, average pressures are calculated using FMB Model Options / Average Pressures, and static pressures should be consistent.

Click to show / hide an example screenshot
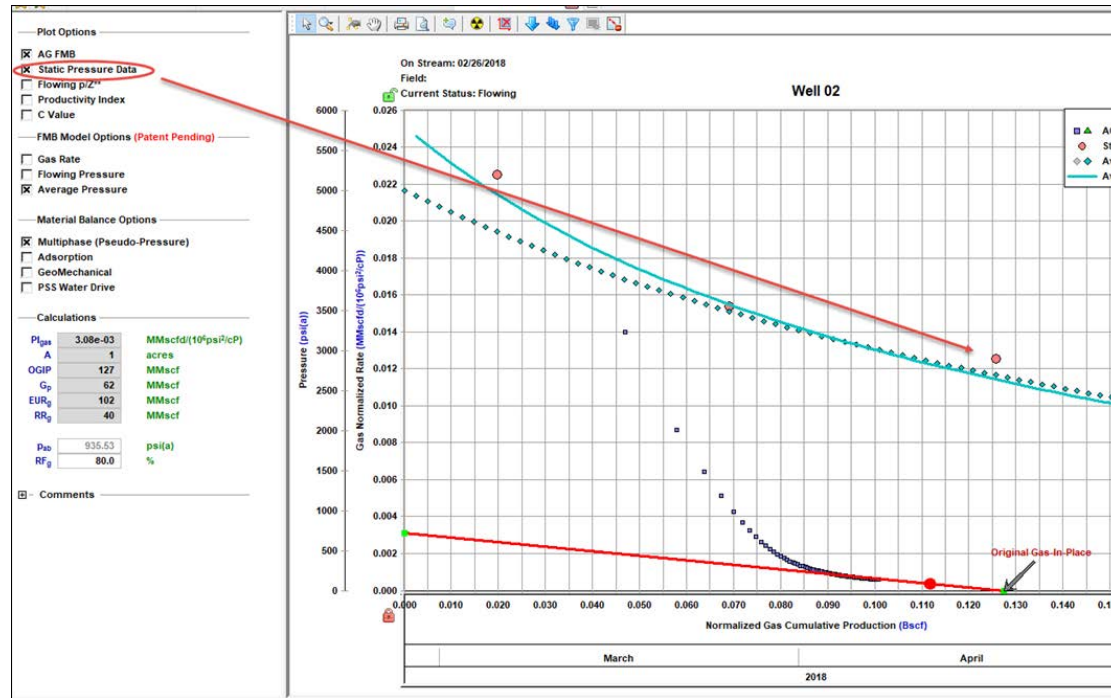
- **Flowing p/z**** — plots flowing p/z** versus Cumulative Gas Production. The underlying calculation is described in underlined variable rate flowing p/Z**.

- **Productivity Index** — plots the productivity index versus Cumulative Gas Production. If the correct OGIP is calculated from the material balance analysis, the productivity index for the boundary-dominated portion of the data should plot as a flat line. A downward sloping line can be an indication that the calculated volume is too large, while an upward sloping line can indicate that the calculated volume is too small. Productivity indexes that fall off a flat line can also be an indication of operational issues with the well. The underlying calculation is described in productivity index.

  Note: AG FMB, Flowing p/Z**, and the Productivity Index plots are different ways to display the same set of production data; therefore, the results of these three analyses should be in agreement. That is why the analysis lines for these three plots are linked to each other and always give the same OFIP.

- **Flowing Pressure** — flowing pressure points are not used in the analysis, but can be displayed as a reference.

- **Gas Rate** — gas rates are not used in the analysis, but can be displayed as a reference.

- **C Value** — coefficient values in the simplified absolute open flow (AOF) equation are not used in the analysis, but can be displayed as a reference.

For Oil FMB:

- **Oil FMB** — plots normalized rate versus Normalized Cumulative Production. The underlying calculation is described in <u>oil theory</u>.

- **Static Pressure** — if <u>static pressures</u> are available, you can use this data as an independent confirmation of the OOIP:

  - in single-phase mode (when the **Multiphase (Pseudo-Pressure)** option is deselected) — static pressure is plotted against

$$Adjusted\ Normalized\ Oil\ Cumulative\ Production = \frac{E}{B}$$

  .
  A straight line drawn through this data defines OOIP. Estimates of OOIP based on flowing pressures and static pressures should be consistent.

  - in multiphase mode (when the **Multiphase (Pseudo-Pressure)** option is selected) — static pressure is plotted against date. If the estimate of OOIP is correct, average pressures are calculated using FMB Model Options / Average Pressures, and static pressures should be consistent.

- **Gas-Oil ratio** — are not used in the analysis, but can be displayed as a reference.

FMB Model Options (Patent Pending)

FMB model options include the following:

- **Oil Rate** — uses the measured flowing pressure to calculate a synthetic oil rate, and compares the synthetic and measured oil rates. Modifies the productivity index and the original-oil-in-place, N, until an acceptable history-match of the oil rates is obtained.

- **Flowing Pressure** — uses the measured oil rate to calculate a flowing pressure, and compares the synthetic and measured flowing pressures. Modifies the productivity index and the original-oil-in-place, N, until an acceptable history-match of the flowing pressures is obtained.

- **Average Pressure** — uses the measured flowing pressure and the flowing oil rate to calculate a synthetic average reservoir pressure. Modifies the productivity index and the original-oil-in-place, N, until an acceptable history-match of the average pressure is obtained.

Material Balance Options

Material balance options include the following:

- **Multiphase (Pseudo-Pressure)** — accounts for the variation of oil properties with pressure. For more information, see <u>accounting for changing oil properties</u>.

- **Adsorption (for Gas FMB)** — corrects the data to include adsorbed gas. For more information, see accounting for adsorbed gas-in-place.

- **GeoMechanical (for Gas FMB and Oil FMB)** — accounts for the variation in rock properties (permeability and formation compressibility) with pressure. For more information, see including pressure-dependent permeability and formation compressibility. **Note:** For the Oil FMB analysis, this option is only available if the Changing Properties (Pseudo-Pressure) option is selected.

- **PSS Water Drive (for Gas FMB and Oil FMB)** — accounts for water drive (additional water drive analysis parameters are displayed). For more information, see analyzing reservoirs with aquifer support.

Calculations

Harmony Enterprise calculates the original fluid in-place based on the position of the analysis line. This value is displayed in the Calculations section, along with some additional parameters.

Calculations		
PI_{gas}	0.530	MMscfd/(10^6psi^2/cP)
A	179	acres
$OGIP_F$	2306	MMscf
$OGIP_{Rs}$	116	MMscf
OGIP	2422	MMscf
G_p	1153	MMscf
EUR_g	1864	MMscf
RR_g	712	MMscf
P_{ab}	109.10	psi(a)
RF_g	77.0	%

Plot toolbar

This toolbar has the following important icons:

- **Single Annotation** — adds a single annotation to a specific point on your dataset.

- **Linked Annotations** — synchronizes your annotation across all plots for FMB, URM, and typecurve analyses. For example, if you move your annotation on one plot using the keyboard arrow keys, the arrow is synchronized on the other plots.

- **Data Filter** — opens the Data Filter dialog box where you can apply a data filter. For more information, see filtering.

- **Rate Type Option** — select either Calendar Rate or Operated Rate.

- **Hide / Show Disabled Points** — toggle between hiding and showing data points that have been disabled.

For information on common plot icons, see plot toolbars.

Filtering

If you believe some of the production data points are of poor quality, or are outliers, you can filter them out (disable these points). To do this, click the **Data Filter** icon ( ) in the FMB plot toolbar. Then, click the **Tools to Select Data Points for Filtering** icon ( ) in the Data Filter dialog box (opens when you click the Data Filter icon) to select and deselect the data points you want. Click to select points, and right-click to deselect points.

Filtered-out (disabled) points are displayed in gray in the FMB plot. (You can hide these points by clicking the **Hide / Show Disabled Points** icon ( ).)

> **Tip:** Selection of filtered-out (disabled) points is shared between all FMB, unconventional reservoir, and typecurve analyses for the same fluid type. In addition, these selections are saved when you export to a local database, or import from a local database.

Best fitting

When you use the spray gun icon ( ) to select data points, you are selecting data points for best fitting (with a normal, or 10% weighting). The analysis line is redrawn to best-fit through the points you selected. If you move the best-fist line (for example, by dragging and dropping), the best-fit selection resets. You can have different selections for best fitting different analysis, and your best-fit selection is saved when you export to a local database, or import from a local database. For more information, see export data and import from an .hldb file.

Analyzing reservoirs with aquifer support

The flowing material balance (FMB) analysis provides the capability to analyze reservoirs with aquifer support. FMB handles water drive in a similar manner to static material balance. For additional information, see water-drive reservoir. A well displaying water drive tends to display an upward departure from the linear trend later in production when the pressure support from the aquifer begins to have an influence.
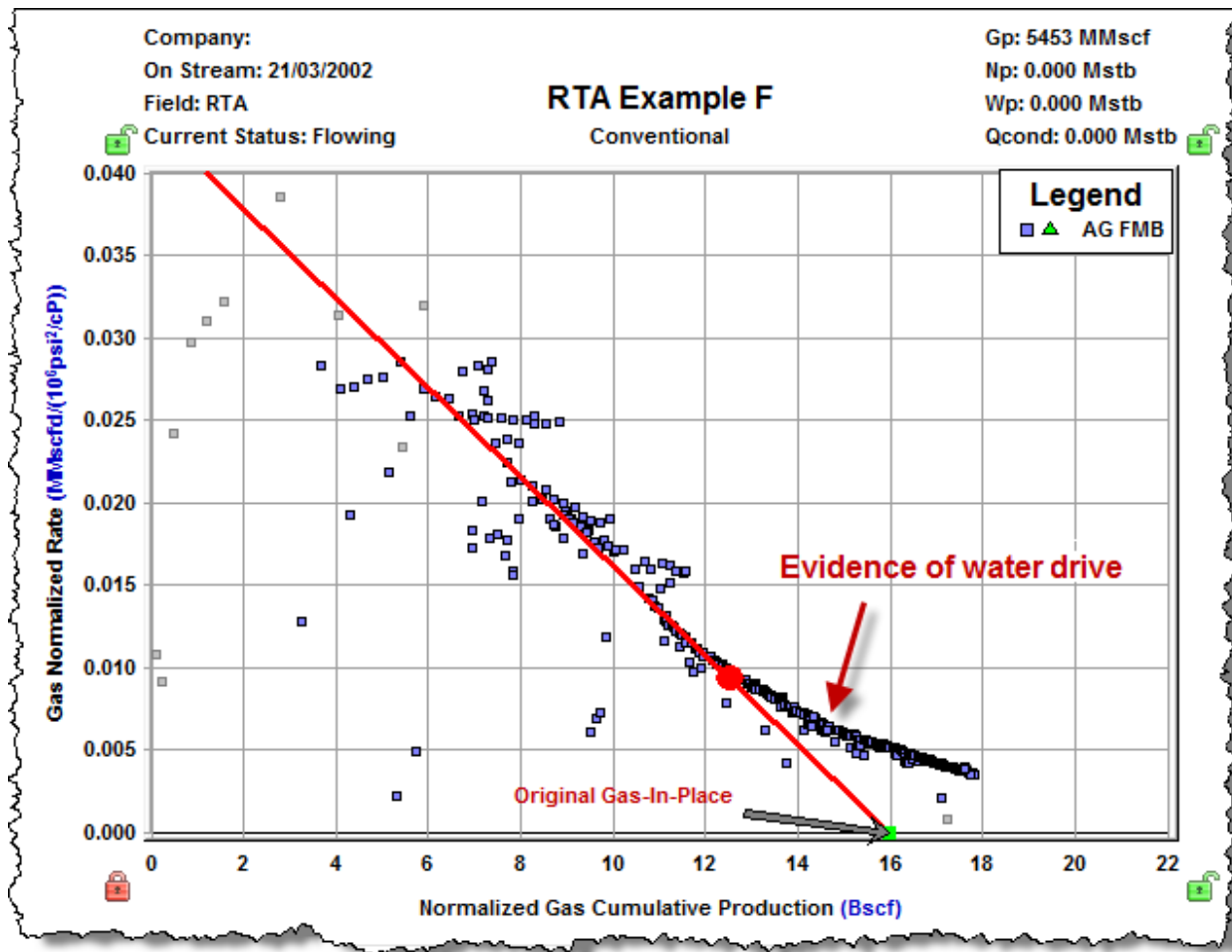
Position the analysis line through the straight portion of the early data. It is assumed that aquifer support is not felt until later in production; therefore, the trend of the early data is the true indication of original volume in place.
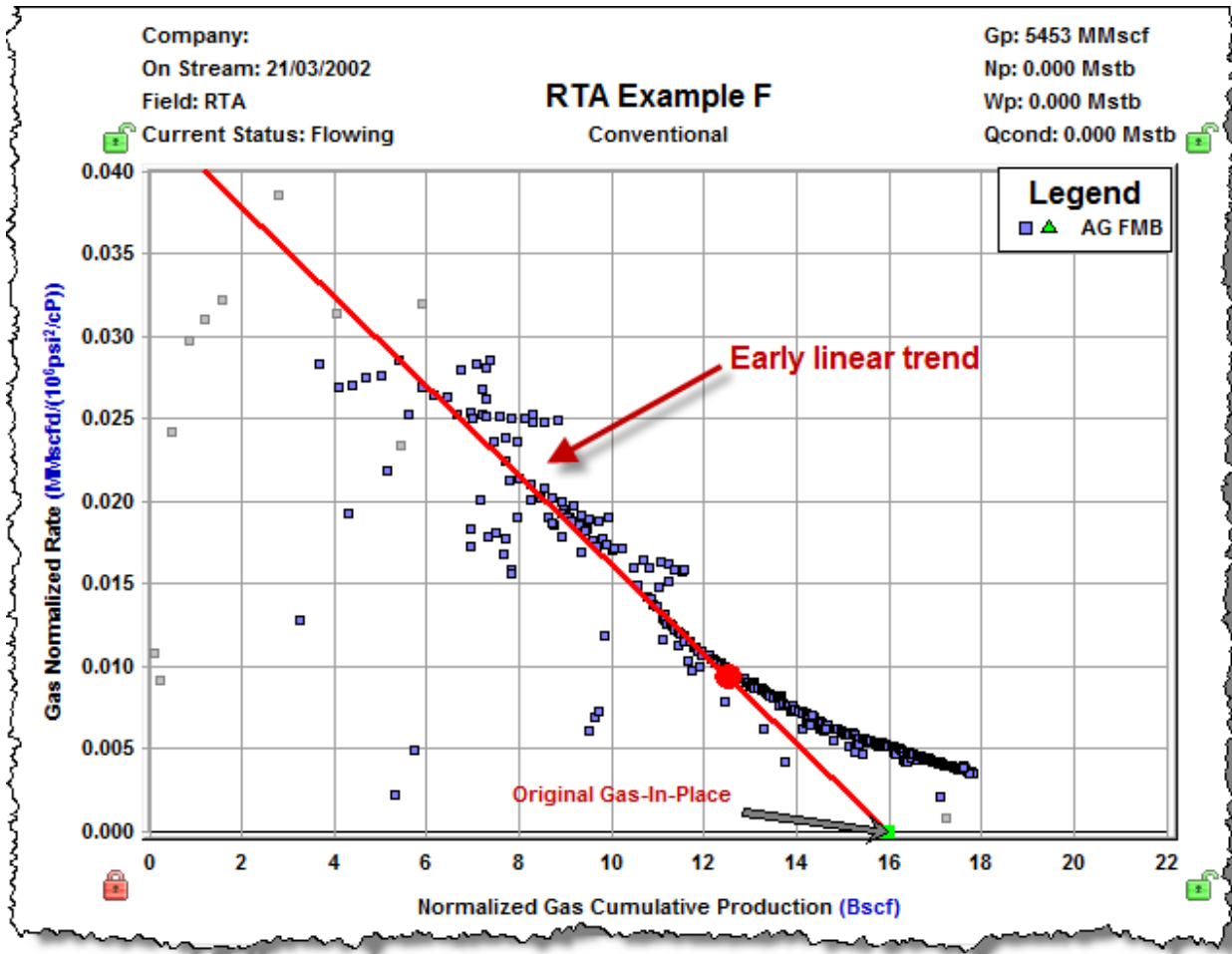
In the Material Balance Options section, click the **PSS Water Drive** checkbox, which displays the Water Drive Analysis parameters.

Material Balance Options

☐ Adsorption
☐ GeoMechanical
☒ PSS Water Drive

Calculations
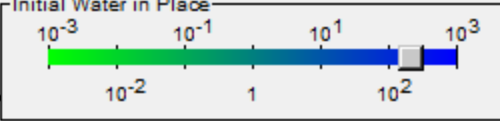
PI_{PSS}	0.043	$MMscfd/(10^6 psi^2/cP)$
A	190	acres
OGIP	15969	MMscf
G_p	5453	MMscf
EUR_g	12775	MMscf
RR_g	7322	MMscf
P_{ab}		psi(a)
RF_g	80.0	%
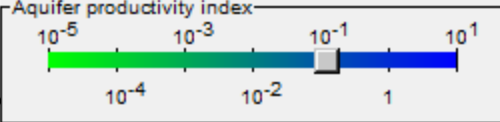
Water Drive Analysis

OWIP	222.215	MMstb
PI_{Aq}	0.123	(bbl/d)/psi

Initial Water in Place

Aquifer productivity index

Adjust the Initial Water in Place and Aquifer productivity index either by entering values into the appropriate fields, or by using the sliderbar.

Note: The limits of the sliderbar can be adjusted by placing the gray slider box at the end of the bar. Then, use your scroll button on your mouse. Double-clicking the gray slider box positions the sliderbar in the middle of the scale.

Continue adjusting both parameters (that is, Initial Water in Place and Aquifer productivity index) until the production data becomes a straight line.

Important: The results of this analysis are not unique, because many different combinations of OWIP, OGIP, and the productivity index can result in a linear trend.
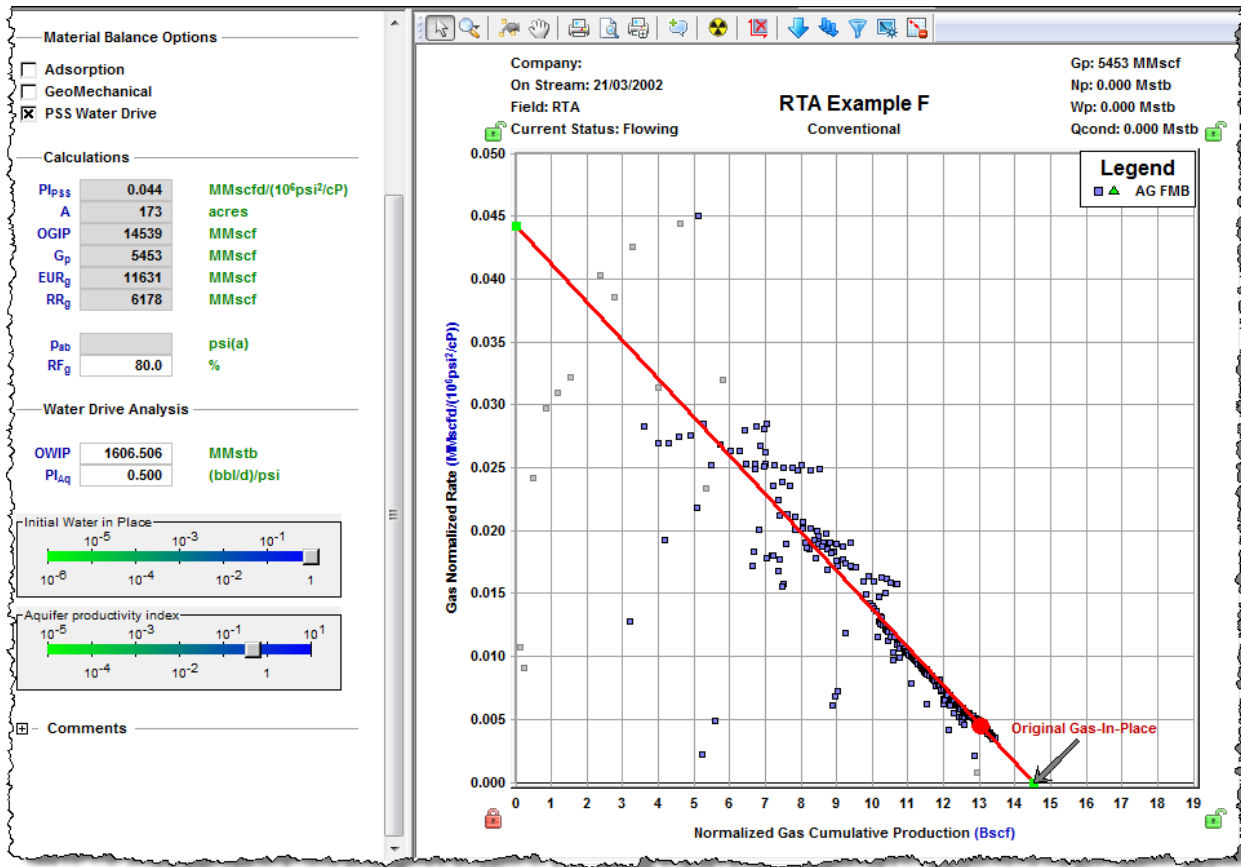
Including pressure-dependent permeability and formation compressibility

The flowing material balance (FMB) analysis provides the capability to include pressure-dependent permeability and rock compressibility in the analysis.

In the Plot Options section, click the **AG FMB** checkbox.

In the Material Balance Options section, click the **GeoMechanical** checkbox. This enables the geo-mechanical correction (see geomechanical reservoir models), which uses inputs from the Properties editor (under Formation / Rock Properties -> Geomechanical).

Note: For the Oil FMB analysis, this option is only available if the Changing Properties (Pseudo-Pressure) option is selected.

Accounting for adsorbed gas-in-place for shale gas plays

The flowing material balance (FMB) analysis provides the capability to account for adsorbed gas-in-place (GIP) for shale gas plays.

In the Material Balance Options section, select **Adsorption**. This corrects the data to include adsorbed gas, and shifts the data points up.

Note: When the Adsorption checkbox is selected, and after you have opened an FMB analysis, your Langmuir Volume (V_{LS}) and Pressure (P_{LS}) values are used. (You need to enter values for the Langmuir Volume (V_{LS}) and Pressure (P_{LS}) in the Properties editor (under **Formation / Rock**, **Adsorption**.)
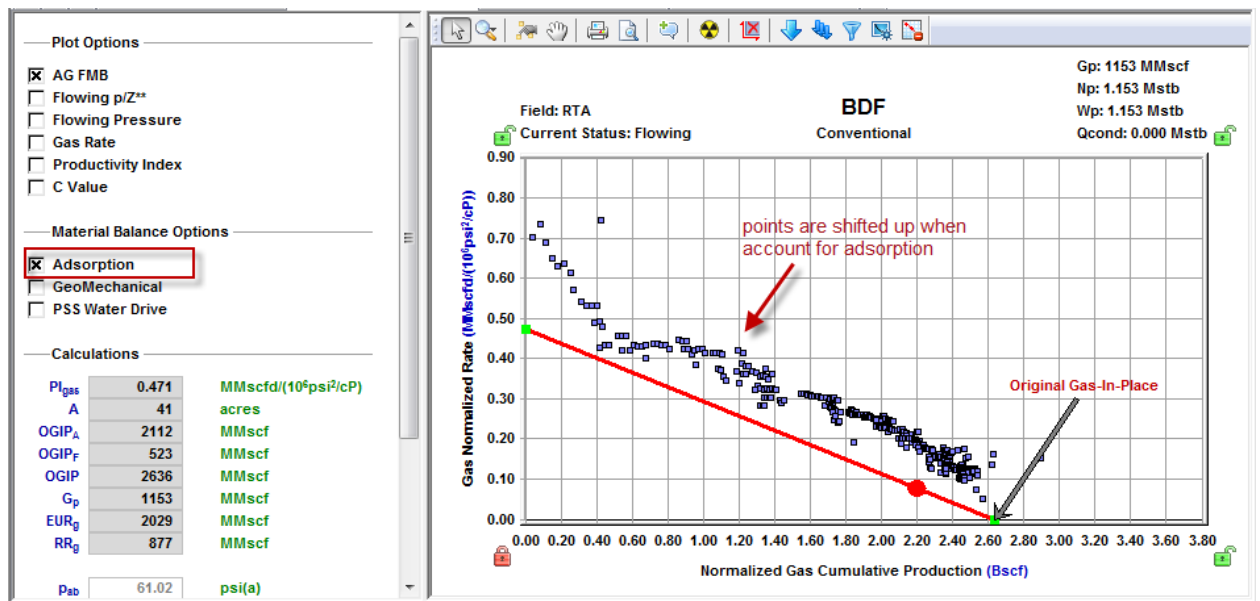
Reposition the analysis line through the data points. The calculated OGIP now includes an adsorbed volume ($OGIP_A$).
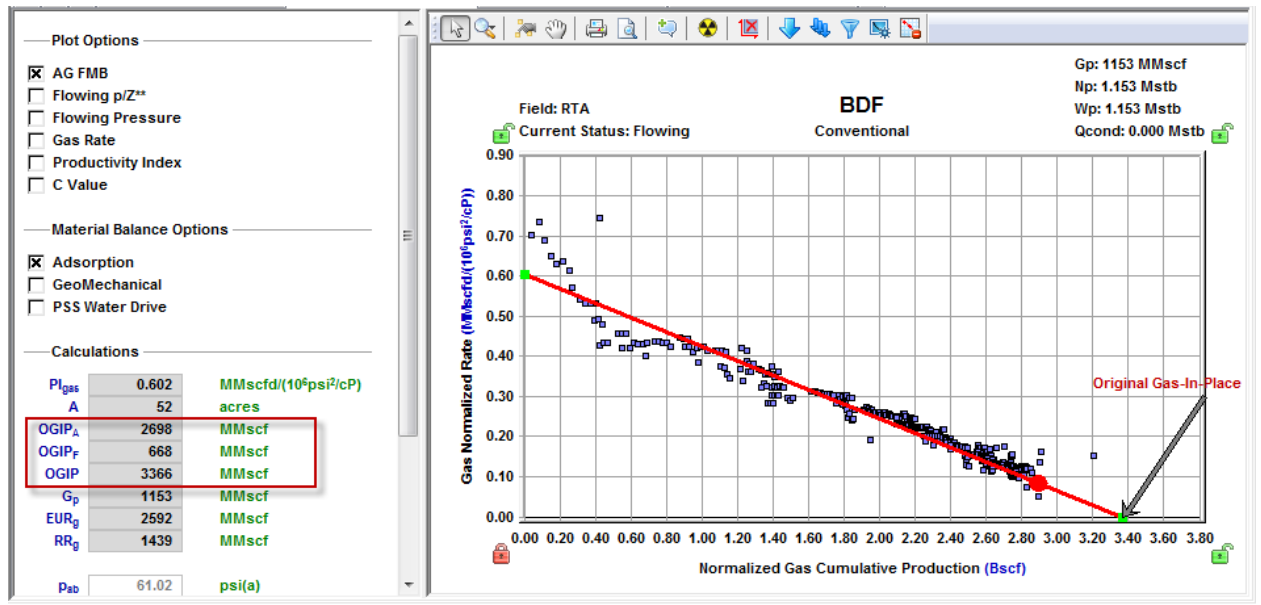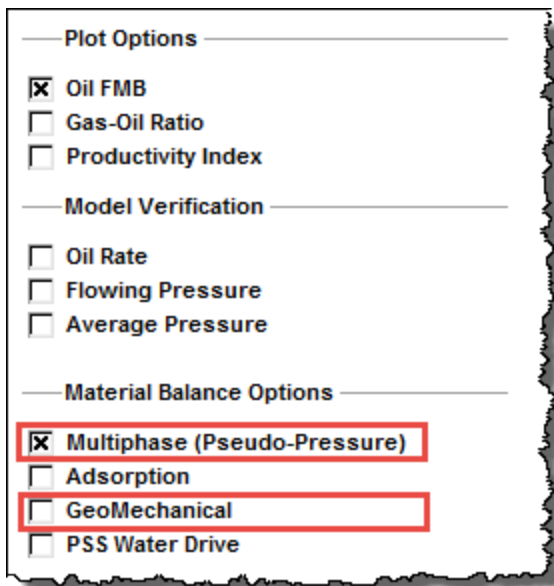
Accounting for changing oil properties

The classical flowing material balance (FMB) analysis is performed under the assumption that the variation of oil properties (compressibility, viscosity, formation volume factor) with pressure is negligible; therefore this variation is not taken into account.

To account for the variation of oil properties with pressure, select the **Multiphase (Pseudo-Pressure)** option. Calculations performed when this option is selected are based on using oil pseudo-pressure and are described in accounting for variation in oil properties. Calculations use the oil properties that are set in the Properties editor.

If you chose to account for the variation in oil properties, you can also account for variation in rock properties (permeability and formation compressibility) with pressure. To do this, select the **GeoMechanical** option. Note that for the Oil FMB analysis, this option is only available when the Multiphase (Pseudo-Pressure) option is selected. Calculations use the rock properties that are set in the Geomechanical section of the Properties editor.

Data Filter dialog box

This dialog box is commonly used when you click the filter data for an <u>FMB</u>, <u>typecurve</u>, or <u>unconventional reservoir analysis</u>.

This dialog box has the following important icons:

- **Tools to Select Data Points for Filtering** — opens an additional toolbar with point-selection options.

  - **spray gun** — selects points when you left-click, and deselects points when you right-click. The mouse wheel can be used to change the spread-tool's size.

  - **select all data points** — selects all the data points on the plot.

  - **deselect all data points** — deselects all the data points on the plot.

  - **lasso** — select points by clicking-and-dragging a shape around your data points. Deselect points by right-clicking-and-dragging a shape around the data points you do not want.

- **Fully Automatic** — select one of these options:

  - **Median Filter** — used to make data less noisy by deselecting data points that are far from the rest of the data (those points are likely to be outliers). Note that the dataset needs to have at least 20 points for this filter to be applicable.

- **Liquid Load Filter** — in some cases, flowing pressures are not measured at sandface; instead they are measured at the wellhead, and Harmony Enterprise calculates sandface pressures (see pressure loss calculations) based on given wellhead pressures in the wellbore editor. If the well is experiencing liquid loading, calculated sandface pressures may be inaccurate. Therefore, you may want to exclude corresponding data points from the analysis. With this filter, you can deselect data points where the well is experiencing liquid loading. For more information, see liquid lift calculations.

- **Saturated Filter** — used to identify the portion of the data where flowing pressure is below the bubble point pressure (oil and gas flowing in the reservoir). For more information, see saturated filter.

For information on common plot icons, see plot toolbars.

Unconventional reservoir analysis

The unconventional reservoir model (URM) analysis is used to identify linear and/or boundary-dominated flow regimes within your data. Additionally, this analysis generates production forecasts for shale or tight oil / gas wells. This analysis requires sandface flowing pressures, production rates, and reservoir / fluid parameters. If the required pressures, rates, and properties are not filled in, the parameters pane of the analysis is disabled. For more information on the calculations, see unconventional reservoir theory.

Note: This analysis works with your Harmony Reservoir™ license.

This analysis has the following solution options:

- **Constant Pressure** — the constant pressure solution for a basic linear flow model. An analysis line is fit to the data on a Reciprocal Rate vs Square Root Time plot. The slope and y-intercept of the analysis line are used to determine the linear flow parameters, along with apparent skin or apparent fracture conductivity, respectively.

- **Variable Pressure** — the constant rate solution for a basic linear flow model. An analysis line is fit to the data on a Normalized Pressure vs Square Root Time plot. This accounts for changing flowing pressures when interpreting the slope of the square-root time plot. The slope and y-intercept of the analysis line are used to determine the linear flow parameters, along with apparent skin or apparent fracture conductivity, respectively.

- **Superposition Time** — the superposition of the constant rate solution for a basic linear flow model applied over time to account for variations of rate over time. An analysis line is fit to the data on a Normalized Pressure vs Linear Superposition Time plot, or Material Balance Time plot, depending on the time option selected in the parameters pane. The slope and y-intercept of the analysis line are used to determine the linear flow parameters, along with apparent skin or apparent fracture conductivity, respectively.

- **Deterministic** — creates an analysis based on known parameters.

- **Most Likely** — creates an analysis based on a range of values, and produces "most likely" values that can be used to estimate model parameters.

Note: The production forecast for the variable pressure and superposition worksheets is estimated using constant sandface pressure (p_{wff}).

Tip: For a multiphase oil URM analysis, pseudo-pressure is used instead of pressure. This may impact your data-point selection, if you manually best fit your data points with Harmony

Enterprise 2017.3 or earlier, and selected the **Changing Properties (Pseudo-Pressure)** checkbox. It is now called the Multiphase (Pseudo-Pressure) checkbox.

Unconventional Reservoir pane

In the Unconventional Reservoir pane, enter the required parameters and select your options.

Parameters

Parameters include the inputs you specify, or the default Harmony Enterprise values and calculated values from the plot interpretations.

Additional gas options for adsorption and geomechanical models can be used by clicking their checkboxes. These model options require that the Langmuir isotherm and permeability and/or compressibility ratio correlations be entered in the Properties editor.
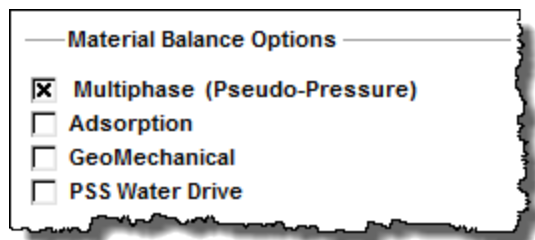
- **Multiphase (Pseudo-Pressure)** — accounts for the variation of oil properties with pressure. Calculations use the Oil properties that are set in the Properties editor.

- **Adsorption** — includes the effect of adsorbed gas.

- **GeoMechanical** — accounts for the variation in rock properties (permeability and formation compressibility) with pressure. Calculations use the rock properties that are set in the Geomechanical section of the Properties editor. Note that for the Oil URM analysis, this option is only available when the Multiphase (Pseudo-Pressure) option is selected.

- **PSS Water Drive** — accounts for pseudo-steady state (PSS) water drive (additional water drive analysis parameters are displayed).

The flowing pressure inputs in the Forecast parameters section are used with the slope of the Square Root Time plot to determine xf√k. You can enter the drainage area, or area of SRV, but by default, these values come from the OOIP / OGIP on the flowing material balance (FMB) plot. Changes to the location of the end of linear flow line (t_{elf}) on the Square Root Time plot updates the OOIP / OGIP. The decline exponent, b, and the final gas rate are used to calculate the hyperbolic decline forecast. The start date is the end of production data for the well. The Δt is set based on the forecast duration to

reach the final rate, and corresponds to the end date. Either q_f or Δt can be entered, and the other value is calculated.

The second half of the parameters pane displays calculated values from the interpretations. The $xf\sqrt{k}$ is displayed from the Square Root Time plot, and can be used to determine x_f, if the matrix permeability is entered. The time to reach the end of linear flow (t_{elf}) is determined from the slope of the Square Root Time plot, the flowing pressure, and the drainage area entered or determined from OOIP / OGIP. The OOIP / OGIP displayed is related to the area used. The expected ultimate recovery (EUR) and remaining recoverable (RR) come from the boundary-dominated flow forecast.

In the Model Type drop-down list, you can apply a vertical single fracture model to your well, or horizontal well models. The horizontal well includes two options: effective permeability or matrix. The analysis procedure is the same for both well types; however, the calculation inputs for horizontal well models are used differently.

In the effective permeability model, the SRV is treated as a region of higher effective permeability, and the horizontal well is treated as a single fracture. The [Le*(2x_f)] value is entered, and the effective permeability is calculated.

The matrix permeability model considers bi-wing fractures extending from the horizontal well, and the area of the SRV is based on the FMB interpretation. When the horizontal well length and number of fractures are provided, the width of the area of the SRV (A_{SRV}) is used to set a fracture half-length (x_f) to each fracture. The matrix permeability in the SRV can then be determined from the total fracture half-length. Alternatively, if the matrix permeability is entered, providing a different total fracture half-length, the area of the SRV and OGIP / OOIP in the FMB changes to match.

Note: None of the inputs in the Calculations section are required, but they can provide additional information about the model used for forecasting.

Primary toolbar

The primary toolbar is located in the Unconventional Reservoir pane and has these icons:

- **Apply Defaults** — copies parameters [1] from the Properties editor or other IHS Reservoir worksheets.

- **Change Top Left View** — select a plot to be displayed in the top left of your dashboard.

- **Change Top Right View** — select a plot to be displayed in the top right of your dashboard.

- **Change Bottom Left View** — select a plot to be displayed in the lower left of your dashboard.

- **Change Bottom Right View** — select a plot to be displayed in the lower right of your dashboard.

- **Float a New View** — select a plot to be displayed in a new floating window.

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[1] These parameters can be copied from one unconventional analysis to another: -fracture height min & max -model type (fracture mode) -changing properties options: geomechanical, changing oil saturation, use pseudo-time -material balance options: adsorption, geomechanical -superposition time options: (superposition time type) -forecast parameters: b, qf -typecurve options: raw derivative status, derivative status

- ![icon] **Save or Erase Default Dashboard** — select either save (to save your current dashboard configuration as the default setting), or reset (to reset the dashboard to its original settings).

- ![icon] / ![icon] **Show / Hide Disabled Points** — toggle between showing / hiding disabled points on your plot.

For a description of common toolbar icons, see toolbars.

Plot dashboard

The plot dashboard displays your four favorite plots.

Note: For the FMB plot on the dashboard, the OGIP is anchored to the x-axis as a pivot point, and you can move the y-axis intercept by clicking-and dragging the green square. The anchored point on the x-axis is dictated by the t_{elf} line on the Square Root / Superposition Time plot.

Plot toolbar

The icons displayed in the plot toolbar vary depending on the type of plot that you have displayed. The important icons are described below.

- ![icon] **Single Annotation** — adds an annotation arrow to the data point you click.

- ![icon] **Linked Annotations** — synchronizes your annotation arrows across unconventional reservoir plots. For example, if you move your annotation on one plot using the keyboard arrow keys, the arrow is synchronized on the other plots. The values vary as you move from the displayed date for one date / time row in the Production editor to the other.

- ![icon] **Data Filter** — opens the Data Filter dialog box where you can apply a data filter. For more information, see saturated filter.

- ![icon] **Boundary Dominated Curve** — applies a boundary-dominated curve to your plot.

- ![icon] **Typecurve Options** — opens the Typecurve Options dialog box where you can toggle the Raw Data Derivative and Beta Derivative options, as well as select your derivative type (Standard, Bourdet, or Difference) and derivative cycles. For bilinear flow, the beta-derivative is 0.25; for linear flow, it is 0.5; for boundary-dominated flow, it is 1.0.

For a description of common plot icons, see plot toolbars.

Unconventional reservoir plots

Unconventional reservoir plots include the following:

- Square Root Time

- Flowing Material Balance

- Typecurve

- Forecast

- Schematic

- Allowable Ax vs Ad Region

- Fourth Root Time

All of these plots can be sent to the comparison plot in the Results Viewer by right-clicking the plot and selecting **Send to Comparison Plot**. For more information, see comparison plot.

Square root time

This plot displays normalized pressure vs square-root time, and displays an automatic best fit of the data. The slope of the best fit line is used to determine the $x_f\sqrt{k}$, while the y-intercept is used to determine the apparent skin or apparent fracture conductivity.
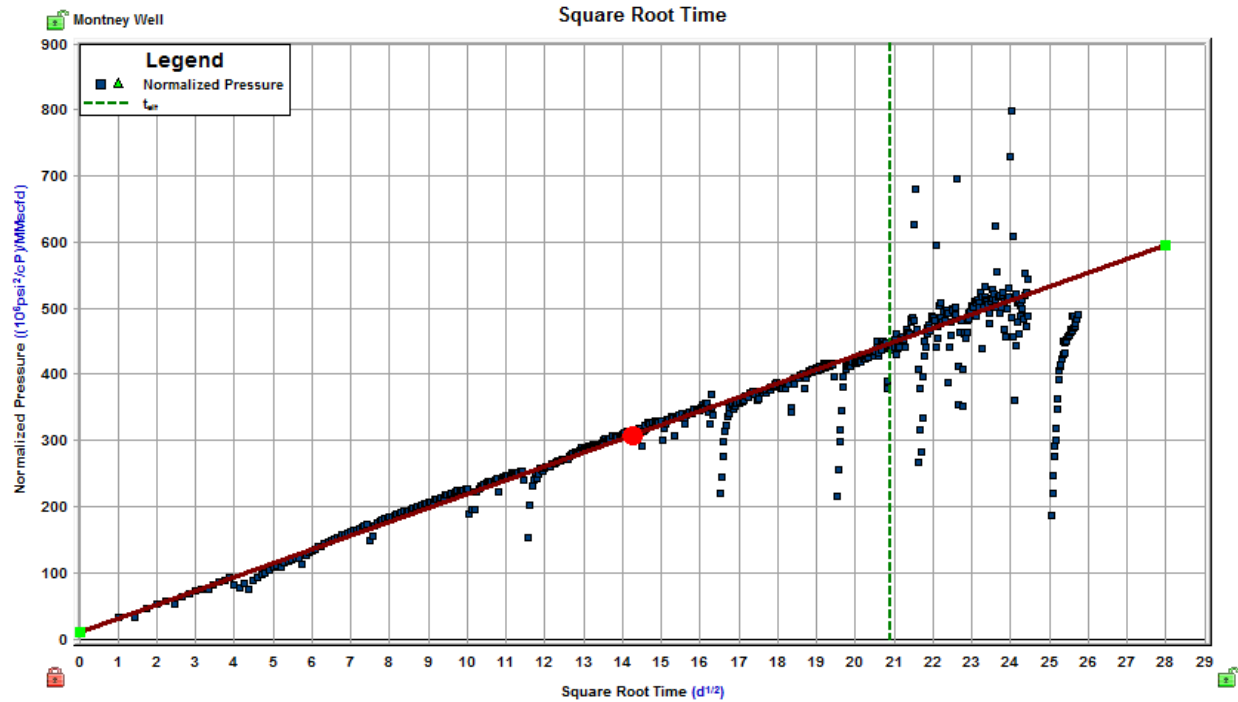
Note: On constant / variable pressure worksheets, Harmony Enterprise can calculate "b" according to your adjustments, if you click the **Boundary Dominated Curve** icon (☑), and move the red analysis line on the plot manually.

Line manipulation

The best-fit line for this plot has the following properties:

- The line has an infinite length to the right.

- The line always has a manipulation point on the left-side on the y-axis.

- The line translates up and down when dragged by the left point.

- You can rotate the line around the center point by dragging the line itself.

Flowing material balance (FMB)

This plot shows the OOIP / OGIP, as well as the area of the stimulated reservoir volume (SRV). In addition, this plot displays an automatic best fit of the data.
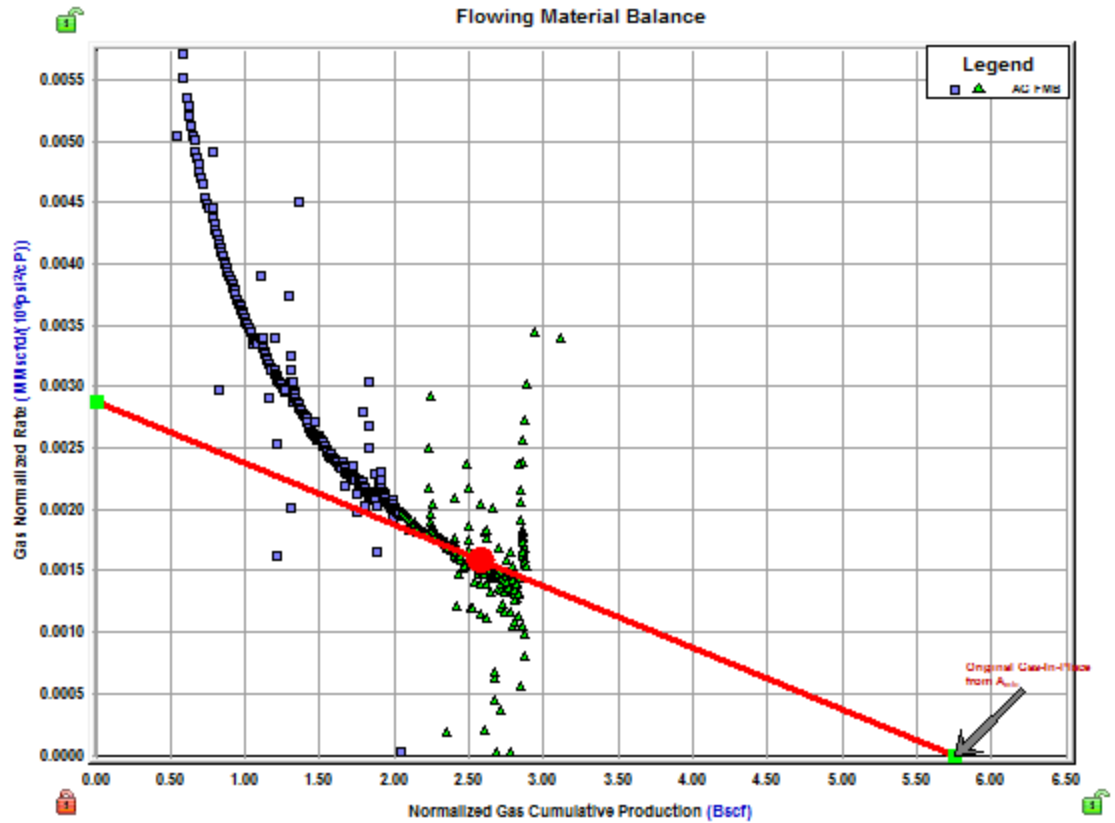
Note: By default, the flowing pressure to be used in the analysis is populated from the last portion of pressure data in the production history.

Typecurve

This plot indicates the flow regime. The red line indicates infinite-acting linear reservoir behavior; the green line indicates bounded reservoir behavior.
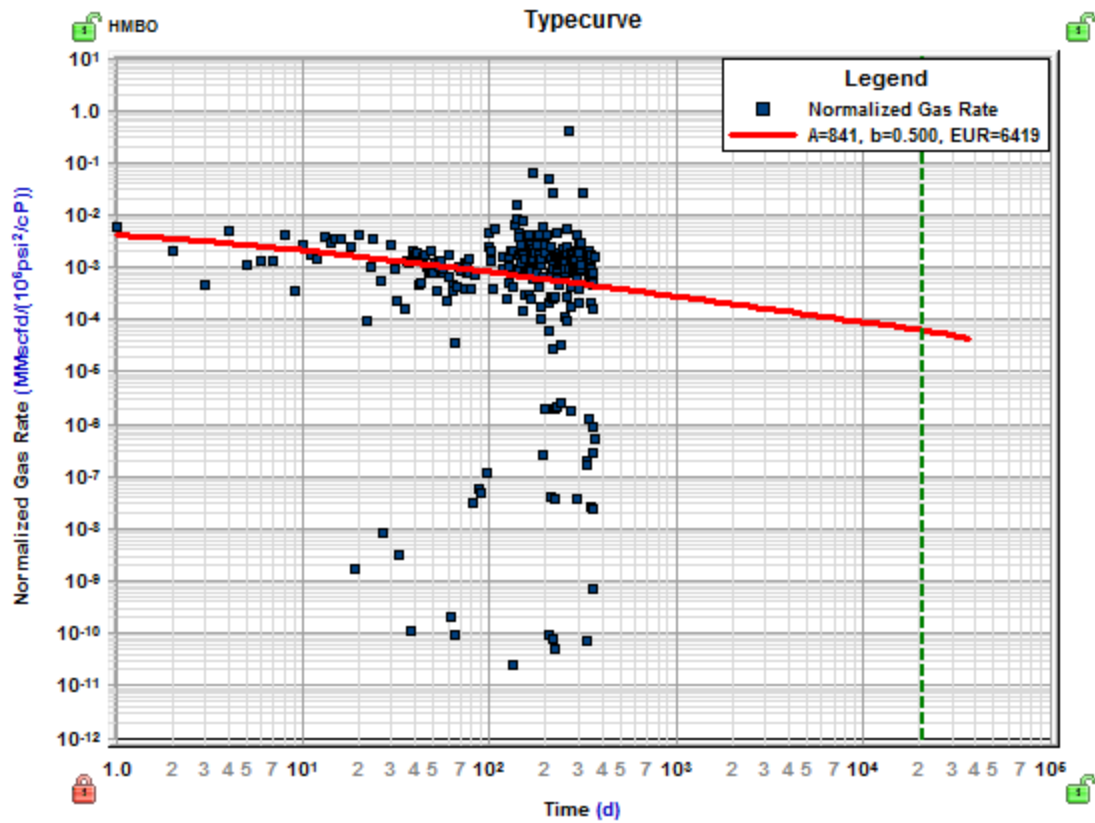
Forecast

This plot displays the forecast rate. The red line indicates infinite-acting linear reservoir behavior; the green line indicates bounded reservoir behavior.
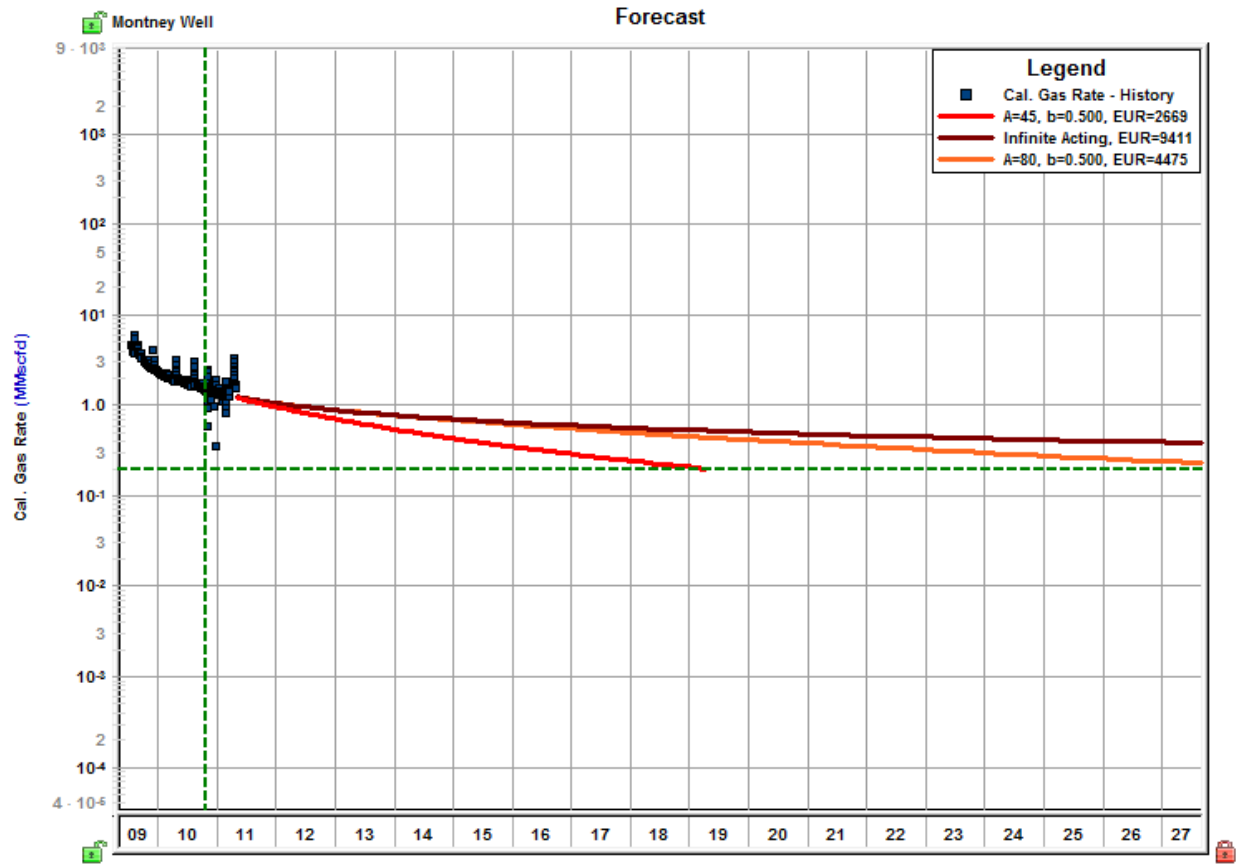
Schematic

In the "most likely" model, the schematic is based on the most likely SRV configuration on the Allowable A_d vs A_x Region plot. In the deterministic model, the schematic is based on the parameters you have entered.

Analytical Hz Multifrac Schematic
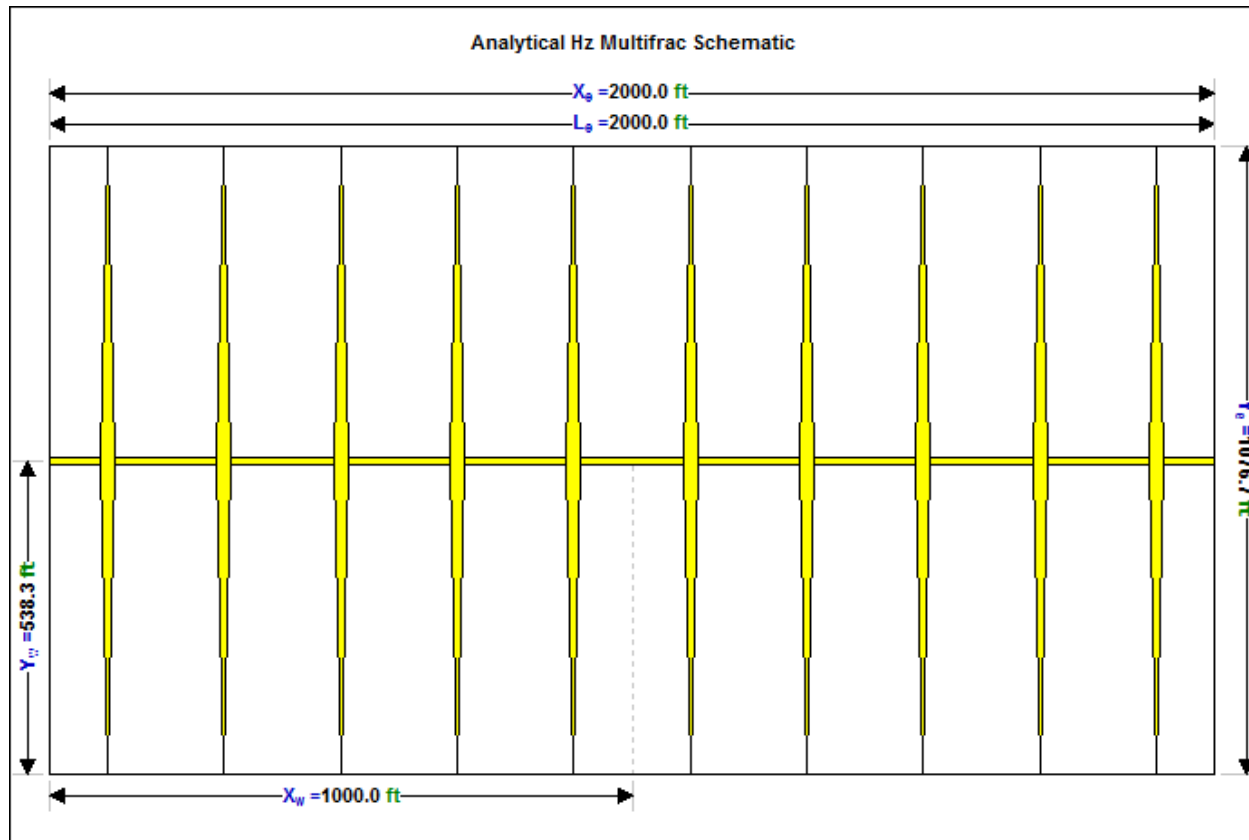
Allowable A_x vs A_d region

This plot defines a region that contains the full set of possible SRV configurations. The point at the center of the mass is used as the "most likely" values. (This plot is only available in the Most Likely model.)

Allowable A_x vs. A_d region

P50 A_d = 302 acres
P50 A_x = 50081675 ft²
P50 x_f = 3287 ft
P50 k_m = 2.752e-07 md
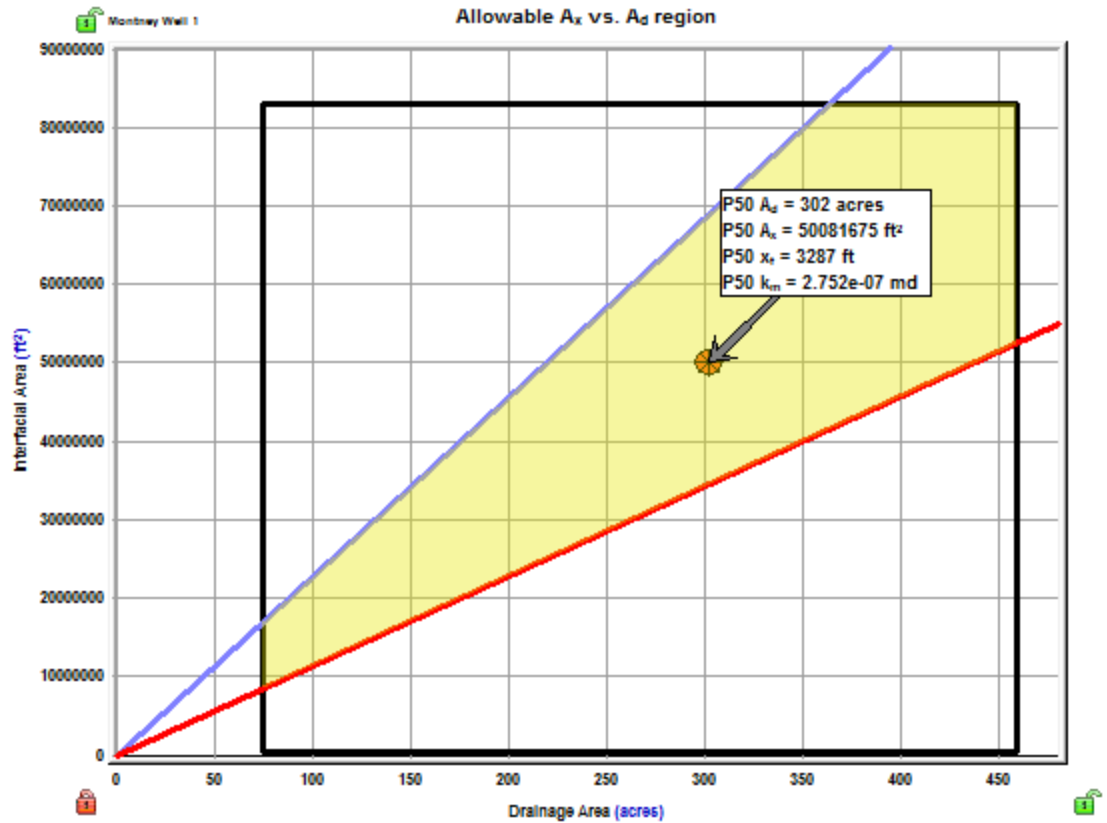
Fourth root time

This plot displays normalized pressure vs fourth-root time, and displays an automatic best fit of the data, as well as calculating values based on bilinear flow equations.
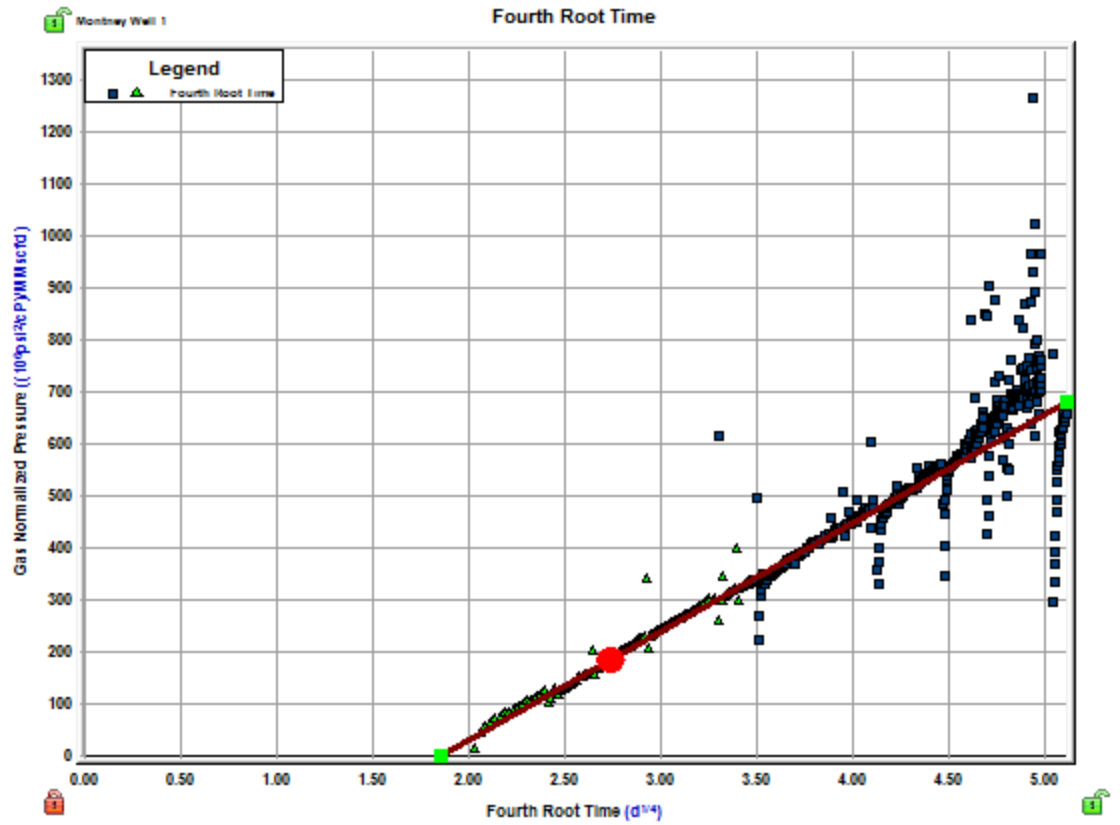
Saturated filter

The unconventional reservoir model (URM) analysis is a single-phase analysis; therefore you should be cautious when applying it to cases where a well exhibits two-phase flow. For oil wells, we can expect two-phase flow after the flowing pressure drops below the oil bubble point pressure. The Saturated Filter option can be used to identify the portion of the data where flowing pressure is below the bubble point pressure (oil and gas flowing in the reservoir).

To use this option:

Click the **Data Filter** icon on a Square Root Time or FMB plot; then click the **Fully Automatic** icon on the Data Filter plot.
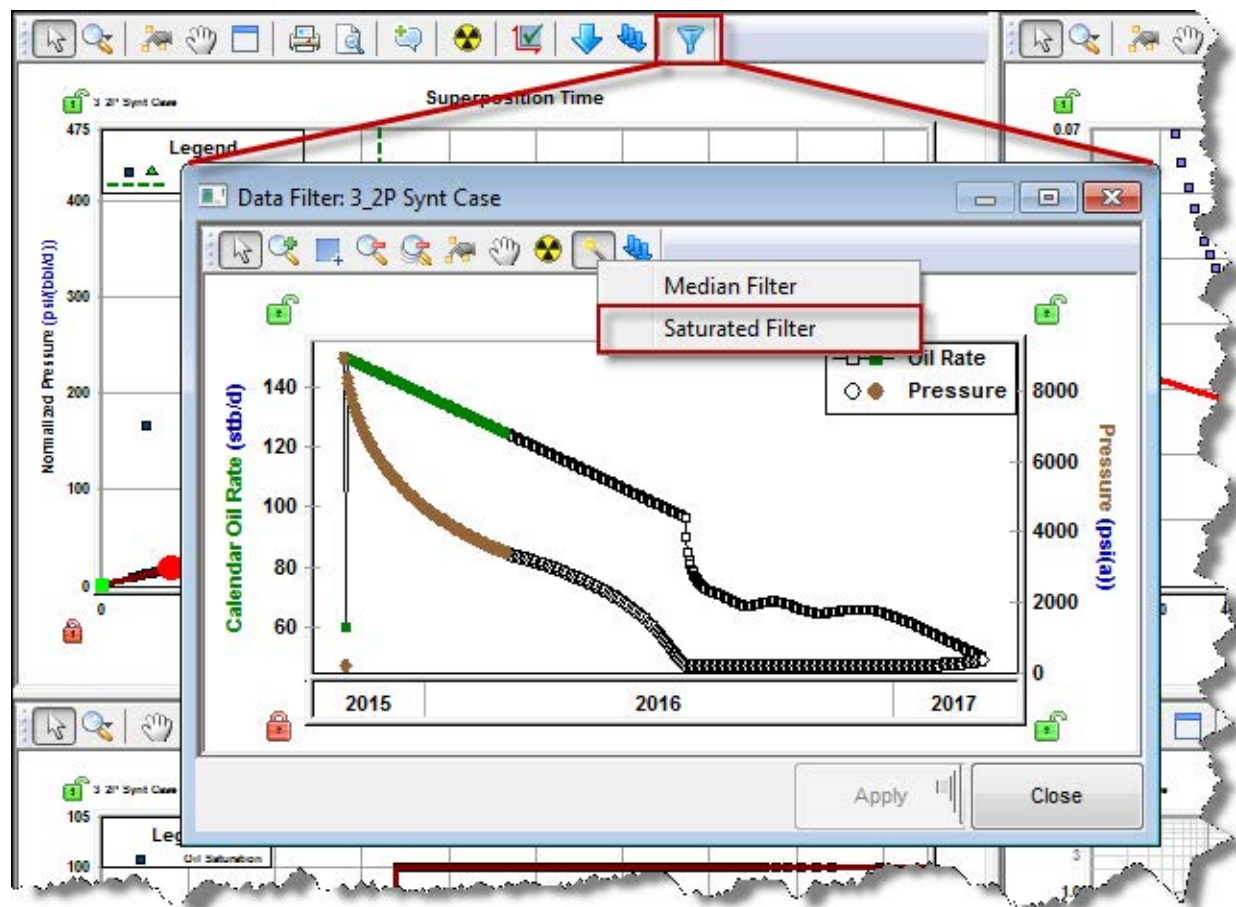
Note: The saturated filter uses the oil bubble point pressure set in the Properties editor; therefore, it is important to set it accurately.

Data Filter dialog box

This dialog box is commonly used when you click the filter data for an FMB, typecurve, or unconventional reservoir analysis.

This dialog box has the following important icons:

- **Tools to Select Data Points for Filtering** — opens an additional toolbar with point-selection options.

    - **spray gun** — selects points when you left-click, and deselects points when you right-click. The mouse wheel can be used to change the spread-tool's size.

    - **select all data points** — selects all the data points on the plot.

    - **deselect all data points** — deselects all the data points on the plot.

    - **lasso** — select points by clicking-and-dragging a shape around your data points. Deselect points by right-clicking-and-dragging a shape around the data points you do not want.

- **Fully Automatic** — select one of these options:

    - **Median Filter** — used to make data less noisy by deselecting data points that are far from the rest of the data (those points are likely to be outliers). Note that the dataset needs to have at least 20 points for this filter to be applicable.

- **Saturated Filter** — used to identify the portion of the data where flowing pressure is below the bubble point pressure (oil and gas flowing in the reservoir). For more information, see saturated filter.

For information on common plot icons, see plot toolbars.

Analytical

Analytical models are used to validate interpretations and provide production forecasting. For more information, see analytical models theory. Analytical models assume single-phase flow in the reservoir and are available for gas, oil, and water production with the following options:

- Vertical

- Vertical with Fracture

- Horizontal

- Hz Multifrac: Enhanced Frac Region

- Hz Multifrac: General Multifrac

Note: This analysis works with your Harmony Reservoir™ license.

Before you start, make sure that all required information is added to the Harmony Enterprise project. Well production data (rates and sandface pressures) should be populated in the Production editor, and reservoir and fluid properties should be specified in the Properties editor.

We recommend that you perform an analysis prior to using the analytical model because this gives you an idea about which values to use. For example, for conventional wells, a flowing material balance (FMB) gives an estimate for original fluid in-place, and the use of a typecurve analysis provides insight about permeability, skin, reservoir shape / size, and fracture properties. For unconventional wells, an unconventional reservoir analysis can be used to estimate permeability, fracture length, apparent conductivity, and the size of the stimulated reservoir volume.

Analytical Model pane

In the Analytical Model pane, enter the required parameters, and select your calculation method from the primary toolbar (CalcP, CalcR, or CalcBoth).

Primary toolbar

There are four toolbars: primary, secondary, Plots sub-tab, and Forecast sub-tab.

The primary toolbar has the following important icons:

- **Defaults** — copies parameters from the Properties editor or other IHS Reservoir worksheets.

Or, if you want to copy only one parameter from the analysis, click the **View Defaults and Limits** button to the right of the field in the Analytical Model pane.

Note: Parameters copied from the reservoir or another analysis are displayed in a gray font. This indicates that they match the default. You can type new values for any parameter, or change values for some parameters by moving elements of the schematic. Parameters, which do not match the default, are shown in a black font.

- **Automatic Parameter Estimation (APE)** — while APE is running, selected parameters are automatically varied to minimize the error between the simulated pressure / rate and the actual pressure / rate depending on the calculation method (see CalcP, CalcR, and CalcBoth below). The updated simulated pressure / rate is shown on the plots while the calculation is running. For more information, see using APE.

  Important: The purpose of history matching is to get the calculated pressures / rates to reproduce actual pressures / rates as closely as possible by changing the model's parameters. You can vary model parameters manually, or use APE.

- **AutoCalc** — recalculates automatically each time you change model parameters.

- **Synthesize** — if you do not click the AutoCalc icon, you must click this icon every time you want to recalculate the model.

- **CalcP** — calculates the sandface flowing pressure based on measured rate. The pressure is calculated and minimized.

- **CalcR** — calculates the rate based on given sandface flowing pressures. The rate is calculated and minimized.

- **CalcBoth** — calculates CalcP and CalcR. Both pressure and rate are calculated and minimized.

- **Derivative Options** — opens the Options dialog box where you can select Standard (points), Bourdet (cycles), or Difference.

- **Copy to / Paste from the Clipboard** — copies and pastes data from the clipboard.

For a description of common icons, see toolbars.

Secondary toolbar

By default, the secondary toolbar is located to the far right of the primary toolbar. (You can move the icons in the secondary toolbar by clicking the dotted line to the left of the icons.)

By default, the Analytical Model Dashboard displays model schematics and three plots with measured and calculated data. You can change this display (that is, replace plots and their positioning) by clicking one of the **Add an Available View** icons (upper left, upper right, lower left, lower right) and selecting the plot you want.
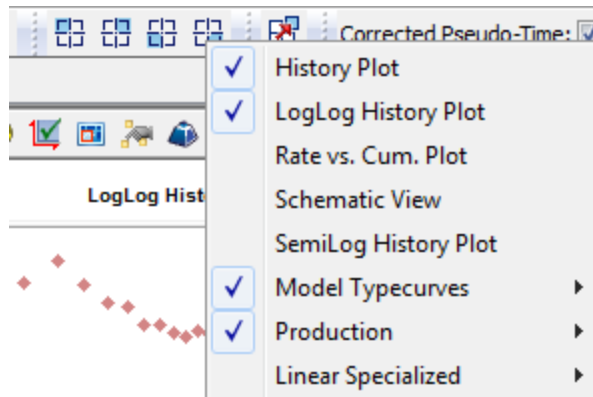
- **Add Floating View** — opens the plot you select from the drop-down list in its own window.

- **Corrected Pseudo-Time** — toggles corrected pseudo-time on or off.

Sub-tabs

There are three sub-tabs: Plots, Forecast, and Tables.

Plots

This sub-tab displays your analytical model dashboard, which you can customize using the secondary toolbar. For information on a plot's context menu, see plot options.

Toolbar

This toolbar is located on the Plots sub-tab and has the following important icons:

- **Reset Plot Attributes** — resets your plot attributes to default settings.

- **Enable / Disable Square LogLog Plot** — changes the range of the x- and y-axes, so that the resolution of a log cycle is consistent between the axes (for example, a log cycle equals 200 pixels on both axes).

- **Weigh Data Points** — used to emphasize matching to specific data points when using APE (for example, the last part of the production). The cursor changes to a spray gun when clicked. Weighted data points are displayed in a brighter color and are given a 100% weighting; unweighted points are given a 10% weighting. (The weighting is displayed when you hover over the data point.)

- **Copy** — copies plot data.

- **Select Anchor Point** — attempts to initialize the anchor to the first measured pressure. If this fails, click the location you want within the plot to set the anchor location. An annotation is shown at the anchor location while this functionality is enabled. Dragging the annotation arrow to a different point updates the calculations. For more information, see anchoring.

  Tip: The Anchor option is currently only available for analytical models in Calculate Pressure (CalcP) mode.

- **Hide the Toolbar** — hides the toolbar. If you want the toolbar displayed, right-click the plot and select **Show Toolbar**.

For information on common plot icons, see plot toolbars.

Forecast

This sub-tab has a toolbar, and displays your forecast: options, constraints, and results.

After the model has been populated (either by entering values, or by clicking the Defaults icon) and calibrated to the production and pressure data through history matching (click the Automatic Parameter Estimation icon), production forecasts can be created and compared under a variety of different constraints.

Toolbar

This toolbar is located on the Forecast sub-tab and has the same common icons described in plot toolbars.

Forecast options

The Forecast Options section is where forecast periods are defined according to either durations (for example, months), or dates.

- Setting the forecast time method to **Duration** begins a forecast at a specified start date. Forecast periods are then defined in the forecast table according to a length of

time (the default is months). For each forecast period, different operating conditions can be specified.

- Setting the forecast time method to **Start Date** creates a forecast of a specified length of time (the default is months). Forecast periods are then defined in the forecast table according to calendar dates.

If you select **Duration** from the Forecast Time Method drop-down menu, the Start Date is automatically populated. (You can change this date later, if needed.)

If you select **Start Date** from the Forecast Time Method drop-down menu, enter a value for Duration (that is, the total length of the forecast).

Forecast Flowing Pressure — when controlling the pressure for forecasting, select whether sandface or wellhead pressure is specified. For more information, see underlined forecasting using wellhead pressure.

Allow Injection — a negative control rate (to forecast as injection) can only be specified when this checkbox is selected. If this option is deselected, the forecast stops if the average pressure intersects flowing pressure.

Further details about each forecast period are entered in the forecast options table.

	Time			Control		Sandface Pressure	
	Step Type	Duration	# of Steps	Interpolation Method	Control Type	Initial	Final
		month				psi(a)	psi(a)
1	Arithmetic ▾	Required	Required	Step ▾	Pressure ▾	1626.85	

Each row of the table above represents a forecast period. An additional forecast period can be added each time an operational change is encountered (for example, the flowing pressure decreases when a compressor is added). The forecast options table has the following sections:

- **Time** — defines the length of each forecast period and each timestep, and has the following columns:

  - Step Type — sets the spacing of the timesteps, and can be set to either Arithmetic or Logarithmic. The Arithmetic step type spaces the number of timesteps equally over the total duration of the period, whereas the Logarithmic step type spaces the number of timesteps logarithmically (that is, increased density near the beginning of the forecast).

  - Forecast Time Method (Duration / Start Date) — sets the length of the forecast period. If the Forecast Time Method is set to Duration, this column shows Duration. If the Forecast Time Method is set to Start Date, this column show Start Date.

  - # of Steps — sets the number of timesteps in the forecast period.

- **Control** — defines how the operating conditions change over the forecast period, and has the following columns:

  - Interpolation — can be set to either Step or Ramp. "Step" keeps the control type constant over the forecast period. "Ramp" varies the control type linearly from an initial value to a final value.

- Control Type — sets what is used to calculate the forecast. For the analytical model, the forecast can be run using either flowing pressure, or the rate being analyzed.

- **Sandface Pressure** — if the Control Type is set to Pressure, the Sandface / Wellhead Pressure column is displayed (depending on the Forecast Flowing Pressure option), and it is used to set the flowing pressure for the forecast period. If Interpolation is set to Step, only the initial pressure is specified. If Interpolation is set to Ramp, initial and final pressure are specified.

- **Gas Rate** — if the Control Type in a period is set to Gas Rate, this column is displayed, and it is used to set the rate for the forecast period. If Interpolation is set to Step, only the initial rate cell is editable. If Interpolation is set to Ramp, initial rate and final rate are editable.

Forecast constraints

The Forecast Constraints section is where maximum rate and abandonment rate conditions for the forecast can be entered. The available constraints depend on the fluid type, and could include the following:

- p_{min} — specifies the minimum sandface / wellhead pressure based on the Forecast Flowing Pressure option.

- $(q)_{max}$ — sets a maximum rate during the forecast. In order to maintain the maximum rate constraint, flowing pressure is adjusted.

- $(q)_{ab}$ — sets the abandonment rate for the forecast. When the abandonment rate is reached, the forecast ends.

Forecast results

The Forecast Results section is where the results of the forecast are summarized. Available results depend on the fluid type, and could include the following:

- EUR — expected ultimate recovery.

  Note: For wells with historical data, EUR is defined as the cumulative of the historical data up to the beginning of the forecast, after which time, the synthetic cumulative calculated from the model is used until the end of the forecast.

- RR — remaining recoverable.

Tables

The sub-tab displays your history match (after you use the synthesize or APE functionality) and forecast data (after you populate all the required values on the Forecast tab) in a tabular format. For more

information, see tables.

Forecasting gas condensate systems

Analytical models in Harmony Enterprise can only analyze single-phase systems. For condensate systems, gas and condensate rates measured at the surface are <u>recombined</u> into a single-phase rich gas for analytical modeling. When forecasting, however, the recombined gas rate must be split back out into gas and condensate rates for estimating production measured at the surface. The main procedure to split the recombined condensate-rich gas into separator gas and condensate is as follows:

- Calculate the recombined gas rate factor (RGRF), which is dependent on the instantaneous value of the condensate gas ratio (CGR).

- $q_{sep\,gas} = q_{rec}$ / RGRF

- $q_{cond} = q_{sep\,gas}$ x instantaneous CGR

  Note: RGRF is calculated from separator conditions, condensate gravity, gas gravity, and CGR.

- q_{rec} = recombined gas rate (rich gas rate); $q_{sep.\,gas}$ = separator gas rate (dry gas rate); q_{cond} = condensate rate

There are two options that control how CGR is calculated over the forecast period:

1. CGR changes with time:

   - In the <u>Properties editor</u>, select **Gas Condensate / Recomb** from the Gas Type drop-down menu.

   - In the Forecast tab, under Forecast Options, select the **Separate Recombined Gas** checkbox.
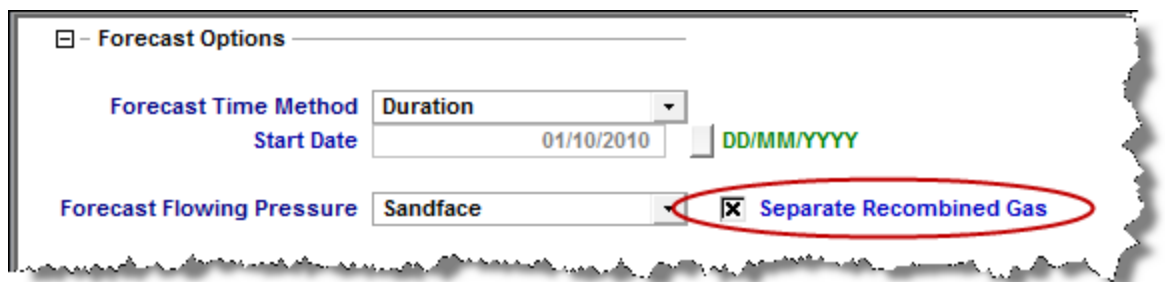
This results in additional columns (that is, Initial CGR and Final CGR) being added to the Ratios section of the forecast table.

	Time			Control		Sandface Pressure		Ratios		
	Step Type	Duration	# of Steps	Interpolation	Control Type	Initial	Final	Ratio Interpolation	Initial CGR	Final CGR
		month				psi(a)	psi(a)		bbl/MMscf	bbl/MMscf
1	Arithmetic ▾			Step ▾	Pressure ▾			Step ▾		

- Fill in the required inputs in the forecast table. The CGR automatically defaults to the value that was entered in the Properties Editor. However, this value can be edited.

- To enter a CGR that varies linearly over the forecasted period, select **Ramp** for the Ratio Interpolation method, then enter a Final CGR value.

	Time			Control		Wellhead Pressure		Ratios		
	Step Type	Duration	# of Steps	Interpolation	Control Type	Initial	Final	Ratio Interpolation	Initial CGR	Final CGR
		month				psi(a)	psi(a)		bbl/MMscf	bbl/MMscf
1	Arithmetic ▾	Required	Required	Step ▾	Pressure ▾	Required		Ramp ▾	Required	Required
2	Arithmetic ▾			Step ▾	Pressure ▾			Ramp ▾		

2. CGR changes with flowing pressure according to the Rv correlation:

- In the Properties Editor, select **Gas Liquid Content / Rv** from the **Gas Type** drop-down menu.

- In the Forecast tab, select the **Separate Recombined Gas** checkbox to split the cal-culated rich-gas rate into separator gas and condensate using the Rv functionality that controls the rate by sandface flowing pressure.

The resulting forecast graph and table show recombined gas, gas (dry), and condensate rates.

In splitting the forecast of analytical models, the assumption is that these effects / properties in the reservoir can be ignored:

- liquid drop-out on material balance

- liquid drop-out on skin

- liquid drop-out on gas composition (that is, recombined gas-specific gravity)

- liquid drop-out on fluid properties that change (that is, viscosity, compressibility, and the compressibility factor)

Note: The effect of liquid blockage on well productivity can be modeled by increasing skin with time.

Forecasting using wellhead pressure

By default, analytical models use sandface pressures for forecasting. When the Control Type is set to Pressure, analytical models calculate production rates based on sandface flowing pressure. When the Control Type is set to Rates, models calculate sandface flowing pressure based on rates.

With analytical models, you can forecast production rates from wellhead flowing pressure. When the Wellhead Flowing Pressure option is selected, and the Control Type is set to Pressure, analytical models calculate production rates based on wellhead flowing pressure.

After you have defined your wellbore in the Wellbore editor, and created an analytical model, click the **Forecast** tab and make sure that **Wellhead** is selected from the Forecast Flowing Pressure drop-down menu.
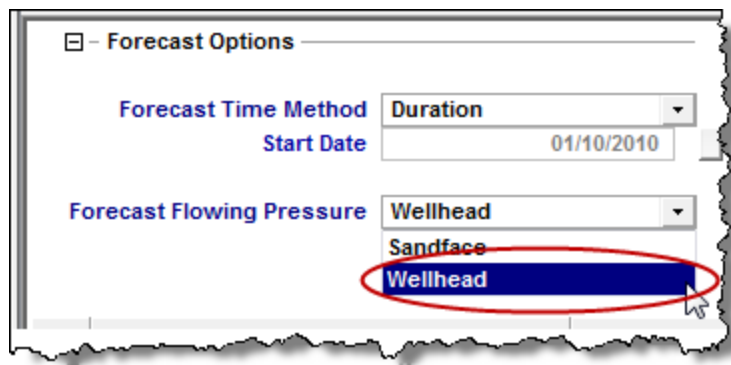
For the Control Type:

- If Pressure is selected, enter the wellhead flowing pressure.

- If Rate is selected, both sandface and wellhead flowing pressures are calculated during the forecast; however, only sandface flowing pressures are displayed on the Results plot. Both the sandface $(p_{wf})_{calc}$ and wellhead flowing pressures $(p_{tf})_{calc}$ are displayed in the Tables tab.

When multiple phases are present in the wellbore, pressures should be calculated based on the multiphase flow rates. To enable multiphase wellbore calculations, the fluid ratio must be defined over the forecast period. Fluid ratios are defined as follows:

- Under Forecast Options, select the appropriate fluid ratio. This results in additional columns being added to the forecast table under the Ratios section.

Note: Available fluid ratios depend on the analysis type. Gas wells show WGR, while oil wells show WOR and GOR.

- Set the ratio interpolation method as either Step (default setting) or Ramp. "Step" defines a constant ratio value over the forecast period, while Ramp allows the ratio value to vary linearly over the forecast period.

- Specify values for the ratio over the forecast period. If Step was selected as the interpolation method, enter an Initial value. If Ramp was selected, enter Initial and Final values.

Note: When the Wellhead Flowing Pressure option is selected, the p_{min} forecast constraint is the minimum wellhead pressure (as opposed to minimum sandface pressure when the Sandface Pressure option is selected).

Default values for fluid ratios (for example, WGR, WOR, and GOR) are calculated based on the reported production rates at the last historical date.

Note that multiphase flow rates are only used in the wellbore calculation, which does the conversion between sandface and wellhead pressures. Multiphase flow rates are not used for any reservoir calculation.

Test design

Test design also uses the same Forecast tab, but its purpose is different. Test design is usually performed for green fields without any production data, and is used to:

- get an estimate of expected production volumes

- see the effect of various reservoir and completion parameters

To start a test design, you need to create a new well (in the Entity Viewer) and fill in the required properties in the Properties editor.

Estimating expected production volumes

In the Forecast tab, set the forecast duration, # of steps, and forecast control.

Your forecast is calculated and displayed on the Results plot. Expected ultimate recovery (EUR) is displayed in the Forecast Results section.
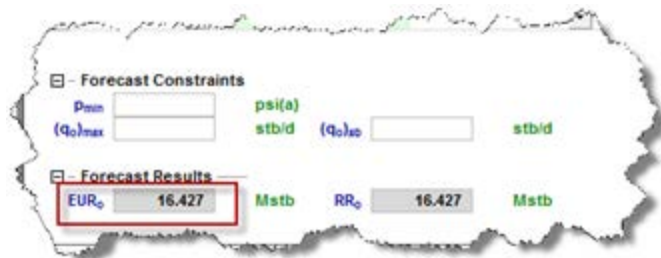
Evaluating the effect of various parameters

To have a better idea of possible outputs (for example, expected production volume estimates), you may want to see how results differ when you change some of the model parameters. This can be best illustrated with an example.

Test design example

Assume you have one model with a horizontal multifrac completion with a test design, and you want to see the effect of changing the number of fractures (n_f).

1. Create an analytical model of the same type.

2. Copy all the parameters from the existing model to the new one by clicking the **Defaults** icon ( ), and then change the number of fractures (n_f) for the new model.
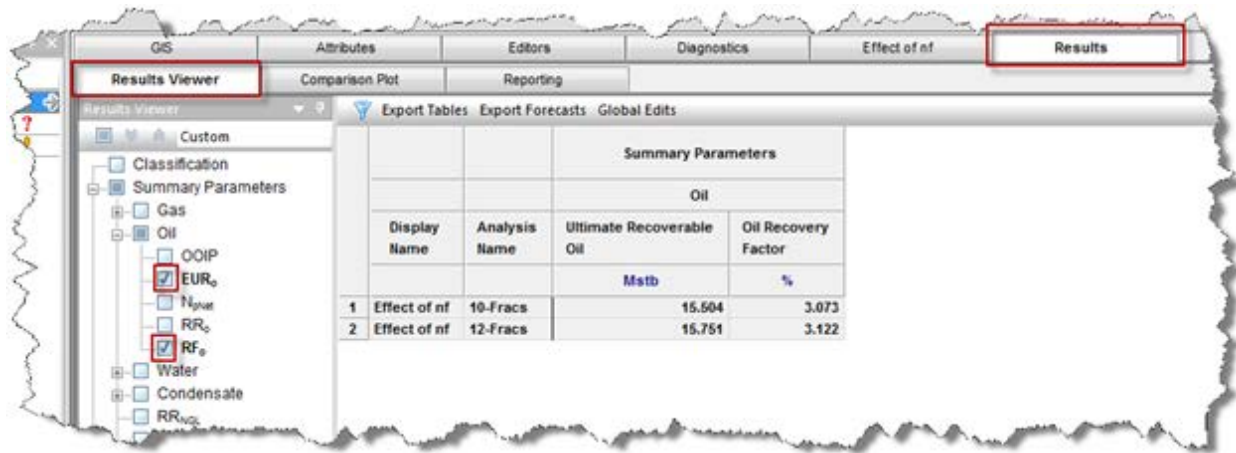
3. Fill in all the Test Design parameters in the same way as the original model.

4. Right-click the analysis tab for both analyses to rename them, so they are easily identified.

5. Compare forecasts for both models using the comparison plot.

   Or, create a Rate Vs. Time analysis, and select the checkboxes to compare both models on a plot.

   The plot below compares forecasts for models with 10 and 12 fractures. This plot illustrates that the model with 12 fractures has higher initial production, but later the rate for the model with 10 fractures becomes higher. Expected ultimate recoveries (EURs) are shown as well.
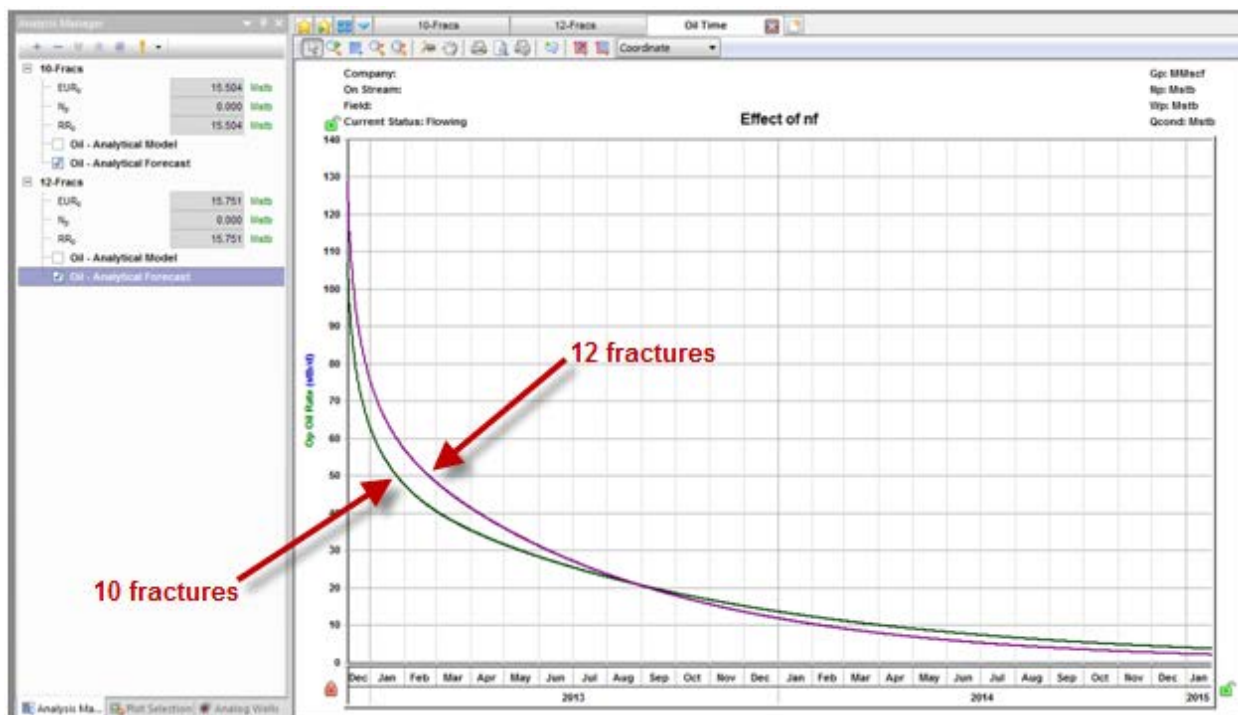
Following the same steps, you can add more models to compare the effect of various parameters.

If you have many models, and want to compare the summary parameters (that is, EUR, or recovery factors), use the Results Viewer.

Advanced analytical options

Advanced analytical options include:

- Accounting for fluid changes
- Anchoring
- Constant-pressure boundaries
- Injection
- Using automatic parameter estimation

Accounting for fluid changes during reservoir depletion in oil analytical models

Fluid properties (such as compressibility, viscosity etc.) depend on pressure; therefore, while a reservoir is being depleted, fluid properties change.

For gas analytical models, pseudo-pressure and pseudo-time are used to account for the change in gas properties.

For oil analytical models, fluid properties are assumed to be constant: properties are estimated at the initial pressure using correlations or tables set in the Properties editor, and these properties are used for calculations throughout the production history and the forecast.

$$B_{oi} = B_o(p_i)$$
$$c_{oi} = c_o(p_i)$$
$$\mu_{oi} = \mu_o(p_i)$$

used for calculations

This assumption is acceptable if the pressure in the reservoir remains above the bubble point, since the variations for under-saturated oil properties with pressure are negligible. However, if the pressure drops below the bubble point, oil properties (in particular – oil compressibility) change significantly.

Oil Compressibility (c_o)

change in c_o when pressure crosses bubble point
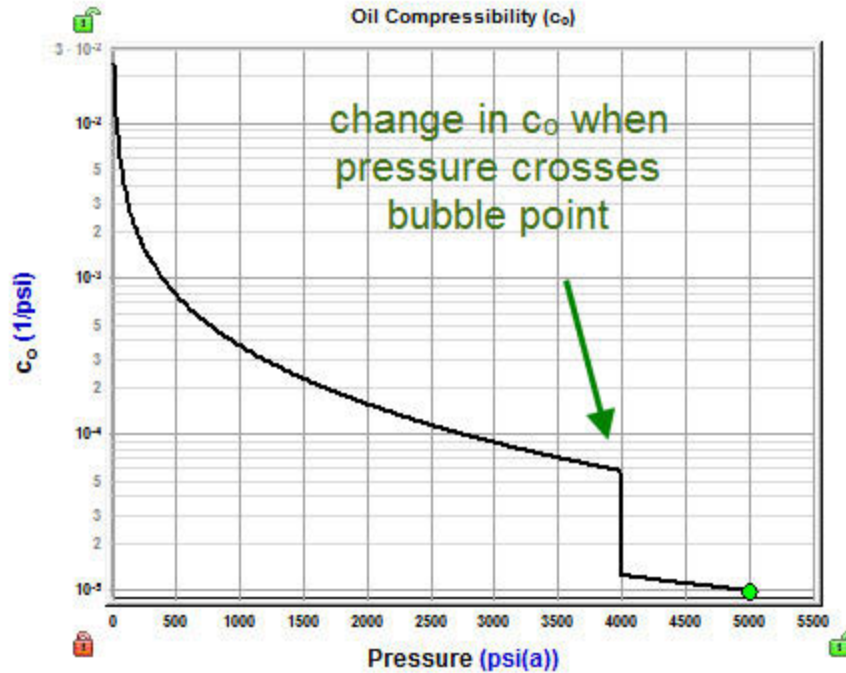
As a result, numerical models are recommended for forecasting in under-saturated oil reservoirs, or for history matching in saturated oil reservoirs. However, analytical models can be used to history match a brief portion of data, such as a buildup, in saturated oil reservoirs because the properties aren't changing significantly during the segment being analyzed. Although oil analytical models do not honor varying oil properties, it is possible to use (constant) oil properties corresponding to the depleted reservoir conditions.

Example: Consider an under-saturated oil reservoir with: p_i = 5000 psi and p_{bp} = 4500 psi.

The well was producing at a constant rate (drawdown) and then was shut in (buildup). During the drawdown, reservoir pressure dropped to 4,400 psi; therefore, during the buildup, the reservoir was filled with saturated oil. As a result, saturated oil properties should be used to history match the buildup.

To do this in an analytical model:

1. Select the **PVT Pressure** option in the Analytical Model pane.

2. Expand the **PVT Pressure** group and set p_{prop} to 4,400 psi.

In this case, the properties used for calculations are evaluated at p_{prop}.

$$B_o = B_o(p_{prop})$$
$$c_o = c_o(p_{prop})$$
$$\mu_o = \mu_o(p_{prop})$$

used for calculations

Note: With this approach, the drawdown portion of the data is not matched. However, matching just the buildup portion of the data is useful, as it helps to estimate current reservoir and completion properties.

Anchoring

Anchoring is a technique for improving the efficiency of the history-matching process when the initial pressure is unknown. You can specify a measured pressure and Harmony Enterprise calculates the initial synthetic pressure, which results in the model's analysis line going through that specified pressure. This specified measured pressure is known as the anchor point.

To add an anchor point, click the **Anchor** icon on the History Plot toolbar of any analytical model.
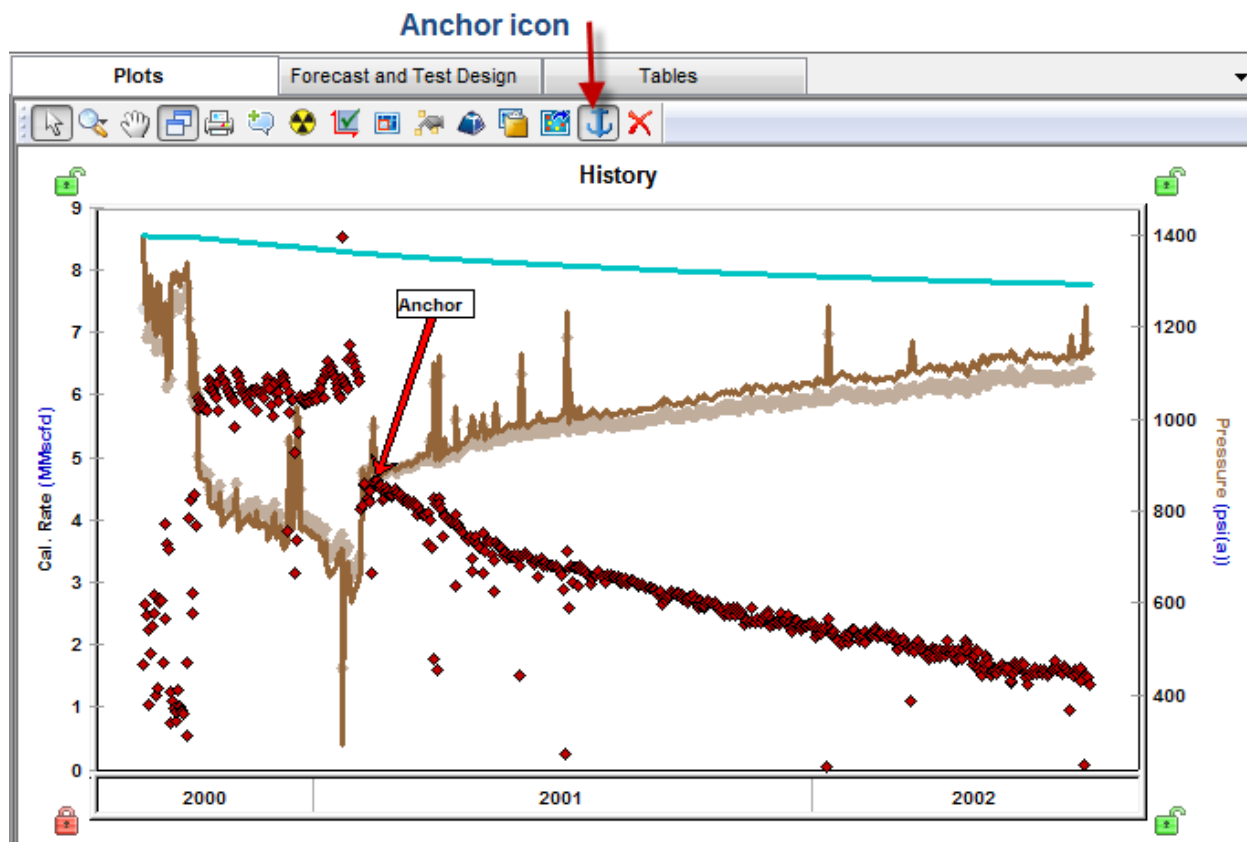
Clicking the Anchor icon automatically places an anchor arrow on the first-measured pressure. In addition, the mouse pointer changes to an anchor, so that you can relocate the anchor from the default position by clicking any measured pressure on the history plot. The anchor point is annotated with an arrow, and if you change the position of the anchor arrow, the model automatically recalculates.

When anchoring is enabled, the initial pressure is calculated and the input cell is read-only. When anchoring is disabled, the initial pressure cell is editable.

Note: The Anchor option is currently only available for analytical models in Calculate Pressure mode.

Constant-pressure boundaries

A constant-pressure boundary is a boundary that provides pressure support, and this kind of boundary can be used to model reservoirs with aquifer support or waterflooding.

You can introduce constant-pressure boundaries for the following analytical models:

- Vertical
- Vertical with fracture
- Horizontal
- General horizontal multifrac

To model constant-pressure boundaries:

1. Expand the **Boundary Type** section in the Analytical Model pane.

   The boundary types for North, West, South, and East boundaries are listed.
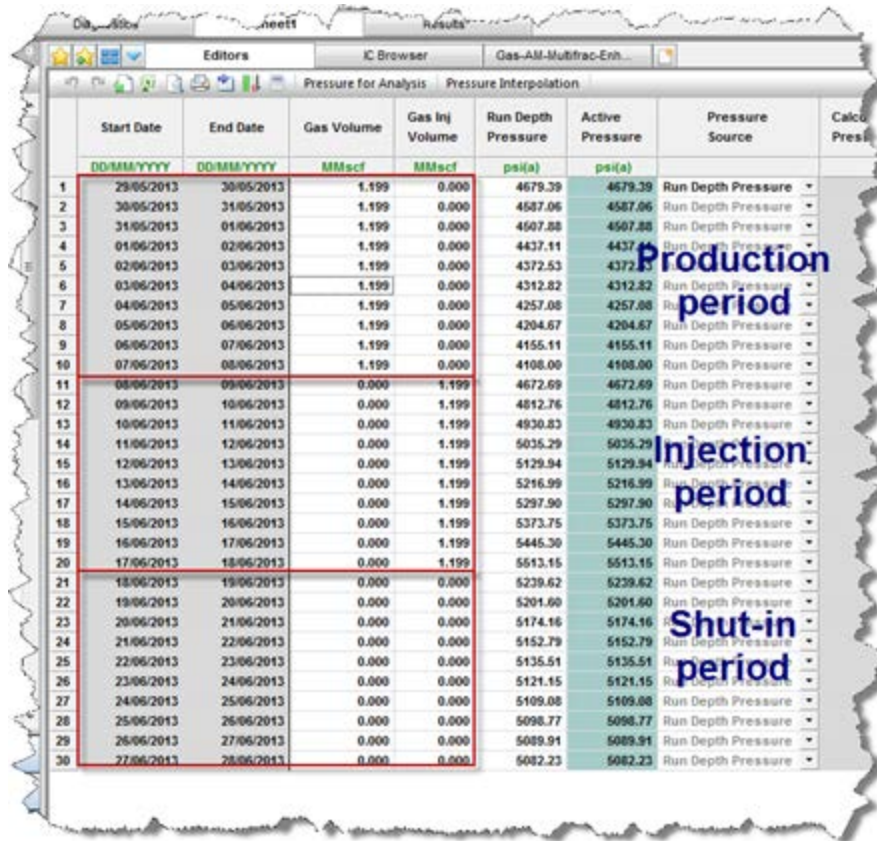
2. Click the drop-down lists to change the boundary type to **Constant Pressure** for any of the boundaries.

3. If you set any of the boundaries to be a constant-pressure boundary, the model schematics and calculations change accordingly. No-flow boundaries are displayed in black, and constant-pressure boundaries are displayed in red.
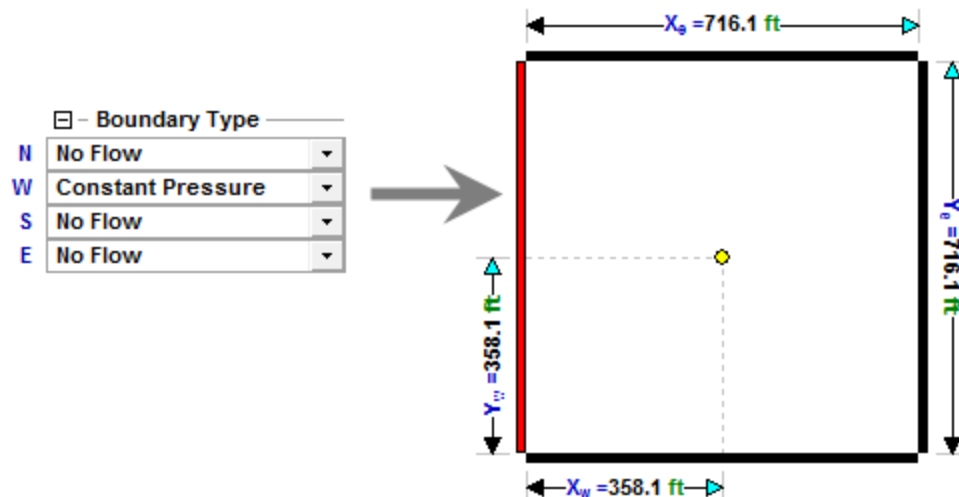
You can switch between boundary types by changing values in the drop-down lists, or by clicking boundaries in the schematics.

Injection

Analytical models can be used to simulate injection. To history match data from a well that has production as well as injection, import both the production and injection data (see get well data into Harmony Enterprise) into the Production editor.

Both production and injection data are honored by the analytical model. If a certain time period has both production and injection data, Harmony Enterprise calculates the difference between the produced and injected volumes, and this calculated net production is used for modeling.

Running forecasts or test designs is similar for injection and production wells, but for injection wells:

- the Allow Injection checkbox must be selected.

- injection rates are denoted using negative values.

Note: Since wellhead forecasting is not yet available for injection, if Wellhead is selected from the Forecast Flowing Pressure drop-down list, the Allow Injection checkbox is grayed-out.

Using automatic parameter estimation

Automatic parameter estimation (APE) is used to perform history matching. The steps to do this are: specify the data points to be used, specify the parameters to vary, and run APE.

Specify data points to be used by APE

By default, all data points are selected to be used by APE, except for the points that were filtered out using the filtering option within one of the analyses you created for that well previously. (Filtering can be performed within FMB, unconventional reservoir, or typecurve analyses.) Filtered-out points are treated as outliers, and are not honored by the APE algorithm. These points are displayed in gray in the History plot.

Additionally, you can deselect more data points by clicking the **Tools to Select Data Points for Best Fitting** icon from the History plot toolbar. (Click to select points, and right-click to deselect points.)

The data points you deselect are not necessarily outliers. They are simply points you do not want to use for history matching in this particular model (for example, if you want to only match the later portion of the production data). Points that are deselected for best fitting are also not honored by the APE algorithm, and are displayed as hollow points (0% weighting) in the History plot.

If it is important to match some specific portion of the data (for example, the last part of the production), you can weight these data points by clicking the **Weight Data Points** icon ( ). Weighted data points are displayed in a brighter color and are given a 100% weighting. (The weighting is displayed when you hover over the data point.)

Specify parameters to vary

To specify which parameters to vary, click the **Automatically calculate variable** checkbox to the right of the parameter's field.
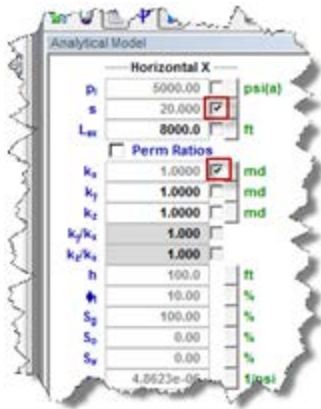
To vary a certain parameter within given limits, click the **View Defaults and Limits** button to the right of the field. Enter the appropriate values, and then click the **Accept** button.

Run APE

To run automatic parameter estimation (APE), click the **APE** icon (⚲).

While APE is running, selected parameters are automatically varied to minimize the error between the simulated pressure and the actual pressure. The updated simulated pressure is shown on the plots right away, and the **Rotating Gear** icon (⚙) on the header of the tab indicates that APE is running.
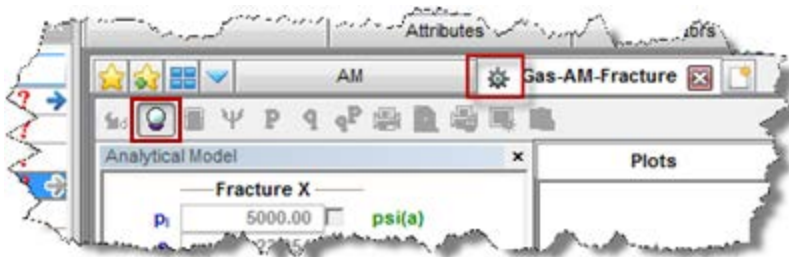
While APE is running, you can wait until it finishes, or if the history match looks good, you can stop the process by clicking the **APE** icon ( ).

After you have achieved your desired result in CalcP mode, we recommend that you switch to CalcR mode and verify if the calculated rate matches the actual rate. If these rates are not close, additional history matching should be done.

Hybrid

The hybrid model is essentially a numerical model, but with certain modifications to significantly reduce computation time, so that it is almost as fast as an analytical model. For more information, see hybrid model theory.

Note: This analysis works with your Harmony Reservoir™ license.

Before you start using the hybrid model, make sure that all required information is added to the Harmony Enterprise project. Well production data (rates and sandface pressures) should be populated in the Production editor, and reservoir and fluid properties should be specified in the Properties editor. When you create a new hybrid model, reservoir properties are automatically applied.

We recommend that you perform an analysis prior to using the hybrid model as a starting point for other model parameters. For example, for conventional wells, a flowing material balance (FMB) gives an estimate for original fluid in-place, and the use of a typecurve analysis provides insight about permeability, skin, reservoir shape / size, and fracture properties. For unconventional wells, an unconventional reservoir analysis can be used to estimate permeability, fracture length, apparent conductivity, and the size of the stimulated reservoir volume.

You can history match your data using two methods (automatic parameter estimation (APE) and synthesize), but there are important differences.
APE — you can select one or more parameters, and the hybrid model keeps the other parameters constant while the parameters being varied are adjusted to reduce the average error between the production history and the model's results.
Synthesize — does not change parameters, but rather all historical data and the parameters in the table are used to run the model. The "match" is what is displayed after the model has been run.
For more information, see the primary toolbar where both of these icons are described.

Hybrid Model pane

In the Hybrid Model pane, enter the required parameters, and select your calculation method. You can use the rates of any of the fluids displayed in the model to calculate rates for the remaining fluids, and the sandface flowing pressure. Or, you can use the sandface flowing pressure to calculate rates for all the fluids displayed in the model.

For information on the hybrid model's options, see underline advanced options.

Important parameter limits

Note that these parameter limits apply:

- k_x, $k_y > 0$

- skin: $-8 \leq s < 200$

- s_{lim} (located within the Chg Skin section): $-8 \leq s_{lim} < 200$

- MinXY / 2 $< X_w < X_e$ - MinXY / 2

- MinXY / 2 $< Y_w < Y_e$ - MinXY / 2

Fluid type selection

With hybrid worksheets, you can select these fluid types based on the fluid behavior you want to simulate:

- **Gas + Immobile Water** — used to create a single-phase model. Only gas flow is modeled in this case; water is considered immobile. If you create a Gas+Immobile Water hybrid model for a liquid-rich gas well, the model is calculated in terms of recombined gas (see recombination).

- **Black Oil** — accounts for gas dissolved in liquid, but does not account for liquid vaporized in gas; therefore, you should not create a Black Oil model for liquid-rich gas wells. Oil and water phases can be turned off within the model.

- **Gas Condensate** — used to create a multiphase model that accounts for liquid vaporized in gas. This model should only be used for liquid-rich gas wells. Condensate and water phases can be turned off within the model.

- **Volatile Oil** — used to create a multiphase model that accounts for liquid vaporized in gas. The water phase can be turned off within the model.

Model geometry

Harmony Enterprise supports the following:

- **Vertical** — this model contains a vertical well located anywhere within a rectangular-shaped homogeneous reservoir.
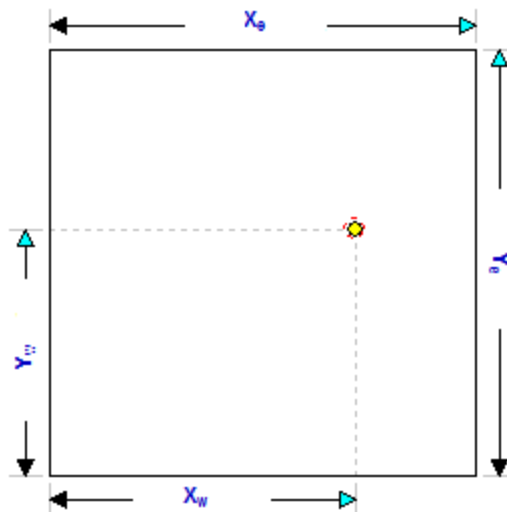
- **Vertical with Fracture** — this model contains a hydraulically fractured vertical well located in the center of a rectangular reservoir. The fracture is surrounded by a symmetrical region of higher permeability.
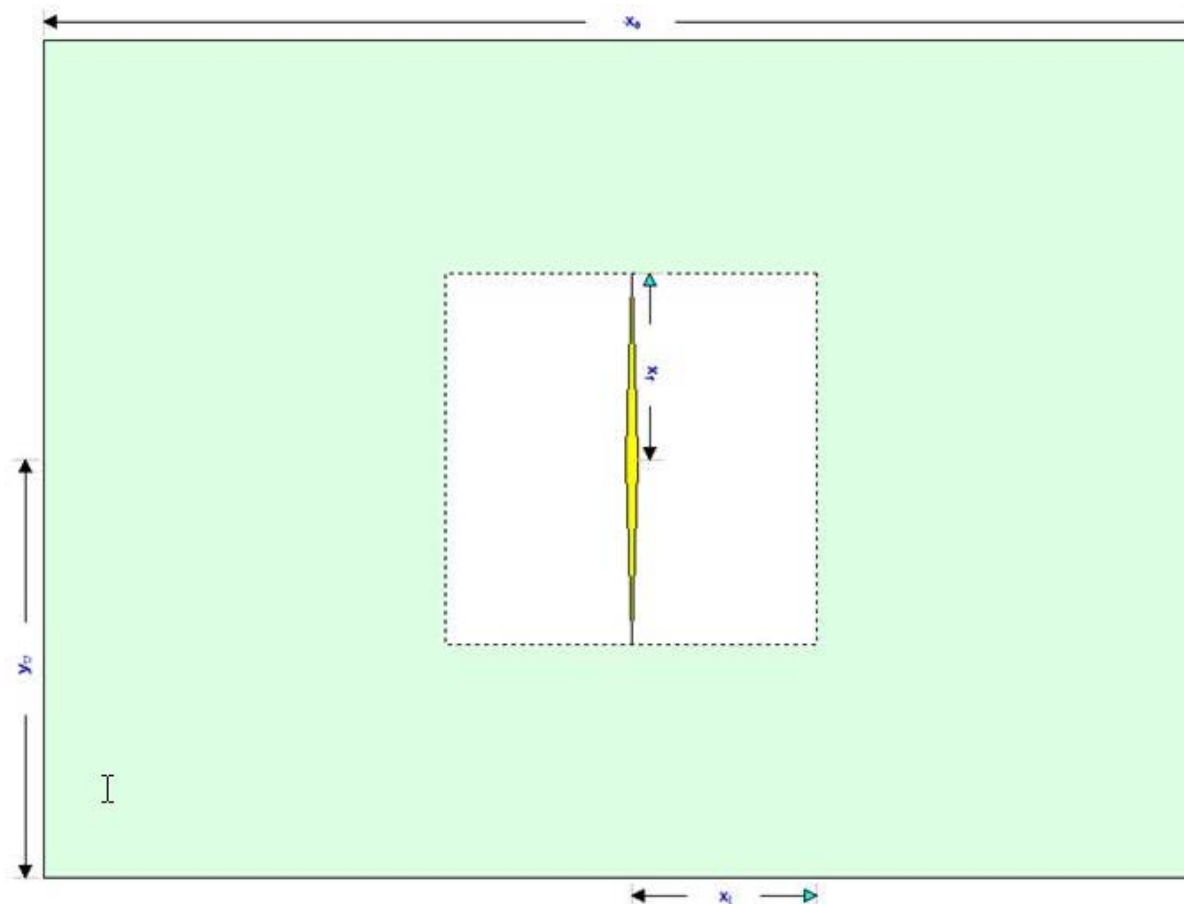
- **Horizontal Multifrac** — this model enables you to specify an enhanced permeability in a region around each fracture. It contains an inactive horizontal well fed by multiple identical, and equally spaced, transverse fractures. The length of the reservoir is defined by the horizontal well. The extent of the enhanced region in the y-direction is defined by the fracture length.
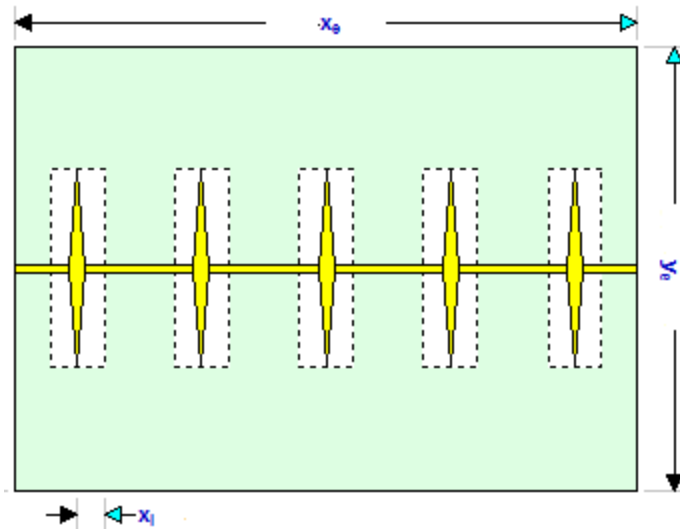
Primary toolbar

There are three toolbars: primary, Plots sub-tab, and Forecast sub-tab.

The primary toolbar has the following icons:

- **Defaults** — copies parameters from the Properties editor or other IHS Reservoir worksheets. If you have any analytical gas horizontal multifrac model created for the same well, we recommend that you use it to populate the hybrid model's parameters.

  Or, if you want to copy only one parameter from an analysis, click the **View Defaults and Limits** button to the right of the field in the Hybrid Model pane.

  Note: Parameters copied from the reservoir or another analysis are displayed in a gray font. This indicates that they match the default. You can type new values for any parameter, or change values for some parameters by moving elements of the schematic. Parameters, which do not match the default, will be shown in a black font.

- **Automatic Parameter Estimation (APE)** — while APE is running, selected parameters are automatically varied to minimize the error between the simulated pressure / rate and the actual pressure / rate depending on the calculation method (rate or pressure calculation method — for additional information, see the hybrid model pane). The updated simulated pressure / rate is shown on the plots while the calculation is running. While APE is running, the icon appears selected. To stop APE, click the icon again and it no longer appears selected. The model remains at the last parameter set and the history matching finishes calculating for the model. For more information, see using APE (same functionality as with the analytical worksheet).

Important: The purpose of history matching is to get the calculated pressures to reproduce actual pressures as closely as possible by changing the model's parameters. You can vary model parameters manually, or use APE.

- **AutoCalc** — recalculates the history match and forecast automatically each time you change model parameters.

- **Synthesize** — if you do not click the AutoCalc icon, you must click this icon every time you want to recalculate the model.

- **Stop Synthesize** — stops the model's synthesize calculations.

- **Use Sparse Production Data** — opens the Use Sparse Production Data dialog box where you specify the number of timesteps for simulation. This enables you to run simulations with a smaller number of timesteps in order to speed up calculation times. Fore more information, see sparse data.

You can replace plots on the right side of the dashboard by clicking the **Add an available view** icons (to the far right of the other icons on the primary toolbar)

- — select a plot to be displayed in the top right corner of your dashboard.

- — select a plot to be displayed in the lower left corner of your dashboard.

Sub-tabs

There are three sub-tabs: Plots, Forecast, and Tables.

Plots

This sub-tab displays a schematic and plot from your well data.

Toolbar

This toolbar has the following important icons:

- **Reset Plot Attributes** — resets your plot attributes to default settings.

- **Picture in Picture** — opens the Zoomed View popup where you can get a closeup view of your datasets.

- **Weight Data Points** — used to emphasize matching to specific data points when using APE (for example, the last part of the production). The cursor changes to a spray

gun when clicked. Weighted data points are displayed in a brighter color and are given a 100% weighting; unweighted points are given a 10% weighting. (The weighting is displayed when you hover over the data point.)

- **Copy** — copies plot data.

- **Hide the Toolbar** — hides the toolbar. If you want the toolbar displayed, right-click the plot and select **Show Toolbar**.

After you click the **Synthesize** icon ( ) in the primary toolbar and the calculations are complete, the icons listed below are enabled in your color-shading plots (vertical, vertical fracture, horizontal, horizontal multifrac). With these playback icons, you can see how pressures or saturations change through time. A schematic for your color-shading plot is displayed as long as you specify reservoir dimensions, and the schematic is updated as you change reservoir parameters (for example, X_e, Y_e). A tooltip displays your value and unit, as well as your cursor's x- and y-position within the model as you hover over your color-shading plot.

- **Skip to Beginning** — resets the display to how things were prior to clicking the Synthesize icon.

- **Step Back One Frame** — view calculations in reverse one frame at a time.

- **Play in Reverse** — view calculations in reverse. You can click this icon multiple times to increase the speed of the playback.

- **Stop** — stops the playback process.

- **Play** — view calculations from start-to-finish. You can click this icon multiple times to increase the speed of the playback.

- **Step Forward One Frame** — view calculations one frame at a time.

- **Skip to End** — shows the last calculation.

For information on common plot icons, see plot toolbars.

As the hybrid model is calculating results, the color-shading plots update every 100 ms. These intervals are maintained in the steps that are available to play as an animation. When a model calculates very quickly, fewer steps are available, resulting in large jumps for the timesteps displayed.

Forecast

This sub-tab has a toolbar, and displays your forecast: options, constraints, and results.

After the model has been populated and calibrated to the production and pressure data through history matching, production forecasts can be created and compared under a variety of different constraints. This can also be used to create a production forecast for wells with no production history.

Toolbar

This toolbar has the same common icons described in plot toolbars.

Forecast options

The Forecast Options section is where forecast periods are defined according to either durations (for example, months), or dates.

- Setting the forecast time method to **Duration** begins a forecast at a specified start date. Forecast periods are then defined in the forecast table according to a length of time (the default is months). For each forecast period, different operating conditions can be specified.

- Setting the forecast time method to **Start Date** creates a forecast of a specified length of time (the default is months). Forecast periods are then defined in the forecast table according to calendar dates.

If you select **Duration** from the Forecast Time Method drop-down menu, the Start Date is automatically populated. (You can change this date later, if needed.)

If you select **Start Date** from the Forecast Time Method drop-down menu, enter a value for Duration (that is, the total length of the forecast).

Further details about each forecast period are entered in the forecast options table.

		Time		Control		Sandface Pressure	
	Step Type	**Duration**	**# of Steps**	**Interpolation Method**	**Control Type**	**Initial**	**Final**
		month				psi(a)	psi(a)
1	Arithmetic ▾	Required	Required	Step ▾	Pressure ▾	1626.85	

Each row of the table above represents a forecast period. An additional forecast period can be added each time an operational change is encountered (for example, the flowing pressure decreases when a compressor is added). To add a row, use the down arrow when the cursor is in a cell of the last existing row.

The forecast options table has the following sections:

- **Time** — defines the length of each forecast period and each timestep, and has the following columns:

  - Step Type — sets the spacing of the timesteps, and can be set to either Arithmetic or Logarithmic. The Arithmetic step type spaces the number of timesteps equally over the total duration of the period, whereas the Logarithmic step type

spaces the number of timesteps logarithmically (that is, increased density near the beginning of the forecast).

- Forecast Time Method (Duration / Start Date) — sets the length of the forecast period. If the Forecast Time Method is set to Duration, this column shows Duration. If the Forecast Time Method is set to Start Date, this column show Start Date.

- # of Steps — sets the number of timesteps in the forecast period.

- **Control** — defines how the operating conditions change over the forecast period, and has the following columns:

  - Interpolation — can be set to either Step or Ramp. "Step" keeps the control type constant over the forecast period. "Ramp" varies the control type linearly from an initial value to a final value.

  - Control Type — sets what is used to calculate the forecast. For the hybrid model, the forecast can be run using either flowing pressure, or one of the rates being analyzed.

- **Sandface Pressure** — if the Control Type is set to Pressure, this column is displayed, and it is used to set the flowing pressure for the forecast period. If Interpolation is set to Step, only the initial pressure cell is editable. If Interpolation is set to Ramp, initial pressure and final pressure are selectable.

- **\<Fluid\> Rate** — if the Control Type is set to a \<Fluid\> Rate, this column is displayed, and it is used to set the rate for the forecast period. If Interpolation is set to Step, only the initial rate's cell is editable. If Interpolation is set to Ramp, initial rate and final rate are editable.

Forecast constraints

The Forecast Constraints section is where maximum rate conditions and abandonment rate conditions for the forecast can be entered. Available constraints include the following:

- p_{min} — the minimum allowable sandface flowing pressure during the forecast. In order to ensure flowing pressure does not go below this value, rates are adjusted.

- $(q_g)_{max}$ — sets a maximum fluid rate during the forecast. In order to maintain the maximum fluid rate constraint, flowing pressure is adjusted.

- $(q_g)_{ab}$ — sets the abandonment fluid rate for the forecast. When the abandonment rate is reached, the forecast ends.

Forecast results

The Forecast Results section is where the results of the forecast are summarized. Available results depend on the analysis type, and could include the following:

- EUR — expected ultimate recovery.

  Note: For wells with historical data, EUR is defined as the cumulative of the historical data up to the beginning of the forecast, after which time, the synthetic cumulative calculated from the model is used until the end of the forecast.

- RR — remaining recoverable.

Tables

The sub-tab displays your history match (after you use the synthesize or APE functionality) and forecast data (after you populate all the required values in the Forecast tab) in a tabular format.

Note: The single-phase model (Gas + Immobile Water) is the only model that displays the Blasingame plot on the dashboard. This plot is created using the gas analytical model with identical input parameters. (To generate a Blasingame plot for the horizontal multifrac hybrid model, Harmony uses a gas analytical enhanced frac region model. To generate a Blasingame plot for the vertical hybrid model, Harmony Enterprise uses a gas analytical vertical model.)

For more information, see tables.

Advanced hybrid model options

Advanced hybrid model options include:

- Adsorption

- Geomechanical

- Refracturing

- Changing skin

- Sparse data

- Adjusting gridding

Note: Automatic parameter estimation (APE) works the same way as with the analytical analysis. For more information, see using APE.

Adsorption option

To include the effect of adsorbed gas, click the **Adsorption** checkbox in the Hybrid Model pane. Note that this option cannot be used for models that include oil or condensate.

For more information, see Langmuir isotherm.

Geomechanical option

To include the effects of changing formation compressibility and permeability related to reservoir pressure, click the **Geomechanical** checkbox in the Hybrid Model pane.

For more information, see geomechanical reservoir models.

Refracturing option

Horizontal multi-fractured wells are sometimes refractured after a few years of production. This is done to access new areas of the reservoir, and therefore increase production.

To use this feature, select the **Refrac** checkbox in the Hybrid Model pane and set your refracturing date (t_{Refrac})

You can select either of these types of refracturing:

1. **Fracture Extension** — in this model, existing fractures are being extended.

Fracture Extension Schematic
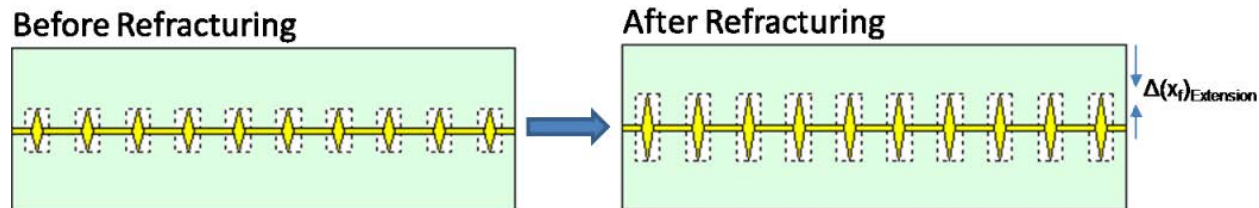
2. **Additional Fractures** — in this model, new fractures are being added in the middle, between existing fractures.

Additional Fractures Schematic
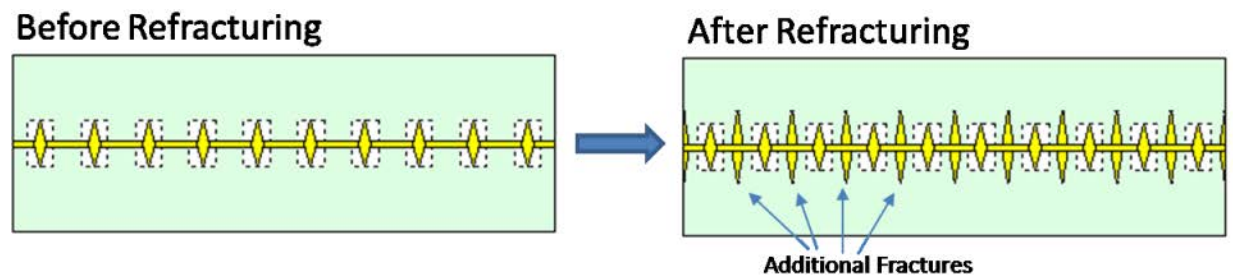
Make sure to set the required parameters.

- **Fracture Extension** model:

  - $\Delta(x_f)_{Extension}$ — after refracturing, the fracture half-length becomes this much longer.

  - $(k_{SRV})_{Extension}$ — the permeability of the stimulated region around the fractures *after* refracturing.

    Note that after refracturing, the x-dimension of the stimulated region remains unchanged, and the y-dimension increases, such that it is equal to a new fracture length.

- **Additional Fractures** model:

  - $(x_f)_{Additional}$ — the fracture half-length for additional fractures.

  - $(X_I)_{Additional}$ — defines the x-dimension of the stimulated region around the additional fractures.

  - $(k_{SRV})_{Additional}$ — the permeability of the stimulated region around the additional fractures.

    Note that if the stimulated regions around the *original* fractures overlap with the stimulated regions around the *additional* fractures, permeability in the overlapping area is the maximum of k_{SRV} and $(k_{SRV})_{Additional}$.

Changing skin option

To include changing wellbore skin at specific points in time, click the **Chg Skin** checkbox in the Hybrid Model pane.

For more information, see time-dependent skin.

Sparse data option

When using sparse data, the hybrid model uses coarse timesteps for calculations, and each coarse timestep contains n points.

Note: We recommend using sparse production data when running automatic parameter estimation (APE).

After you enter a value for **n** in the Use Sparse Production Data dialog box (opens when you click the **Use Sparse Data** icon ( ) on the Hybrid Model pane's toolbar), the history plot displays a new sparse set of production data to be used for calculations:

- Sparse rate data is displayed as thin lines (red for gas, green for oil or condensate, blue for water)
- Sparse flowing pressure is displayed as a thin brown line

To ensure that the sparse dataset represents the actual production history, adjust the value for n, as required.

Click the **Synthesize** icon ( ) to run the model. Note that the calculated results correspond to coarse timesteps.

If you run APE, each calculation runs using coarse timesteps based on your n value.

Note: Your weighting and point selection are honored when running APE using sparse data.

While calculation results are slightly less accurate, the calculations run faster. After APE finds a match using sparse data, you can run one calculation using the entire production dataset (n = 1) to ensure that the match is still good.
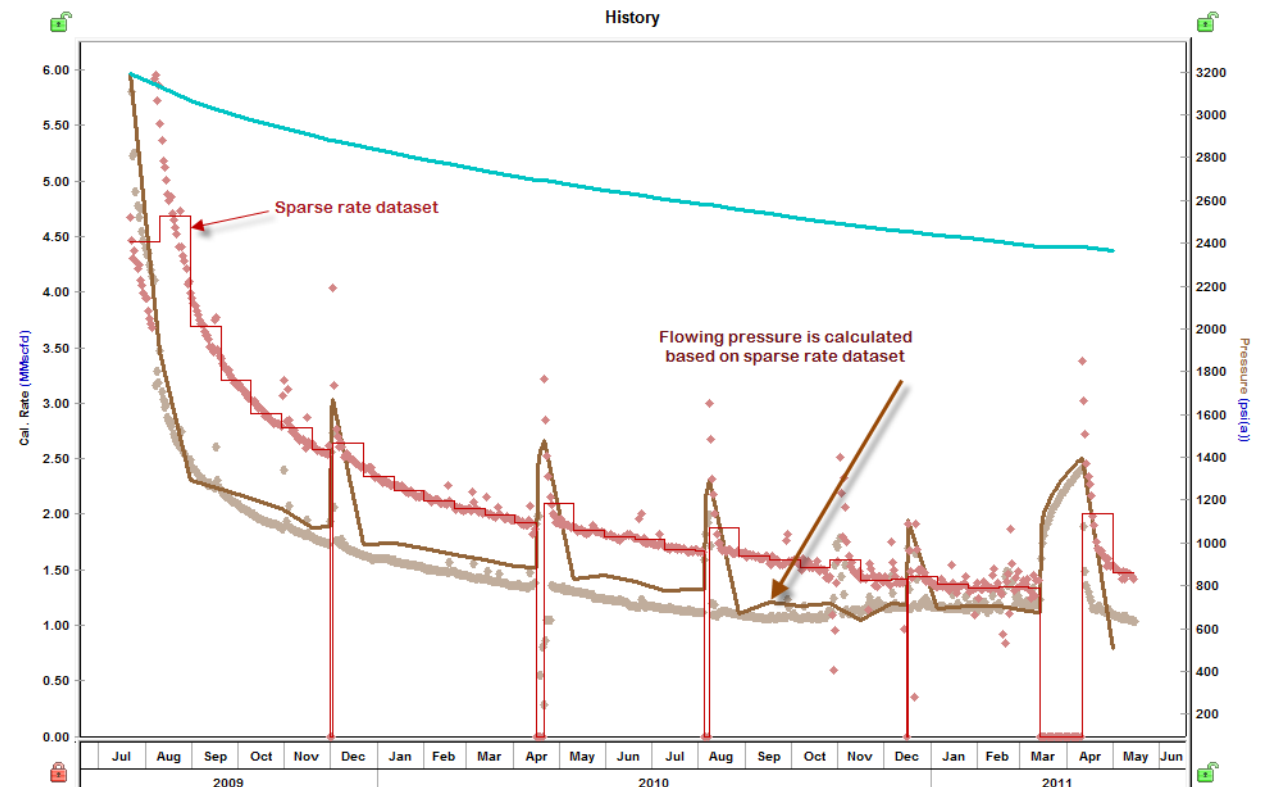
How sparse datasets are calculated

For Use Rate mode: Drawdowns are divided in coarse timesteps. Coarse timesteps contain n points, and the rate for each timestep is calculated as "total volume produced over the timestep" / "duration of the timestep". For buildups, all of the production data is used.

For Use Pressure mode: Drawdowns are divided in coarse timesteps. Coarse timesteps contain n points, and the pressure for each timestep is calculated as "last-measured pressure of the timestep". For buildups, all of the production data is used.

Tip: You can select a rate or pressure in the Calculation Method section.

Adjusting gridding

After you set your reservoir and completion dimensions, Harmony Enterprise creates an appropriate grid for the model to get accurate results with minimal calculation time. The default gridding settings work well most of the time, but in some cases, you may want to adjust the gridding options by clicking the **Options** tab in the Hybrid Model pane.
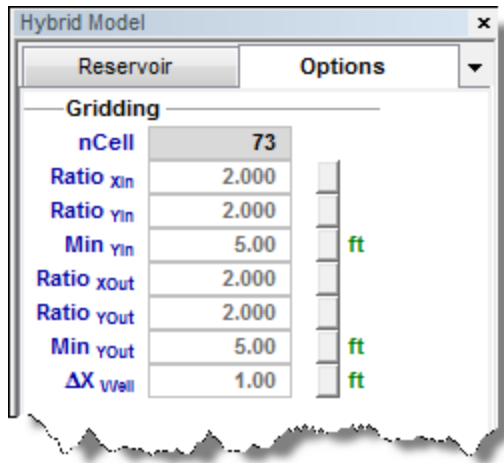
The figure below is a schematic of a model's grid for one quarter of a fracture stage.

- The *inner* zone has geometric gridding. The smallest cell in the inner zone is the cell containing the wellbore. Its dimensions are given by ΔX_{Well} and Min_{Yin}. The geometric ratio for the x-dimensions of the grid cells is set by Ratio X_{in} and the geometric ratio for the y-dimensions of grid cells is set by Ratio Y_{in}.

- The *outer* zones have geometric gridding. The smallest cell in the outer zones have dimensions given by ΔX_{Well} and Min_{YOut}. The geometric ratio for the x-dimensions of grid cells is set by Ratio $_{XOut}$ and the geometric ratio for y-dimensions of grid cells is set by Ratio $_{YOut}$.

- The *nCell* field displays the total number of grid cells used to model one quarter of a fracture stage. This number is important because it directly affects the model's calculation time. This field is populated after you run your model calculations.
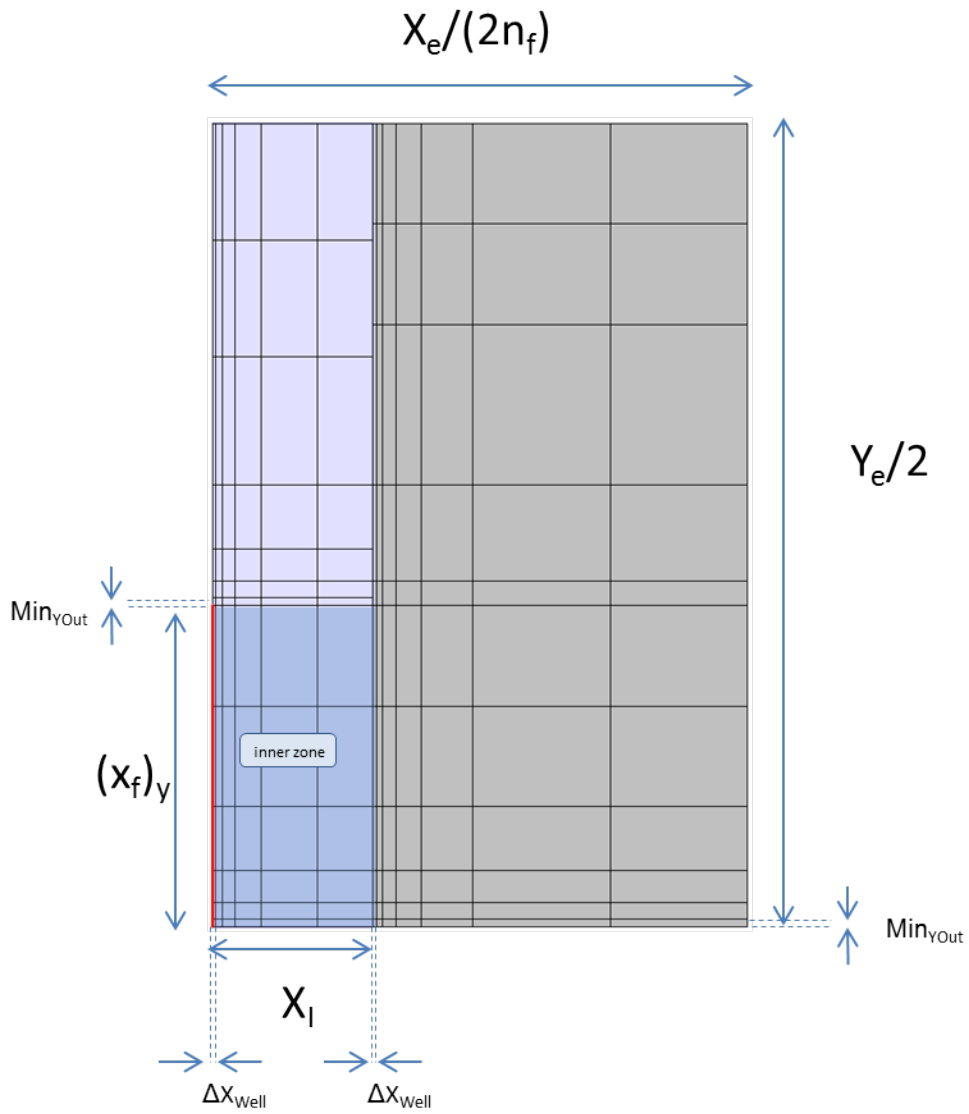
Probabilistic analysis

A probabilistic analysis works by repeatedly running a hybrid model to generate a range of forecasts. For each run, the values for the majority of the parameters are taken from the base hybrid model, and values for parameters that are uncertain, are drawn from given distributions. As a result, you get a range of forecasts and a distribution for values of expected ultimate recovery (EUR).

Note: This analysis works with your IHS Reservoir™ license.

A probabilistic analysis can be run on any hybrid analysis with valid parameters and a forecast.

If values for some of a hybrid model's parameters are uncertain, but you have some idea about their range and distribution, you can use a probabilistic analysis to account for this uncertainty.
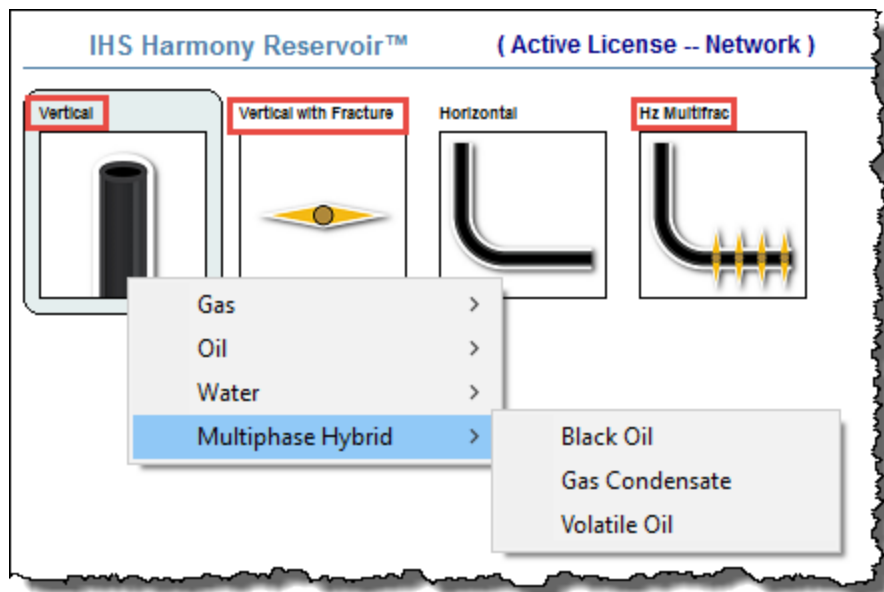
A probabilistic analysis has three tabs: Setup, Dependencies, and Results.

Setup tab

This tab contains parameters for the probabilistic analysis, and cards where you can define the distributions for parameters.

To indicate that a parameter's value is uncertain, click the **Add Parameters** icon ( ), and select the parameter from the drop-down list. A distribution card is added to this tab where you can define the distribution to be used for this parameter.

Number of runs

Probabilistic simulation may take a long time, especially if the number of runs is high.

You can set your number of hybrid-model runs in the simulation as follows:

- **Auto** — automatically detects when the P50 forecast has converged, and is no longer changing significantly with additional runs. We recommend using this setting because it can drastically reduce the number of runs required to achieve a good result.

- **Specific number** — runs the number of runs you specify.

Run simulation

After you add and set up distribution cards for all your uncertain parameters, click the **Run Simulation** button to start your simulation.
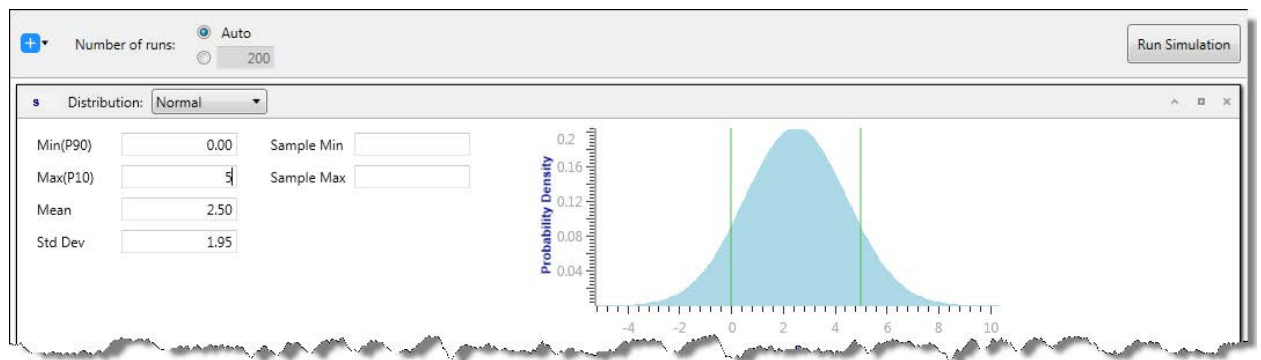
Distribution cards

After you add distribution cards for your uncertain parameters, you can select one of these distribution types: normal, log-normal, triangular, or uniform. For more information, see the descriptions below and probabilistic theory.

With some parameters, you can select automatic parameter estimation (**APE**) from the **Distribution** drop-down list. For more information, see APE.

Normal

By selecting Normal, you can apply a normal distribution to a particular parameter by entering a mean and variance, or a Min (P90) and Max (P10).
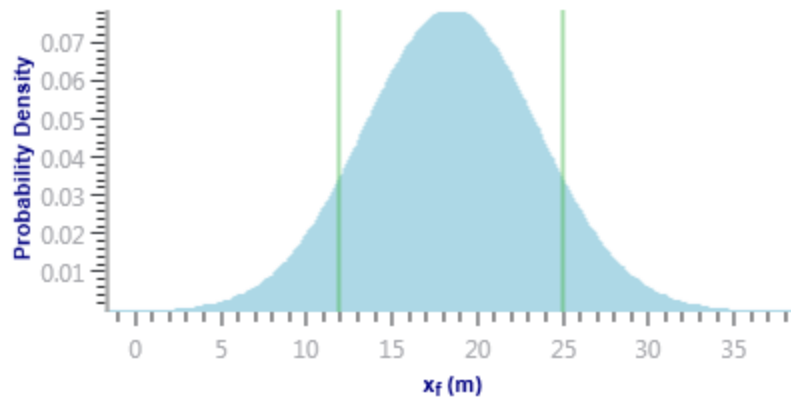
Additionally, you can enter a Sample Min and Sample Max for a normal distribution. In this case, the distribution is truncated, and the probability function is adjusted such that the total probability still sums up to 100%. For more information, see truncated distributions.

Log-Normal

By selecting Log-Normal, you can apply a log-normal distribution to a particular parameter by entering a mean and variance, or a Min (P90) and Max (P10).
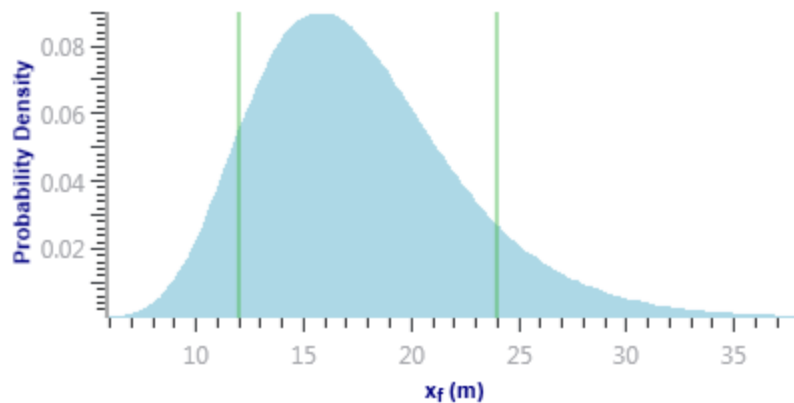
Additionally, you can enter a Sample Min and Sample Max for a log-normal distribution. In this case, the distribution is truncated, and the probability function is adjusted such that the total probability still sums up to 100%. For more information, see truncated distributions.

Triangular

By selecting Triangular, you can apply a triangular distribution to a particular parameter by entering a minimum, mode, and maximum. The minimum and maximum values define the extent to which the probability density is equal to zero. The mode defines the peak.
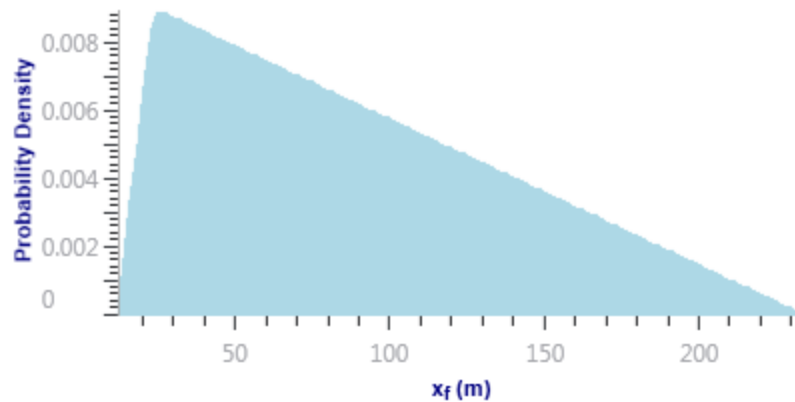
Uniform

By selecting Uniform, you can apply a uniform distribution to a particular parameter by entering a minimum and maximum.
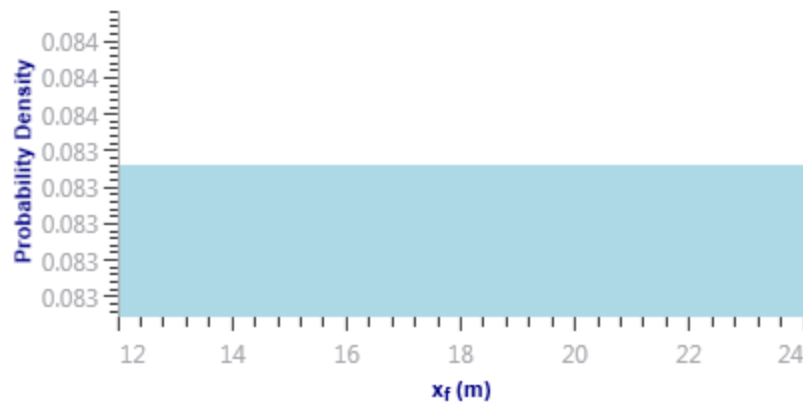
APE

In a typical scenario, you would run probabilistic analysis for a hybrid model that matches historical data. However, after you change the values for uncertain parameters based on a given distribution, the history match is likely to get spoiled. You may want to adjust some other parameters to restore the match. To do this, set the distribution for those additional parameters to APE.

APE iteratively varies the value of a parameter and attempts to minimize the total error between the measured data and the simulated values. When the model uses a rate to calculate pressure, it minimizes the difference between the simulated and measured pressures. When the model uses pressure to calculate rates, it minimizes the difference between the measured and simulated primary fluid rate. Only the primary fluid rate match is minimized.

For each probabilistic run, the best match that APE could find is used to generate a forecast. There is no filtering of these results based on the quality of the match found by APE.

Example:

Assume you have a base hybrid model that matches historical data, and this model has x_f = 120 ft. In reality, you are not certain if the value of x_f is indeed 120 ft, but based on the available information, you can confidently assume that x_f is varying between 80 ft and 160 ft, and can set the distribution for x_f to Normal.

For each run within the probabilistic analysis, Harmony Enterprise picks a value for x_f based on the given distribution. Simply changing the value for x_f results in runs that do not match the historical data.

To mitigate this problem, set the distribution for k_{SRV} and/or k_{matrix} to APE. In this case, for each run within the probabilistic analysis, Harmony Enterprise picks x_f based on the given distribution, and then runs APE on k_{SRV} and/or k_{matrix} (keeping x_f at the value drawn from the given distribution).

Using APE for some of the model's parameters ensures that all probabilistic runs match historical data as closely as possible. However, it is important to keep in mind that when using APE, each probabilistic run requires many runs of the hybrid model; therefore, the overall simulation time increases significantly.

When running APE on a certain parameter, you can set user-defined limits for it by clicking the **View Defaults and Limits** button (⬚) to the right of the parameter in the base model.

Dependencies tab

After values are sampled during simulation, they are displayed in this tab where relationships between any of the uncertain parameters can be entered. For example, if you know that the porosity and permeability in the reservoir are proportional, a correlation coefficient can be entered to represent this relationship. These values must be between -1 and 1, and must be entered in the field that intersects the two desired variables.

	p_i	k_{inner}	ϕ_t
p_i	1		
k_{inner}		1	1.000
ϕ_t		1.000	1

The lower plot displays a cross-plot for the variables you select in the above table.
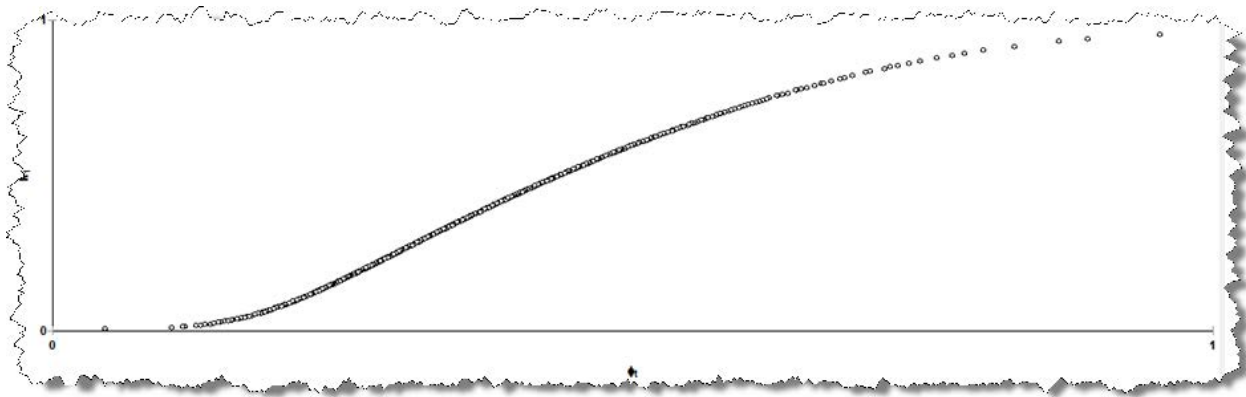
If you set up more than two parameters in the Setup tab, correlation coefficients between each pair of parameters are not independent. After you enter the correlation coefficients, a **Correct the matrix** button appears. Click this button to adjust the coefficients you enter, such that the coefficients for each pair become consistent.

Before

	x_f	k_{matrix}	c_f
x_f	1	1.000	
k_{matrix}	1.000	1	0.200
c_f		0.200	1

After

	x_f	k_{matrix}	c_f
x_f	1	0.980	0.002
k_{matrix}	0.980	1	0.197
c_f	0.002	0.197	1

Results tab

In this tab, a dashboard view is displayed.
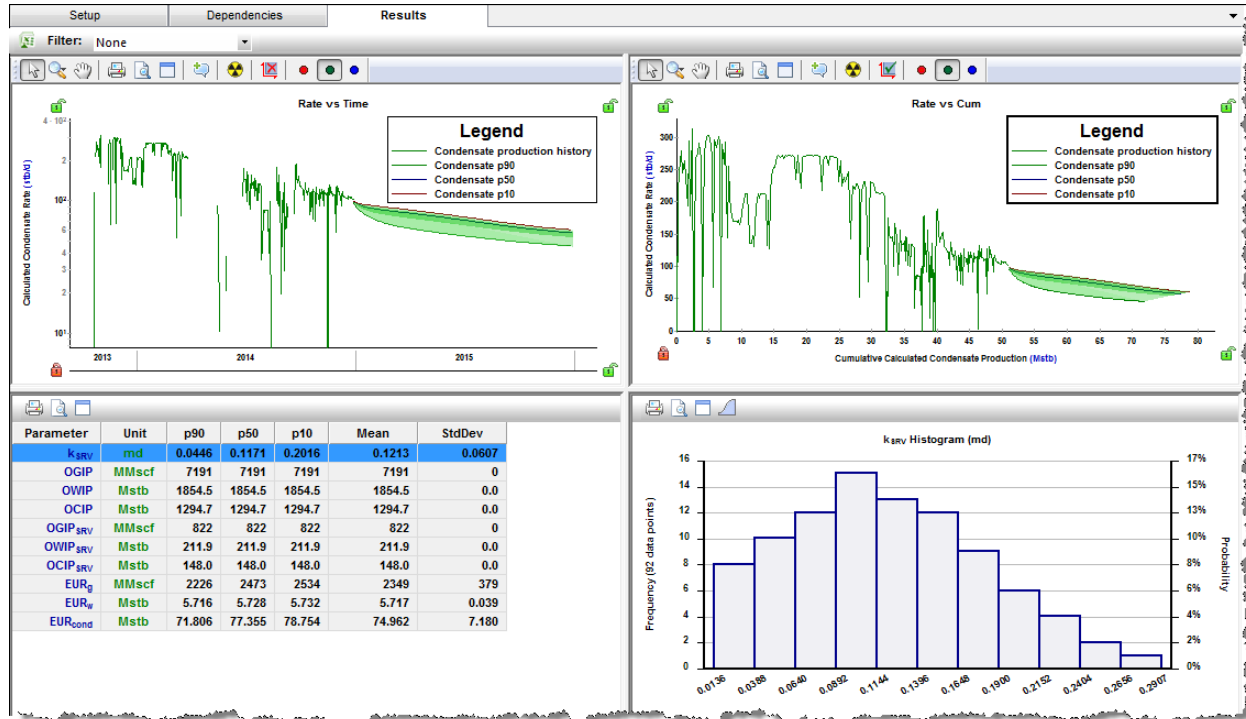
After your simulation runs are complete, you can export your data to Excel by clicking the **Export Data** icon ().

To take the varied parameters from the first probabilistic run and populate them in the base model in the Hybrid Model pane, click the icon.

> **Tip:** If you see a warning that the "Source model changed", you may need to re-run the simulation on the Setup tab, or the base hybrid model to clear the warning. The base model can get out-of-date when auto-calculate is deselected (see AutoCalc) and you make changes to parameters (that is, the results become out-of-date).

Filter — you can filter the cases / runs used in determining the P90, P50, and P10 based on a cut-off for the average error (E_{avg}) of each run. Therefore, in every model's run, an average error is determined: it is the average of the error between each measured data point and the synthetic one calculated by the model at that point. The average error is intended to give a sense of the quality of a match. This is true of any hybrid or analytical model, as well as the runs calculated for the probabilistic cases. When you are viewing the variation of forecast outcomes based on a range of model parameters, it is

useful to be able to exclude any randomly selected parameter sets in the defined range that produce a "bad" match. Above the Rate vs Time plot, there is a drop-down list. By selecting **Add Filter**, you can type in a value for the error cut-off (*between 0 and 1*). Or you can select the default value of **None** (1.5 times the average of all the E_{avg} values from the probabilistic runs). When you type a value (instead of selecting the default None setting), all the table results and forecast ranges displayed only include runs that have an E_{avg} below this value.

Tip: Any E_{avg} cut-offs you enter are saved within your current session, but are not saved to the database.

By default, these views are displayed from the upper left to lower right:

- Rate vs Time — your historical data, range of generated forecasts (displayed as shaded areas), P90, P50, and P10 forecasts (see percentile calculations) are displayed. Data is displayed with rate on the y-axis and time on the x-axis. For multiphase cases, you can switch between available fluids by clicking one of the **Show Fluid** icons ( ).

- Rate vs Cumulative — your historical data, along with range of generated forecasts (displayed as shaded areas), P90, P50, and P10 forecasts (see percentile calculations) are displayed. Data is displayed with rate on the y-axis and cumulative production on the x-axis. For multiphase cases, you can switch between available fluids by clicking one of the **Show Fluid** icons ( ).

- Summary table — your parameters are displayed in a summary table.

- Parameter Distribution plot — when you select a parameter in the summary table, the lower-right plot displays the probability distribution for the selected parameter. You can display the distribution as either a Histogram or a cumulative distribution function (CDF). Toggle the **Switch Plot** icon (/) to switch between these two plots.

  - A histogram is a graphical representation of a distribution of data. It is an estimate of the probability distribution of a variable. The dataset is split up into bins (ranges) on the x-axis, and the y-axis plots the frequency at which the data falls in each bin. Only one result variable can be plotted on a histogram at a time.
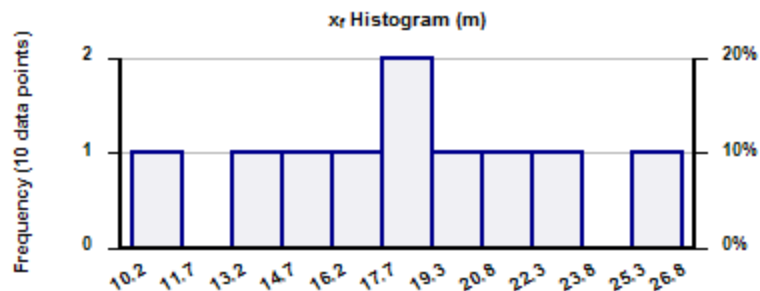
- A CDF calculates the probability that a random variable with a given probability distribution is found at a value less than or equal to "x". Only one result variable can be plotted on a CDF plot at a time. The black horizontal lines originating at cumulative frequencies of 10%, 50%, and 90% intersect the CDF curve, and then line up with the P90, P50, and P10 values of that dataset, respectively.
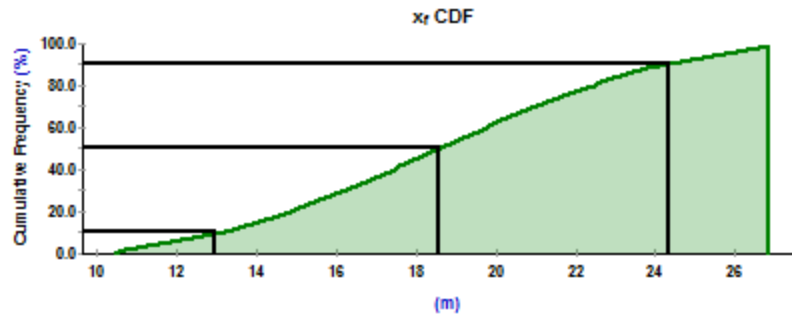
Displaying results

After the probabilistic simulation is complete, Harmony Enterprise creates P10, P50, and P90 forecasts based on all the successful runs within the probabilistic simulation. Remaining recoverable (RR) volumes and EUR volumes are calculated for these forecasts. For more information on calculations, see percentile calculations.

In some regards, P10, P50, and P90 forecasts (also called percentile forecasts) can be treated as separate analyses in Harmony Enterprise. For example, you can:

- View percentile forecasts in the Analysis Manager. You can toggle these forecasts on or off by clicking their checkboxes in the tree structure.

- Display percentile forecasts on decline plots. Toggling a percentile forecast on in the Analysis Manager displays the forecast in the decline plot.
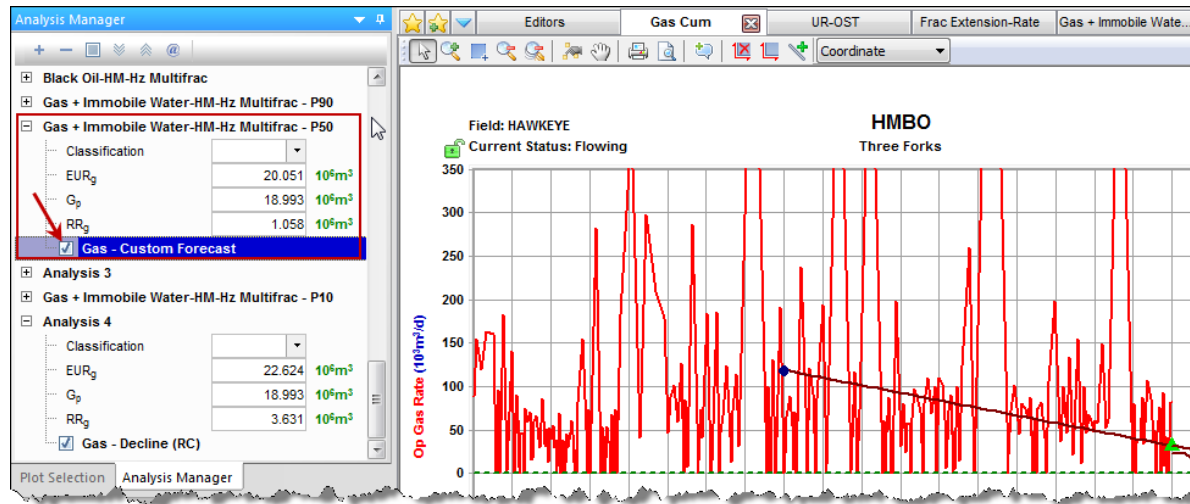
- Fit the decline analysis to match the percentile forecast. In the Analysis Parameters toolbar, you can click the **Fit Decline to Forecast and Selected Production Points** icon ( ) to fit the decline analysis to your percentile forecast.

- Display RR and EUR for percentile forecasts in the Results Viewer.

	Display Name	Analysis Name	Summary Parameters	
			Gas	
			EUR$_g$	RR$_g$
			MMscf	MMscf
1	HMBO	Hybrid Model	391	4
2	HMBO	Hybrid Model - P10	428	41
3	HMBO	Hybrid Model - P50	408	21
4	HMBO	Hybrid Model - P90	391	4

Percentile calculations for input parameters, forecasts & EURs

After the probabilistic analysis is run, and all the runs are completed, Harmony Enterprise generates percentiles (P10, P50, P90) for input parameters, percentile forecasts, and percentile expected ultimate recovery (EUR) volumes. Details about these calculations are given below.

Percentile (P10, P50, and P90) input parameters and OFIPs

Input parameters and original fluid-in-place (OFIP) values are calculated using the following steps:

1. Consider all the successful runs generated by the probabilistic analysis.

2. Calculate P10 for a certain input parameter as a P10 percentile of values for this parameter for all successful runs. (Do the same thing for the P50 and P90 values.)

3. Calculate P10-OFIP as a P10 percentile of values for OFIP for all successful runs. (Do the same for the P50 and P90 OFIPs.)

Percentile (P10, P50, and P90) forecasts

These forecasts are calculated using the following steps:

1. Consider all the successful runs generated by the probabilistic analysis.

2. At each timestep, calculate a P10-rate as a P10 percentile of rates at this timestep for all successful runs. (Do the same for P50 and P90 rates.)

3. Calculate a P10 forecast by combining all the rates calculated in step 2. (Do the same for the P50 and P90 forecasts.)

Note: Percentile forecasts do not correspond to any of the runs generated by the probabilistic analysis. Therefore, there is no combination of input parameters that results in a forecast that is equal to the percentile forecast.

Percentile (P10, P50, and P90) EURs

EURs are calculated using the following steps:

1. Calculate P10, P50, and P90 remaining recoverable (RR) volumes by summing up production based on P10, P50, and P90 forecasts.

2. Calculate P10, P50, and P90 EURs as:

- P10 EUR = Historical cumulative production + P10 RR

- P50 EUR = Historical cumulative production + P50 RR

- P90 EUR = Historical cumulative production + P90 RR

Note: The P10 EUR calculation shown above is *not the same* as considering EUR values for all the successful runs generated by a probabilistic analysis and calculating a P10 percentile among them. (This is also true for P50 and P90 EURs.)

Tips: speeding up the probabilistic analysis

With the probabilistic analysis, the hybrid model is run multiples times; therefore, the simulation may take significant time. Below are few tips to make the probabilistic analysis run faster.

Base hybrid model

Before setting up and running a probabilistic analysis, ensure that the base hybrid model is in a good shape:

- The base model should match historical data reasonably well, and the simulation time for the base model should not be too long.

- If you are planning to use automatic parameter estimation (APE) within the probabilistic analysis, test APE on the same parameters for the base model *first*. Make sure you deselect outliers, and set user-defined limits for those parameters, if required.

- Consider using the sparse data option to speed up the base model. If this option increases speed and retains acceptable accuracy for the base hybrid model, you can use it for the probabilistic analysis as well.

- Consider adjusting gridding to speed up the base model. If this option increases speed and retains acceptable accuracy for the base hybrid model, you can use it for the probabilistic analysis as well.

APE

If some of the uncertain parameters are set to APE, the probabilistic analysis requires more hybrid model runs, and therefore takes longer time. In many cases, it is required to have at least some of the model parameters varied by APE to achieve a history match for each probabilistic run. However, we recommend that you keep the number of such parameters to a minimum (one or two).

Changes that affect properties

Due to the way the hybrid model uses properties, calculations can require additional time whenever properties change. Therefore, we recommend to *not* include the following parameters in the list of uncertain parameters:

- p_I (initial reservoir pressure)

- γ (permeability module under the Geomechanical group)

- Fluid saturations

- c_f (formation compressibility)

- ϕ_t (porosity)

- h (net pay)

Multi-well model

There are two types of multi-well model:

- Conventional
- Unconventional (beta)

Conventional multi-well model

With the conventional multi-well model, you can simulate multiple wells using the *group* hybrid model to history-match producing wells and forecast future production.

Note: This model works with your Harmony Reservoir™ license.

Before you start using the multi-well model, make sure that all required information is added to the Harmony Enterprise project:

- Populate sandface locations for each well in the Attributes tab.

- Populate well production data (rates and sandface pressures) in the Production editor for each well in the group.

- Specify reservoir and fluid properties in the Properties editor of the group. When you create a new multi-well model, group reservoir properties are automatically applied.

- Populating wellbore information (such as, a deviation survey, completion, and perforation data) is not required. However, we recommend populating this information because it helps to initiate the multi-well model with correct default settings.

We recommend that you perform analyses and/or modeling for individual wells prior to using the multi-well model. You can bring parameters from individual well analyses as a starting point for the multi-well model. Additionally, you can perform certain group analyses. For example, a flowing material balance (FMB) performed on the group gives an estimate for original fluid in-place for the reservoir.

The tab for this analysis has a parameters input pane and a dashboard with four plots. For more information, see dashboard.

Model geometry

This analysis currently supports vertical and horizontal wells. Wells are placed in the reservoir according to their actual locations (specified by sandface lat / long in the Attributes tab). Length and direction of horizontal wellbores are drawn according to L_e and Azimuth parameters. Reservoir boundaries default to 1,320 ft (a 1/4 section) from the outermost wells. These boundaries can be adjusted using the ⬚ and ⬚ icons. For more information, see the Schematic plot toolbar description.

This is a reservoir with well regions:
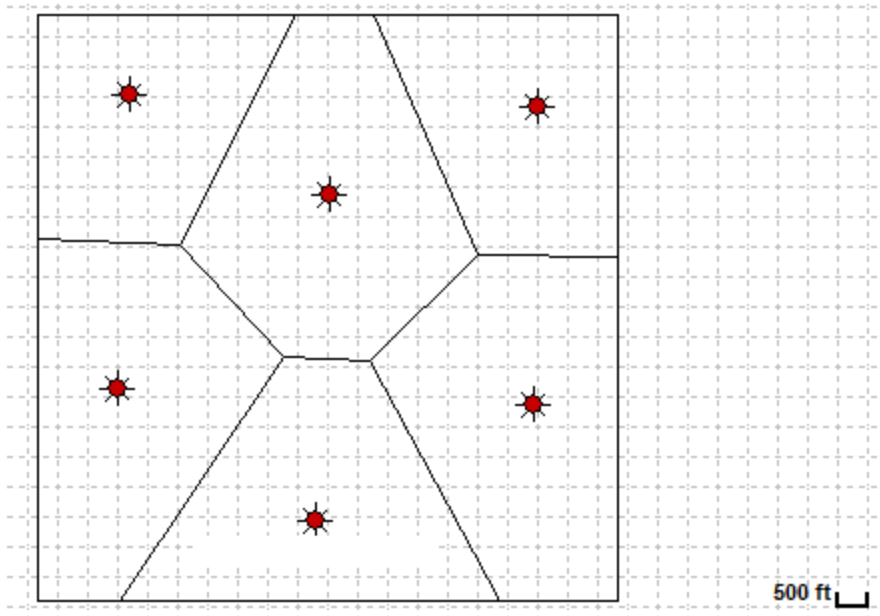
These are vertical wells with cell regions:
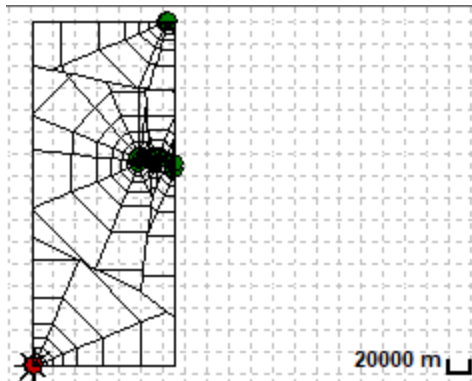
These is a horizontal well with cell regions:

200 ft
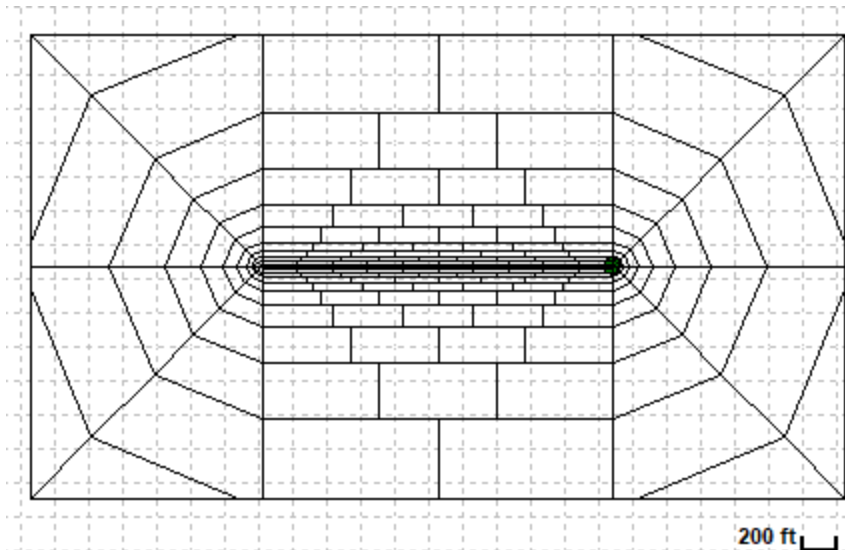
Setting model parameters

The well regions are automatically created for the model by drawing boundaries halfway between adjacent wells. These regions are used for setting parameters, such as net pay and permeability in the grid cells of each region. They do *not* represent no-flow boundaries.

To specify the properties for each region, select the well by clicking it in the schematic, or select the well from the drop-down menu, or use the arrows in the primary toolbar. In the Wells sub-tab, you can manually enter properties, or click the **Defaults** icons in the primary toolbar to use values from analyses in the well.

The initial pressure, bubble-point pressure, compressibility, and area are specified in the Reservoir sub-tab and are applied to the entire reservoir. If you have the Properties editor populated for the group before creating the Multi-well model, this information is pre-populated when the worksheet is created.

Primary toolbar

The primary toolbar has the following icons:

- **Pull Defaults** — select from these options:

    - **Group Properties** — copies default values from the Properties editor of the group.

    - **Selected Well Properties** — copies default values from Properties editor of the selected well.

- **Group Analysis** — displays a sub-menu with all the other multi-well analyses for the group. (If there are no other multi-well analyses, this option is not displayed.) Selecting one of the existing analyses copies one multi-well analysis to another in the same group, which can be useful if you want to experiment with the copy of the analysis while preserving the original content. Note that the parameters on the Forecast tab are not copied.

- **Selected Well Analysis** — displays a sub-menu with all the analyses (that is, typecurve, analytical, and hybrid) for the selected well. (If there are no other analyses, this option is not displayed.) Selecting one of the existing analyses, copies parameters of that analysis to the currently selected well.

- **Another Well in this Model** — displays a sub-menu with all the other wells in the same model. Select one of the wells to copy the calculation method, well parameters, and constraints from that well to the currently selected well (displayed in the Wells sub-tab under Selected Well).

- Ψ **Synthesize** — click this icon every time you want to history-match and create a forecast.

- 🔴 **Stop Synthesize** — stops the model's synthesize calculations.

- ⬅️ **Previous Well** — jumps to the previous well.

- ➡️ **Next Well** — jumps to the next consecutive well.

- 📋 **Copy to / Paste from Clipboard** — copies / pastes entity parameters from the clipboard.

Plots tab

This tab displays four plots in a dashboard and a parameter pane, which has two sub-tabs: Wells and Reservoir.

Tip: If the dashboard is blank, you need to provide well locations (latitude / longitude) for your wells. You can enter these latitudes and longitudes in the Attributes tab, **Location** node.

Wells sub-tab

In this sub-tab, you can specify model parameters on a per-well basis, and view various regions of your reservoir.

There are two drop-down lists in this sub-tab:

- **Selected Well** drop-down list — select the well you want to modify within your multi-well group.

- **Include** — by default, all wells in the group are included in the model. Deselect **Include** to exclude the selected well from the model (it is modeled as a shut-in well). If the well is excluded, you still need to set up valid parameters for it; the geometry of the well region is still being used to generate a grid used in the model. However, if the well is excluded, its production is not taken into account, and permeability for the whole well region (including fracture and SRV) is modeled to be equal to the matrix permeability (k_{matrix}).

- **Completion Type** drop-down list — select either **Vertical** or **Horizontal**.

  If you select **Horizontal**, two parameters are displayed:

  - **Le** — type your effective horizontal well length, or accept the default values from your perforation data in the Wellbore editor by clicking the **Pull Defaults** icon ( ) on the primary toolbar. (You can accept wellbore data from the reservoir or an analysis.)

  - **Azimuth** — is the angle between North and the wellbore. Type your value in degrees, or click the **Pull Defaults** icon to use the default values from your deviation-survey data in the Wellbore editor (as long as you have easting and northing data).

  - In addition, two permeabilities must be entered: k_{xy} (permeability in the horizontal direction) and k_z / k_{zy} (permeability ratio).

- **Calculation Method for Production** — set if the selected well is to be operated at rate, or at pressure control.

- **Calculation Method for Injection** — if you have injection rates for your well in the Production editor, the Calculation Method for Injection section is enabled, and you can set controls to be used during injection.

Reservoir sub-tab

In this sub-tab, you can specify parameters that are used for the entire reservoir model. For example, you can change the bubble-point pressure in the Reservoir section.

Fluid type selection

This analysis currently supports the Black Oil fluid type, which accounts for gas dissolved in liquid, but does not account for liquid vaporized in gas. Therefore, you should not create a Black Oil model for liquid-rich gas wells. Oil and water phases can be deselected within the model.

To select your fluid type, click the **Reservoir** sub-tab and select **Gas**, **Oil**, and/or **Water**.
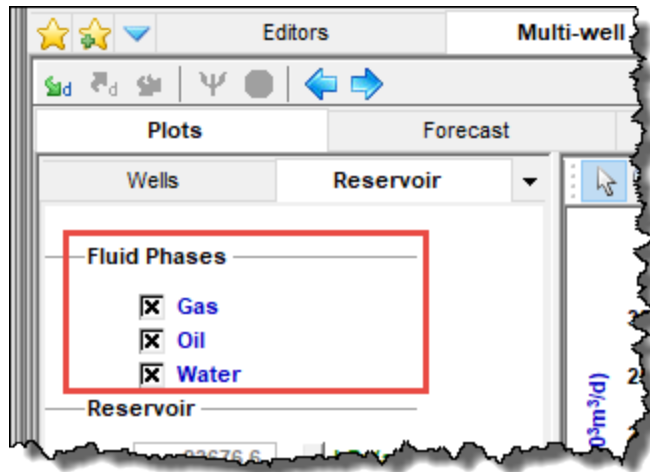
Aquifer

In the Aquifer section, you can have an aquifer edge, bottom, or both. In order to account for an aquifer in your reservoir, you need to connect it. For more information, see the Connect Aquifer icon description.

If you select **Edge Aquifer**, you must specify values for $OWIP_{E\Delta q}$ and $k_{E\Delta q}$.

If you select **Bottom Aquifer**, you must specify values for $OWIP_{B\Delta q}$ and $k_{B\Delta q}$.
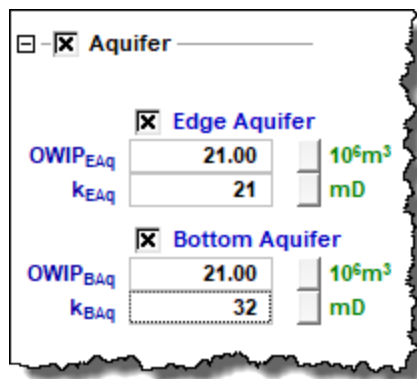
Dashboard

In the dashboard, there are four plots, which are described below.

Well Rate Time plot

This top-left plot displays historical and simulated rates and pressure for a single well. To switch wells, you can:

- Click the arrows on the main toolbar.

- Click a well on the schematic plot.

- Select a different well from the **Select Well** drop-down list.

For a description of its common icons, see toolbars.

Total Rate / Cum Time plot

This plot displays the total historical and simulated rates / cumulative production for the entire reservoir and the reservoir pressure. This plot has one unique toolbar icon:

 / **Switch to Rate vs Time / Switch to Cumulative vs Time** — toggle between these two views. (Only available on the Reservoir Rate vs Time plot, *not* on individual well plots.)

Schematic plot

This plot displays a schematic view of the reservoir shape and the location of the wells within it, as per their sandface latitudes and longitudes. You can edit / rotate your reservoir, display shapefiles, view / edit your aquifer, and view shaded plots while you run a simulation.

These toolbar icons are unique to this plot:

Edit Reservoir Boundary — click and drag to move your reservoir. Scroll your mouse wheel to expand or shrink your reservoir. White circles move an entire edge of the reservoir boundary. Red squares move only the selected vertex. Click a mid-section of a reservoir edge to add a new red vertex; note that your cursor changes to a cross.

Rotate Reservoir — scroll your mouse wheel, or use your keyboard's arrow keys to rotate the boundaries of your reservoir (the physical location does *not* change) around the reservoir center. To rotate your reservoir around your cursor, press the **Ctrl** key and scroll / use your arrow keys.

Display Shapefile — display the shapefile you have in the GIS tab in the multi-well model. If you do not have a shapefile, this icon is grayed-out.

Undo — undoes your last action. (You cannot undo your zoom as this icon applies to resizing only.)

Redo — reapplies the size of your reservoir to your previous settings. (You cannot redo your zoom as this icon applies to resizing only.)

Reset Reservoir Boundary — resets your reservoir size to the default setting.

Connect Aquifer — this icon is available if **Edge Aquifer** or **Bottom Aquifer** are selected in the Reservoir sub-tab. Click this icon to set the parts of the reservoir boundary that are connected to the edge or bottom of the aquifer. Segments of the boundary that are highlighted in blue are connected to the edge of the aquifer. By default, the entire reservoir boundary is connected to the aquifer, but you can select and deselect edges by clicking them. Cells that are highlighted in blue are connected to the bottom of the aquifer. (The mouse cursor becomes blue when you are in connect-aquifer-selection mode.) You can also select **Connect All to Aquifer** or **Deselect All from Aquifer** for your cell regions by right-clicking the schematic.

Show Pressure — displays pressure in each grid cell after you click the **Synthesize** icon (Ψ).

Show Gas Saturation — displays gas saturation in each grid cell after you click the **Synthesize** icon (Ψ).

Show Oil Saturation — displays oil saturation in each grid cell after you click the **Synthesize** icon (Ψ).

Show Water Saturation — displays water saturation in each grid cell after you click the **Synthesize** icon (Ψ).

For information on common plot icons, see plot toolbars.

After you click the **Synthesize** icon (Ψ) in the primary toolbar and the calculations are complete, the icons listed below are enabled in your schematic. With these playback icons, you can see how pressures or saturations change through time. A tooltip displays the pressure or saturation value and unit, as you hover over your color-shading plot.

- **⏮ Skip to Beginning** — displays the first timestep.

- **⏪ Step Back One Frame** — view timesteps in reverse one frame at a time.

- **◀ Play in Reverse** — view timesteps in reverse. You can click this icon multiple times to increase the speed of the playback.

- **⏹ Stop** — stops the playback process. As you hover over various cells in your well, the pressure or saturation is displayed.

- **▶ Play** — view timesteps from start-to-finish. You can click this icon multiple times to increase the speed of the playback.

- **⏩ Step Forward One Frame** — view one frame at a time.

- **⏭ Skip to End** — displays the last timestep.

As the synthesis proceeds, Position lines are displayed to indicate calculation progress. The shaded plot displays the distribution of pressure or saturation at the timestep that has just been calculated (as indicated by the time-stamp in the lower left corner, which displays the exact date and time). After the calculation is completed, these Position lines can be dragged to the moment in time you want to examine more closely, and all plots are synchronized.

If you find that the color scale for your shaded plot needs adjusting, right-click the legend and select **Customize Color Scale**, and then enter customized min and max values. To revert back to the default min and max values, right-click the legend and select **Reset Color Scale**.

Note: After you click the Show Pressure icon or any of the saturation icons, you can view values for each cell region by hovering over the shaded plot. Tooltips are displayed for each cell region.

Context menu

Right-clicking the reservoir view for your wells lists these options:

- **Reservoir Region** — show / hide the reservoir boundary.

- **Wells** — show / hide the wells in the reservoir.

- **Well Names** — show / hide the well names in the reservoir.

- **Well Regions** — show / hide the boundaries of the well regions.

- **Cell Regions** — show / hide the grid cell boundaries for each well in the reservoir.

- **Selected Well** — show / hide the well name for the selected well.

- **Scale Gridline** — show / hide gridlines with a scale marker.

- **Connect All to Aquifer** — when **Bottom Aquifer** has been selected in the Aquifer section of the Reservoir tab and you are in aquifer-selection mode, you can select all of the cell regions at once by selecting this option.

- **Disconnect All from Aquifer** — when **Bottom Aquifer** has been selected in the Aquifer section of the Reservoir tab and you are in <u>aquifer-selection mode</u>, you can deselect all of the cell regions at once by selecting this option.

- **Copy Lat / Long to Clipboard** — copies the latitude and longitude of the current position of the mouse pointer. These latitude / longitude values can be used to add a new infill well at the location you want:

  - Move the mouse pointer to the location for the new infill well; then, right-click and select **Copy Lat / Long to Clipboard**.

  - Create a new well using the <u>Entity Viewer - Hierarchy</u>. For more information, see <u>adding an entity</u>.

  - Open the <u>Attributes tab</u> for this well and paste the surface latitude and longitude from the clipboard.

  - Add this new well to the multi-well group previously used to run the multi-well analysis. (You can drag-and drop the new well from the Entity Viewer - Hierarchy to the <u>Entity Viewer - Custom</u>.)

Ratios plot

This plot displays historical and simulated ratios for the selected well. For a description of its common icons, see <u>toolbars</u>.

Forecast tab

This tab has the same features as the <u>hybrid Forecast sub-tab</u>, but all wells in the group are displayed.

Forecast Plot

This plot displays group-level rates and reservoir pressures, *not* data for individual wells.

Forecast Options

The Duration column is set for all of the wells in your group. If you create a new row in the Forecast Options table, make sure to type a value in the Duration column or Harmony Enterprise ignores this table row.

Prior to setting a duration in the Forecast table, each time you synthesize the reservoir model, the first row of the table is populated with the last synthetic flowing pressure for each well. After you have specified a duration in the first row, this is no longer updated.

To forecast injection for any well, select one of these options from **Control Type** drop-down list:

- **Gas Inj Rate** — the forecast at a given gas injection rate.

- **Water Inj Rate** — the forecast at a given water injection rate.

- **Pressure (Inj Gas)** — the forecast at a given sandface flowing pressure. (This pressure is reached by injecting gas.)

- **Pressure (Inj Water)** — the forecast at a given sandface flowing pressure. (This pressure is reached by injecting water.)

Note: In order for the above options to be available, the corresponding fluid phase must be selected in the Reservoir sub-tab.

For Well Forecast Constraints, the minimum pressure and maximum rate limit are applied per well, and the same value is used for all wells. Note that the $p_{inj<=}$ field is only required if you have selected an injection value from the Control Type drop-down list. Other injection constraints are applicable when at least one of the wells has an injection forecast.

- $p_{inj<=}$ — sets a maximum sandface flowing pressure during the forecast. In order to maintain the maximum flowing pressure, the injection rate is adjusted.

- $q_{ginj<=}$ — sets a maximum gas injection rate during the forecast. In order to maintain the maximum rate constraint, flowing pressure is adjusted

- $q_{winj<=}$ — sets a maximum water injection rate during the forecast. In order to maintain the maximum rate constraint, flowing pressure is adjusted

Toolbar

This toolbar has the same common icons described in plot toolbars.

Tables tab

This tab displays synthesis data for your wells in three sub-tabs: <well name>, Total, and Run.

Unconventional multi-well model (beta)

With the unconventional multi-well model, you can simulate multiple horizontal multifrac wells using the *group* hybrid model to history-match producing wells and forecast future production. With this analysis, wells are considered to be parallel, with the same length, and the same number of fractures.

Note: This model works with your Harmony Reservoir™ license.

Before you start using the multi-well model, make sure that all required information is added to the Harmony Enterprise project:

- Populate sandface locations for each well in the Attributes tab.

- Populate well production data (rates and sandface pressures) in the Production editor for each well in the group.

- Specify reservoir and fluid properties in the Properties editor of the group. When you create a new multi-well model, group reservoir properties are automatically applied.

- Populating wellbore information (such as, a deviation survey, completion, and perforation data) is not required. However, we recommend populating this information because it helps to initiate the multi-well model with correct default settings.

We recommend that you perform analyses and/or modeling for individual wells prior to using the multi-well model. You can bring parameters from individual well analyses as a starting point for the multi-well model.

The tab for this analysis has a parameters input pane and a dashboard with four plots. For more information, see dashboard.

Primary toolbar

The primary toolbar has the following icons:

- **Pull Defaults** — select from these options:

  - **Group Properties** — copies default values from the Properties editor of the group.

  - **Group Analysis** — displays a sub-menu with all the other multi-well analyses for the group. (If there are no other multi-well analyses, this option is not displayed.) Selecting one of the existing analyses copies one multi-well analysis to another in the same group, which can be useful if you want to experiment with

the copy of the analysis while preserving the original content. Note that the parameters on the Forecast tab are not copied.

- **Selected Well Analysis** — displays a sub-menu with all the analyses (that is, URM, analytical, and hybrid) for the selected well. (If there are no other analyses, this option is not displayed.) Selecting one of the existing analyses, copies parameters of that analysis to the currently selected well.

- **Another Well in this Model** — displays a sub-menu with all the other wells in the same model. Select one of the wells to copy the calculation method, well parameters, and constraints from that well to the currently selected well (displayed in the Wells sub-tab under Selected Well).

- **Ψ Synthesize** — click this icon every time you want to history-match and create a forecast.

- ⏺ **Stop Synthesize** — stops the model's synthesize calculations.

- ⬅ **Previous Well** — jumps to the previous well.

- ➡ **Next Well** — jumps to the next consecutive well.

- 📋 **Copy to / Paste from Clipboard** — copies / pastes entity parameters from the clipboard.

Plots tab

This tab displays four plots in a dashboard and a parameter pane, which has two sub-tabs: Wells and Reservoir.

Tip: If the dashboard is blank, you need to provide surface locations (latitude / longitude) for your wells. You can enter these latitudes and longitudes in the Attributes tab, **Location** node.

Wells sub-tab

This tab has parameters related to the wells in the model.

Currently, the wells within the unconventional multi-well model are considered to be parallel, with the same length, and with the same number of fractures. Therefore, the following parameters are shared between all wells:

- **L_e** — effective horizontal well length. By default, this field is populated based on the perforations that are set up in the Wellbore editor for each well in the group, but you can edit it.

- **n_f** — number of fractures.

- **x_e** — extent of the reservoir in the x-direction. This value cannot be edited directly, but can be changed by changing x_{wL} and x_{wR} for individual wells.

The rest of the parameters in the Wells tab are set up on a per-well basis. Select a well from the **Selected Well** drop-down list to set or modify parameters related to that particular well. (You have to set up parameters for each well for the multi-well model to be valid.)

- **Include** — by default, all wells in the group are included in the model. Deselect **Include** to exclude the selected well from the model. If the well is excluded, you still need to set up valid parameters for it: the geometry of the well region is still being used to generate a grid used in the model. However, if the well is excluded, its production is not taken into account, and permeability for the whole well region (including fracture and SRV) is modeled to be equal to the matrix permeability (k_{matrix}).

Geometry
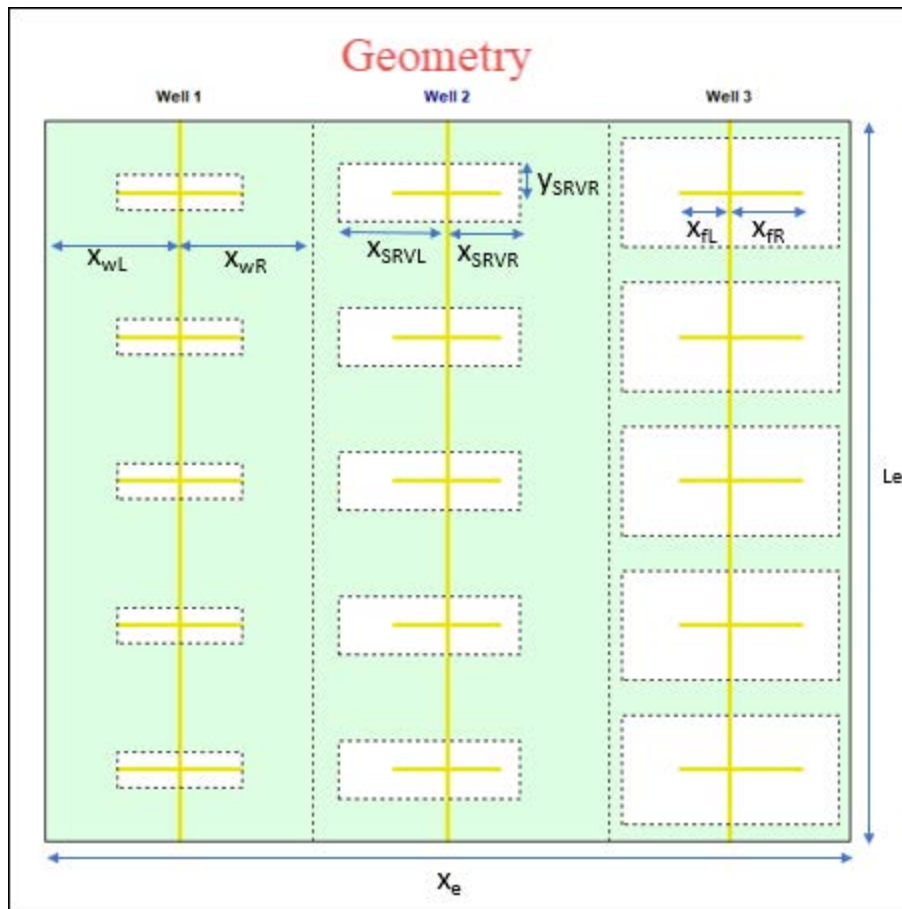
- x_f — fracture half length. Set this field if you want to model a symmetrical fracture with an SRV region extending along the whole fracture. Otherwise, set x_{fL}, x_{fR}, x_{SRVL}, and x_{SRVR} in the Advanced Geometry section.

- y_{SRV} — half SRV in the y-direction.

- x_{wL}, x_{wR} — each well has a rectangular well region around it. (Model gridding is done based on the well regions.) The x_{wL} and x_{wR} parameters define the distance between the well and the boundaries to its well region (see geometry above). These default values are based on the spacing between wells, but can be changed.

  Note: You can change spacing between the wells by changing their x_{wL} and x_{wR}.

- x_{fL}, x_{fR} — use these parameters to set a non-symmetrical fracture. The left wing of the fracture (x_{fL}) and the right wing of the fracture (x_{fR}) can be different (see geometry above).

- **x$_{SRVL}$, x$_{SRVR}$** — use these parameters to set up an SRV that extends less than, or beyond the x$_f$ (see geometry above).

Other parameters

- **k$_{SRV}$** — SRV (Inner zone) permeability.

- **k$_{matrix}$** — matrix permeability within the well region of the selected well.

- **F$_{CD}$** — dimensionless fracture conductivity.

- **k$_f$w$_f$** — fracture conductivity. Fracture conductivity and dimensionless fracture conductivity are related by:
  $F_{CD} = k_f w_f / (k_{SRV} x_f)$. You can set any of these two parameters (F_{CD} or $k_f w_f$) and the other one is calculated based on the one you set.

- **Calculation Method for Production** — set if the selected well is to be operated at rate, or at pressure control.

- **Calculation Method for Injection** — if you have injection rates for your well in the Production editor, the Calculation Method for Injection section is enabled, and you can set controls to be used during injection.

Reservoir sub-tab

In this sub-tab, you can specify parameters that are used for the entire reservoir model.

To include the effect of adsorbed gas, click the **Adsorption** checkbox. Note that this option cannot be used for models that include oil or condensate. For more information, see Langmuir isotherm.
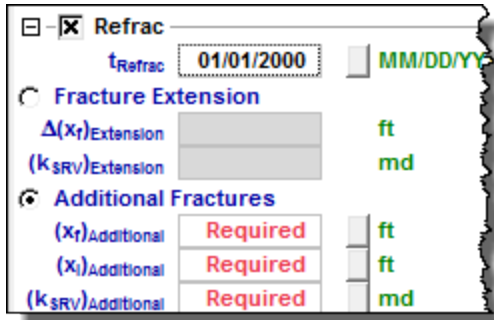
To include the effects of changing formation compressibility and permeability related to reservoir pressure, click the **Geomechanical** checkbox. For more information, see geomechanical reservoir models.

Fluid type selection

To select your fluid type, click the **Reservoir** sub-tab and select **Gas**, **Oil**, and/or **Water**.
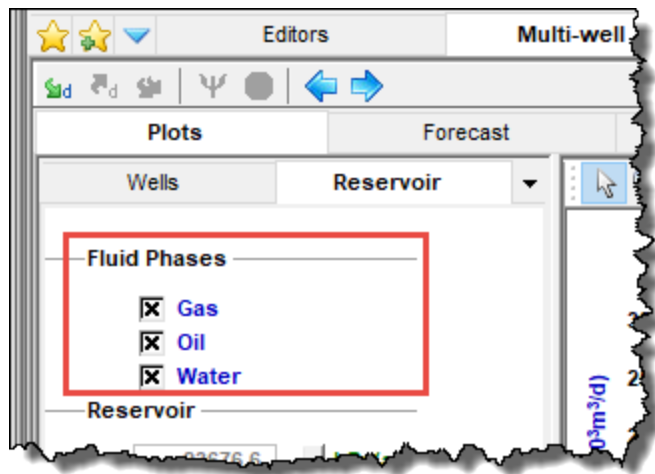
Dashboard

In the dashboard, there are four plots, which are described below.

Well Rate Time plot

This top-left plot displays historical and simulated rates and pressure for a single well. To switch wells, you can:

- Click the arrows on the main toolbar.

- Select a different well from the **Select Well** drop-down list.

For a description of its common icons, see toolbars.

Total Rate / Cum Time plot

This plot displays the total historical and simulated rates / cumulative production for the entire reservoir and the reservoir pressure. This plot has one unique toolbar icon:

⊾ / ⊾ **Switch to Rate vs Time / Switch to Cumulative vs Time** — toggle between these two views. (Only available on the Reservoir Rate vs Time plot, *not* on individual well plots.)

Schematic plot

This plot displays a schematic view of the reservoir shape and the location of the wells within it.

Click to show / hide an example screenshot

These toolbar icons are unique to this plot:

P **Show Pressure** — displays pressure in each grid cell after you click the **Synthesize** icon (Ψ).

g **Show Gas Saturation** — displays gas saturation in each grid cell after you click the **Synthesize** icon (**Ψ**).

o **Show Oil Saturation** — displays oil saturation in each grid cell after you click the **Synthesize** icon (**Ψ**).

w **Show Water Saturation** — displays water saturation in each grid cell after you click the **Synthesize** icon (**Ψ**).

For information on common plot icons, see plot toolbars.

After you click the **Synthesize** icon (**Ψ**) in the primary toolbar and the calculations are complete, the icons listed below are enabled in your schematic. With these playback icons, you can see how pressures or saturations change through time. A tooltip displays the pressure or saturation value and unit, as you hover over your color-shading plot.

- **Skip to Beginning** — displays the first timestep.

- **Step Back One Frame** — view timesteps in reverse one frame at a time.

- **Play in Reverse** — view timesteps in reverse. You can click this icon multiple times to increase the speed of the playback.

- **Stop** — stops the playback process. As you hover over various cells in your well, the pressure or saturation is displayed.

- **Play** — view timesteps from start-to-finish. You can click this icon multiple times to increase the speed of the playback.

- **Step Forward One Frame** — view one frame at a time.

- **Skip to End** — displays the last timestep.

As the synthesis proceeds, Position lines are displayed to indicate calculation progress. The shaded plot displays the distribution of pressure or saturation at the timestep that has just been calculated (as indicated by the time-stamp in the lower left corner, which displays the exact date and time). After the calculation is completed, these Position lines can be dragged to the moment in time you want to examine more closely, and all plots are synchronized.

If you find that the color scale for your shaded plot needs adjusting, right-click the legend and select **Customize Color Scale**, and then enter customized min and max values. To revert back to the default min and max values, right-click the legend and select **Reset Color Scale**.

Context menu

Right-clicking the reservoir view for your wells lists these options:

- **Show Grid Cells** — displays a grid layout on your schematic.

- **Show Shaded Plot** (after Synthesizing) — displays the plot after the synthesis process is completed.

- **Show Scale Gridlines** — show / hide gridlines with a scale marker.

- **Show Dimensions** — show / hide dimensions on the right-side of the plot.

- **Different Colors for SRV and matrix** — when this option is selected, the SRV and matrix are displayed in a different color from the rest of the schematic. When this option is deselected, the entire schematic is displayed in white.

- **Show Single Fracture Schematic** — displays a close-up view of the fracture. You can toggle back to Show Entire Model Schematic.

Ratios plot

This plot displays historical and simulated ratios for the selected well. For a description of its common icons, see toolbars.

Forecast tab

This tab has the same features as the hybrid Forecast sub-tab, but you have the option to display all wells in the group, or individual wells.

Forecast Plot

If **All Wells** is selected in the Select Well drop-down list, the Forecast plot displays group-level rates and reservoir pressures. If one of the wells is selected in the Select Well drop-down list, the Forecast plot displays rates and flowing pressures for that selected well.

Forecast Options

Use the Select Well drop-down list to pick any individual well or All Wells. Select one of the wells to see forecast settings for just that well in the Forecast table, or select **All Wells** to see forecast settings for all the wells together.

The Forecast Start Date is set for the entire model (the forecast for *all* the wells starts at this given date).

The values in the Duration column are shared between all the wells in the model.

Forecast Constraints are applied for all of the wells in the model.

After you set up a valid forecast and synthesize it, the Forecast Results table displays EUR, RR, and historical volumes for each well for each of the fluid phases available in the model.

Forecast injection

To forecast injection for any well, select one of these options from **Control Type** drop-down list:

- **Gas Inj Rate** — the forecast at a given gas injection rate.

- **Water Inj Rate** — the forecast at a given water injection rate.

- **Pressure (Inj Gas)** — the forecast at a given sandface flowing pressure. (This pressure is reached by injecting gas.)

- **Pressure (Inj Water)** — the forecast at a given sandface flowing pressure. (This pressure is reached by injecting water.)

Note: In order for the above options to be available, the corresponding fluid phase must be selected in the Reservoir sub-tab.

Injection constraints are applicable when at least one of the wells has an injection forecast.

- $p_{inj<=}$ — sets a maximum flowing pressure during the forecast. In order to maintain the maximum flowing pressure, the injection rate is adjusted.

- $q_{ginj<=}$ — sets a maximum gas injection rate during the forecast. In order to maintain the maximum rate constraint, flowing pressure is adjusted

- $q_{winj<=}$ — sets a maximum water injection rate during the forecast. In order to maintain the maximum rate constraint, flowing pressure is adjusted

Toolbar

This toolbar has the same common icons described in plot toolbars.

Tables tab

This tab displays synthesis data for your wells in three sub-tabs: <well name>, Total, and Run.

Navigation

Harmony Enterprise navigation consists of the following:

- Clipboard
- Menus
- Panes
- Selecting entities
- Status Window
- Tabs
- Toolbars

This screenshot outlines the main elements in the Harmony Enterprise interface. For a description of more technical elements in the interface, see Components.
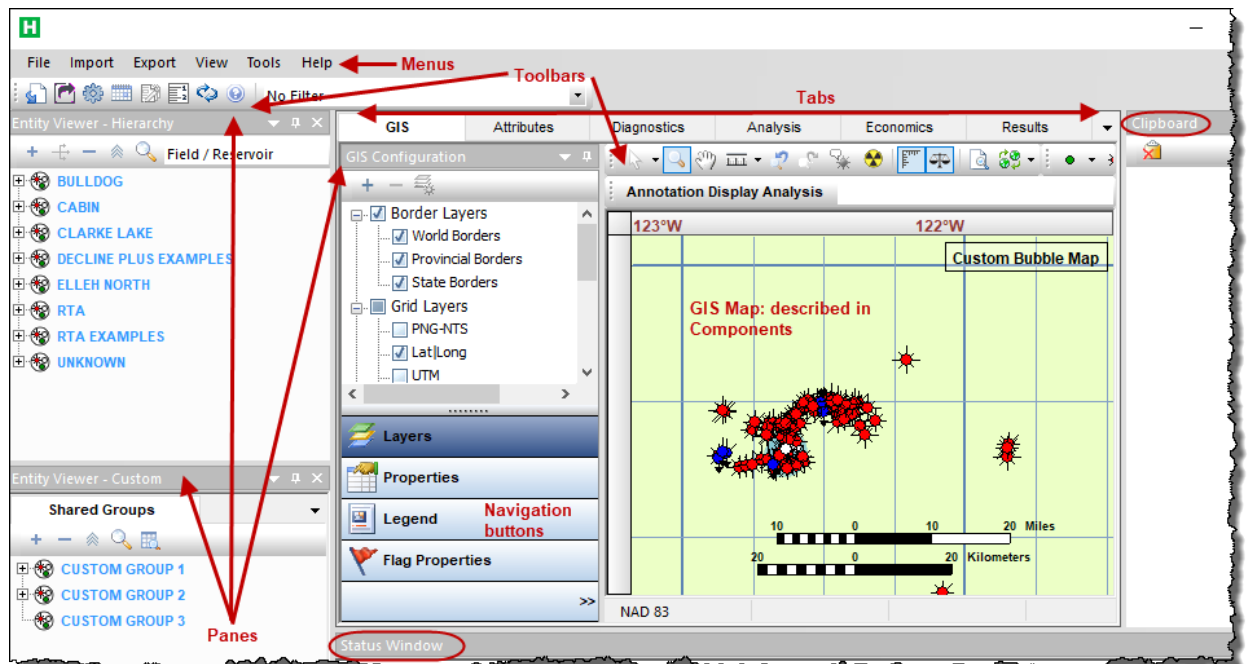
Clipboard

With the clipboard, you can copy and paste data, including analyses, between entities, or within a single entity. You can also copy data from Harmony to Harmony Enterprise.

The clipboard supports:

- Decline analyses

- Analytical analyses

- Unconventional reservoir analyses

- Properties editor

- Wellbore editor

- Multi-well models

The clipboard also supports bulk pasting properties to a selection of wells. After selecting wells in the Entity Viewer, dragging a clipboard item to one of the selected wells pastes the copied properties to the entire selection.

When you copy data to the clipboard, the Clipboard docking window opens, and data is displayed within the pane as a button.
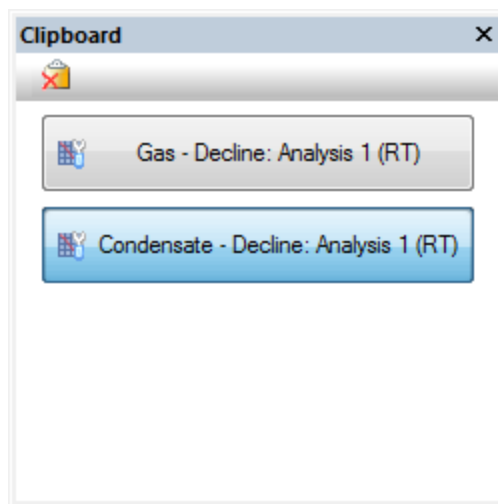
Menus

Harmony Enterprise has the following menus.

File

Close Data Source Connection — closes your data source connection, but keeps the Harmony Enterprise window open.

Exit — closes Harmony Enterprise.

Import

Database Connection — imports well data from a database.

Enerdeq / IHDC — imports / updates your Harmony Enterprise project with data from Enerdeq or IHDC. For more information, see import from Enerdeq.

PowerTools — opens the PowerTools File import dialog box where you browse to your PowerTools file and historical Enerdeq data (optional).

.Harmony file — imports a project from single-user Harmony. (You can import a single file or multiple files.)

.hldb file — imports data from a local database (by default, a local database is created when Harmony Enterprise is installed) extracted from Harmony Enterprise. For more information, see importing from Harmony Enterprise. (You can import a single file, or you can bulk import multiple files in the Browse dialog box.) Note that this functionality does *not* apply to SE licenses.

Piper Forecasts — opens the Well Selection and Piper Forecast Import dialog box where you can update your selected wells, or update all wells, with your Piper forecasts (.fdb files). Note that your existing analyses are never overwritten.

File — imports well data from a file.

Export

Production Data, Forecasts, or Decline Analyses — opens an export wizard where you select your production data, forecasts, or decline analyses.

To .hldb file — browse to the location for your .hldb file. you can export a portion of the data from an existing Harmony Enterprise project to create a new project. This function can be used for breaking a master project into smaller files (which you can merge at a later date), or for sending a portion of the data in your project to technical support. The following data is available for extracting: entities and their attributes, custom attributes, production, custom datasets, worksheets, analyses, reference dates, wellbore data, wellbore configurations (if none exist), and hybrid models.

To Piper — opens the Piper Export wizard, which guides you through exporting entities, and entity-and-analysis pairs for use in Piper®.

View

Toolbars and Docking Windows — select the toolbars and docking windows you want to display.

Toggle Units — switches between metric and field (imperial) units.

Tools

Import Templates / Workflows — imports an .hrmtemplate file. After browsing to your file, you select from the following options:

- **Discard existing** — deletes your existing templates / workflows.

- **Keep existing, and discard imported duplicates** — keeps your existing templates / workflows, and when there are duplicate templates / workflows being imported, they are not imported.

- **Keep existing, and append imported duplicates** — keeps your existing templates / workflows, and when duplicates exist, additional templates / workflows are created (for example, <filename>1, <filename>2, and so on).

- **Keep existing, and overwrite existing duplicates** — keeps your existing templates / workflows, and overwrites existing templates / workflows when duplicate templates / workflows are imported.

Export Templates / Workflows — exports an..hrmtemplate file of your templates and workflows.

Options — opens the Options dialog box.

Help

Web Help — opens the Harmony Enterprise help system. Note that an Internet connection is required.

Licensing — opens the Licensing dialog box where you can request and release licenses.

Error Report Directory — opens File Explorer and the location where log files are saved.

Online Support — opens the Customer Care web page.

Getting Started Video — opens the On24 web page, which lists free webcasts to help you get started.

Technical Resources — opens the Energy Resources web page, where you can view technical videos, published papers, and unconventional energy maps.

Panes

Panes are windows in Harmony Enterprise that contain specific groups of data. Panes include the Entity Viewer – Hierarchy pane, the Entity Viewer - Custom pane, the Clipboard, the Status Window, and all of the data windows inside the tabs. You can move panes to a variety of positions to suit your needs.

Docking functionality

When you click-and-drag the pane's title bar, the docking navigator is displayed.
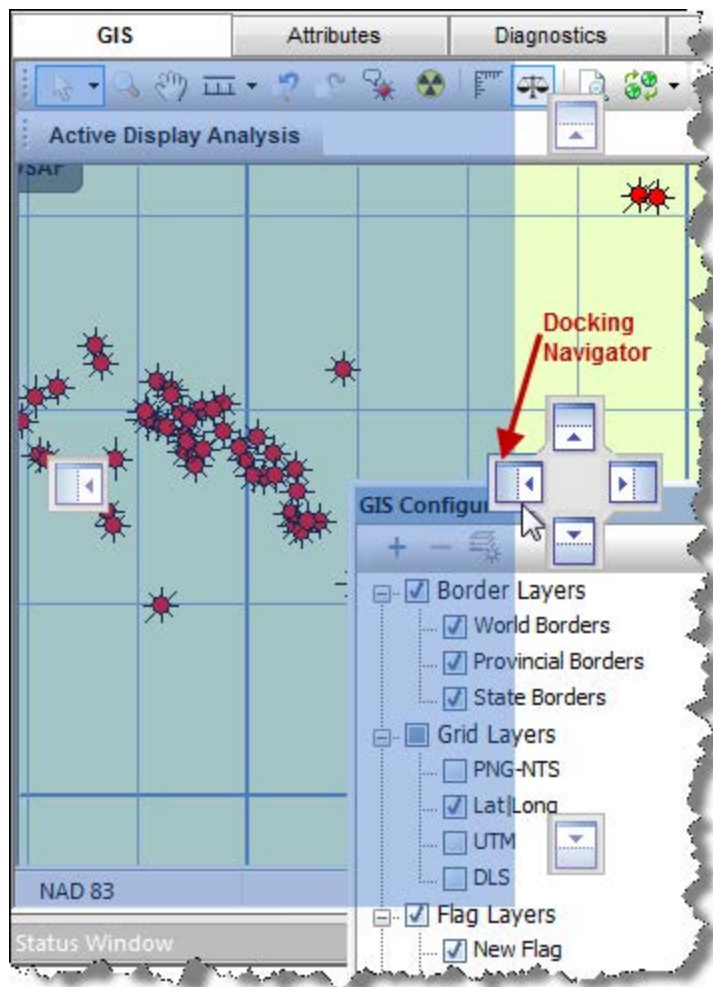
You can dock the pane in these positions:

- top, bottom, left, and right of the application's window

- in a tabbed view

To dock the pane in a tabbed view, hover over the center box and release. Note that you can-not use a tabbed view with non-docking panes.
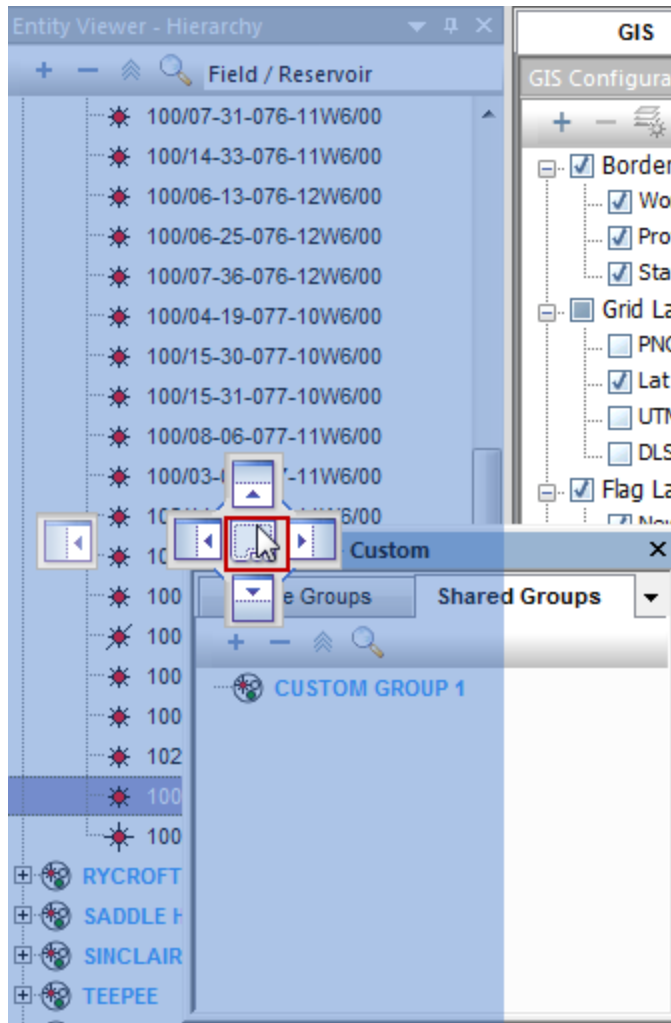
To undock the pane, click-and-drag the tab to a new location.

Pane options

When you right-click the pane's title bar, you can select various options from the context menu.
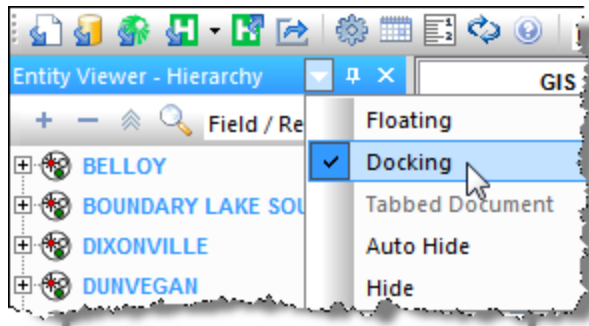
- **Floating** — detaches the pane from the main window. You can move the pane to your preferred location, including outside the application's window.

- **Docking** — returns the pane to its last docked position.

  You can also double-click the pane's title bar to float / dock the pane.

- **Auto Hide** — moves the pane to a tabbed position on the left-side of the application.
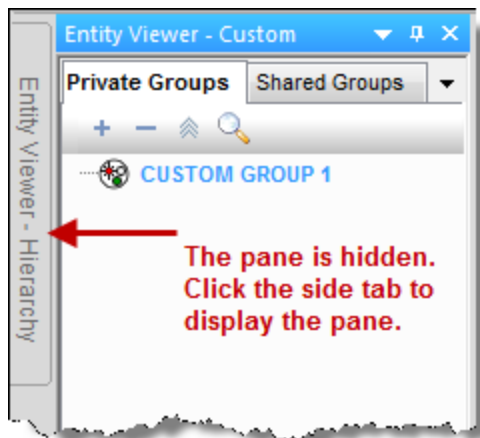
- **Hide** — this option is only applicable for the Clipboard and the Status Window. If you select this option, the pane is hidden. To show a hidden pane, click the **View** menu and select **Toolbars and Docking Windows**, **Clipboard** or **Status Window**.

Pin functionality

If you click the **Pin** icon ( ) in the pane's title bar, the pane moves to a tabbed position on the left-side of the application.

To return the pane to a docked position, click the sideways pin icon.
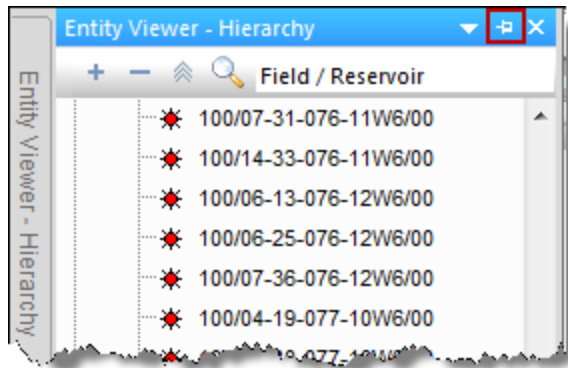
Selecting entities

You can select entities in a variety of ways. For example, you can select entities from the:

- GIS map

- Entity Viewer - Hierarchy pane

- Entity Viewer - Custom pane

There is a direct connection between the Entity Viewers (Hierarchy pane and Custom pane) and the tabs. Wells and groups listed in the entity viewers can be selected by clicking them in the Hierarchy pane or Custom pane. You can select multiple entities by clicking wells while holding down the **Ctrl** key (to make individual selections), or the **Shift** key (to make group selections).

Wells that are selected in the Custom pane are automatically selected in the Hierarchy pane. However, if a well is originally selected in the Hierarchy pane, it is not automatically selected in the Custom pane. Also, a selection of a custom groups cannot be made simultaneously with an additional selection of individual wells in the Hierarchy pane.
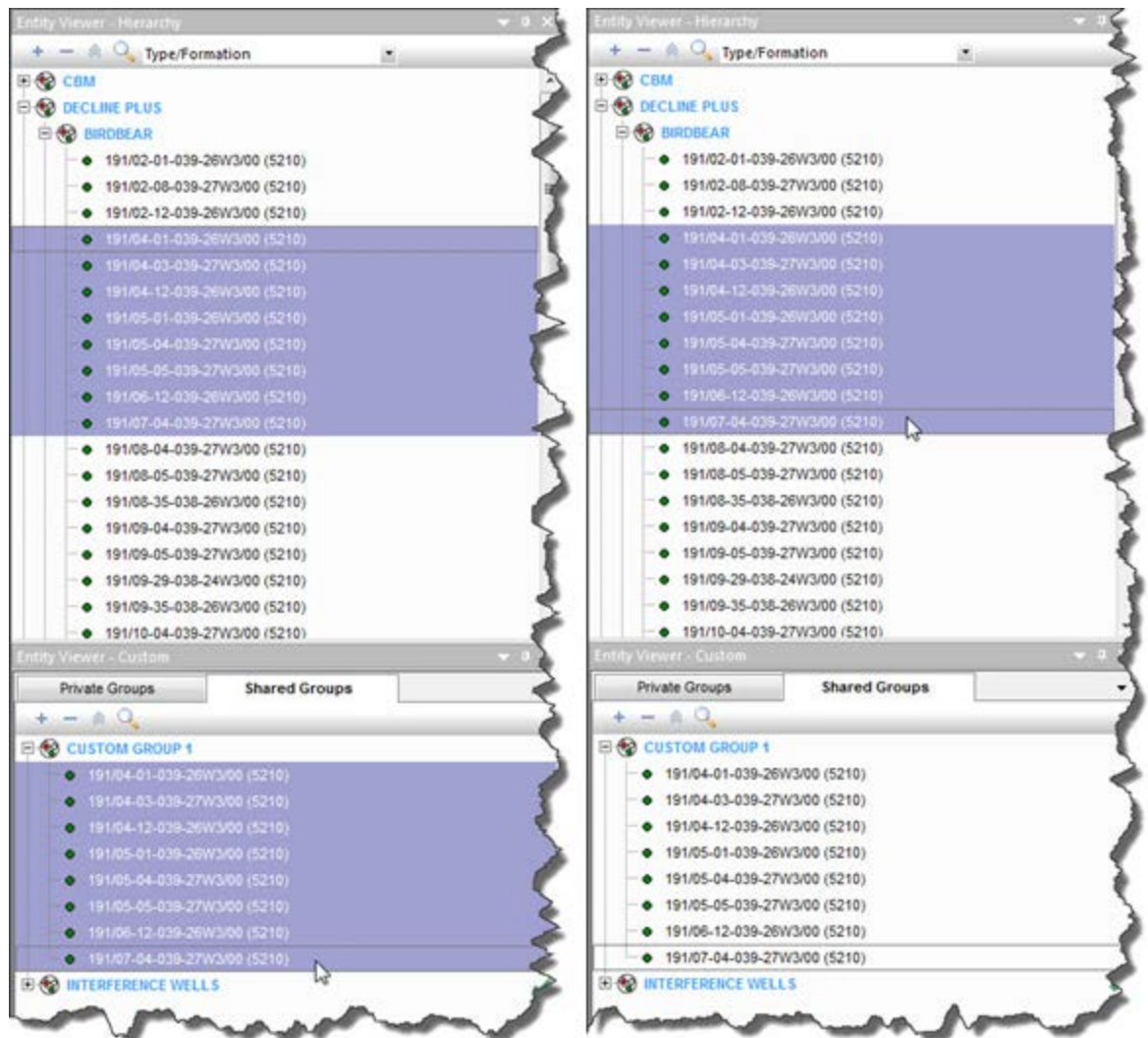
Entities displayed on the GIS map can be selected by clicking them on the map (GIS tab). For example, when a well is selected, it turns light green. When one or more entities are selected in the GIS tab, the same entities are selected in the Hierarchy pane. Multiple entities can be selected in the GIS tab by pressing the **Ctrl** key while clicking entities on the map.
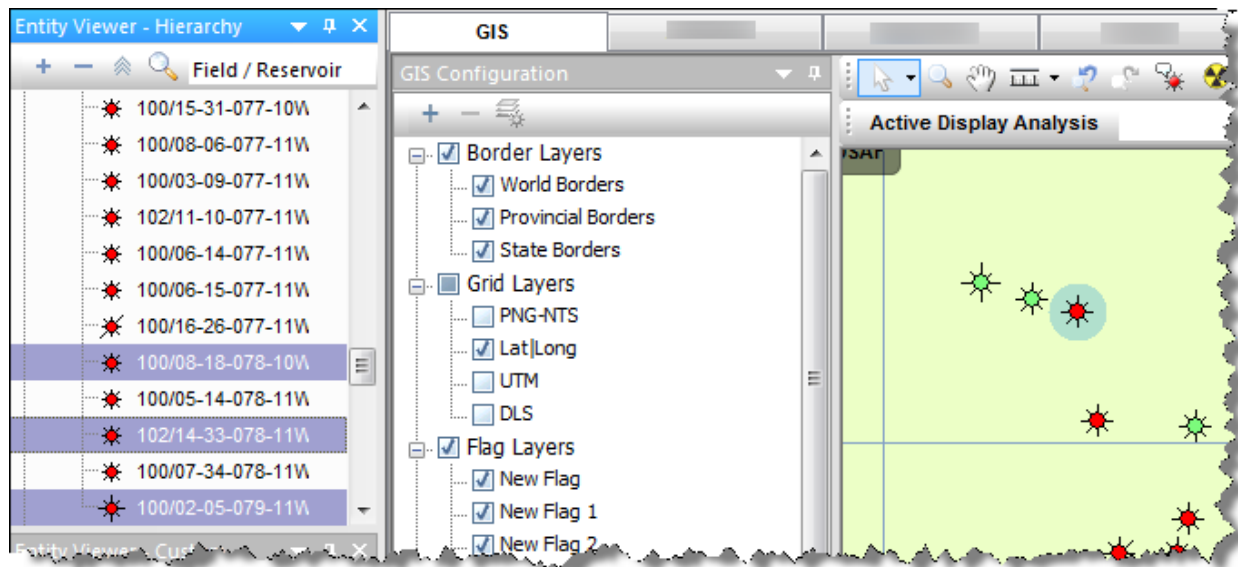
Multiple selections can be further refined by using the Select Subset option on the <u>Attributes tab</u> and <u>Results tab</u>.

You can also adjust your entity selection on the Analysis tab, using the typewell worksheet, but only a single entity can be selected from the Typewell worksheet. This entity must be a member of the group that the typewell analysis is being applied to, and the selection is only displayed in the Hierarchy pane. You can select this entity by right-clicking an individual well's dataset in the Typewell plot and selecting **Select Entity**. You can also select wells using their analysis lines.
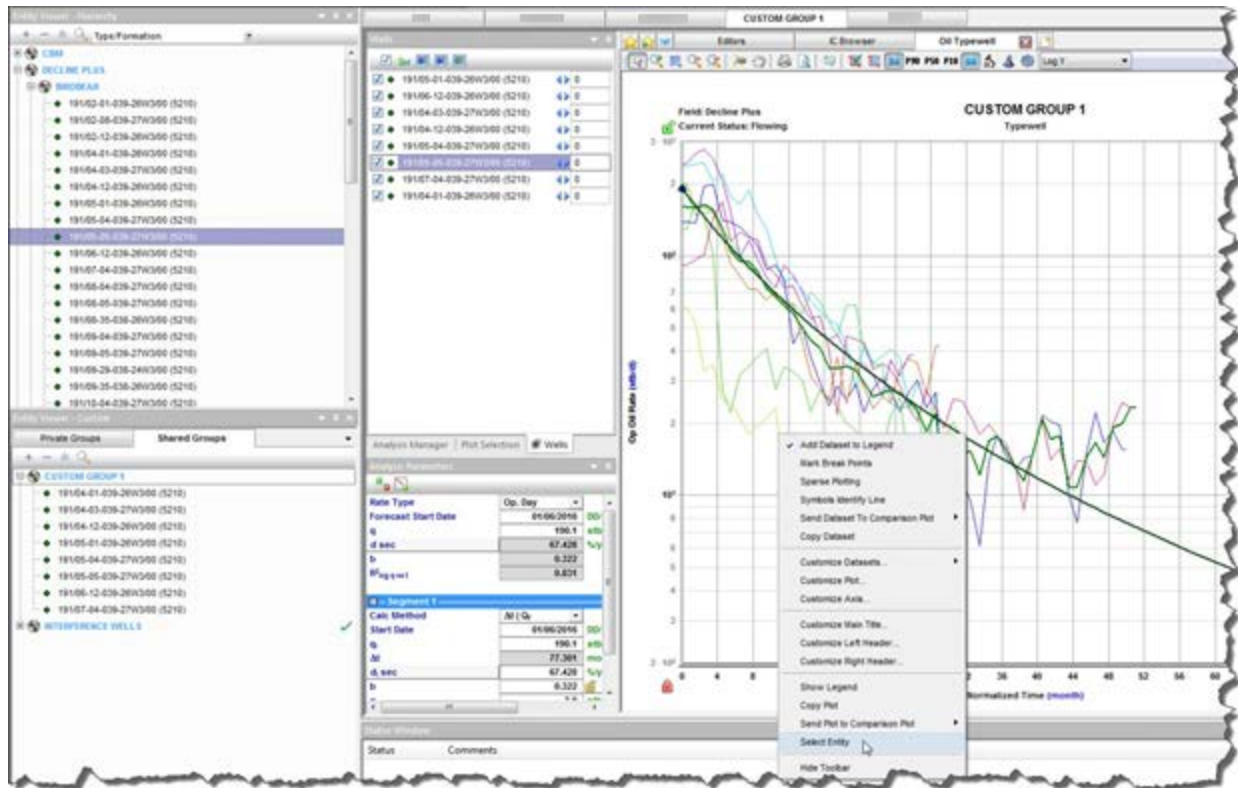
Tip: You can also use your keyboard's arrow keys to change your selections. (This can be useful when, for example, you preview data on the Diagnostics tab.)

Status Window

By default, the Status Window is docked at the bottom of Harmony Enterprise's content pane. The Status Window displays short descriptive messages pertaining to the current state of the project, or the results of actions as you perform them. Scenario names are used in the Status Window.

Note: To hide or show the Status Window, click the **View** menu, **Toolbars and Docking Windows**, **Status Window**.

Status Window options

When you right-click a message in the Status Window you can select various options from the context menu.
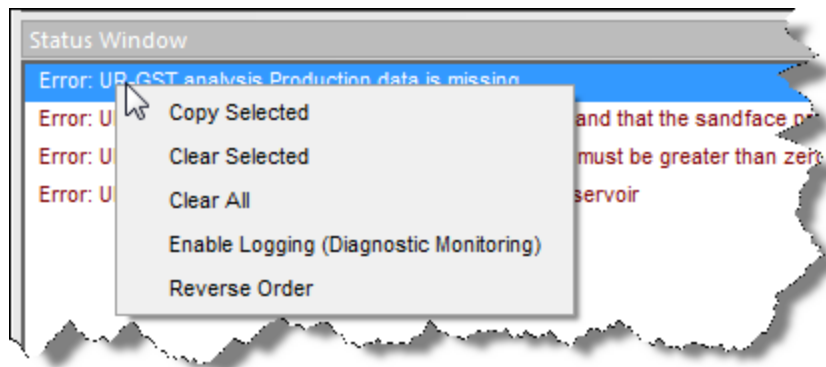
- **Copy Selected** — copies the selected message to the clipboard.

- **Clear Selected** — removes the selected message from the Status Window.

- **Clear All** — removes all messages from the Status Window.

- **Enable / Disable Logging (Diagnostic Monitoring)** — if you enable logging, a text file is saved to your computer's hard drive. This text file logs all of the messages displayed in the Status Window.

  This log file is stored in the following location: \Users\<username>\Documents\FAST\<software version>. Note that the Status Window log file is different from the full log file; for more information on the full log file, see user permissions in local folders.

- **Reverse Order** — by default, the most recent messages are displayed at the bottom of the Status Window. To reverse this display order, select this option.

Message categories

There are three categories of messages:

1. **Normal** — operations that are running correctly. No action is required.

2. **Warning** — operations that can run, but may give erroneous results due to invalid or missing parameters. Corrective action is likely required.

3. **Error** — operations that cannot be completed. Corrective action is required to resolve the error.

Status Window

Error: Gas + Immobile Water-HM-Vertical - k_z is not set

Error: Gas + Immobile Water-HM-Vertical - X_w is not set

Error: Gas + Immobile Water-HM-Vertical - Y_w is not set

Warning: The entity data used in this model may be out of date. You may need to re-run the simulation
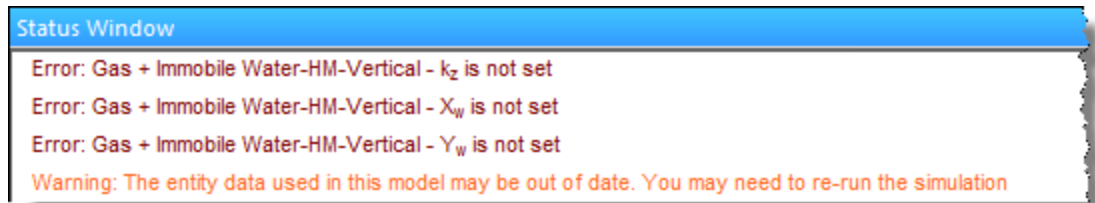
Note: You can double-click some issues to go to the problem area as soon as the issue arises.

Tabs

Tabs are displayed across the top of the Harmony Enterprise window, and can be detached from the application window to facilitate comparing data, especially when comparing multiple entities at the same time.

To float a tabbed window, double-click the tab.
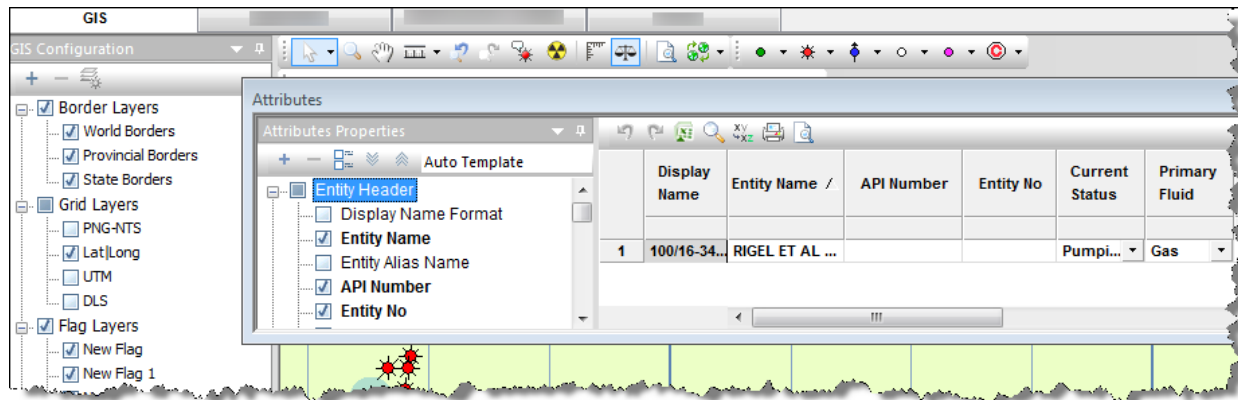
To return a floating tab to its docked position, double-click the tab.

Tip: All of the tabs can float except for the Analysis tab and Diagnostics tab.

Toolbars

Harmony Enterprise has many toolbars. Some toolbars have icons that are specific to a certain toolbar (for example, the GIS toolbar), while other toolbars have common icons. This topic describes the most common toolbars and related icons.

Main toolbar

The main toolbar has the following icons:

- **Import** — select from these options:

  - **Database Connection** — imports data from a database. For more information, see import well data from a database.

  - **Enerdeq / IHDC** — imports / updates your Harmony project with data from Enerdeq or IHDC. For more information, see import from Enerdeq.

  - **PowerTools** — opens the PowerTools File import dialog box where you browse to your PowerTools file and historical Enerdeq data (optional).

  - **.Harmony file** — imports a project from Harmony. (You can import a single file or multiple files.)

  - **.hldb file** — imports data from a local database extracted from Harmony Enterprise. (This functionality does not apply to SE licenses.) For more information, see import from an .hldb file. (You can import a single file, or you can bulk import multiple files in the Browse dialog box.)

  - **Piper Forecasts** — opens the Well Selection and Piper Forecast Import dialog box where you can update your selected wells, or update all wells, with your Piper forecasts (.fdb files). Note that your existing analyses are never overwritten.

  - **File** — imports a file. For more information, see import well data from a file

- **Export** — select from these options:

  - **Production Data, Forecasts, or Decline Analyses** — export production data, parameters from decline and multi-segment decline analyses,

or export all forecasts. For more information, see export data.

- ■ **To .hldb file** — you can export a portion of the data from an existing Harmony Enterprise project to create a new project. This function is useful, for example, for breaking a master project into smaller files (which you can merge at a later date), or for sending a portion of the data in your project to technical support. The following data is available for exporting: entities and their attributes, custom attributes, production, custom datasets, worksheets, analyses, reference dates (excluding active reference dates), wellbore data, wellbore configurations, and hybrid models.

  Note: You need to install a LocalDB (under *Shared Features* for SQL Server Express 2012 / 2014 or SQL Server 2012 / 2014) in order to export wells. If you attempt to export wells without a local database, an error message is displayed.

- ■ **Piper Export** — opens the Piper Export wizard, which guides you through exporting entities, and entity-and-analysis pairs for use in Piper®.

- • **Options** — opens the Options dialog box, which contains settings for various processes in Harmony Enterprise.

  Any of the User Settings you change are applied after you close the dialog box, and do not impact existing entities. However, Shared Settings are database settings that apply to all entities, both new and old.

- • **Reference Dates** — opens the Reference Dates dialog box where you can create a new reference date, specify the active reference date, or hide archived reserve analyses.

- • **Bulk Editor** — opens the Bulk Editor dialog box where you can delete analyses and worksheets. You must select an entity from the Entity Viewer prior to clicking this icon.

- • **Toggle units** — switches the units displayed between metric and field (imperial).

- • **Refresh** — reads the most up-to-date information from the data source you are connected to. Click this icon to see / get changes made by other users connected to the same data source.

- • **Help** — opens the online help.

- • **Project Filter** — click the drop-down list to select a filter you previously created, modify a filter, or select no filter (the default setting). For more information, see project filters.

Plot toolbars

Different plots have different icons available on their toolbars. The most common icons are listed below:

- **Set Mouse to Default** — switches the cursor to its default state. When the cursor is in its default state, you can hover over any dataset displayed on the plot to read its values on the tooltip.

- **Display a toolbar with options to zoom** — opens an additional toolbar with zooming options:

    - **Point Zoom** — click a data point to zoom in 50%.

    - **Rectangular Zoom** — click-and-drag a rectangle around the area you want to zoom into.

    - **Undo last zoom** — undo your latest zoom.

    - **Undo all zooms** — resets the plot display to your original view.

- **Pan Data** — switches the cursor to a Pan Data state. When the cursor is in this state, you can pan the x- and/or y-axes by clicking-and-dragging within the plot or the desired axis.

- **Print** — opens the Print dialog box.

- **Print Preview** — opens the Plot (Preview) window where you can adjust how your plot prints.

- **Create Annotation** — opens the Create Annotation dialog box. Select your type of annotation from the **Attach To** drop-down list:

    - **screen** — attaches your annotation to a fixed area on the screen. This annotation retains its position, if you rescale your axes.

    - **plot** — attaches your annotation to a fixed area on the plot. This annotation moves with the plot, if you rescale your axes.

    - **data** — (default setting) attaches your annotation to an x- and y-data point. If you use your keyboard arrow keys, you can move your annotation along the dataset and view the coordinate values of each plotted point. This annotation moves with the data point, if you rescale your axes.

- **Toggle the Autoscaling Option for the Plot** — switches automatic scaling on and off. When automatic scaling is on (the icon is in the state), the plot scales adjust to fit all the data whenever the data is modified. When automatic scaling is off (the icon is in the state), the plot scales remain unchanged whenever the data is modified.

- **Rescale all axes** — adjusts the minimum and maximum of the x- and y-axes to fit all data within the plot.

- **Display a toolbar with options to select data points** — opens an additional toolbar with point-selection options for best-fitting your analysis. These icons are described from left-to-right.

Scrolling your mouse wheel increases / decreases the spraygun tool's selection area

- **spray gun** — selects points when you left-click, and deselects points when you right-click. The mouse wheel can be used to change the spread-tool's size.

- **select all data points** — selects all the data points on the plot.

- **deselect all data points** — deselects all the data points on the plot.

- **lasso** — select points by clicking-and-dragging a shape around your data points. Deselect points by right-clicking-and-dragging a shape around the data points you do not want.

- **Maximize / Restore Window** — if the plot is a part of a dashboard, the Maximize / Restore window switches between displaying just one plot and displaying all plots on the dashboard.

- **Add a diagnostic line** — adds a diagnostic line to your plot, which can be useful for identifying and extrapolating trends in the data.

- **Reset Scaling** — resets your plot attributes to default settings.

- **Plot options drop-down list** — select your options (for example, coordinate, log). Note that your plot options vary depending on the type of plot you select.

Pane toolbars

Different panes have different icons available on their toolbars. The most common icons are listed below:

- **＋ / ━ Add / Remove** — adds / removes objects displayed on the pane.

- **Expand All / Collapse All** — expands / collapses all nodes of the tree structure displayed on the pane.

- **Deselect all series / Select all series** — deselects / selects all of the items in the tree structure.

- **Import** — imports data related to the pane.

- **Undo** — undo changes to data inputs, series display selections, and column-specific unit and precision changes.

- **Redo** — redo changes that have been undone.

- **Export to Excel** — create a *.csv file of the data displayed in the table.

Table toolbars

Different tables have different icons available on their toolbars. The most common icons are listed below:

- **Print** — opens the Print dialog box.

- **Print Preview** — opens the Grid (Preview) window where you can adjust how your table prints.

- **Export to Excel** — saves your table data to a .csv file.

Components

Harmony Enterprise components / modules include the following:

- Analysis Manager
- Analysis tab
- Attributes tab

- Entity Viewer - Custom
- Entity Viewer - Hierarchy
- GIS

- Query Wells dialog box
- Reference Dates dialog box
- Results tab

  - Results Viewer - Grid View
  - Results Viewer - Plot View
  - Comparison Plot
  - Reporting
  - Bulk modify decline analyses

- Best-fitting functionality
- Bulk Editor dialog box
- Database connection
- Diagnostics tab
- Economics
- Editors

- Import functionality
- Options dialog box
- Piper export
- Plots
- Plot Selection pane
- Project filters

- Role-based security
- Scenarios
- Spatial Explorer
- Tables / grids
- Worksheets

Analysis Manager

The Analysis Manager opens each time you create a new decline worksheet, or open an existing decline worksheet. Within the Analysis Manager, you can display and manage the analyses on an open worksheet.
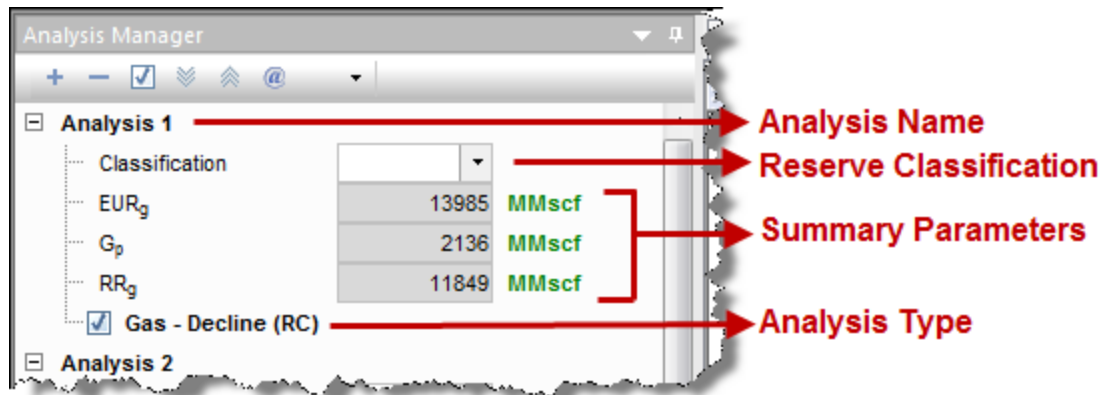
Within the Analysis Manager pane is a tree structure that displays all of the existing analyses. If you want to rename an analysis, right-click it and type a new name. Under each analysis:

- You can set your reserve classification from the **Classification** drop-down list.

- A summary of analysis results are displayed, showing the estimated ultimate recovery (EUR), historical cumulative production at the forecast start date (G_p or N_p), and remaining recoverable (RR) for the fluid in the analysis.

- You can select / deselect the analysis type to show / hide the analysis on the worksheet. After you select an analysis, a list of detailed parameters pertaining to that analysis is displayed in the Analysis Parameters pane below the Analysis Manager pane. Within the Analysis Parameters pane you can view and modify your parameters.

- If you created a probabilistic hybrid analysis, you can toggle the P10, P50, and P90 forecasts on or off.

- If you imported a Piper® Forecast, it is displayed with a "- Piper Forecast" suffix (for example, Gas - Piper Forecast, Oil - Piper Forecast, or Water - Piper Forecast) in the Forecast worksheet.

Toolbar

This toolbar has the following icons:

- **Add Analysis** — adds an analysis to the current entity with the type specified. You can add these types of analysis:

- Arps Decline	- Forecast Consolidation	- WOR Analysis
- Stretched Exponential Decline	- Ratio Forecast	- Oil Cut Ratio Analysis
- Duong Decline	- WOR / Oil Cut Forecast	
- Multi-segment Decline	- Custom Forecast	

  Note that the analysis you are adding to a worksheet needs to be compatible with the selected entity for analysis, fluid type, and the worksheet itself. Harmony Enterprise does not restrict analyses based on the primary fluid of a well, but there are two restrictions:

  - the entity type has to support the analysis (depending on whether the entity is a hierarchy group, custom group, or well).

  - the worksheet has to support the analysis (to add a gas decline, the plot has to be cal / op gas rate vs time, normalized time, or cumulative gas).

- **Remove Analysis** — deletes the currently selected analysis.

- **Select All / Deselect All** — selects / deselects all of the analyses in the Analysis Manager.

- / **Expand All / Collapse All]** — expands / collapses all nodes of the tree structure displayed in the pane.

- **Reference Volume** — updates the cumulative production at the reference date for all classified analyses associated with the active reference date.

- **Set Entity Work Status** — assigns a symbol to the entity you have selected based on your selection. This work status is displayed in both the Analysis Manager and the Entity Viewer.

For a description of common icons, see toolbars.

Context menu

Right-clicking an analysis type within the Analysis Manager lists these options:

Duplicate into Analysis — moves a copy of the analysis to the destination you select, while retaining the original analysis in the Analysis Manager. To duplicate an analysis:

- Right-click the analysis type and select **Duplicate into Analysis**, and then select a destination:

    - **<New Analysis>** — lists the copy as a new analysis in the Analysis Manager, at the bottom of the pane.

    - **[Analysis Name]** — links a copy of the analysis to a selected analysis, while maintaining the original analysis.

The linked analyses can only associate a single forecast type (for example, decline or ratio) per fluid type. For example, you cannot link a multi-segment gas decline with any other type of gas decline. Neither can you link two WOR ratio analyses. However, you may:

- *duplicate* an oil decline into a gas decline analysis (or vice versa). The results of both analyses are displayed under the parent analysis name in the Analysis Manager.

- *duplicate* an oil decline analysis into a WOR analysis. The decline results always overwrite the ratio analysis results. This is a permanent action, and removing links does not restore the results of the WOR analysis.
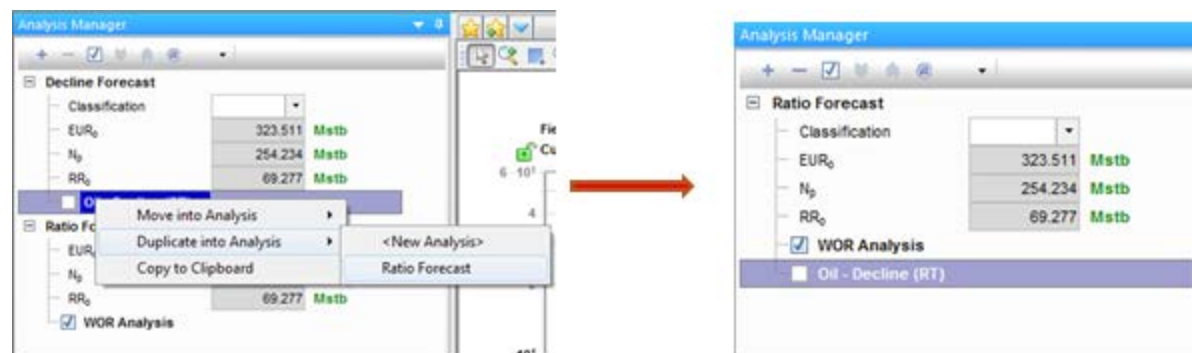
Copy to Clipboard — you can copy a decline or multi-segment decline analysis into the clipboard and paste it into the Analysis Manager of another entity. To copy an analysis to other entities:

- Right-click the analysis type and select **Copy to Clipboard**.

    The Clipboard pane opens.

- Drag the copied analysis from the Clipboard to the Analysis Manager of another entity. Or, right-click the empty space in the Analysis Manager and select **Paste Analysis from Clipboard**.

Move into Analysis — links the analysis to a destination analysis that you select. To move an analysis:

- Right-click the analysis type, select **Move into Analysis**, and then select the name of the analysis you want to link it to.

Analysis tab

The Analysis tab displays your analyses. If you click this tab without first selecting an entity, you are prompted to do so.

After you have selected an entity and clicked this tab, you can select your worksheet. For more information, see selecting an entity for analysis.
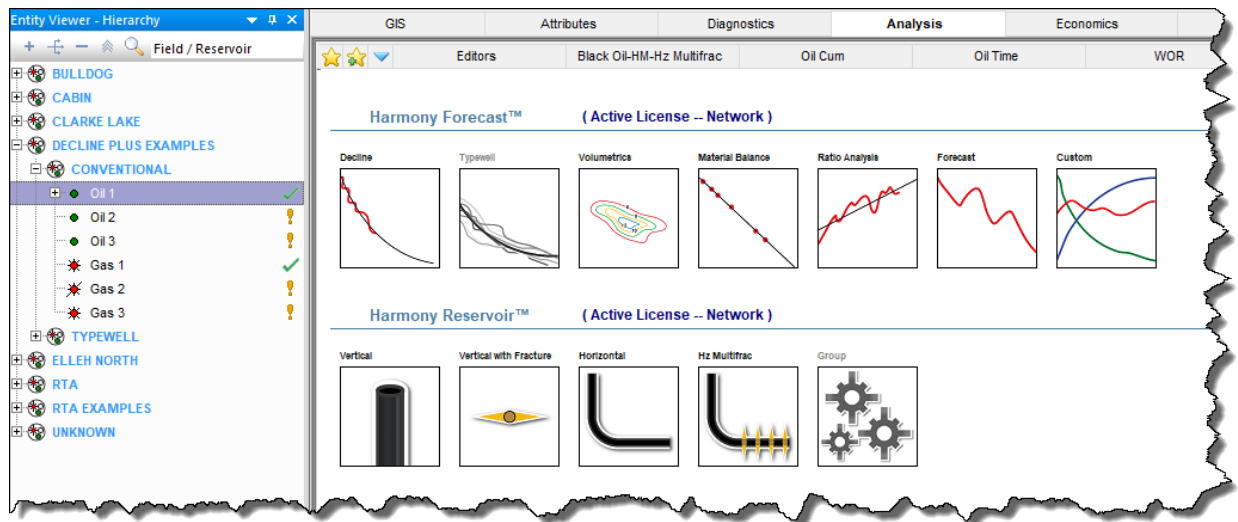
Tip: You can only display a single well, scenario, or group in this tab. Since a Typewell worksheet is used to display multiple decline analyses, it is grayed-out.

After you have selected an entity for analysis, that entity is locked until you select another entity. In other words, the lock is released when you click another entity. If another user tries to open the same entity for analysis while the lock is in place, a message is displayed in the main pane and the Status Window. There is no way to force the release of the well, but the username with the locked well is displayed in the Status Window.

Note: The editors are also locked when you are performing an analysis.

Attributes tab

The Attributes tab displays <u>entity</u> information in a table. Harmony Enterprise displays a default selection of attributes (named Auto Template) when one or more entities are selected in the Entity Viewer.
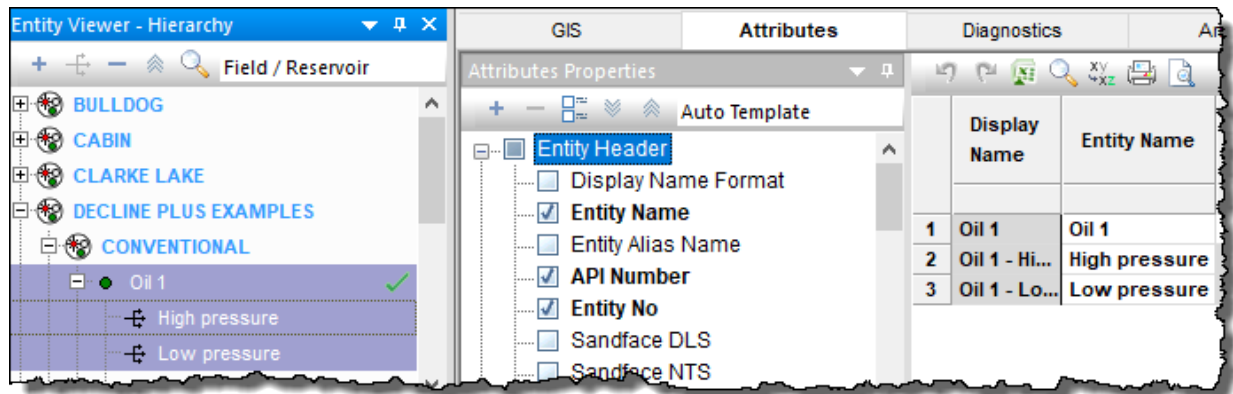
You can export this table to a .csv file. Some of the information displayed (for example, Reservoir or Operator name) is not required to perform a well analysis, but can be helpful for filtering data.

- The *Attributes Properties* tree structure to the left of the table lists all of the available well attributes. When you select an item in the *Attributes Properties* list, it is displayed in the table as a column heading. (Deselecting an attribute removes it from the table.)

- Columns added to the table are appended to the far right in the order in which they are selected. However, you can click-and-drag columns to change this order, or add a new column. You can also click-and-drag a column off of the table if you do not want that column displayed.

- Clicking a column header sorts the table data by its attribute value, according to the same sorting rules as MS Excel.

  If you click a column header, and then press the **Ctrl** key, you can sort multiple columns at the same time. This is indicated by a sorting arrow in each of the columns. The columns are sorted in the order you click the header.

- The first predefined attribute column is the Display Name. You can define the format of this column in the *Display Name Format* column. After the display name is set, that name format is used in every module and worksheet in Harmony Enterprise.

Tip: Many users like to display an Alias for their entities. You can customize this display by selecting **Entity Alias Name** in the Attributes Properties pane and typing your alias name in the Entity Alias Name column.

Well attribute data can be imported from a file / database, entered manually, or copied-and-pasted from another table cell. The table cell's color can be used to identify the method by which data can be entered into the cell:

- **Gray** — read-only. These cells display data from another location in Harmony Enterprise, or these cells indicate that it is a calculated cell (for example, a custom attribute). Data in these cells cannot be modified.

- **White (no drop-down list)** — you can enter a value, or paste content from another cell.

- **White (with a drop-down list)** — you can select a value from the drop-down list, or you can paste a value from the drop-down list into these cells.

Scenarios

Scenarios are displayed in the same manner as wells, with these columns for additional information:

- **Scenario Name** — the name of the scenario. For more information, see promote to well.

- **Created By** — the name of the user that created the scenario.

- **Last Modified Date** — the last date when the scenario was modified.

- **Last Modified By** — the name of the user that last modified the scenario.

- **Notes** — optional notes for the scenario.

Toolbars

The Attributes tab has two toolbars: primary and secondary. The unique items are described below; for a description of common icons, see toolbars.

Primary toolbar

The primary toolbar is located below the *Attributes Properties* pane.

Clicking the ✛ icon on this toolbar lists two options.
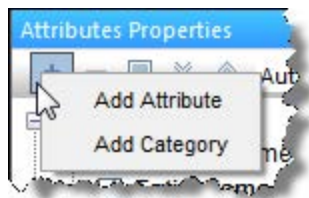
1. **Add Attribute** — opens the Create Custom Attribute dialog box. You can create two different types of custom attributes: *Input* (using values you enter), and *Calculated* (using equations you enter).

2. **Add Category** — opens the Create Custom Category dialog box where you can create custom categories to group your attributes. The selection tree updates after you add your category.

Other notes on this toolbar include the following:

- You can click the **Delete custom attribute / category** icon (⬚) after selecting the custom attribute or category you want to delete. You are prompted to confirm your decision when deleting a custom attribute, but a custom category is immediately deleted. Multiple custom attributes and datasets can be deleted quickly by using the **Ctrl** and **Shift** keys.

- After you have customized the table / grid display to your liking (for example, showing or hiding attribute properties and re-ordering the category headers), you can save your configuration as a template for re-use. Click the drop-down arrow on the toolbar and select **Save / Delete Template**. To load a previously saved template, select it from the drop-down list.

- To return to Harmony Enterprise's default template, select **AutoTemplate**.
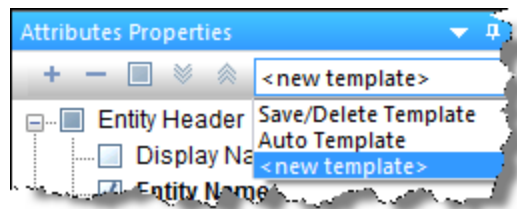
Note: Templates are user- and computer-specific; they are not database-specific.

Secondary toolbar

The secondary toolbar is located above the attributes table / grid and has the following important items:

- ↺ ↻ **Undo / Redo** — undo your previous action, or redo your action.

- 🔍 **Find / Replace** — type the text you want to search for, and then type the text you want to use instead.

Context menus

Right-clicking the top left of your table lists these options:
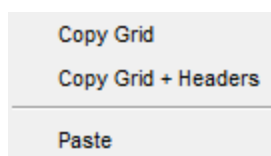
- **Copy Grid** — copies the table to the clipboard.

- **Copy Grid + Headers** — copies the table and table headers to the clipboard.

Right-clicking the numeric columns' headers (the columns displaying units in green text) lists these options:
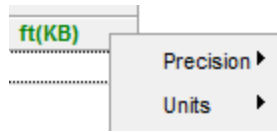
- **Precision** — select between decimal, scientific, or engineering.

- **Units** — select the units you want to display from the submenu.

After selecting your rows using the row headers, right-clicking the row numbers to the left and selecting **Select Subset** removes the other rows in the table, and this selection persists across Harmony (for example, the Entity Viewer, GIS map, and so on).
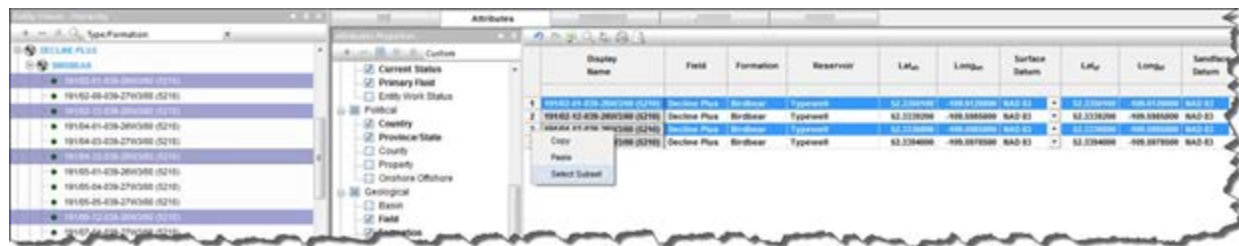
Right-clicking a *white table cell* lists these options: cut, copy, paste, and clear.

Custom attributes

You can create custom attributes in Harmony Enterprise.

- When you click the **Add Custom Attribute / Category** icon (+) icon on the *Attributes Properties toolbar* and select **Add Attribute**, the Create Custom Attribute dialog box opens.

- Your custom attribute is displayed in the *Attributes Properties pane*, under the category you have selected.

- You can remove a custom attribute by selecting it and clicking the **Remove Custom Attribute / Category** icon (—) icon in the *Attributes Properties toolbar*. Multiple custom attributes and datasets can also be deleted quickly by selecting them and pressing the **Ctrl** and **Shift** keys.

- You can rename or edit your custom attribute's formula, by right-clicking it and selecting **Rename** or **Edit Formula**.

Custom-calculated numeric attributes

If you selected **Number** for your *Unit Type* in the Create Custom Attribute dialog box, you created a custom-calculated numeric attribute.

Clicking the **Edit Formula** button in this dialog box opens the Equation Editor, where you can use a combination of existing production datasets, custom-input datasets, custom-calculated datasets, well attributes, custom-input attributes, custom-calculated attributes, constants, and mathematical operators to build your equation. For more information, see the Equation Editor dialog box.

Custom-calculated text attributes

You can add a custom-calculated text attribute using a combination of existing text attributes, custom-text attributes, custom-calculated text attributes, and user-defined text.

When you click the ✚ (**Add Custom Attribute / Category**) icon and select **Add Attribute**, the Create Custom Attribute dialog box opens.

- When you select **Text** from the *Attribute Style* drop-down list and **Calculated** for the *Type of Attribute*, the Equation Editor opens.
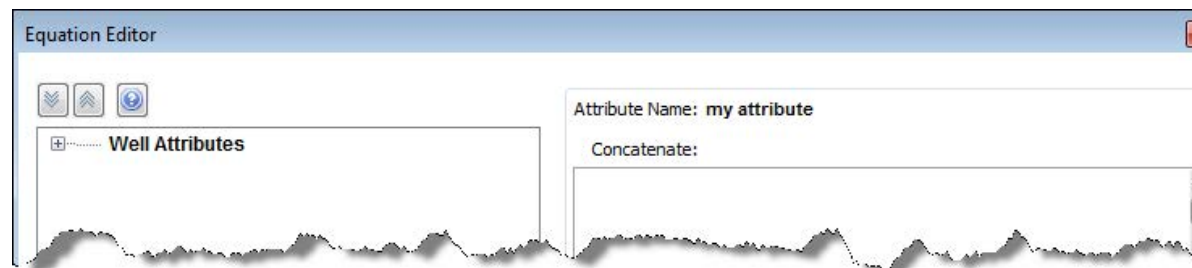
- You can type in the Concatenate pane, or you can select the attributes you want from the tree structure; then click **OK**.

The top part of the Equation Editor has the following components:

- **Tree structure** — displays an updated list of all the text attributes that are available for concatenation. This includes existing text attributes, custom-input text attributes, and custom-calculated text attributes. Clicking an item in the tree structure inserts it into the formula.

- **Concatenate pane** — displays the text attributes and user-defined text for concatenation (links items together).

Create Custom Attribute dialog box

This dialog box is commonly used when you add custom attributes. In this dialog box you are required to select your attribute type (*Input* or *Calculated*), style (*Number* or *Text*), and unit type (when applicable). You are also required to define a name and location for your attribute.

- **Attribute Name** — type a name for your custom attribute. This cannot be edited after the attribute is created, and this is a required field.

- **Attribute Style** — select Text, Number, or Date from the drop-down list. Note that this field cannot be edited after it is set.

- **Unit Type** — select your unit type from the drop-down list (enabled when you select Number for your Attribute Style). Note that this field cannot be edited after it is set.

- **Default Field Unit** — select your default field unit from the drop-down list (enabled when certain unit types are selected). By choosing a default unit, you specify in what unit, by default, your attribute is displayed. This can later be changed by toggling the displayed unit at the top of your attribute column.

- **Default Metric Unit** — select your default metric unit from the drop-down list (enabled when certain unit types are selected). By choosing a default unit, you specify in what unit, by default, your attribute is displayed. This can later be changed by toggling the displayed unit at the top of your attribute column.

- **Location** — select the attribute's location in the Attribute tab's tree structure from the drop-down list. This is a required field and you cannot click OK until a location has been selected.

- **Input** — uses values you enter.

- **Calculated** — opens the Equation Editor dialog box where you enter formulas for this attribute.

Equation Editor dialog box

This dialog box is commonly used when you <u>add custom datasets</u> or <u>add custom attributes</u>, and you want to use a Calculated type of dataset or attribute.

The Equation Editor has the following components:

- **Tree structure** — displays an updated list of all the production datasets that exist in the Production editor, as well as the numerical attributes that exist in the Attributes tab. This includes custom-calculated datasets, custom-input datasets, custom-input attributes, and custom-calculated attributes. Clicking an item in the tree structure inserts it into the formula.

- **Inputs / Units pane** — displays the units associated with each input.

  - If a dataset or attribute is displayed in an equation twice, only one unit can be associated with that variable.

  - The table / grid displays a list of datasets / attributes in the formula pane when you click the **Update Grid** button, *after* you enter a valid formula. You can also update the table / grid each time you make a modification to the formula by clicking the **Update Grid** button.

- Note that if your formula is invalid, clicking **OK** or **Update Grid** displays an error message in the lower left corner of the dialog box.

- **Calculator** — consists of numbers and mathematical functions.

- **Formula pane** — displays the formula as you create it.

  - The *output unit* is the unit associated with the output of your formula.

  - By clicking the four icons directly above the formula area, you can insert subscript, superscript, and symbols within the formula.

  - You can use both the on-screen calculator (by clicking the buttons in the dialog box) and your keyboard.

Tip: When entering a formula, make sure to add the closing **")"** when using a function that opens with a **"("**. If your formula is invalid, clicking **OK** displays an error message in the lower left corner of the dialog box.

Referencing other datasets / attributes

You can enter a formula into the Formula pane using the keyboard. To reference another dataset or attribute, you must use the following format:

- Attribute: [A:Attribute Name]

- Dataset: [P:Dataset Name]

Best-fitting functionality

Click to see subtopics:

There are several methods you can use to manipulate your decline curve.

When manipulating the decline curve, there are three data points to be aware of.
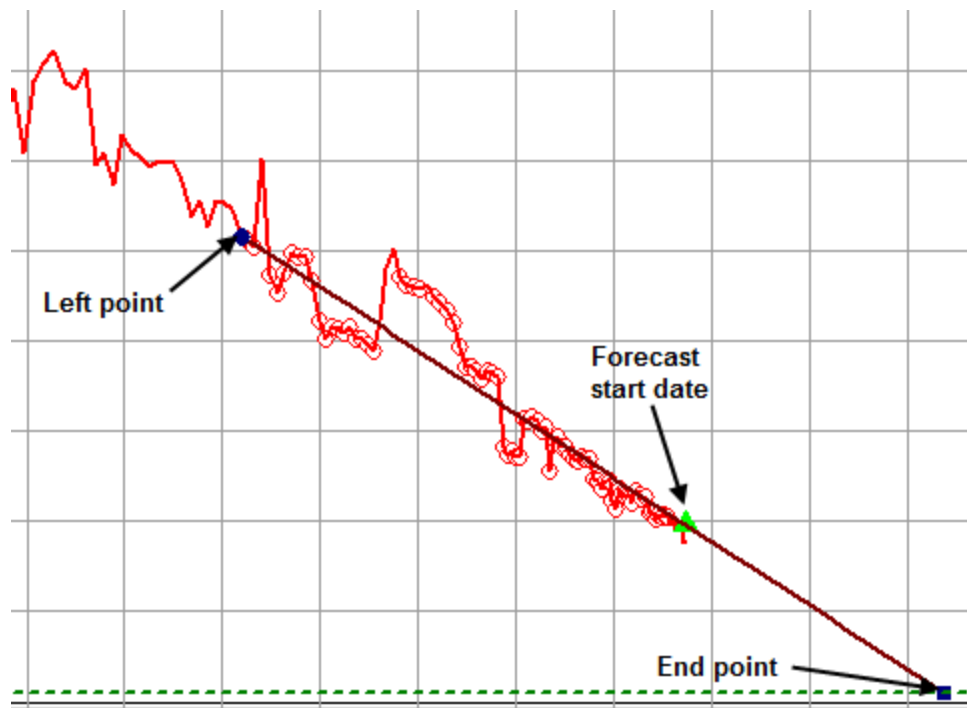
1. **Left point** — any historical data point. (The section between the left point and the forecast start date is not included in the forecast; it is only used to show the match to historical production.)

2. **Forecast Start Date** — the middle point on the line; this is the forecast start date (FSD).

3. **End point** — the expected ultimate recovery.

Changing the slope of the decline curve

To change the slope of the decline curve, click the decline curve line and drag. The line pivots around the FSD point, changing the decline rate and forecast duration. (If you drag the segment that does not have the FSD within it, the line pivots around the segment's start point.)
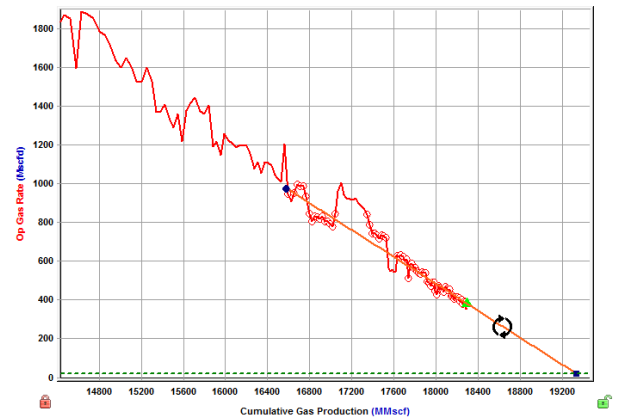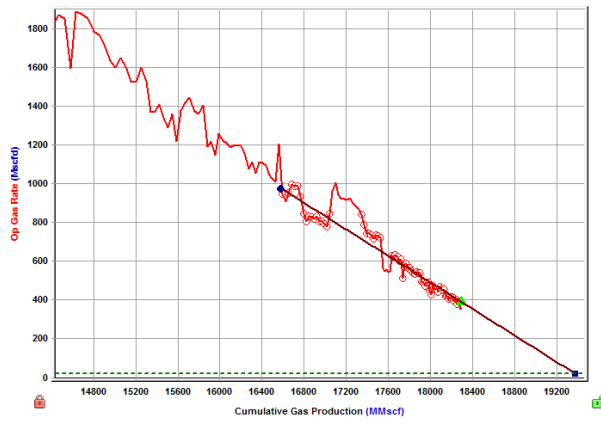
Changing the historical match

To change the historical match, click the left point while pressing the **Shift** key, and then drag it to a new position. This changes the portion of the historical production data used, but it does not change the analysis.
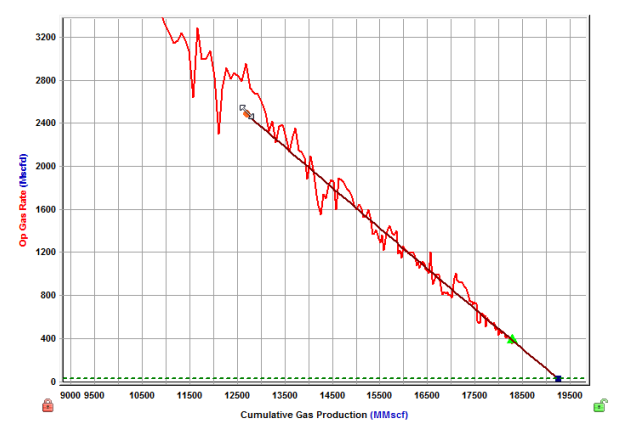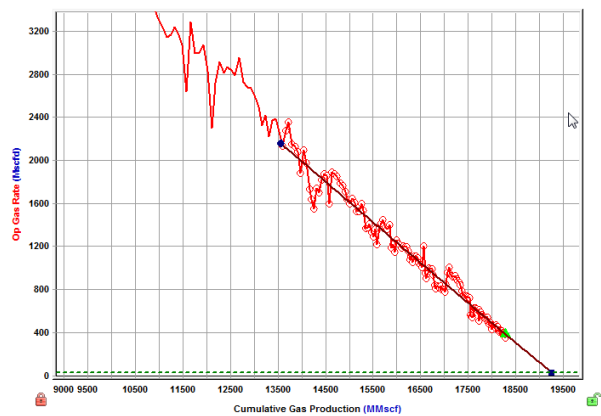
Changing the initial rate

To change the initial rate, click-and-drag the left point up or down. The initial rate and forecast duration change. Alternatively, you can click-and-drag the FSD point up or down.
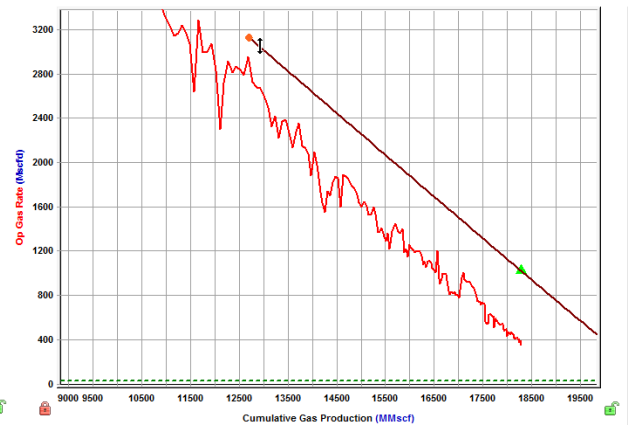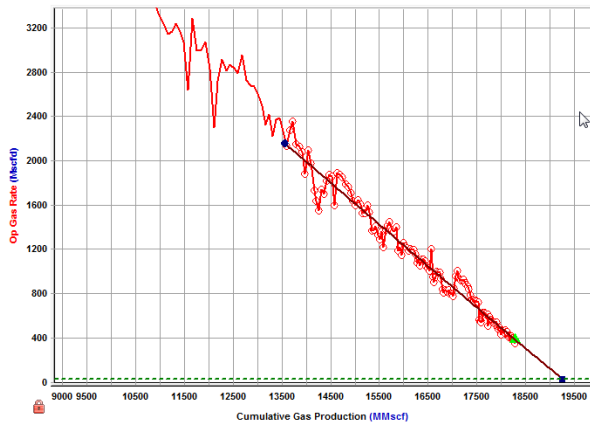
Changing the FSD

To change the FSD, enter a new date in the Forecast Start Date field in the Analysis Parameters pane.

If you click-and-drag the FSD point left or right while holding down the **Ctrl** key, the FSD point moves together with the decline curve.

If you click-and-drag the FSD point left or right while holding down the **Shift** key, the FSD point moves along the decline curve (the curve itself does not move).

Changing initial cumulative production & final cumulative production

To change the initial cumulative production and final cumulative production, click-and-drag the left point while holding down the **Ctrl** key. This changes the start point without changing the initial oil / gas rate or decline rate.
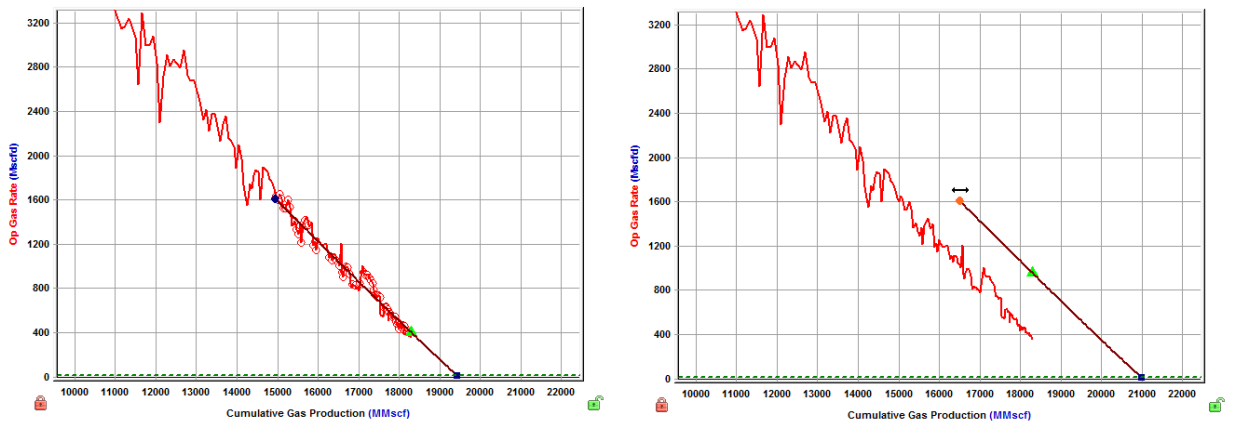
Changing the *b* value

To change the *b* value, click-and-drag the decline curve while holding down the **Ctrl** key. This changes the decline exponent value and the start point, while the left point and end point remain fixed. (The gray guidelines represent decline exponents of 0 and 1.)
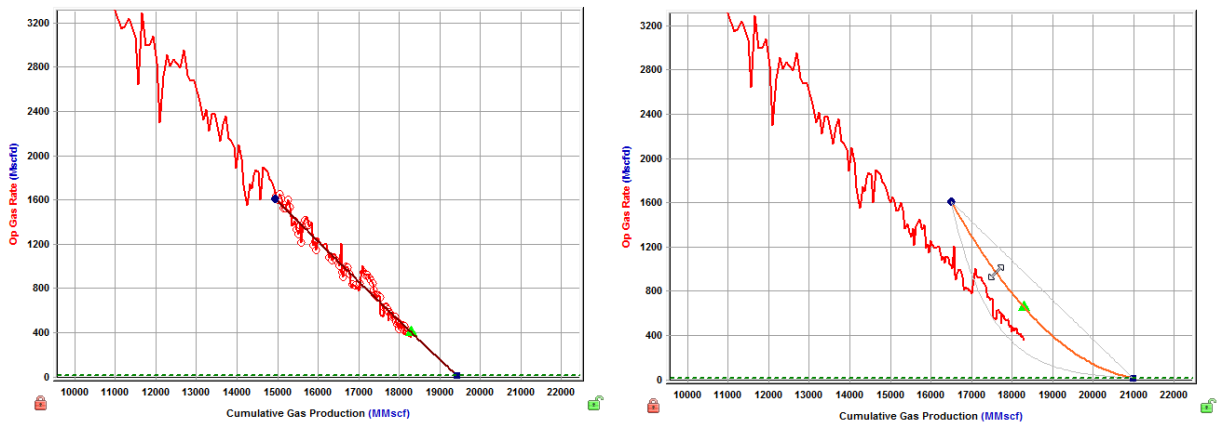
Changing the *b* value & final cumulative production

To change the *b* value and final cumulative production while maintaining the initial gas / oil rate, drag the end point while holding down the **Ctrl** key. (This method does not show the gray guidelines.)
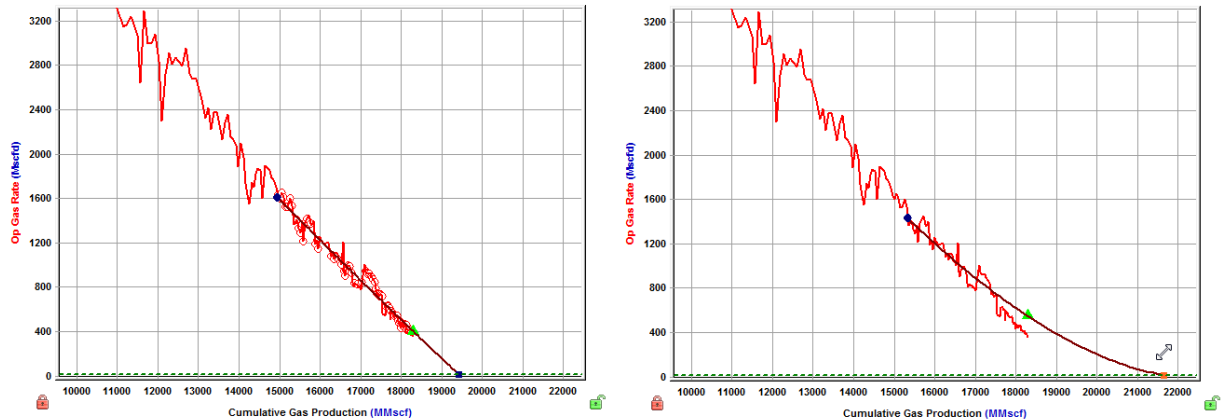
Changing final cumulative production & decline rate

To change the final cumulative production and the decline rate, drag the end point left or right. This changes the cumulative production of the segment and the forecast duration, without changing the final rate. The initial gas / oil rate and decline rate are also changed.
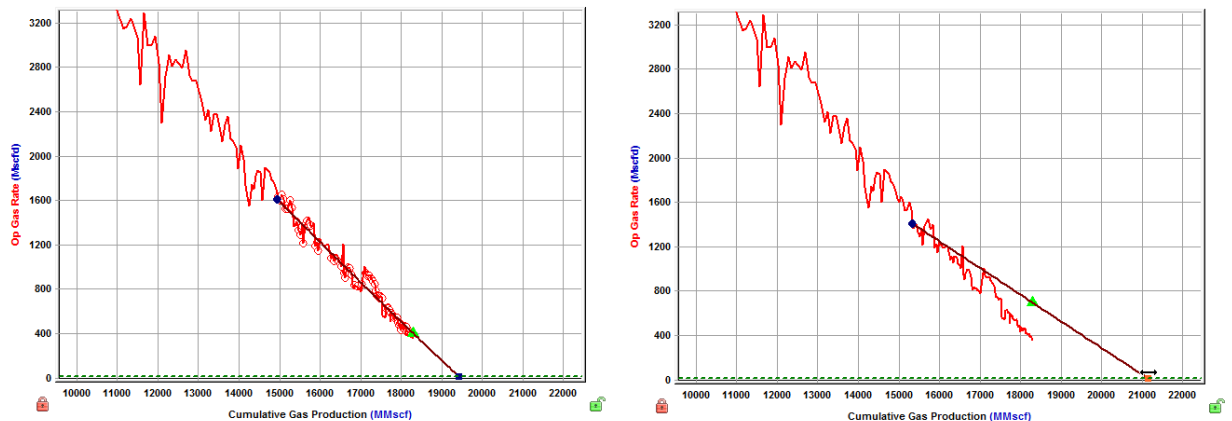
Changing the abandonment rate

To change the abandonment rate, drag the end point while holding down the **Shift** key. The final rate, cumulative production, and forecast duration are changed without changing the decline exponent, or effective decline rate.
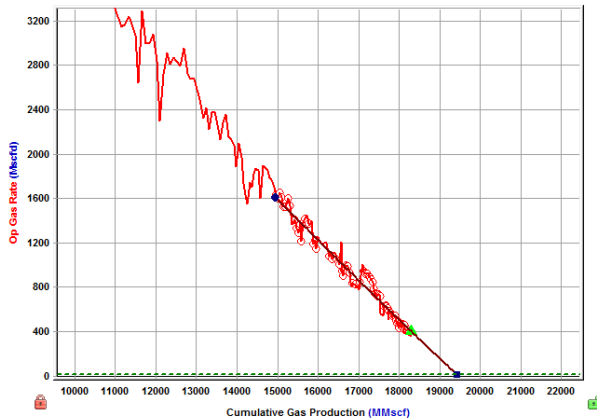
Manipulating multiple segments

Individual segments can be best fit to the corresponding data interval by using the data selection tool, and selecting data points between the start and end date of that segment.

Alternatively, selecting data points that span multiple segments best fits each segment to the points that lie between their individual start and end dates.
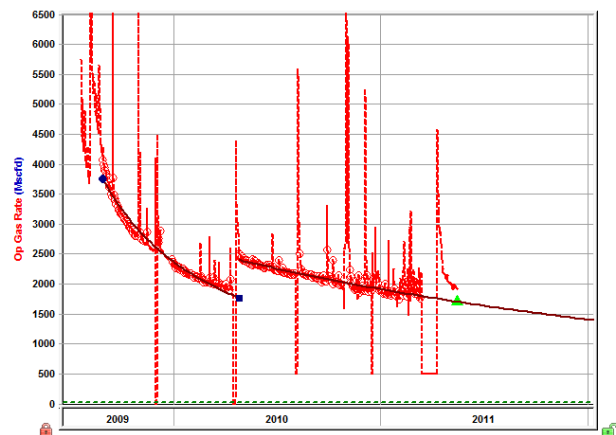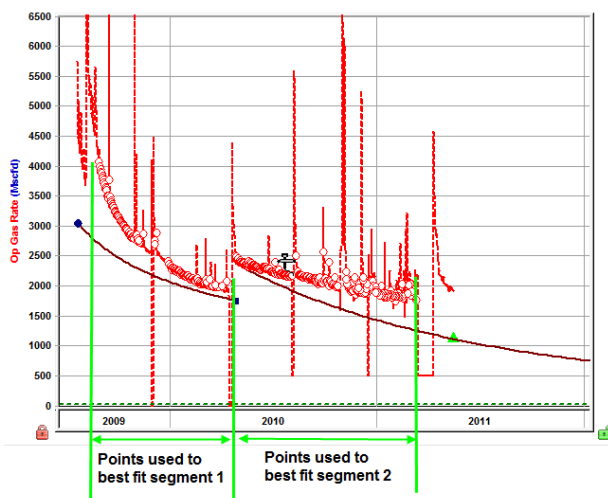
When best fitting using the data selection tool, the start date of the first segment corresponds to the first data point that is selected. The end date of the first segment can be changed by clicking-and-dragging the point left or right.

The end date of the first segment corresponds to the start date of the second segment. These dates are always be the same; however, the initial rate of the second segment does not necessarily have to be the same as the final rate of the first segment. (Additional segments can be added as needed.)

Manipulating a multi-segment decline

A multi-segment decline is initially "best fit" using all data points as follows:

- with the start date of the first segment equal to the start of production

- the end point of the first segment defined by the constraints entered in the Options dialog box

- the start date of the second segment equal to the end date of the first segment

- the end date of the second segment defined by the final gas rate

The first and second segments are always continuous, with the end date of the first segment equal to the start date of the second segment. As well, the instantaneous decline rate at the end of the first segment is equal to that at the beginning of the second segment.

Due to the continuity between the first and second segments, manipulating the shape of the first segment's decline curve impacts the second segment's decline curve.

All line manipulations described above can be applied to the multi-segment decline analysis. The length of the first decline segment can be changed by clicking the end point of the first segment and dragging left or right.
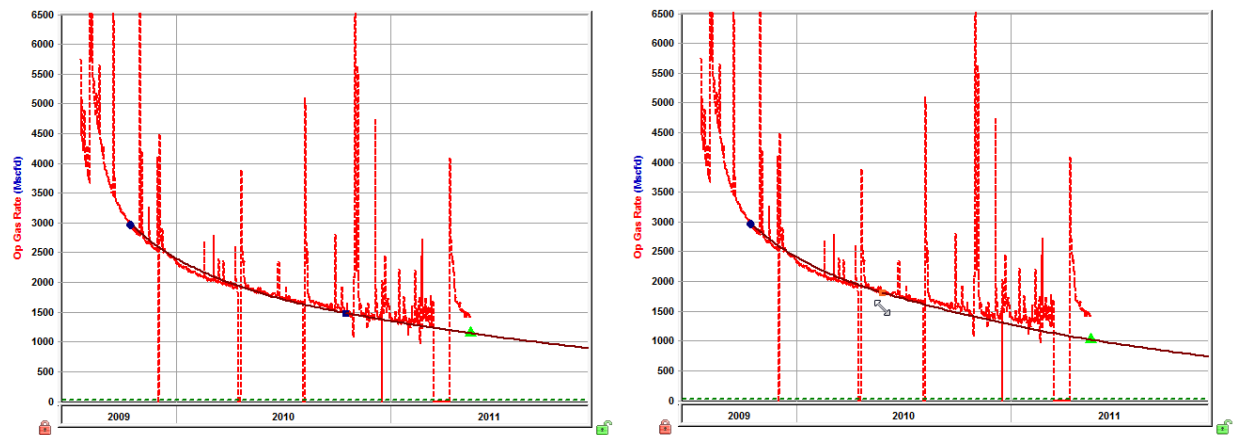
Bulk Editor dialog box

Click to see subtopics:
Icons
Exceptions

This dialog box is accessible by clicking the **Bulk Editor** icon (📝) in the main toolbar.

In this dialog box, you can delete multiple analyses and worksheets quickly.
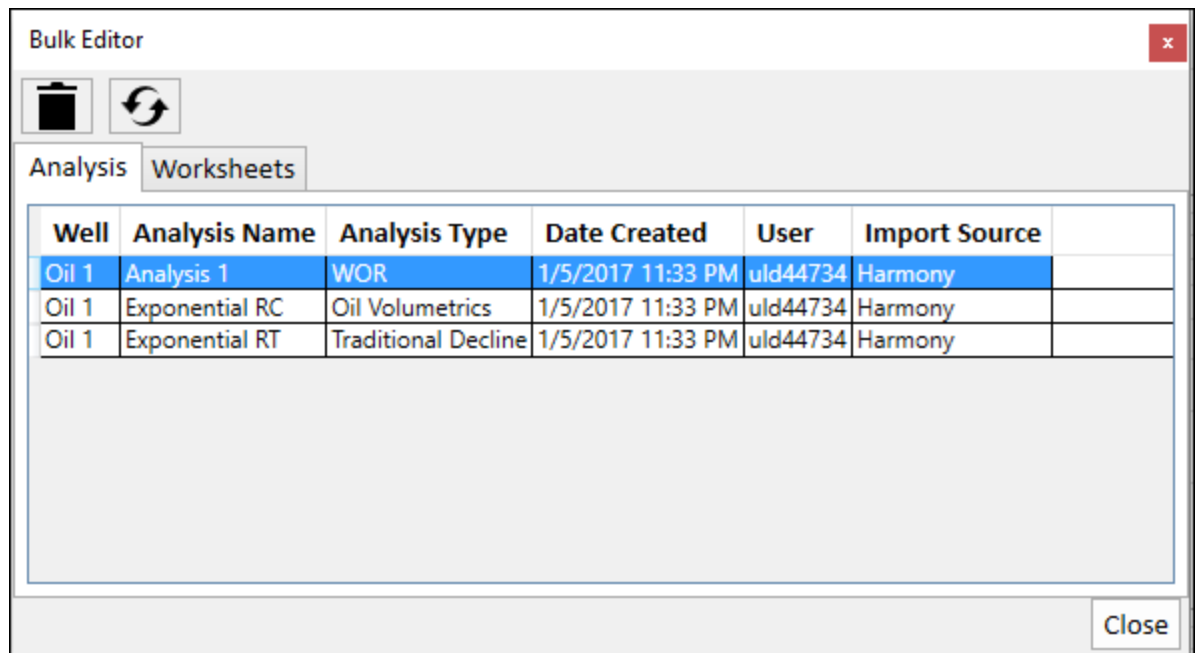
Select the analyses you want to delete in the Analysis tab, and select the worksheets you want to delete in the Worksheets tab. If you want to sort columns, click the column headers.

Icons

Both tabs have the same icons.

🗑️ **Delete** — deletes the analyses or worksheets you have selected. If an analysis or worksheet is locked by another user, a message is displayed at the bottom of this dialog box and in the Status Window. You are prompted to confirm your deletion.

Refresh — refreshes the list in the table, which can be useful when another user releases / unlocks an analysis or worksheet.

Exceptions

These exceptions apply to the bulk editor:

Selected groups of entities only display the analyses / worksheets at the group level, and not for individual entities. For example, if Well 1 and Well 2 are in a group called Pool A, and you select Pool A before opening the bulk editor, then analyses for Pool A are displayed, but analyses for Well 1 or Well 2 are not displayed individually.

Classified reserve analyses are not listed and cannot be deleted using the bulk editor.

The bulk editor treats linked analyses differently from other analyses. (You can tell that an analysis is linked if the Analysis Manager has more than one sub-analysis listed.) If you delete a linked analysis, both the parent and child items are deleted.

If you delete an FMB, typecurve, analytical, or hybrid analysis, then the associated worksheet is also deleted. If you delete the worksheet, the analysis is also deleted. The reason for this is because unlike other worksheet types that can display multiple analyses of various types, each of these worksheets is linked to its own analysis.

If you delete a consolidated forecast, only the consolidation is deleted. The child analyses used in the consolidation are not deleted.

Database connection

These items apply to the database connection:

- Assign Mapping dialog box

- Filter a Column dialog box

- Select Wells to Import dialog box

- Set Up Connection Settings dialog box

- Set up Filters dialog box

Assign Mapping dialog box

This dialog box is commonly used when you import well data from a database. You can import well production, attributes, fluid properties, wellbore configurations, and declines (Aries only). Mappings for each connection are saved and shared with all users for the current Harmony Enterprise database.

Note: The Source columns shown below are for the table in your source database. The Next button is disabled until all of the mapping errors are corrected. The view definitions that outline the data fields that can be imported, and the expected format, are summarized in the View Definition spreadsheet. By default, this spreadsheet is located as follows: C:\Program Files (x86)\IHS Markit\IHS Harmony Enterprise <versionX.X>\FDBCSupportFiles\IHS.

Views:

To import data from your internal database into Harmony Enterprise, views / tables in your database (**Client Tables / Views**) must be mapped to the corresponding Harmony Enterprise view.

- ARIES_DECLINE_ANALYSES — supports Arps' decline analyses formatted from Aries.

- PRODUCTION_HISTORY — historical production rates and volumes including custom datasets. Custom datasets must be created in Harmony Enterprise before they can be imported.

- WELL_INFORMATION — well attributes and reservoir properties including custom attributes. Custom attributes must be created in Harmony Enterprise before they can be imported.

- RESERVOIR_PROPERTIES — general initial reservoir properties, such as initial reservoir pressure, temperature, and saturations.

- GAS_PROPERTIES_HISTORY — gas gravity and produced gas composition. Can accommodate multiple PVT test results over time, or a single result.

- LIQUID_RICH_GAS_PROPERTIES — condensate gravity along with CGR and recombined gas rate.

- OIL_PROPERTIES — oil gravity, bubble point pressure, and initial GOR.

- OIL_CALIBRATION_PROPERTIES — calibration pressure, temperature, formation volume factor, compressibility, and viscosity.

- SEPARATOR_PROPERTIES — temperature and pressure in the separator.

- CUSTOM_GAS_PVT_PROPERTIES — custom gas formation volume factor table.

- CUSTOM_GAS_VAPORIZED_OIL_PROPERTIES — custom vaporized oil ratio table.

- CUSTOM_GAS_VISCOSITY_PROPERTIES — custom gas viscosity table.

- CUSTOM_VISCOSITY_OIL_PROPERTIES — custom oil viscosity table.

- CUSTOM_SATURATED_OIL_PROPERTIES —oil formation volume factor and solution gas oil ratio custom tables below bubble point.

- CUSTOM_UNSATURATED_OIL_PROPERTIES — oil formation volume factor and solution gas oil ratio custom tables above bubble point.

- WATER_PROPERTIES — water gravity, salinity, viscosity, compressibility, formation volume factor, and solution gas water ratio.

- SHALE_PROPERTIES — shale Langmuir volume, shale Langmuir pressure, and bulk density.

- WELLBORE_CONFIG — configuration name, date and ID, as well as datum, flow path, and pressure loss calculation correlation.

- WELLBORE_CONFIG_DETAILS — top and bottom casing depths, tubing and perforations, along with casing and tubing diameters. Deviation surveys and detailed temperature profiles are also defined here.

- PVT_PROPERTY_CORRELATION — sets all correlations used in the Properties editor along with the Gas Type.
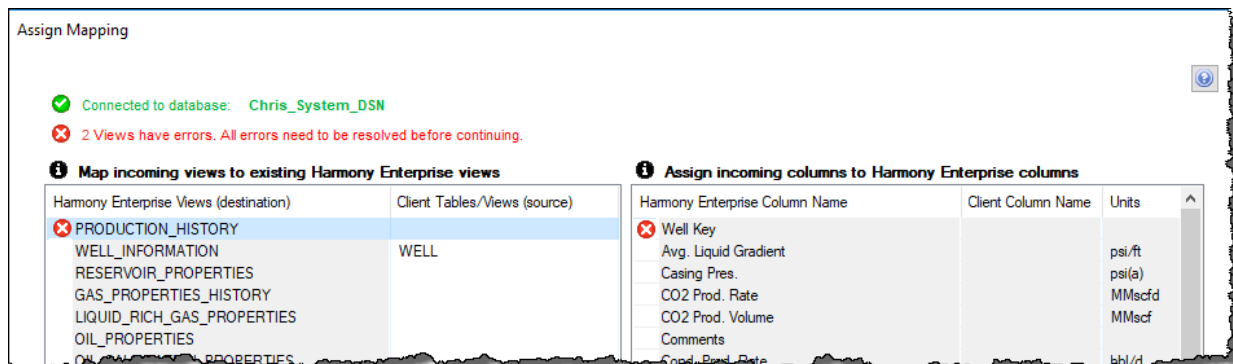
Columns:

After mapping your views / tables to the Harmony Enterprise incoming views, the columns within these views must be mapped. For numeric columns that have been mapped, specify the units that these values use in your database.

Errors and minimum requirements

Every table that is mapped must have at least the well key and one other column specified. (The well key is the identifier used in the source database to separate wells.) For database imports, the absolute minimum requirements are the well key and date time in the PRODUCTION_HISTORY table.

When there are errors in the database mapping, a red X is displayed next to the Harmony Enterprise Views (destination) and the Harmony Enterprise Column Name. At the top of the Assign Mapping dialog box, an error count is listed. Errors may include missing identifiers, or mapping a column of an inconsistent data type (for example, mapping text to numeric Harmony Enterprise data).

Filter a Column dialog box

This dialog box is commonly used when you <u>import well data from a database</u>.

> **Filter Column** — selecting a value from the drop-down list specifies which attributes are used by the filter. To reduce the time it takes to display wells, specify values and then press the **Enter** key to separate one value from another. The columns displayed in the drop-down list are based on your mapped columns in the WELL_INFORMATION view.

Some of the attribute values use checkboxes instead of a user-defined list. In these cases, click the checkboxes for the values you want.

Select Wells to Import dialog box

This dialog box is commonly used when you import well data from a database. If the left pane is blank, you need to click the Tree Hierarchy icon ( ) and configure your well hierarchy.

Note: The hierarchy structure needs to be set up for each user for each database connection, but after this is set up, these settings persist (are saved).

Toolbar

This dialog box has these items on its toolbar:

- **Tree hierarchy** — opens the Configure Well Hierarchy dialog box where you can organize entities in a hierarchical structure according to specific attributes. Click this icon to create a hierarchy view of your wells, which is categorized to your preferences.

- **Expand all** — expands all nodes of the tree structure displayed in the pane.

- **Collapse all** — collapses all nodes of the tree structure displayed in the pane.

Plot preview
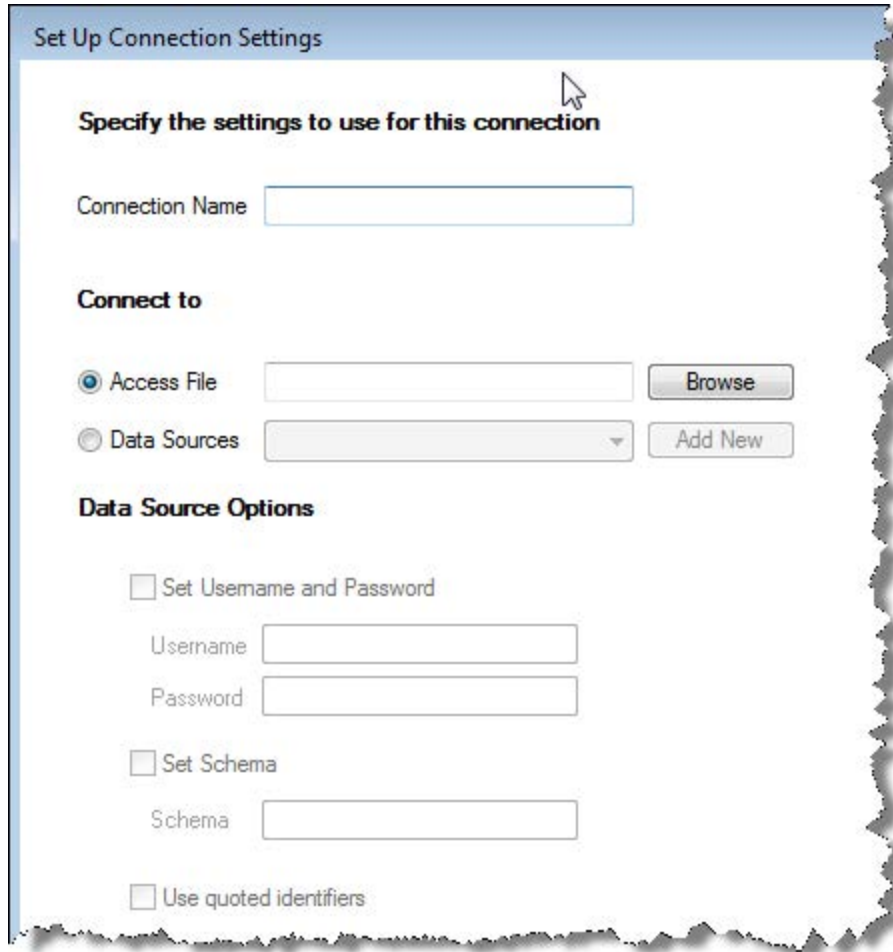
To see a preview of your well production, click the well's name (not its checkbox).

To limit the number of rows displayed in the Plot Preview pane, click the Limit Rows checkbox and type a limit. The default setting is 1000 rows. Note that your preview limit is saved for all of your database connections, and changing the limit value affects the next well that is selected.

The *Continuous Time Track* option is used to adjust your data depending on your shut-in conditions. It is extremely important that you use this feature correctly, as your volume and rate data is influenced by this setting. For more information, see Continuous Time Track.

Set Up Connection Settings dialog box

This dialog box is commonly used when you import well data from a database, and enables you to create or edit your database connections.

Connection Name — type the name of your database connection.

Connect to — select your data source: either an Access database or other data source.

- **Access File** — browse to the location of your Access database.

- **Data Sources** — select the open database connection (ODBC) that connects Harmony Enterprise to your source database.

- **Set Username and Password** — if login credentials are required for accessing your database, you can save the user name and password. Note that this field can be left blank.

- **Set Schema** — set the database schema that the data is stored in. Note that this field can be left blank.

- **Use quoted identifiers** — encloses database object names within quotes for queries. For more information, contact technical support (opens in a new window).

Set Up Filters dialog box

This dialog box is commonly used when you import well data from a database, and lists filter columns and values in a table. You can filter a column to filter out certain wells being queried.

- **Add** — opens the Filter a Column dialog box.

- **Edit** — after selecting a filter, you can click Edit and update your filter values.

- **Delete** — after selecting a filter, you can delete it.

If you select or deselect the **Disable all Filters** option, this setting is saved for your current database connection. Enabling this option means that no filtering is done; all of your wells are imported. (It is the same thing as not setting up any filters.)

Note: All of the filter settings are stored for each user for each database connection. These settings are *not* saved between users.

Diagnostics tab

The Diagnostics tab displays customizable plots consisting of production, injection, and pressure data for each well or scenario in a Harmony Enterprise project. Selecting parameters in the Data Viewer Properties pane displays these items on the plot.

- If you select more than one entity, the selected data from all these entities is displayed in the diagnostic plot.

- Hovering your mouse over selected entities in the Entity Viewer (Hierarchy or Custom) makes their plot lines become bold.
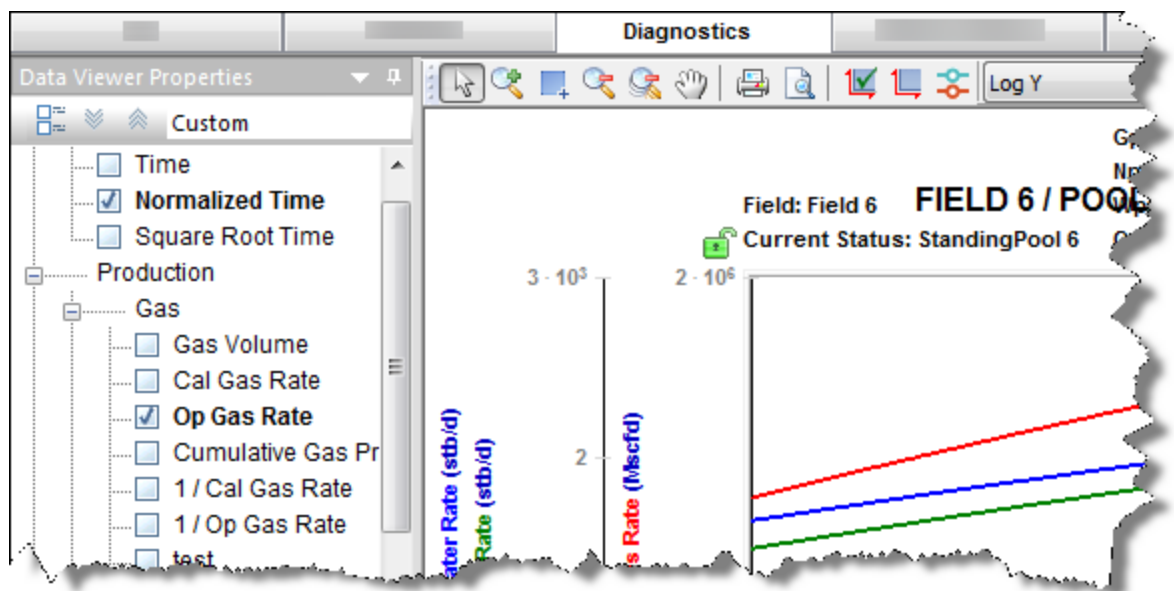
You can send your plot to a comparison plot, by right-clicking it and selecting **Send Plot to Comparison Plot**. You can also right-click a dataset in the plot and select **Send Dataset to Comparison Plot**. For information on other options, see plot options and locks.

Note: If a custom dataset does not exist when a template is applied, the dataset is not added to the plot.

Toolbars

This tab has two toolbars: a primary toolbar for the Data Viewer Properties pane and a secondary toolbar above the plot. For a description of common icons, see toolbars.

Primary toolbar

The important item on this toolbar is the Template drop-down list.
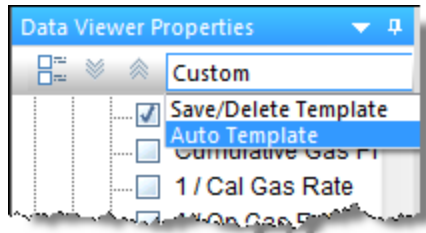
Auto Template is the default setting, but you can select **Save / Delete Template** in order to create a template with the plot selections / datasets you prefer. This template can also be used in a custom worksheet to perform a decline analysis or ratio analysis. For more information, see the Save Template dialog box.

Secondary toolbar

The secondary toolbar is above the plot, and in addition to the common toolbar items, has the following items:

- **Toggle Coloring by Entity or Dataset** — displays unique colors for entities / datasets. In other words, entities can use the default colors (red for gas, green for oil, etc.), or every dataset can have a unique color. (This feature is available in a diagnostic plot with multiple wells selected.)

- **Plot drop-down list** — select your plot type (semi-log vs. coordinate).

Context menus

Right-clicking within the *Data Viewer's* tree structure displays the same context menu as for a pane.

Right-clicking within the Diagnostic plot (the main pane) displays plot options.

Save Template dialog box

This dialog box is commonly used when you save, delete, or rename a template on the Diagnostics tab.

- **Name** — type a name for your template.

- **Worksheet Category** — select the appropriate worksheet category from the drop-down list (that is, Decline, Ratio Analysis, or Custom). After you click **Save**, the template is available for the new worksheets you create in the respective categories.

For example, if you are saving a template for the Decline category, you can customize these things in your template:

- You can set your rate (operated vs. calendar rate), and after adding a new decline worksheet, you can select the template and your decline worksheet initializes with that rate type.

- You can set any individual axis type to log-log (vs. coordinate) by right-clicking it.

To rename a template, select it in the Existing Templates box and type a new name in the Name field; click **Save**.

To delete a template, select it in the Existing Templates box and click **Delete**.

Hall plot

The slope of a Hall plot indicates a well's average injectivity. At normal conditions, this plot is a straight line; deviations indicate changes in injection conditions. For more information, see Hall plot theory.

Note: The Hall plot uses tubing pressure, not injection tubing pressure, as an input.

You can display this plot as follows:

- Click **Injection**, **Water**, and drag **Cumulative Water Inj** to the x-axis.
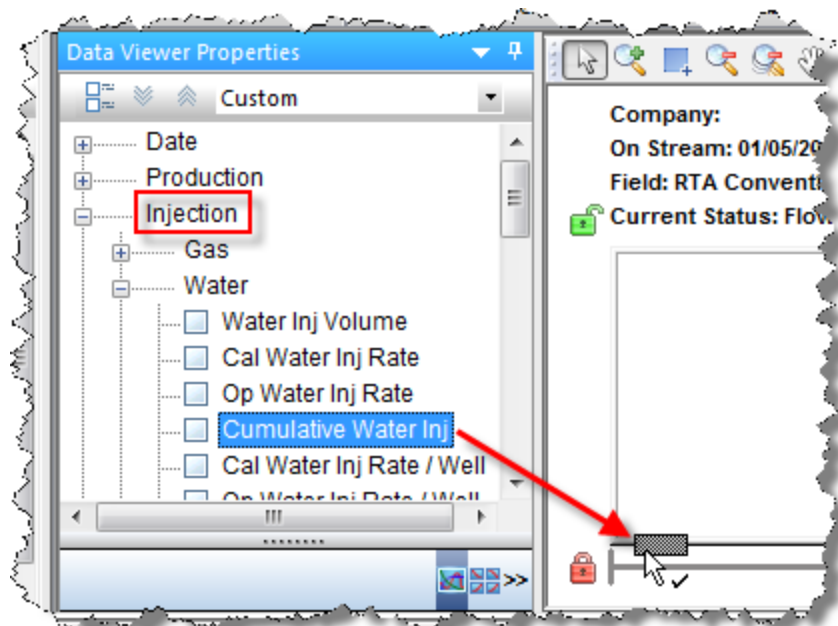
- Click **Hall**, and drag **Hall Coefficient** or **Hall Coefficient Slope** to the y-axis.
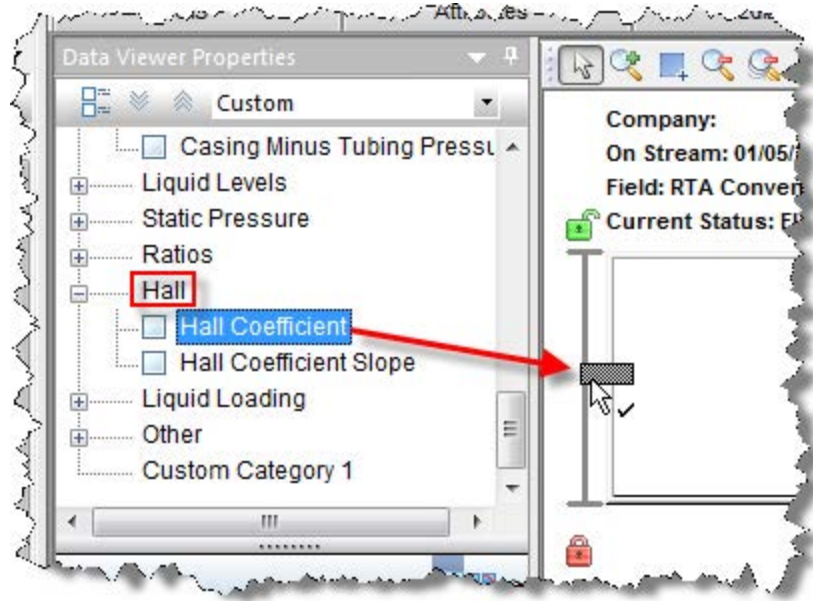
The Hall plot opens.
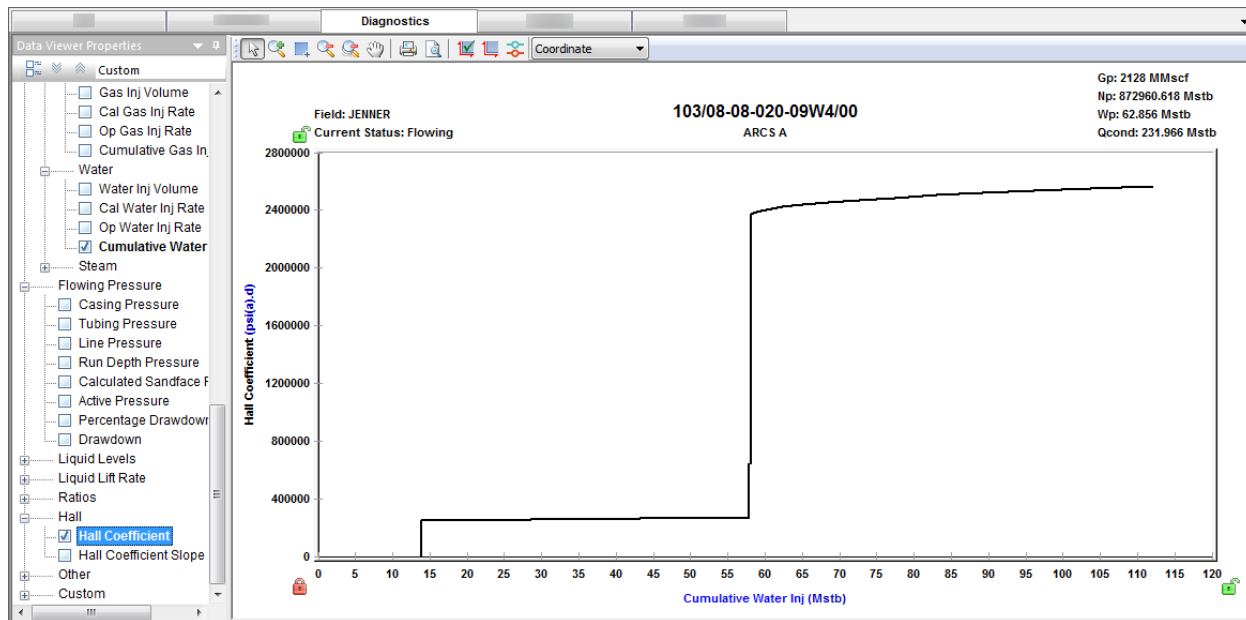
Economics

The Economics tab displays the economics for a well, scenario, or group of wells on a monthly basis, and you can run economics for multiple cases with multiple wells. Economics are calculated on a monthly basis by:

- taking the estimated production from decline curve analysis

- multiplying the production volume by the oil, gas, condensate, water, or BOE price that applies to the well at that month

- subtracting fixed and variable expenses

- calculating net revenues for the month

Note: Economics works with your Harmony Forecast™ license.

After clicking **Add Case**, the Case section opens. Click the inverted chevron icon (⌄) to open the case section.

Case

In this section, you can type a name for your economics scenario and add notes. Only one case can be open at a time.

A case can be added to a single entity or multiple entities.

Case — the title for your economics scenario. You can rename your case by clicking the Case field and typing a new name, or you can leave the default name. However, you cannot have cases with the same name. If you rename a case, its order in the list of cases is automatically resorted alphabetically.

Notes — (optional) click this field to begin typing your notes.

The effective date and duration date are displayed in gray text below the toolbar icons. These dates are automatically taken from the production data you select in the Forecast section. For example, if you have a gas forecast that ends earlier than an oil forecast, the duration date is extended to match the oil forecast's end date for the analysis.

Toolbar

These icons are displayed at the top of the Case section:

● **Delete Case** — removes the currently selected case. If you delete the last case, your settings are reset to the default blank settings (the initial view).

● **Copy Case** — creates a duplicate of the currently selected case. The name is appended with the word "Copy".

● **Show / Hide Case** — toggle between showing or hiding the plot / grid for the currently selected case.

Discount Rate

The discount rate is a percentage discount, which is applied per year. This adjustment applies to your monthly cash flows received in the future to show its present value.

Type your annual discount rate for your case. The default value is 10%.

Forecast

In this section, up to five fluids can be displayed: oil, gas, condensate, barrel of oil equivalent (BOE), and water.

Your forecast is selectable from the existing decline analyses you have for the currently selected entity.

Select forecast data — select from the drop-down list. If there is an issue with your selection, the Fluid table below displays an error message (for example, invalid forecast, no forecast, etc.).

Note: Forecast volumes are only displayed for the fluids (that is, oil, gas, or BOE) that apply to the currently selected entity, and you can only select one forecast (not one forecast for each fluid).

Price & Revenue

In this section, up to five fluids can be displayed: oil, gas, condensate, BOE, and water.

Type your price, percentage of escalation / year, and your revenue is automatically calculated.

Revenue represents money you have earned *before* any expenses are accounted for.

Edit Price Deck — opens the Enter Price Decks dialog box. Click this icon to paste values from an existing price deck, or type prices for your fluids. Note that if your price deck has an end date that falls short of the duration date of the forecast for your analysis, the last value in the Price Deck table is used for the remainder of the forecast period. If you paste content with more rows than are automatically displayed in the Price Deck table, note that additional rows are automatically added.

Tip: To decouple your case from a price deck, you need to delete the content in the Enter Price Decks dialog box. Then, you can type a price and percentage of escalation for your fluids.

Capital Expenses

Capital expenses represent investments that generate benefits for more than one period (for example, drilling, completions, tanks, buildings, etc.).

Tip: For upfront costs, leave the Date field blank. These costs are not included in the net present value (NPV) calculation.

Description — type a name for your capital expense.

Date — select a month from the calendar. Note that you must enter a date between the effective date and duration date for your economic analysis.

Dollar Amount — type a value for your capital expense.

Delete icon — deletes the currently selected capital expense.

Add icon — adds a new capital expense item.

Operating Costs

Operating costs represent expenditures that generate a benefit for the current period (for example, labor, maintenance, water disposal, etc.).

Description — type a name for your operating cost.

Dollar Amount — type a value for your operating cost.

Operating Cost Type — select from the drop-down list (that is, $ / month, $ / year, $ / bbl, $ / Mscf).

⊗ **Delete** icon — deletes the currently selected operating cost.

⊕ **Add** icon — adds a new operating cost item.

From — select a month from the calendar. Note that you must enter a date between the effective date and duration date for your economic analysis.

to — select a month from the calendar. Note that you must enter a date between the effective date and duration date for your economic analysis.

Note: If no dates are selected, by default, the effective date and duration date are used.

Taxes & Royalties

Taxes and royalties are calculated as percentages for the following categories:

Severance Tax — type your percentage. This tax is calculated based on oil & gas earnings *before* deductions for operating costs, and is also known as the production tax.

Ad Valorem Tax — type your percentage. This "according to the value" tax is calculated based on local taxes (for example, metro district tax, county tax). It is calculated based on revenue less the severance tax.

Royalties — type your percentage. This tax is calculated based on the ongoing right to use certain properties or assets. This tax may be based on a percentage of revenues, or a fixed price per unit sold.

Note: Taxes and royalties are calculated for the duration of the forecast, not annually.

Working Interest

Type your percentage of working interest for revenue and operating costs, which applies for the entire course of the project.

If you want to apply your operating interest to all capital expenses, click this checkbox.

Cumulative Net Cash Flow

This represents a summation of all the values for your case.

Important metrics

These metrics are displayed at the bottom of the plot:

Net Present Value ($) (NPV) — provides the dollar value of a project taking into account the time value of money.

Discounted Payout — the length of time it takes in months to pay back the original investment. If you are running economics on an existing well, the discounted payout is zero.

Internal Rate of Return (IRR) — measures the potential profitability of a project. This metric is a discount rate that measures the percentage of return needed in order for the project to break even (where NPV is equal to zero). IRR is used to evaluate the attractiveness of a project, and is also known as the discounted cash flow rate of return. Generally, if the IRR is a high percentage, this indicates that you have a good project to invest in.

Plot / grid

The cash-flow plot is displayed in the main pane of the Economics window and has the following icons:

Show Plot — displays a plot view for your case. Up to 10 cases can be plotted with cumulative and periodic cash flows. If you plot more than 10 cases, only the cumulative values are displayed. Note that the active case is displayed in bold on the plot.

Show Grid — displays a tabular view for your active case, which can be copied and pasted, or exported as a .csv file.

Export to .csv — (only visible when the Show Grid icon is selected) copies your tabular data to a .csv file.

Rescale plot to show all data — (only visible when the Plot icon is selected) automatically fits all your data to the plot.

The following drop-down list items are only visible when the Plot icon is clicked:

Cumulative and Periodic Cash Flows — displays both the cumulative cash flow and period cash flow on the same plot.

Periodic Series Cash Flows — depending on how you scale the resolution on the x-axis, cash flow is displayed in a bar graph by month, quarter, year, or every five years.

Cumulative Series Cash Flows — displays an aggregate of cash flows in a line graph. The point where the line graph crosses the x-axis is the break-even point.

Y-axis icons

These icons are displayed when you hover your mouse over the y- axis:

↕ **y-axis panning** — visible when you hover over the middle of the y-axis, and enables you to pan the axis up and down.

↕ **y-axis panning with a lock on the top of the top of the axis** — visible when you hover over the lower part of the y-axis, and enables you to pan the axis up and down, while you maintain the top value on the y-axis.

↕ **y-axis panning with a lock on the bottom of the axis** — visible when you hover over the upper part of the y-axis, and enables you to pan the axis up and down, while you maintain the lower value on the y-axis.

X-axis icons

These icons are displayed when you hover your mouse over the x- axis:

↔ **x-axis panning** — visible when you hover over the middle of the x-axis, and enables you to pan the axis left and right.

↔| **x-axis panning with a lock on the right of the axis** — visible when you hover over the left-side of the x-axis, and enables you to pan the axis left and right, while you maintain the value on the right.

|↔ **x-axis panning with a lock on the left of the axis** — visible when you hover over the right-side of the x-axis, and enables you to pan the axis left and right, while you maintain the value on the left.

Editors

To open the Editors pane, select an entity (in either Entity Viewer, or on the GIS map), click the Analysis tab, and then click the Editors sub-tab.

Tip: You cannot use the editors with group selections.

Harmony Enterprise has the following editors:

- Properties (opens when you click the Editors tab)
- Wellbore
- Production
- Static Pressure

Properties editor

In the Properties editor (located within the Editors pane), you can set properties and correlations for the formation and fluids, as well as reservoir properties.

Toolbars

There are three toolbars associated with the Properties editor: primary, secondary, and plot toolbars.

Primary

The primary toolbar has the following icons:

- **Change plot options** — opens the Plot Options dialog box where you can set your minimum and maximum pressure, as well as your step size. You also have the option to display numerical or non-numerical analysis properties.

- **Copy to / paste from clipboard** — click this icon to copy / paste properties between different wells.

- **Calculate sandface pressure** — calculates sandface pressure based on given wellhead pressure and fluid rates. These calculations use fluid properties set in the Properties editor. If you change fluid properties, you need to re-run sandface pressure calculations by clicking this icon.

Secondary

The secondary toolbar is located to the right of the Editors pane, and has the following icons:
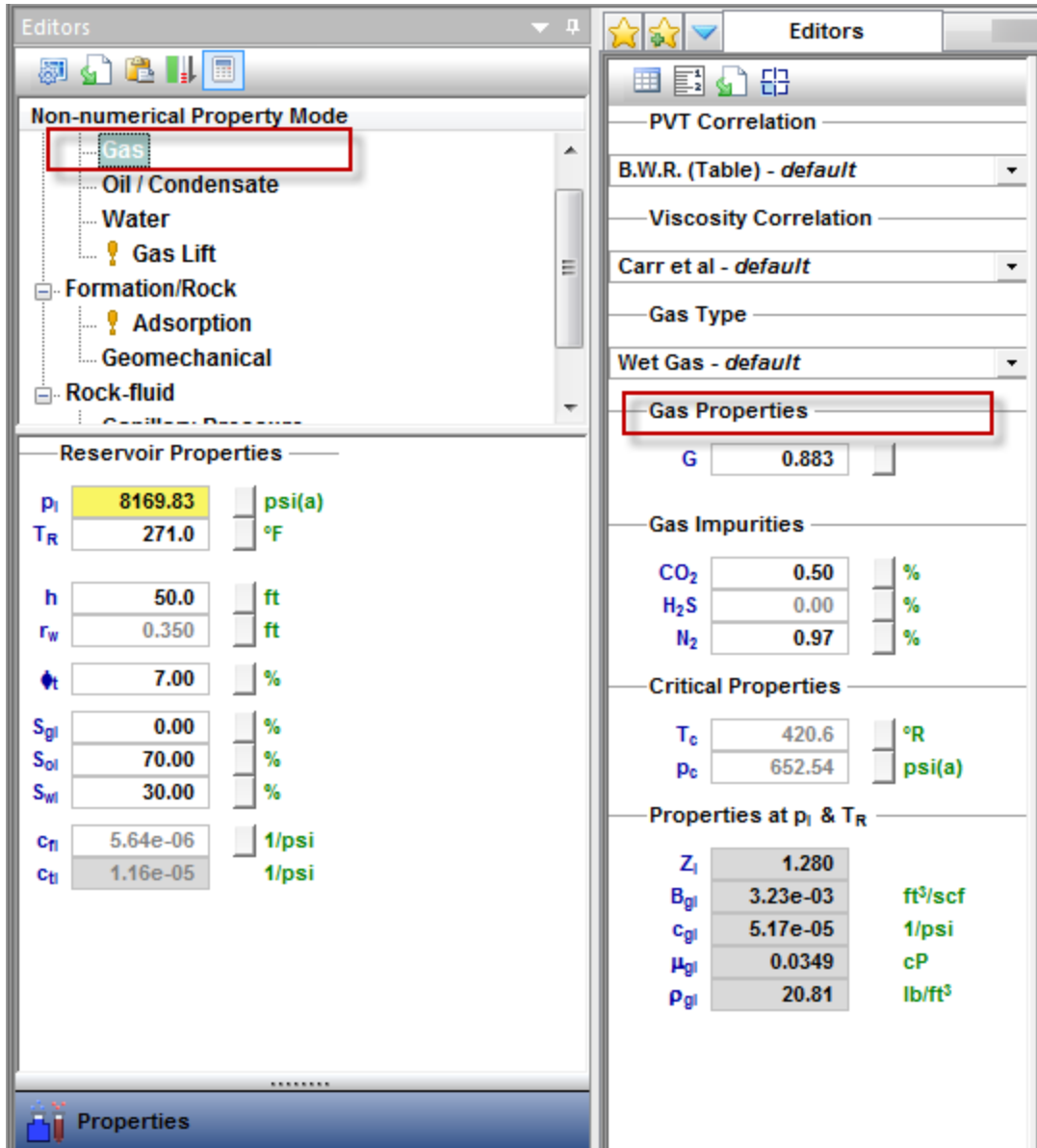
- **View Data** — toggle between a table view and a plot view.

- **Toggle Units** — toggle between metric and field (imperial) units.

- **Change Bottom Left Plot** — (gas properties only) toggles the bottom left plot between the Vaporized Oil Ratio (R_v) and Gas Compressibility (c_g).

Plot

The plot toolbar is located directly above the plots in the main pane. For more information, see plot toolbars.

Selection tree

The selection tree is located directly below the primary toolbar. After you select a certain node in the selection tree, a corresponding set of properties is displayed in the pane to the right (for example, if you select the Gas node, gas properties are displayed in the right pane). The Reservoir Properties pane is located below the selection tree.

Gas properties

After you select **Gas** in the selection tree, you can select a PVT correlation, or custom table from the **PVT Correlation** drop-down list. Use the correlation selection for gas PVT to select the appropriate correlation. If you select **Custom Table**, you can enter or import your own data.

Similarly, you can select a viscosity correlation, or custom table from the **Viscosity Correlation** drop-down list. Use the correlation selection for gas viscosity to select the appropriate correlation.

From the **Gas Type** drop-down list, you can select dry gas, wet gas, or liquid-rich gas.

Gas properties as functions of pressure are calculated based on selected correlations, using the values set for gas gravity (G), critical temperature (T_c), and critical pressure (p_c). You can enter these values, or leave the default values calculated by Harmony Enterprise.

The calculated properties at initial conditions (p_i and T_R) are displayed in the **Properties at p_I & T_R** section.

Gas properties vs. pressure are plotted, including Z, ψ, B_g or B_{gd}, $ρ_g$, c_g, R_v, V_L / V_{sat}, and $μ_g$.
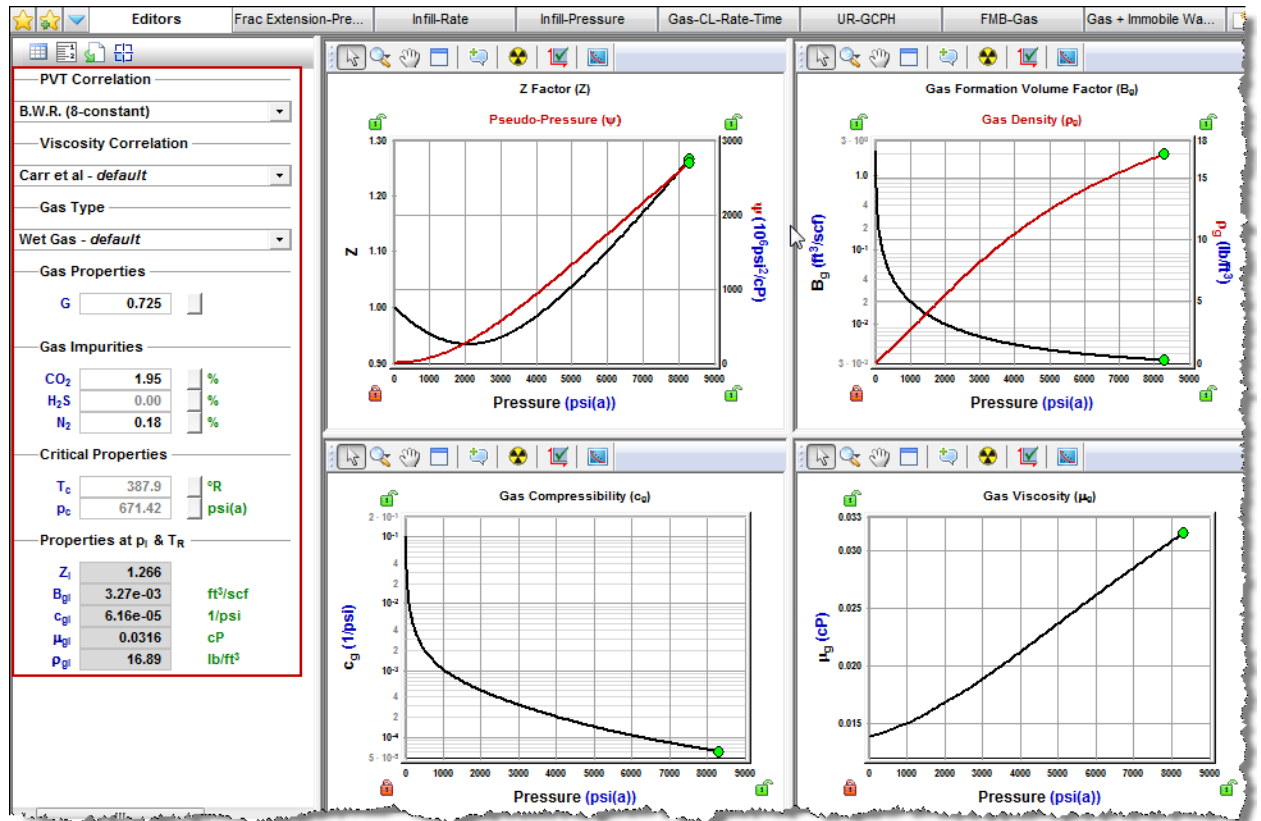
Additional properties for liquid-rich gas

If the Gas Type is set to **Liquid-Rich Gas**, additional properties are displayed:

- **Vaporized Oil Ratio Correlation** — defines the amount of liquid vaporized in gas as a function of pressure.

- **p_{dew}** — dew point pressure. It should be set to the same value as the bubble point pressure defined under Oil / Condensate properties.

- **CGR$_l$** — condensate gas ratio at the separator.

- **γ$_{cond}$** — condensate gravity. It should be set to the same value as the oil gravity defined under Oil / Condensate properties.

- **T$_{sep}$, p$_{sep}$** — temperature and pressure at the separator.

- **RGRF** — recombined gas rate factor. We recommend keeping the default value.

- **G$_r$** — recombined gas gravity. All gas property functions are generated based on this gas gravity (as well as critical temperature and pressure).

Correlation selection for gas

There are two correlation selections for gas: PVT and viscosity.

PVT

Various gas PVT correlations are described below:

- **B.W.R. (Table)** — the Benedict-Webb-Rubin equation is an empirical relationship that predicts the state of liquids and gases. Tables were developed for approximately 50

substances, mostly hydrocarbons that related gas density, formation volume factor, and temperature to pressure.

- **B.W.R. (8-constant)** — the Benedict-Webb-Rubin (8-constant) equation of state developed a set of generalized coefficients in order to be applied to all types of gases.

- **B.W.R. (11-constant)** — the Benedict-Webb-Rubin (11-constant) equation of state is a further refined method to predict the state of liquids and gases. It is used for all types of gases, and uses 11 empirical constants to achieve a more accurate interpolation of the data.

- **AGA8 Detail** — calculates the Z-factor based on the physical chemistry of the gas components at specified temperatures and pressures. It can be used when the exact composition (fraction mole percents) of the gas is available.

- **Carbon Dioxide (Table)** — the Carbon Dioxide tables are for calculating a Z factor for 100% CO2 content.

- **Nitrogen (Table)** — the Nitrogen tables are for computing a Z factor for 100% N2 content.

- **Hydrogen Sulfide (Table)** — the Hydrogen Sulfide tables are for computing a Z factor for 100% H2S content.

- **Custom Table** — you can enter laboratory measurements for a gas Z factor or formation volume factor. The Z factor is calculated from the formation volume factor or vice versa. Gas compressibility is subsequently calculated from these two values.

Viscosity

Various gas viscosity correlations are described below:

- **Carr et al.** — developed to predict the viscosity of gas hydrocarbon mixtures for temperatures between 32ºF and 400ºF, and pressures up to 12,000 psi. It applies to both sweet and sour gas, and is designed to handle non-hydrocarbon components (CO2, H2S, N2) in concentrations of up to 15% each.

- **Lee, Gonzalez, Eakin** — applies to sweet gas, but does not account for the presence of non-hydrocarbon components. It is applicable for a pressure range of 100 - 8,000 psi, and temperatures between 100ºF - 340ºF. It is less accurate for gases with a specific gravity above 1.0.

- **Optimized Lee et al.** — developed using the Lee, Gonzalez, and Eakin method, but uses an optimized temperature history to achieve more accurate results, thus resulting in different coefficients in the equations. (There is less than a 5% difference in extreme cases from the original correlations.)

- **Lucas et al.** — uses the method of corresponding states to calculate gas viscosity. It is better suited for higher density gases at lower pressures.

- **Custom Table** — you can enter custom gas viscosity values from laboratory measurements.

Oil / condensate properties

After you select **Oil / Condensate** in the selection tree, you can select a PVT correlation, constant properties, or custom table from the **PVT Correlation** drop-down list. Similarly, you can select a correlation, constant properties, or custom table from the **Viscosity Correlation** drop-down list.

Use the underlined correlation selection for oil to select the appropriate correlation. If you select **Custom Table**, you can enter or import your own data.

Oil properties vs. pressure are plotted, including R_{so}, B_o, ρ_o, c_o, and μ_o. The calculated properties at p_i and T_R are also displayed.
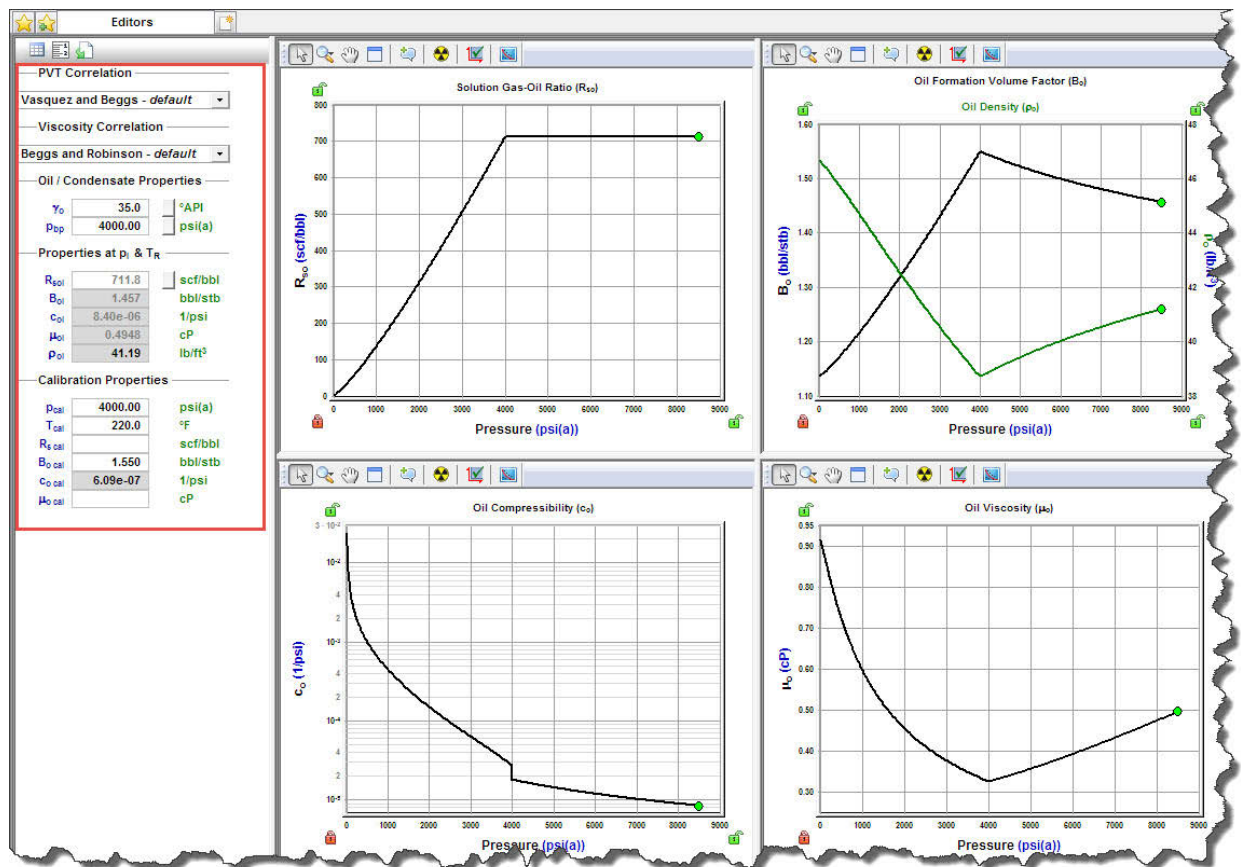
Calibration properties for oil

This functionality is used to calibrate existing correlations for oil PVT and viscosity to anchor them to a certain (known) value. This is usually done when you have some custom data for oil properties, and want to calibrate oil correlations to match custom data as closely as possible.

To see if the selected correlation is close to the custom data you entered, click the **Show the Custom Data Points** icon on the plot toolbar.
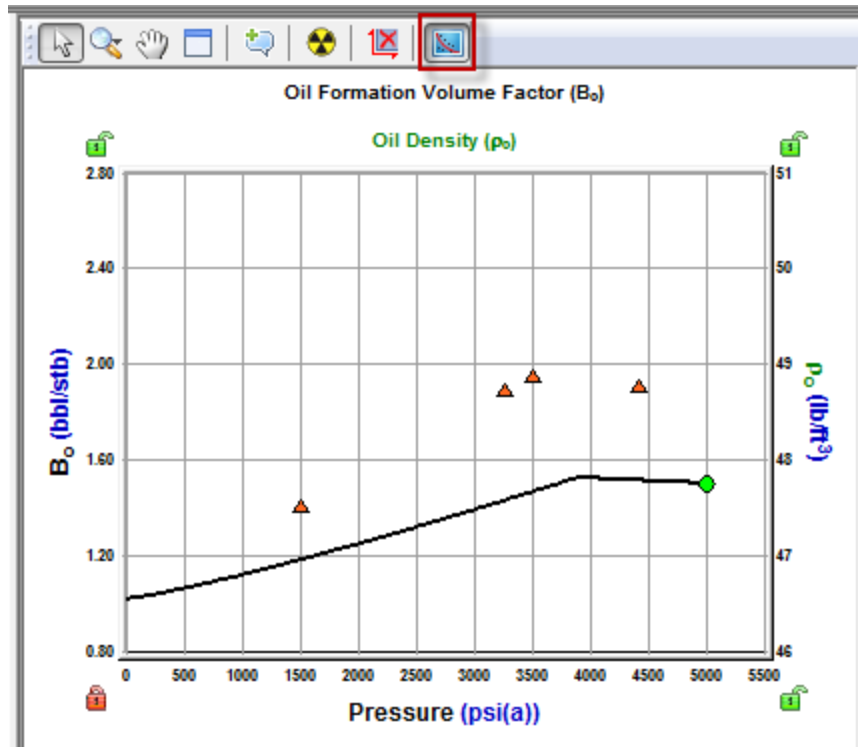
In the Calibration Properties section, these fields are displayed:

- **p$_{cal}$ and T$_{cal}$** — calibration pressure and temperature.

- **R$_{s\ cal}$** — the correlation curve for the solution gas-oil ratio (R$_s$) shifts such that R$_s$ (p=p$_{cal}$, T=T$_{cal}$)=R$_{s\ cal}$.

- **B$_{o\ cal}$** — the correlation curve for the oil formation volume factor (B$_o$) shifts such that B$_o$(p=p$_{cal}$, T=T$_{cal}$)=B$_{o\ cal}$.

- **c$_{o\ cal}$** — the correlation curve for oil compressibility (c$_o$) shifts such that c$_o$(p=p$_{cal}$, T=T$_{cal}$)=c$_{o\ cal}$.

- **μ$_{o\ cal}$** — the correlation curve for oil viscosity (μ$_o$) shifts such that μ$_o$(p=p$_{cal}$, T=T$_{cal}$)=μ$_{o\ cal}$.

Calibration Properties

p_{cal}	5000.00	psi(a)
T_{cal}	120.0	°F
$R_{s\,cal}$		scf/bbl
$B_{o\,cal}$	1.500	bbl/stb
$C_{o\,cal}$		1/psi
$\mu_{o\,cal}$	0.800	cP

Correlation selection for oil

There are two correlation selections for oil: PVT and viscosity.

PVT

Various oil PVT correlations are described below:

- **Vasquez and Beggs** — developed from field data (from locations all over the world). It is generally applicable for all oil types, and covers a wide range of pressures, temperatures, and oil properties.

- **Al-Marhoun** — developed for Saudi Arabian oils. It is valid for all types of gas-oil mixtures ranging from 14 - 45 °API.

- **De Ghetto et al.** — developed for heavy oils (10 < °API < 22.3) and extra-heavy oils (°API < 10) from the Mediterranean Basin, Africa, and the Persian Gulf. It requires separator pressure and temperature.

- **Glaso** — developed for North Sea oils. It is suitable for oil mixtures ranging from 22-48 °API, and is valid for all types of oil and gas mixtures after correcting for non-hydrocarbons in the surface gases, and the paraffinicity of the oil.

- **Hanafy et al.** — developed for Egyptian oils gathered from the Gulf of Suez, Western Desert, and Sinai regions. It is independent of oil gravity and reservoir temperature. Although the authors claim that the correlations are applicable to a wide range of crude oils ranging from heavy to volatile oils (14.3 – 47 °API), it appears to be more applicable to light oils.

- **Petrosky and Farshad** — developed for Gulf of Mexico oils gathered from offshore regions in Texas and Louisiana. It is applicable for oil mixtures ranging from 16 - 45 °API, and provides improved results for the Gulf of Mexico oils compared to Standing, Vasquez and Beggs, Glaso, and Al-Marhoun correlations.

- **Standing** — developed for California oils. It is applicable for oil mixtures ranging from 16 - 64 °API.

- **Velarde et al.** — developed for black oils. It is applicable for oil mixtures ranging from 12 - 55 ºAPI.

- **Constant Properties** — you can enter values for the oil compressibility, solution gas-oil ratio, and oil formation volume factor at initial reservoir conditions.

- **Custom Table** — you can enter laboratory measurements for the oil compressibility, solution gas-oil ratio, and oil formation volume factor.

Viscosity

Various oil viscosity correlations are described below:

- **Beggs and Robinson** — developed from field data (from locations all over the world). It is generally applicable for all oil types, and covers a wide range of pressures, temperatures, and oil properties.

- **De Ghetto et al.** — developed for heavy oils (10 < °API < 22.3) and extra-heavy oils (°API < 10) from the Mediterranean Basin, Africa, and the Persian Gulf. It requires separator pressure and temperature.

- **Hanafy et al.** — developed for Egyptian oils gathered from the Gulf of Suez, Western Desert, and Sinai regions. It is independent of oil gravity and reservoir temperature. Although the authors claim that the correlations are applicable to a wide range of crude oils ranging from heavy to volatile oils (14.3 – 47 ºAPI), it appears to be more applicable to light oils.

- **Khan et al.** — developed using oil samples collected from Saudi Arabian reservoirs. It gives more accurate predictions for Saudi Arabian oils, compared to the Beggs and Robinson.

- **Ng and Egbogah** — this correlation contains two methods for calculating dead oil viscosity using a modified Beggs and Robinson viscosity correlation, and a correlation that uses the pour point temperature, which is the lowest temperature at which the oil is observed to flow when cooled. The purpose of introducing the pour point temperature into the correlation is to reflect the chemical composition of crude oil into the viscosity correlation. To obtain the viscosity for live oils, the dead oil correlations are used with the Beggs and Robinson viscosity correlation. This correlation is applicable for oil mixtures ranging from 5 - 58 ºAPI.

- **Constant Properties** — you can enter a value for oil viscosity at initial reservoir conditions.

- **Custom Table** — you can enter laboratory measurements for oil viscosity.

Water properties

After you select **Water** in the selection tree, you can select a correlation, constant properties, or a custom table from the **General Correlation** drop-down list.

Water properties vs. pressure are plotted, including R_{sw}, B_w, ρ_w, c_w, and μ_w. The calculated properties at p_i and T_R are also displayed.
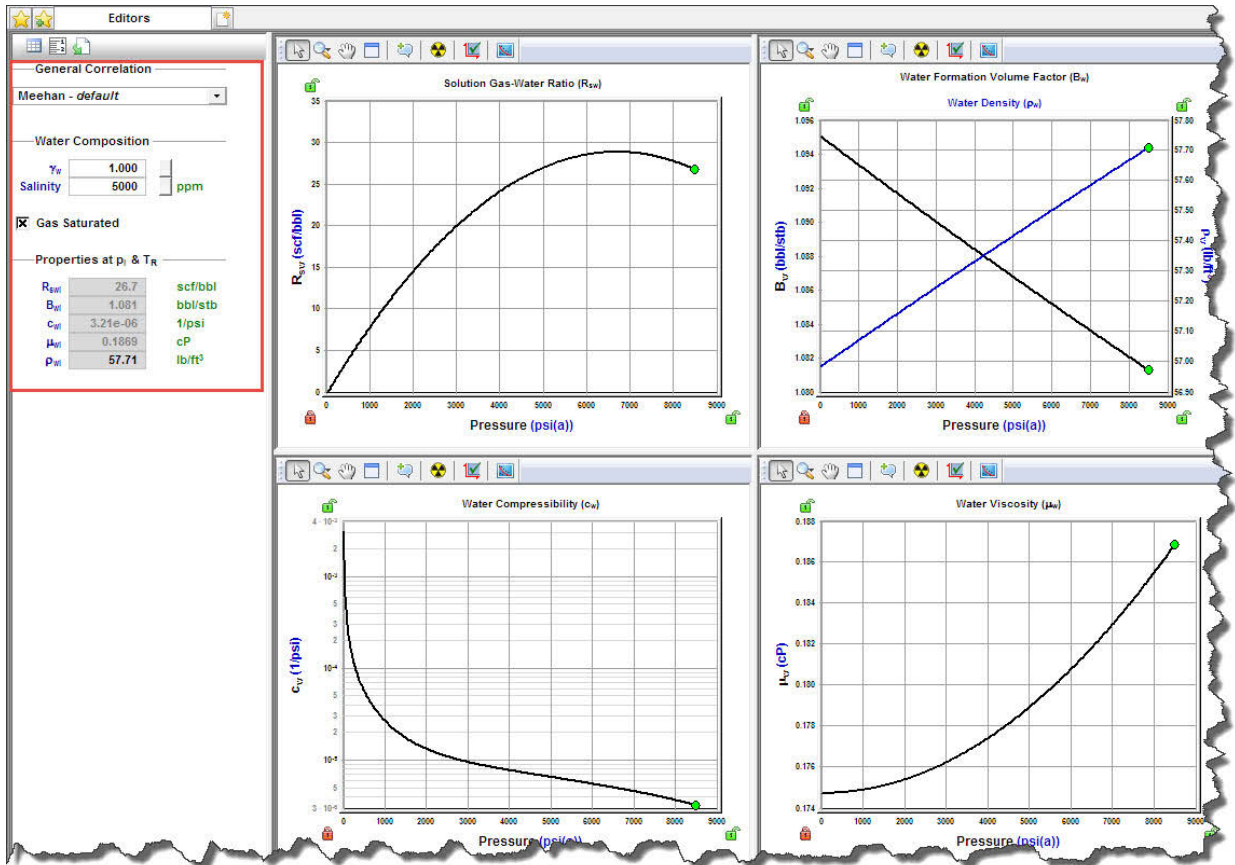
Gas lift properties

After you select **Gas Lift** in the selection tree, simplified gas properties are listed, to be used on analyses with gas lift. Only limited options are available for PVT Correlation, Viscosity Correlation, and Gas Type.

Note: It you want to change the PVT Correlation or Viscosity Correlation for your gas lift, you must change these selections in gas properties.

Adsorption properties

After you select **Adsorption** in the selection tree, these properties are displayed:

- V_{LS}, P_{LS} — Langmuir volume and Langmuir pressure (for shale). For more information, see Langmuir isotherm.

- ρ_b — bulk density (for shale).

Gas content vs. pressure is plotted.
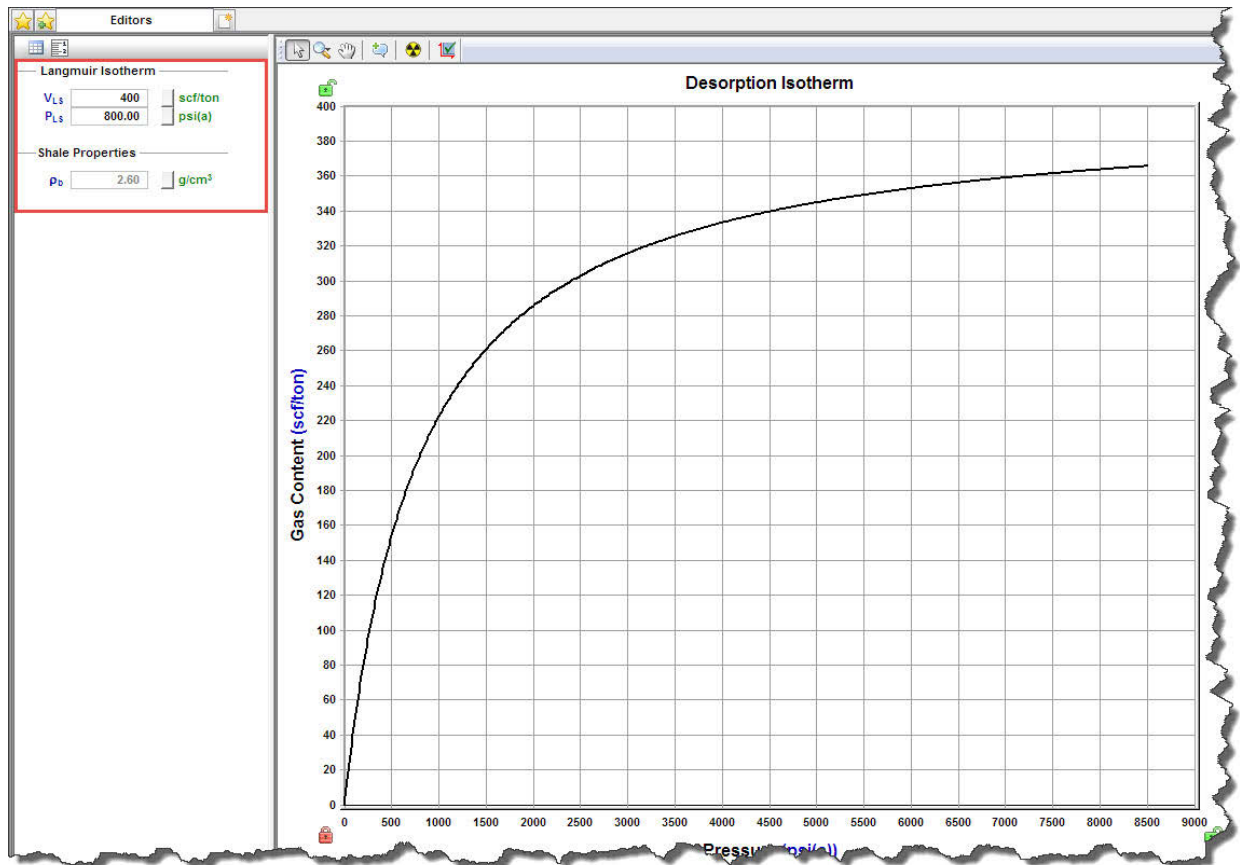
Geomechanical properties

After you select **Geomechanical** in the selection tree, you can set how rock properties (permeability and formation compressibility) vary with pressure.

- **Permeability Ratio Correlation drop-down list** — select a correlation for the variation of permeability with pressure.

- **Compressibility Ratio Correlation drop-down list** — select a correlation for the variation of formation compressibility with pressure.

- **α** — Biot effective stress coefficient (for Dobrynin correlation). The larger this parameter is, the more permeability and formation compressibility vary with pressure.

- γ — permeability modulus (for the Yilmaz & Nur correlation). The larger this parameter, the more permeability varies with pressure.

For more information, see Geomechanical reservoir models.

Geomechanical properties vs. pressure are plotted, including k / k_i and c_f / c_{fi}.
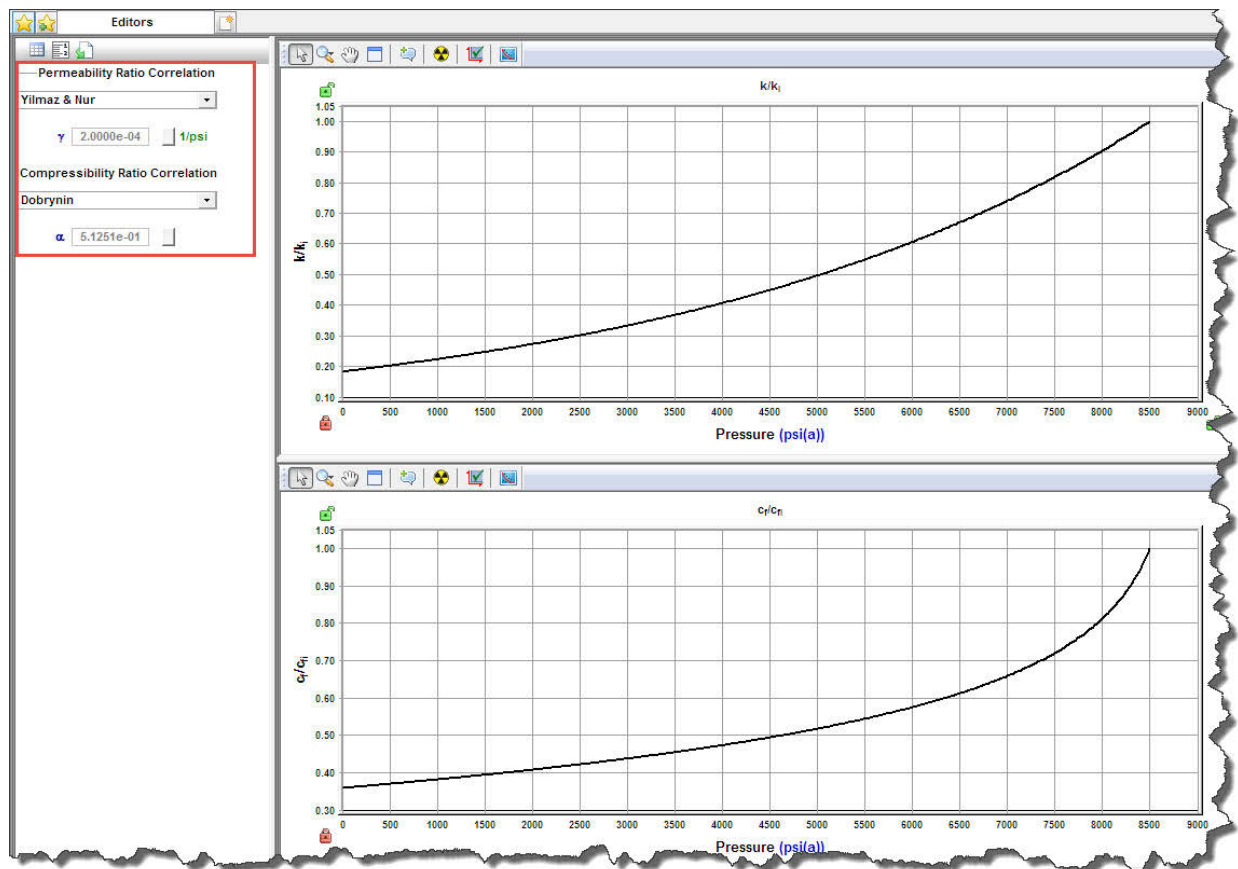
Relative permeability properties

After you select **Relative Permeability** in the selection tree, you can set correlations and parameters describing relative permeability between different fluids flowing together.

- **2-Phase Model Correlation drop-down list** — select a relative permeability correlation. For more information, see relative permeability correlations.

- (located at the bottom of the pane) **3-Phase Model Correlation** — defines how given 2-phase relative permeabilities are combined to calculate permeability for each phase for the cases when all three phases (oil, gas, and water) are flowing together. For more information, see three-phase correlations.

Water-gas section

Parameters in the Water-Gas section describe relative permeabilities for the case when water and gas are flowing together:

- $S_{w\ irr}$ — irreducible water saturation. This is the immobile water when gas is the displacing fluid.

- S_{gc} — critical gas saturation. This is the minimum saturation for gas to become mobile.

- $k_{rw}(S_{gc})$ — water relative permeability at S_{gc}.

- $k_{rg}(S_{w\ irr})$ — gas relative permeability at $S_{w\ irr}$.

- n_w — water relative permeability exponent. This parameter describes how much the water relative permeability curve bends.

- n_q — gas relative permeability exponent. This parameter describes how much the gas relative permeability curve bends.
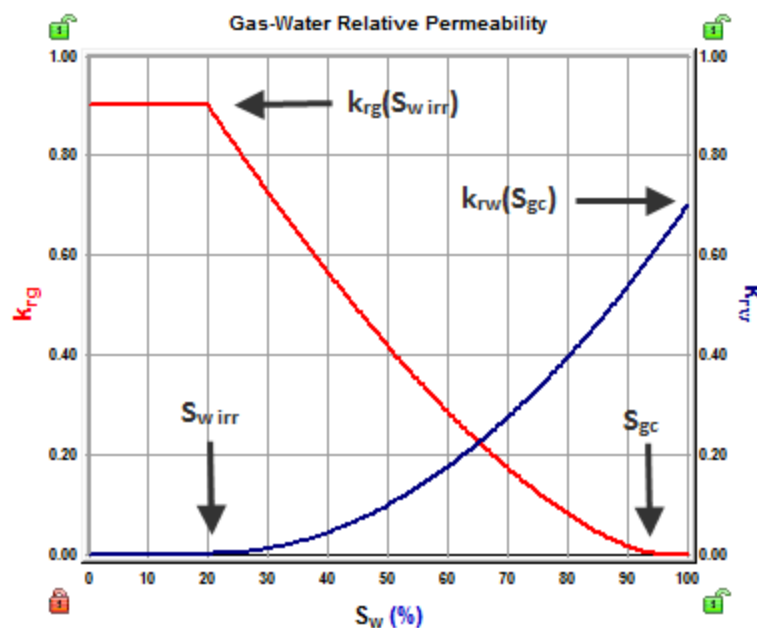
Oil-gas section

Parameters in the Oil-Gas section describe relative permeabilities for the case when oil and gas are flowing together:

- $S_{w\,irr}$ — irreducible water saturation. This is the immobile water when oil or gas is the displacing fluid.

- S_{org} — residual oil saturation to gas. This is the immobile oil when gas is the displacing fluid.

- S_{gc} — critical gas saturation. This is the minimum saturation for gas to become mobile.

- $k_{ro}\,(S_{w\,irr})$ — oil relative permeability at $S_{w\,irr}$.

- $k_{rg}\,(S_{org})$ — gas relative permeability at S_{org}.

- n_{og} — oil relative permeability exponent to gas. This parameter describes how much the oil relative permeability curve bends.

- n_q — gas relative permeability exponent to gas. This parameter describes how much the gas relative permeability curve bends.
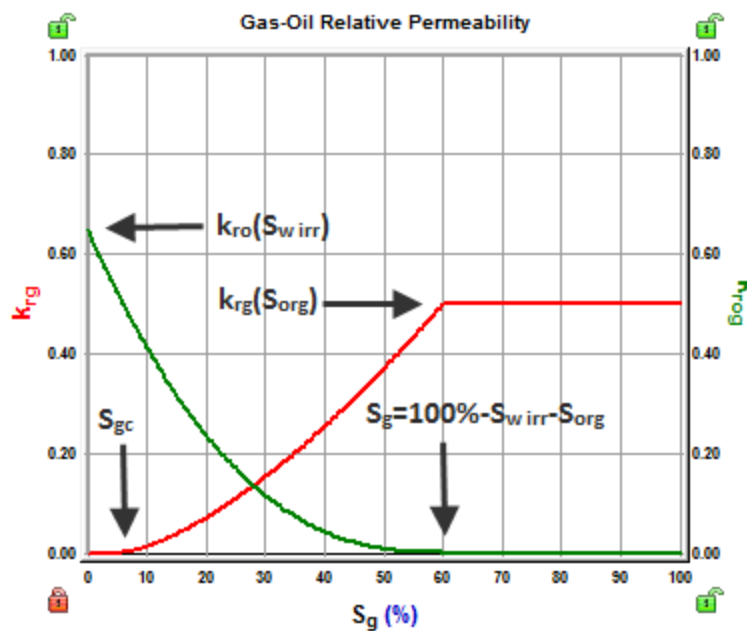
Water-oil section

Parameters in the Water-Oil section describe relative permeabilities for the case when oil and water are flowing together:

- $S_{w\,irr}$ — irreducible water saturation. This is the immobile water when oil is the displacing fluid.

- **S_{orw}** — residual oil saturation to water. This is the immobile oil when water is the displacing fluid.

- **$k_{rw}(S_{orw})$** — water relative permeability at S_{orw}.

- **$k_{ro}(S_{wirr})$** — oil relative permeability at S_{wirr}.

- **n_w** — water relative permeability exponent. This parameter describes how much the water relative permeability curve bends.

- **n_{ow}** — oil relative permeability exponent to water. This parameter describes how much the oil relative permeability curve bends.
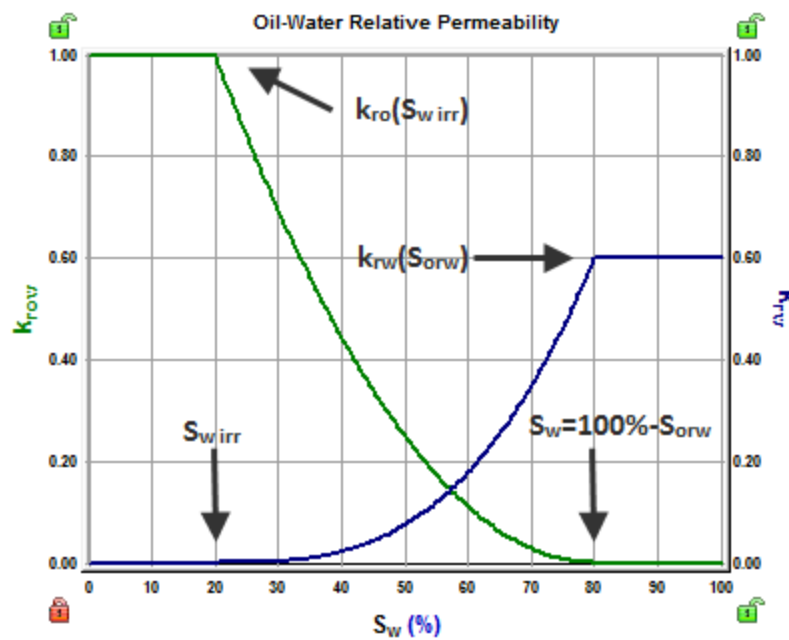
Wellbore editor

In the Wellbore editor (located within the Editors pane), you can create multiple wellbore configurations for a well. Wellbore configurations are used to calculate flowing pressures in the Production editor. Configurations are assigned a date and are used in calculations until the date of the next configuration. Temperature and deviation surveys can also be added for the initial configuration. A schematic of the wellbore is displayed on the right side of this editor.

After you have entered completion data and set temperature gradients, this data can be used in analyses and pressure calculations.

Note: Many rate transient analysis (RTA) analyses use sandface flowing pressures. In order to calculate sandface flowing pressures, you must enter wellbore information.
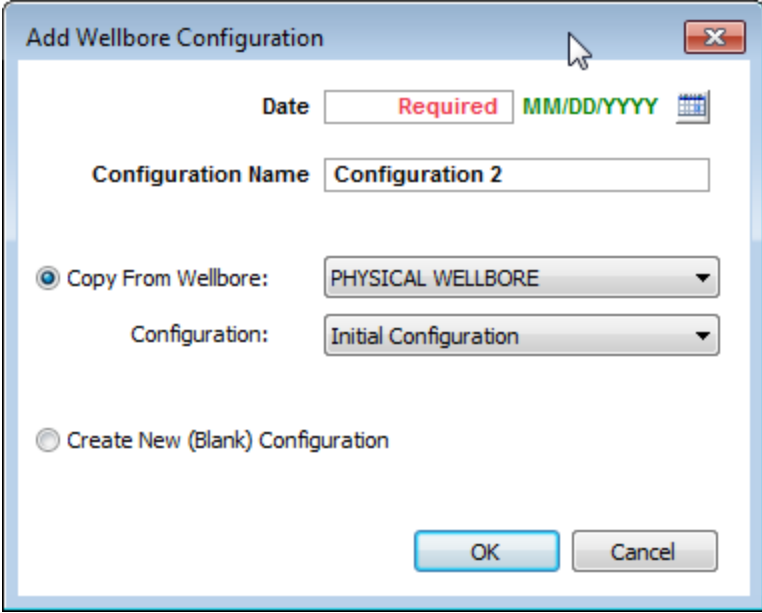
Toolbars

There are two toolbars associated with the Wellbore editor: primary and schematic.

Primary

The primary toolbar has the following icons:

- **Add Configuration** — opens the Add Wellbore Configuration dialog box where you can select an existing wellbore or configuration to copy from, or create a blank configuration. By default, Harmony Enterprise makes a copy of the wellbore. However, you can create a new, blank configuration.

- **Delete Configuration** — this icon is enabled after you select a wellbore in the Editors pane. If the initial configuration is removed, the next configuration is set as the Initial Configuration. When only one configuration exists, it cannot be deleted.

  Note: Pressures are not updated after deleting a wellbore until the Calculate icon is clicked. If the Auto Calculate feature is enabled, pressures are recalculated when a wellbore is deleted.

- **Liquid Loading** — opens the Liquid Loading Parameters dialog box where you enter the required parameters:

  - select the correlation used to calculate liquid-loading conditions.

  - select the liquid type.

  - select how the critical gas rate used to determine liquid-loading conditions is calculated: at Datum, or at end of tubing (at EOT).
    Note that for configurations with a casing flow path, the critical gas rate is always calculated at Datum.

- **Calculate Sandface Pressure** — calculates sandface pressure each time you click this icon.

- **Toggle Name / Date** — toggle between the name and date of the configuration in the pane below.

- **Copy to / Paste from Clipboard** — copy / paste configurations.

Tip: To set various elevations (for example, ground level, kelly bushing), enter these values in the Attributes tab.

Schematic

The schematic pane is located on the right-side of this editor in the Schematic pane, and has the following icon:

- **Preferences** — opens the Schematic Preferences dialog box where you can customize your schematic.
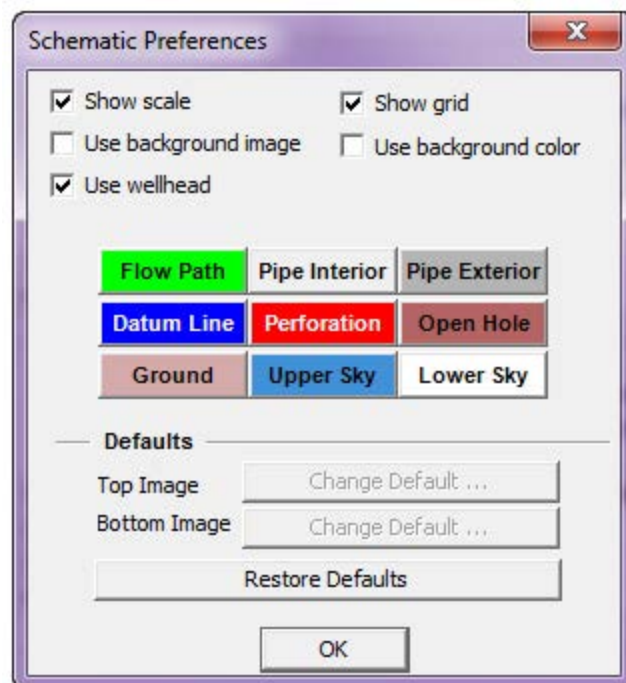
Main pane

In the main pane, you can edit your wellbore profile, which is important for rate transient analysis (RTA) as it provides a model of your well to calculate sandface pressures.

Click **Initial Configuration** in the Editors pane; then enter values in the Casing Data, Tubing Data, Perforation Intervals, and Pressure Loss Calculation Parameters areas.

When entering casing or tubing data, clicking the 🔍 icon on the right-side of each row opens the Sizes dialog box, where tubing /casing / pipe sizes can be edited.
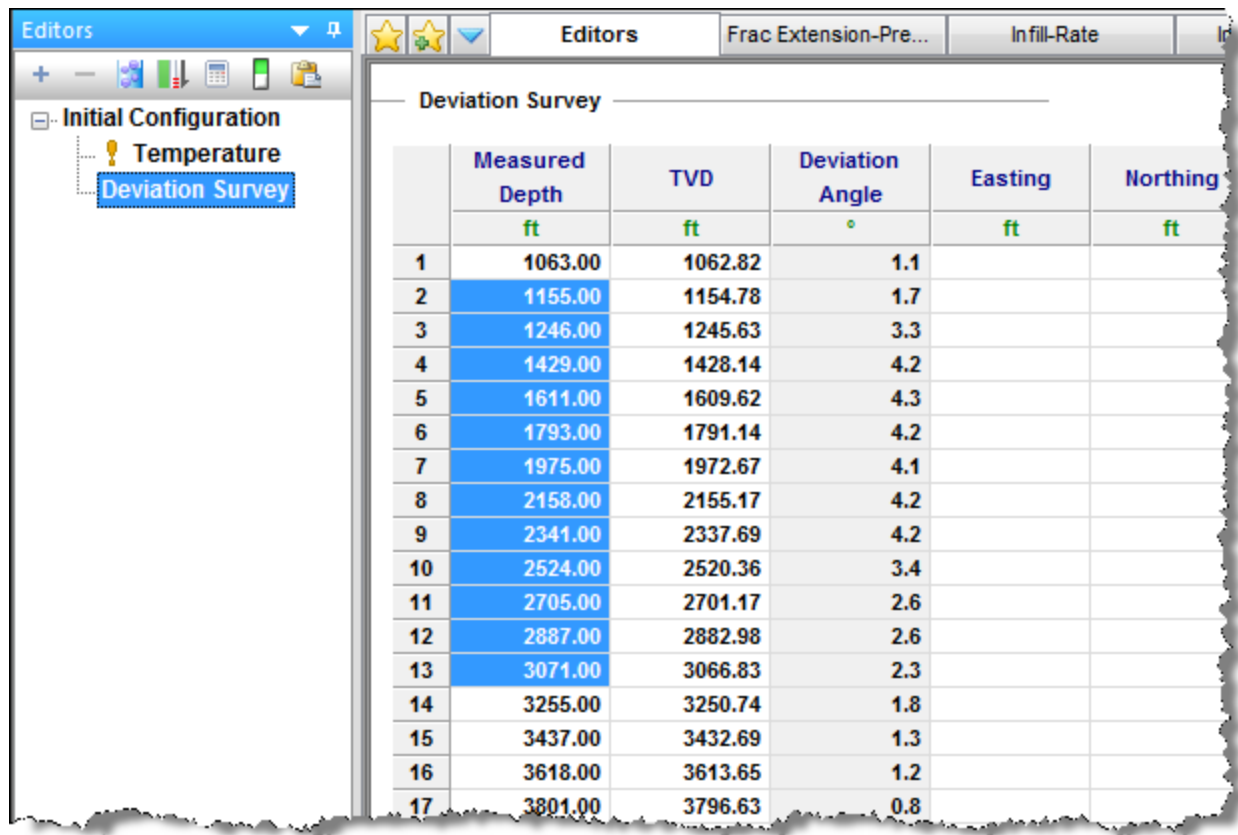
If you select **Pumping** in the **Flow Path** drop-down list and **Auto Template** is selected (default setting), these columns are displayed in the Production editor:

- Gas Volume

- Casing Pressure

- Pressure Source

- Active Pressure

- Calculated Sandface Pressure

- Liquid Level (MD)

- Average Liquid Gradient

- Gas Gradient

- Oil Gradient

- Water Gradient

Click **Temperature** in the Editors pane; then enter your temperature profile.
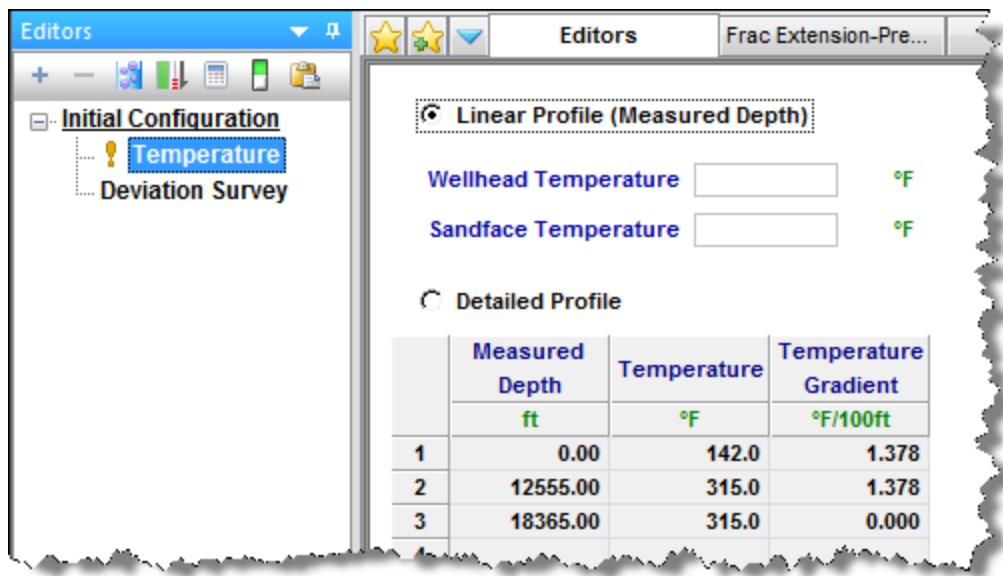
Click **Deviation Survey** in the Editors pane; then enter measured depth and TVD. In this way, you can emulate a horizontal or directional well. For a vertical well, deviation data is unnecessary.

	Measured Depth	TVD	Deviation Angle	Easting	Northing
	ft	ft	°	ft	ft
1	1063.00	1062.82	1.1		
2	1155.00	1154.78	1.7		
3	1246.00	1245.63	3.3		
4	1429.00	1428.14	4.2		
5	1611.00	1609.62	4.3		
6	1793.00	1791.14	4.2		
7	1975.00	1972.67	4.1		
8	2158.00	2155.17	4.2		
9	2341.00	2337.69	4.2		
10	2524.00	2520.36	3.4		
11	2705.00	2701.17	2.6		
12	2887.00	2882.98	2.6		
13	3071.00	3066.83	2.3		
14	3255.00	3250.74	1.8		
15	3437.00	3432.69	1.3		
16	3618.00	3613.65	1.2		
17	3801.00	3796.63	0.8		

If you want to add a deviation survey with 3-dimensional data, enter your data in the Easting and Northing columns.

Schematic pane

By default, the wellbore Schematic pane opens to the right of the configuration parameters. This schematic is a two-dimensional visual representation of the well information that has been provided. The depth scale appears to the left of the wellbore. The flow path of the produced fluid in the well is displayed in green, and injected fluid is displayed in red. Perforations are indicated in red, and the datum is depicted with a dashed blue line.
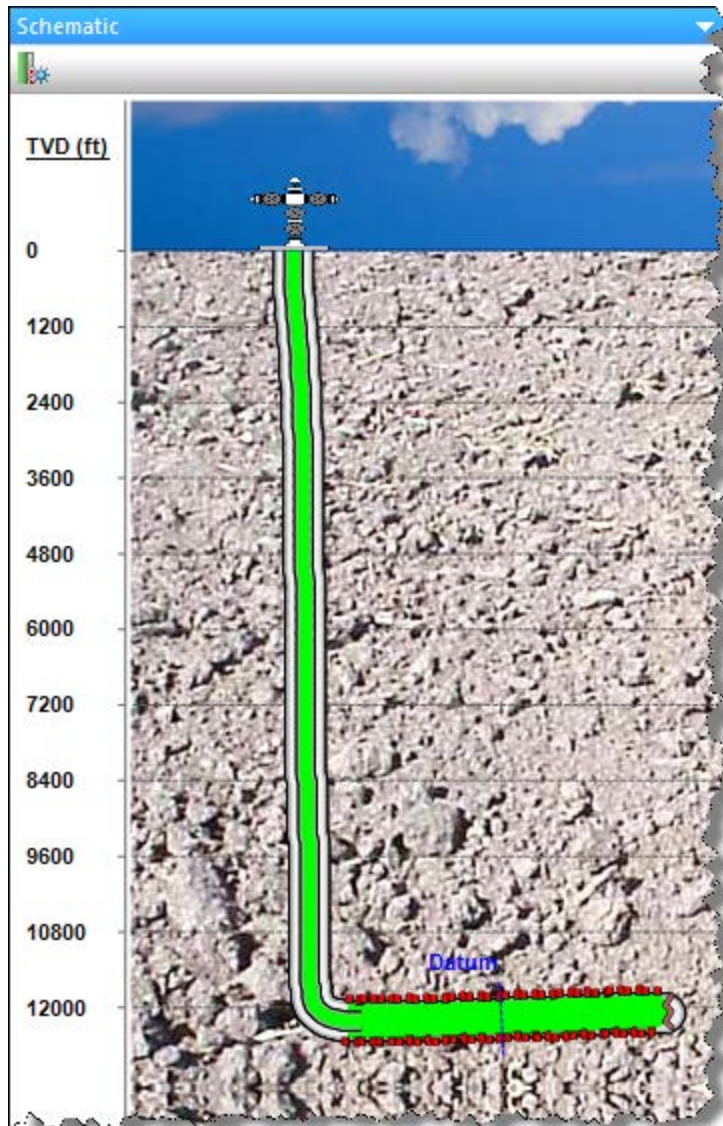
Production editor

In the Production editor (located within the Editors pane), you can manipulate imported production and flowing pressure data, and create new production records. To open the Production editor, click **Production** at the bottom of the pane.

The required inputs for calculating sandface pressure (including auto-calculated sandface pressure) are:

1. A complete wellbore (wellhead + sandface temperature, casing, tubing (if flow path !=casing), datum).

2. Properties for the fluids being produced (gas, oil, water, and condensate).

3. An active pressure (set by Pressure Source; either casing, tubing, gauge depth, or imported sandface pressure).

4. Production for the fluids being produced (although sandface pressures are calculated without production / assumed to be shut-in)

The Production editor consists of the following parts:

- Toolbars
- Selection tree
- Grid (table)

Toolbars

The Production editor has two toolbars: primary and secondary. The unique items are described below; for a description of common icons, see toolbars.

Primary toolbar

The primary toolbar for the Production editor is located directly below the Editors pane.

Clicking the **+** icon on this toolbar lists two options.
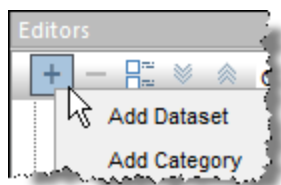
- **Add Dataset** — opens the <u>Create Custom Dataset dialog box</u>. You can create two different types of custom datasets: input (using values you enter) and calculated (using equations you enter). The selection tree updates after you add your dataset and your update is viewable on the Plot Selection pane and Diagnostics tab.

- **Add Category** — opens the Create Custom Category dialog box where you can create custom categories to group your data. The selection tree updates after you add your category and your update is viewable on the Plot Selection pane and Diagnostics tab.

You can click the **–** icon after selecting the custom dataset or category you want to delete. You are prompted to confirm your decision when deleting a custom dataset, but a custom category is immediately deleted.

After you have customized the table / grid display to your liking, you can save your configuration as a template for re-use. Click the drop-down arrow on the toolbar and select **Save / Delete Template**. To load a previously saved template, select it from the drop-down list.
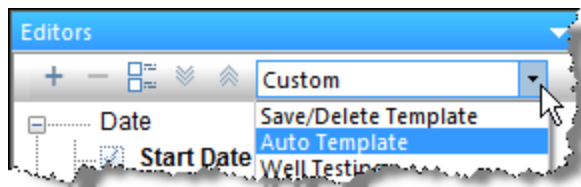
If you select **Auto Template** (default setting), the following columns are displayed, if they have data:

- Gas Volume

- Oil Volume

- Water Volume

- Cond Volume

- CO2 Volume

- Gas Lift Inj Volume

- Gas Inj Volume

- Water Inj Volume

- Casing Pressure

- Tubing Pressure

- Line Pressure

- Gauge Depth Pressure

- Imported Sandface Pressure

The following Flowing Pressure columns are displayed, if at least one of these columns has data: casing pressure, tubing pressure, gauge depth pressure, or imported sandface pressure:

- Pressure Source

- Active Pressure

- Calculated Sandface Pressure

The following columns are displayed if any wellbore configuration has the Flow Path set to "Pumping":

- Gas Volume

- Casing Pressure

- Pressure Source

- Active Pressure

- Calculated Sandface Pressure

- Liquid Level (MD)

- Liquid Level (TVD)

- Average Liquid Gradient

- Gas Gradient

- Oil Gradient

- Water Gradient

Downhole gauge pressure data can be used to calculate the sandface pressure. This functionality is only available for Tubing, Pumping and Casing flowpaths with the following assumption: gauge and tubing are landed above datum (MPP).

Note: For the pumping flowpath the gauge cannot be above the end of tubing (EOT).

Secondary toolbar

This editor has the following important icons on its secondary toolbar (to the right of the Editors pane):
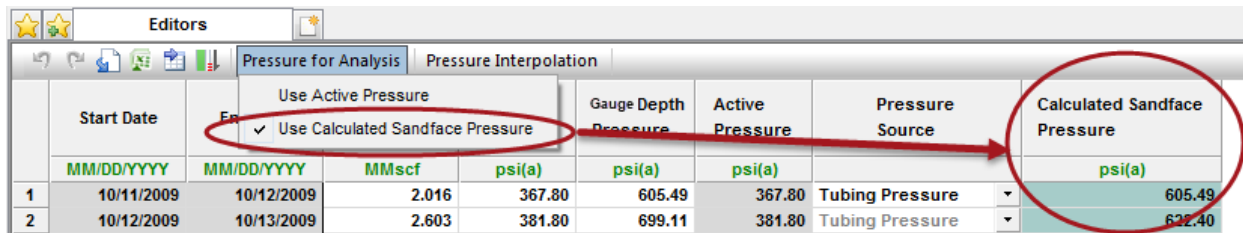
- **Add Data** — adds data to the current well. Select either:

    - **Enter Data** — opens the Import Data dialog box where you assign column headers (by clicking the drop-down arrows) and type in your data.

- **Import Data** — browse to the undefined text file (for example, .csv, .txt, etc.) you want to import.

- **Prior Production** — loads prior production data into the table.

- **Calculate Sandface Pressure** — calculates sandface pressure each time you click this icon.

- **Pressure for Analysis** — select either Use Active Pressure or Use Calculated Sandface Pressure. For more information, see pressure for analysis.

- **Pressure Interpolation** — select either Linear (affects Custom CGR and Liquid Level MD columns) or Step (affects Pressure Source and CGR Source columns). Interpolated pressures are displayed in gray and populate rows that have not been specified. For more information, see pressure interpolation.

Pressure for analysis

With this option, you can specify which flowing pressure is used in any analyses with calculations that require this value (for example, analytical models, etc).

The Pressure for Analysis option is located in the toolbar of the Production Editor grid.

When selected, there are two options to choose from:

1. **Use Active Pressure** — uses the pressure that has been set under the Pressure Source column of the grid (that is, casing, tubing, gauge depth, or imported sandface pressure) as the flowing pressure in analyses.

Note: If active pressure has been set to a wellhead pressure (for example, tubing pressure), and "Use Active Pressure" has been selected, all analyses will use the tubing pressure as the flowing pressure in calculations. This could result in significant differences in results compared to using a calculated sandface flowing pressure. If imported sandface pressures are not available, we recommend calculating a sandface pressure and setting the pressure for analysis to "Use Calculated Sandface Pressure".

2. **Use Calculated Sandface Pressure** — uses the calculated sandface pressure in the Production editor for flowing pressure in analyses. This is the default selection.

Note: A valid wellbore is needed to calculate sandface pressures.

The pressure used in analyses is highlighted in turquoise.

Pressure interpolation

Flowing-pressure columns are interpolated based on whether you select Linear or Step. If the table cell is in the bottom row, and you press the Enter or Tab keys, the cell selection does not change. This affects these columns: Casing Head Pressure, Tubing Pressure, Gauge Depth Pressure, and AWS Wellhead Pressure.

For both Linear and Step, all rows prior to the first-specified value are set to the first-specified value. All rows after a specified value are set to the last-specified value.

For the step method, all rows after a specified value are set to the specified value until the next specified value.
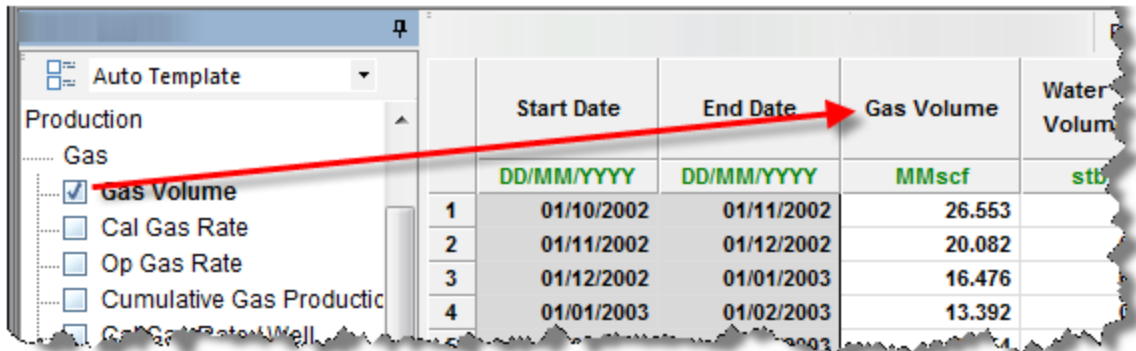
For the linear method, all rows between two specified values are linearly interpolated. Linear interpolation is calculated at the mid-period for each row. The table below demonstrates this interpolation. (Cells in gray have been calculated or interpolated.)

Start Date	End Date	Value	Mid-period Date	
2010/01/01	2010/02/01	100.00	2010/01/16	12:00:00
2010/02/01	2010/03/01	132.96	2010/02/15	00:00:00
2010/03/01	2010/04/01	165.92	2010/03/16	12:00:00
2010/04/01	2010/05/01	200.00	2010/04/16	00:00:00

For more information, see interpolation theory.
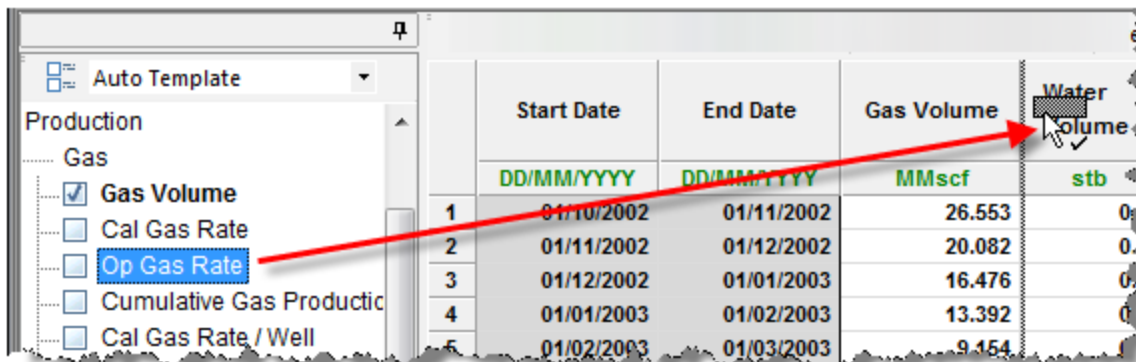
Selection tree

The selection tree has production / injection, flowing pressure, and other data reported by date / time. To display data in the table to the right, click your dataset's checkbox in the tree structure. Deselecting a dataset's checkbox removes it from the table.

You can also add data to the table by clicking the dataset name and dragging it to its desired location

If you want to rename a custom dataset or category, right-click it in the selection tree and select Rename. (You can add these custom datasets and categories using the primary toolbar.)

Grid (table)

The grid (or table), located on the right-side of the Production editor, displays the selected entity's production data. The Start Date and End Data columns are always displayed as the leftmost columns in the grid, and cannot be moved or removed. All of the other columns can be shown / hidden by selecting / deselecting the parameter's name in the selection tree, or by moving the parameter within the grid.

To change the units, click the unit sub-header and select from the list. You can also set precision.

Fields with a white background can be edited by typing within the field, or pasting from another source (for example, Excel).

Note: If you select multiple wells, or a well group in the Entity Viewer, you cannot edit any of the fields. Gray fields (including cumulative production, ratios, and aggregates) are read-only.

To remove a row from the grid, right-click the row number and select Remove Row. You can only remove rows at the end of production.

Create Custom Dataset dialog box

This dialog box is commonly used when you add custom datasets.

Tip: Harmony Enterprise supports up to 100 custom datasets.

- **Dataset Name** — type your dataset name. This is a required field and you cannot click OK until this field has been entered. "Invalid Dataset Name" is displayed until you type a name.

- **Unit Type** — select from the drop-down list. Note that this field cannot be edited after it is set.

- **Default Field Unit** — select your default field unit from the drop-down list.

- **Default Metric Unit** — select your default metric unit from the drop-down list.

- **Location** — select the dataset's location in the Production Editor's tree structure from the drop-down list.

- **Input** — uses values you enter.

- **Calculated** — opens the Equation Editor dialog box where you enter formulas for this dataset.

Equation Editor dialog box

This dialog box is commonly used when you <u>add custom datasets</u> or <u>add custom attributes</u>, and you want to use a Calculated type of dataset or attribute.

The Equation Editor has the following components:

- **Tree structure** — displays an updated list of all the production datasets that exist in the Production editor, as well as the numerical attributes that exist in the Attributes tab. This includes custom-calculated datasets, custom-input datasets, custom-input attributes, and custom-calculated attributes. Clicking an item in the tree structure inserts it into the formula.

- **Inputs / Units pane** — displays the units associated with each input.

- If a dataset or attribute is displayed in an equation twice, only one unit can be associated with that variable.

- The table / grid displays a list of datasets / attributes in the formula pane when you click the **Update Grid** button, *after* you enter a valid formula. You can also update the table / grid each time you make a modification to the formula by clicking the **Update Grid** button.

- Note that if your formula is invalid, clicking **OK** or **Update Grid** displays an error message in the lower left corner of the dialog box.

- **Calculator** — consists of numbers and mathematical functions.

- **Formula pane** — displays the formula as you create it.

  - The *output unit* is the unit associated with the output of your formula.

  - By clicking the four icons directly above the formula area, you can insert subscript, superscript, and symbols within the formula.

  - You can use both the on-screen calculator (by clicking the buttons in the dialog box) and your keyboard.

Tip: When entering a formula, make sure to add the closing **")"** when using a function that opens with a **"("**. If your formula is invalid, clicking **OK** displays an error message in the lower left corner of the dialog box.

Referencing other datasets / attributes

You can enter a formula into the Formula pane using the keyboard. To reference another dataset or attribute, you must use the following format:

- Attribute: [A:Attribute Name]

- Dataset: [P:Dataset Name]

Dataset-specific functions

There are four special functions: *MinCol*, *MaxCol*, *Avg*, and *ValueAt*. These functions require production datasets (in columns) as inputs, and normalized time must also be specified.

- The units of normalized time can be selected in the Inputs / Units pane in this dialog box.

- The values "start" and "end" can also be entered as normalized time values. "Start" refers to the beginning of production history, and "end" references the last date of production.

Note: Normalized time must be specified as an integer.

1. **MinCol** — this function returns the smallest value of the specified column, over a specified period of normalized time.

   Equation Format: MinCol(column, start time, end time)

   Example: MinCol([P:Gas Volume], end-6, end)
   This returns the minimum gas volume during the last six months of production.

2. **MaxCol** — this function returns the highest value of the specified column, over a specified period of normalized time.

   Equation Format: MaxCol(column, start time, end time)

   Example: MaxCol([P:Gas Volume], start, end)
   This returns the maximum gas volume during the entire production history of the well.

3. **Avg** — this function returns the weighted average of the specified column, over a specified period of normalized time.

   Equation Format: Avg(column, start time, end time)

   Example: Avg([P:Gas Volume], 3, 12)
   This returns the average gas volume between the 3rd and 12th months of production, based on the following equation:

$$average\left(x, t\right) = \frac{\Sigma(x^* \Delta t)}{\Sigma \Delta t}$$

   Although you can specify the period in months, Harmony Enterprise inputs the Δt in days when calculating the weighted average. So, based on the month in the year, Δt can be 28 - 31 days for a full month.

4. **ValueAt** – this function returns a scalar value from the specified column, at a specified normalized time.

   Equation Format: ValueAt(column, time).

   Example: ValueAt([P:Gas Volume], 1.5)

   This returns the gas volume at 1.5 months. Calculations are done using days, and monthly values are converted using 365.25/12. So, in this case, 1.5 months would be equivalent to 45.6
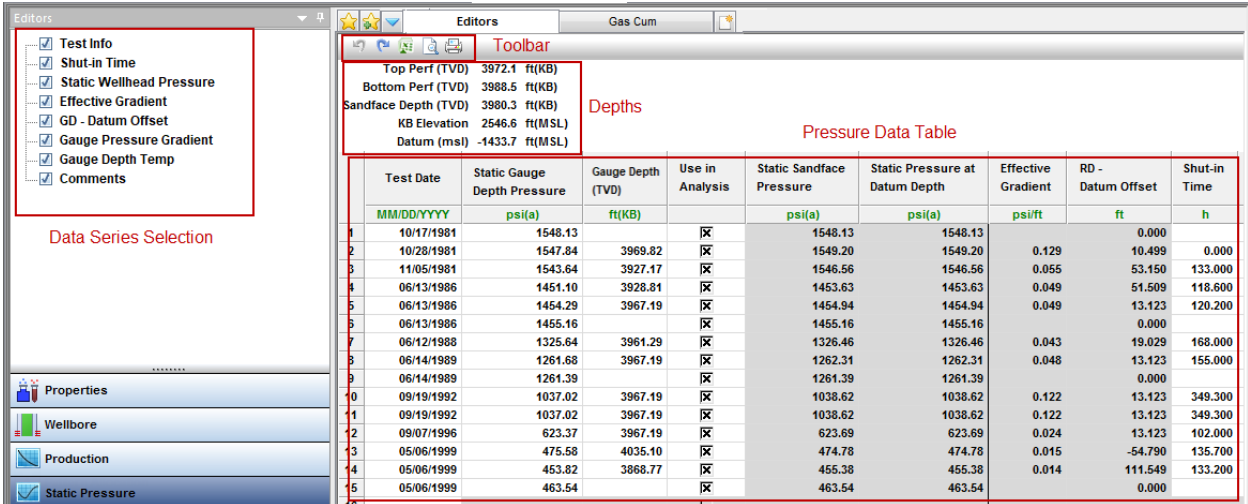
days. Harmony returns the value at the row that covers the time range which includes this specific time.

Note: The start time in Harmony Enterprise is inclusive, and the end time is exclusive.

Static pressure editor

In the Static Pressure editor (located within the Editors pane), you can view, enter, and modify static pressures for wells. Static pressures can also be viewed at the group level, but not manipulated. In addition, you can view static pressures for scenarios.

The Editors pane on the left-side has a list of data series that you can select to be displayed in the table. By default, all of the series are selected to be displayed. In addition, the following columns are always displayed (that is, they cannot be hidden): test date, static gauge depth pressure, gauge depth, use in analysis, static sandface pressure, and static pressure at datum).

Depths

The perforation intervals, sandface depth, kelly bushing (KB) elevation, and datum for the entity are displayed above the pressure data table. Some import file types (such as *.mer) include this well data. When it is not imported, the data that is specified in the Wellbore editor is used to populate these values. For wells, the sandface depth midpoint of perforation (MPP) is assumed to be the same as the datum depth. When a group is viewed, a common datum is determined for the group based on the datum of each well. No sandface depth is displayed for a group, as it is not meaningful.

Header

These items are displayed above the table in the main pane:

- **Top Perf (TVD)** — the uppermost perforation depth from the Attributes tab or the Wellbore editor. (The Wellbore editor's perforation interval inputs override the Attributes tab's inputs.) The top perf depth is converted from measured depth (MD) to true vertical depth (TVD) based on the Deviation Survey entered in the Wellbore editor.

- **Bottom Perf (TVD)** — the lowermost perforation depth. The bottom perf depth is converted from MD to true vertical depth TVD based on the Deviation Survey entered in the Wellbore editor.

- **Sandface Depth (TVD)** — the midpoint of the perforated interval (MPP). You cannot change the Sandface Depth in the Static Pressure editor by changing the Datum Depth in the Wellbore editor. It is calculated based on top and bottom perf inputs (form the Attributes tab or Wellbore editors) only. You cannot type a fixed reservoir datum depth.

- **KB Elevation** — the kelly bushing (KB) reference elevation. All datum calculations reference the KB elevation.

- **Datum (msl)** — the true vertical depth relative to mean sea level (msl). This value changes depending upon the launched entity as described below:

  - For Well entities: "Datum" depth is always the Sandface or MPP depth in TVD for the well. This is *not* the Datum Depth referred to in the Wellbore editor.

  - For Group entities: "Datum" depth is calculated from the average well Datum Depths of the wells in the group. As group membership changes, the group datum depth changes. The intention is to automatically minimize the Datum Depth correction required for each well in the group. You cannot type a fixed reservoir datum depth.

Pressure data table

The minimum requirements for an entry in the pressure table are a date and a static gauge depth pressure. Additional information that can be provided includes the gauge depth, shut-in time, static wellhead pressure, gauge pressure gradient, gauge depth temperature, comment, and test info.

In the Use in Analysis column, you can select which static pressures are displayed on worksheets and which are used in the analysis. By default, all static pressures are selected.

When a gauge depth is not provided, the gauge depth is assumed to be the same as the datum. When a gauge depth is available, the gauge depth pressure gradient is used to convert the static pressure at the gauge depth to a datum pressure. The same approach is used to convert static pressures from a well datum to a group datum. When the gauge depth pressure gradient is not provided (or if the input value is 0), fluid properties from the Properties editor are used to estimate a pressure gradient.

Column headers

Column headers are defined as follows:

- **Static Gauge Depth Pressure** — the gauge measured pressure in absolute pressure units.

- **Gauge Depth** — the depth of the gauge used to measure the static pressure.

- **Static Sandface Pressure** — the Gauge Depth Pressure corrected to the Sandface Depth or MPP of a launched well entity.

- **Static Pressure at Datum Depth** — the Gauge Depth Pressure corrected to the Datum Depth for a launched group entity. You cannot type a fixed reservoir datum depth. The Static Pressure at Datum Depth for a well entity, or a group with only one well, is always the same as the Static Sandface Pressure. The Static Pressure at Datum Depth and the Static Sandface Pressure are only different when there are multiple wells in the group with differing MPPs based on datum depths.

- **Effective Gradient** is either:

    - (a) the "Gauge Pressure Gradient" you entered, or

    - (b) An internally calculated gradient based on the specified Primary Fluid in the Attributes tab, the input Gauge Depth Pressure, the reservoir temperature in the Properties editor, as well as inputs in the Wellbore and Fluid Properties editors.

    - We use (a) when the Gauge Gradient contains a non-zero value

    - We use (b) when the Gauge Gradient contains a zero, or is blank.

- **Static Wellhead Pressure** — you can type a value for information purposes. In rare circumstances, we have only measured well static pressure data and no gauge measured data. In those cases, you can copy / paste the Static Wellhead Pressures over to the Gauge Depth Pressure column. If you specify a Gauge Depth of "0" (zero) and set the Primary fluid to gas, oil, or water, Harmony Enterprise calculates Sandface and Group Datum pressures based on sandface depth (MPP) and the Effective Gradient. This method can be used for gas, oil, or water, but generally should only be used for gas. It also assumes there are no wellbore or reservoir fluid contacts between the wellhead and the calculated datum depth.

- **Gauge Pressure Gradient** — the pressure gradient measured at or near the gauge depth in the wellbore. You should be careful when using imported values, as these gradients generally reflect wellbore fluid contacts, and not necessarily the fluid contacts in the reservoir.

Note: The remainder of the column headers are provided for information only, and are not used in the calculations.

Entity Viewer - Custom

The Entity Viewer - Custom displays private groups and shared groups. You can create custom groups from your list of wells in the hierarchy based on locations and groupings that are not possible within the hierarchy structure.
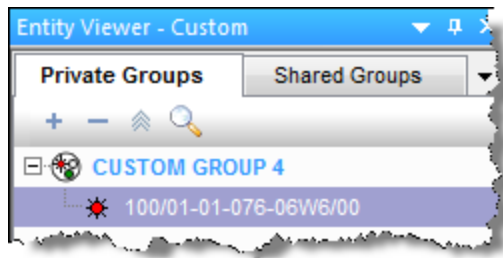
If you import custom groups, they are shared, and each custom group is guaranteed a unique name. Note that custom groups are not imported when their ID already exists.

Clicking an entity in this pane highlights the entity on the GIS map and Spatial Explorer, and displays the entity's data under the other tabbed headings. (Only well and meter station entities are shown on the GIS map, and only if they have valid location information entered in their attributes.)

You can scroll through wells using your keyboard's arrow keys by doing the following: click the tab you want to view (for example, Analysis or Diagnostics), click a well in the Entity Viewer, and then press the Up and Down arrow keys on your keyboard.

You can select multiple entities by clicking wells while holding down the **Ctrl** key (to make individual selections), or the **Shift** key (to make group selections).

Toolbar

The Entity Viewer - Custom has the following important icons:

- **+** **Add Entity** — create an empty custom group or create a group from entities you have selected.

- **—** **Remove Selected Entities** — select an entity or group in the tree structure and then click this icon to remove it. Note that if you delete an entity in a custom group, it is removed from the group, but it still exists in the project.

- **🔍** **Search** — opens a search box where you can search for entities by name. (You can also initiate a search by pressing **Ctrl + F**.)

- **Query** — opens the Query Wells dialog box where you can query and filter wells using attribute data.

For a description of common icons, see pane toolbars.

Note that if you selected a previously created filter (see project filters) prior to creating a new custom group, this custom group automatically exists in the filter.

Private groups tab

On this tab, you can view groups that only you can see.

These entities are not accessible by others unless you right-click a custom group and select **Share Group**. This moves the custom group to the Shared Groups tab.

Shared groups tab

On this tab, you can view groups and wells that are shared with users who have access to the database.

Work status icons

The Entity Viewer panes use icons to indicate the work status of entities. The icons and their meanings are as follows:

- (**Complete**) — an analysis has been completed for this entity.

- (**In Progress**) — this entity has been selected, and an analysis has been started, but it has not yet been completed.

- (**Invalid**) — data for this entity has changed, or wells within this group have changed. If an analysis has been run, it may no longer be valid.

You can set your work status manually by right-clicking the entity and selecting **Set Entity Work Status**. To rest your work status, right-click and select **Clear Status**.

Context menu

Right-clicking within this pane lists various options, which depend on the type of entity you select (for example, a well, group, or multiple wells).

- **Rename** — renames the entity.

- **Remove Selected Entities** — removes the selected entities from the custom group, but retains the entities in the database.

- **Rerun Well Query** — (visible after you have run a well query): if you have modified wells in your database, running the query again updates your results.

- **Select Constituent Wells** — (for groups): selects all of the wells that belong to the group. (This selection is applied to the Entity Viewer - Hierarchy as well.)

- **Set Entity Work Status** — changes the work status icon for the selected entity.

- **Apply Workflow to Selected Entities** — applies your workflow to the entities you selected. For more information, see apply a workflow.

- **Move Selected into Custom Group** — moves the selected entities into a custom group.

- **Duplicate Selected into Custom Group** — copies the selected entities into the custom group you select from the submenu.

Entity Viewer - Hierarchy

The Entity Viewer - Hierarchy displays the entities in a project, which you can view, sort, and select for analysis.

Clicking an entity in this pane highlights the entity on the GIS map and Spatial Explorer, and displays the entity's data under the other tabbed headings. (Only well and meter station entities are shown on the GIS map, and only if they have valid location information entered in their attributes.)

You can scroll through wells using your keyboard's arrow keys by doing the following: click the tab you want to view (for example, Analysis or Diagnostics), click a well in the Entity Viewer, and then press the Up and Down arrow keys on your keyboard.

You can select multiple entities by clicking wells while holding down the **Ctrl** key (to make individual selections), or the **Shift** key (to make group selections).

Toolbar

The Entity Viewer - Hierarchy has the following important icons:

- **Add Entity** — opens a submenu where you can select your entity type (for example, gas, oil, water, and so on).

- **Add Scenario** — (for wells) adds a scenario child item below the parent well in the Entity Viewer - Hierarchy pane.

- **Duplicate Scenario** — (for scenarios) adds a copy of the scenario below the scenario you have selected.

- **Remove Selected Entities** — select an entity / scenario in the hierarchy structure and then click this icon to remove it. This removes the entity from the database, so you are prompted to confirm your decision.

  Any entities that you add or delete are reflected in the GIS, Spatial Explorer, Diagnostics tab, analysis tab, Results tab, and Attributes tab. Deleting a well or group also removes it from the active filter.

- **Search** — opens a search box where you can search for entities by name. (You can also initiate a search by pressing **Ctrl + F**.)
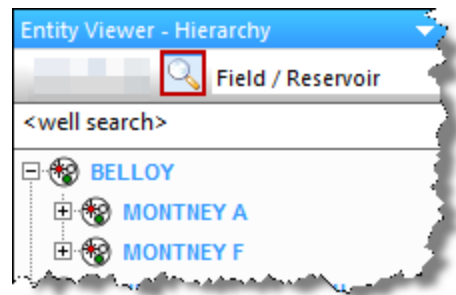
- **Hierarchy Structure** — you can add a hierarchy structure, modify an existing hierarchy structure ,or select Field / Reservoir. If you select Add / Modify Hierarchy Structure, you can drag-and-drop fields from the Available Fields pane to the Current Hierarchy pane.

For a description of common icons, see pane toolbars.

Work status icons

The Entity Viewer panes use icons to indicate the work status of entities. The icons and their meanings are as follows:

- ✓ (**Complete**) — an analysis has been completed for this entity.

- ❗ (**In Progress**) — this entity has been selected, and an analysis has been started, but it has not yet been completed.

- ❓ (**Invalid**) — data for this entity has changed, or wells within this group have changed. If an analysis has been run, it may no longer be valid.

You can set your work status manually by right-clicking the entity and selecting **Set Entity Work Status**. To rest your work status, right-click and select **Clear Status**.

Hierarchy structure

The Hierarchy pane organizes entities in a hierarchical structure according to specific attributes, which you can view in the Attributes tab.

To initially view wells, Harmony Enterprise provides a default hierarchy structure: Field / Reservoir.

You can select your hierarchy structure from the drop-down list on top of the pane.
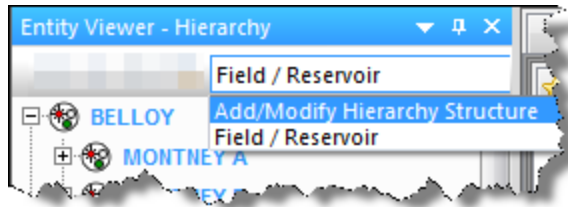
To create a new hierarchy structure, select **Add / Modify Hierarchy Structure** from the drop-down list.

Context menu

Right-clicking within this pane lists various options, which depend on the type of entity you select (for example, a well, group, or multiple wells).

- **Add Scenario** — adds a scenario child item below the parent well in the Entity Viewer - Hierarchy pane.

- **Duplicate Scenario** — (for scenarios) copies your currently selected scenario.

- **Promote to Well** — (for scenarios) replaces the parent well with the selected scenario, and demotes the parent well to a scenario. You are prompted to confirm your decision.

- **Rename** — opens a dialog box where you can type a new name for your entity (well or scenario).

- **Delete Selected Entities** — you are prompted to confirm the deletion, which removes the entities from the database. Note that you are not able to delete an entity that is locked by another user. To see the latest list of entities, click the **Refresh** icon ( ) on the main toolbar.

- **Set Entity Work Status** — changes the work status icon for the selected entity.

- **Select Constituent Wells** — (for groups): selects all of the wells that belong to the group.

- **Expand Selected Group Only** — (for groups): expands the selected group.

- **Apply Workflow to Selected Entities** — applies your workflow to the entities you selected. For more information, see apply a workflow.

- **Copy / Paste from Clipboard** — copies / pastes data from the Properties editor.

- **Go To** — after selecting an entity, you can right-click it and select Go To, which highlights the entity on the GIS map with a blinking circle. If location information is not available for the well, a warning message is displayed in the Status Window.

GIS

The geographic information system (GIS) tab displays entities on a map based on one of the standard coordinate systems.
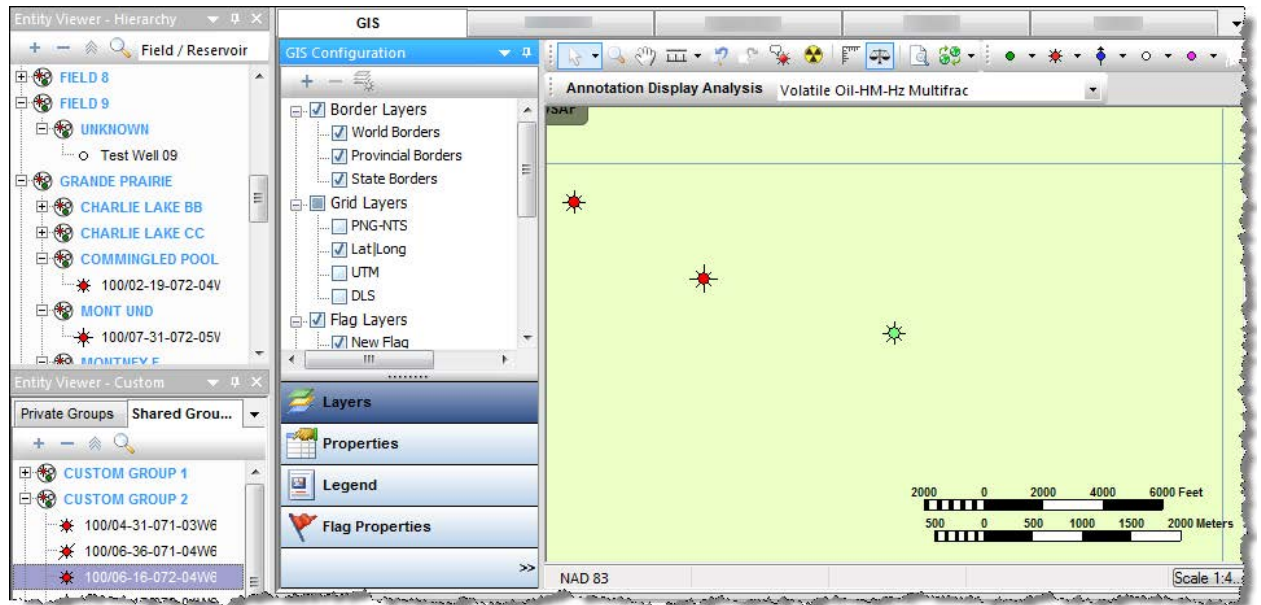
Entities are displayed on the GIS map only if their attributes include geographical coordinates. If you expect to see well on the GIS map and it is not there, highlight it in the Entity Viewer - Hierarchy or Custom, click the **Attributes tab**, double-click **Location** in the tree structure, and verify that the latitude / longitude attributes are valid. For more information, see GIS map.

Toolbars

There are four toolbars on the GIS tab:

1. GIS Configuration pane

2. GIS toolbar

3. GIS design mode tools

4. Active analysis

GIS Configuration pane

This toolbar handles layer functionality.
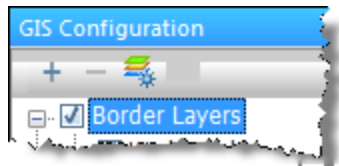
- **Add Layer** — adds various types of layers (that is, a shapefile layer, image layer, general annotation, bubble map layer, or a flag layer).

- **Remove Layer** — deletes a layer. Note that you cannot delete Project Layers.

- **Layer-specific options** — select from these options: group display layers by type, shapefile info, DBF info, customize shapefile drawing, highlight shape(s), and show / hide labels.

GIS toolbar

This toolbar handles map-related functionality. For a description of common icons, see toolbars.
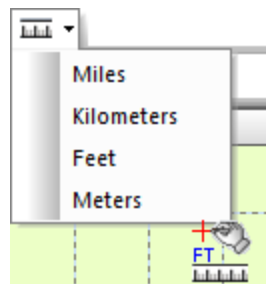
- **Measure** — select your scale from the drop-down list. Click the first location on the map and then drag the mouse to the second location. The distance is displayed between the two points, and updates automatically when the distance changes.

- **Go back to Previous Extents** — reverts your display to the previous zoom setting.

- **Go to Next Extents** — updates your display to the next zoom setting.

  The current extents are saved on a per-user, per-project basis. When you open the project again, the last-used extents (zoom level) is applied.

- **Annotation Display Options** — opens the Facility Annotation Editor dialog box where you can customize your annotation display. This icon is grayed-out when the annotation layer is not supported because there are too many wells on-screen.

- **Reset GIS** — zooms out to display all the wells on the map, or if there are no wells, the map zooms out to display the entire world).

- **Rulers** — displays a ruler along the top and left-side of the map. This can be toggled on or off.

- **Scale** — displays a map scale in the lower right corner of the map. This can be toggled on or off.

- **NAD Conversion** — from the drop-down list, select NAD 83 (North American Datum, modified in 1983), NAD 27 (North American Datum, created in 1927), or WGS 84 (World Geodetic System, modified in 1984).

Tip: To reset to the default mouse pointer, press the **Esc** key.

GIS design mode tools

Use this toolbar to draw wells on the map.

From left-to-right, the icons enable you to add an oil well (green), gas well (red), water well (blue), location (white), and other well (pink) to the GIS map.

Note: Icons on this toolbar are only active if you are zoomed-in close enough.

Active analysis

From this toolbar, you can select an analysis name from the drop-down list. The data from this analysis is used in Results annotations.
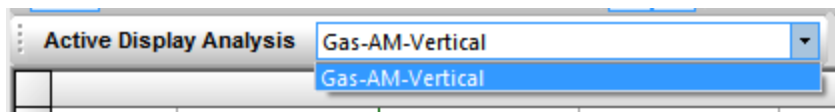
GIS Configuration pane

The GIS Configuration pane has the following buttons:

- Layers

- **Properties** — are used to fine-tune the GIS map. Property descriptions are displayed at the bottom of the pane as they are selected.
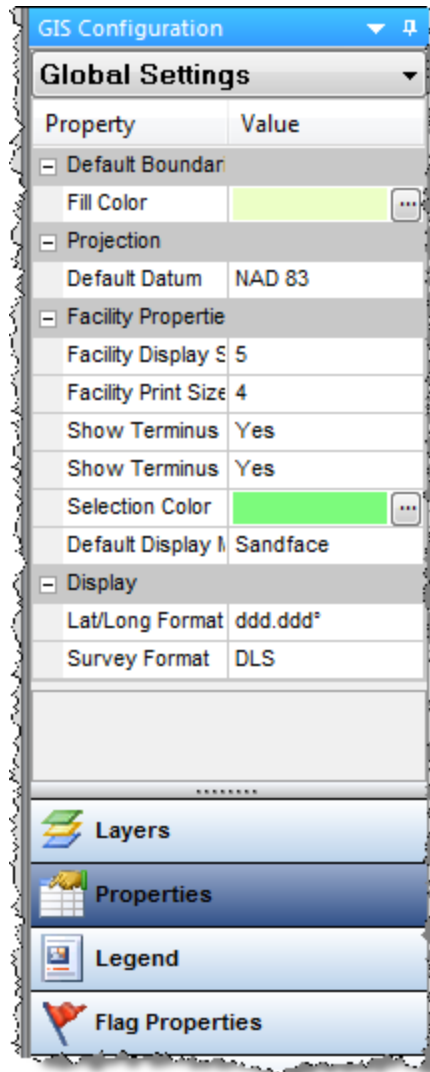
- **Legend** — lists all of the symbols that may be found on the GIS map.
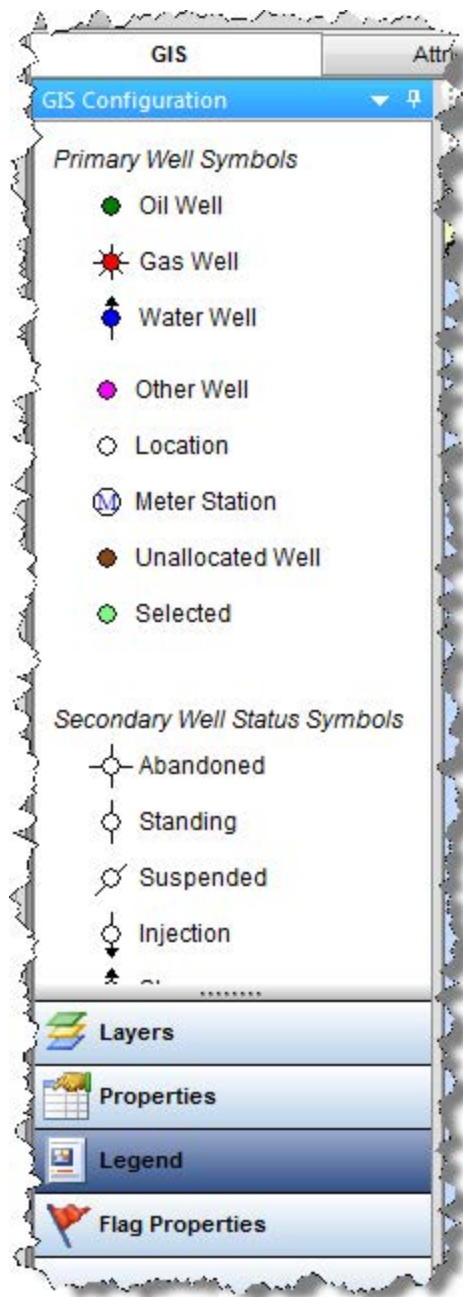
Note: Meter stations are displayed on the GIS map only if they are included in an imported .dp2 or a 298 file.

- Flag Properties

If you do not see these buttons, click the angle brackets (**>>**) and select **Show All Buttons**.
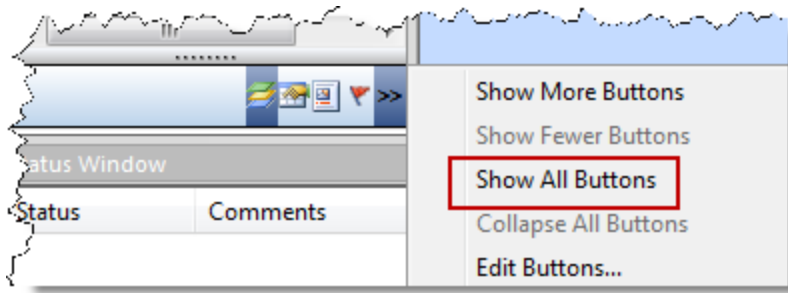
Context menus

Right-clicking within the GIS Configuration pane lists various options, which depend on the type of layer you select (for example, border layers, grid layers, and so on):

- **Select All Layers** — selects all of the layers for that layer type (for example, border layers).

- **Deselect All Layers** — deselects all of the layers for that layer type.

- **Group Display Layers By Type** — selecting this option groups layers by type; deselecting displays a flat list.

- **Add Shapefile Layer** — browse to your shapefile (.shp) file.

- **Shapefile Info** — opens the Shapefile Info dialog box where detailed information is provided (such as, the number and type of shape, label selection) along with a preview image.

- **DBF Info** — opens the DBF Info dialog box where attribute information is displayed. (The information in the DBF file is used when shapes are converted to facilities.)

- **Customize Shapefile Drawing** — opens the Customize Shapefile Drawing dialog box where you can change the line color, line thickness, fill color, and other visual attributes of the shape. You can also reset the settings to the default values.

- **Highlight Shapes** — highlights the selected shape.

- **Show Labels** — displays the label title for the shape.

- **Rename Shapefile Layer** — opens the Rename Layer dialog box where you can type in a new name for your shapefile.

- **Remove Shapefile Layer** — deletes the shapefile layer. Note that you are not prompted to confirm your decision.

- **Add Flag Layer** — adds a flag layer to the map.

- **Flag Properties** — opens the flag properties for that flag.

- **Remove Flag Layer** — deletes the flag layer.

- **Options** — opens the Bubble Map Editor dialog box where you can customize your bubble-map display.

- **Auto Range** — calculates a range based on the data for the entities used in the pie chart bubble map.

- **Legend** — select the item you want to display in the legend from the submenu (for example, color, size, section, and so on).

- **Rename** — opens the Rename Layer dialog box where you can type in a new name for your bubble-map layer.

- **Remove Bubble Map Layer** — deletes the bubble-map layer. Note that you are not prompted to confirm your decision.

- **Add General Annotation** — opens the General Annotation Editor dialog box where you can type your annotation and customize its display. You can also anchor the annotation to a specific location.

GIS map

The GIS map displays entities (wells and groups) as long as their attributes include geographical coordinates.

> **Tip:** If you select an entity in the GIS map, it is also displayed in the Spatial Explorer (and vice versa). However, you may have to pan the map in order to see it. Actions such as moving or deleting an entity are also mirrored in the Spatial Explorer.

When you mouse over the GIS map, the status bar displays the latitude, longitude, and dominion land survey (DLS) at the current location.
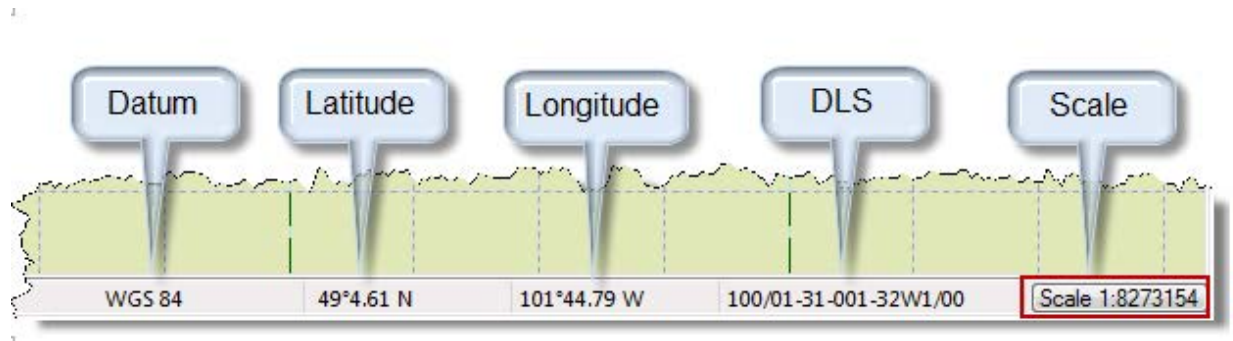
The GIS map supports three datum systems / projections:

1. NAD 27 (North American Datum, created in 1927)

2. NAD 83 (North American Datum, modified in 1983)

3. WGS 84 (World Geodetic System, modified in 1984)

To create new facilities, click the icons located on the GIS design mode tools toolbar. If you want other options (for example, setting a flag), right-click the well on the map.

When you select a well on the map, it is synchronized with the Entity Viewer and vice versa. Selected wells are highlighted in the Entity Viewer and are displayed in light green on the GIS map.
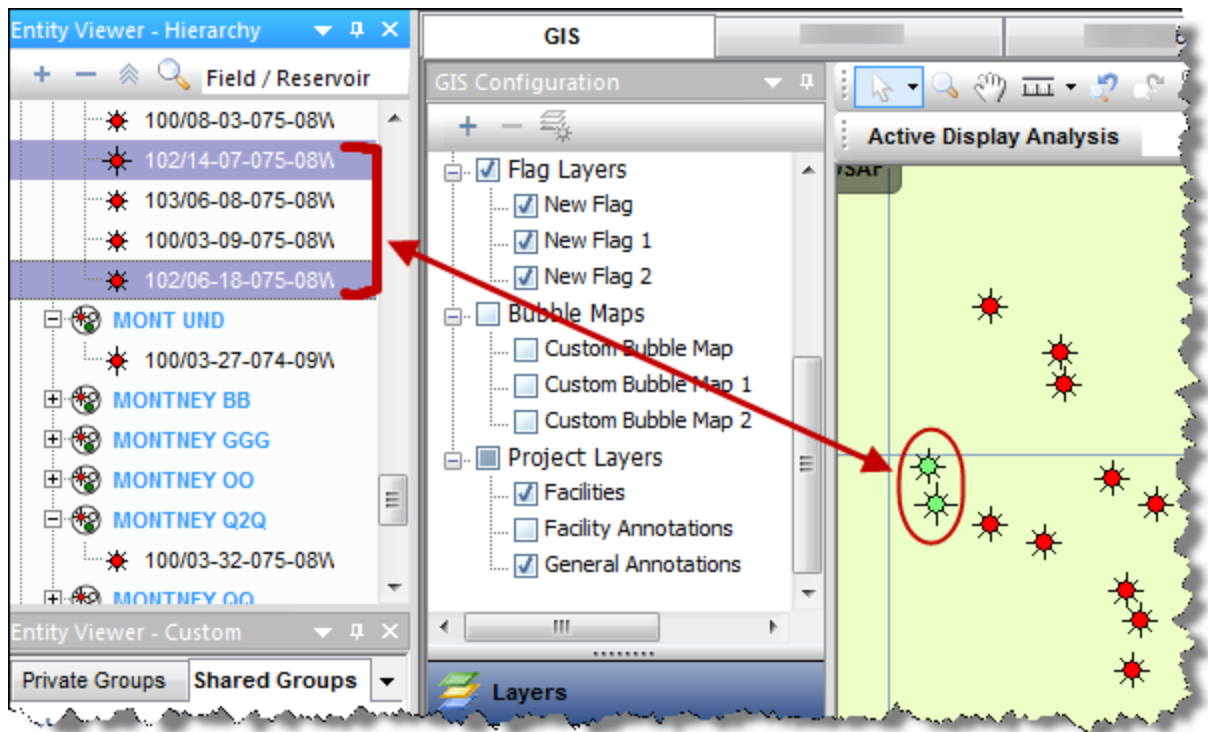
Context menus

If you right-click the map, you can add a general annotation by selecting **Create General Annotation**. This anchors the annotation at the point on the map you clicked.

If you right-click an annotation, you can edit it.

If you right-click a well on the map, these options are displayed:

- **Flags**

  - **Create New Flag** — adds a flag layer for this well and displays the flag properties in the GIS Configuration pane.

  - **Delete Flag** — deletes the flag for this well.

  - **Add Selection to Flag** — select your flag from the submenu.

  - **Remove Selection from Flag** — this option is enabled if a flag layer is already in place. Delete the appropriate flag by selecting it from the submenu.

  - **Flag Properties** — displays the flag properties in the GIS Configuration pane.

- **Bubble Maps**

- **Create New Bubble Map** — opens a dialog box where you can create and customize your bubble map.

- **Add to Bubble Map** — select your bubble map from the submenu.

- **Remove From Bubble Map** — this option is enabled if a bubble map is already in place. Delete the appropriate bubble map by selecting it from the submenu.

Layers

Click to see subtopics:

Shapefiles

    Compatibility

Layers are graphical strata that you can display on top of the GIS map. Layers include gridlines, geo-political borders, and well icons. You can show and hide layers by selecting or deselecting items in the tree structure.

Layers include the following:

- **Border Layers** — displays the political borders for all countries, the provincial borders in Canada, and the state borders in the United States.

- **Grid Layers** — displays each of the available coordinate systems. The DLS and NTS coordinate systems are only available within certain regions.

- **Shapefile Layer** — a shapefile is a collection of files that contains simplified geo-spatial and attribute information to describe points, arcs, and polygons. These points and shapes represent objects or locations on a map (for example, a well, a lake, or political borders). For more information, see shapefiles.

- **Image Layer** — any image (for example, a photograph) can be imported as an image layer. While importing an image file you are prompted to set desired coordinates for three points on the image. These points are used to position the image on the GIS map.

- **Project Layers** — includes all wells / facilities and annotations.

  - **Facilities** — this layer includes all wells and meter stations.

  - **Facility Annotations** — annotations connected to a specific entity (such as, wells) that display selected attribute and analysis information. For more information, see the Facility Annotation Editor dialog box.

  - **General Annotation** — annotations to be displayed on the GIS map. While adding a general annotation, you can customize the text, appearance, and position.

- **Bubble Map Layer** — bubble maps graphically represent attributes associated with wells and other entities. For more information, see bubble maps.

- **Flag Layer** — flags are similar to bubble maps, but they do not reflect well attributes. Instead, they are simple markers that can be used to designate individual or multiple entities. For more information, see flags.

By default, layers are displayed with Project Layers being drawn on top of the GIS map, followed by Grid Layers, and Border Layers. This corresponds to Project Layers being at the bottom of the tree structure and Border Layers being at the top.
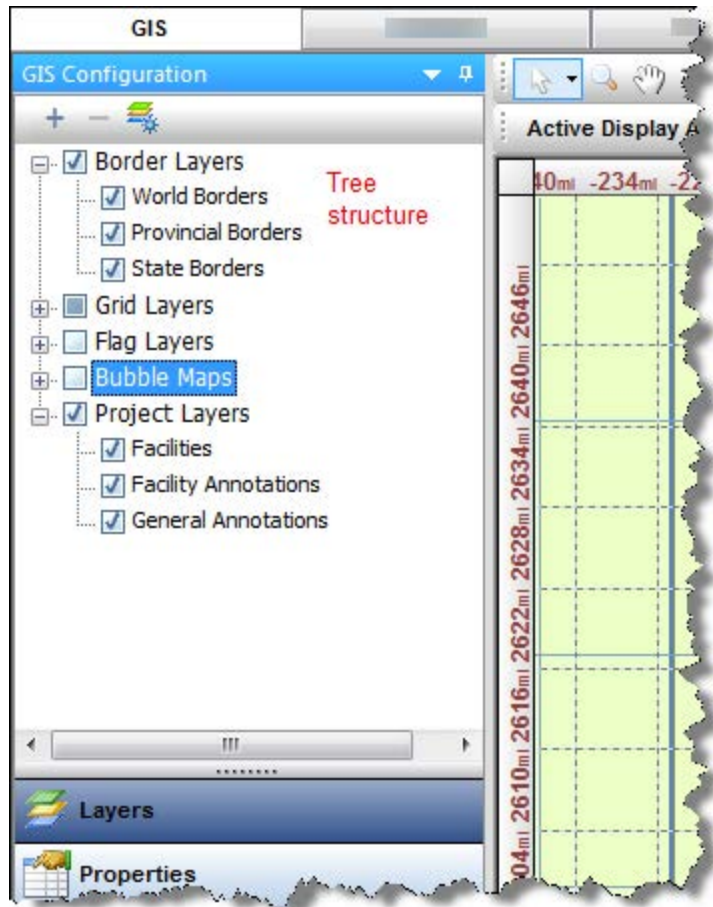
To change your display order, drag the category in the tree to your new location.

Note: Drawing layers on top of others may hide certain information. You can avoid this by setting the transparency of the top layer by right-clicking it in the tree and editing its properties.

Shapefiles

With Harmony Enterprise, you can only select shapefiles with the .shp extension, but shapefiles usually contain a collection of files with different extensions. Harmony Enterprise uses the following file types to make the import process faster and more accurate:

- **DBF** — contains shapefile information and labels for the data. (The information this file contains is used when shapes are converted to facilities.) This file is the least critical; if it is missing, the shapefile is still imported.

- **PRJ** — contains the datum for the shapefile in projection, unit, datum format. (Harmony Enterprise supports NAD27, NAD83, and WGS84.) If this file is missing, the shapefile may not be placed in the correct location.

- **SHX** — loads individual shapes from the file. This file reads the bounding boxes of an area and works as a sort of index for the .shp file, so that all the data contained in the .shp does not need to be cached. If this file is missing, loading may be slow and more memory may be consumed.

These files make using shapefiles easier, so we recommend keeping them together in the same directory.

Compatibility

If you encounter issues importing a shapefile, it may be because your shapefile is incompatible with Harmony Enterprise. Ensure that your shapefile meets the following requirements:

- Mercator projection

- Geographic coordinate system (GCS)

- NAD 27, or NAD 83, or WGS 84

- Latitude and Longitude in decimal degrees

Facility Annotation Editor dialog box

This dialog box is commonly used when you click the <u>Annotation Display Options icon</u> on the GIS tool-bar.

Important: Clicking **OK** applies your changes to all your annotations *excluding* those that have been individually modified by right-clicking specific annotations. Clicking **Apply to All** updates every annotation.

- **Search** — type a search term in this field, and results are automatically displayed.

- **Attributes** — select the attributes you want displayed in your annotation.

- **Results** — select the results you want displayed in your annotation.

- **Include in Apply to All** — if you select this checkbox, the settings in the Label Position section are applied to all of your wells when you click **Apply to All**. When this checkbox is deselected, only the well annotations that have not been individually edited are modified.

- **Angle** — sets the angle that the annotation is offset at from the well. A negative value is rotated counterclockwise from the well.

- **Distance** — sets the distance (in inches) that the annotation is offset at from the well.

- **Display** — select one of the display options for title, value, and unit.

- **Draw Settings** — if you select **Frame**, a box is drawn around your annotation. If you select **Anchor**, your annotation is fixed to the well.

- **Background** — set your background color and transparency for the annotation.

Bubble maps
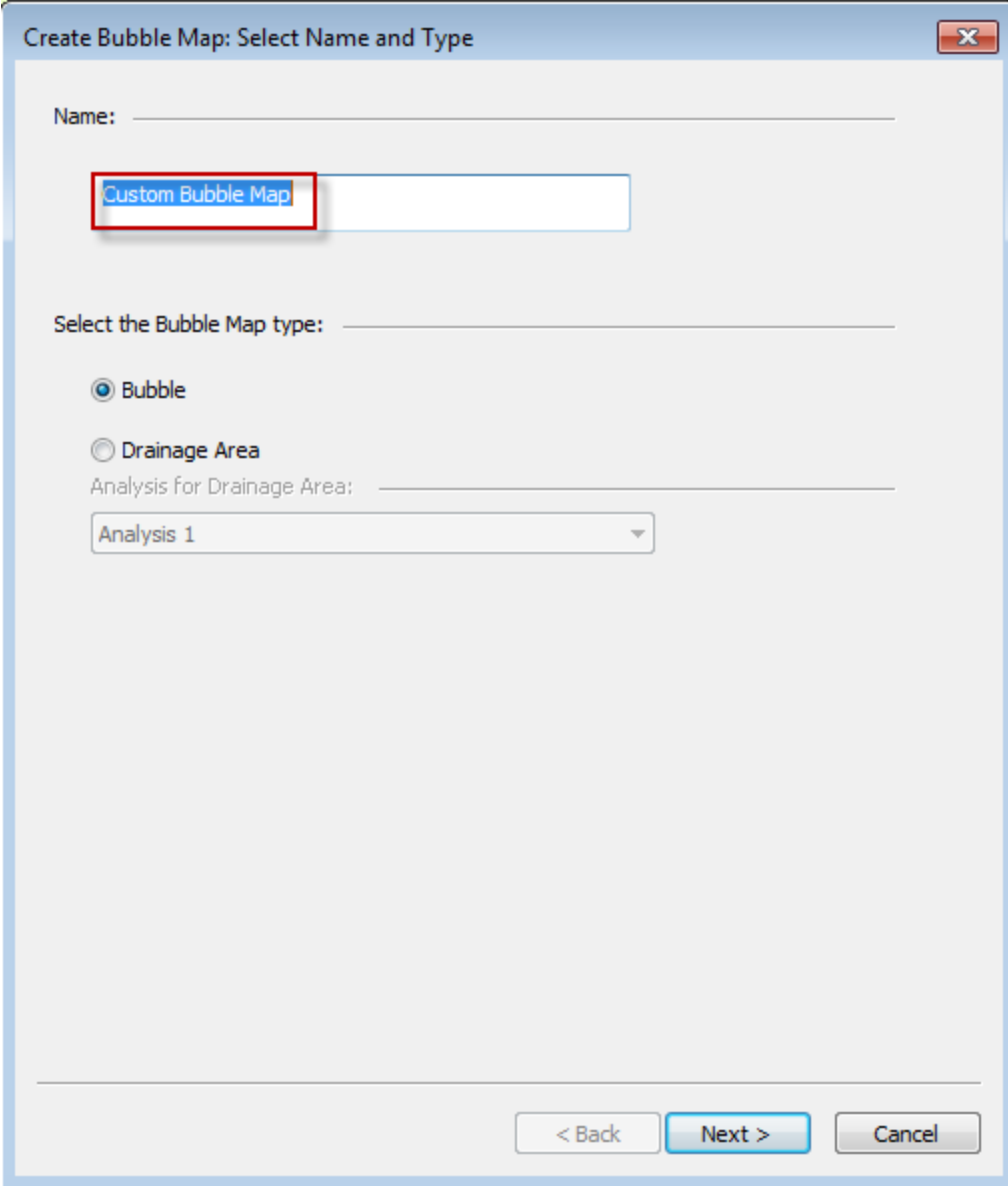
Bubble maps provide a means of graphically representing attributes and analyses associated with specific wells.

Bubble maps are represented as layers within the GIS tab, and can be selectively enabled or disabled like other layers. To create these graphic representations, a colored shape is overlaid on the entity. Both the color and the shape reflect one of the properties associated with the entity. As the value of the property changes, the color changes within a set range. In more complicated cases, multiple properties can be associated with different settings including variations in color, size, angle, and shape, according to the scale you set.

To show or hide the bubble map, select or deselect it in the tree structure.
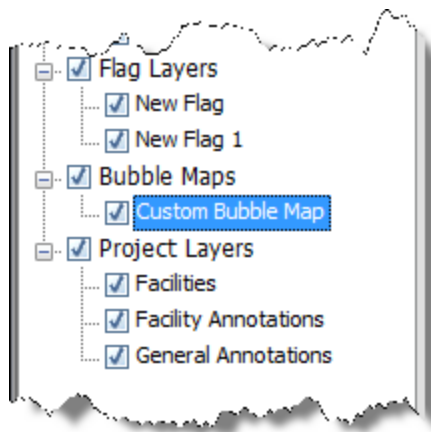
To add / create a bubble map, start by selecting wells for the bubble map. In the GIS Configuration pane, click the **+** icon and select **Add Bubble Map Layer**.

Type a name for your bubble map layer and click **Next**. If you create a bubble map with the same name, a number is incrementally added to the name (for example, custom bubble map 1, custom bubble map 2, and so on).

Each tab in Preferences enables you to customize a different property that varies with well properties. (Fixed settings are used by default.)
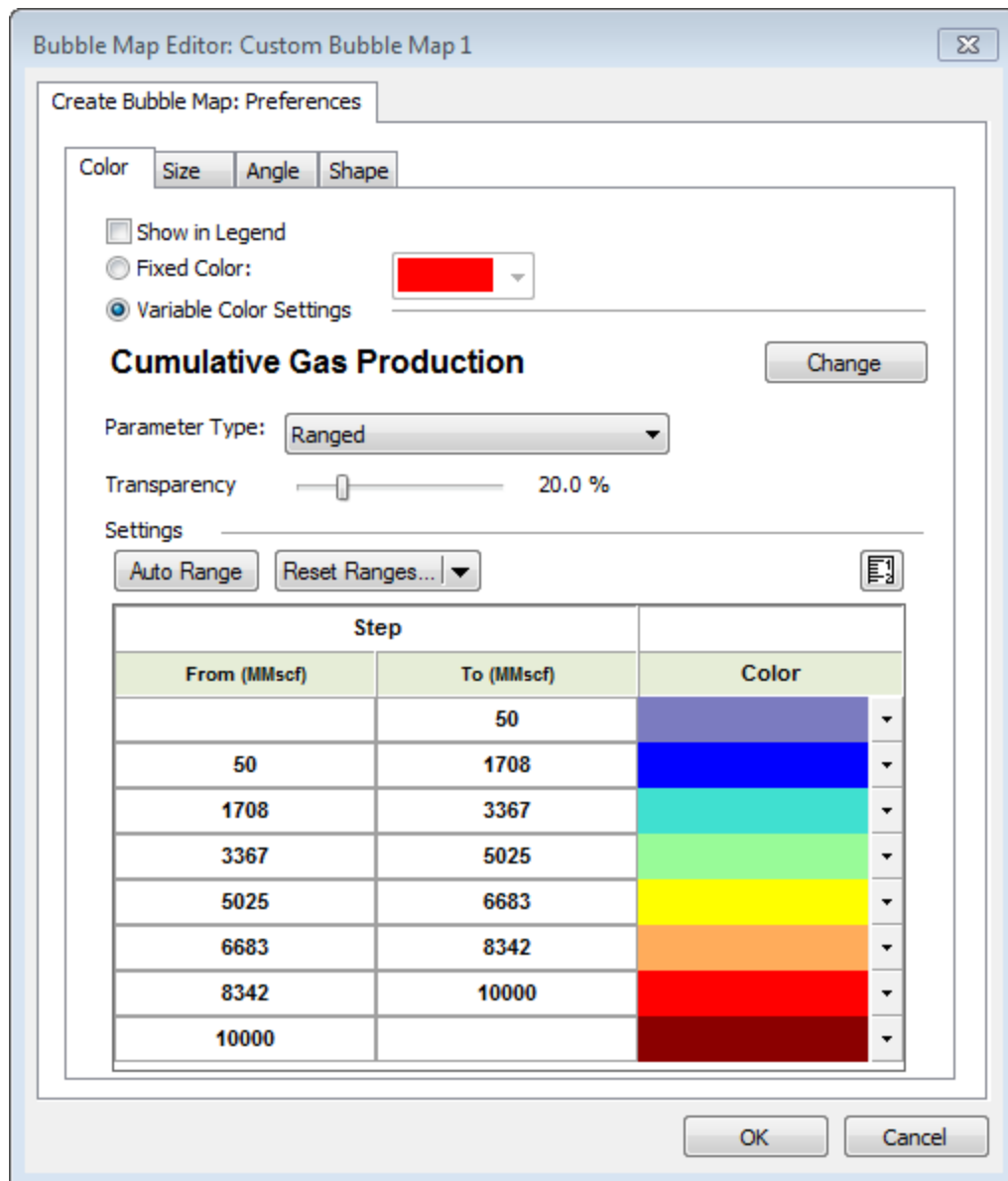
- **Show in Legend** — select whether this property is displayed in the legend. If the property is using a variable color setting, by default, the property is displayed in the legend.

- **Fixed Color / Size / Angle / Shape** — all wells show the same property, as set in the dialog box.

- **Variable Color / Size / Angle / Shape** — select an attribute or analysis result on which to vary the property. When selecting analysis results, an analysis name must also be selected.

- **Parameter Type:**

  - **Ranged** — the color, size, etc. displayed corresponds to a range of property values for each parameter.

  - **Set Point** — the color, size, etc. displayed corresponds to a specific value for each parameter.

- **Transparency** — use the slider to set the level of transparency / opacity for your bubbles.

- **Auto Range** — for each ranged property, Harmony Enterprise automatically detects the appropriate range and division to separate values.

- **Reset Ranges** — reverts back to a previously saved range, or to the default values.

- **Change** — when you click this button, the <Color> Attribute: Select a Property dialog box opens.

  Select the attribute / result from the tree structure.
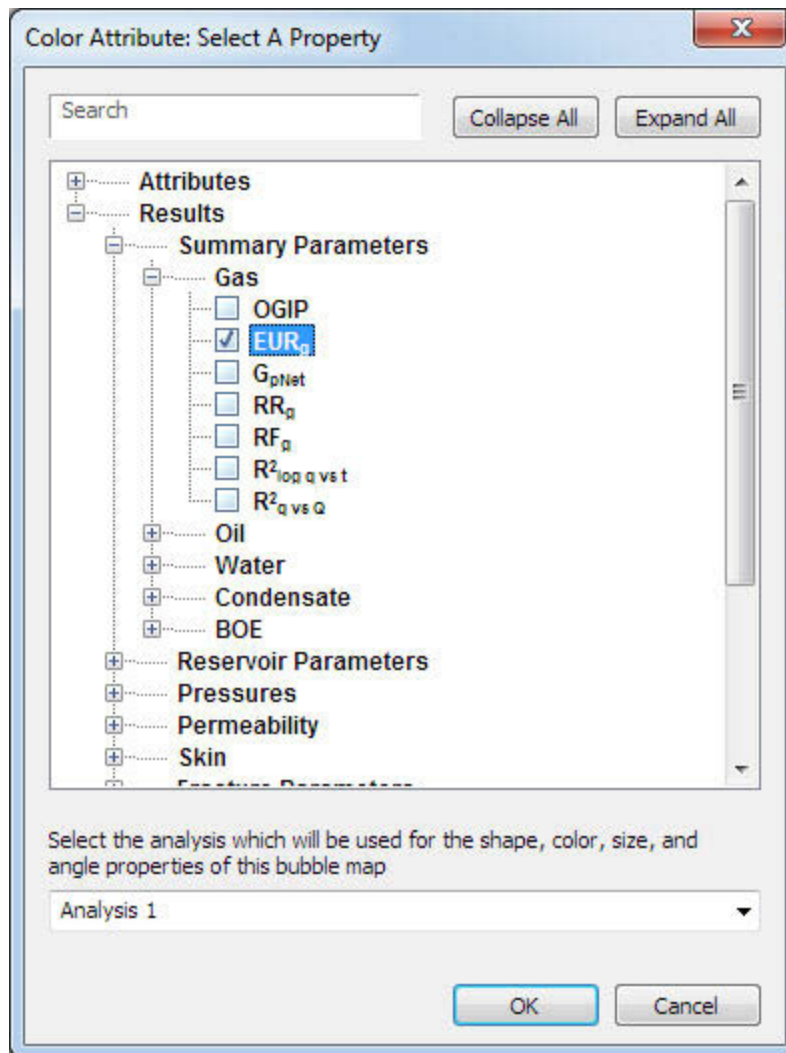
- **Search** field — type your search term to find attributes or analysis results.

- **Analysis** drop-down list — select the analysis to populate values for the selected property. Note that this only applies to the Results tree structure, and does not apply to attributes.
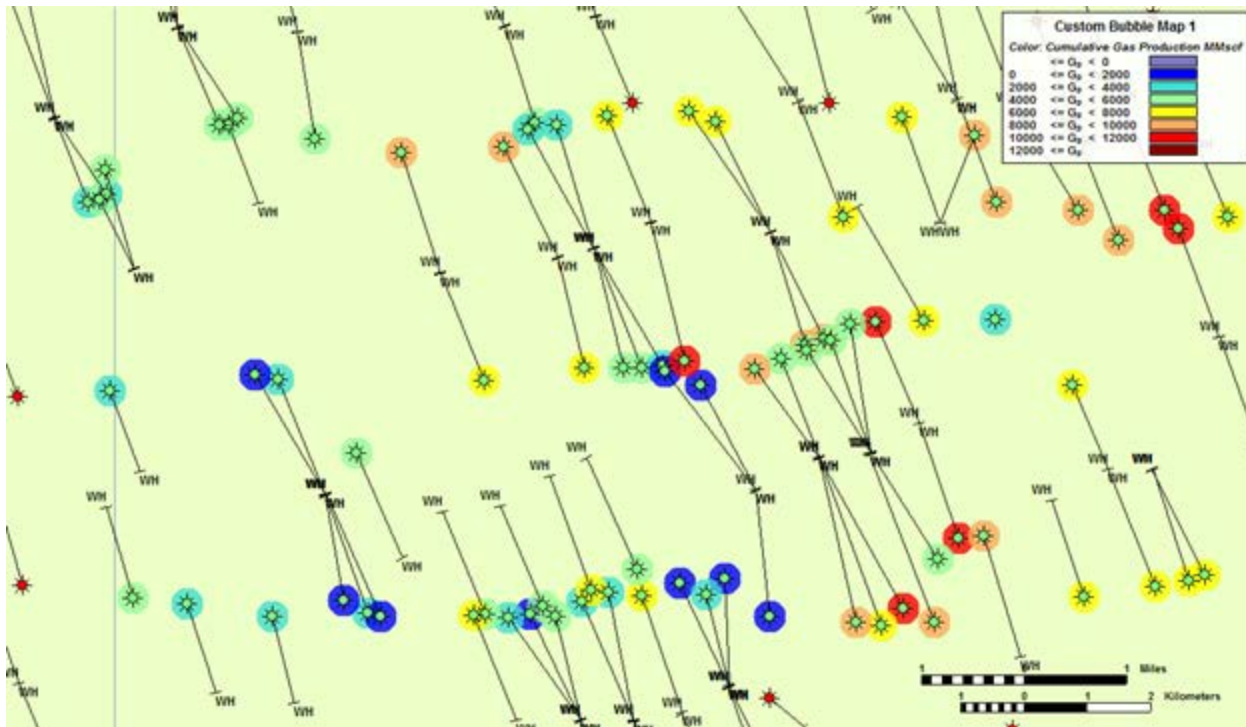
To edit an existing bubble map, right-click it in the tree structure and select **Options**. If you click **Variable Color Settings**, the **Change** button is enabled and you can set the <color> for a specific attribute.
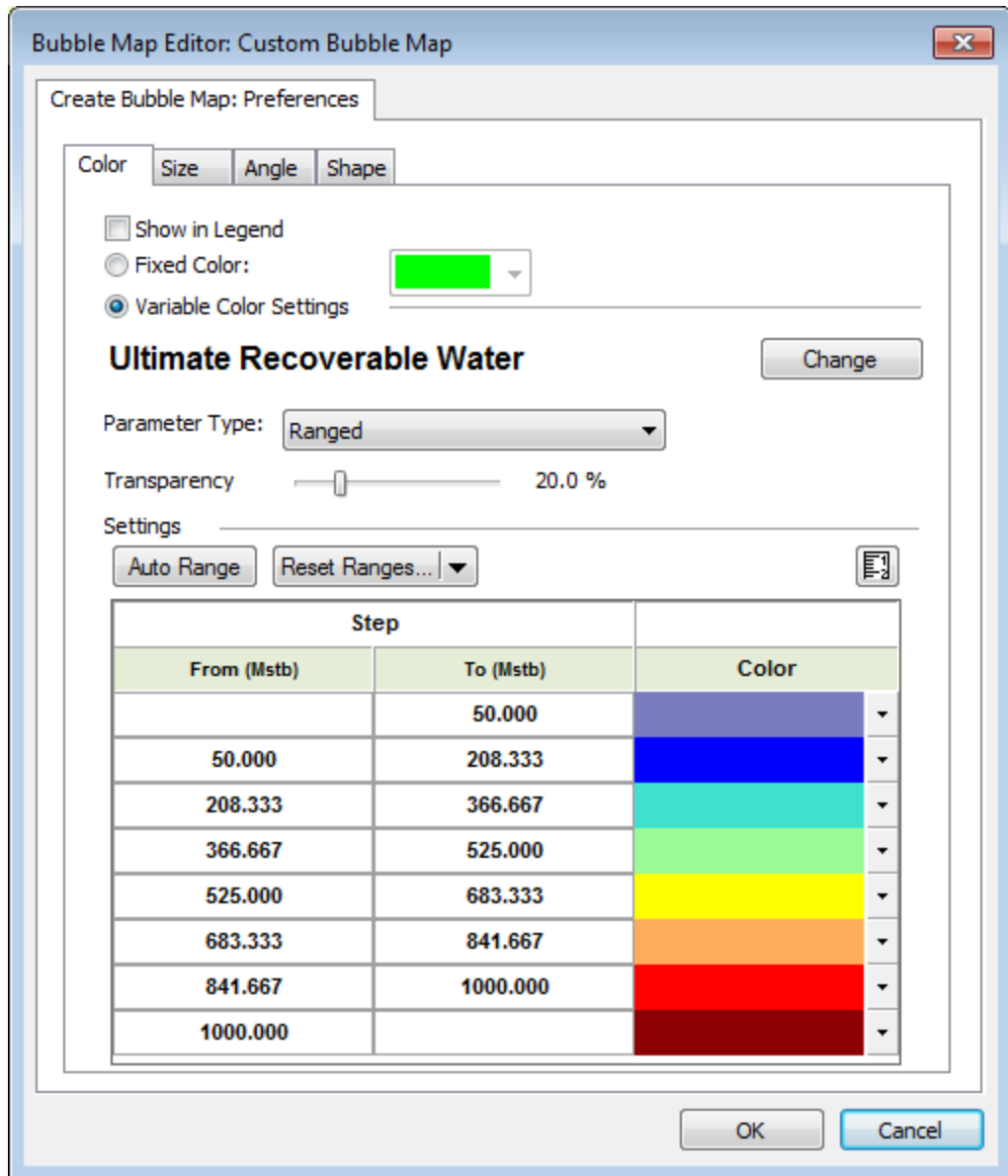
To add wells to an existing bubble map, select the well, right-click it and select **Bubble Map**, **Add to <bubble map name>**.

Drainage area maps

A drainage area map is a bubble map (plotted as a circle), which plots the drainage area of a well to scale on the GIS map, based on the area each well is draining. While traditional bubble maps can plot drainage areas, they only show relative areas, with the size of the bubble corresponding to the range you set.

Note: If the drainage area is small, you may have to zoom in to see the bubble map.

To add a drainage area map, see bubble maps. Note that with drainage area maps, color is the only variable preference that can be set.

Flags

Flags are similar to bubble maps, but they do not reflect well attributes. Instead, they are simple markers that can be used to designate individual or multiple entities.

If you add a flag layer (click the **+** icon on the GIS Configuration pane), a corresponding node in the tree structure is added. You can show or hide flags by selecting or deselecting their checkboxes.
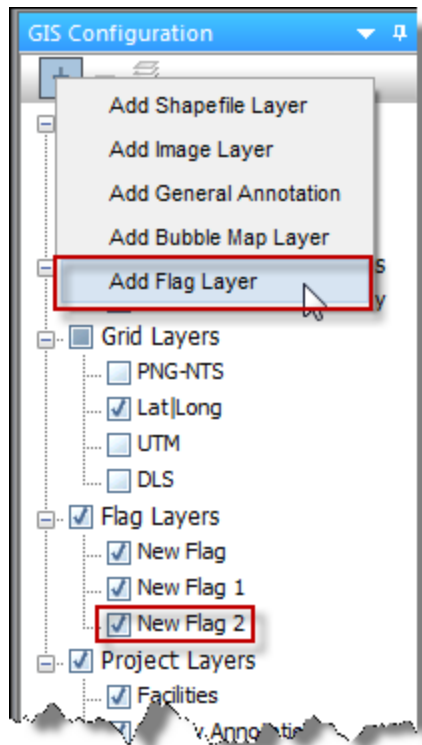
To add wells to an existing flag, select the appropriate wells on the GIS map, and then right-click and select **Flags**, **Add Selection to Flag**.

To modify flags, right-click the flag in the tree structure and select **Flag Properties**. Edit your flag's name, color, size, or transparency.

Flag properties

When you click the Flag Properties button at the bottom of the GIS Configuration pane, you can edit the appearance of flags displayed on top of entities on the GIS map. The drop-down list at the top of the pane determines which flag is being edited.
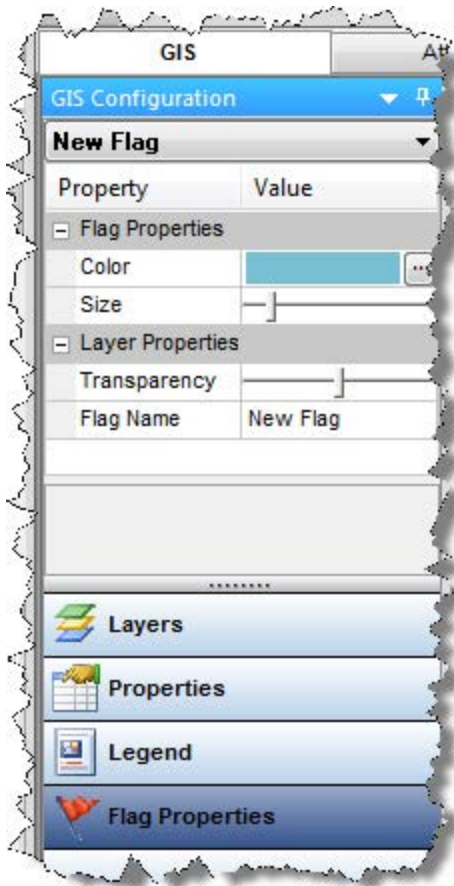
- **Color** — click the **...** button and select the color for the selected flag.

- **Size** — click the slider to increase or decrease the size of the circle displayed on the map for the selected flag.

- **Transparency** — click the slider to increase or decrease the transparency of the selected flag. Moving the slider to the left, makes the flag more opaque, and moving the slider to the right, makes the flag more transparent.

- **Flag Name** — use this field to type a name for the selected flag layer.

Flags are similar in appearance to bubble maps, but they do not reflect well attributes. Instead, they are simple markers that can be used to designate individual or multiple entities.
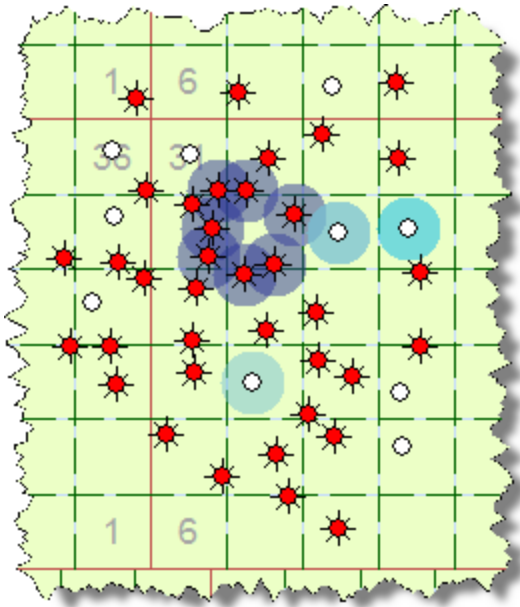
Flags are represented as layers on the GIS map, and can be selectively enabled or disabled like other layers.

Import functionality

To prevent other users from modifying data at the same time, wells must be locked while they are imported. Importing a new well does not impact other users because the well is not visible to them until the well import is complete. However, when you are updating existing wells, these wells are locked to other users. If Harmony Enterprise is unable to lock a well during importing or updating, the update of this well fails, and an error message is displayed in the Status Window.

Import functionality includes the following:

- Scheduling well updates
- Import Data dialog box
- Link Incoming Wells to Existing Wells dialog box
- Import Options dialog box

Scheduling well updates

In most cases, scheduling well updates refers to specifying a time to import additional data for one or more wells.

Note: This functionality does *not* apply to SE licenses.

You can schedule well updates on a one-time basis using the Import Database wizard (step 12), or automatically using the auto-import feature. If you decide to import your wells automatically, you can schedule imports to occur outside of business hours on a recurring basis without using a Harmony Enterprise license. For more information, see the Import Options dialog box.

In order to schedule well updates, you need:

- permission to modify and execute tasks. If adjustments are needed, see your IT department.

- permission to import data. For more information, see role-based security.

- to be logged in to Windows when the updates occur. Note that locking your computer is fine.

After your automatic well import is complete, a log file is generated, which is viewable by double-clicking the summary message in the Status Window.

Windows Task Scheduler

The Windows Task Scheduler is commonly used when setting Auto Import options in the Import Options dialog box.

To use the Task Scheduler:

- Type a name for your task.

- Set a start date and time.

- Select the frequency of the task from the drop-down list (that is, daily, weekly, or monthly).

- To rename your task, type a new name in the Task Name field, and click **Save Task**.

- To save your task, click **Save Task**.

- To delete your task, click **Delete Task**. (You are *not* prompted to confirm your decision.)

When your task is scheduled, you can preview it in the Task Scheduler.
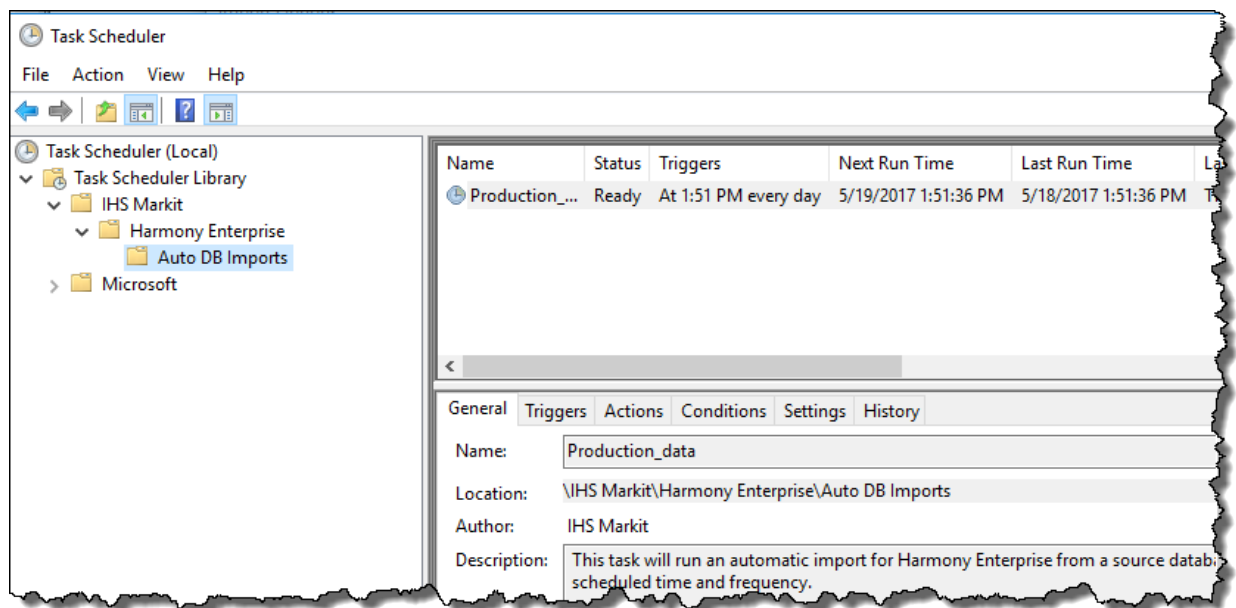
Command line

Command line is commonly used when setting Auto Import options in the Import Options dialog box.

Copy and paste the text in the Program and Arguments fields to your application or script. If you are not able to open a Command prompt, you may need to contact your IT dept.

Note: The last part of the text in the Arguments field represents the abbreviations for updating data (for example, "nnao"). For more information, see the Options dialog box (Updating Data settings).

Import Data dialog box

This dialog box is commonly used when you <u>import well data from a file</u>. The main purpose of this dialog box is to assign column headers (by clicking the drop-down arrows) to your data, which brings this data into Harmony Enterprise.

Toolbar

This dialog box has these items on its toolbar:

- **Open folder** — lists two options:

    - **Reset and Open** — closes the existing imported file and opens the Open File to Import dialog box.

    - **Open Another File** — opens the Open File to Import dialog box.

- **Discard Changes** — clears all content in the table / grid.

- **Options** — opens the Import Options pane.

- **Separate** (Production data only with multiple wells in one file; not applicable to attributes) — if you specify a Well Identifier for your first column and click **Separate**, multiple wells in the same file are listed as tabs, which divides the single import file into multiple entities for import.

- **Apply To** — applies the column headers you have set in one worksheet to all of the other worksheet tabs in the spreadsheet file. The single import file generates multiple entities for importing, with each one named according to the original worksheet name.

Import Options pane

In this pane, you can change import options, including the standard operating conditions of the file to be imported, and the configuration of the unit list.

Rows

(You can also <u>right-click rows</u> to set this range.)

- **Start Import from row** — set the first row number in the table that you want to import.

- **End Import at row** — set the last row number in the table that you want to import.

Format

- **Save format for this file while importing** — saves your column and row mapping for this file.

- **Save current format as default while importing** — saves your column and row mapping as the default setting for other files.

- **Remove default format (if it exists) while importing** — resets your settings, so you can remap columns and rows.

- **Save current format as** — saves your current mapping as a template.

- **Saved Formats** — select the saved formats you want to apply or delete.

- **Multi-level unit picker** — when selected, the column-mapping menus display the menu items horizontally in multiple columns, instead of the default setting of a single vertical column.

- **Continuous time track** — this option is selected by default for cumulative time. If you deselect this option, gaps in your order, as determined by irregularities in the data sampling interval, are interpreted as shut-ins. For additional information, see continuous time track.

- **Sample interval for Date / Time matching** — we recommend keeping the default setting. This option specifies the interval for comparisons. For example, every 50 rows a comparison is performed on the date / time column to verify if the format is acceptable.

- **Date / Time Sensitivity Level** — we recommend keeping the default setting. You can use the slider to specify how closely a format has to match. For example, a 100% setting means that the imported file has to match your format exactly.

Plot pane

In this pane, your column selections are plotted as long as you have populated x- and y-axis data in your table / grid.

Link Incoming Wells to Existing Wells dialog box

This dialog box opens when any one of these conditions is met after the import process is complete:

1. You import wells (markup files or Harmony files) that have one or more non-unique matches to existing wells.

2. You have an API that has multiple Production IDs encountered in the import, or the database.

3. You have selected the Imported Well Linking option in the Options dialog box (Tools menu, Options, Importing node).

Note: If the Link Incoming Wells to Existing Wells dialog box does not open, linking to existing wells is done automatically based on the well ID (*.harmony files only), DLS, NTS, API, or Prod ID.

The OK button is enabled after the incoming wells are linked up and are displayed in the Linked Well (Incoming | Existing) pane. In other words, incoming wells cannot be imported unless they are linked to existing wells, or are categorized as new wells.

In this dialog box, you can:

- Display which incoming wells are linked, and which are not, as a result of the auto-mapping process.

- Link an incoming well to a well in the database manually.

- Compare the production data for any two wells (one from the import, and the other from the database, or from a pair of linked wells).

- Compare the well attributes of two or more wells (one from the import, and the other(s) from the database).

The options in this dialog box include the following:

- **Incoming Wells** — lists incoming wells that have not been linked up.

- **Link** — links a single well from the incoming list to a single well from the database list. After a link has been made, the two linked items are moved to the Linked Wells pane. This button is disabled if the two selected items are not compatible. For example, in an unallocated .dp2 or .298 file, a meter station cannot be linked to an unallocated well.

- **New Well** — this button is enabled when incoming wells are selected that are not currently in the database. Clicking this button moves the selected wells to the Linked Wells pane.

- **Existing Potential Well Matches** — lists wells in the database that are a potential match for the incoming wells based on the Display Link by setting. Or, if the Show all wells option is selected, lists all wells in the database. A well in this list is not updated on import.

- **Show all wells** — when this checkbox is selected, all of the wells in the database are displayed in the Existing Wells pane.

- **Auto Link** — clears the current linking results and restarts the auto-mapping process according to the single attribute displayed in the Display / Link by field. This button is disabled when the Display Name field is selected because the manual auto-link feature only operates on a single attribute. The Auto Link feature operates on a 1:1 basis with wells too. In other words, you cannot auto-map multiple wells to a single well.

- **Unlink** — removes the items selected in the Linked Wells pane and returns them to their original locations. (If the well ID in a *.harmony file has been used for matching, it cannot be unlinked.)

- **Unlink All** — removes the links for all of the items in the Linked Wells pane.

- **Reset** — resets the entire dialog box to its original settings (initial view).

- **Display / Link by** — displays the primary attribute used to link up wells in the auto-mapping process. It also indicates how the wells are displayed in this dialog box.

- **Linked Wells (Incoming I Existing)** — lists the wells that have been linked (incoming to existing), or new wells to be imported. Wells on the left-side of this pane are used to update the corresponding wells on the right-side.
Empty wells have only their well name set (their API, DLS, NTS, Production ID, and Well Alias Name are blank) and are listed as new wells in this pane.

- **Compare by** — displays the production variables that can be plotted (one at a time).

- **Production tab** — clicking wells in either the Imported Wells or the Existing Wells pane displays the production data for the selected wells. Clicking two wells (one from each of the panes), or a single well in the Linked Wells pane, displays the production data for both wells. Data from the database is displayed in black, while data from the incoming well is displayed in the color of the primary fluid. The plot is disabled when more than one item is selected in the Linked Wells pane.

- **Attributes tab** — clicking wells in the Imported Wells pane displays its corresponding data in the Attributes tab. Subsequently clicking one or more wells in the Existing Wells pane displays their corresponding data in the Attributes tab.

- **Stop Import** — stops the import process of wells that do not have a 1:1 mapping.

- **Cancel** — cancels the current batch of wells that do not have a 1:1 mapping.

Note: Meter stations cannot be manually linked up in Harmony Enterprise. If meter stations exist in an imported .298 or .harmony file, they are automatically brought into a project when they are imported.

Import Options dialog box

Click to see subtopics:

This dialog box is used when you import well data from a database.

Updating Data Options

The Updating Data Options section displays the global Updating Data settings from the Options dialog box.

To change these settings for the current database import, select from the drop-down lists and click **Finish**.

Production Data

The Production Data drop-down list has the following options:

- **Append** — adds new production data after the end of the existing production history

- **New** — adds new production data for any dates that do not exist in the current production history

- **Overwrite** — adds new production data and replaces production data for any dates that exist in the current production history. When this option is selected, additional options are displayed below. You can choose to overwrite the entire production history, or only the last 90 days.
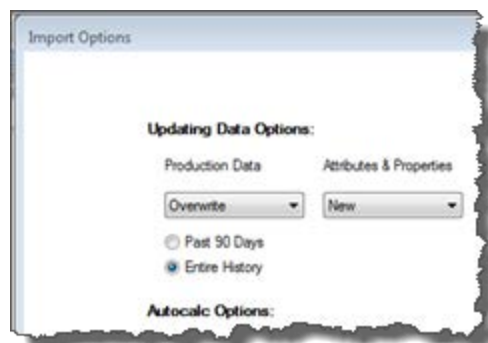
Attributes & Properties

The Attributes & Properties drop-down list has the following options:

- **Discard** — does not import attributes and properties for existing wells

- **New** — adds new attributes and properties when data did not previously exist

- **Overwrite** — adds new attributes and properties, and replaces existing values with newly imported ones

Analysis Data

The Analysis Data drop-down list has the following options:

- **Discard** — does not import analyses

- **New** — only adds new analyses

- **Overwrite** — replaces existing analyses when matched with imported ones, and adds new analyses

Tip: If you are importing decline analyses from an Aries database via the Database Connection wizard, you may want to adjust your default settings, especially if your default settings include the Discard option.

Wellbore

The Wellbore drop-down list has the following options:

- **Append** — adds new wellbore configurations

- **Discard** — does not import wellbore configurations

- **Overwrite** — adds new wellbore configurations, and replaces existing configurations with newly imported ones when the dates match

AutoCalc Options

To automatically calculate sandface pressures during the import, ensure the **Autocalc Options** check-box is selected. Note that calculating sandface pressures can take a considerable amount of time (depending on the number of wells and their complexity).

Auto Import

To schedule automatic well updates using the Windows Task Scheduler or command line, click the **Auto Import** box.

For more information, see Windows Task Scheduler and command line.

Options dialog box

Click to see subtopics:

You can access the Options dialog box from the **Tools** menu, or by clicking the **Options** icon ( ) on the main toolbar. Any of the User Settings you change apply after you close the dialog box, and do not affect existing analyses. However, Shared Settings are database settings that apply to all entities, both new and old.

Importing

Unreported Volume or Rate

- **Leave as Null (empty)** — assigns no value to volumes / rates whose true value is not reported.

- **Zero** — assigns a value of "0" to volumes / rates whose true value is not reported.

- **Step Interpolate** — carries over the preceding value to an unreported volume. This creates a step-like plot.

- **Linearly Interpolate** — assigns a value to an unreported volume that is equidistant from the preceding and following reported values. This creates a linear plot.

Imported Well Linking

- **Display Link Imported Wells to Existing Wells dialog** — opens the Link Imported Wells to Existing Wells dialog box every time data is imported from a markup file into a non-empty database.

Number Format

- **Use Comma as Decimal Separator** — applies to some European customers where commas are used as a decimal. If this applies to some of your text imports, click to select this option, so that Harmony Enterprise can appropriately handle the numbers.

Updating Data

These settings apply globally unless you specify other options on a per-data-source connection basis in the Import Options dialog box.

Production Data

- **Append from last production date** — imports production data from the last production end date. Abbreviated as "a" in the Auto Import section of the Import Options

dialog box.

- **Overwrite / Merge existing data** — imports all new production data and overwrites existing property and attribute data with imported values. Abbreviated as "o" in the Auto Import section of the Import Options dialog box.

- **New data only** — imports new production data and does not overwrite any data. Abbreviated as "n" in the Auto Import section of the Import Options dialog box.

Attributes and Properties

- **New data only** — imports new attribute and property data and does not overwrite any data. Abbreviated as "n" in the Auto Import section of the Import Options dialog box.

- **Overwrite / Merge existing data** — imports all new production data and overwrites data with the same dates as those being imported. Abbreviated as "o" in the Auto Import section of the Import Options dialog box.

- **Discard all incoming data** — does not import attribute nor property data. Abbreviated as "d" in the Auto Import section of the Import Options dialog box.

Analysis Data

These settings only apply when you import well data from a database (Aries), or from PowerTools.

- **New data only** — imports new analyses and does not overwrite any data. Abbreviated as "n" in the Auto Import section of the Import Options dialog box.

- **Overwrite / Merge existing analyses** — adds all analyses, even if analyses with the same name exist in the project. If a duplicate analysis / worksheet exists, the analysis / worksheet names are appended with a number. Abbreviated as "o" in the Auto Import section of the Import Options dialog box.

- **Discard all incoming data** — does not import analyses. Abbreviated as "d" in the Auto Import section of the Import Options dialog box.

Tip: When you import well data from a .harmony file, if an analysis or worksheet already exists, it is not imported. For .hldb files (local database files), if an analysis or worksheet already exists, it replaces the existing copy.

Wellbore

- **Append with incoming wellbore data** — only imports new / incoming wellbore data. Abbreviated as "a" in the Auto Import section of the Import Options dialog box.

- **Overwrite existing data** — only applies to IHS Enerdeq / IHDC imports and the deviation survey if it is empty (that is, when the wellbore configurations are empty). Abbreviated as "o" in the Auto Import section of the Import Options dialog box.

- **Discard all incoming data** — does not import wellbore data. Abbreviated as "d" in the Auto Import section of the Import Options dialog box.

Static Pressures

- **New data only** — imports static pressure data and does not overwrite any data. Abbreviated as "n" in the Auto Import section of the Import Options dialog box.

- **Overwrite / Merge existing data** — imports all new static pressure data and overwrites data with the same dates as those being imported. Abbreviated as "o" in the Auto Import section of the Import Options dialog box.

Custom Data

- **Import New Custom Attributes** — if this option is selected, all custom attributes are brought in when importing .hldb or .harmony files. If this option is deselected, values for custom attributes that are already set up in the project are brought in, but no new custom attributes are created on import.

- **Import New Custom Datasets** — if this option is selected, all custom datasets are brought in when importing .hldb or .harmony files. If this option is deselected, values for custom datasets that are already set up in the project are brought in, but no new custom datasets are created on import.

Autocalc Settings

By default, sandface pressure calculations are calculated after your data has been imported because this can be a time-consuming process. However, if you want these calculations to be done automatically during the import, click the Import Autocalculation Options checkbox to deselect it.

Tip: Scenarios do *not* automatically recalculate when importing an .hldb file even when the Autocalculation checkbox is selected.

Analysis

To automatically add the Add Analysis menu to a new worksheet, click the Worksheet Creation checkbox (default setting).

Decline

These options set the initialization of new decline analyses and constrain the use of best-fit tools:
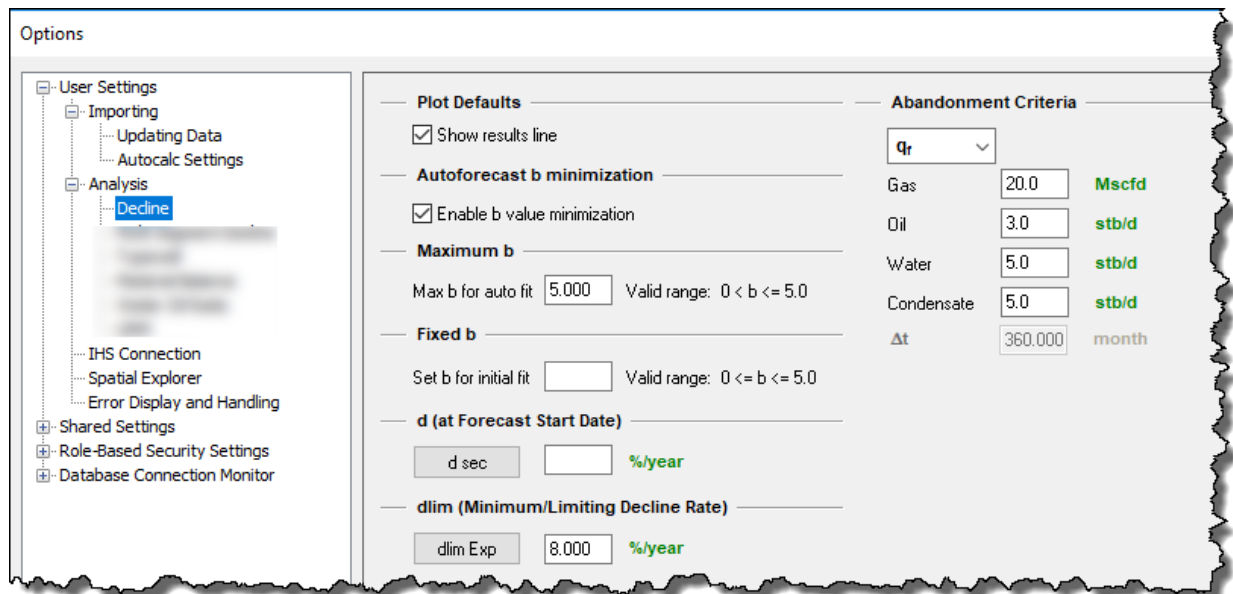
You can set the parameters that initialize all decline analyses in Harmony Enterprise, and you can change these initialization values while performing an analysis (within the analysis worksheet). The decline parameters and settings are as follows:

- **Show results line** — displays / hides a green-dashed line for abandonment rates on your decline plot.

- **Enable b value minimization** — when you add a decline analysis, Harmony Enterprise automatically selects the best subset of your data for an initial best fit. When this option is selected, the b value (slope) is minimized without sacrificing the quality of the fit. This can be of particular use with unconventional reservoirs where there is more curvature in the declines. (This option is selected by default.)

- **Maximum b value** — sets the maximum b value allowed for the best-fit decline. Harmony Enterprise accepts any value between 0 and 5.

- **Fixed b** — if a value is defined, every decline initializes with this b value, and the yellow lock icon defaults to a locked (🔒) position. Harmony Enterprise accepts any value between 0 and 5.

- **d (at Forecast Start Date)** — sets an effective decline rate from the forecast start date of a segment, so that each new decline curve initializes with this value. This parameter can be toggled among the effective decline rates (*d sec and d tan*), or the initial nominal decline rate (*a*).

- **d$_{lim}$ (Minimum / Limiting Decline Rate)** — defines a limiting effective decline rate, and every decline switches to an exponential decline (b=0) when this value is

reached. The default setting is 8%. This parameter can be toggled from d_{lim} Hyp to d_{lim} Exp.

- **Abandonment Criteria** — defines the abandonment rates (q_f) for different fluids, or the duration of the decline (Δt) as abandonment criteria.

Multi Segment Decline

You can set the parameters that initialize all multi-segment decline analyses in Harmony Enterprise, and you can change these initialization values while performing the analysis, within the analysis work-sheet. The multi-segment decline parameters and settings are as follows:

Gas Defaults

Segment #1:

- **b value** — select your *b type* for the *first segment* from the drop-down list: *Best Fit*, *Input*, or *Custom*.

    - **Input** — enter your *b* value between 0 and 5 inclusively.

    - **Best Fit** — Harmony Enterprise performs a curve-fitting to the selected historical portion of the data and reports a *b* value.

    - **Custom** — if you have already created a custom attribute for b values, you can select *Custom* from the *b* drop-down list. (The custom attribute must be without units.)

- **Constraints** — you can define up to four constraints for the *first segment*. Harmony Enterprise needs at least one constraint within this section. If you define multiple constraints, the first constraint that is chronologically encountered, is the constraint that is applied.

    - You can select your Δt_{max} to be an *Input* or *Custom* value from the drop-down list. A default value of 12 months is used. If you select a custom attribute for your Δt_{max}, make sure that the attribute has a unit of time. All attributes that have a time unit are displayed in the *Custom* drop-down list.

    - You can also set your constraints to be a minimum production rate (q_{min}), minimum effective decline rate (d_{min}), and/or maximum incremental cumulative production (ΔQ_{max}).

Segment #2:

- **b value** — you can define b-value settings for the *second segment*, similar to Segment #1 (see above).

- **d$_{lim}$ Exp** — click this button to toggle between *exponential d$_{lim}$* and *hyperbolic d$_{lim}$*. For more information, see d$_{lim}$ decline options. If there is no value in the d$_{lim,\ exp}$ field, a limiting decline calculation is not performed on the *second segment*. If you toggle this option, any values you enter are saved, and the current selection is what is used.

Liquid Defaults

See the Gas Defaults section above.

Best-Fit criteria

For your *first segment*, you can select to start at either:

- **from initial peak rate** (default setting) — equivalent to the highest rate that the entity has produced throughout its entire history.

- **from initial production** — the first production data point for that entity.

Typewell

These settings apply to the average rate, P90 rate, P50 rate, P10 rate, and the number of producing wells. For additional information, see the typewell analysis.

- **All Rates** — includes all wells in your rate calculations

- **Producing Rates Only** — only includes producing wells in your calculations

Material Balance

These options affect the behavior of material balance analyses:

- **Show abandonment line** — shows / hides the abandonment line on your plot.

- **Abandonment Pressure** — sets which "Abd Calc" method (in the Analysis Parameters view of the Analysis tab) is used by default when an analysis is created.

Water Oil Ratio

You can set the parameters that initialize water-oil ratio (WOR) analyses in Harmony Enterprise. These inputs can be overridden with each analysis, and the Options dialog box inputs are only used when the analysis is created. The WOR parameters and settings are as follows:

- **Show results line** — shows / hides the green-dashed line for abandonment on your plot.

- **WOR** — sets the abandonment WOR. Harmony Enterprise uses 49 bbl/stb as the default.

- **WC** — sets the abandonment water cut (WC). Harmony Enterprise uses 98% as the default.

- **Initial Best Fit** — specifies the percentage of your historical data that you want to be included in the initial best fit.

URM

Display Pseudo-Time Option — if selected, the **Use Corrected Pseudo-Time checkbox** is shown in the Unconventional Reservoir pane. The default setting is to hide this option.

IHS Connection

These options determine the behavior of the direct connection to IHS.

- **Save Login Information** — saves your username and password, so you can log into Enerdeq USA without manually entering your login credentials.

- **Split Enerdeq Wells by Production ID** — when importing wells, you can separate wells based on production ID. For example, this may apply when you are importing US data where the production IDs have changed throughout the life of a well. In Harmony Enterprise, there is one well per API, and production history from individual production IDs are aggregated together to make sure that the whole production history is captured.

- **Save Login Information** — saves your username and password, so you can log into IHDC without manually entering your login credentials.

Spatial Explorer

If the Enable Spatial Explorer Component option is deselected, the Spatial Explorer tab is hidden. The default setting is to have the Spatial Explorer tab hidden.

Error Display and Handling

Click the checkboxes to show or hide error messages and warnings in the Status Window. By default, errors and warnings are displayed in the Status Window.

To enable logging for the license module, click to select the options you want.

Shared Settings | Production Calculations

Gas conversion to BOE: barrel of oil equivalent (BOE) = oil volume + gas volume / factor. This factor can be changed from the default value of six, but the factor must be greater than one.

Role-Based Security Settings

These options apply to role-based security. If any of these settings are grayed-out, you do not have permission to make changes in this area.

Enable / Disable

Role-based security checkbox — by clicking this checkbox, you can assign permissions to other users for certain Harmony Enterprise tasks. Note that any changes you make to this node require Harmony Enterprise to be closed and re-opened in order for the changes to take effect.

Role Definitions

The Superuser and Default roles are always available and cannot be edited nor deleted.

- **Add** — clicking this button creates a new role (by default, Role 1, Role 2, and so on). You can rename a role (*excluding* the Superuser and Default roles) by clicking the role and typing a new name.

- **Remove** — after selecting a role and clicking this button, the role is deleted from the Roles pane.

Permissions:

- **Edit Role-Based Security** — if you select this option, the role selected in the Roles pane can edit permissions for other users (excluding the Superuser and Default users).

- **Import Wells / IHS Update** — if you select this option, the role selected in the Roles pane can import wells and update from IHS Enerdeq or IHDC (for example, by clicking the first four icons on the main toolbar).

- **Delete Wells** — if you select this option, the role selected in the Roles pane can delete wells in the Entity Viewer - Hierarchy pane.

Assignments

You can assign roles to various users by clicking the appropriate checkboxes in the table.

Database Connection Monitor

This table displays all the currently connected users to Harmony Enterprise. If you are not able to view this content, contact your DBA. For more information, see active directory.

Piper export

Piper export functionality includes the following:

- Export Type dialog box
- Analyses Selection dialog box
- Well-Analysis Pairing Conflicts dialog box
- Export logs

Export Type dialog box

This dialog box opens when you access the Piper Export wizard (after the Welcome dialog box). In this dialog box, you select the type of export, and the file name and path for the file you want to export.

Important: Calibration must be done prior to forecasting.

Type of export

Select from these two options:

1. **Building and Calibration** — exports well locations, fluid properties, wellbore, rates, and pressures for each well as of the effective date. This information is used to calibrate your selected wells.

   Effective Date — if you have production up to the current month, the default date is midnight on the first day of the current month. Click the date and time fields to select the appropriate snapshot in time for your measured rates and pressures.

   Tip: When selecting an effective date, it may be helpful to view the Diagnostic tab.

   There are four reasons to select this option:

   a. to build a new model

   b. to add new wells to an existing model

   c. to create conventional deliverability typewells in Piper (e.g., Gas: wellhead test, wellhead c&n, sandface c&n, Gas and oil wells: fixed rate or profile)

   d. to validate a Piper model (also known as calibration)

2. **Forecasting** — exports well locations and other attributes together with one analytical model per well. This information is used to predict future production.

File name and path

Browse to the appropriate location for your text file to be saved. After you complete the steps in the wizard, you can import this file into Piper®.

Note: If you run the wizard again with the same filename, wells with the same name are overwritten.

Analyses Selection dialog box

This dialog box is part of the Piper Export wizard. In this dialog box, you select your analyses for export, and you are given the option of exporting wells without analyses.

Note: You must select at least one analysis in order to proceed, or you can include wells without analyses.

Analyses for the wells you want to export are displayed by analysis type. You can export well locations and other attributes together with one analytical model per well.

Select one analysis for each well you want to export.

If you want to export wells that are not paired with an analysis, click the checkbox in the lower left. Note that your wells are exported without rate and pressure data.

Well-Analysis Pairing Conflicts dialog box

This dialog box is part of the Piper Export wizard and it only appears when there is more than one analysis paired with a well. In this dialog box, you resolve any conflicts by selecting from the Select Analysis drop-down list.

Note: You must resolve all conflicts in order to proceed.

Any wells that have more than one analysis assigned to them are listed in the Well column.

Select Analysis drop-down list — select either:

- **Exclude from Export** — excludes the well from the export
- **<Analysis name>** — pairs your selected analytical analysis with the well

Piper export logs

You can view these logs by clicking the link in the Piper Export | Summary, or by browsing to your export data file.

Calibration data

An example Calibration data log is shown below.

Piper Export initiated at Wednesday, September 12, 2018, 11:28:03
Wells exported successfully:
- With analyses: 0
- With well data only: 15
Corrections performed during export:
- Sandface pressure recalculations: 0
- Flowpath corrections: 1
Details of modified or failed wells:
- Well 4 wellbore has been modified from unsupported casing flowpath to tubing flowpath.

Forecast data

An example Forecast data log is shown below.

Piper Export initiated at Wednesday, September 12, 2018, 12:01:00
Wells exported successfully:
- With analyses: 15
- With well data only: 0
Corrections performed during export:
- Sandface pressure recalculations: 9
- Flowpath corrections: 1
Details of modified or failed wells:
- Well 1 has been modified with its sandface pressure recalculated.
- Well 2 wellbore has been modified from unsupported casing flowpath to tubing flowpath.
- Well 2 has been modified with its sandface pressure recalculated.
- Well 3 has been modified with its sandface pressure recalculated.
- Well 4 has been modified with its sandface pressure recalculated.
- Well 5 has been modified with its sandface pressure recalculated.
- Well 6 has been modified with its sandface pressure recalculated.
- Well 7 has been modified with its sandface pressure recalculated.
- Well 8 has been modified with its sandface pressure recalculated.
- Well 9 has been modified with its sandface pressure recalculated.

Plots

Plots are a vital tool used in analyzing well data, comparing data (see comparison plot), and are displayed in many different areas in Harmony Enterprise.

These items apply to plots:

- Plot components
- Plot types
- Diagnostic line

Plot components

Plot components include locks, a legend, and context menus. For information on toolbars, see plot tool-bars.

Locks

Each axis has a lock at both ends to control resizing and movement. Locks are represented by two different icons, depending on their state:

Icon	Status	Description
🔓	Unlocked	This end of the axis is free to move or change in scale.
🔒	Locked	This end of the axis is locked down (that is, immobile).

Locks can be toggled independently by clicking them. The state of these locks affects the behavior of the axis when you click-and-drag. The possible lock states and their effects on the axis are described below:

Lock States	Effect on Axis
🔓 🔓	Both ends are free to move; dragging the axis pans / slides without changing in scale.
🔒 🔒	Neither side of the axis can move; dragging the axis zooms in.
🔒 🔓 or 🔓 🔒	The end that is unlocked stretches or shrinks, rescaling the axis.

Legend

The legend displays the relevant datasets on the plot. To show or hide a legend on any plot: right-click the plot and select **Show Legend** or **Hide Legend**.

- Single-well plot legends display the available datasets for the selected well.
- Multi-well plot legends display the individual wells as differently colored lines.

Plot context menus

Plots have two sets of context menus.

Axis options

Right-clicking an axis lists these options:

- **Autoscale Axis** — scales the axis to fit the data.

- **Change Axis Units** — select your units from the submenu.

- **Sync - Snap - Square** — links up major axis lines between multiple axis scales.

- **Customize Axis** — select your axis preferences (labels, font settings, and so on) in the Axis dialog box.

- **Move Axis to Right / Left Side** — moves the axis to the other side of the plot.

- **Link / Unlink Axes** — connects axes of different datasets to share a common scale (must be the same units), or disconnects them.

- **Major Grid Lines** — shows / hides major grid lines.

- **Minor Grid Lines** — shows / hides minor grid lines.

- **Snap Scale** — snaps the axis to the closest major grid line division / whole number.

- **Sync all log axes to use 1 log cycles** — synchronizes log axes to 1-log cycles.

- **Show / Hide Toolbar** — shows / hides the tab's toolbar.

Plot options

Right-clicking a plot lists these options:

- **Send Dataset to Comparison Plot** — opens a snapshot of your dataset in a new or existing comparison plot. (You must right-click a specific dataset.)

- **Copy / Paste Dataset** — copy and paste your dataset content. For example, you can copy your dataset to the comparison plot as an independent dataset, which retains the customizations you set up (name, line / symbol properties, axis titles, and so on). (You must right-click a specific dataset.)

- **Customize Datasets** — change the display order, and / or customize the display for specific datasets.

- **Customize Plot** — select your plot preferences in the Plot dialog box.

- **Customize Axis** — select your axis preferences in the Axis dialog box.

- **Customize Main Title** — type or select attributes for your title and subtitle in the Titles dialog box.

- **Customize Left Header** — type or select attributes for your left-header information in the Left Header dialog box.

- **Customize Right Header** — type or select attributes for your right-header information in the Right Header dialog box.

- **Show / Hide Legend** — shows / hides the legend.

- **Customize Legend** — select your legend preferences in the Legend dialog box.

- **Copy / Paste Plot** — copy and paste your plot content. For example, you can copy your plot to the comparison plot.

- **Send Plot to Comparison Plot** — opens a snapshot of your plot in a new or existing comparison plot.

- **Show / Hide Toolbar** — shows / hides the tab's toolbar.

Plot types

There are different types of plots in Harmony Enterprise, and often the plots that are available for viewing depend on the datasets currently displayed.

For example, you can select a plot type from the drop-down menu in the Diagnostics tab:
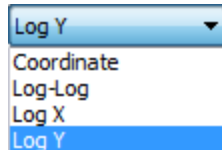
Coordinate plots

Coordinate (also called 'Cartesian') plots display data in a 1:1 ratio with no manipulation of the axes.

An example of a coordinate plot:
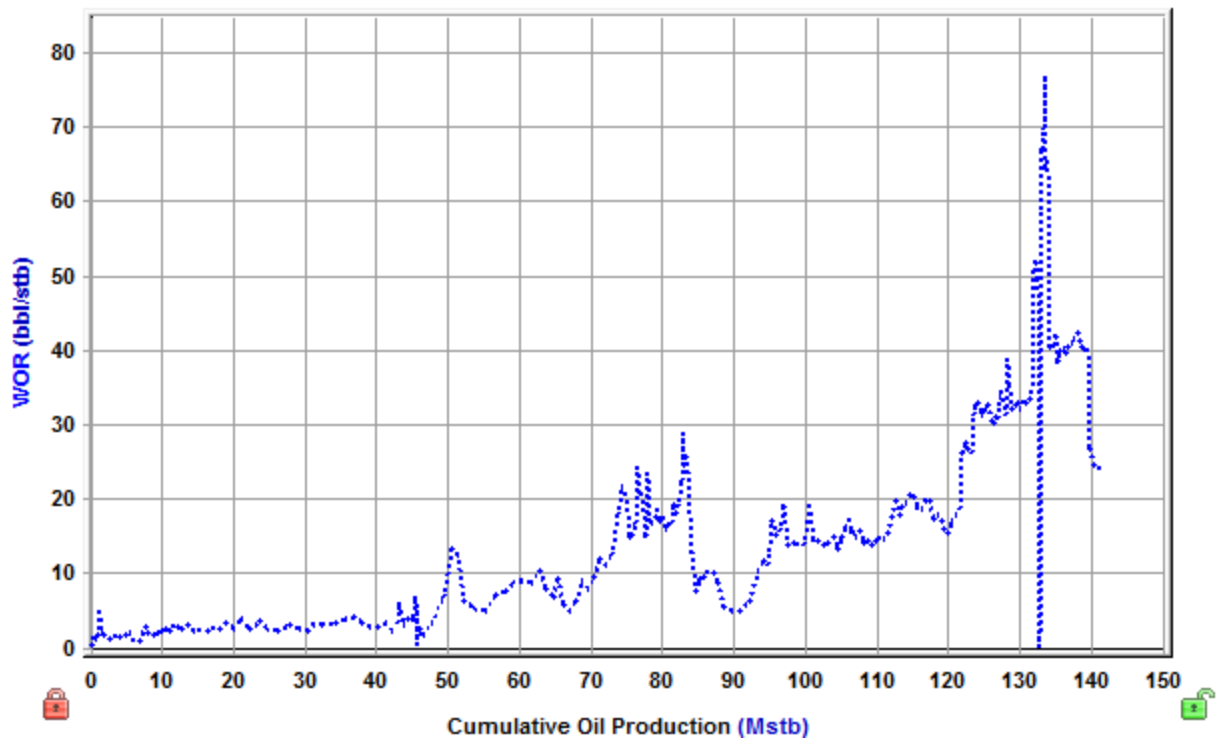
Log-log plots

Log-log plots use logarithmic scales on the x- and y-axes to stretch data in order to view trends in the data that are not apparent with Cartesian coordinates.

An example of a log-log plot:
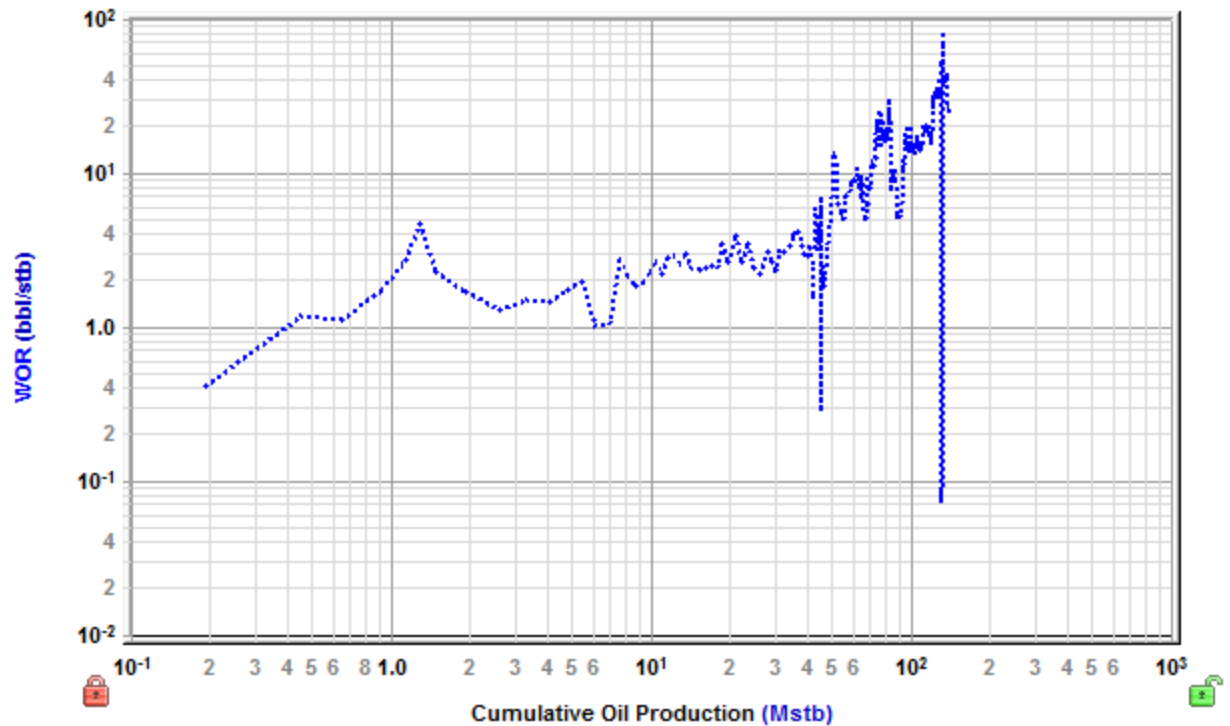
Log-X plots

In log-X plots, the scale of the x axis increases exponentially. Manipulating the y-axis in this way places emphasis on a specific portion of the data set (for example, semi-log time emphasizes early-time data).

An example of a log-X plot:
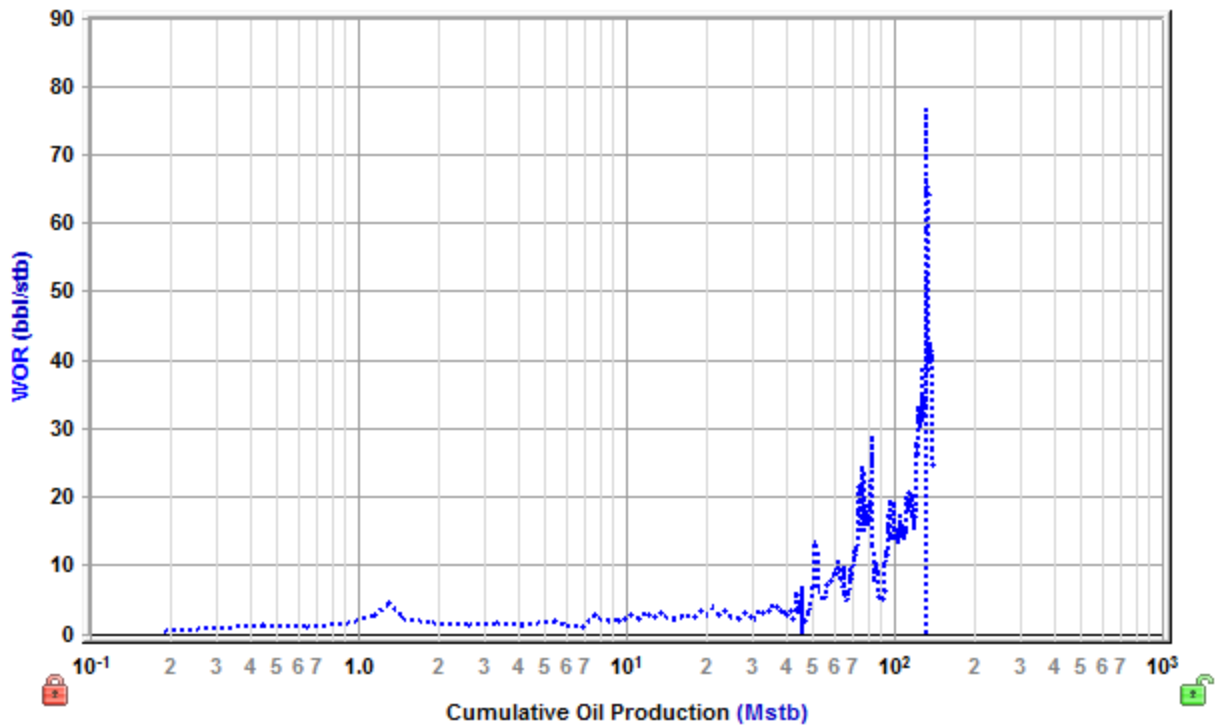
Log-Y plots

In log-Y plots, the scale of the y-axis increases exponentially. Manipulating the x-axis in this way normalizes a large range of data that is difficult or impossible to analyze on a coordinate plot.

An example of a log-Y plot:
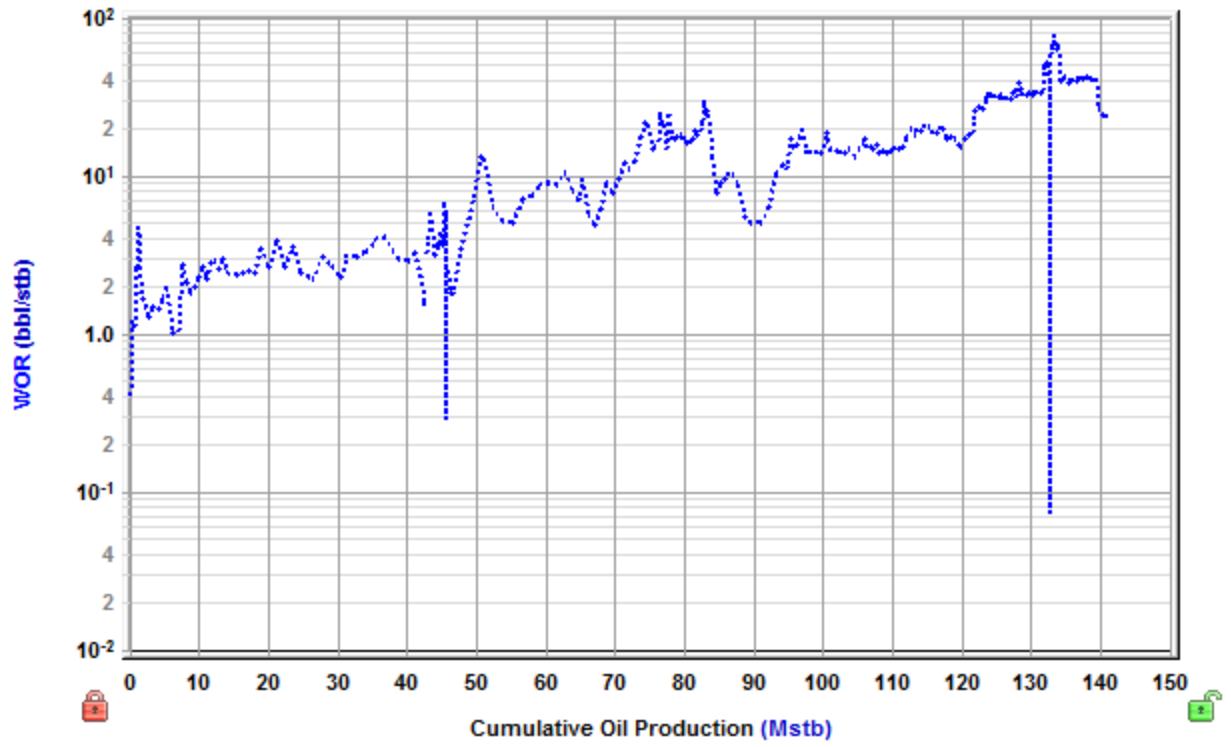
Diagnostic line

On many of Harmony Enterprise's plots (for example, analysis plot-style worksheets and the Results Viewer cross-plot), you can add a diagnostic line, which is useful for identifying and extrapolating trends in the data.

To add a diagnostic line, click the **Add a Diagnostic Line** icon ( ) on the toolbar.

> A diagnostic line requires at least one dataset or forecast. If there are multiple datasets, a popup opens where you can associate the diagnostic line with a data series. If that data series has one of its axes scaled, the diagnostic line scales with it.
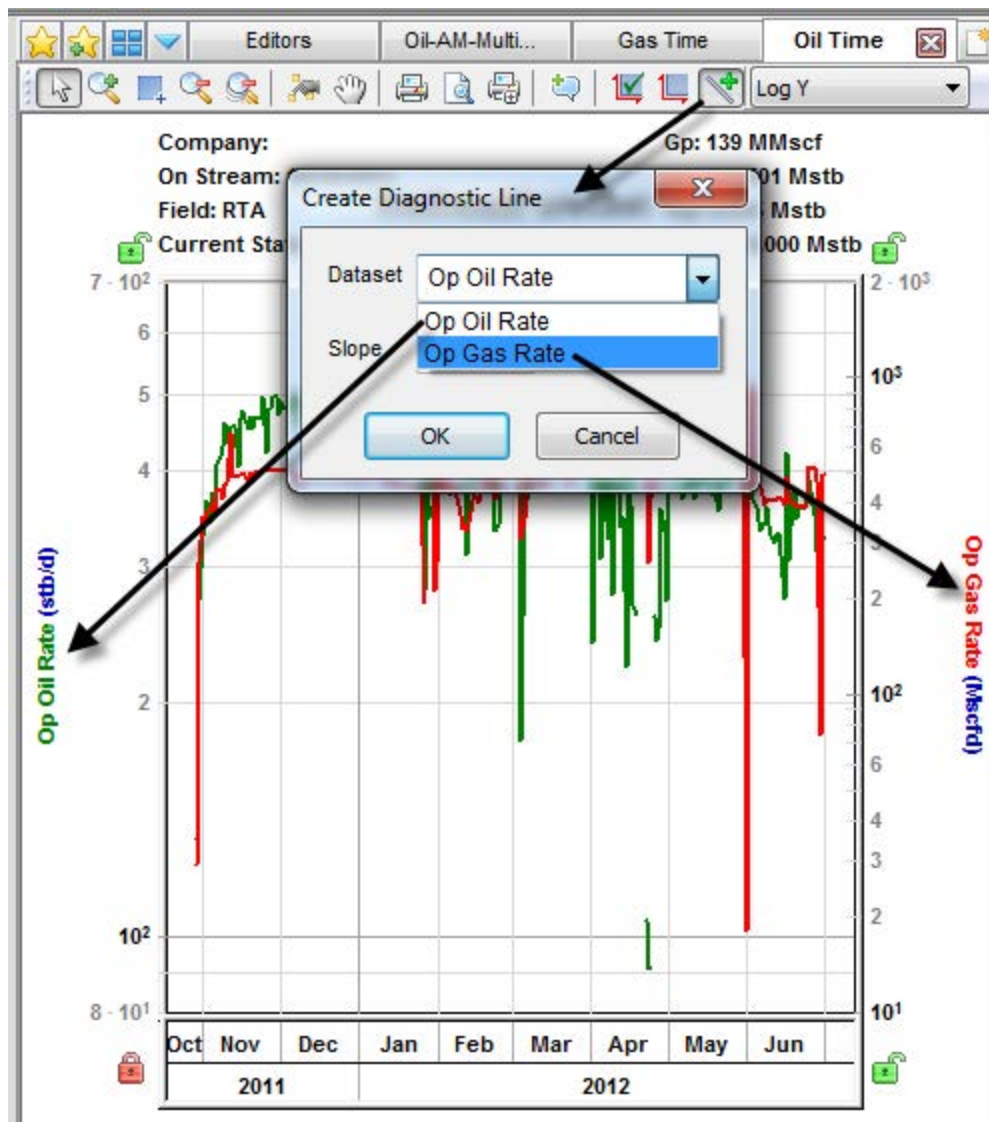
If the plot's vertical and horizontal axes are both set to use logarithmic scales (that is, if the plot is "log-log"), when you click the Add a Diagnostic Line icon, a popup opens where you can select a preset value.
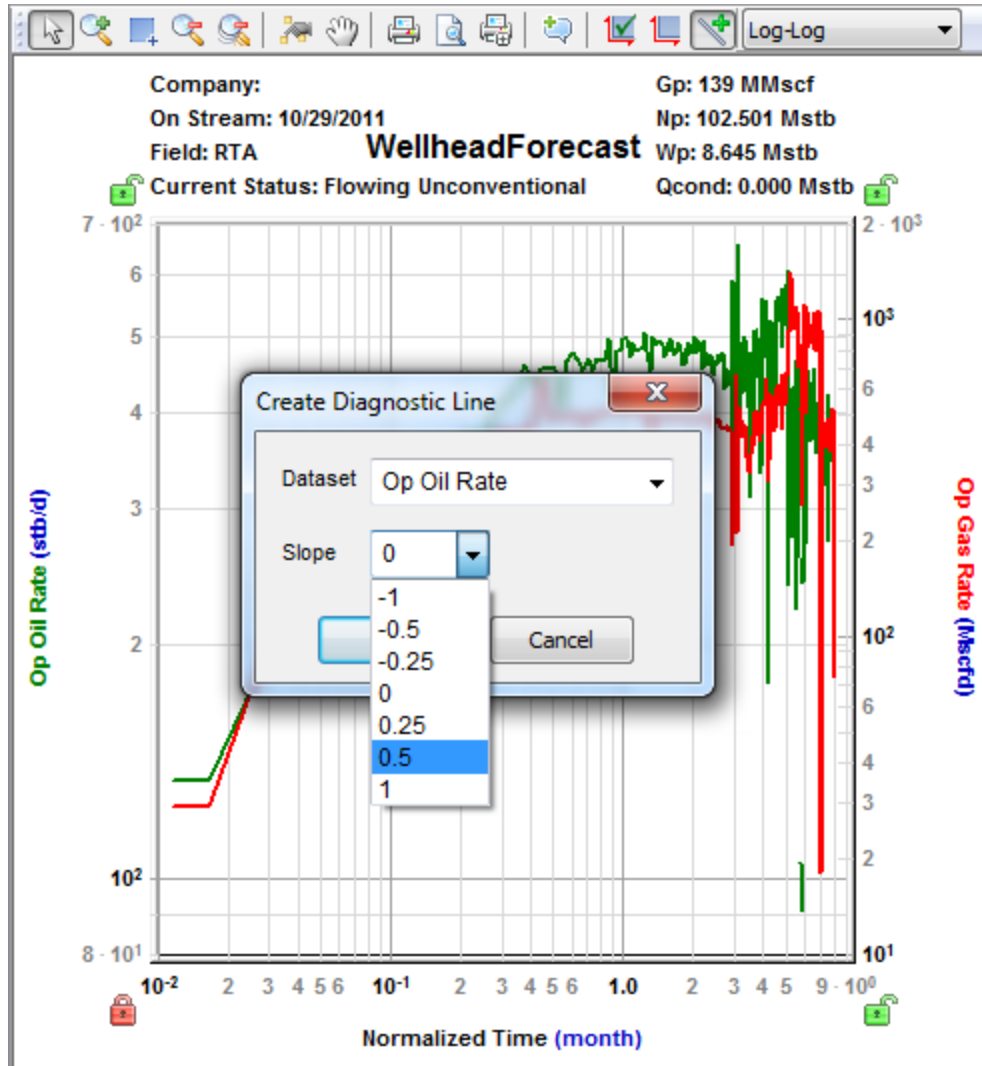
Context menu

Right-clicking the diagnostic line lists these options:

- **Show All Annotations** — shows the x, y coordinates for both endpoints, as well as the slope of the line, denoted by 'm'.

- **Customize Line** — for changing the line width and color.

- **Default Slopes** — for changing the slope to a preset value; this is only shown for log-log plots.

- **Remove Line** — deletes the line from the plot.

Line manipulation

You can manipulate the diagnostic line as follows:

- **Rotate** — rotates the line, keeping the center point in its original position

- **Move end points** — drag either end point, while the other end point stays in its original position

- **Move line** — drag near the center of the line to move it to another location

Plot Selection pane

By default, this pane opens in a tab to the right of the Analysis Manager while a worksheet is in focus. For a description of common icons, see toolbars.

To add / remove plot axes:

- **Checkboxes** — Toggling the checkbox for an item within this pane adds / removes the axis from the worksheet.

- **Double-click** — Double-clicking an item within this pane adds / removes the axis from the worksheet.

- **Drag-and-drop** — Dragging an item from this pane to the worksheet, adds the axis. The item can be dropped to the position you want: x-axis, y-axis, or over an existing axis to link the axes. If you drop the item to a location that is not over an axis, it is added as a y-axis, unless the item is a cumulative or date series.

To customize datasets / categories:

Whenever you modify a custom dataset or category in the Production editor (add, delete, rename, or update a formula), these changes are reflected in this pane. In order to see renamed items or formula changes from other users, you need to click the **Refresh** icon on the main toolbar.

Project filters

Project filters are used to reduce the number of entities displayed in large databases in your specific area of interest. When filters are set, wells and groups outside the filter are not displayed in any of the modules within Harmony Enterprise. All filters are global to the database they are created in; this is, all users can see them. Each user selects an active filter independently.

After clicking the Project Filter drop-down list on the main toolbar, you have the following options:

- **Add / Modify Filters** — opens the Add / Modify Filters dialog box where you can:

    - **Add a new filter** — click the **Add** button and type your filter name. Click the checkboxes in the Hierarchy, Shared Groups, and Private Groups tabs to include entities in the filter. Click **Save**.

    - **Modify an existing filter** — select the filter in the Filters pane, and then select the wells and groups you want in your filter (you can select from the Hierarchy, Shared Groups, or Private Groups tabs). Click **Save**.

    - **Delete a filter** — select the filter in the Filters pane and click the **Remove** button.

    - **Rename** — right-click or double-click the filter in the Filters pane, and then type in your new name.

- **No Filter** — displays all of the wells and groups in your project.

- **<previously created filter>** — displays your filtered results on the GIS map, Attributes tab, analysis tabs, and so on.
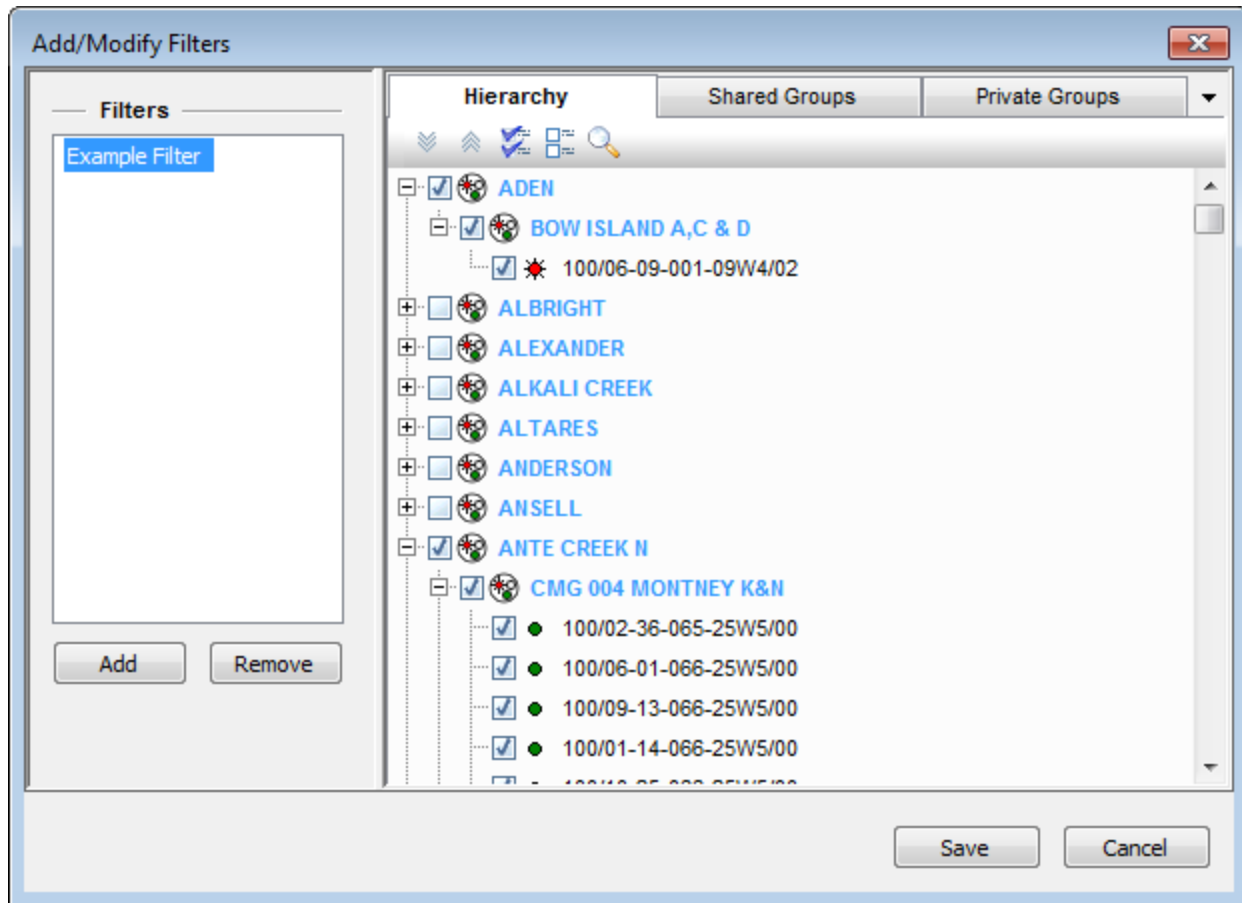
Tip: When creating a filter, you select your entities using one of the available three tabs.

Hierarchy tab

In the Hierarchy tab, selecting a hierarchy group selects all the wells below it automatically. Constituent wells can be deselected from a hierarchy group, and that hierarchy group is no longer selected in the dialog box. If that hierarchy structure is used when working in the filtered database, a partially selected hierarchy group is displayed. However, any analyses performed on this group only include production from wells included in the filter. When you select the group for analysis, it is locked for other users, which is the same behavior as for an unfiltered database.

Shared and Private Group tabs

Both Shared Groups and Private Groups (custom groups) can be added to filters. In order for a custom group to be included in a filter, *all* wells in the group must also be in the filter. When a custom group is selected, all its wells are displayed as selected in the Hierarchy tab. If wells are deselected in the

Hierarchy tab, and the custom group remains selected, saving the change to the filter fails, and an error message is displayed in the Status Window. If you are modifying a filter created by another user, this can occur because you cannot see the private custom groups the other user has added to the filter.

Importing with filters

Project filters interact with imports from Harmony Enterprise as follows:

- If the well is new to Harmony Enterprise, it is imported and added to the active filter.

- If the imported well is already in Harmony Enterprise and exists in the active filter, Harmony Enterprise attempts to merge the well.

- If the imported well is already in Harmony Enterprise and does not exist in the active filter, Harmony Enterprise skips the import.

- If the well exists in the active filter, but is not imported, Harmony Enterprise skips the well.

Project filters interact with imports from files (everything except *.harmony) as follows:

- If the well is new to Harmony Enterprise, or is already in Harmony Enterprise and does not exist in the active filter, it is imported as a new well, and is added to the active filter.

- If the imported well is already in Harmony Enterprise and exists in the active filter, Harmony Enterprise attempts to merge the well.

- If the well exists in the active filter, but is not imported, Harmony Enterprise skips the well.

Query Wells dialog box

You can access this dialog box by clicking the **Query Wells** icon in the Entity Viewer - Custom's tool-bar (either the Private Groups or Shared Groups tab).

In this dialog box, you can query wells using attribute data, and your queries are saved as custom groups. To limit the scope of your results, well queries use the criteria in your project filters.

Each query includes one of more query statements, and each query statement includes a property, an operator, and a value. The property corresponds to a specific kind of information in the database, the operator is the logical evaluation you want to perform on the property, and the value is what you use to make the logical evaluation. For example:

Property	Operator	Value
Entity Header	Equal	Well 1
DTOP FORMATION (TVD)	Between	500 and 15,000
Display Name Format	DLS	100/13-076-12W6/00
Spud Date	Calendar	07/22/2016

There are four different property types:

- Text — has three different operators: equals, contains, and starts with. Note that you can paste a list of items in the text field.

- Number — has four different operators: equals, greater than or equal to, less than or equal to, and between.

- Selectable values — select from a drop-down list.

- Date — has the same operators as numbers, plus you can select a date from a calendar.

Note: You can also have properties for custom attributes. If your query has attributes with units (for example, cumulative gas production), these units correspond to what you have set on the main toolbar using the Toggle Units icon (that is, metric or field units).

Attributes pane

This pane displays all of the available attributes from the database.

To create a query, select the attributes you want to search for from the tree structure, and then refine them on the right-side. For example, if you select Province / State, your operators are Equals, Contains, or Starts with. You could select Equals from the drop-down list, and then type Alberta in the field below. To continue, click the **Add** button. Your query is displayed in the main pane.

Main pane

In this pane, you can refine your query with these operands:

- **NOT** (top right corner) — the inverse / opposite of all the query items below. For example, display wells that are not in Alberta, and basins that do not begin with the letter "a" (applies the OR condition). If you select the NOT checkbox at the top and a NOT checkbox within the query below, the effect is to clear the NOT condition.

- ⊗ **DELETE** — either of the delete icons deletes the query item.

- ☑ **CHECKBOX** — to enable a query item, click the box, and a checkmark is displayed. To disable a query item, click the box, and the checkmark is cleared.

- **AND** — includes other queries. For example, display wells that are in Alberta and have basins that start with the letter "a".

- **OR** — includes one query or the other (less restrictive than AND). For example, display wells that are in Alberta, as well as basins that start with the letter "a".

- **NOT** — the inverse / opposite of a query. For example, display wells that are not in Alberta, and basins that do not begin with the letter "a".
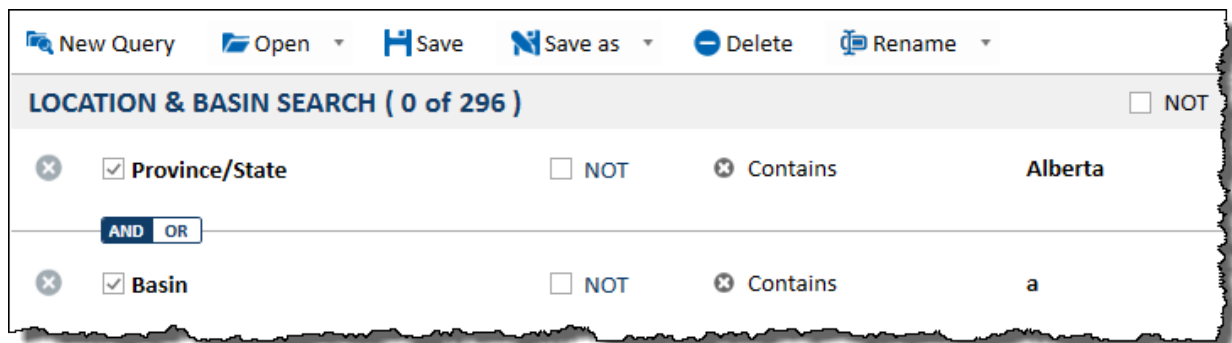
Icons

These icons are at the top of the main pane:

- **New Query** — resets your existing query, so you can start a new one.

- **Open** — select queries from your saved custom groups. When you open a query, your results are updated with any database changes that occurred after the last time you saved this query.

- **Save** — saves your query as a custom group in the Entity Viewer - Custom pane. When you save a query, your results are updated with any database changes that occurred after the last time you saved this query.

- **Save as** (visible after you have a saved query) — creates a copy of your query. Type a new name for the query you have open.

- **Delete** (visible after you have a saved query) — deletes the query you currently have open. You are prompted to confirm the deletion.

- **Rename** (visible after you have a saved query) — type a new name for the query you have open.

Preview pane

In this pane, the wells that dynamically match your query are displayed, and the attributes that are used in the query are displayed as columns in a table.

By default, the Display Name matches your display in the Entity Viewer - Hierarchy pane (for example, well name, DLS, API, etc.). Note that clicking column headers sorts the column alphanumerically, even for columns with numerical values (that is, the Display Name is used to sort numerical columns).

Display Name	Cumulative Gas Production (MMscf)	Primary Fluid
141/02-27-033-25W3/00	1021	Gas
ARBALEST 33-03H	1024	Gas
ARBALEST 25-14H	1028	Gas

Reference Dates dialog box

In this dialog box, you set the effective date for reserves evaluation, and you can access it by clicking the **Reference Dates** icon ( ) on the main toolbar.

Toolbar

This dialog box has these items on its toolbar:

- **＋ Add reference date**

    - **Add New Reference Date** — adds a reference date, by default, at the end of the current month.

    - **Duplicate from previous reference date** — adds a reference date with a copy of the analyses from the most recent previous date. Cumulative volumes at the reference date are determined for the copied analyses using the precedence specified (IP-2P-3P or 2P-1P-3P).

- **— Remove reference date** — deletes the reference date currently selected.

Grid columns

The reference dates you add are listed in the table / grid and are shared between all users.

- **Date** — only the most recent date is editable by clicking the **Calendar** icon ( ). Note that after the **Save** button is clicked, the date specified gets committed and cannot be changed.

- **Active Date** — specifies which date is used when classifying analyses. Only one reference date can be specified as the Active Date. The chosen date is user-specific (it is *not* shared), and no date is selected by default.

- **View Analyses** — toggle the View Analyses checkboxes to show or hide analyses with a particular reference date.

- **Description** (Optional) — type a name for your reference date in the Description field.

Note that clicking **Save** closes all open analyses.

Results tab

The Results tab consists of three sub-tabs: the Results Viewer, Comparison Plot, and Reporting. (The Results Viewer opens when you click the Results tab.)

Results Viewer sub-tab

The Results Viewer has two buttons at the bottom of its pane: Grid View and Plot View.

Grid view

The Grid View displays attributes and results in a table / grid based on selections in the Entity Viewer - Hierarchy or Custom Groups panes. As you change selections, the grid columns are retained, but the entities and their analyses are updated.

The grid is empty until you select attributes and parameters to be displayed. Columns are added to the grid by selecting checkboxes from the tree structure on the left. After you have created a selection of columns in the grid and customized them, you can save it as a template by selecting **Save / Delete Template** from the drop-down list above the tree structure.

Clicking a column header sorts the table data by its attribute value, according to the same sorting rules MS Excel uses. For alphanumeric attributes, numbers are sorted first from left-to-right (instead of top-to-bottom), then special characters, and finally letters. Apostrophes and hyphens are ignored except when there is text with a hyphen. In this case, the text with the hyphen is sorted last. If you click a column header, and then press the **Ctrl** key, you can sort multiple columns at the same time. This is indicated by a sorting arrow in each of the columns.

On Stream	Last Known Record	Cumulative G...
DD/MM/YYYY	DD/MM/YYYY	MMscf
01/09/2001	01/02/2002	11
08/09/2002	10/10/2004	101
01/01/2001	01/01/2003	380
08/06/2004	07/06/2024	1196
01/06/1992	01/03/2006	10012
01/01/1985	01/10/2010	17374
01/01/1985	01/10/2010	18292

Plot view

The Plot View displays the axis parameters you select from the tree structure in a plot; you can plot attribute and result values to analyze relationships between input and output parameters. If you are only plotting attribute values, you do not need to perform an analysis. For a description of plot options, see plot components.

To build the plot for the currently selected entity, select the parameters / datasets you want to display by selecting the appropriate checkboxes in the Results Viewer pane (tree structure). Or, you can drag-and-drop the parameters to the plot.

> **Tip:** You can send your plot to a comparison plot, by right-clicking it and selecting **Send Plot to Comparison Plot**, or you can right-click and select **Send Dataset to Comparison Plot**. For information on other options, see plot options.

There are two plot types: cross plot and cumulative distribution function (CDF).

Cross plot

A cross plot displays data as a collection of points, each having the value of one variable determining the position on the horizontal axis, and the value of the other variable determining the position on the vertical axis. This is also known as a scatter plot. These plots are most commonly used for identifying trends or relationships between different variables.

Results can be added to the cross plot by clicking the checkboxes in the tree structure on the left, or by dragging results to the desired axis. Multiple results can be plotted on the y-axes, but only one result can be plotted on the x-axis at a time. (Date variables can only be plotted on the x-axis.)
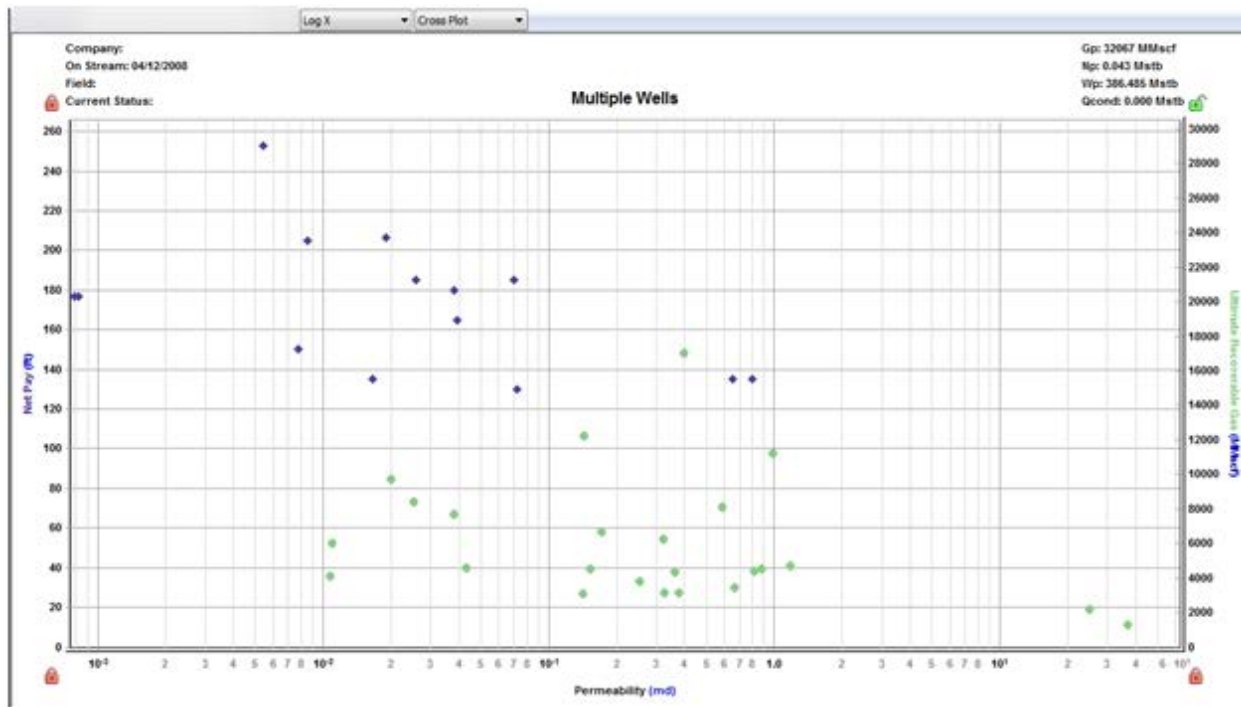
CDF

A CDF calculates the probability that a random variable with a given probability distribution is found at a value less than or equal to "x".

Only one result variable can be plotted on a CDF plot at a time, and results can only be added by clicking the appropriate checkboxes in the tree structure on the left. If a result variable is already selected, making another selection replaces the current selection.
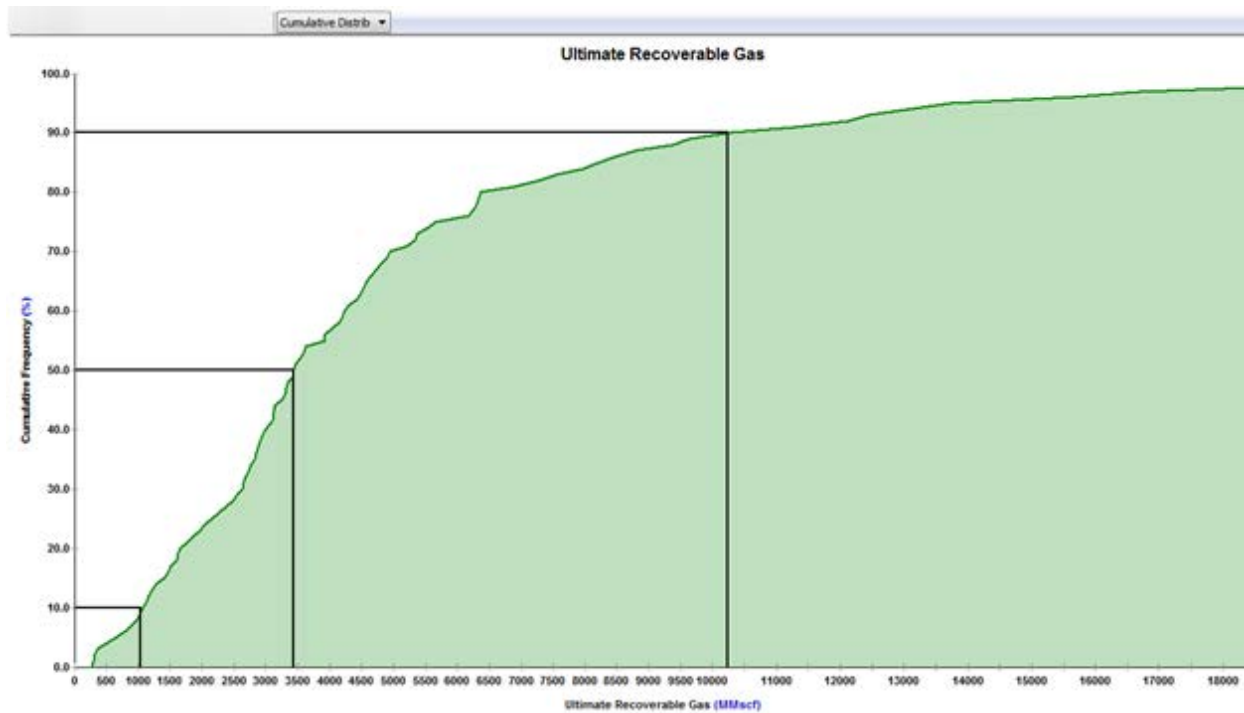
The black horizontal lines originating at cumulative frequencies of 10%, 50%, and 90% intersect the CDF curve, and then line up with the P90, P50, and P10 values of that dataset, respectively.

Toolbar

The important icons are described below. For a description of common icons, see toolbars.

- (Grid View and Plot View) **Save / Delete Template** — is the default setting, but you can select you saved templates with the plot selections / datasets you prefer.

- (Grid View and Plot View) 🔽 **Analysis Filtering** — lists the analysis names that exist for the currently selected entities. Deselecting an analysis name removes all analyses of that name from the plot or grid for all entities. By default, all analyses associated with the selected entities are displayed.

- (Grid View) **Bulk Edit Declines** — you can edit decline parameters for all the selected wells as a group. For more information, see bulk modify decline analyses.

- (Plot View) 🔍 **Search** — after specifying search criteria, the tree structure filters the results to only display parameters that match. The search considers both the description (for example, the initial rate) and nomenclature (for example, q_i) for each parameter.

- (Plot View) **Select data points** — you can select data points, and then to exclude any you do not want, right-click them (to deselect them).

Context menus (grid view)
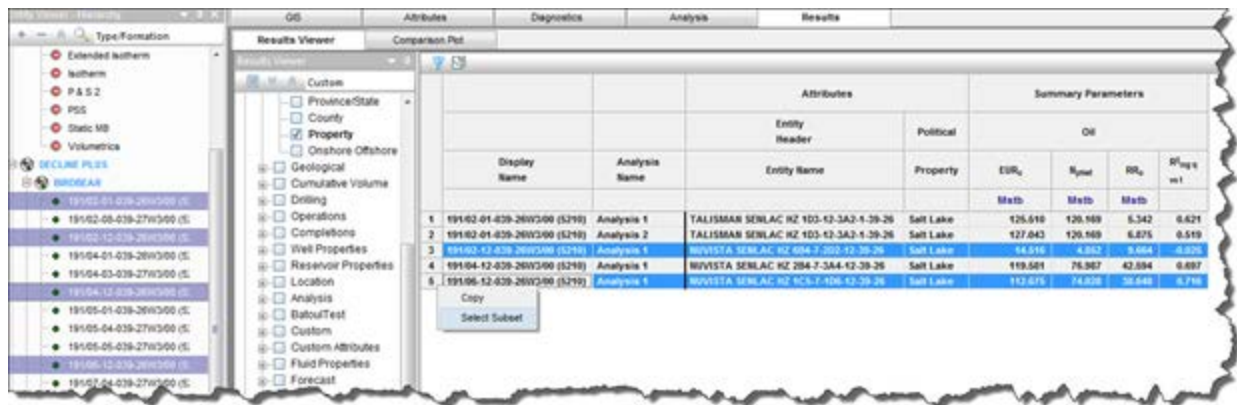
Right-clicking the top left of your table lists these options:

- **Copy Grid** — copies the table to the clipboard.

- **Copy Grid + Headers** — copies the table and table headers to the clipboard.

Right-clicking table headers lists these options:

- **Precision** — select between decimal, scientific, or engineering.

- **Units** — select the units you want to display from the submenu.

After selecting one or more rows in your table, you can right-click the row numbers to the left and select **Select Subset**. This removes the other rows in the table, and this selection persists across Harmony Enterprise (for example, the Entity Viewer, GIS map, and so on).

By right-clicking a table cell, you can copy / paste the table cell's contents.

Comparison plot sub-tab

In the Comparison plot, you can combine plots and/or datasets from many Harmony Enterprise plots. Comparison plots are static (a snapshot of a point in time), meaning that the plot does not change even if the source plot / dataset is modified. This can be useful to compare plots of slightly modified data-

sets or scenarios, and to compare analyses between entities. Each tab in the Comparison plot contains a separate plot.

Plots created within the Comparison Plot tab are user-specific, meaning they are not shared with other users. The plot and its axes and datasets can be customized, and these changes persist with each plot (such as line / symbol properties, axis title, color, and so on).

Toolbar

The unique icons are as follows:

- **New Plot** — opens a new blank tab to the right of your existing tabs.

- **Copy Plot to New Tab** — copies the content of your existing plot to a new tab.

- **Paste Plot from Clipboard** — pastes the plot in the clipboard to the current tab. When an axis is added, if it has the same units as an existing axis, they are linked (default setting).

- **Copy to Clipboard** — copies the plot on the current tab to the clipboard.

- **Delete Current Plot** — deletes the current tab you are on.

- **Add an Arrow Annotation** — adds an annotation arrow to the data point you click.
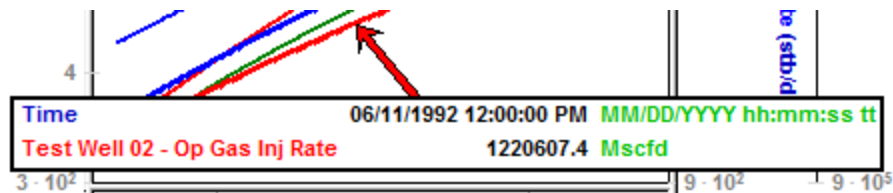
For a description of common icons, see plot toolbars.

Tab context menu

Right-clicking the tab below the toolbar lists these options:

- **New Plot** — opens a new tab to the right of the existing tabs.

- **Copy Plot to New Tab** — copies the content of your current plot to a new tab.

- **Paste Plot from Clipboard** — pastes the plot / dataset in the clipboard to the current tab.
  When an axis is added, if it has the same units as an existing axis, they are linked (default setting).

- **Copy to Clipboard** — copies the plot on the current tab to the clipboard.

- **Delete Current Plot** — deletes the current tab.

- **Rename Tab** — opens the tab's name field where you can type a new name.

Plot context menu

Right-clicking within a plot lists these options:

- **Paste plot**

  - Enabled only if a plot is currently in the clipboard.

  - Pastes the plot in the clipboard of the current tab.
    When an axis is added, if it has the same units as an existing axis, they are linked (default setting).

  - When any plot is pasted to the comparison plot, all datasets coming from the same plot are grouped together under a parent node in the Data Selection pane. By default, these nodes are called Paste 1, Paste 2, etc., but they can be renamed (for example, to indicate where the data was originally copied from).
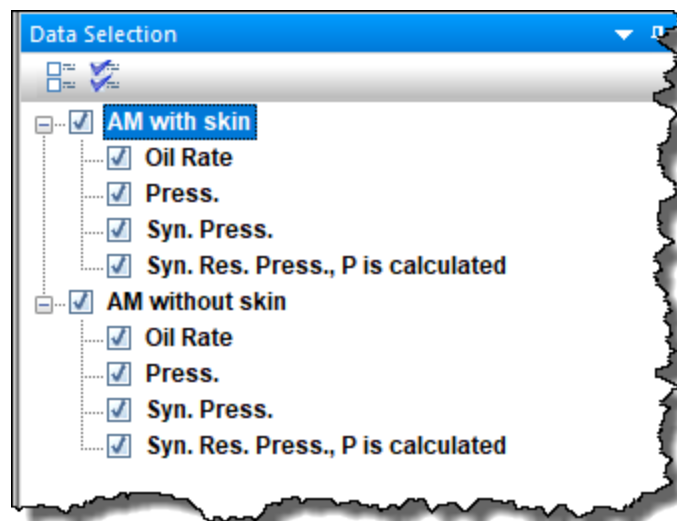
- **Paste dataset**

  - Enabled only if a dataset is currently in the clipboard.

- Pastes the dataset in the clipboard of the current tab.
  When an axis is added, if it has the same units as an existing axis, they are linked (default setting).

> **Note:** When you hover over the dataset in the plot, the tooltip has the name of the node, followed by the name of the dataset (for example, AM with skin: Oil Rate). You can rename the dataset by right-clicking the plot and selecting Customize Dataset, but the tooltip retains the name of the parent node.
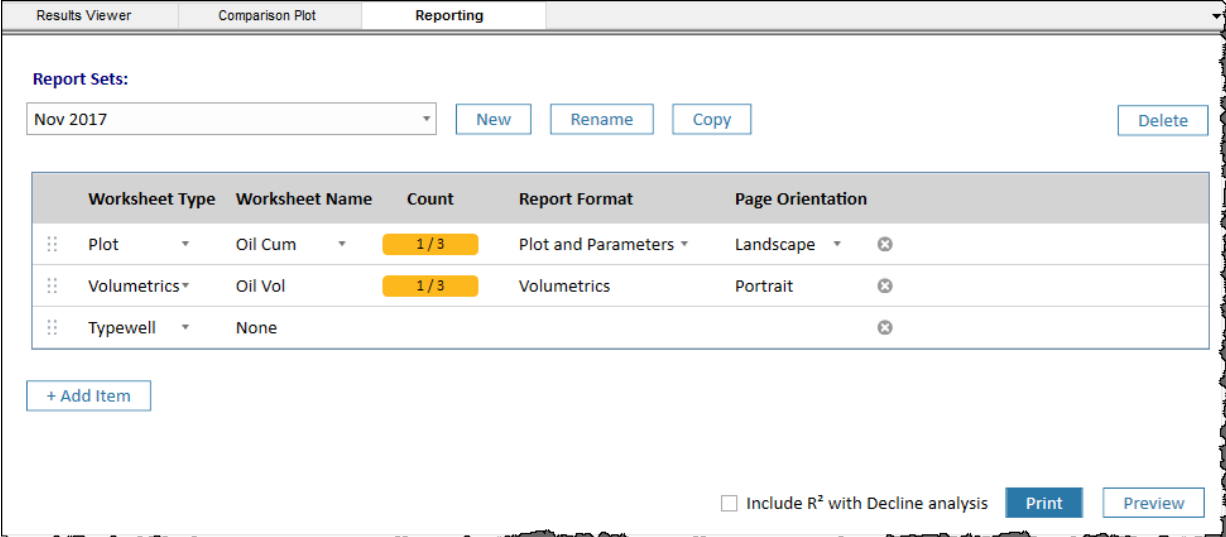
For a description of common plot context menus, see plot components.

Reporting sub-tab

In the Reporting sub-tab, report sets are created to print your specified worksheets using the Report Format you select. Report sets are database specific, and are shared between users connecting to the same database, with the last-saved action persisting. Each report set can include multiple items with no hard limit. The report set and its meta-data are automatically saved when you navigate away.

Note: Reports of plot and analysis parameters have been designed to fit up to nine analyses on the first page, and additional analyses are printed on subsequent pages.

Clicking the **Print** or **Preview** buttons prints the active report set for the entities selected (wells and groups).

If you select multiple entities in the Entity Viewer, a subset of the selection may not have the specified worksheet. If this happens, a warning is displayed to the right of the Worksheet Name column. In this example, 13 of the 14 entities have the specified worksheet name. In the same manner, errors are also displayed to the right of the Worksheet Name column.

These items are defined as follows:

Report Sets — select your previously saved report sets from the drop-down list. If you have not created a report set yet, this drop-down list is blank.

New button — type a name for your report set.

Rename button — type a new name for the currently selected report set.

Copy button — creates a copy of the currently selected report set. Type a unique name for this copied report set.

Delete button — deletes the currently selected report set. You are not prompted to confirm the deletion.

⠿ button — enables you to rearrange rows in your table by dragging-and-dropping.

Worksheet Type column — select Forecast, Plot, Typewell, or Volumetrics.

Note: The reporting feature only supports worksheet types that are created with the Harmony Forecast™ license. Additionally, when you select Plot, worksheets for Decline, Ratio Analysis, or Custom can be used.

Worksheet Name column — select from your list of worksheet names. If you do not have a worksheet for the Worksheet Type you selected, this column displays None. The Worksheet Name drop-down list is blank until you create a worksheet that corresponds with your Worksheet Type selection. If there is only one worksheet that corresponds with your Worksheet Type, it is automatically selected.

Report Format column — if you selected Plot from the Worksheet Type drop-down list, you can select Plot, Parameters, or Plot and Parameters from this drop-down list. Otherwise, this column is not editable because only one report format is supported.

Page Orientation column — select either Portrait or Landscape. For Plot and Typewell worksheets, the default orientation is Landscape; otherwise the default is Portrait.

Delete icon — deletes the currently selected item / row in the table. Note that this icon is only visible after you have added at least one item in the Report Set table.

+ Add Item — adds a table row where you can specify your Worksheet Type, Worksheet Name, Report Format, and Page Orientation, by selecting from the drop-down lists.

Include R^2 with Decline analysis — click this checkbox to include the R^2 parameter in your reports for Report Formats set to Parameters or Plot and Parameters.

Print — prints the currently selected report set. Entities are printed in the same top-to-bottom order as the Entity Viewer (Hierarchy or Custom), and worksheets for an entity are printed in the same order as the report-set table. Plots are formatted as they look in the Analysis tab.
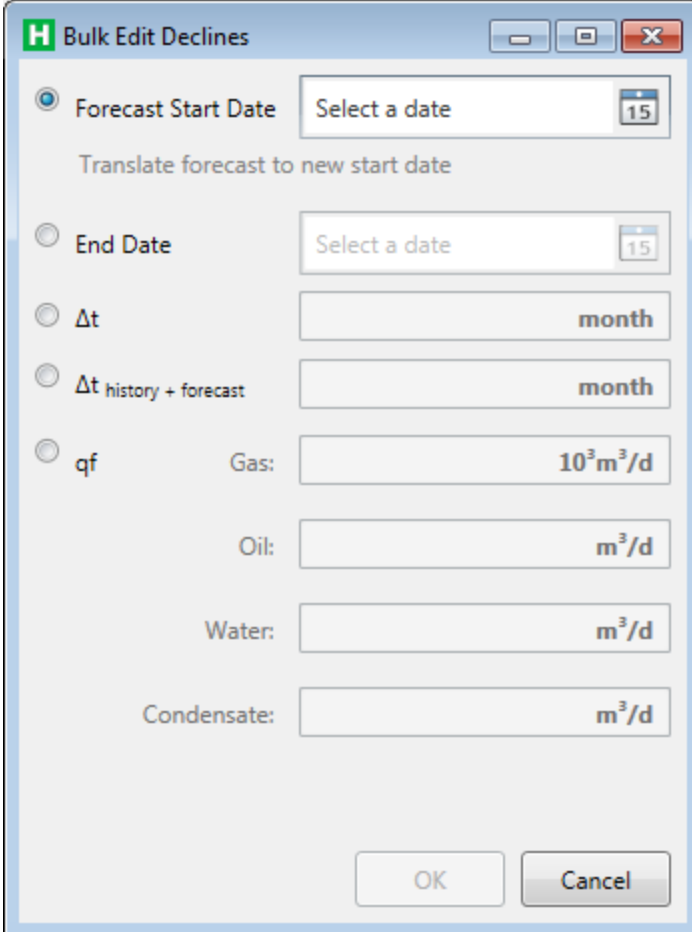
Preview — opens a Preview window where you can adjust your view, page setup, and print options for the currently selected report set. Entities are displayed in the same top-to-bottom order as the Entity Viewer (Hierarchy or Custom), and worksheets for an entity are displayed in the same order as the report-set table. If you open and close the Preview window, when you open it again, it opens to the last page where you left off.

Tip: *(Windows 7)* If your Preview window opens without a Close Window button, make sure that the **Enable desktop composition** option is deselected in your Performance Options dialog box (see your Windows help for more information).
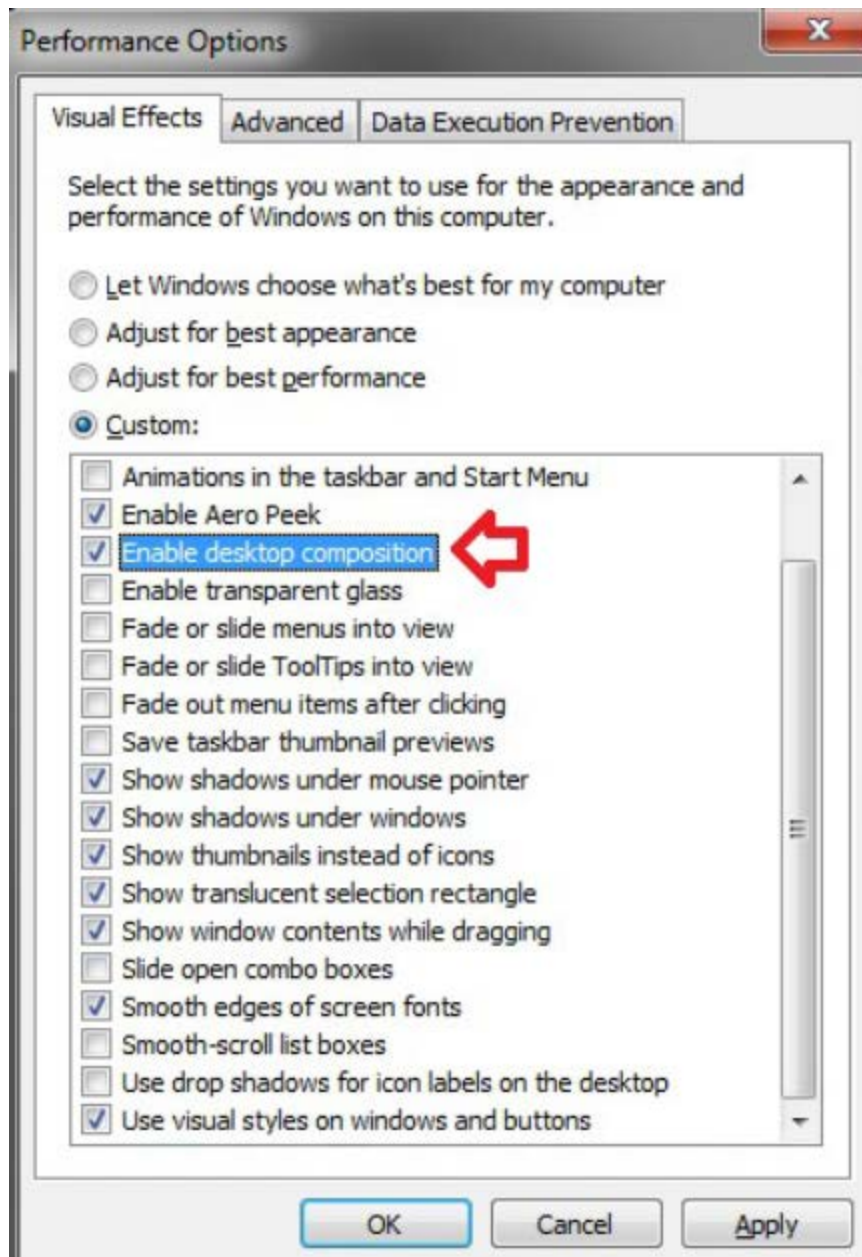
Bulk modify decline analyses

This feature is used to change selected decline analysis parameters for multiple entities simultaneously. By clicking the **Bulk Edit Declines** icon (⊞) on the Results Viewer - Grid View toolbar, you can apply changes to all the entities selected in the Entity Viewer. (If any filters have been applied in the table / grid, only the displayed analyses are modified.)

Tip: A brief description for each of the options is displayed after you click the option.

The following parameters are available:

- **Forecast Start Date (FSD)** — changes the FSD for all declines to the input date. The decline forecasts are shifted in time to the new start date, but the decline parameters remain unchanged. When a decline forecast has a reserves classification, the FSD cannot be set earlier than the reference date.
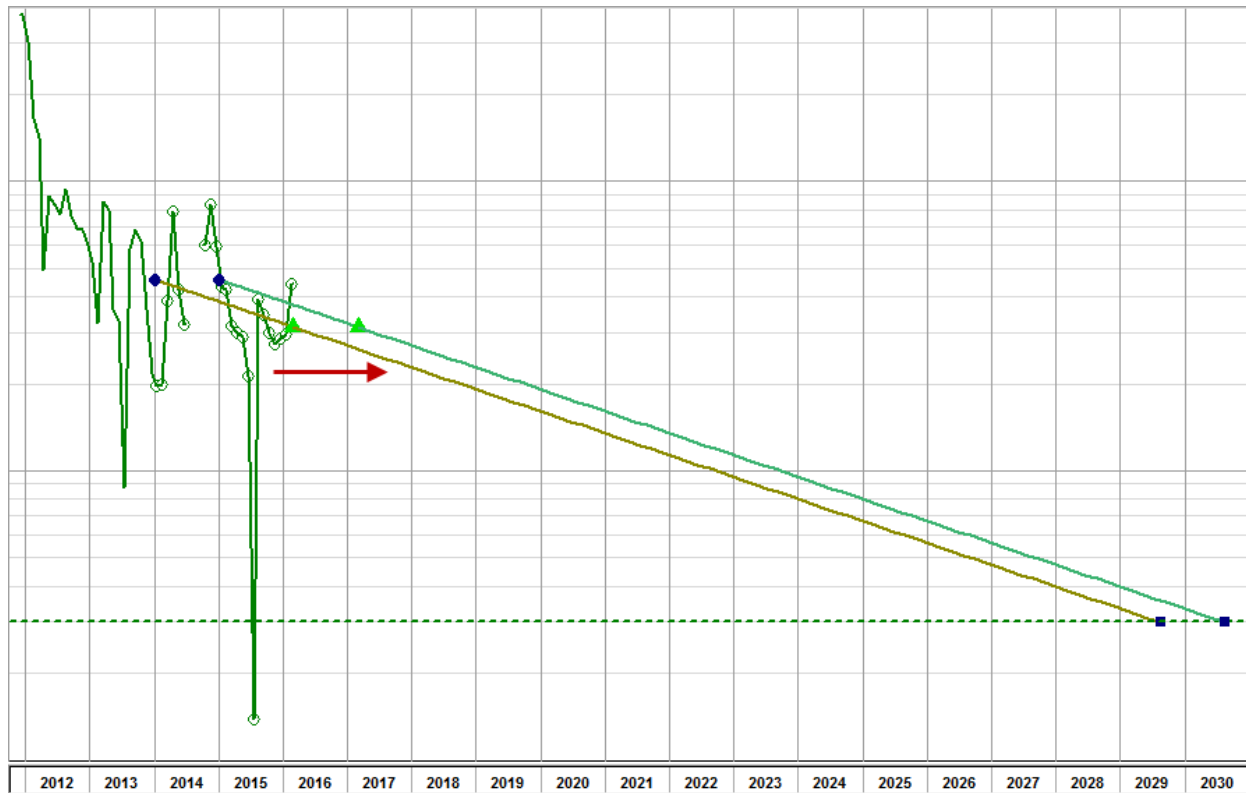
- **End Date** — changes the end date of the decline forecast to the input date. The decline forecast is truncated or extended to the new end date, and the abandonment rate is adjusted to match. Additionally, there is an option to prevent the end date from being extended.

- **Δt** — changes the duration of the forecast to the specified number of months. The decline forecast is truncated or extended to the new duration, and the abandonment rate is adjusted to match. Additionally, there is an option to prevent the forecast from being extended. This is useful in order to "bulk set" declines that end at the earlier of an abandonment rate or end date. This is done by creating declines with the abandonment rate, and then bulk applying the delta t to the forecasts.

- **Δt** $_{history + forecast}$ — changes the duration of the total duration (historical time and forecast) to the specified number of months. The decline forecast is truncated or extended to the new end date, and the abandonment rate is adjusted to match. Additionally, there is an option to prevent the forecast from being extended.

- **q$_f$** — changes the abandonment rate of the forecast to the specified rate(s). The decline forecast is truncated or extended to the new abandonment rate, and the end date is adjusted to match. If declines for multiple fluid types are displayed / selected, only type values for the fluid types to be changed. Any empty cells are left alone.
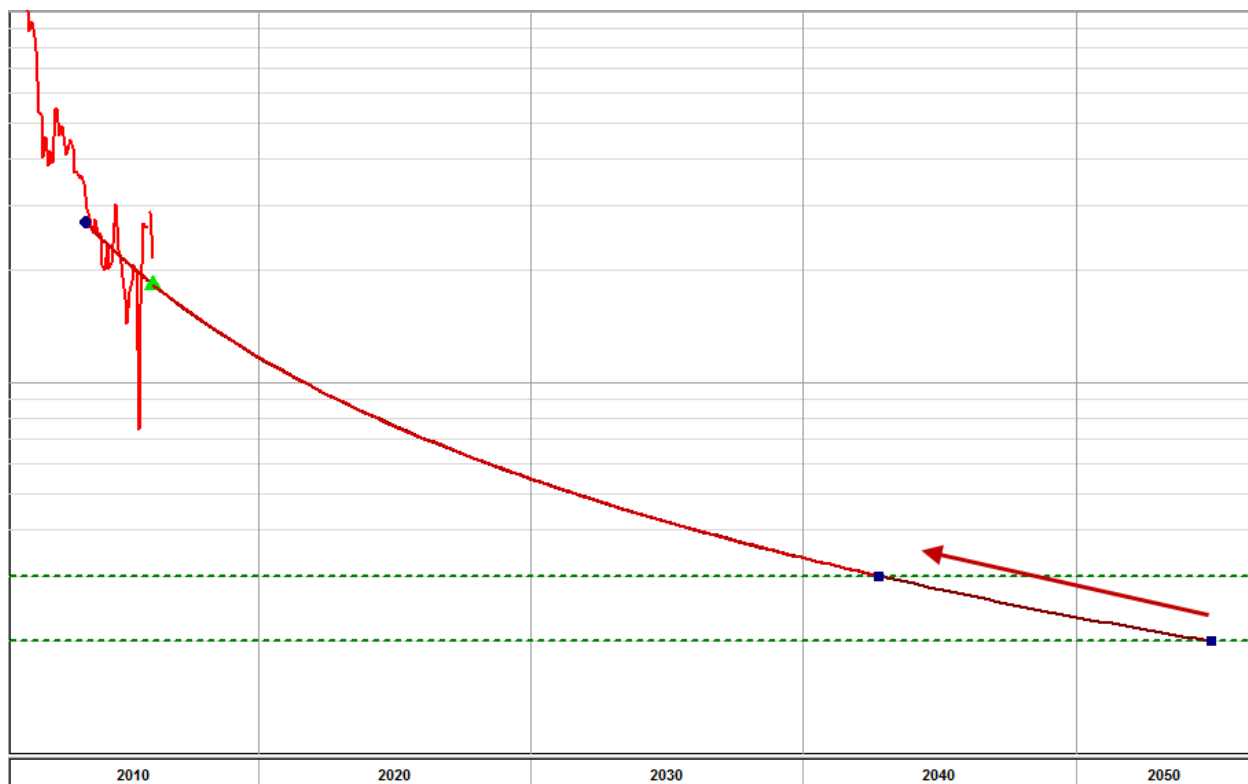
Role-based security

Role-based security (RBS) provides you with the ability to limit access to certain functions in Harmony Enterprise, based on permissions that are associated with assigned roles.

Note: This functionality does *not* apply to .hldb files.

Depending on your role in Harmony Enterprise, you are able to do various things:

- **Super user** — represents the highest level of authority and their role definitions cannot be altered. This user can create role permissions, and assign role definitions to other users.

- **Default** — (RBS: on) has full access to Harmony Enterprise, *except* for these areas: importing wells (importing a file, importing from a database, importing from Harmony Enterprise, and importing from a local Harmony Enterprise database), performing an IHS update, deleting wells in the Hierarchy pane, and modifying RBS settings.

- **Default** — (RBS: off) has full access to Harmony, *except* for modifying RBS settings.

  Tip: Importing wells and performing an IHS update are tasks represented by the first four icons on the main toolbar.
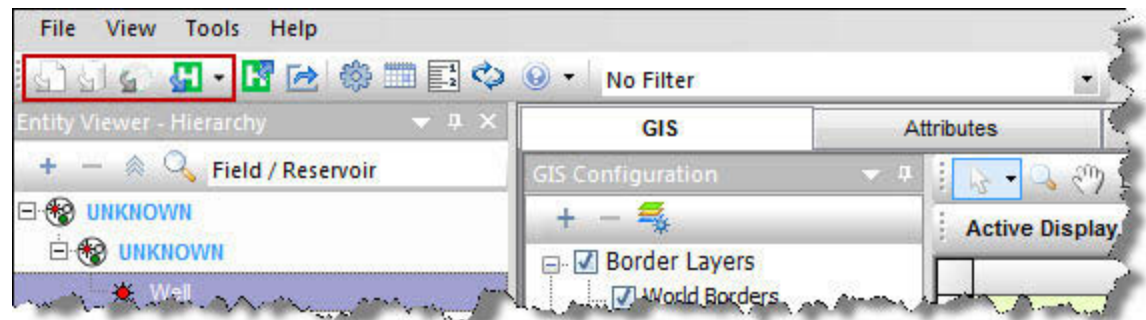
- **User-defined roles** — has full access to the rest of Harmony Enterprise along with a combination of any of the following three permissions: edit RBS settings, import wells / update wells from IHS, and delete wells.

Role-based security is set in the Options dialog box, under the Role-based Security Settings node. To determine your permissions for your current session, click the **Enable / Disable** node. Any activities that are not allowed are displayed in red text under the Activities Not Permitted heading.
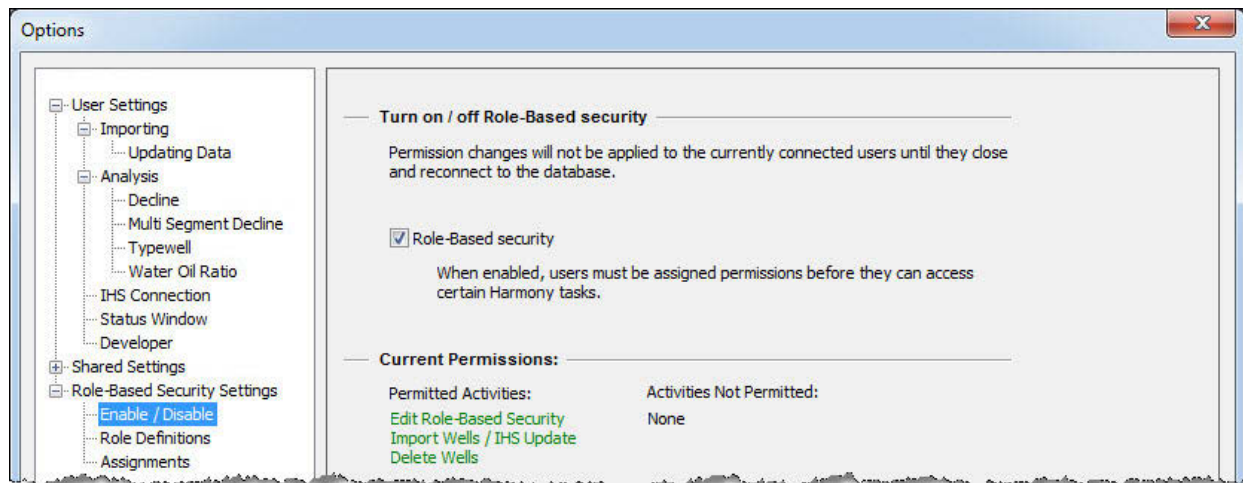
After clicking the **Role Definitions** node, you can add or remove roles. After you have added a role, you can rename it by double-clicking the role name in the Roles pane. (If you do not have permission to modify roles, the Permissions pane is grayed-out.)
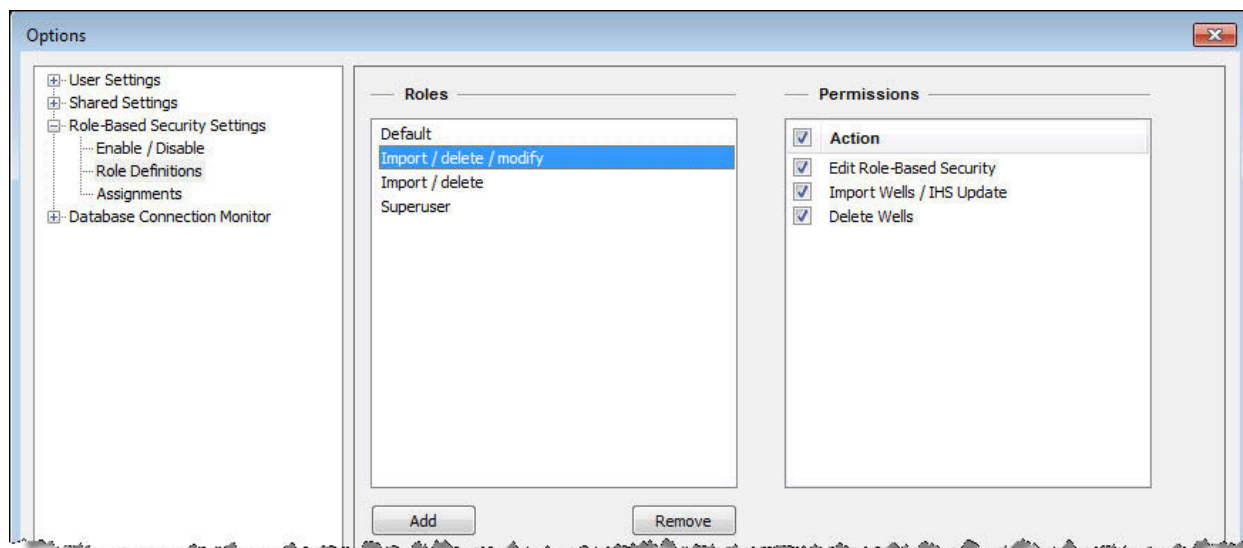
After clicking the **Assignments** node, you can assign users to various roles by clicking the checkboxes for the access you want to grant. Note that the superuser role cannot be assigned from the dialog box, and therefore it is grayed-out.
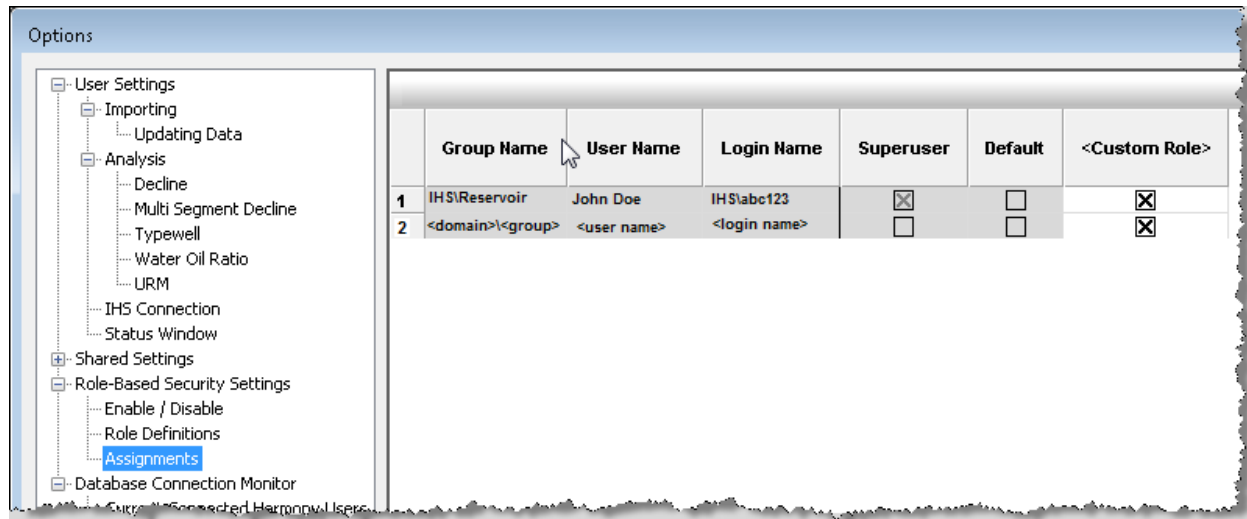
The permission you have for a given session remains the same, regardless of whether another user has made modifications to your permissions. To see any permission changes another user has made, requires Harmony Enterprise to be closed and re-opened. These changes persist after you click **OK**. Changes made by a user to their own role or role assignments (when they have the "modify role" permission) take effect immediately after they click OK.

Note: If another user is updating user roles and assignments at the same time, you may need to close the project, reconnect, and try again. If this is the case, an error message is displayed in the Status Window.

After clicking the **Database Connection Monitor** node, you can see the currently connected Harmony Enterprise users. However, if the **View server state** checkbox is deselected in SQL Server Management Server, you are not able to see this content. If this is an issue, contact your database administrator. For more information, see active directory.

Scenarios

With scenarios, you can create a copy of your parent well, so you can perform "what if" scenarios without risking your original data.

Scenarios are created in the Entity Viewer - Hierarchy (toolbar or by right-clicking), and copy the following information:

- attributes
- properties
- wellbore data
- static pressures
- analyses

Note: While you are working with a scenario, it is locked, and other users cannot access it.

Core data in the Production editor is read-only (that is, volumes and casing / tubing pressures are kept from the parent well). However, you can still calculate your own sandface pressures by using different properties and a different wellbore configuration.

Importing

When importing new production data, the parent well and all scenarios underneath it are updated. After an import, the other scenarios are static and out-of-date. For sandface pressure updates, you need to click the **Calculate Sandface Pressure** icon ( ) in the Production editor's toolbar for all scenarios.

Note: If you are using the Import Auto-calculation option to automatically calculate sandface pressures, this function only applies to the parent well.

Spatial Explorer tab

Spatial Explorer displays wells on a map, which you can customize with various layers. The default layer / data source is Bing maps. However, you can add multiple data sources to the Spatial Explorer map. For more information, see Data Source pane.

Tip: By default, this tab is hidden. To enable it, click the Spatial Explorer node in the Options dialog box.

If you select an entity in the Spatial Explorer, it is also displayed in the GIS map and Entity Viewer (and vice versa). The scale can be different, but both the Spatial Explorer and GIS map display a consistent view. The map that was last used (for example, panning or zooming in the Spatial Explorer or GIS) determines the viewable map area. Actions such as moving or deleting an entity are also mirrored in the GIS map. Any selections (for example, different layers) are saved when you close and re-open Harmony Enterprise.
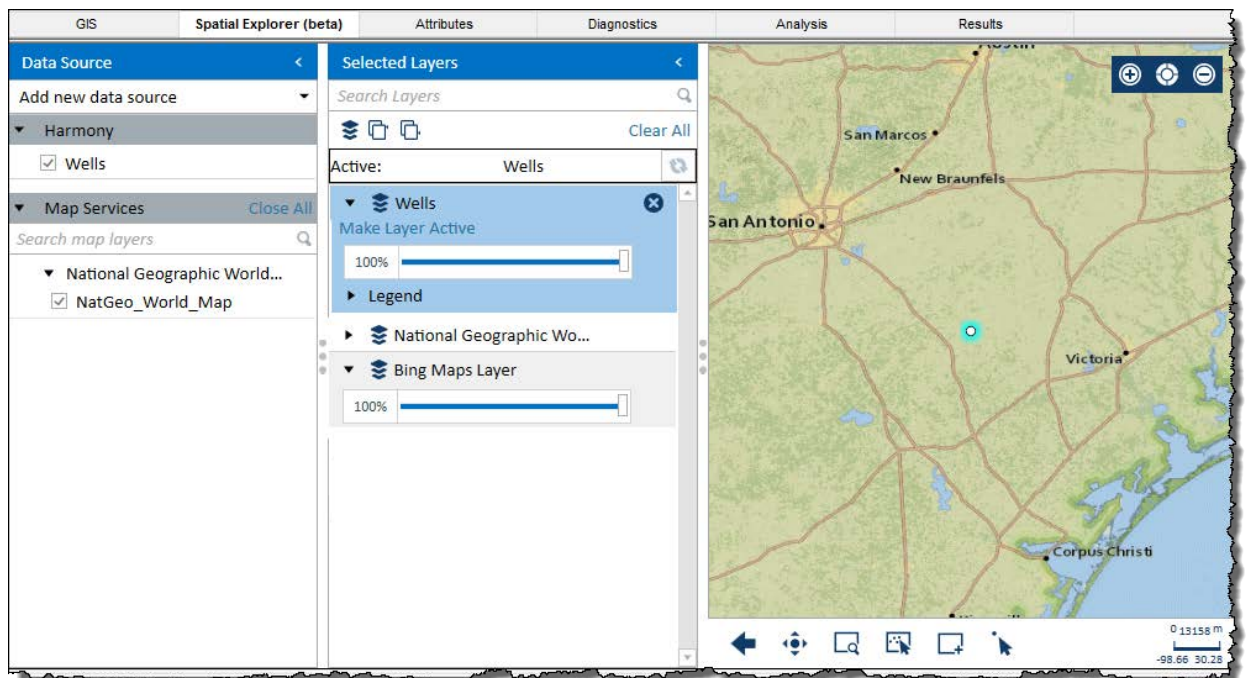
Spatial Explorer supports one datum system / projection: WGS 84 (World Geodetic System, modified in 1984)

The Spatial Explorer tab has two panes: Data Source and Selected Layers. Both panes can be hidden by clicking the left arrow (<) on the right-side of the pane.

Data Source pane

By default, the Harmony / Wells layer is selected, which displays your selected wells on the map.

Each data source you add to Spatial Explorer includes all the data layers available from that source. If the data source requires a username and password, you are prompted to enter these credentials the first time you connect to the data source.

To set up a new data source, click **Add new data source**:

- **Portal for ArcGIS** — the first time you connect to the portal, a Settings dialog box opens. Click the **...** button to browse to a .csv file with the following structure: PortalURL, key. (A portal administrator grants access and saves an authentication key to a shared network location where Harmony Enterprise users can access it.)

- **Feature Services** — a special case of a map server's services, which can be used to execute queries to get features, perform edits applied to the server, and apply templates for an enhanced user experience. Type your address and display name; then click **Connect**.

- **Map Services** — also known as Environmental Systems Research Institute (ESRI) files. Map services are used to make maps available to other applications. Type your address and display name; then click **Connect**.

- **WMS Services** — web map service (WMS) maps are generated by a map server using data from a geographic information system (GIS) database. For example, you can log in to the IHS energy map services website at https://ihs.com.

- **Bing Maps** — Microsoft's Google maps. If you add more than one Bing layer, the additional Bing layers are displayed in red because only one Bing map layer can be used at a time.

To move the data source to the Selected Layers pane so that you can display the data source on the map, click the data source's checkbox.

Important: After adding a layer, you need to deselect and select the Harmony / Wells layer's checkbox in order to see your wells. If your wells become hidden, deselect then select the Harmony / Wells layer's checkbox to show them.

Data sources and any data layers they include may appear outlined in red. This means that Spatial Explorer can no longer access that data source. This can occur if the data source is no longer available, or if you need to provide login credentials for the data source.

To remove all of your data sources (excluding the Harmony / Wells layer, click **Close All**.

Selected Layers pane

You can display any of the data sources as a layer on the map.

Spatial Explorer adds layers to the Selected Layers list on top of each other, so each new layer you add is added at the top of the list. If you want to change the active layer, click **Make Layer Active** for the layer you want to be active. Or, you can click a layer and then click the **Refresh** icon ( ).

> **Tip:** The Active field near the top of this pane indicates which layer is the active one. This can be an important thing to be aware of when clicking zoom icons at the bottom of the map.

The order of layers in the Selected Layers list defines the display order, meaning that data layers at the top of the list display on top of any layers that are lower in the list. You can drag layers within this tab to the order you want.

If you add a layer containing well data, Spatial Explorer automatically adds an additional layer containing deviation survey data for the wells in the layer you added. If none of the wells have deviation survey data, then this additional layer does not contain any data.

Icons

This pane has the following icons:

- **Search Layers** — type your search term and press **Enter**.

- / **Show / Hide Layers** — toggle your layers on or off.

- **Expand All** — opens all of your layers in this pane.

- **Collapse All** — closes all of your layers in this pane.

- **Clear All** — removes all of the layers from this pane except Bing Maps.

- **Refresh** — click this icon after selecting an inactive layer in order to change it to the active layer.

- **Remove Layer** — deletes the layer from your map.

- 100% ——————————————
  Opacity — use the slider to set the transparency of your layer.

- **Legend** — summaries what various symbols stand for.
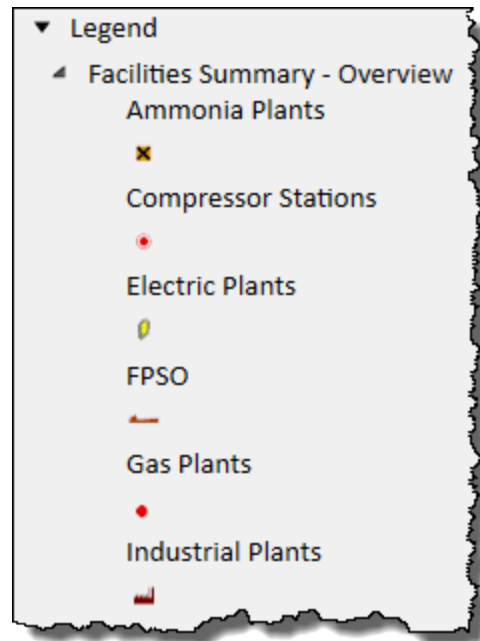
Map

The map displays your layers as selected in the Selected Layers pane.

Icons

The map has the following icons:

- **Zoom In** — Zooms in on the map.

- **Original Extent** — restores the map to the original view shown when starting Spatial Explorer.

- **Zoom Out** — zooms out on the map.

- **Previous Extent** — restores the map to the previous view.

- **Pan** — enables you to move the map.

- **Rectangle Zoom** — zooms in on the map based on the rectangle you draw.
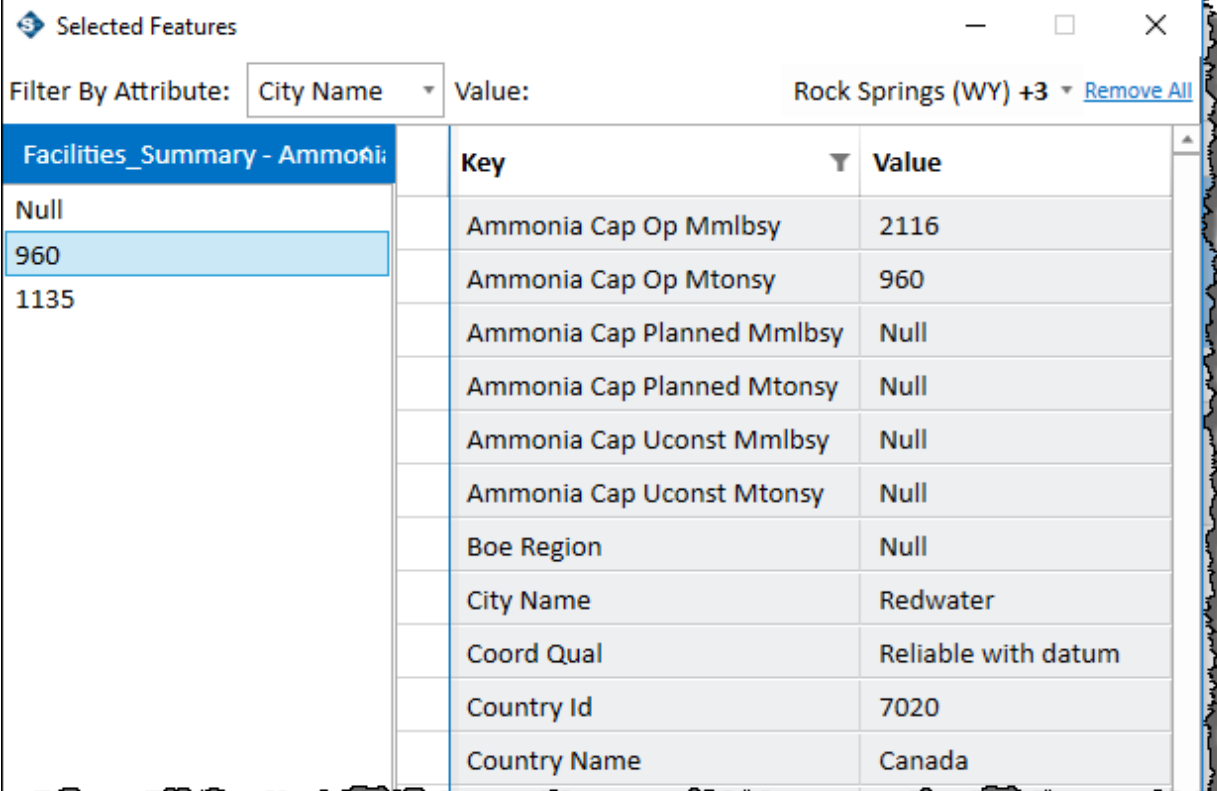
- **Select All In View** — if the Harmony / Wells layer is active, all the data points currently in view on the map are selected. If another layer is active, the <u>Selected Features dialog box</u> opens.

- **Select by Rectangle** — if the Harmony / Wells layer is active, selects all the data points enclosed within the rectangle you draw. If another layer is active, the Selected Features dialog box opens.

- **Select** — if the Harmony / Wells layer is active, you can select individual data points, or multiple data points if you press the **Ctrl** or **Shift** keys. If another layer is active, the Selected Features dialog box opens.

Selected Features dialog box

This dialog box is commonly used with <u>Spatial Explorer</u> to obtain information on layers other than the Harmony / Wells layer. If this dialog box opens with blank content, this means that there is no attribute data for that particular layer.

Tip: Well attributes are *not* displayed in this dialog box because these attributes are listed in the "Attributes tab" on page 327.

- **Filter By Attribute** — select from the drop-down list.

- **Value** — select from the **No values selected** drop-down list and click **Apply**.

- **Remove All** — resets your attribute selections.

- **Key** — lists attributes based on your Filter By Attribute selection.

- **Secondary Filter** — further refine your filter with additional criteria.

- **Value** — lists information for each entry in the Key field.

Tables / grids

Harmony Enterprise often displays data in tabular form and uses functionality similar to Excel. For example, you can click-and-drag the bottom right corner of a table cell to copy your data to a range of rows below. The cursor changes to a large X, and you drag the table cell contents to the next row or rows.

	Start Date	End Date	Gas Volume	Wate Volu
	MM/DD/YYYY	MM/DD/YYYY	MMscf	s
1	02/01/1992	03/01/1992	1.828	
2	03/01/1992	04/01/1992	16.497	
3	04/01/1992	05/01/1992	6.034	
4	05/01/1992	08/01/1992		
5	08/01/1992	09/01/1992	0.000	
6	09/01/1992	10/01/1992		

Note: For a description of common table icons, see table toolbars.

To change the height and width of rows and columns, drag the boundary between the header cells.

	p	ψ	Z	B_g	ρ_g	c_g
	psi(a)	10^6psi^2/cP		ft^3/scf	lb/ft^3	1/psi
1	0.00	0.000				
2	10.00	1.779e-02	0.999	2	0.03	1.00e-01
3	20.00	4.449e-02	0.997	1	0.06	5.01e-02
4	30.00	8.905e-02	0.996	1	0.09	3.35e-02
5	40.00	1.515e-01	0.995	0	0.12	2.51e-02
6	50.00	2.319e-01	0.993	0	0.15	2.01e-02
7	60.00	3.303e-01	0.992	0	0.18	1.68e-02
8	70.00	4.468e-01	0.991	0	0.21	1.44e-02

To move a column to a new location, click-and-drag the column you want to move. The cursor changes to a gray box with a checkmark, and when you release your mouse button, the column moves to its new location.

Context menus

Right-clicking an entire table or columns in a table, display different context menus.

Entire table

To copy an entire table, right-click the top-left cell of a table and select one of these options:

- **Copy Grid** — copies the table to the clipboard.

- **Copy Grid + Headers** — copies the table and table headers to the clipboard.

Columns

To copy one or more columns of a table, select your columns by clicking their headers, and then right-click and select **Copy**.

After you have copied your content from a table, you can paste it to another application (for example, Excel).

To change the precision and/or units displayed in a column, right-click the numeric columns' headers (the columns displaying units in green text).

- **Precision** — select between decimal, scientific, or engineering.

- **Units** — select the units you want to display from the submenu.

Note: Changing the precision only affects the way values are displayed. All of the calculations use exact values, even if the displayed value looks rounded-up.

Worksheets

Worksheets are plots or tables of entity data and analyses. Worksheets are related to the currently selected entity for analysis (a well or group), and each worksheet can be used for one or many analyses. You must add a worksheet before you can analyze an entity.

The New Worksheet tab opens when you select an entity for analysis, or click the New Worksheet tab.

An important distinction exists between Forecast worksheets and Reservoir worksheets.

- Forecast worksheets support multiple analyses and these analyses can be displayed on multiple worksheets (*many:many relationship*). With forecast worksheets, click your worksheet, and then select from the context menus (if applicable).

- Reservoir worksheets support one analysis and this analysis is displayed on one worksheet (*1:1 relationship*). With reservoir worksheets, click your reservoir, and then select the fluid, analysis, and model (if applicable).
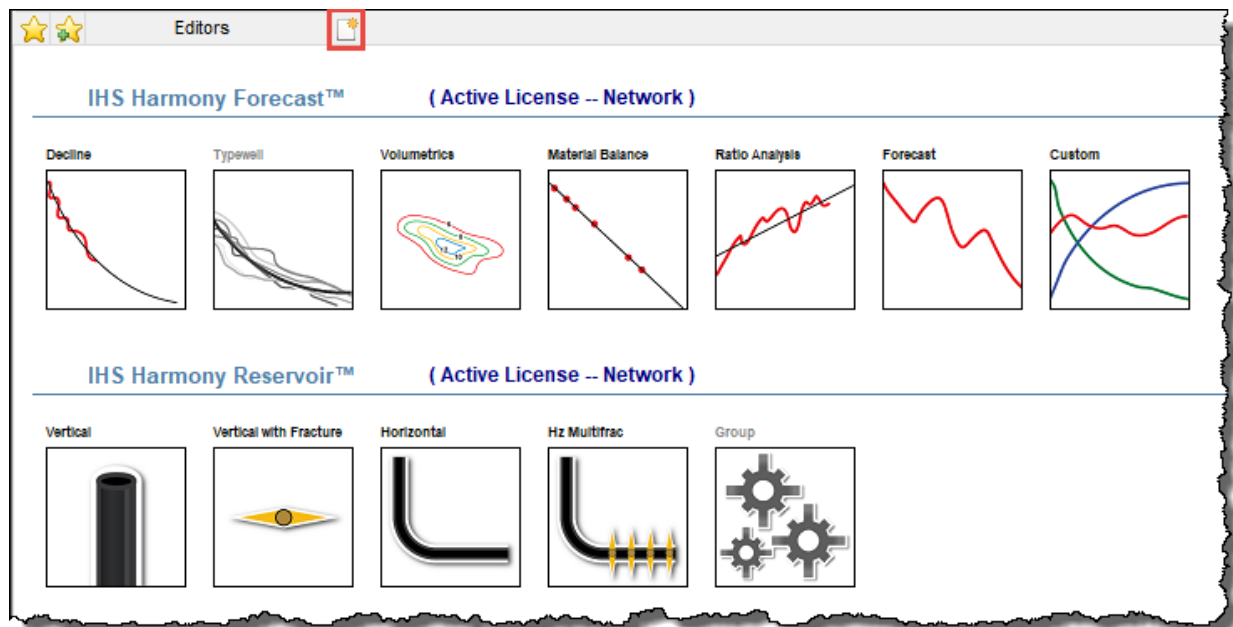
For group analyses, (for example, typecurve, FMB), click **Group** and select your worksheet from the context menu.

Tip: After working on your analysis, you can click another tab and your work is automatically saved. If you want to export specific wells and later import them back into the database, see work offline.

Harmony Enterprise supports the following worksheets:

Harmony Forecast™ License	Harmony Reservoir™ License (links to various analyses)
Decline	Typecurve
Typewell	FMB
Volumetrics	URM
Material Balance	Analytical
Ratio	Hybrid
Forecast	Probabilistic
Custom	Multi-well

Decline worksheet

Decline worksheets display the production data of a well using the selected plot options (such as, time or cumulative production for the x-axis). These worksheets can be used to add, display, and modify decline forecasts based on your production data. For more information, see the analysis manager and plot selection pane.

Note: This worksheet works with your Harmony Forecast™ license.

In the decline category, you can select these plot types for gas, oil, water, and barrel of oil equivalent (BOE):

- **Rate Time** — production rates are plotted against time on a semi-log plot

- **Rate Cum** — production rates are plotted against cumulative production on a coordinate plot

- **Cum Time** — cumulative production is plotted against time on a coordinate plot. Note that this is a read-only display and the decline cannot be modified on this plot.

Default decline worksheets can be modified in the Plot Selection pane.

In the Analysis Manager, you can add hybrid forecasts for gas, oil, or water.

You can also add condensate decline analyses (that is, Arps, multi-segment, stretched exponential, and Duong) to your decline worksheet, but the procedure is different. For more information, see analyzing a condensate decline analysis.

BOE

The BOE applies to wells and groups, and it is of interest because oil and gas are often produced together. The BOE is calculated as oil volume + gas volume / factor. This factor can be changed from the default value of 6.00 Mcf/bbl in the Production Calculations section of the Options dialog box (**Tools** menu, **Options**).

Important: This value is shared by all users, and updating this value affects new and existing analyses.
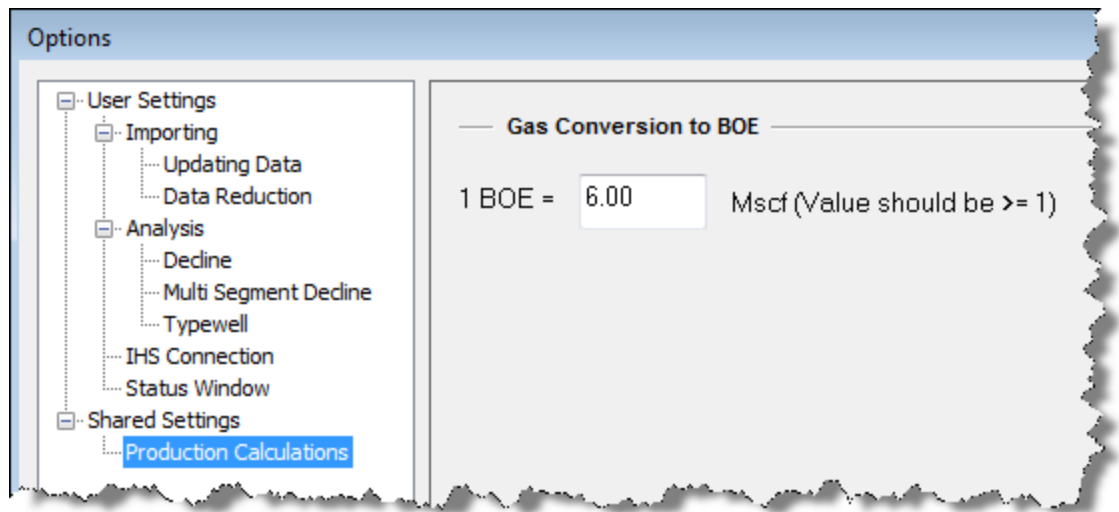
If you set this factor to less than one, an error message is displayed in the Status Window and the value resets to six.

Typewell worksheet

The typewell worksheet is used to view well-level production on a group of wells and calculate average performance. This can be used to create a forecast for wells with limited or no historical production based on a relevant group.

Note: This worksheet works with your Harmony Forecast™ license.

You can add the following typewell worksheet types:

- gas typewell

- oil typewell

- water typewell

- BOE typewell

- condensate typewell

Note: Only the traditional decline analysis is available for each of the above fluid types.

Plot toolbar

You can toggle different rates by clicking these icons on the toolbar above the plot:

- **Select a Best Fit range using the options listed** — see best fit.

- **Show / Hide Average rate** — by default, the average rate is shown. Click this icon to show / hide the average rate on the plot. The arithmetic average of all selected wells is determined in each period.

- **Show / Hide Wells** — by default, all wells are shown.

- **P90 / P50 / P10 rates** — by default, all these rates are hidden. Click the P90, P50, or P10 icons to show / hide these various rates on the plot.

- **Show / Hide Number of Producing Wells** — you can display the number of producing wells in each period.

- **Append historical production with selected forecast** — you can use an individual well's historical production and forecasts to create a typewell forecast.

- **Color Management** — select from these options:

    - **All Grey** — displays all wells in a gray color.

    - **All Unique** — displays each well in a unique color.

    - **Color by Attribute** — opens a submenu where you can select a specific attribute. All wells with the same attribute appear in the same color.

- **Settings** — select which rate calculations you want to display on the plot: All Rates or Producing Rates Only.

- **Plot drop-down list** — select your plot type from the drop-down list: log y, coordinate, log-log, or log x.

For a description of common icons, see plot toolbars.

Best fit

There are several tools that you can use to create a "best fit" using the point-selection method. Selecting any of these options opens the Set Axis Ranges dialog box where you can define the portion of data to be used for the best fit.
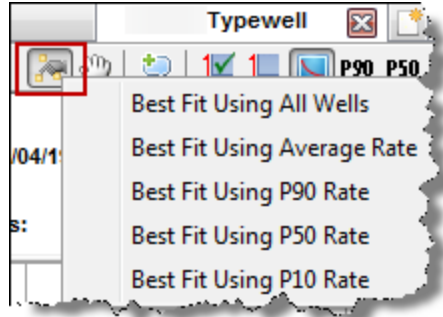
Plot Selection tab

The Plot Selection tab lists the options for your plot.

X-axis:

- **Normalized Time** — This option plots well data as cumulative time from 'time zero' (0 on the x-axis) rather than as dates. Time periods are displayed in increments of months or days. If the increments are mixed within the group, the lowest-resolution time period is used to ensure consistency. When the average line is calculated, each producing well's rate is averaged at each period.

- **Normalized Flowing Time** — This option is similar to normalized time, but all shut-in, missing, or blank periods are removed from each well's production history.

- **Cumulative Production** — Production volume is displayed based on volume produced per time period. (The period size is the one the data is imported in.) When creating the average well, all wells are aggregated to the lowest resolution period, and the average production volume and rate are determined for each period.

- **Resolution** — Toggle between Daily and Monthly.

Y-axis:

- **Rate** — This option displays the rates for each well in the group and uses these rates to create the average well's rate.

- **Rate per Attribute** — Well rates are normalized (that is, divided) by the value of the selected attribute. If the attribute is blank, the well's production history is not displayed.

- **Rate Type** — Toggle between Operated Rate and Calendar Rate.

- **Cumulative Production** — Production volume is displayed based on volume produced per time period. (The period size is the one the data is imported in.) When creating the average well, all wells are aggregated to the lowest resolution period, and the average production volume and rate are determined for each period.
  Note that if you select this for your y-axis, the typewell becomes read-only.

Wells tab

Use the Wells tab to synchronize well settings between typewell worksheets via the toolbar. In addition, you can change the start period of a well by entering a value in the Start Date Offset boxes, or by clicking the blue left- or right-facing arrows next to the boxes.
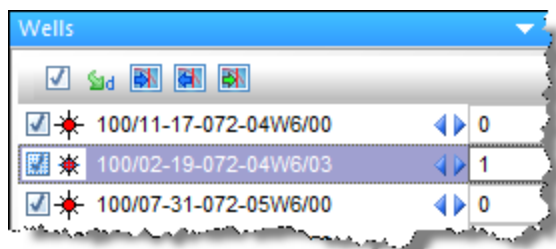
The number in the box corresponds to the time period in which production data starts for the well. (On a time plot, this is either months or days. On a cumulative plot, this is production volume produced in that time period. Therefore, a well with larger production volume moves more than a well with less production volume.)
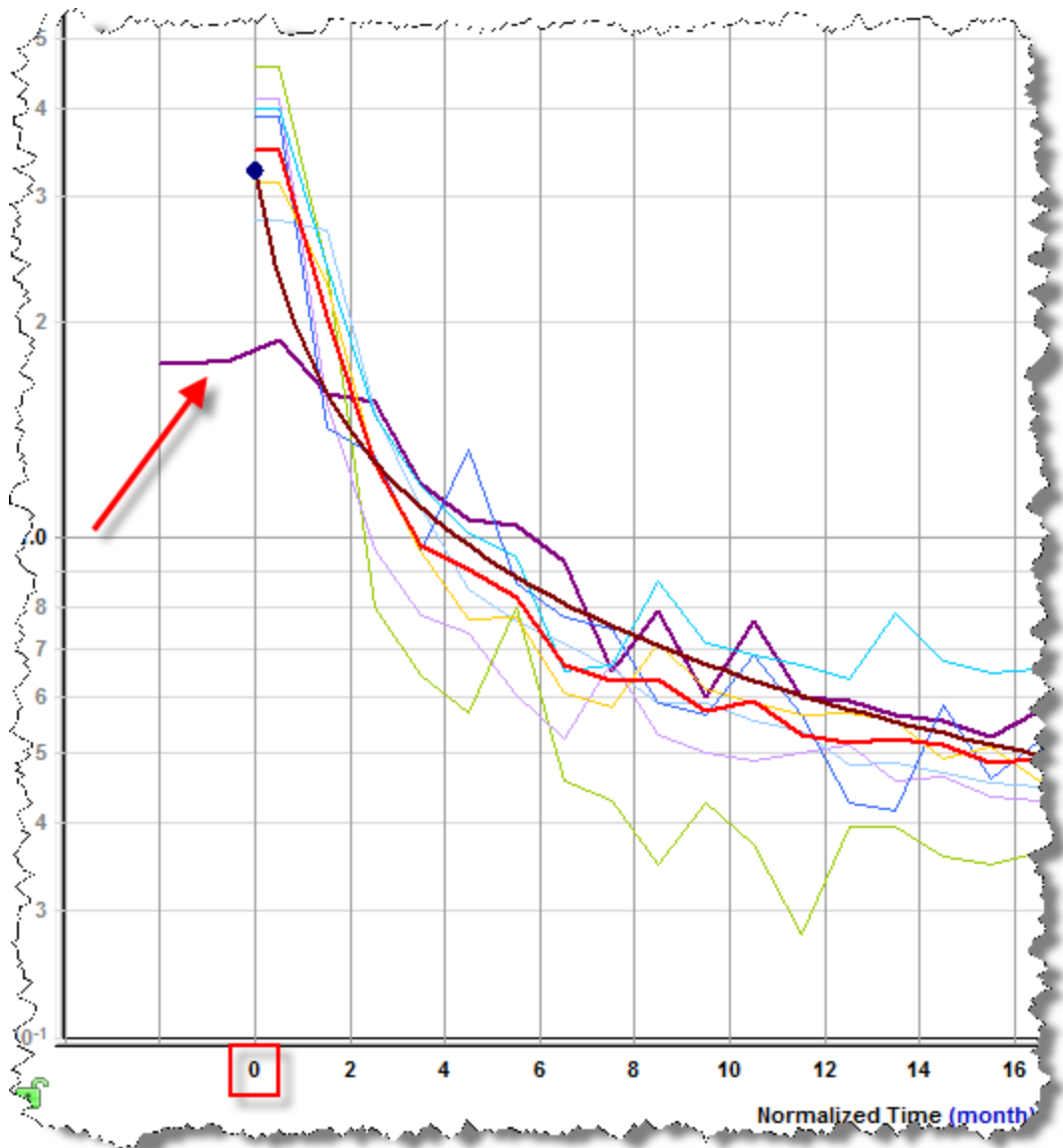
Anything to the left of time zero (0 on the y-axis) is not used for the calculated lines or the decline forecast.

Hovering over a well temporarily displays a thicker line for the associated dataset on the plot.

A selection can be made within the Wells tab, or on the plot. Selections are maintained between the Wells tab and the plot. A selected dataset is displayed with a thicker line to indicate that it is selected.

Wells can be selected in the Wells tab using standard selection behavior (including using the Ctrl and Shift keys). For more information, see selecting entities.

Clicking a dataset clears the existing selection, and then selects the new dataset. Pressing the **Ctrl** key while selecting a dataset adds / removes the dataset from the existing selection.

Toolbar

This tab has the following icons on its toolbar:

- ☐ **Check all / uncheck all** — selects or deselects all of the wells displayed on the plot

- **Apply Selections from another Typewell Worksheet** — gets selections (selects the same wells) and spinner values (offset values that translate the rate history for a well) from another typewell worksheet in the same custom group.

- **Set Start Date Offsets to Zero** — sets all well offsets to zero.

- **Set Start Date Offsets to Peak Rate** — sets all well offsets to the well's peak rate – time zero for the well becomes the peak rate instead of the first period.

- **Set Start Date Offsets to Specified Value** — opens the Shift Spinner Value dialog box where you can set your well offsets (positive values only). This moves the plot to the right (0 corresponds to the beginning of production data. You can also use the blue left- or right-facing arrows on the Wells tab.

Context menu

Right-clicking wells on this tab lists these options:

- **Duplicate Selected into Shared Custom Group** — copies the selected wells into a new or existing shared custom group.

- **Duplicate Selected into Private Custom Group** — copies the selected wells into a new or existing private custom group.

- **Move Selected into Shared Custom Group** — moves the selected wells into a shared custom group. Only available if the active group is a Custom Group.

- **Move Selected into Private Custom Group** — moves the selected wells into a private custom group. Only available if the active group is a Custom Group.

Analysis Manager tab

The Analysis Manager tab has an Analysis Manager pane and an Analysis Parameters pane. The Analysis Manager only shows typewell analyses, unlike other worksheets, which show all analyses while

disabling ones that cannot be displayed on the plot.
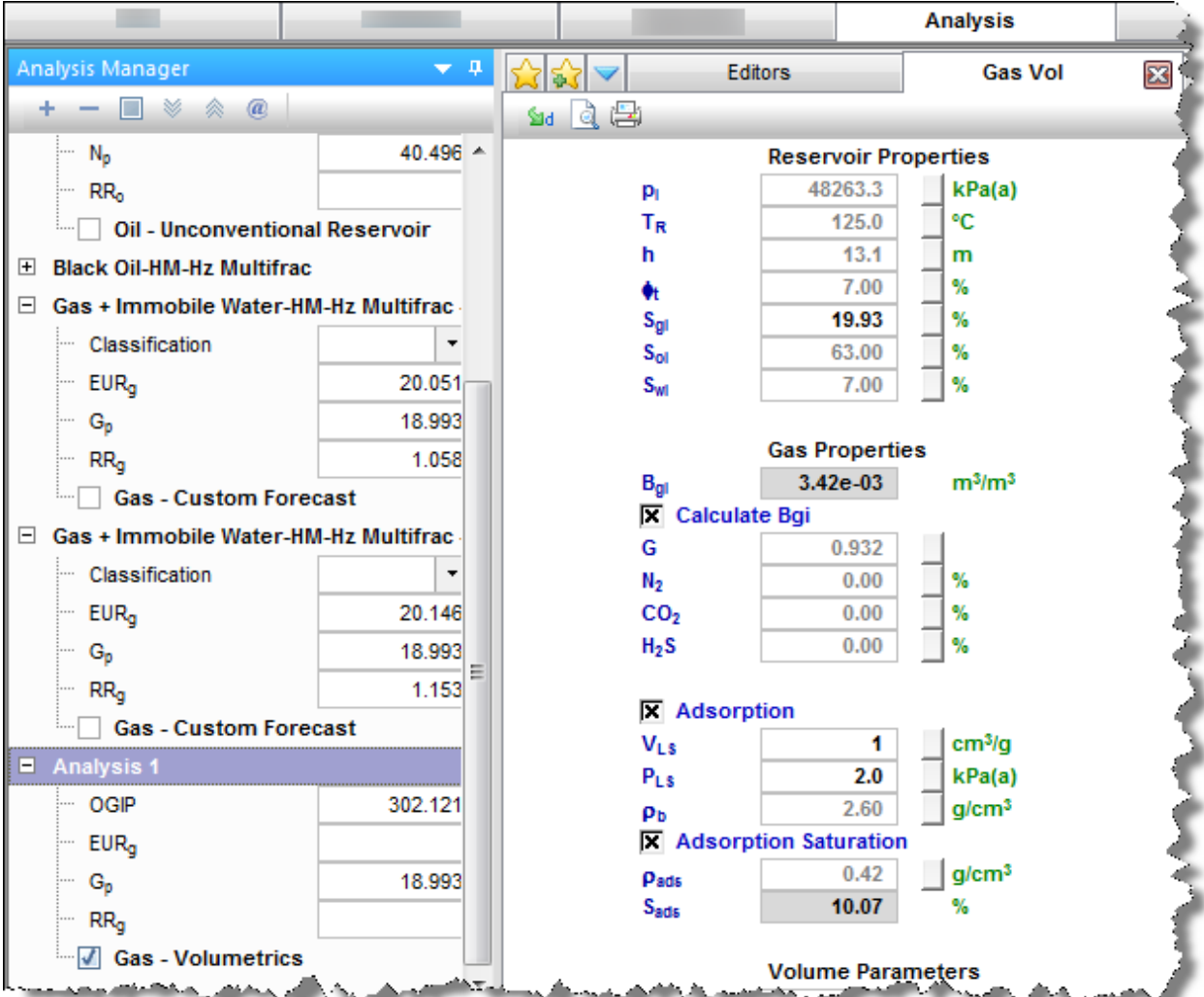
Decline and multi-segment decline analyses displayed on the typewell worksheet have their forecast start dates matched to the start date of the first segment, and the forecast always starts at t / Q = 0.

Volumetrics worksheet

The volumetrics worksheet is used to view gas and oil volumetrics analyses. For more information, see the volumetrics analysis.

Note: This worksheet works with your Harmony Forecast™ license.

Click to show / hide an example screenshot

Material Balance worksheet

The Material Balance worksheet is used to view gas material balance analyses. For more information, see the materials balance analysis.

Note: This worksheet works with your Harmony Forecast™ license.

Ratio worksheet

With a ratio worksheet, you can establish a trend based on the relationship, or ratio, between oil and water production rates.

This ratio trend can then be used to create rate forecasts for individual fluids.

- The water-oil ratio (WOR) is simply $\frac{Water\ Rate}{Oil\ Rate}$ and is generally expressed as Bbl/stb or m^3 / m^3

- WOR + 1 minimizes the value of water-oil ratio data where the watercut is less than 50%. WOR should never be extrapolated for watercuts less than 50%. It is generally expressed as Bbl/stb or m^3/m^3

- Water cut is $\frac{Water\ Rate}{Water\ Rate\ +\ Oil\ Rate}$ and is generally expressed as a percentage

- Oil cut is $\frac{Oil\ Rate}{Water\ Rate\ +\ Oil\ Rate}$ and is generally expressed as a percentage

Note: This worksheet works with your Harmony Forecast™ license.

For more information, see water-oil forecasting theory.

You can select from the following default worksheets:

- **WOR vs. Cumulative Oil** — presents the water-oil ratio (WOR) from a historical perspective. It has little or no analysis value. The WOR + 1 analysis curve can be presented on this plot.

- **WOR + 1 vs. Cumulative Oil** — this is our main analysis plot for estimating oil EUR by extrapolating the linear portion of the WOR + 1 trend. This plot is used because it helps ensure you only use the data where water cut exceeds 50% and it tends to produce more reliable linear trends. This plot can be used directly to extrapolate EUR because the x-axis is cumulative oil, or it can be used as a trend line in the Forecast worksheet to create an oil-rate forecast based on a projection of Total Liquids Rate (Oil + Water). This is a crude, but workable method.

- **Water cut vs. Cumulative Oil** — water cut can be defined as the ratio of water produced compared to the volume of total liquids produced. The water cut in waterdrive reservoirs can reach very high values (from the Schlumberger Oilfield Glossary).

- **Oil cut vs. Time** — is a method sometimes used for wells with very high WORs to linearly extrapolate similar oil rates to an economic oil-cut limit. It can be very dangerous because it encourages you to identify and extrapolate trends that may be partially or entirely created by measurement errors, and not due to progressive saturation changes in the reservoir.

You can add your own worksheets, but the WOR analysis can only be added when the required axes are present.

Forecast worksheet

The forecast worksheet displays raw data for existing production forecasts in a table. The forecast worksheet can also be used to create a ratio forecast from an existing forecast using an input ratio.

Note: This worksheet works with your Harmony Forecast™ license.

On this worksheet, forecasts start at the forecast start date. You can change your table resolution by clicking the **D** (day), **M** (month, the default setting), or **Y** (year) icons on the toolbar. For a description of common icons, see table toolbars.

If you imported a Piper® Forecast, it is displayed with a "- Piper Forecast" suffix (for example, Gas - Piper Forecast, Oil - Piper Forecast, or Water - Piper Forecast) as a Custom Forecast.

Custom worksheet

The custom worksheet is a blank worksheet where you can display the parameters you select on the Plot Selection pane. In addition, you can select the custom templates you create in the Diagnostics tab.

Note: This worksheet works with your Harmony Forecast™ license.
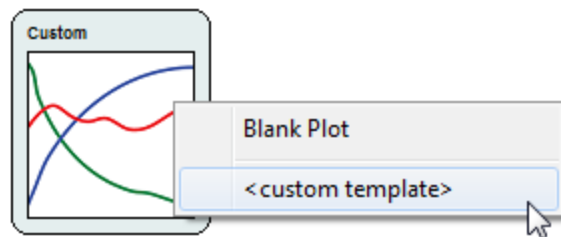
For a description of common icons, see toolbars.

Reference materials

Reference materials include the following:

- analysis and theory

- calculations & correlations

- general concepts

- nomenclature

- references

Analysis and theory

Analysis and theory includes the following:

- Analytical

- Decline analysis

- FMB | Multiphase theory, Model theory

- Duong decline

- Hall plot

- Hybrid model

- Material balance

- Probabilistic

- Stretched exponential decline

- Typecurve | Argarwal-Gardner, Blasingame, Compound linear, Fetkovich, NPI, Transient, Wattenbarger

- Typewell

- Unconventional reservoir

- Volumetrics

- WOR forecasting

Analytical models theory

Modeling is the process of history matching pressure and rate transient data based on a mathematical model. There are many different models available to match the data depending on the situation. Thus, it is important to analyze the pressure and rate transient data before modeling because it forces the analyst to think about the probable reservoir configurations and provide good estimates of reservoir parameters. Models are not unique (different model types can match the same set of data), and as a result, we recommend selecting the model type after the analysis step. The following summarizes the advantages of modeling pressure and rate transient data:

- Modeling makes use of all the information within a dataset. For example, while analyzing data from vertical wells, the analyst might try and determine permeability and skin by analyzing the data points that make up the zero slope on the derivative plot, and the semi-log straight line on the radial plot, but ignore the data points in the transition period between wellbore storage and radial flow. Models make use of the information contained in transition periods.

- Modeling takes all flow regimes into account. In multi-rate situations, analyses depend on the superposition of the equation for a single flow regime. For example, the derivation of Horner time includes the assumption that all flow, including the entire drawdown, is radial. Modeling does not assume that only one flow regime has occurred.

- With modeling, you can simultaneously analyze multiple flow periods, so that a single set of parameters can be found.

Parameter values obtained during the analysis step provide a good starting point for an appropriately chosen model type. Parameters can then be optimized by automatic parameter estimation (APE). Before using the APE method, corrupted data should be removed from the dataset to prevent the attempt to match invalid points.

Choice of model

As stated above, different models can be used to match a single set of data. Choosing a probable model type requires the consideration of a number of factors including seismic data, geology, log data, and information provided from other wells drilled in the same formation.

The choice of model can drastically change the outcome of a forecast. For example, pressure and rate transient analysis of radial flow data can be used to find the reservoir flow capacity (kh). The analyst must decide which model is better.

Model assumptions

There are many assumptions that go into the model itself which can lead or mislead the analyst. Most models assume that a reservoir is homogeneous (dual porosity excluded, where the dual porosity flow within each layer can be modeled either as pseudo-steady state or transient interporosity flow). There is no single reservoir that is actually homogeneous in nature, but many reservoirs behave as homogeneous reservoirs.

Vertical model

The vertical model simulates the pressure response in a vertical well within a rectangular-shaped reservoir with homogeneous or dual-porosity characteristics. Note that the well may be at any location within the reservoir, and that the reservoir for the vertical model has no-flow boundaries. During very early times, the cylindrical source solution is used, which is followed by the Green's function solutions (Grindarten and Ramey, 1973). No-flow boundaries are modeled using the method of images. The result is superposed in time based on the rate history provided.

Vertical with fracture model

The fracture model simulates the pressure response in a vertical well intercepted by an infinite-conductivity vertical fracture within a rectangular-shaped reservoir with homogeneous or dual-porosity characteristics (see the figure below). Note that the well may be at any location within the reservoir, and that the reservoir for the fracture model has no-flow boundaries. During very early times, the cylindrical source solution is used, which is followed by Green's function solutions. The Green's function solution, as developed by Thompson et al. (1991), is used with slight modifications to simulate an infinite-conductivity vertical fracture. No-flow boundaries are modeled using the method of images. The result is superposed in time based on the rate history provided.
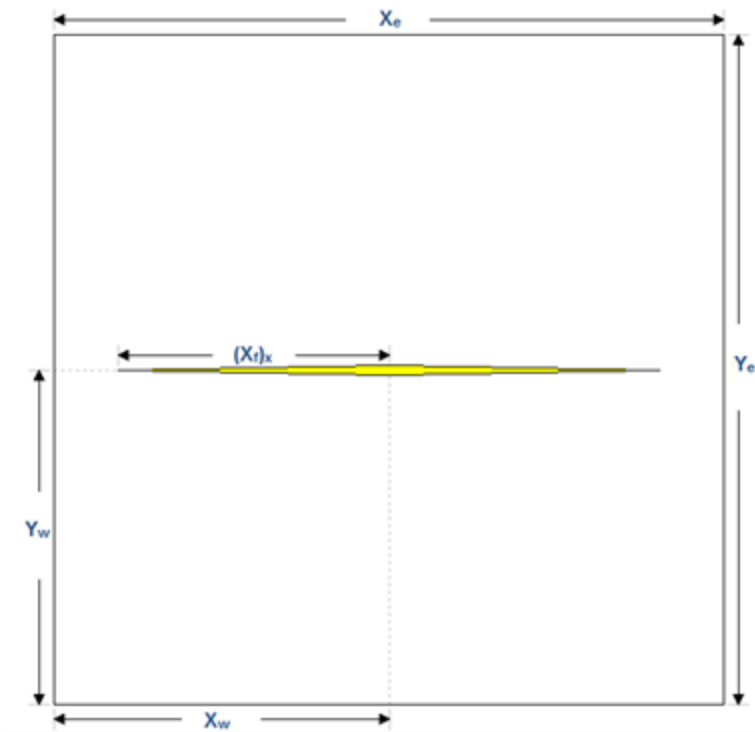
Horizontal model

The horizontal model simulates the pressure response in a horizontal well within a rectangular-shaped reservoir with anisotropic heterogeneities (that is, differences in permeability in the x, y, and z directions), or dual-porosity characteristics. The anisotropy is handled using a conformal mapping procedure that adjusts the boundary sizes accordingly to mimic the effect of increased or decreased permeability in each direction. The horizontal well is oriented in the x-direction, and may be at any location within the reservoir (see the figure below) and supports no-flow boundaries.
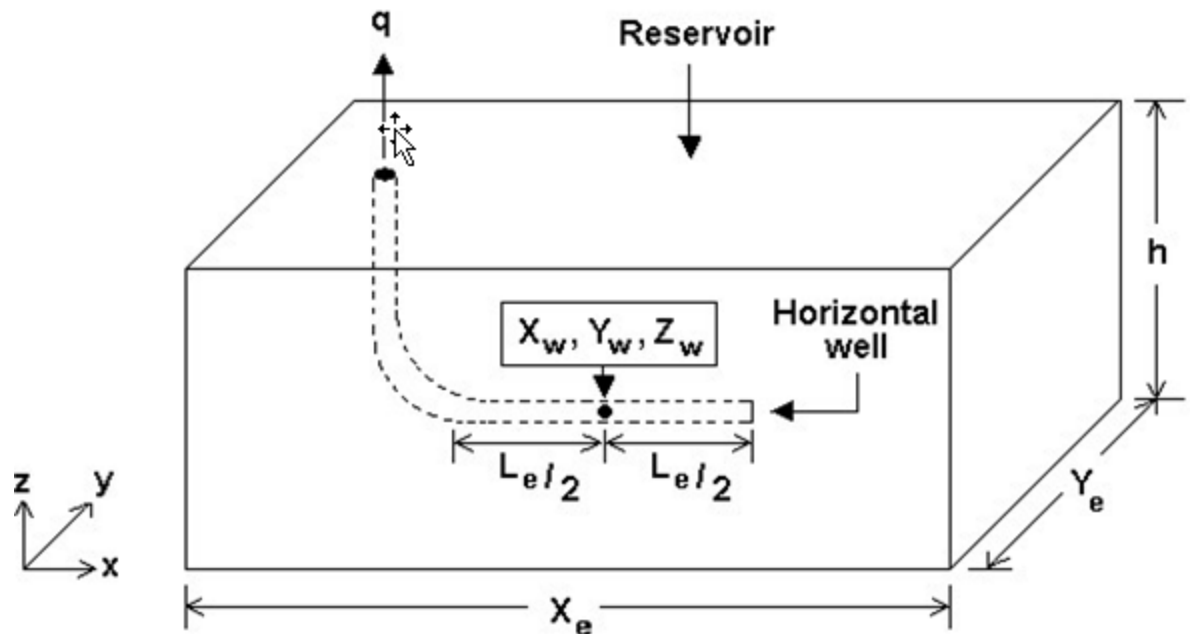
Note that the effective wellbore length (L_e) defines the wellbore area open to fluid flow. The cylindrical source solution is used at very early times, which is followed by Green's function solutions for horizontal wells, as developed by Thompson et al. (1991). No-flow boundaries are modeled using the method of images. The result is superposed in time based on the rate history provided. The following flow regimes can be handled by this model:

- Wellbore storage

- Vertical radial flow

- Linear horizontal flow

- Elliptical flow

- Horizontal radial flow

- Boundary effects

- Pseudo-steady state flow

Horizontal multifrac enhanced fracture region model

This model is a rectangular reservoir model consisting of a non-contributing horizontal well and transverse fractures. This model assumes that all the fractures are uniformly spaced with equal half-fracture length. (The reservoir can extend beyond the fracture tips.) This model has an improved effective

permeability region around each fracture, and you can specify the distance from the fracture to the permeability boundary (X_I).
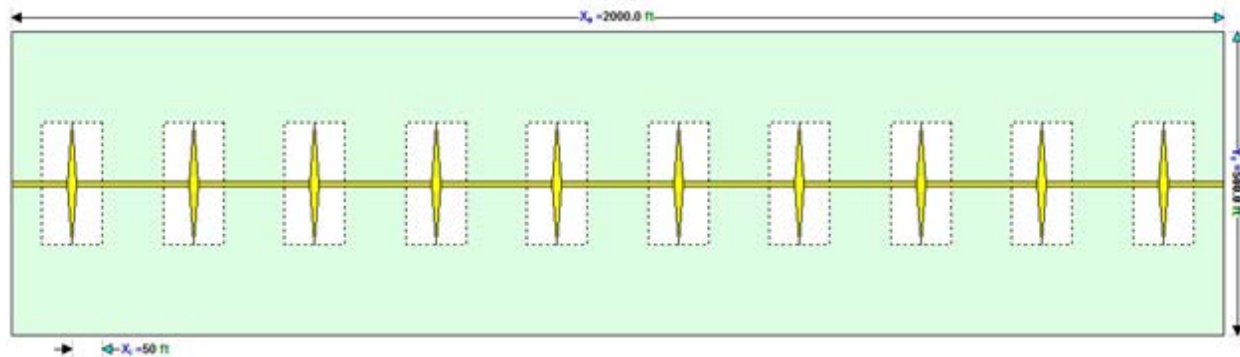
This model takes the following linear flow regimes into account:

- linear flow within the fracture (at very early time)

- linear flow within the stimulated region towards the fractures

- linear flow within the non-stimulated regions towards the stimulated region

- linear flow within the non-stimulated region towards the wellbore

Note: A detailed description of the model is given by Stalgorova and Mattar (2012).

General horizontal multifrac model

The general horizontal multifrac model is a homogeneous, single-phase, rectangular reservoir model consisting of a horizontal wellbore and transverse fractures. The horizontal multifrac solution is created through superposition of individual infinite conductivity fracture solutions in space.

You can specify the reservoir dimensions and well position, provided the entire wellbore and all fractures fit within the reservoir boundaries. In addition, each fracture can be situated anywhere along the horizontal wellbore and configured to have a unique fracture half-length and conductivity. Thus, it is possible to model the combined effects of the horizontal wellbore and multiple fractures as well as the transition into middle-time flow regimes and boundary-dominated flow for any number of different geometrical configurations. Depending on the configuration, pseudo-radial flow can be observed with this model.

Damage skin is applied along the length of the horizontal wellbore and a turbulence factor may be specified.
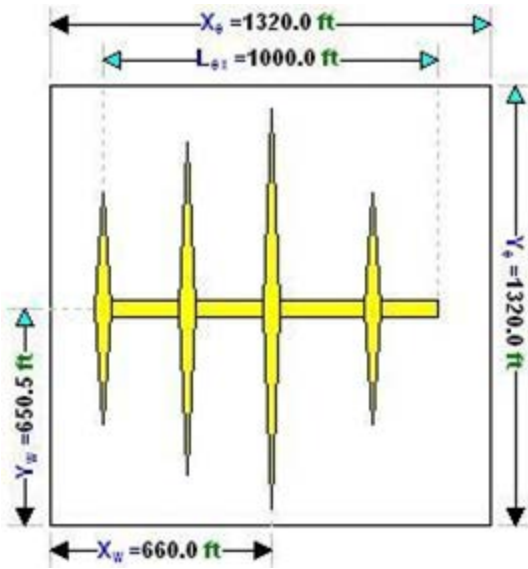
Decline analysis theory

Conceptual definition: decline analysis

Decline analysis is a reservoir engineering empirical technique that extrapolates trends in the production data from oil and gas wells. The purpose of a decline analysis is to generate a forecast of future production rates, and to determine the expected ultimate recoverable (EUR) reserves.

Figure 1: Rate versus cumulative gas production
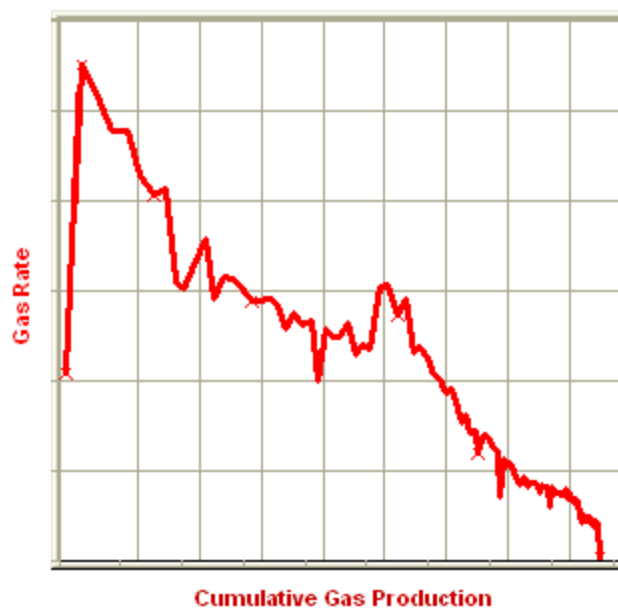
Typically, a decline analysis is conducted on a plot of rate versus time, or rate versus cumulative production (as shown in the figure above). The most commonly used trending equations are those first documented by J.J. Arps (1945). The following figure demonstrates a match trend and extrapolation to the EUR.

Figure 2: Rate versus cumulative gas production
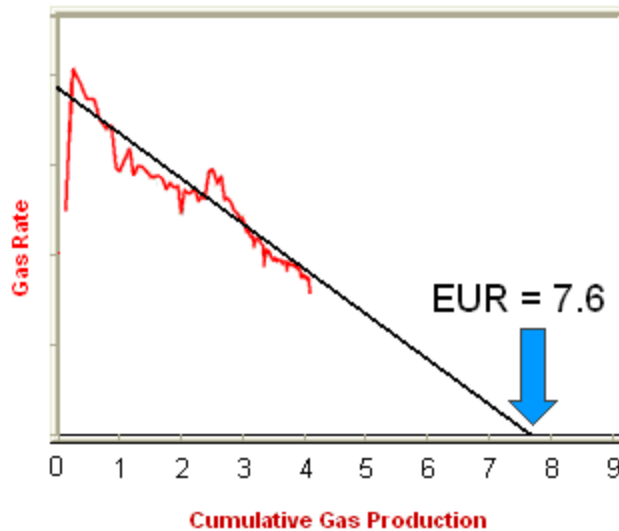
Historical background

J.J. Arps was an American geologist who published a mathematical relationship for the rate at which oil production from a single well declines over time (1945). His paper made several references to existing methods and theory about decline analysis. References included Arnold and Anderson (1908), W.W. Cutler (1924), H.N. Marsh (1928), and R. E. Allen (1931).

Many contemporary published papers have tried to investigate or modify the Arps decline based on theoretical derivations. However, after 70 years, the original method is still widely in use.

Practical decline analysis: key points

All production can be characterized as having an initial transient flow period followed by a boundary-dominated-flow period. During the transient period, the reservoir pressure at the flow boundary remains constant at the initial reservoir pressure, and the flow boundary moves outward from the well through the reservoir. This portion of a well's flow is characterized by very high decline rates. When the flow boundary reaches an actual reservoir boundary, or meets with a flow boundary of another well, the reservoir pressure begins to decline, and the well enters the boundary-dominated- flow period. It is in this period that traditional decline methods (that is, Arps) can be used.

The transient flow period can last for time periods from several minutes to several years, depending upon permeability and the areal extent of the reservoir. For most conventional production, the transient flow period ends after a few days. Tighter reservoirs that have permeability in the 0.5 to 1.0 mD range can have transient periods that last several months. Reservoirs that have even lower permeabilities that require extensive fracture networks can have transient periods that could last for several years.

Once a well has achieved boundary-dominated flow, another important consideration is the sandface flowing pressure. For the period of production included in the decline analysis, the sandface flowing pressure must be relatively constant before a reliable set of decline parameters can be extracted. Factors that affect sandface flowing pressure are rate-controlled wells, changing wellhead backpressure, changing wellbore configurations, and liquid loading.

Decline theory

The theory of all decline curve analysis begins with the concept of the nominal (instantaneous) decline rate (a), which is defined as the fractional change in rate per unit time:

$$a = \frac{(\Delta q / q)}{\Lambda t} = \frac{1}{q} \frac{\Delta q}{\Delta q}$$

Another way of representing the decline rate is based on rate (q), and the decline exponent constant, b.

$$a = kq^b$$

When production is plotted as flow rate vs. time, the nominal decline rate is equal to the slope at a point in time divided by the rate at that point.

Figure 3
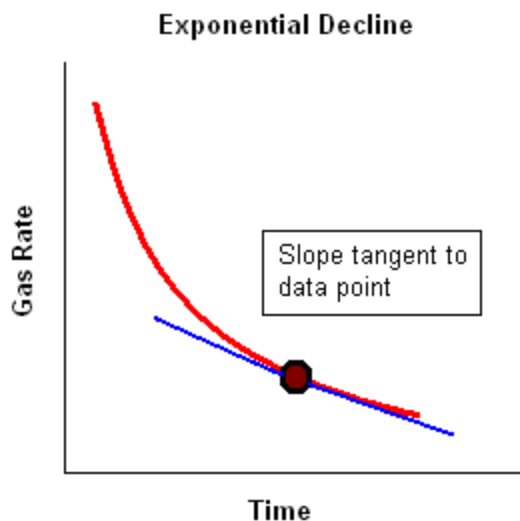
The behavior of the production data can be characterized based on the way in which the nominal decline rate varies with rate, based on the value of the decline exponent constant b.

- **Exponential** — b = 0

- **Hyperbolic** — b is a value other than 0 or 1

- **Harmonic** — b = 1

Exponential

For the exponential case, b = zero. The decline rate can be shown as:

$$a = kq^o$$

Where k is a constant equal to a / q^b at initial conditions:

$$k = \frac{a_i}{a_i{}^o} = a_i = a$$

As the decline rate remains constant, the integration of the equation for decline rate results in:

$$a = kq^b = -\frac{1}{q}\frac{dq}{dt}$$

$$\int_0^t a\,dt = \int_{q_i}^q -\frac{dq}{q}$$

$$-at = \ln\frac{q}{q_i}$$

$$q = q_i e^{(-at)}$$

Therefore, a plot of flow rate vs. time, with rate set to a logarithmic axis, results in a straight line.

The cumulative production is defined as:

$$Q = \int_o^t q\,dt$$

$$Q = \int_o^t q_i e^{(-at)}\,dt$$

$$Q = \frac{q_i - q_i \; e^{(-at)}}{a}$$

$$Q = \frac{q_i - q}{a}$$

Therefore, a plot of flow rate vs. cumulative production results in a straight line.

Hyperbolic

For the hyperbolic case, b is equal to any number between zero and one. The decline rate can be shown as:

$$a = kq^b$$

$$a \; \alpha \; q^b$$

Where k is a constant equal to a / q^b at initial conditions:

$$k = \frac{a_i}{q_i^b}$$

As the decline rate is not constant, the substitution and integration of the equation for decline rate results in:

$$a = kq^b = -\frac{1}{q} \frac{dq}{dt}$$

Substituting

$$k = \frac{a_i}{q_i^b} :$$

$$a = \frac{a_i}{k_i} q^1 = -\frac{1}{q} \frac{dq}{dt}$$

$$\int_0^t \frac{a_i}{q_i} \, dt \;=\; \int_{q_i}^q \;-\; \frac{dq}{q^2}$$

$$\int_0^t \frac{a_i}{q_i} \, dt \;=\; \int_{q_i}^q \;-\; \frac{dq}{q^{(b+1)}}$$

$$\frac{a_i}{q_i^b} t \;=\; \frac{1}{b}\left(q^{-b} - q_i^{-b} \right)$$

$$q \;=\; \frac{q_i}{(1 + ba_i t)^{\left(\frac{1}{b}\right)}}$$

The cumulative production is defined as:

$$Q \;=\; \int_o^t q \, dt$$

$$Q \;=\; \int_o^t \frac{q_i}{(1 + ba_i t)^{\left(\frac{1}{b}\right)}} \, dt$$

$$Q \;=\; \frac{q_i}{a_i(1-b)} \left[1 - (1 + ba_i t)^{\left(1 - \frac{1}{b}\right)} \right]$$

Substituting

$$\left(\frac{q_i}{q}\right)^b = \left(1 + b\,a_i\,t\right):$$

$$Q \;=\; \frac{q_i}{a_i(1-b)} \left[1 - \left(\frac{q_i}{q}\right)^{(b-1)} \right]$$

$$Q = \frac{q_i^b}{a_i(1-b)} \left(q_i^{(1-b)} - q^{(1-b)} \right)$$

Note that neither a plot of flow rate vs. time nor flow rate vs. cumulative production results in a linear relation (regardless of whether rate is set to a Cartesian or logarithmic axis).

Harmonic

The harmonic case is a special case of the above hyperbolic case, where b is equal to one. The decline rate can be shown as:

$$a = kq^1$$

Where k is a constant equal to a / q^b at initial conditions:

$$k = \frac{a_i}{q_i^{(1)}} = \frac{a_i}{q_i}$$

As the decline rate is not constant, the substitution and integration of the equation for decline rate results in:

$$a = kq^b = -\frac{1}{q}\frac{dq}{dt}$$

Substituting

$$k = \frac{a_i}{q_i} :$$

$$a = \frac{a_i}{q_i}q^{(1)} = -\frac{1}{q}\frac{dq}{dt}$$

$$\int_0^t \frac{a_i}{q_i} dt = \int_{q_i}^q -\frac{dq}{q^2}$$

$$\frac{a_i}{q_i} t = -\left[\left(-\frac{1}{q}\right) - \left(-\frac{1}{q_i}\right)\right]$$

$$q = \frac{q_i}{(1 + a_i t)}$$

The cumulative production is defined as:

$$Q = \int_o^t q\, dt$$

$$Q = \int_o^t \frac{q_i}{(1 + a_i t)}\, dt$$

Substituting

$$\frac{q_i}{q} = \left(1 + a_i t\right):$$

$$Q = \frac{q_i}{a_i} \ln\left(\frac{q_i}{q}\right)$$

Note that a plot of flow rate vs. time does not result in a linear relation (regardless of whether rate is set to a Cartesian or logarithmic axis). A plot of flow rate vs. cumulative production, with rate set to a logarithmic axis, results in a straight line.

Exponential decline rate: nominal vs. effective

When production follows an exponential decline, there are two different ways of defining the decline rate: nominal and effective.

The first is the nominal decline rate, represented by the symbol "a". The nominal decline rate is defined as:

$$a = \frac{\ln\left(\frac{q_1}{q_2}\right)}{t_2 - t_1} = \frac{\ln\left(\frac{q_1}{q}\right)}{t}$$

The nominal decline rate is used to calculate the rate decline at a specific time. For a given time, the equation for rate using nominal decline is:

$$q_2 = q_1 e^{(-a(t_2 - t_1))}$$

$$q = q_1 e^{(-a\ t)}$$

The second is the effective decline rate, represented by the symbol "d". The effective decline rate, for a particular time period (typically one year), is defined as:

$$d = \frac{(q_1 - q_2)}{q_1} = \frac{(q_i - q)}{q_i}$$

The effective decline rate is used to calculate the rate decline for particular time periods. For one timestep, the equation for rate using effective decline is:

$$q_2 = q_1 (1 - d)$$

$$q = q_i (1 - d)$$

Note that the time interval is included in the equation for rate using effective decline, but is explicitly stated in the equation for rate using nominal decline.

Although the equations for nominal and effective decline rates are different from one another, there is a relationship that gives the same answer for q_2 provided the time intervals between q_1 and q_2 are the same. The relationship between the two is given by:

$$a = -\ln(1 - d)$$

Note: The above equation is only valid for the exponential equations.

The difference between the two decline rates is shown below. In effect, the nominal decline rate is related to the instantaneous slope of the line, whereas the effective decline rate derives from the chord segment approximating that slope. Also, the rate by which the slope is divided is different – instantaneous rate (q) is used in the case of nominal decline, whereas the preceding rate (q_1) is used in the case of effective decline.

Figure 4: Comparison of Nominal Decline and Effective Decline
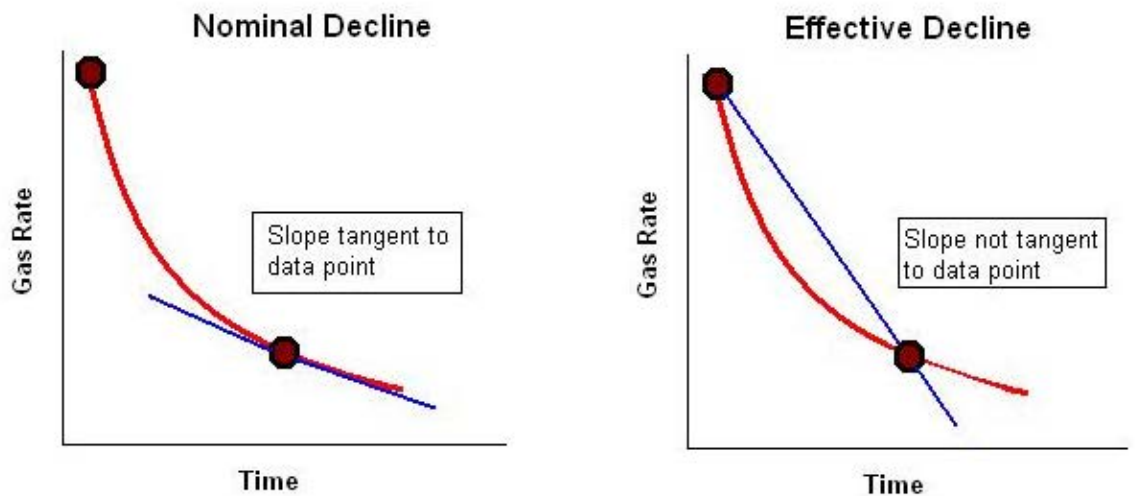
The effective decline rate typically arises when dealing with flow-rate data in tabular rather than graphical format. The difference between the nominal and effective decline rates is very small when the nominal decline rate is small, but as the nominal decline rate gets larger, the difference between the two increases. Therefore, it is important to use these values correctly.

Modified hyperbolic decline

Extrapolation of hyperbolic declines over long periods of time frequently results in unrealistically high reserves. To avoid this problem, it has been suggested that at some point in time the hyperbolic decline be converted into an exponential decline (Robertson). Thus, assume that for a particular example, the decline rate starts at 30% and decreases through time in a hyperbolic manner. When it reaches a specified value, 10% for example, the hyperbolic decline can be converted to an exponential decline, and the forecast continued using the exponential decline rate of 10%.

Limited decline rate

The limited decline rate begins as a hyperbolic decline curve and transitions into an exponential decline curve at a specified limiting effective decline rate, d_{lim}. The limiting effective decline rate is converted to a limiting nominal decline rate, a_{lim}, and the following rate – time equations are applied in the analysis:

$$At\ d > d_{\lim}:\ q = \frac{q_i}{(1+ba_it)^{\left(\frac{1}{b}\right)}}$$

$$At\ d \leq d_{\lim}:\ q = q_{\lim}e^{(-a_{\lim}(t-t_{\lim}))}$$

where:

$$q_{\lim} = q_i\left(\frac{a_{\lim}}{a_i}\right)^{\left(\frac{1}{b}\right)}$$

$$t_{\lim} = \frac{\left(\frac{q_i}{q_{\lim}}\right)^b - 1}{b\ a_i}$$

The limited decline rate can also be expressed as rate – cumulative production using the following equations.

For b > 1:

$$At\ d > d_{\lim}:\ Q = \frac{q_i{}^b}{a_i(1-b)}\left(q_i^{(1-b)} - q^{(1-b)}\right)$$

$$At\ d \leq d_{\lim}:\ Q = \frac{q_i^b}{a_i(1-b)}\left(q_i^{(1-b)} - q_{\lim}^{(1-b)}\right) + \frac{q_{\lim}-q}{a_{\lim}}$$

For b = 1:

$$At\ d > d_{\lim}:\ Q = \frac{q_i}{a_i}\ln\left(\frac{q_i}{q}\right)$$

$$At\ d \leq d_{\lim}:\ Q = \frac{q_i}{a_i}\ln\left(\frac{q_i}{q_{\lim}}\right) + \frac{q_{\lim}-q}{a_{\lim}}$$

Values of b > 1

$$q = \frac{q_i}{(1 + b\, a_i\, \Lambda\, t)^{\left(\frac{1}{b}\right)}}$$

A value of b = 0 corresponds to exponential decline; values of b >0 and < 1 correspond to hyperbolic decline; and a value of b = 1 corresponds to harmonic decline. Values of b >1 are not consistent with decline curve theory, but they are sometimes encountered, and their meaning is explained below.

Decline curve analysis is based on empirical observations of production rate decline, and not on theoretical derivations. Attempts to explain the observed behavior using the theory of flow in porous media led to the fact that these empirically observed declines are related to boundary-dominated flow. When a well is placed on production, there is transient flow initially. Eventually, all of the reservoir boundaries are felt, and it is only after this time that decline curve analysis becomes applicable. During boundary-dominated flow, the value of "b" lies in the range of 0 to 1, depending on the reservoir boundary conditions and the recovery mechanism.

Occasionally, decline curves with values of b > 1 are encountered. Below are some reasons that have been presented to explain this:

- The interpretation is wrong, and another value of b < 1 fits the data.

- The data is still in transient flow and has not reached boundary-dominated flow.

- Gentry and McCray (1978), using numerical simulation showed that reservoir layering can cause values of b > 1.

- Bailey (1982) showed that some fractured gas wells exhibit values of b > 1, sometimes as high as 3.5.

Arps production decline equation summary

Type	Exponential Decline	Hyperbolic Decline	Harmonic Decline
	Decline is constant b=0	Decline is proportional to a fractional power (b) of the production rate 0 < b< 1	Decline is proportional to production rate b = 1
$d_i \rightarrow a_i$	$a_i = -\ln(1 - d_i)$	$a_i = \frac{1}{b}\left[\left(1 - d_i\right)^{-b} - 1\right]$	$a_i = \frac{d_i}{1 - d_i}$
$a_i \rightarrow d_i$	$d_i = 1 - e^{-a_i}$	$d_i = 1 - \left(1 + b a_i\right)^{-\frac{1}{b}}$	$d_i = \frac{a_i}{1 + a_i}$
a(t)	$a = a_i$	$a = a_i\left(1 + b a_i \Delta t\right)^{-1}$	$a = a_i\left(1 + a_i \Delta t\right)^{-1}$

Type	Exponential Decline	Hyperbolic Decline	Harmonic Decline
Rate-Time	$q = q_i e^{(-a\Delta t)}$	$q = \dfrac{q_i}{(1+ba_i\Delta t)^{\left(\frac{1}{b}\right)}}$	$q = \dfrac{q_i}{(1+a_i\Delta t)}$
Rate-Cumulative	$Q = \dfrac{q_i - q}{a}$ $q = q_i - Qa$	$Q = \dfrac{q_i^b}{a_i(1-b)}\left(q_i^{(1-b)} - q^{(1-b)}\right)$ $q^{(1-b)} = q_i^{(1-b)} - \dfrac{Qa_i(1-b)}{q_i^b}$	$Q = \dfrac{q_i}{a_i}\ln\left(\dfrac{q_i}{q}\right)$ $q = q_i e^{\left(\frac{-Qa_i}{q_i}\right)}$
EUR	$Q_f = Q_i + \left[\dfrac{q_i - q_f}{a}\right]$	$Q_f = Q_i + \left[\dfrac{q_i^b}{a_i(1-b)}\left(q_i^{(1-b)} - Q_f^{(1-b)}\right)\right]$	$Q_i + \left[\dfrac{q_i}{a_i}\ln\left(\dfrac{q_i}{q_f}\right)\right]$

Goodness of fit

Whenever the decline curve is created to approximate production data, you may want a quantitative way to evaluate how good the fit is. There are various metrics that can be used to estimate goodness of fit. In Harmony Enterprise, R^2 is reported (this statistic is also known as the coefficient of determination).

R^2 is calculated using the following equations:

For decline curves created on the q vs t plot:

$$R^2_{\log\ q\ vs.\ t} = 1 - \frac{\sum_i \left(\log\ q_{i,p} - \log\ q_{i,c}\right)^2}{\sum_i \left(\log q_{i,p} - \overline{\log q}\right)^2}$$

For decline curves created on the q vs Cum plot:

$$R^2_{q\ vs.\ Q} = 1 - \frac{\sum_i \left(q_{i,p} - q_{i,c}\right)^2}{\sum_i \left(q_{i,p} - \bar{q}\right)^2}$$

where:

- i: is the index of summation, and summation is done for all data points after the analysis start date

- $q_{i,p}$: is the *i*-th rate (based on given production data)

- $q_{i,c}$: is the *i*-th rate (based on decline-curve approximation)

- $\bar{q}$: is the average for all rates $q_{i,p}$ used in calculations

- $\overline{\log\ q}$: is the average for all $\log\ q_{i,p}$ used in calculations

Note: The closer R^2 is to 1, the better the fit.

Flowing material balance (FMB) theory

The determination of reserves is a fundamental calculation in reservoir engineering. The material balance method uses actual reservoir performance data, and therefore is generally accepted as the most accurate procedure for estimating original hydrocarbons-in-place. In order to generate a traditional material balance plot, the well is shut in at several points during its producing life to obtain the average reservoir pressure. However, this is sometimes impractical, and usually the duration of the shut-in is often not long enough to obtain an accurate measurement. A FMB uses the concept of boundary-dominated flow or pseudo-steady state flow, as well as flowing pressures and rates, to calculate original hydrocarbons-in-place.

Pseudo-steady state

The flow of hydrocarbons through a porous medium can be divided into transient and boundary-dominated flow periods. When a well has reached boundary-dominated flow, its behavior is governed by the pseudo-steady state equations. When a reservoir is in pseudo-steady state flow and the flow rate is constant, the pressure at all locations in the reservoir declines at the same rate. The figure below depicts pressures in the reservoir at all locations when the wellbore is located at the left, and the exterior boundary of the reservoir is located at the right. Each of the lines, one, two, and three, represents the pseudo-steady state pressure in the reservoir when the well is flowing at a constant rate. The pressure decline from "time one" to "time two" is the same throughout the reservoir as the curves are parallel.
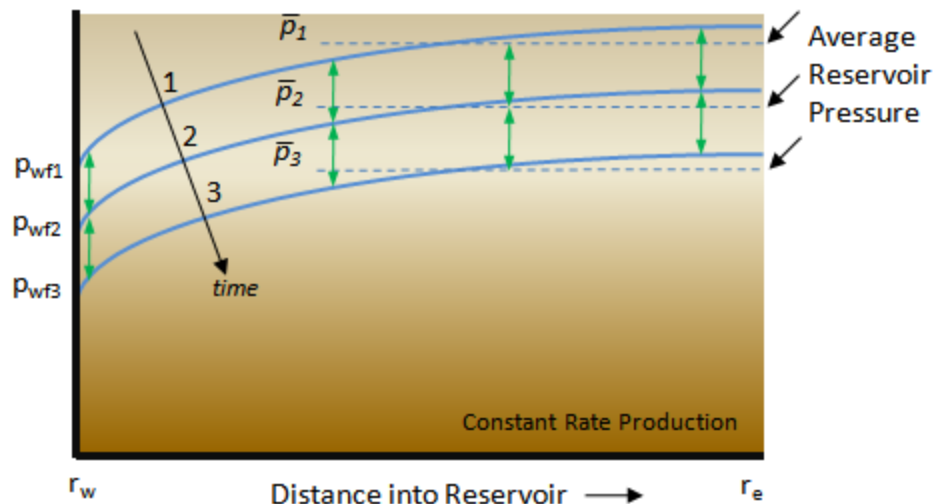
The traditional material balance method shuts in the well several times during the productive life of the reservoir, and lets the pressure stabilize to an average pressure p_1. Similarly, the pressure profile in the reservoir at later times would result in shut-in average reservoir pressures of p_2 and p_3. It is evident that the drop in pressure from p_1 to p_2 to p_3 is the same as the drop in pressure at any selected point along curves one, two, or three. A convenient point for analysis could be at the wellbore. Remembering that curves one, two, and three represent a flowing well, it is evident that a plot of the flowing wellbore pressure (p_{wf1}, p_{wf2}, p_{wf3}) should be parallel to a plot of the average reservoir pressure (p_1, p_2, p_3).

In a flowing situation, the average reservoir pressure clearly cannot be measured. However, as demonstrated above, in a stabilized-flow situation, there is very close connectivity between well-flowing pressures, which can be measured, and the average reservoir pressure. The pressure drop measured at the wellbore while the well is flowing at a *constant* rate is the same as the pressure drop that is observed anywhere in the reservoir, including the location that represents average reservoir pressure. This is *only* true if pseudo-steady state conditions are present, meaning that all boundaries have been reached, and the rate of withdrawal is constant for the period of time when p_{wf1} through p_{wf3} were measured.

Gas

For gas reserves, the material balance p/z plot is a very useful tool for estimating original gas-in-place (OGIP). The conventional p/z plot uses the extrapolated straight-line trend of measured shut-in pressures to predict OGIP. The same can be done with flowing pressures, provided that the pseudo-steady state assumption is valid (that is, constant rate boundary-dominated flow). For gas, the pseudo-steady state equation for a vertical well in the center of a circular reservoir is as follows:

$$\Delta p_p \; = \; p_{pi} \; - \; p_{pwf} \; = \; \frac{2qp_i t_a}{(\mu c_t Z)_i G_i} \; + \; \frac{1.147 \cdot 10^6 T}{k\, h} \left[\ln\left(\frac{r_e}{r_{wa}}\right) - \frac{3}{4} \right]$$

Furthermore, the pressure decline illustration above shows that a material balance plot of flowing wellbore pressures should be parallel to the material balance plot using the average static reservoir pressure. This procedure, shown below, consists of a plot of p_{wf} / Z, where p_{wf} is the flowing sandface pressure at the wellbore vs. cumulative production. A straight line drawn through the flowing sandface pressure data and then extrapolated parallel from the initial reservoir pressure gives the OGIP.

Basically this means that the slope of the resulting best-fit line should be the same as the slope of the conventional p/z line, but shifted upwards, so that it falls through the initial p/z point. This is the flowing gas material balance. Therefore, using flowing pressures and rates, a material balance analysis can be conducted without shutting in the well.
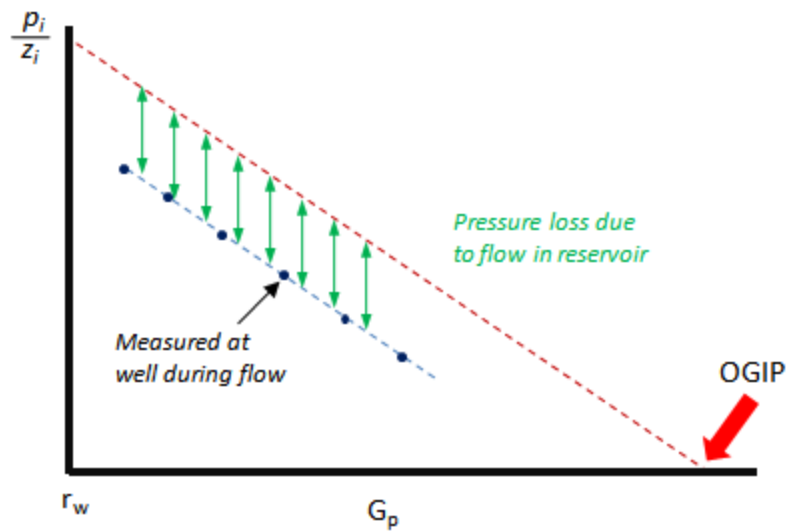
This technique can use either flowing sandface pressures or flowing surface pressures. However, when using surface pressures, the line drawn parallel to the data must pass through the initial "well-head" pressure, not the initial "reservoir" pressure.

Variable rate flowing p/Z**

Most gas wells do not have extended periods of constant-rate production. Thus the above concepts cannot be directly applied. A typical gas well may have a production profile as shown below.
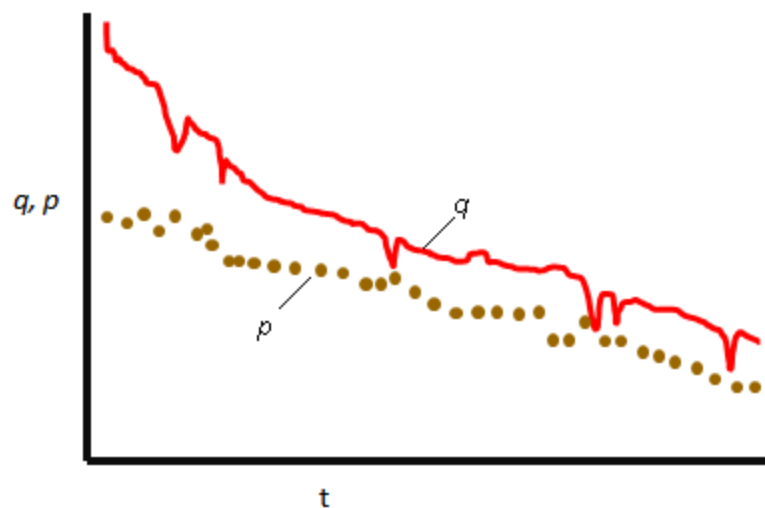
With the above profile, we cannot assume a constant pressure difference between average reservoir conditions and flowing conditions. We know that during boundary-dominated flow:

$$\overline{P}_p = p_{pwf} + qb_{pss}$$

where:

$$b_{pss} = \frac{1.147 \cdot 10^6 T}{k\,h} \left[\ln\left(\frac{r_e}{r_{wa}}\right) - \frac{3}{4}\right]$$

b_{pss} represents the pressure loss due to the steady-state inflow of gas, and is assumed to be constant over time.

For a variable-rate system, the equation above clearly shows that the difference between reservoir p/z and flowing p/z is not constant, but rather is a function of flow rate. Since the flow rate is known, we need only to determine the value of b_{pss}, using some independent method. Note that the value of b_{pss} did not have to be explicitly determined for the constant rate case because the total value of "$q\ b_{pss}$" (the product of flow rate and b_{pss}) was determined graphically.

One way to obtain a reliable estimate of b_{pss} is to plot the production and flowing-pressure data in the following manner:
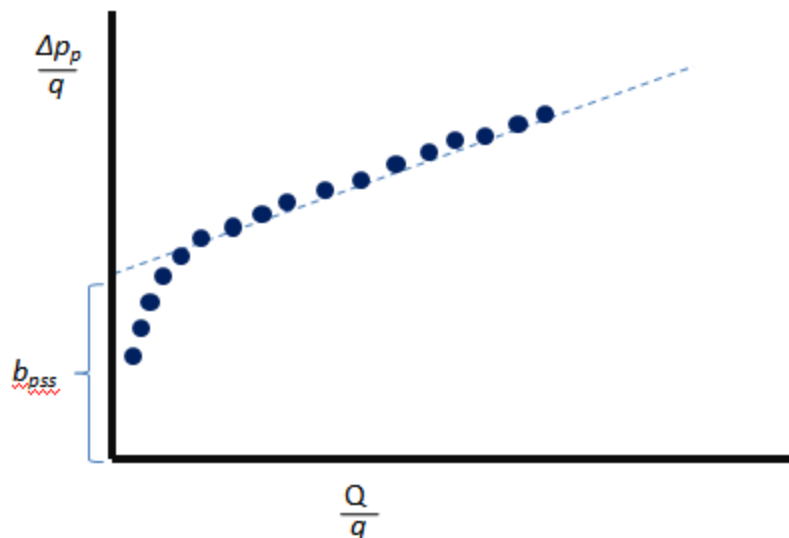
The straight line portion of this graph represents boundary-dominated flow, and the y-intercept is b_{pss}. This value of b_{pss} may then be used in the above equation to calculate the average reservoir pressure. Note that the value of b_{pss} is always subject to interpretation as it depends on proper identification of the stabilized (straight line) section of the above graph.

Alternatively, b_{pss} can be obtained from the Agarwal-Gardner FMB analysis plot. As shown below, $1/b_{pss}$ is the y-intercept on that plot. Obtaining the value from the best-fit straight line interpretation below, the flowing p/z** values can be calculated.
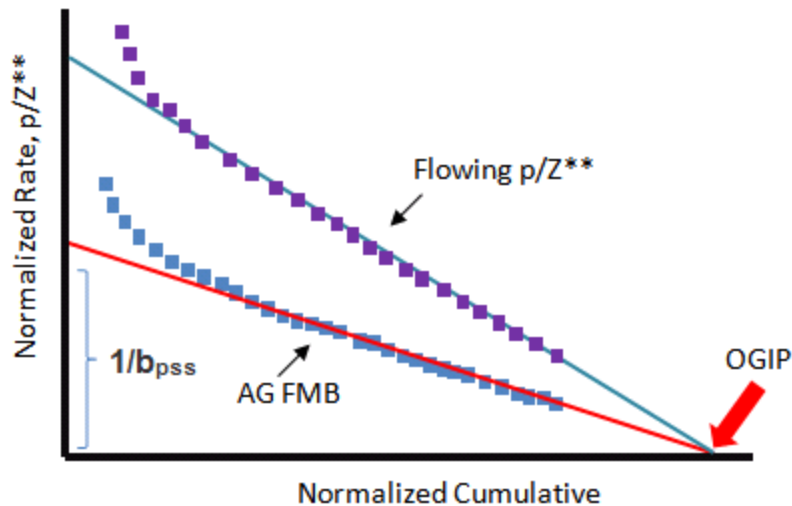
Agarwal-Gardner normalized rate

An alternative to the flowing p/z plot is the normalized rate / normalized cumulative analysis. The normalized rate approach applies to both oil and gas reservoirs, and works for constant, or variable-rate systems. Its advantage is its flexibility and ease of use. Its primary drawback is that the resulting analysis plot is not as intuitive as that of the flowing p/z.

The procedure is similar to the pseudo-steady state approach, but involves plotting the inverse of the pseudo-steady state equation, so that a declining trend is produced. The normalized rate is plotted against the normalized cumulative. A line is then drawn through the best-fit of the points, and the x-intercept is the OGIP. The governing equation for the straight-line equation for the Agarwal-Gardner analysis is:

$$\frac{q}{\Delta p_p} = \frac{-1}{b_{pss}\, G_i} \frac{2\, qt_{ca}p_i}{(c_t\mu Z)_i\, (p_{pi} - p_{pwf})} + \frac{1}{b_{pss}}$$

where:

$$Q_m = \frac{G\,(p_{pi} - \bar{p}_p)}{(p_{pi} - p_{wf})} = \frac{2qt_{ca}p_i}{(c_t\mu Z)_i\,(p_{pi} - p_{pwf})}$$

$$Normalized\ Rate\ =\ \frac{q_g}{p_{pi} - p_{pwf}}$$

and:

$$Normalized\ Cumulative\ =\ \left(\frac{p_{pi} - \bar{p}_p}{p_{pi} - p_{pwf}}\right) G$$

To calculate the average reservoir pressures, use the general material balance equation below, and first assume a value for OGIP. This is an estimate and can be obtained from volumetrics, modeling, or some other analysis.

$$\frac{P}{Z^{**}} = \frac{p_i}{Z_i^{**}}\left(1 - \frac{G_p}{G}\right)$$

The step-by-step procedure for generating the Agarwal-Gardner analysis for a gas well with varying flow rate is:

1. Convert initial pressure to pseudo-pressure.

2. Convert all flowing pressures to pseudo-pressures.

3. Assume a value for OGIP.

4. Calculate p/z** from the general material balance equations.

5. Using lookup tables, find the corresponding average reservoir pressure.

6. Convert average reservoir pressure to pseudo-pressure.

7. Using the equations above, plot a graph of normalized rate versus normalized cumulative.

8. Draw a straight line through the best-fit of the data points. (The intercept on the x-axis gives OGIP.)

9. Using this new value for OGIP, repeat steps 4-8 until the OGIP converges.

Productivity index

The productivity index of a well is a measure of the production rate achievable under a given drawdown pressure, which is the difference between the average reservoir pressure and the flowing sandface

pressure. Defined as the flow rate per unit pressure drop, the productivity index gives an indication of the production potential of a well.

$$PI = \frac{1}{b_{pss}}$$

From the pss equation above:

$$\bar{p}_p = p_{pwf} + q\,b_{pss}$$

therefore:

$$PI = \frac{q_g}{\bar{p}_p - p_{pwf}}$$

From a reservoir point of view, well management primarily depends on the well productivity index, which is in turn dependent on rock and fluid properties. One of the principal causes for the reduction in well productivity is formation damage around the wellbore. For an FMB analysis, when the "correct" OGIP is found, the productivity index dataset should be relatively flat, indicating that the productivity index is not drastically changing over time.
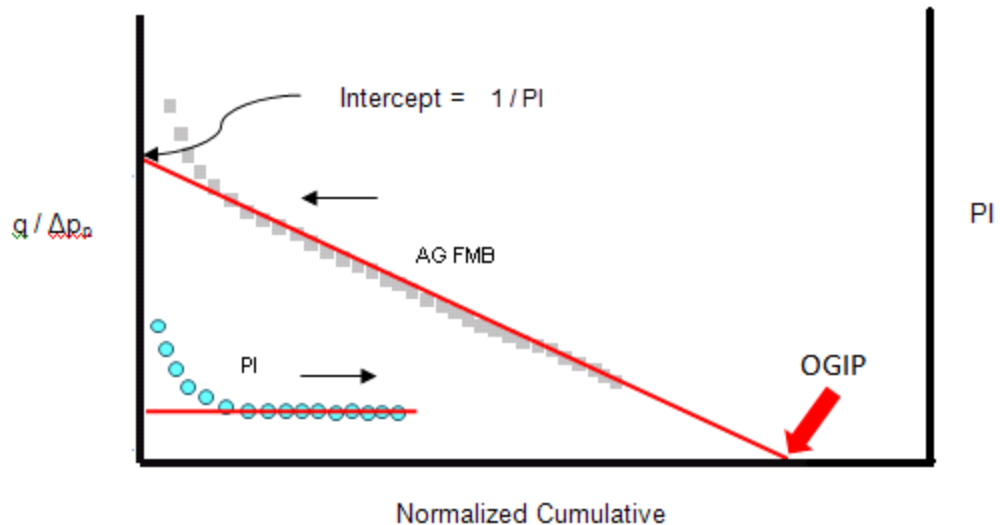
As can be seen above, the productivity index equation is very similar to the traditionally used simplified absolute open flow (AOF) equation, shown below. The major differences being that:

- The productivity index is written rigorously using pseudo-pressures and the AOF equation uses the simpler pressure-squared method.

- The AOF equation introduces the concept of laminar / turbulent flow using the exponent "n".

$$q = c\left(\bar{p}^2 - p_{wf}^2\right)^n$$

Assuming n = 1:

$$c = \frac{q_g}{\bar{p}^2 - p_{wf}^2}$$

Advanced gas material balance techniques – p/Z**

The graphical simplicity of the conventional p/Z material balance analysis makes it quite popular. Developed for a "volumetric" gas reservoir, it assumes a constant pore volume of gas, and accounts for the energy of gas expansion. However, advanced methods have been developed to account for other sources of energy, such as the effects of formation compressibility, residual fluids expansion, and aquifer support. Furthermore, these methods can also account for other sources of gas storage such as connected reservoirs, or adsorption in coal / shale. The FMB analysis accounts for all of these effects, if required. The formulation for the calculation of p/Z** is highlighted below:

$$\frac{P}{Z^{**}} = \frac{p_i}{Z_i^{**}} \left(1 - \frac{G_p}{G}\right)$$

where:

$$Z^{**} = \frac{p}{\left[\frac{1}{S_{gi}} \frac{p}{Z} \left(S_{gi} - c_{wip} - c_{ep} - c_d\right) + \frac{p_i}{Z_i}\left(\frac{G}{G_f} - 1\right)\right] \frac{G_f}{G}}$$

$$\frac{G}{G_f} = 1 + \frac{B_{gi}}{S_{gi}} \frac{\rho_B \left(1 - a - W_c\right)}{\phi} \frac{\left(V_L\, p_i\right)}{p_L\, p_i}$$

and total compressibility is defined as:

$$c_t = \left(c_g \left[S_{gi} - c_{wip} - c_{ep} - c_d \right] - \frac{\partial\ c_{wip}}{\partial\ p} - \frac{\partial\ c_{ep}}{\partial\ p} - \frac{\partial\ c_d}{\partial\ p} \right)$$

The table below outlines the formulations for the total-compressibility equations for all reservoir types.

Definition	Comment
$c_{wip} = \dfrac{5.615(W_e - W_p\,B_w)}{\frac{G_f B_{gi}}{S_{gi}}}$ $\dfrac{\partial\ c_{wip}}{\partial\ p} = \dfrac{5.615}{\frac{G_f B_{gi}}{S_{gi}}}\dfrac{\partial W_e}{\partial\ p}$	Water-drive reservoir
$c_{ep} = \left(c_f + c_w S_{wi} + c_o S_{oi} \right)\left(p_i - p \right) = c_e\left(p_i - p \right)$ $\dfrac{\partial\ c_{ep}}{\partial p} = -\left[c_f\left(1 - c_f\left(p_i - p\right)\right) + S_{wi}c_w\left(1 + c_w\left(p_i - p\right)\right) + S_{oi}c_o\left(1 + c_o\left(p_i - p\right)\right)\right]$	c_o, c_w, and c_f are constant c_{ep} is the approximate form
$c_{ep} = \left(1 - e^{-c_f\left(p_i - p\right)}\right) + S_{wi}\left(e^{c_w\left(p_i - p\right)} - 1\right) + S_{oi}\left(e^{c_o\left(p_i - p\right)} - 1\right)$ $\dfrac{\partial\ c_{ep}}{\partial p} = -\left[S_{oi}\,c_o e^{c_o\left(p_i - p\right)} + S_{wi}c_w e^{c_w\left(p_i - p\right)} + c_f e^{-c_f\left(p_i - p\right)}\right)$	c_o, c_w, and c_f are constant c_{ep} is the simple form
$c_{ep} = \left(1 - e^{-\int_p^{p_i} c_f d_p}\right) + S_{wi}\left(e^{\int_p^{p_i} c_w d_p} - 1\right) + S_{oi}\left(e^{\int_p^{p_i} c_o d_p} - 1\right)$ $\dfrac{\partial\ c_{ep}}{\partial p} = \left(c_f e^{-\int_p^{p_i} c_f dp} + S_{wi}c_w e^{\int_p^{p_i} c_w dp} + S_{oi}c_o e^{\int_p^{p_i} c_o dp}\right)$	c_o, c_w, and c_f are pressure-sensitive *without* matrix shrinkage. c_{ep} is the rigorous form
$c_{ep} = \left(1 - F_\phi\left(p\right)\right) + S_{wi}\left(e^{\int_p^{p_i} c_w dp} - 1\right) + S_{oi}\left(e^{\int_p^{p_i} c_o dp} - 1\right)$ $\dfrac{\partial\ c_{ep}}{\partial p} = \left(-\dfrac{d\,F_\partial\left(p\right)}{dp} + S_{wi}c_w e^{\int_p^{p_i} c_w dp} + S_{oi}c_o e^{\int_p^{p_i} c_o dp}\right)$	c_o, c_w, and c_f are pressure-sensitive with matrix shrinkage. c_{ep} is the

Definition	Comment
	rigorous form
$c_d = \frac{\rho_B B_g}{\phi}(1-a-m)\left(\frac{V_L p_i}{p_L+p_i} - \frac{V_L p}{p_L+p_i}\right)$ $\frac{\partial c_d}{\partial p} = \frac{\rho_B B_g V_L}{\phi}(1-a-m)\left[-c_g\left(\frac{p_i}{p_L+p_i} - \frac{p}{p_L+p}\right) + \left(-\frac{1}{p_L+p} + \frac{p}{(p_L+p)^2}\right)\right]$	Shale gas reservoir

Note: For more information, see Moghadam et al. (2009).

Oil

The basis for the FMB of oil comes from both the definition of compressibility and the steady-state inflow equation. Compressibility is defined as:

$$c = -\frac{1}{V}\frac{\partial V}{\partial p}$$

This equation shows that compressibility is defined as the relative change in fluid volume per unit change in pressure.
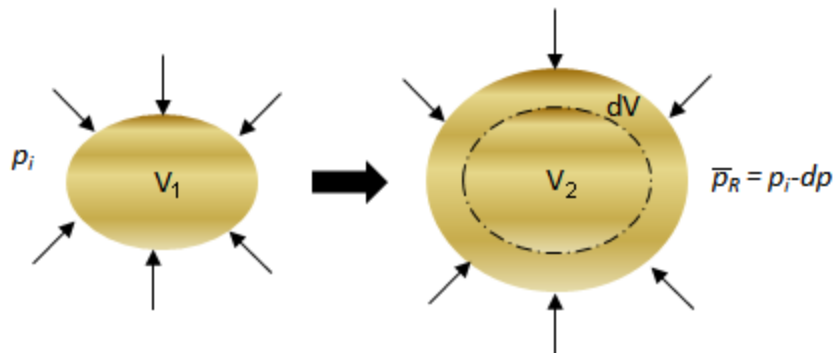
The above schematic demonstrates that as pressure is reduced, the fluid expands to occupy a larger volume such that $V_2 > V_1$. However, most reservoirs can reasonably be expected to have a constant pore volume such that $PV_1 = PV_2$. Consequently, as we produce fluid from a reservoir, the remaining fluid in the reservoir expands to fill the pore volume, and so the reservoir pressure is reduced.

Production from an undersaturated* oil reservoir can be visualized as follows:

Pore Volume:

Container Volume 1 (PV$_1$)　　=　　Container Volume 2 (PV$_2$)

Fluid Volume:

Fluid Volume 1 (N)　　=　　Fluid Volume 2 (Remaining N) + Extracted Volume (N$_p$)

Reservoir Pressure:

Initial Reservoir Pressure (p$_i$)　　=　　Current Reservoir Pressure ($\bar{p}_R$) + Depletion (N$_p$ / N * c)

* There is no free gas since the reservoir pressure is greater than the bubble-point pressure of the oil.

Thus, the change in pressure is the difference between the initial reservoir pressure and the average reservoir pressure, and the change in volume is the produced volume up to that point in time. Knowing that the initial volume is the total oil-in-place, these terms are applied to the compressibility equation.

$$c = \frac{1}{N} \frac{N_p}{(p_i - \bar{p}_R)}$$

Combining the above relationship with the pseudo-steady equation, and then rearranging and substituting for material balance time gives the following:

$$\frac{\Delta p}{q} = \frac{p_i - p_{wf}}{q} = \frac{B_o}{B_{oi}} \frac{S_o N_p}{q c_t N} + \frac{141.2 B_o N_p \mu}{k h} \left[\ln\left(\frac{r_e}{r_{wa}}\right) - \frac{3}{4} \right]$$

The above equation clearly illustrates the relationship between initial pressure, flowing pressure, and rate.
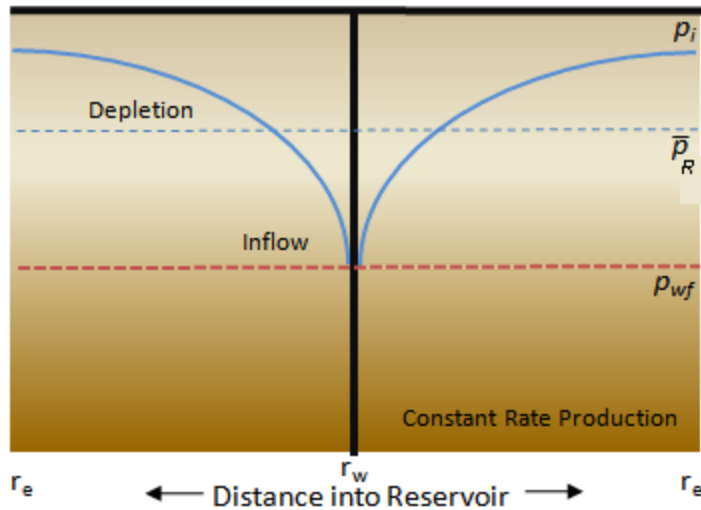
From the figure above, it is apparent that the pseudo-steady state equation is the sum of two distinct pressure-loss components:

Pressure loss due to depletion:

$$p_i - \overline{p}_R = \frac{B_o}{B_{oi}} \frac{S_o qt}{c_t N}$$

Pressure loss due to inflow:

$$\overline{p}_R - p_{wf} = \frac{141.2 \, B_o \, \mu \, q}{k \, h} \left[\ln \left(\frac{r_e}{r_{wa}} \right) - \frac{3}{4} \right]$$

The advantage of the pseudo-steady state formulation is that the average reservoir pressure is eliminated during the addition of pressure loss due to depletion and pressure loss due to inflow, and thus is not explicit in the equation. This is an obvious advantage because the average reservoir pressure is an unknown. Since both terms (pressure loss due to depletion and pressure loss due to inflow) are functions of rate, we can simplify the pseudo-steady state equation as follows:

$$\frac{\Delta p}{q} = \frac{B_o}{B_{oi}} \frac{S_o}{c_t N} t + b_{pss}$$

where:

$$b_{pss} = \frac{141.2 \, B_o \, \mu}{k \, h} \left[\ln \left(\frac{r_e}{r_{wa}} \right) - \frac{3}{4} \right]$$

A graph of normalized pressure vs. time produces a straight line, the slope of which provides the original oil-in-place (OOIP). This is the most basic form of FMB, and is directly applicable to undersaturated oil reservoirs. In well testing, this procedure is commonly referred to as a "reservoir limits test".
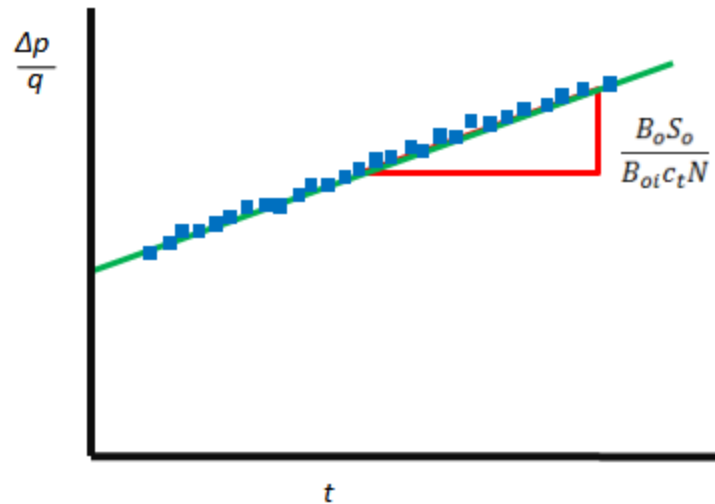
However, to make it more intuitive and similar to a gas material balance plot, the pseudo-steady state equation above is rearranged to the following:

$$\frac{q}{\Delta p} = \frac{1}{b_{pss}} - \frac{B_o \, S_o \, N_p}{B_{oi} \, c_t \, N \, \Delta p \, b_{pss}}$$

Plotting normalized rate vs. normalized cumulative (similar to the Agarwal-Gardner plot), the following plot is derived, where the x-intercept is equal to the OOIP.
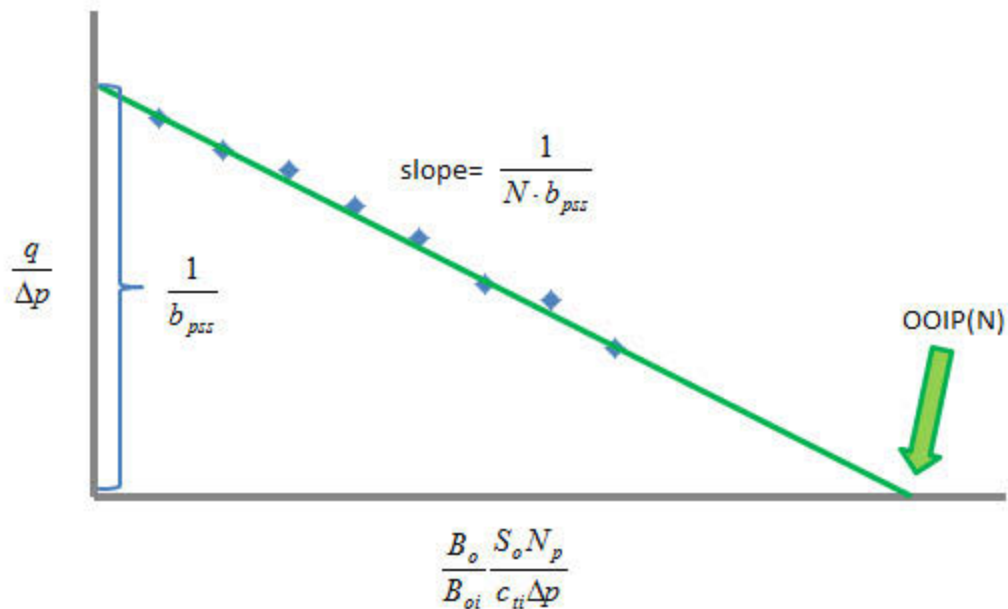
The above equation and associated figure describe the flowing oil material balance analysis for a volumetric circular reservoir.

Static pressure data

If static pressures are available, you can use this data as an independent confirmation of the OOIP. This is an equation describing material balance for an oil reservoir for a simple case (that is, no gas cap, no water production), assuming constant total compressibility:

$$N_p\, B_o = \frac{N}{S_o} \cdot B_{oi}\,(p_i - \bar{p}\,)^{c_{ti}}$$

This equation can be rearranged as:

$$\bar{p} = p_i - \frac{B_o}{B_{oi}} \cdot \frac{S_o\, N_p}{c_{ti}\, p_i} \cdot \frac{p_i}{N}$$

y-value   x-value

Therefore, plotting average pressure against

$$Adjusted\ Normalized\ Oil\ Cumulative\ Production = \frac{B_o}{B_{oi}} \frac{S_o N_p}{c_{ti} p_i}$$

should follow a straight line, with the x-intercept of the line being equal to the OOIP.

Accounting for variation in oil properties

The derivation for oil Flowing Material Balance (FMB) given above is valid under the assumption that the variation of oil and rock properties (c_t, B_o, μ_o, and k) with pressure is negligible. That assumption is valid for some cases, but sometimes (for example, 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.

This is done similarly to Agarwal-Gardner FMB analysis for gas.

Oil pseudo-pressure is defined as:

$$p_{po}(p) = \frac{B_o(p_i)\,\mu_o(p_i)}{k(p_i)} \int_0^p \frac{k(p)}{B_o(p)\,\mu_o(p)} dp$$

Total pseudo-pressure drop can then be written in terms of oil pseudo-pressure and can be presented as:

$$\Delta p_{po} = p_{po}(p_i) - p_{po}(p_{wf}) = (p_{po}(p_i) - p_{po}(\bar{p})) + (p_{po}(\bar{p}) - p_{po}(p_{wf}))$$
$$total \qquad\qquad\qquad = due\ to\ depletion \qquad + \quad due\ to\ Darcy\ flow$$

Under conditions of pseudo-steady state, the pressure drop due to Darcy flow and flow rate are related by:

$$q_o = Constant \cdot \int_{p_{wf}}^{\bar{p}} \frac{k(p)}{\mu_o(p)\,B_o(p)} dp$$

Where *Constant* is defined by reservoir and completion geometry, but does not change with pressure. Using rules of integration, this can be re-arranged as:

$$q_o = Constant \cdot \int_{p_{wf}}^{\bar{p}} \frac{k(p)}{\mu_o(p)\, B_o(p)} dp = Constant \cdot \left(\int_0^{\bar{p}} \frac{k(p)}{\mu_o(p)\, B_o(p)} dp - \int_0^{p_{wf}} \frac{k(p)}{\mu_o(p)\, B_o(p)} dp \right) =$$

$$= \left(Constant \cdot \frac{k(p_i)}{\mu_o(p_i)\, B_o(p_i)} \right) \left(p_{p_{po}}(\bar{p}) - p_{p_{po}}(p_{wf}) \right)$$

Therefore, pressure drop due to Darcy flow in terms of oil pseudo-pressure can be expressed as:

$$p_{po}(\bar{p}) - p_{po}(p_{wf}) = q_o \cdot b'_{pss}$$

Where b'_{pss} does not vary with pressure.

Using this formulation for pressure drop due to Darcy flow, total pressure drop can be presented as:

$$\Delta p_{po} = \left(p_{po}(p_i) - p_{po}(\bar{p}) \right) + q_o \cdot b'_{pss}$$

Dividing both sides by $\Delta p_{po}\, b'_{pss}$ and re-arranging we get:

$$\frac{q_o}{\Delta p_{po}} = \frac{1}{b'_{pss}} - \left(\frac{p_{po}(p_i) - p_{po}(\bar{p})}{\Delta p_{po}} N \right) \cdot \frac{1}{N\, b'_{pss}}$$

$$y\, value = intercept - x\, value \cdot slope$$

(Note that we added *N* to both the numerator and denominator of the last term.)

This equation is used to create a plot for oil FMB analysis that accounts for variation of oil and formation properties.

The *y*-values for each data point can be readily calculated based on production data:

$$Oil\ Normalized\ Rate = \frac{q_o}{\Delta p_{po}}$$

To calculate *x*-values, use an iterative procedure:

    1. Estimate a value for oil in place, N_{guess}.

2. Calculate the average reservoir pressure based on N_{guess}, known production data, and using rigorous material-balance calculations.

3. Calculate x-values:

$$Normalized\ Oil\ Cumulative\ Production\ =\ \frac{p_{po}(p_i)\ -\ p_{po}\ (\bar{p})}{\Delta p_{po}} N_{guess}$$

4. Generate an FMB plot (y-values vs. x-values).

5. Draw a straight line through the data points corresponding to boundary-dominated flow (the late portion of the data).

6. The y-intercept of the line equals $1/b'_{pss}$, and the slope of the line equals $1/(Nb'_{pss})$; therefore N can be calculated.

7. Compare the calculated N with N_{guess}. If they are not equal, set the next N_{guess} to the value calculated in step 6, and return to step 1.

8. Iterate until $N = N_{guess}$.

This approach is described by Stalgorova and Mattar (2016).

Multiphase flowing material balance (FMB) theory

There is significant research in the field of multiphase FMB, and rate-transient analysis in general, that is ongoing at the University of Calgary, under the direction of Dr. Chris Clarkson. This research has been supported by industry sponsors of the Clarkson-led Tight Oil Consortium, and by NSERC CRD grants held by Clarkson. This partial list of publications attests to the interest, effort, and success of his team in this field. All the methods have a certain number of assumptions and approximations, and are therefore not exact analytical solutions for all flow conditions. For example, they are not meant to be applicable to "transient flow", but they are intended for analyzing boundary-dominated flow. Our (IHS Markit) development of Multiphase FMB, implemented in Harmony Enterprise version 2018.1 builds on the work of Dr. Clarkson's team and extends it. Most of the studies define one two-phase pseudo-pressure for oil, and one for gas. Some define a total pseudo-pressure that combines all three phases.

There are two major components to the FMB methodology: defining an appropriate pseudo-pressure and an appropriate pseudo-time. Sometimes, as in the current implementation, pseudo-time is not visible explicitly, but is couched in expressions that combine the average pseudo-pressure and cumulative production.

Multiphase FMB parallels the single-phase methodology. In simple terms, single-phase FMB was derived for oil (in terms of pressure). Multiphase FMB uses the same format of equations, but replaces pressure by a pseudo-pressure that accounts for the variations in pressure, volume, and temperature (PVT) properties, saturation changes, relative permeability, and individual flowing phases.

As an introduction, a simplified version of the single-phase FMB formulation is presented below:

(Boundary-dominated flow) fundamental flow equation:

$$p_i - p_{wf} = \frac{qt}{c_t N} + \frac{141.2qB\mu}{kh}\left[(\ln \frac{r_e}{r_{wa}}) - \frac{3}{4}\right]$$

Can be simplified to:

$$p_i - p_{wf} = \frac{qt}{c_t N} + bq$$

$$p_i - p_{wf} = \frac{N_p}{c_t N} + bq$$

Rearranging — divide by b and by $(p_i - p_{wf})$:

$$\frac{q}{(p_i - p_{wf})} = -\frac{N_p}{bc_t N(p_i - p_{wf})} + \frac{1}{b}$$

Material balance equation:

$$p_i - \overline{p}_R = \frac{N_p}{c_t N}$$

Combining these two equations:

$$\frac{q}{(p_i - p_{wf})} = -\frac{(p_i - \overline{p}_R)}{b(p_i - p_{wf})} + \frac{1}{b}$$

Multiplying top and bottom by N:

$$\frac{q}{(p_i - p_{wf})} = -\frac{1}{bN}\left\{\frac{(p_i - \overline{p}_R)}{(p_i - p_{wf})}N\right\} + \frac{1}{b}$$

This is the **FMB equation** that is represented in the **Agarwal-Gardner (A-G) plot**: Plotting the **left-side** against {…} results in an **x-intercept** of **N** (original-oil-in-place), and a **y-intercept** of **1/b** (Productivity Index).

Multiphase FMB equation

The multiphase FMB analysis is structured in a format similar to the above equation, but pressure is replaced by an appropriately defined multiphase pseudo-pressure.

$$\frac{q}{(p_{pi} - p_{pwf})} = -\frac{1}{bN}\left\{\frac{(p_{pi} - \overline{P}_{pR})}{(p_{pi} - p_{pwf})} N\right\} + \frac{1}{b}$$

The discussion below is focused on oil as the flowing fluid of interest. The pseudo-pressure defined below is the "oil" pseudo-pressure. A parallel discussion, mutatis mutandis (after the necessary changes have been made), is relevant when gas is the primary fluid of interest.

The "oil" pseudo-pressure defined below accounts for:

    a. multiphase flow — oil, gas, and water, for both production and injection

    b. fluid property variations with pressure

    c. saturation changes in the reservoir caused by production or injection

    d. geomechanical effects, desorption, water influx.

Single phase Black Oil (constant PVT Properties)

$$\frac{q_o}{p_i - p_{wf}} = \frac{1}{b} - \frac{1}{bN}\frac{(p_i - \overline{p}_R)}{(p_i - p_{wf})} N$$

Equation 1

Convert Pressure (p) to Pseudopressure (p_p)

General Form of FMB

$$\frac{q_o}{p_{pi} - p_{pwf}} = \frac{1}{b} - \frac{1}{bN}\frac{(p_{pi} - \overline{p}_{pR})}{(p_{pi} - p_{pwf})} N$$

Equation 2

Definition of pseudopressure

$$p_{pi} - p_{pwf} = \int_{p_{wf}}^{p_i}\left(\frac{k k_{ro}}{\mu_o B_o} + R_v\frac{k k_{rg}}{\mu_g B_g}\right) dp$$

Equation 3

Multiphase Volatile Oil (variable PVT and Permeability)

$$p_{pi} - \overline{p}_{pR} = \int_{\overline{p}_R}^{p_i}\left(\frac{k k_{ro}}{\mu_o B_o} + R_v\frac{k k_{rg}}{\mu_g B_g}\right) dp$$

Equation 4

In evaluating the above equations, the following considerations apply:

i: k_{rg} and k_{ro} are functions of saturation (*not* pressure). In order to evaluate the pseudo-pressure integral, the k_{rg} and k_{ro} functions have to be expressed in terms of pressure (*not* saturation). Therefore, we need to have a relationship between saturation and pressure. However, saturations depend on production. Consequently, multiphase pseudo-pressure can only be evaluated *after* the production rates are known. This is in contrast to single-phase

pseudo-pressure, where the pseudo-pressure can be evaluated independently from production.

ii: At any point in time, the flow rates of gas, oil, water, and the flowing pressures are known from measurement. The average reservoir pressure is obtained from material balance equations.

iii: At any point in time, using the production data, the k_{rg} / k_{ro} ratios are determined from:

$$\frac{k_{rg}}{k_{ro}}(S_g, S_w) = \left(\frac{GOR - R_s}{1 - R_v GOR}\right)\frac{\mu_g B_g}{\mu_o B_o}$$

Equation 5

And the k_{rw} / k_{ro} ratios are obtained from:

$$\frac{k_{rw}}{k_{ro}}(S_g, S_w) = WOR\frac{\mu_w B_w}{\mu_o B_o}$$

Equation 6

iv: The relative permeability curves are reformulated in terms of k_{rg} / k_{ro} ratios versus saturations. The k_{rg} / k_{ro} ratios will be a single curve for two-phase (gas / oil) flow, but become a surface, when water production is included.

v: From the permeability ratios obtained from production data (*see step iii*) and the relative permeability curves (*see step iv*), the saturations are obtained for every point in time, and the corresponding pseudo-pressure is evaluated, using Equations 3 and 4.

vi: The calculation of pseudo-pressure involves the evaluation of an integral. In the literature, there are two ways of doing this: a) using the Sandface Integral, or b) using the Reservoir Integral. The more rigorous of the two is the Reservoir Integral, and that is what is used in the current implementation of Harmony Enterprise. It recognizes that the saturations change, not only through time, but also with location in the reservoir. This makes the pseudo-pressure calculations complex, cumbersome, and iterative. At every point in time, they consist of a step-

wise integration from p_{wf} to $\bar{p}_R$, and from $\bar{p}_R$ to p_i.

As a result, because analysis lines are dynamically calculating the pseudo-pressures, the line movement can be slow, when there is a large number of data points. Figure Int-1 and Int-2 below demonstrate that the Reservoir Integral is more effective in straightening out the multiphase data than the Sandface Integral.

Multiphase Pseudopressure- Sandface Integral	Multiphase Pseudopressure- Reservoir Integral
Figure Int-1	Figure Int-2
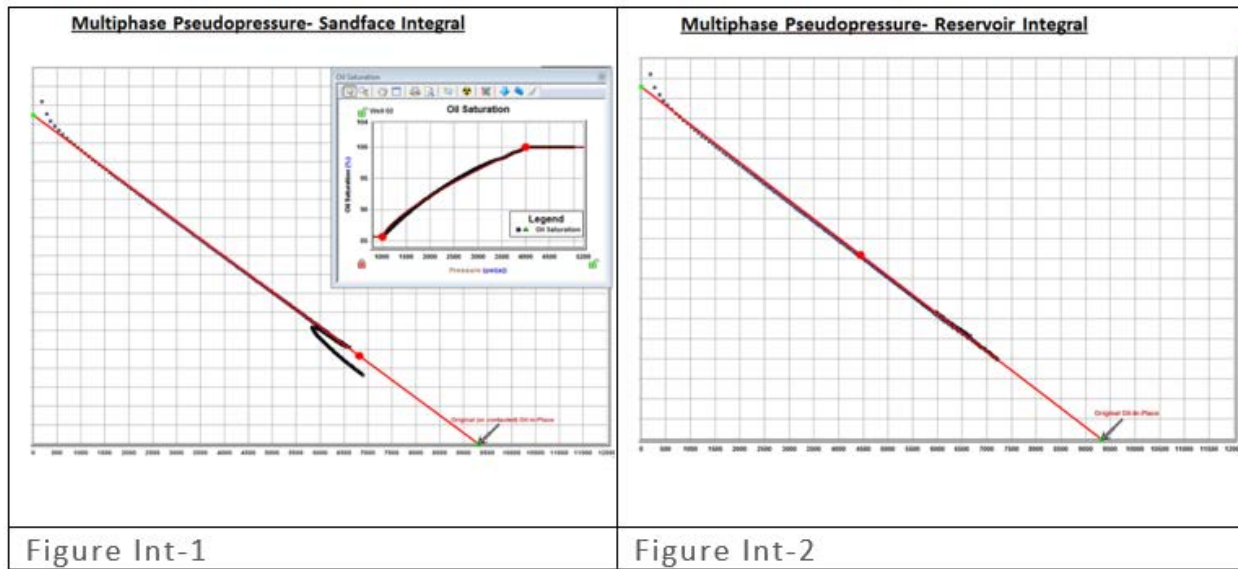
vii: On the basis of Equation 2, an FMB (A-G) analysis is created by plotting $\dfrac{q_o}{p_{pi}-p_{pwf}}$ versus $\dfrac{p_{pi}-\bar{p}_{pR}}{p_{pi}-p_{pwf}}\,N$.

Since the Oil-In-Place, N, is not known, the solution is iterative. The value of N is modified until the data forms a straight line. This is illustrated in Figure FMB-1 and FMB-2.

Figure FMB-1

Figure FMB-2
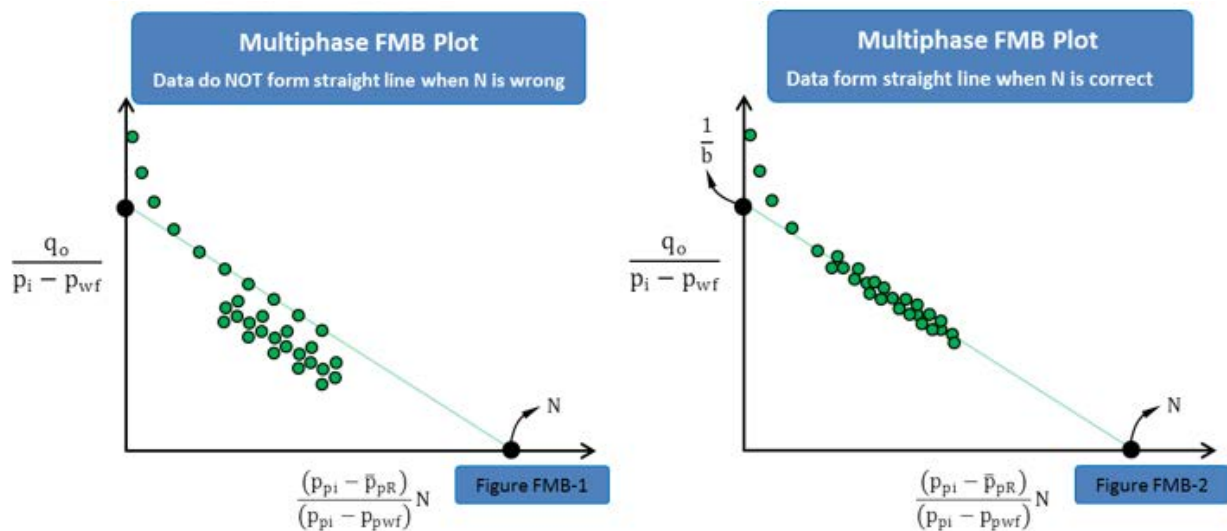
The x-intercept is the desired value of N. The y-intercept (1/b) is the (pseudo) Productivity Index, which is defined as:

$$\text{Productivity Index} = \frac{1}{b} = \frac{q_o}{\bar{p}_{pR} - p_{pwf}} \qquad \text{Equation 7}$$

viii: The productivity index varies during transient flow, but becomes constant during boundary-dominated flow. Because the pseudo-productivity index is defined in terms of pseudo-pressures, variations in saturation and relative permeabilities are accounted for (albeit in an approximate manner). As a result, the pseudo-productivity index becomes a constant (dependent only on reservoir shape, size, initial permeability, initial saturations, and well completion, which are all considered to be constant).

ix: For oil wells producing below the bubble point or producing water, the results of the multiphase FMB can be significantly different from a single-phase oil analysis.

x: For oil wells producing at a flowing pressure above the bubble point, the gas produced is purely solution gas, and flow in the reservoir is actually single phase. In this situation, the traditional single phase (using "pressure" for analysis) can yield the correct value of N at the beginning (when PVT properties are still relatively constant) — see Figure FMB-3a. When PVT properties change (while still in single-phase flow), a single-phase pseudo-pressure can be defined, and this straightens the data — see Figure FMB-3b. When pressures go below the bubble point, multiphase flow occurs and the multiphase pseudo-pressure defined above must be used to straighten the data, and obtain the correct value of N. This is demonstrated in Figure FMB-3c.

No Pseudopressure is used

- Above bubble point (Single-phase)
- Pressure changes are small
- (PVT properties are small)
- No pseudopressure is required

Figure FMB-3a

Single phase Pseudopressure is used

- Above bubble point (Single-phase)
- Pressure changes are NOT small
- (PVT properties are NOT constant)
- Single-phase pseudopressure used

Figure FMB-3b

NEW multiphase Pseudopressure is used

- Below bubble point (Two-phase)
- Multiphase Pseudopressure is used

Figure FMB-3c

Important considerations

The multiphase FMB equations are developed for boundary-dominated flow, and like most reservoir engineering equations, involve simplifying assumptions. Since the multiphase FMB model has only

recently been implemented, the effect of these assumptions has not been extensively evaluated, and the results must be used with caution until they have been verified in everyday production situations. Some of the issues that need to be validated through use and independent confirmation of results are discussed below:

In some of the following situations, anomalies in the behavior of the data (even synthetic data) have been observed:

a. When the bubble / dew-point pressure is crossed while production is still in transient flow. However, it is expected that the data catches up to the correct trend as production continues.

b. Selecting Liquid-Rich Gas in the PVT Properties section. This option is sensitive to any inconsistencies inherent in the PVT properties.

c. The Z** used in the flowing P/Z** calculation does not account for condensate and water production. Therefore, for rich-gas condensate reservoirs and cases with significant water production, the flowing P/Z** plot may not line up with the analysis line. However, the analysis is correct: the A-G straight line points to the correct Original-Gas-in-Place, and the model's verified gas flow rates and flowing pressures are correct. The only problem is that the P/Z** plot does not match, and this mismatch is not indicative of an incorrect analysis. Rather it indicates that the Z** is not accounting for the liquid production.

d. In some cases, a minimal adjustment of the relative permeability exponents (for example, changing n_g from 1.5 to 2) does improve the match between the data and the analysis.

e. When analyzing multiphase production data in FMB, it is possible to generate an incorrect straight-line trend by increasing the volume in place. The recommended procedure is to select the **minimum** value of original-oil-in-place, which results in an A-G Analysis straight line. This issue becomes more critical when analyzing data that is still in transient flow, especially when the bubble / dew-point pressures are hit before the boundary-dominated flow is reached. An example of incorrect and correct interpretation is shown below (see item *h*).

f. Since multiphase FMB takes into account the production rate of all phases that are entered in the Production editor, the often poorly measured or misreported water production rates might result in a more scattered FMB plot. In some jurisdictions, the condensate is inconsistently reported, sometimes as condensate production, sometimes as oil production, and sometimes as part of the (recombined) gas. These issues can be evaluated by removing these poorly reported rates from the Production editor.

g. In analyzing the multiphase flow in the unconventional reservoir model (URM), moving the end-of-linear flow line in the square-root time plot, may cause the data to move (even when pseudo-time has not been selected). The reason for this is that by changing the end-of-linear flow line, the reservoir size is changing. Therefore, the average pressure, will correspond to a different saturation distribution, and as a result, has

different pseudo-pressure calculations. For a large reservoir volume, where changes in the saturation profile are not as important as for a smaller reservoir volume (or for single-phase flow), moving the end-of-linear flow line has an insignificant effect on the data.

h. Since FMB equations are focused on boundary-dominated flow, caution has to be exercised during transient flow. For single-phase flow, the FMB has been used to reliably estimate the "contacted" volume. However, for multiphase flow, it may not be reliable for this purpose, and may give significantly misleading results. Moreover, the effect of flow geometry has not been completely studied. Two examples that illustrate some problems with Linear and Transient Flow are shown below:
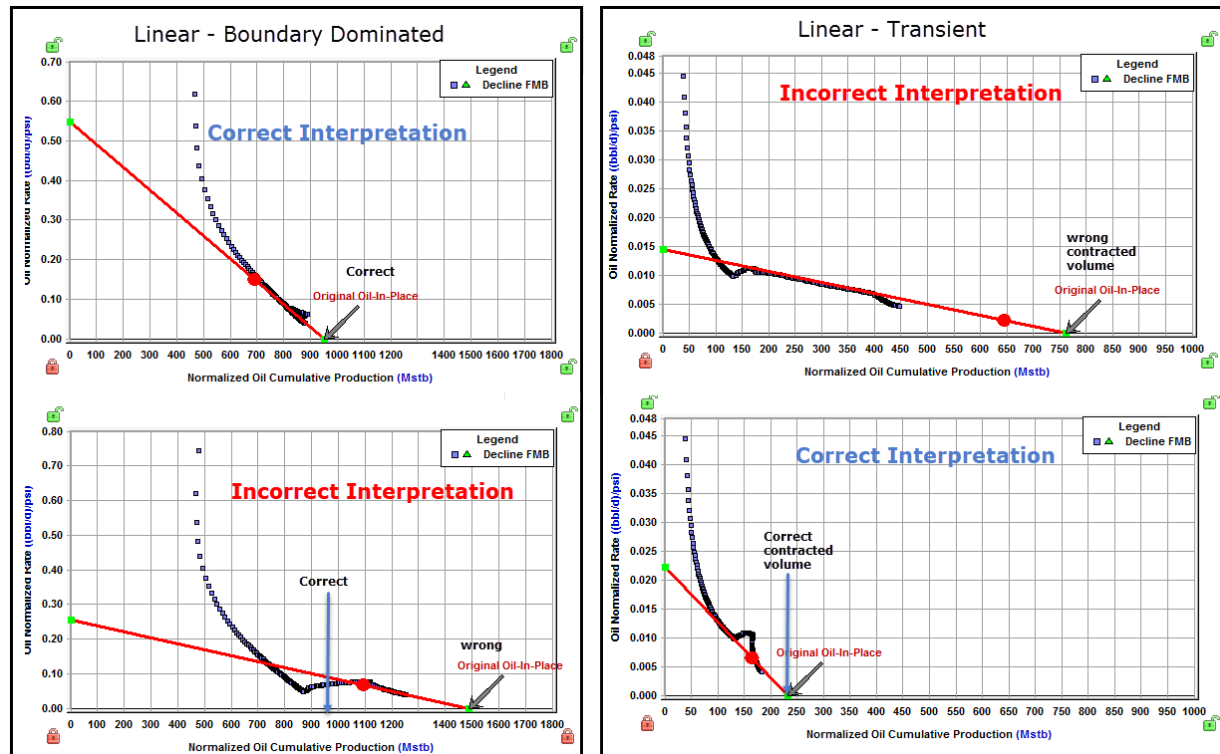
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FMB model *(patent pending)* theory

The following theory is focused on oil as the flowing fluid of interest. The pseudo-pressure referenced is the "oil" pseudo-pressure. A parallel discussion, mutatis mutandis (after the necessary changes have been made), is relevant when gas is the primary fluid of interest.

The Agarwal-Gardner (A-G) flowing material balance (FMB) plot yields the original-oil-in-place as the x-intercept, and the pseudo-productivity index as the y-intercept. The pseudo-productivity index is given by:

$$\text{Pseudo-Productivity Index} \quad = \quad \frac{q}{\overline{p}_{pR} - p_{pwf}} = \frac{1}{b}$$

The pseudo-productivity index depends on the average reservoir pseudo-pressure, the flowing pseudo-pressure, and the flowing rates of the three producing fluids: oil, gas, and water. The pseudo-productivity index is a parameter that combines Darcy's law, material balance, and accounts for the variations of fluid and reservoir properties such as: viscosity, formation volume factor, oil-gas-water saturations, geomechanical effects, desorption, etc.

Multiphase FMB uses the rigorous material balance equation to determine the average reservoir pressure, as a function of oil, gas, and water production for specified values of original-oil-gas-water-in-place. Multiphase FMB can account for the presence of water influx, and includes both production and injection rates. In addition, multiphase FMB also takes into account variations of fluid and reservoir properties such as: formation volume factor, oil-gas-water saturation, geomechanical effects, and desorption.

Having determined the oil pseudo-productivity index and the average pseudo-pressure in the FMB analysis, the FMB model uses the pseudo-productivity index and material balance equations in reverse, as follows:

1. Using the pseudo-productivity index:

   a. **Oil Rate** — uses the measured flowing pressure to calculate a synthetic oil rate, and compares the synthetic and measured oil rates. Modifies the productivity index and the original-oil-in-place, N, until an acceptable history-match of the oil rates is obtained.

   b. **Flowing Pressure** — uses the measured oil rate to calculate a flowing pressure, and compares the synthetic and measured flowing pressures. Modifies the productivity index and the original-oil-in-place, N, until an acceptable history-match of the flowing pressures is obtained.

c. **Average Pressure** — uses the measured flowing pressure and the flowing oil rate to calculate a synthetic average reservoir pressure. Modifies the productivity index and the original-oil-in-place, N, until an acceptable history-match of the average pressure with 2a (see below) is obtained.

2. Using the material balance equation:

a. **Average Pressure** — uses the measured flowing pressure and the flowing oil rate to calculate a synthetic average reservoir pressure. Modifies the productivity index and the original-oil-in-place, N, until an acceptable history-match of the average pressure with 1c (see above) is obtained.

Novelty of the FMB model

Historically, the FMB analysis is based on the A-G analysis (Agarwal et al. 1999). An example of an A-G FMB plot is shown in Figure FMB-Model-1a and FMB-Model-2a. This example is a multiphase gas well, but the FMB model applies to multiphase oil wells as well.

Figure FMB-Model-1a and FMB-Model-2a are plots of different analyses of the same data. Both analyses appear reasonable, but they give significantly different answers. It is obvious that for this dataset, the analysis' straight line can be placed in many locations, and that the corresponding original-gas-in-place values are non-unique over a wide range. Up until recently, there was no way out of this dilemma.
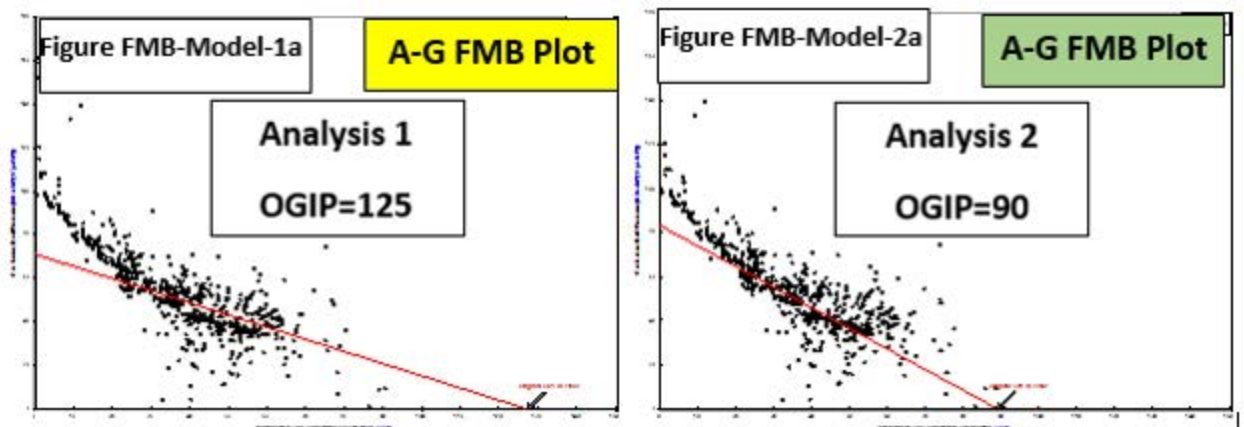
The FMB model solves this problem by creating a history-match of the flowing pressures, or the flow rates.

Figure FMB-Model-1b shows the rate history-match corresponding to Analysis 1. Clearly, this history-match is unacceptable. On the other hand, Figure FMB-Model-2b shows the rate history-match corresponding to Analysis 2. Clearly, this is an excellent history-match and confirms that the original-oil-

in-place determined from Analysis 2 is *consistent* with the data, whereas that of Analysis 1 is *inconsistent*.
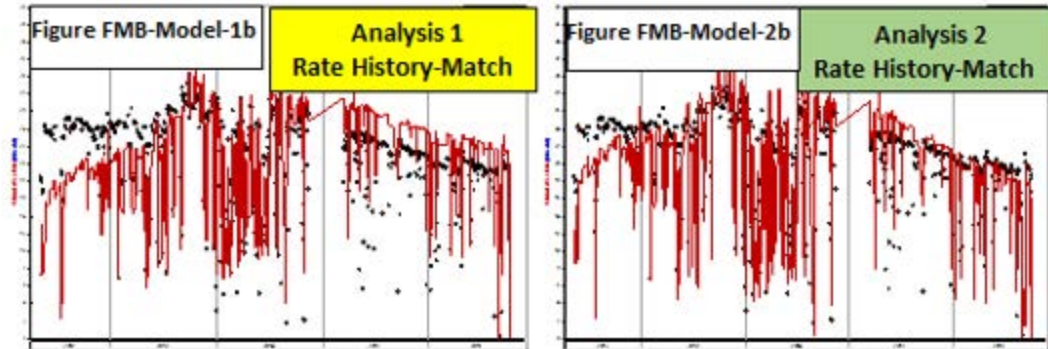
Similarly, Figure 1c and 2c are history-matches of the flowing pressures and confirm that Analysis 1 is *incorrect*, and that Analysis 2 is *correct*.
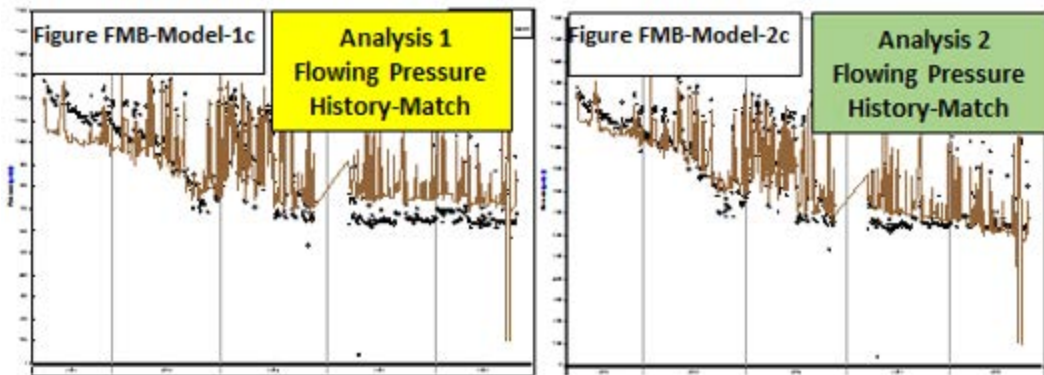
In addition to the rate history-match and the flowing pressures history-match, the FMB model can generate the average pressure within the drainage area of a well. This is shown in Figure FMB-Model-1d and FMB-Model-2d. The average reservoir pressure can be generated in two ways: from the productivity index (PI) and from the material balance (MB). When these two methods are congruent, the analysis is correct, as shown in Figure FMB-Model 2d. The utility of this plot is discussed further in reservoir group identification.

Figure FMB-Model-1d — Analysis 1 Average Pressure History-Match

Figure FMB-Model-2d — Analysis 2 Average Pressure History-Match
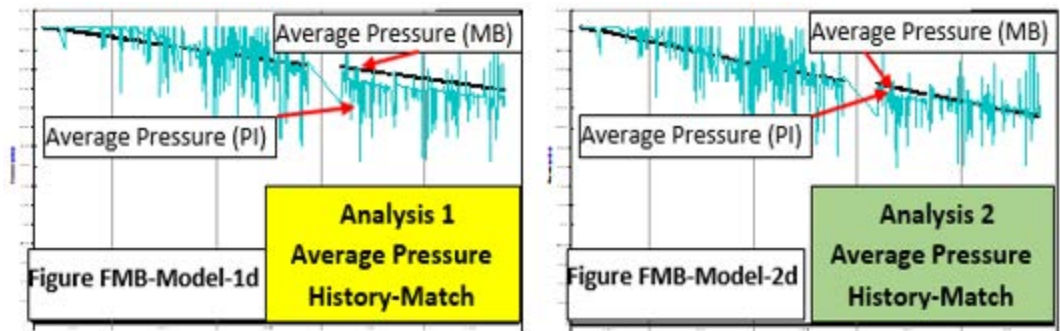
The conclusion for this example, is that the original-oil-in-place for this well is 90 BCF. This conclusion would not have been possible without the FMB model.

Reservoir group identification

The objective for using the Reservoir Group Identification plot is to identify which wells are in the same reservoir, and which wells are in separate reservoirs. If there are several wells producing from the same reservoir under stable conditions, they establish their own drainage areas, approximately in proportion to their flow rates. These drainage areas vary in shape and size, and depend in part on the flow rates. If the well's flow rates change, the no-flow boundaries between the wells move, and each well's drainage area changes correspondingly, until all the drainage areas have the same average pressure within them.

The phenomenon that, under stable flowing conditions, wells in the same reservoir have a common average pressure within their drainage areas as a function of time, provides a diagnostic to identify if two wells are in the same reservoir, or in different reservoirs.

Using the FMB model, the average pressure within the drainage area can be determined by selecting **Average Pressure** — see Figure FMB-Model-2d above. For each well, determine the correct average pressures (FMB Model Pressure-PI) as shown in Figure 2d. Compare these average pressures in the Comparison plot, as a function of time. If they follow the same trend, they most-likely belong to the same reservoir — (see Wells A and B in Figure 3), and if they have different trends, they most-likely belong to separate reservoirs — (see Well C in Figure 3).

Figure 3 — Reservoir Group Identification
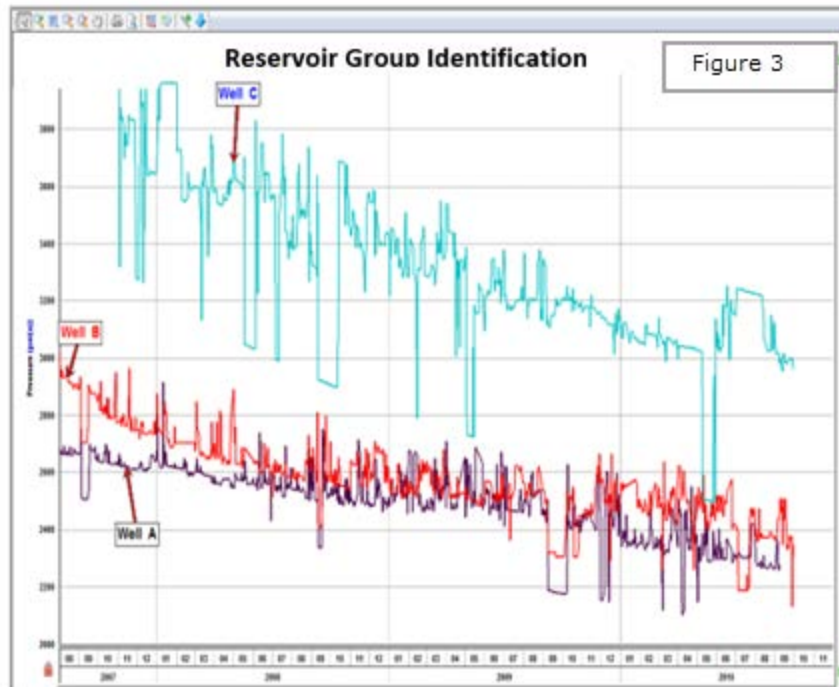
Duong decline analysis theory

The Duong analysis was developed specifically for unconventional reservoirs with very low permeability. The shape of the curve is suited for wells that exhibit long periods of transient flow. The Duong method will reach a finite EUR, and tends to be more conservative than traditional Arps declines with b > 1.

The Duong Production Decline Model		
q =	$q_1 \, t^{-m} \exp\left[\frac{a}{1-m}\left(t^{1-m} - 1\right)\right] + q_\infty$	Rate expression as a function of time
Q =	$\frac{q_1}{a} \exp\left[\frac{a}{1-m}\left(t^{1-m} - 1\right)\right]$	Cumulative production as a function of time
EUR =	$\frac{q_f}{a} \, t_f^{m}$	EUR in terms of model parameters
Reference SPE paper 137748.		

Hall plot theory

The Hall plot analyzes steady-state flow at an injection well. In general, the slope of a Hall plot is interpreted as an indicator of the average well injectivity. At normal conditions, the plot is a straight line. Kinks on the plot indicate changes to injection conditions.

Hall (in 1963) presented this technique to interpret routinely collected injection well data to draw conclusions regarding near-wellbore skin effects and average injectivity performance. The data required for a Hall plot analysis includes the following:

- monthly sandface injection pressures (monthly average)

- average reservoir pressure

- monthly water injection volumes

- injection days for the month

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

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

(Equation 1)

where:

k = permeability,

h = reservoir thickness

p_{wi} = flowing wellhead pressure

p_{avg} = average reservoir pressure

μ = fluid viscosity

r_e = reservoir effective radius

r_w = wellbore radius

S = skin

Equation 1 is based on the following assumptions:

- the fluid is homogenous and incompressible

- the reservoir is vertically confined and uniform, both with respect to permeability and thickness

- the reservoir is horizontal and gravity does not affect flow (consequently, the flow is radial)

- the flow is steady-state

- the mobility ratio is equal to 1

- during the time of observation, the pressure at the distance equal to r_e is constant, and this distance itself is constant as well

At this point, it is assumed that k, h, μ, r_e, r_w, and S are constant. Therefore, Equation 1 reduces to:

$$i_w = C(p_{wi} - p_{avg})$$ (Equation 2)

where:

$$C = \frac{0.00707\,kh}{\mu\left[ln\frac{r_e}{r_w} + S\right]}$$ (Equation 3)

Rearranging Equation 2 yields the following:

$$(p_{wi} - p_{avg}) = \frac{i_w}{C}$$ (Equation 4)

Integrating both sides of Equation 4 with respect to time gives:

$$\int_0^t (p_{wi} - p_{avg})dt = \frac{1}{C}\int_0^t i_w\, dt$$ (Equation 5)

The integral on the right- side of Equation 5 is cumulative water injected, so Equation 5 can be represented as:

$$\int_0^t (p_{wi} - p_{avg})dt = \frac{W_i}{C}$$ (Equation 6)

where:

W_i = cumulative volume of water injected at time t, bbls

Closer inspection of Equation 6 indicates that a coordinate graph of its left-side of versus the right-side should form a straight line with a slope of 1/C. This type of graph is called the Hall plot. If h, μ, r_e, r_w,

and S are constant, then from Equation 3, the value of C is constant and the slope is constant. However, if the parameters change, C changes, and thus the slope of the Hall plot changes, which is where the diagnostic value of the plot lies.

Changes in injection conditions may be noted from the Hall plot. For example, if wellbore plugging, or other restrictions to injection are gradually occurring, the net effect is a gradual increase in the skin factor, S. As S increases, C decreases; thus, the slope of the Hall plot increases. Conversely, if S decreases (as would be the case if injecting pressure exceeds fracture pressure, causing fracture growth), then C increases and the slope of the Hall plot decreases. See Figure 1 for various injection well conditions and their Hall plot signatures.

Figure 1. Hall plot characteristic signatures
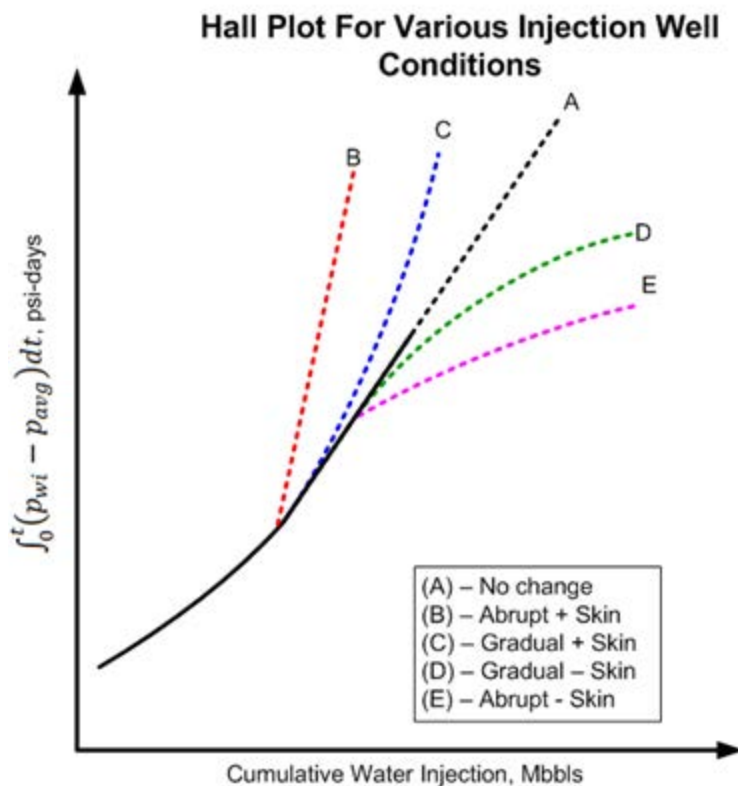
The most challenging part of developing the Hall plot is calculating the pressure-integral function of the y-axis. Fortunately, the integral can easily be solved. Consider Figure 2, which shows a graph of monthly sandface injection pressure, p_{wi}, and periodic estimates of average reservoir pressure, p_{avg}.

Figure 2. Sandface (bottomhole) injection and reservoir pressure vs. time

Bottomhole Injection and Reservoir Pressure vs. Time
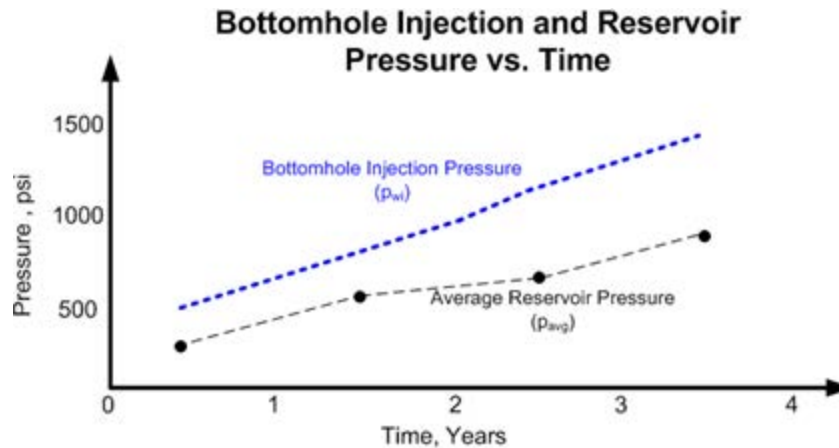
If it can be assumed that p_{wi} and p_{avg} are average for the month, then

$$\int_0^t (p_{wi} - p_{avg})\, dt = \sum \Delta p * \Delta t$$

(Equation 7)

where:

$\Delta p = p_{wi} - p_{avg}$

Δt = number of injection days for the month

Changes in the slope of the Hall plot typically occur gradually, so several months (six months or more) of injection history may be needed to reach reliable conclusions about injection behavior, as is the case for production decline curve analysis.

It is important to note that changes in the slope of the Hall plot can be the result of other factors. Early in the life of an injection well (before gas fillup), the radius of the water and oil zones increase with cumulative injection and cause the value of C to increase, resulting in a concave upward trend in the Hall plot. Recall that 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 after gas fillup (as shown in curve D in Figure 1); if the mobility ratio is less than 1.0, it gradually trends concave upwards (see curve C). 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.

If after gas fillup it can be assumed that p_{avg} does not change significantly, then calculating the y-axis on the Hall plot is greatly simplified by dropping p_{avg}. This is because if p_{avg} is constant and ignored, the Hall plot is only shifted on the y-axis without changing the slope, or its diagnostic interpretive value. Under this condition, the sandface injection pressure (p_{wi}) is simply the wellhead injection pressure, plus a hydrostatic gradient, minus a frictional loss term. Since these two terms can usually be

assumed to be constant and neglected, the left-side of Equation 6 can simply reduce to the integral of the wellhead injection pressure, a dataset that is more readily available.

To determine whether average reservoir pressure is changing, it is necessary to conduct regular pressure buildup / falloff tests, and to monitor monthly voidage replacement ratio (VRR) plots. The objective of the Hall plot is to detect changes in the injection well's skin factor. It is not a perfect tool, but can, under certain conditions, provide reasonable insight on skin changes. The best tool for quantifying injection wellbore skin damage is a properly designed, well executed, and fully analyzed pressure fallout test.

References: Waterflooding Course, William M. Cobb & James T. Smith.

Hybrid model theory

Background

There are two main types of models used to simulate the flow of fluid through porous media: analytical models and numerical models. Both types have their advantages and disadvantages.

Analytical models

Analytical models have relatively short calculation times, so you can history match with these models quickly. More than that, you can even match the model automatically using automatic parameter estimation (APE).

The main disadvantage for these models is that they can only simulate single-phase flow – either liquid or gas, but not gas and liquid flowing together. Additionally, analytical models do not fully account for changing fluid properties with pressure. In case of liquid flow, fluid properties are assumed to be constant, and in case of gas flow, the change of fluid properties with pressure is accounted for by using pseudo-pressure and pseudo-time.

Unfortunately, pseudo-time is not an exact transformation. As a result, changing gas properties are only accounted for to a certain extent. Therefore, in cases where pressure varies significantly across the reservoir (for example, pays with low permeability), long-term forecasts for gas analytical models may be inaccurate. There is no known way to fully account for the change in fluid properties when using analytical models.

Numerical models

With numerical models, you can model multiphase flow, and account for changing properties of each phase, and the interaction between phases.

The main disadvantage for these models is their long computation time. With the numerical model, the reservoir is divided into a number of cells, and then the flow is modeled simultaneously in all cells. To be able to assume constant pressure and constant fluid properties within each cell, the size of each cell needs to be relatively small. Therefore, the number of cells required for an accurate solution becomes large, which results in a long computation time. Note that decreasing the number of cells to reduce computation time may significantly affect calculation results.

Performing a manual history match for numerical models is time consuming. In addition, an automatic history match for numerical models is complicated, and thus not widely available in commercial software.

Hybrid model

The hybrid model is essentially a numerical model, but with certain modifications to significantly reduce computation time, so that it is almost as fast as an analytical model. These modifications include:

- using the pseudo-pressure formulation

- optimized "gridding" — by using the pseudo-pressure formulation, you can use larger grid cells without affecting the accuracy of calculation results; using larger grid cells also makes calculations run faster.

General formulation for the single-phase model

To calculate pressure across the reservoir, we divide it into a number of grid cells. At each timestep *(n+1)*, we formulate a material balance for each cell.
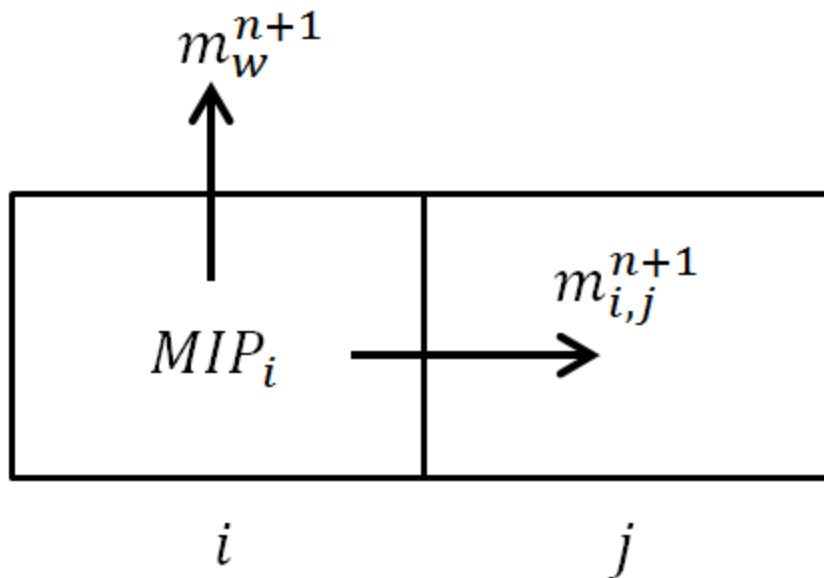
To define components of mass balance for cell *i* at timestep *n+1*:

Mass in place (MIP) for cell *i* at timestep *n+1* can be calculated as:

Equation 1

$$MIP_i^{n+1} = MIP_i\left(p_i^{n+1}\right) = V_{bi}\,\varphi\left(p_i^{n+1}\right)\rho\left(p_i^{n+1}\right)$$

where:

V_{bi} = bulk volume for cell i

p_i^{n+1} = pressure for cell i at timestep $n+1$

φ = porosity

ρ = density

Mass flow from cell i to the adjacent cell j during timestep $n+1$ can be calculated as:

Equation 2

$$m_{i,j}^{n+1} = \rho\left(p\right)q_{i,j}^{n+1}\Delta t = \frac{A_{i,j}k}{L_{i,j}}\frac{\rho(p)k_m(p)}{\mu(p)}\left(p_i^{n+1} - p_j^{n+1}\right)\Delta t$$

(We used Darcy's Law to calculate flow rate.)

In equation 2:

$q_{i,j}^{n+1}$ = flow rate from cell i to cell j at timestep $n+1$

$A_{i,j}$ = cross-section area between cells i and j

$L_{i,j}$ = distance between the centers of cells i and j

μ = viscosity

k = permeability at the initial pressure

$k_m(p)$ = permeability multiplier (permeability at a certain pressure is calculated as $k_{effective} = k \cdot k_m\left(p\right)$).

Mass produced at the well during timestep *n+1* (if well penetrates cell *i*) can be calculated as:

Equation 3

$$m_{i,w}^{n+1} = \rho\left(p\right)\, q_{i,w}^{n+1} \Delta t \;=\; WI \frac{\rho(p) k_m(p)}{\mu(p)} \left(p_i^{n+1} - p_{wb}^{n+1}\right)\Delta t$$

where:

WI = wellbore index (as per Peaceman 1978 or Babu and Oden, 1989)

p_{wb}^{n+1} = pressure at the wellbore at timestep *n+1*

Material balance for cell *i* at timestep *n* can be written as:

Equation 4

$$\overset{\textit{flow to othercells}}{\underset{j}{\sum} m_{i,j}^{n+1}} + \overset{\textit{flow to the well}}{m_{i,w}^{n+1}} = \overset{\textit{change in mass inplace}}{MIP_i\left(p_i^{n+1}\right) - MIP_i\left(p_i^{n}\right)}$$

Using equations 1, 2, and 3, and bringing all the terms to the left, we can rewrite equation 4 as:

Equation 5

$$\sum_j \left(\frac{A_{i,j}k}{L_{i,j}}\frac{\rho(p)k_m(p)}{\mu(p)}\left(p_i^{n+1} - p_j^{n+1}\right)\Delta t\right) + WI\frac{\rho(p)k_m(p)}{\mu(p)}\left(p_i^{n+1} - p_{wb}^{n+1}\right)\Delta t - \left(V_{bi}\varphi\left(p_i^{n+1}\right)\rho\left(p_i^{n+1}\right) - V_{bi}\varphi\left(p_i^{n}\right)\rho\left(p_i^{n}\right)\right) = 0$$

Assuming that the pressure distribution has been calculated for timesteps 1, 2, ... *n*, to calculate pressure distribution at timestep *n+1*, we formulate material balance (equation 5) for each cell, and solve all these equations simultaneously. Unknowns of the system are p_i^{n+1} for each cell *i*; therefore, the number of equations is the same as the number of unknowns, and the system can be solved.

Well constraint considerations

For a well producing at a specified sandface pressure, the described system of equations can be used directly (because p_{wb}^{n+1} is known). However, for a well that produces at a specified surface *q*, an extra equation is required.

Equation 6

$$\sum_i \left(WI_i \frac{\rho(p)k_m(p)}{\mu(p)} \left(p_i^{n+1} - p_{wb}^{n+1} \right) \right) = q\rho_{sc}$$

where:

i = summation index for all cells penetrated by the well

ρ_{sc} = fluid density at standard conditions

Considerations when estimating fluid properties

In the above formulation, we use rock and fluid properties estimated at certain pressures. The term $\frac{\rho(p)k_m(p)}{\mu(p)}$ is used in $m_{i,j}^{n+1}$ (equation 2) and in $m_{i,w}^{n+1}$ (equation 3).
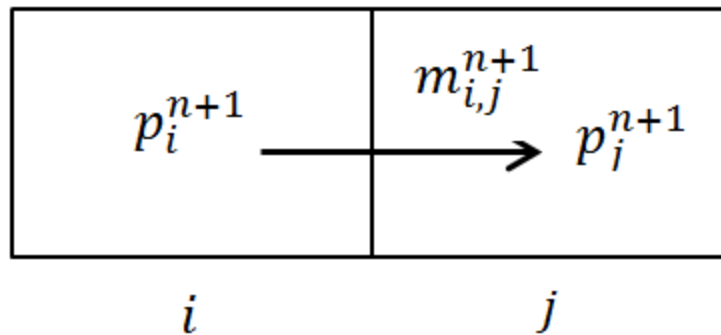
Some logical questions are:

- At what pressure should we estimate this term?
- Should we use pressure in one of the cells, or some kind of average?

Fluid properties may significantly vary with pressure (especially if the modeled fluid is gas); therefore, selecting the correct way of estimating properties becomes important.

In classical numerical simulation (including numerical models in Harmony), properties are estimated at the pressure of the upstream cell (i.e., the cell with the higher pressure). For such a simulation to be accurate, you should ensure that properties in the adjacent cells are close. ***To achieve this, grid cells have to be small enough***. Unfortunately, having smaller grid cells results in longer computation times.

With the hybrid model, we use the pseudo-pressure formulation to estimate fluid properties and calculate mass transfers.

Hybrid model pseudo-pressure definition

The hybrid model pseudo-pressure is defined as:

Equation 7

$$\psi_h\left(p\right) = \int_0^p \frac{\rho(p)k_m(p)}{\mu(p)}\,dp$$

Note: For gas, the definition of hybrid model pseudo-pressure is very similar to a traditional pseudo-pressure. To see this, express density as $\rho = \frac{pM}{zRT}$ (z = gas compressibility factor, T = temperature, R = gas constant, M = molar mass). This results in the following equation:

Equation 8

$$\psi_h\left(p\right) = \int_0^p \frac{\rho(p)k_m(p)}{\mu(p)}\,dp = \frac{M}{2RT}\int_0^p \frac{k_m(p)p}{z(p)\mu(p)}\,dp = \frac{M}{2RT}\psi\left(p\right)$$

Therefore, the hybrid model pseudo-pressure and traditional pseudo-pressure are different by a constant factor.

Hybrid model pseudo-pressure formulation

As was mentioned in considerations when estimating fluid properties, the calculation of mass flow from one cell to another given in equation 2 has a deficiency: it does not account for a variation of fluid properties with pressure. The hybrid model formulation modifies equation 2 to get a relationship between the mass flow rate and pressure drop when properties are changing with pressure.
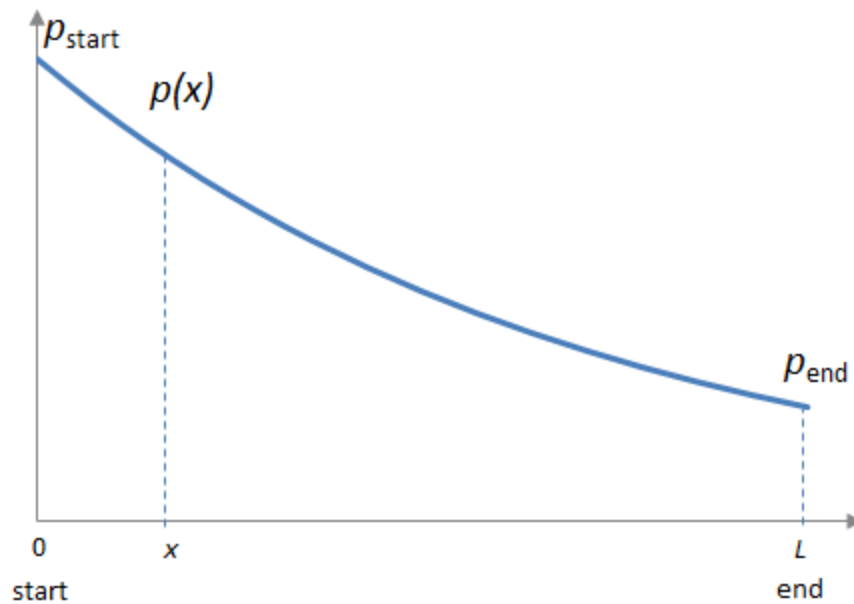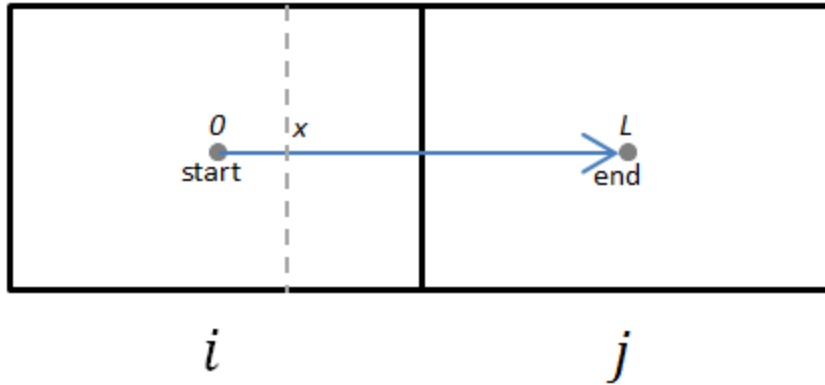
At each cross-section at any given distance (*x*), the pressure gradient across the cross-section can be expressed using the differential form of Darcy's Law:

Equation 9

$$-\frac{dp}{dx} = q \cdot \frac{\mu(p(x))}{k \cdot k_m(p(x)) \cdot A} = \underbrace{\frac{(m/\Delta t)}{\rho(p(x))}}_{q} \cdot \frac{\mu(p(x))}{k \cdot k_m(p(x)) \cdot A}$$

where $(m/\Delta t)$ is the mass flow rate across the cross-section. This can be re-arranged as:

Equation 10

$$\frac{(m/\Delta t)}{Ak} = -\frac{\rho(p(x))k_m(p(x))}{\mu(p(x))}\frac{dp}{dx}$$

Integrating both parts from 0 to *L* with respect to *x*, and using the left-side of the equation is a constant with respect to *x*, we get the following equation:

Equation 11

$$\frac{(m/\Delta t)}{Ak}\cdot L = -\int_{x=0}^{x=L}\frac{\rho(p(x))k_m(p(x))}{\mu(p(x))}\frac{dp}{dx}dx = -\int_{p_{start}}^{p_{end}}\frac{\rho(p)k_m(p)}{\mu(p)}dp = \psi_h(p_{start}) - \psi_h(p_{end})$$

Note: We used the definition given in equation 7 for the last transformation.

To summarize, when fluid properties are changing with pressure, the mass flow rate through the cross-section can be calculated as:

Equation 12

$$m/\Delta t = \frac{Ak}{L}\left(\psi_h\left(p_{start}\right) - \psi_h\left(p_{end}\right)\right)$$

Therefore, equation 2 can be modified to account for changing properties. The mass flow from cell *i* to cell j during timestep *n+1* is calculated as:

Equation 13

$$m_{i,j}^{n+1} = \frac{Ak}{L}\left(\psi_h\left(p_i^{n+1}\right) - \psi_h\left(p_j^{n+1}\right)\right)\Delta t$$

Equation 3 can be modified in a similar fashion. Mass produced at the well during timestep *n+1* is calculated as:

$$m_{i,w}^{n+1} = WI\left(\psi_h\left(p_i^{n+1}\right) - \psi_h\left(p_{wb}^{n+1}\right)\right)\Delta t$$

As a result, the material balance equation for each cell (equation 5) is modified to:

Equation 14

$$\sum_j \left(\frac{A_{i,j} k}{L_{i,j}} \left(\psi_h \left(p_i^{n+1} \right) - \psi_h \left(p_j^{n+1} \right) \right) \right) \Delta t + WI \left(\psi_h \left(p_i^{n+1} \right) - \psi_h \left(p_{wbj}^{n+1} \right) \right) \Delta t - \left(V_{bi} \varphi \left(p_i^{n+1} \right) \rho \left(p_i^{n+1} \right) - V_{bi} \varphi \left(p_i^n \right) \rho \left(p_i^n \right) \right) = 0$$

Assuming that the pressure distribution has been calculated for timesteps 1, 2, ... *n*, to calculate pressure distribution at timestep *n+1*, we formulate a modified material balance (equation 14) for each cell, and solve all these equations simultaneously. Unknowns of the system are p_i^{n+1} for each cell *i*; therefore, the number of equations is the same as the number of unknowns, and the system can be solved.

Note: Well constraints are treated in a similar way to general numerical model formulations.

Modifications for the multiphase model

In the case where there are two or three phases flowing together, the multiphase solution follows similar logic as single-phase flow, with a few modifications.

- The mass balance equation (equation 4) has to be modified to account for the fact that fluid can change from one phase to another (e.g., oil can evaporate and become gas, or gas can condense to liquid).

- In the single-phase case, the mass balance equation is written for each cell; therefore, we get *n* equations (where *n* is the number of cells). In the multiphase case, the mass balance equation is written for each cell for each phase; therefore, we get *n*•"number of phases" as equations.

- In the single-phase case, the unknowns of the system are pressures in each cell; therefore, we get *n* unknowns. In the multiphase case, the unknowns of the system are pressures in each cell (*n*), and saturations for each cell; therefore, we get total *n*•"number of phases" as unknowns. (We use the fact that the sum of all saturations is equal to 1 for any of the grid cells.)

- When calculating a mass transfer from one cell to another (equation 2) and a mass transfer from the cell to the well (equation 3), we have to account for relative permeability.

- For the single-phase case, we re-write the mass transfer term in terms of pseudo-pressure (equation 13). In the multiphase case, we can do the same thing, but there will be different pseudo-pressure functions for different phases. (The pseudo-pressure formulation for each phase follows the definition given in equation 7, but ρ, μ, and k are different for different phases.)

- For the single-phase case, the system of equations can be solved in terms of pseudo-pressures (the unknowns are pseudo-pressures in each cell). For the multiphase case, equations have to be solved in terms of pressure (the unknowns are pressures and saturations in each of the cells). The pseudo-pressure formulation is only used to calculate mass transfer between cells.

Advantages of using the pseudo-pressure formulation

Pseudo-pressure formulation makes simulation significantly faster than classical numerical simulation modeling for the following reasons:

1. **Smaller number of grid cells**: In classical numerical simulation, grid cells have to be small enough to consider constant fluid properties within each cell. Pseudo-pressure formulation accounts for a variation of fluid properties between the centers of two adjacent cells; therefore, it is possible to have larger grid cells. By having a smaller *number* of grid cells, calculation speed increases.

2. **Faster solution for a non-linear system**: While performing numerical modeling, equation 5 is solved at each timestep. This system of equations is non-linear; therefore, it is solved iteratively, using the Newton-Raphson method. This method involves calculating derivatives of each matrix element with respect to each unknown. Calculating these derivatives is faster for pseudo-pressure formulation (equation 14), because we have to deal with one fluid property function ($\Psi_h(p)$) as opposed to a combination of three functions ($\rho(p), k_m(p), \mu(p)$) for traditional formulation. More than that, due to the integral nature of $\Psi_h(p)$, its derivative is calculated easily.

Material balance analysis theory

Overview

Material balance analysis is an interpretation method used to determine original fluids-in-place (OFIP) based on production and static pressure data. The general material balance equation relates the original oil, gas, and water in the reservoir to production volumes and current pressure conditions / fluid properties. The material balance equations considered assume tank-type behavior at any given datum depth — the reservoir is considered to have the same pressure and fluid properties at any location in the reservoir. This assumption is quite reasonable provided that quality production and static pressure measurements are obtained.

Consider the case of the depletion of the reservoir shown below. At a given time after the production of fluids from the reservoir has commenced, the pressure drops from its initial reservoir pressure p_i, to some average reservoir pressure, p. Using the law of mass balance, during the pressure drop (Δp), the expansion of the fluids left over in the reservoir must be equal to the volume of fluids produced from the reservoir.
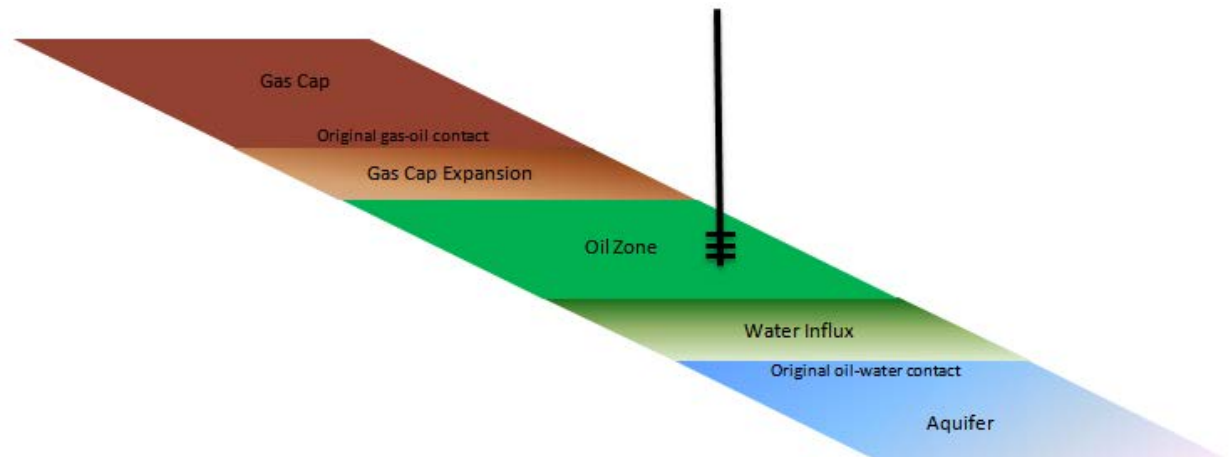
The simplest way to visualize material balance is that if the measured surface volume of oil, gas, and water were returned to a reservoir at the reduced pressure, it must fit exactly into the volume of the total fluid expansion, plus the fluid influx.

The general form of the equation can be described as net withdrawal (withdrawal - injection) = expansion of the hydrocarbon fluids in the system + cumulative water influx. This is shown in the equation below.

$$N_p\left[B_o + B_g(R_p - R_s)\right] + W_p B_w - W_{inj} B_{winj} - G_{inj} B_{ginj}$$

$$= N\left\{\left[B_o - B_{oi} + B_g(R_{si} - R_s)\right] + \frac{B_{oi}}{B_{gi}}m(B_g - B_{gi})\right.$$

$$\left. + B_{oi}(1 + m)\left(\frac{c_f + c_w S_w}{1 - S_w}\Delta p\right)\right\} + W_e B_w$$

Each term in the equation can be grouped based on the part of the system it represents. The table below shows the terms and a simplified version of the general equation based on the terms.

Summary of terms in the material balance equation

Term	Description
$F = NE_t + W_e B_w$	Simplified general equation.
$F = N_p\left[B_o + B_g(R_p - R_s)\right] + W_p B_w - W_{inj} B_{winj} - G_{inj} B_{ginj}$	Volume of withdrawal (production and injection) at reservoir conditions is determined by the oil, water, and gas produced at the surface.
$E_t = E_o + \dfrac{B_{oi}}{B_{gi}}mE_g + B_{oi}(1 + m)E_{fw}$	Total expansion.
$E_o = B_o - B_{oi} + B_g(R_{si} - R_s)$	If the oil column is initially at the bubble point, reducing the pressure results in the release of gas and the shrinkage of oil. The remaining oil consists of oil,

Term	Description
	and the remaining gas still dissolved at the reduced pressure.
$E_g = B_g - B_{gi}$	Gas expansion factor. For example, as the reservoir depletes, the gas cap expands into the reservoir volume previously occupied by oil.
$E_{fw} = \dfrac{c_f + c_w S_w}{1 - S_w} \Delta p$	Even though water has low compressibility, the volume of connate water in the system is usually large enough to be significant. The water expands to fill the emptying pore spaces as the reservoir depletes. As the reservoir is produced, the pressure declines and the entire reservoir pore volume is reduced due to compaction. The change in volume expels an equal volume of fluid

Term	Description
	as production, and is therefore additive in the expansion terms.
$m = \dfrac{G\,B_{gi}}{N\,B_{oi}}$	Ratio of gas cap to original oil in place. A gas cap also implies that the initial pressure in the oil column must be equal to the bubble point pressure.
$W_e B_w$	If the reservoir is connected to an active aquifer, then once the pressure drop is communicated throughout the reservoir, the water encroaches into the reservoir resulting in a net water influx.

Not all terms are used at any one time, but the purpose of a complete equation is to provide a basis from which to analyze many types of reservoirs: gas expansion, solution gas drive, gas cap drive, water drive, etc. Terms that are not needed for a particular reservoir type cancel out of the equation. For example, when there is no gas cap originally present, the G and B_{gi} terms are zero.

Application of material balance

Material balance is an important concept in reservoir engineering because it is a performance-based tool used to establish the original volume of hydrocarbons-in-place in a reservoir that typically contains many wells. Additionally, the process of matching pressure-based depletion trends between wells

gives the reservoir engineer the ability to create a performance-based view of the connected pore volume in the reservoir. Consequently, it is important that:

1. All fluids taken from, or injected into the reservoir be measured accurately.

2. Pressure, volume, and temperature characteristics (PVT properties) be measured and validated. Subsurface samples from several properly conditioned wells are preferred.

3. At least one static pressure from each well prior to production, and several after production has commenced, are required to achieve good results.

The establishment of original-in-place fluid volumes and connected pore volume are critical to the development of ongoing depletion plans, especially where secondary or tertiary recovery methods are being considered.

Gas material balance

Gas material balance is a simplified version of the general material balance equation. When the general equation is reduced to its simplest form containing only gas terms, it appears as shown below:

$$G = \frac{G_p B_g}{\left(B_g - B_{gi}\right)}$$

In this equation, it is assumed that gas expansion is the only driving force causing production. This form is commonly used because the expansion of gas often dominates over the expansion of oil, water, and rock. B_g is the ratio of gas volume at reservoir conditions to gas volume at standard conditions. This is expanded using the real gas law.

$$B_g = \frac{V_{res}}{V_{std}} = \frac{Z_{res} n R T_{res} p_{std}}{Z_{std} n R T_{std} p_{res}}$$

The reservoir temperature is considered to remain constant. The compressibility factor (Z) for standard conditions is assumed to be 1. The number of moles of gas do not change from reservoir to surface. Standard temperature and pressure are known constants. When Bg is replaced and the constants are canceled out, the gas material balance equation then simplifies to:

$$\frac{p}{Z} = -\left(\frac{p_i}{Z_i}\frac{1}{G}\right)G_p + \frac{p_i}{Z_i}$$

When plotted on a graph of p/Z versus cumulative production, the equation can be analyzed as a linear relationship. Several measurements of static pressure and the corresponding cumulative productions can be used to determine the x-intercept of the plot - the original gas-in-place (OGIP), shown as G in the equation.
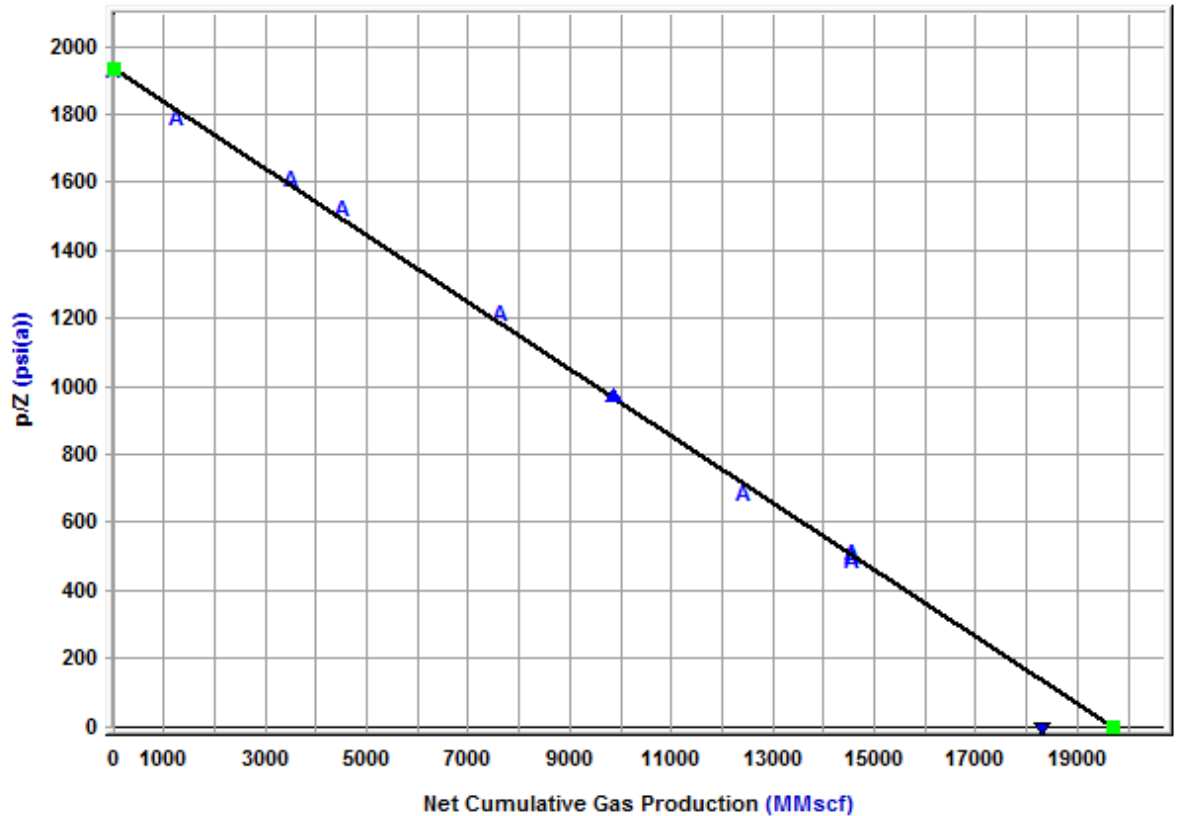
Advanced gas material balance

For a volumetric gas reservoir, gas expansion (the most significant source of energy) dominates depletion behavior; and the general gas material balance equation is a very simple, yet powerful tool for interpretation. However, in cases where other sources of energy are significant enough to cause deviation from the linear behavior of a p/Z plot, a more sophisticated tool is required. For this, a more advanced form of the material balance equation has been developed, and the standard p/Z plot is modified to maintain a linear trend with the simplicity of interpretation.

In his work on CBM, King (1993) introduced p/Z* to replace p/Z. By modifying Z, parameters to incorporate the effects of adsorbed gas were incorporated, so the total gas-in-place is interpreted, rather than just the free gas-in-place; and a straight line analysis technique is still used. This concept has been extended to additional reservoir types with Fekete's p/Z** method (Moghadam et al. 2009).

The reservoir types considered in the advanced material balance equation are: overpressured reservoirs, water-drive reservoirs, and connected reservoirs. The total Z** equation is shown below with the modified material balance equation.

$$\frac{p}{Z^{**}} = \frac{p_i}{Z_i^{**}} \left(1 - \frac{G_p}{G} \right)$$

$$Z^{**} = \frac{p}{\left[\frac{1}{S_{gi}} \frac{p}{Z} \left(S_{gi} - c_{wip} - c_{ep} - c_d \right) + \frac{p_i}{Z_i} \left(\frac{G}{G_f} - 1 \right) \right] \frac{G_f}{G}}$$

Overpressured reservoir

At typical reservoir conditions, gas compressibility is orders of magnitude greater than that of the formation rock or residual fluids. In reservoirs at high initial pressures the gas compressibility is much lower, in the same order of magnitude as the formation. A typical example of this is an overpressured reservoir, which is a reservoir at a higher pressure than the hydrostatic column of water at that depth — in other words, a higher than expected initial pressure given the depth. In this situation, ignoring the formation and residual fluid compressibility results in over-prediction of the original gas-in-place. The initial depletion shows the effects of both depletion and reservoir compaction, and the slope of a p/Z plot is shallower. Once the pressure is much lower than the initial pressure, gas expansion is dominant and a steeper slope is observed on the p/Z plot. When matching on the shallower slope of this bow-shaped trend, all later pressure data is lower than the analysis line, and the estimated original gas-in-place is higher than the true original gas-in-place. The plot below shows an overpressured reservoir matched on the initial data, and the analysis line of the advance material balance method.
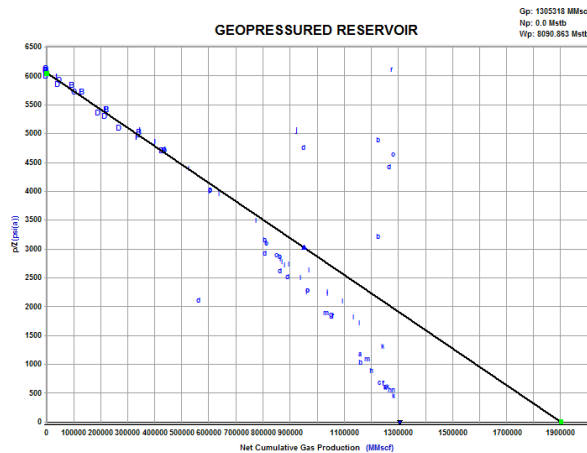
p/Z plot
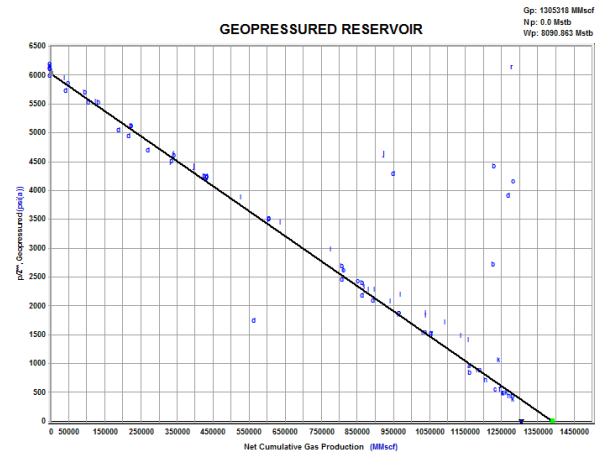
p/Z** plot

Based on the definition of compressibility, the following equation represents the total effect of formation and residual fluid compressibility:

$$\Delta V_{ep} = \frac{B_{gi}G}{S_{gi}}\left[\left(1 - e^{-\int_p^{p_i} c_f dp}\right) + S_{wi}\left(e^{\int_p^{p_i} c_w dp} - 1\right) + S_{oi}\left(e^{\int_p^{p_i} c_o dp} - 1\right)\right]$$

The approximate form of this equation, found by considering compressibility for oil, water, and the formation as constant; and e^x as $1 + x$, is:

$$\Delta V_{ep} = \frac{B_{gi}G}{S_{gi}}\left(c_f + S_{wi}c_w + S_{oi}c_o\right)\left(p_i - p\right)$$

In order to use this compressibility in the material balance equation, the change in pore volume is taken relative to the initial pore volume. The rigorous and approximate forms are shown below.

Rigorous form:

$$c_{ep} = \left(1 - e^{-\int_p^{p_i} c_f dp}\right) + S_{wi}\left(e^{\int_p^{p_i} c_w dp} - 1\right) + S_{oi}\left(e^{\int_p^{p_i} c_o dp} - 1\right)$$

Approximate form:

$$c_{ep} = \left(c_f + S_{wi}c_w + S_{oi}c_o\right)\left(p_i - p\right)$$

Water-drive reservoir

Some gas reservoirs may be connected to aquifers that provide pressure support to the gas reservoir as it is depleted. In this case, the pressure decrease in the gas reservoir is balanced by water encroaching into the reservoir. As this happens, the pore volume of gas is decreasing and the average reservoir pressure is maintained. Often this reservoir shows a flat pressure trend after some depletion. An example of this behavior on a p/Z plot is shown below.

The change in reservoir volume due to net encroached water can be determined from the following equation:

$$\Delta V_{wip} = 5.615(W_e - W_\rho B_w)$$

To use this in the material balance, the change in pore volume is taken relative to the initial pore volume, shown below.

$$c_{wip} = \frac{5.615\,(W_e - W_\rho B_w)}{B_{gi}\,G/\,S_{gi}}$$

When dealing with this equation, the major unknown value to be determined is water encroachment from the aquifer (W_e). Two aquifer models are provided to determine net encroached water: Schilthuis Steady-State Model and Fetkovich Model.

Schilthuis steady-state model

This is the simplest aquifer model and assumes the rate of water influx is proportional to pressure draw-down. In this model it is assumed that the aquifer volume is much larger than the gas reservoir and remains at the initial pressure.

$$W_e = K \int_0^t \, (p_i - p)\,dt = K \sum_{j=0}^{n} \left(p_i - \frac{p_j + p_{j-1}}{2} \right) \left(t_j - t_{j-1} \right)$$

Using this model, the only parameter to solve for is the transfer coefficient (J).

Fetkovich

In the Fetkovich aquifer, the aquifer is assumed to be in pseudo-steady state and depleted according to the material balance equation. In this model, both the aquifer volume and transfer coefficient must be determined. The equations are shown below.

$$W_e = K \int_0^t \, (p_i - p)\,dt = K \sum_{j=0}^{n} \left(p_i - \frac{p_j + p_{j-1}}{2} \right) \left(t_j - t_{j-1} \right)$$

$$W_{ei} = c_w p_{aqi} V_{aq}$$

$$J = \frac{k\,h}{141.2\mu \left(\ln \frac{r_e}{r_o} - \frac{3}{4} \right)} \frac{\theta}{360}$$

While the transfer coefficient is defined, the required inputs to calculate the transfer coefficient are often not known. More commonly the transfer coefficient is determined as part of matching the p/Z plot.

Connected reservoir

Another scenario which appears as pressure support on the p/Z plot is the connected reservoir model. The generic description is that two gas reservoirs are connected, described by a transfer coefficient between them, and gas feeds from one tank to the other as one of the tanks is depleted. This can be observed with two gas reservoirs with some communication, two zones in a reservoir with different permeability, or some barrier between them, or even another way of considering the situation of free and adsorbed gas in a reservoir. Because both water-drive and connected reservoirs show pressure support, it can be easy to mistake which model should be used. In a connected reservoir, the influx into the main reservoir is gas, as compared to an influx of water in water-drive. So the pressure support is accompanied by more gas in the reservoir, rather than a shrinking reservoir as in water-drive. Typically if the initial p/Z trend points to an original gas-in-place smaller than the cumulative production, a connected reservoir is the appropriate model to use.
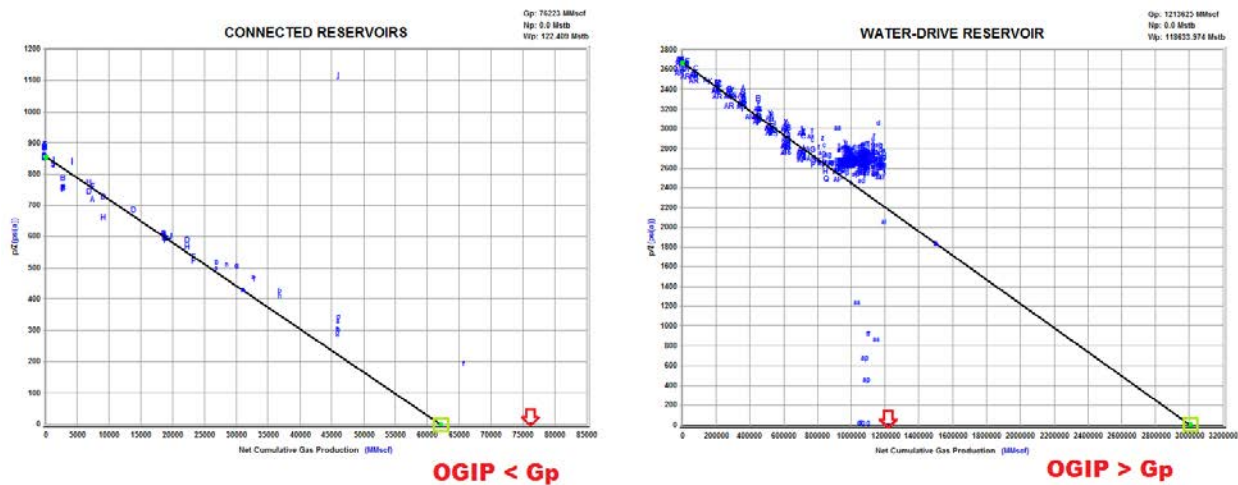
For a connected reservoir, the material balance equation is written as shown below to account for gas influx.

$$\frac{p_1}{Z_1}\left(S_{gi} - c_{wip} - c_{ep}\right) = \frac{p_i}{Z_i}\left(1 - \frac{G_{p1} + G_T}{G_1}\right)S_{gi}$$

$$\frac{p_2}{Z_2}\left(S_{gi} - c_{wip} - c_{ep}\right) = \frac{p_i}{Z_i}\left(1 - \frac{G_{p2} + G_T}{G_2}\right)S_{gi}$$

This can be converted into a dimensionless term similar to the terms describing relative change in pore volume (c_{wip}, c_{ep}, and c_d) for other models, as shown below.

$$c_d = -\frac{Z_1}{p_1}\frac{p_i}{Z_i}\,S_{gi}\,\frac{G_T}{G_1}$$

Similar to the water-drive model, the influx of gas from the second reservoir (G_T) is likely not a known value, and therefore it must be determined based on the size of the connected reservoir, and the transfer coefficient between the reservoirs. The equation for gas influx is shown below.

$$\Delta G_T = C(p_1 - p_2)\Delta t$$

Oil material balance

As seen in the general material balance equation, there are many unknowns, and as a result, finding an exact or unique solution can be difficult. However, using other techniques to help determine some variables (for example, m or original gas-in-place from volumetrics or seismic), the equation can be simplified to yield a more useful answer. Various plots are available to conduct an oil material balance rather than calculating an answer from individual measurements of reservoir pressure.

Havlena-Odeh (all reservoir types)

Similar to the interpretation of gas material balance, oil material balance uses plotting techniques. However, unlike the equation for single-phase gas expansion, the standard form of the material balance equation for oil reservoirs does not easily yield a linear relationship. The equation can be organized to show linear behavior. Based on the rearrangement below, the large combinations of terms are used as x and y, while G is the slope, and N is the intercept. This of course implies that water influx term for each data point is a known value, or the simpler scenario that there is no water influx. Additionally, if the water influx is neglected in calculating the terms, the result is non-linear behavior on the plot. This can be a diagnostic to determine the presence of water drive. In practice, the scatter in the data may be great enough, and the signature of water drive subtle enough that deviation from linear behavior on the Havlena-Odeh plot may go unnoticed.

$$\frac{F - W_e B_w}{E_o + B_{oi}E_{fw}} = N + G\left(\frac{E_g + B_{gi}E_{fw}}{E_o + B_{oi}E_{fw}}\right)$$

An example of the plot is shown below. The scatter shown in the data points demonstrates the difficulty in determining trends in the reservoir behavior.
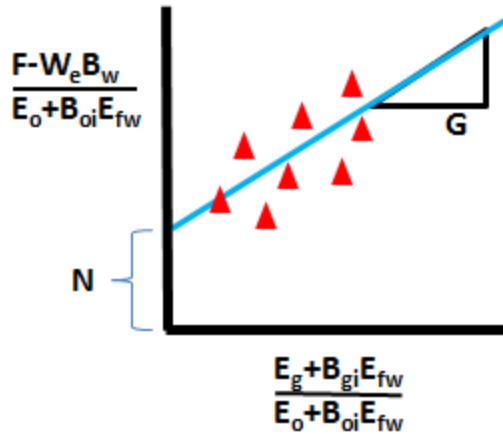
This method works for most reservoir types. In the case of an undersaturated reservoir (above bubble point), the $E_g + B_{gi} * E_{fw}$ term is zero, and this plot is not as useful. The standard Havlena-Odeh plot can be substituted for one that excludes free gas terms.

Havlena-Odeh F vs. Et (no initial gas cap)

If the reservoir to be analyzed has no initial free gas, the free gas terms of the equation can be eliminated. This equation is now much simpler to linearize. In the equation shown below, the total expansion term is split into the oil and water / formation expansion terms. Once again, the inclusion of water influx is such that it is assumed to be known.

$$F - W_e B_w = N \left(E_o + B_{oi} E_{fw} \right)$$

In this form of the equation, N is the slope on a plot of expansion terms versus withdrawal and influx terms. There is no intercept, so the analysis line is typically forced through zero. Similar to the Havlena-Odeh plot that includes gas terms, if water influx is neglected and a non-linear trend results, this can be a diagnostic for observing water-drive effects. An example of the plot is shown below.
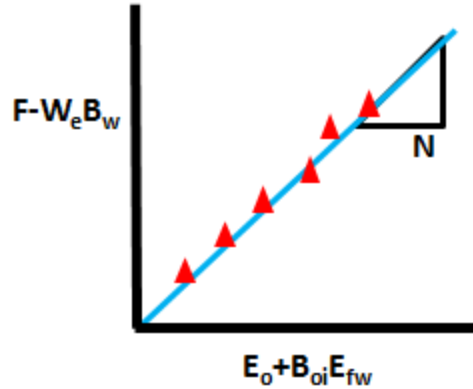
N vs. time

Using plots of various terms in the material balance equation can be used for overall analysis, but each pressure measurement can be independently used for material balance calculations. Comparing the results of the overall analysis and single-point calculations demonstrates whether there is consistency between methods. It is expected that the single-point calculations remain in a trend around the original oil-in-place determined from the overall analysis. This comparison can be plotted as a series of original oil-in-place results displayed at the point in time of the pressure measurement, with a continuous line at the value of original oil-in-place from the overall analysis. The plot is shown below.
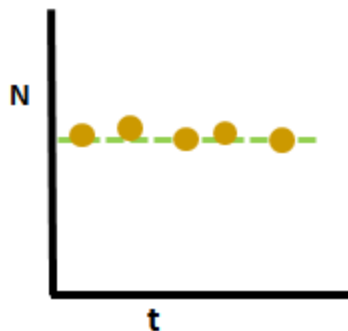
This plot is also useful as a diagnostic to determine if the correct reservoir type has been assumed, and also to assess the data quality. An inconsistent trend usually indicates that the quality of the pressure measurements are not good, or the definition of the wells in the reservoir should be reviewed. A consistent upward trend indicates that another drive mechanism may be present, whereas a downward trend indicates that not all wells in the reservoir have been included in the analysis.

Pressure history match

The pressure match method uses an iterative procedure that uses the values of original oil-in-place, original gas-in-place, and W to calculate the reservoir pressure versus time. The pressure match is then plotted against the real measured static reservoir pressures and compared. This is by far the most robust and easily understood material balance technique for the following reasons:

1. Pressure and time are easily understood variables, so sensitivity analysis can be conducted relatively easily.

2. Use of time enables the analyst to see directly the impact of:

   - Changing withdrawal rates, especially shut-ins on reservoir pressure declines.

   - Injection operations on pressure response.

   - Water drive and connected reservoirs on reservoir depletion, especially since these are both cumulative withdrawal and time-based processes.

3. A relatively simple, iterative process is used to achieve a unique solution wherein:

   - Start with the simplest solution (oil and/or gas depletion only) and then proceed to more complex models only if demonstrated to be required.

   - Employ a left-to-right matching technique (early-time to late-time), wherein initial reservoir pressure is matched first, followed by early-time depletion response, and then late-time responses. Since water drive and connected reservoir models are cumulative withdrawals and time-based, their responses are minimal at early-times and maximized at late-times.

4. Major changes to depletion, such as conversion to storage or blowdown can be both segregated (time) and integrated in a single analysis method.

An example of a pressure history match is shown below:
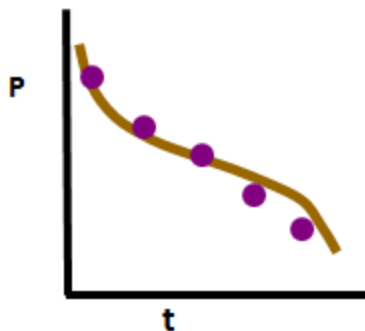
Drive indices

Drive indices for oil reservoirs indicate the relative magnitude of the various energy sources acting in the reservoir. A simple description of a drive index is the ratio of a particular expansion term to the net withdrawal (hydrocarbon voidage). These drive indices are cumulative and change as the reservoir is produced. A plot of drive indices and the details of specific drive indices are shown below.
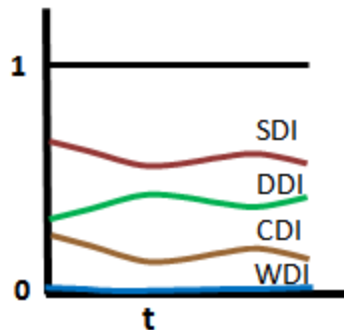
Summary of drive indices

Drive Index	Description
$DDI = \dfrac{NE_o}{F}$	Depletion drive index
$SDI = \dfrac{NmE_g\left(\dfrac{B_{oi}}{B_{gi}}\right)}{F}$	Segregation (gas cap) drive index
$WDI = \dfrac{W_e B_w - W_p B_w}{F}$	Water drive i Index
$CDI = \dfrac{N(1+m)E_{fw}B_{oi}}{F}$	Formation and connate water compressibility index

If the drive indices do not sum to unity (or very close to 1), the correct solution to the material balance has not been obtained.

Diagnostics — Dake and Campbell

Dake and Campbell plots are used as diagnostic tools to identify the reservoir type based on the signature of production and pressure behavior. The plots are established based on the assumption of a volumetric reservoir, and deviation from this behavior is used to indicate the reservoir type.

In the Dake plot, the simplest oil case of solution gas / depletion drive (no gas cap, no water drive), is used to determine the axes of the plot. The material balance equation is rearranged as shown below.

$$\frac{F}{E_o + B_{oi}E_{fw}} = N$$

In a volumetric reservoir producing due to depletion drive only, production is balanced by the oil and water / formation expansion, and the original oil-in-place is constant. If a plot of cumulative oil production versus the net withdrawal over expansion is created with this reservoir type's data, the points remain along a horizontal line.

If a gas cap is present, there is a gas expansion component in the reservoir's production. As production continues and the reservoir pressure decreases, the gas expansion term increases with an increasing gas formation volume factor. To balance this, the withdrawal over oil / water / formation expansion term must also continue to increase. Thus in the case of gas cap drive, the Dake plot shows a continually increasing trend.

Similarly, if water drive is present, the withdrawal over oil / water / formation expansion term must increase to balance the water influx. With a very strong aquifer, the water influx may continue to increase with time, while a limited or small aquifer may have an initial increase in water influx that eventually decreases.

Additional energy in system, water drive or gas cap drive

Downward trend may be due to outer boundary interference or aquifer interference due to offset drainage

Weak Water drive

Volumetric system expansion of oil/gas - withdrawals

$F/(E_o + B_{oi} E_{fw})$

N_p
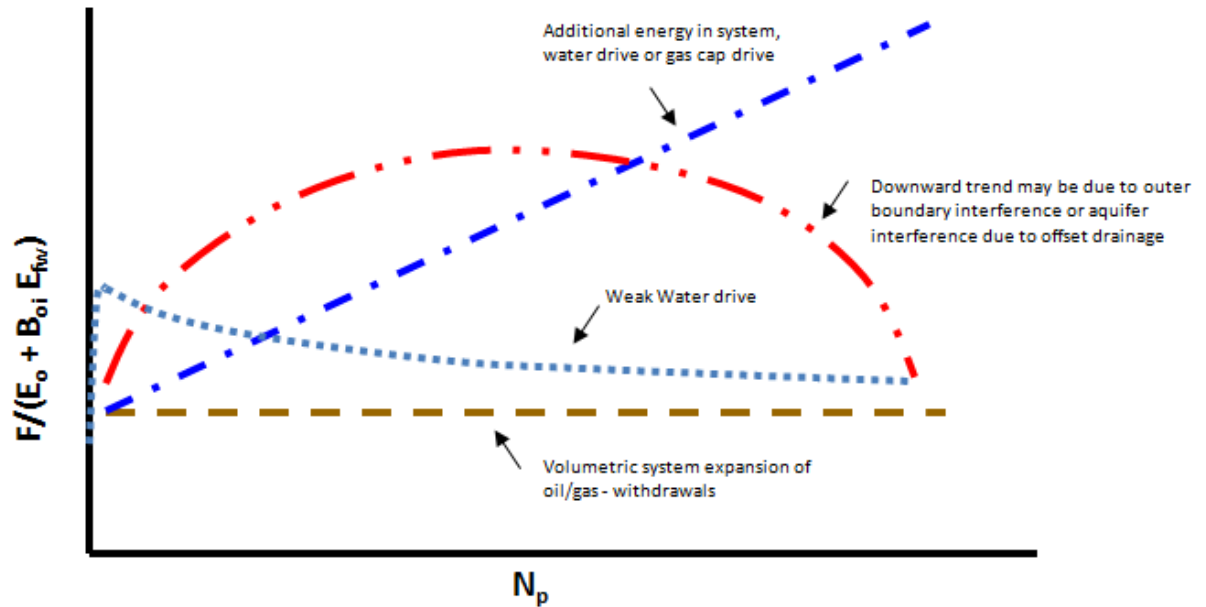
The Campbell plot is a very similar diagnostic to Dake, with the exception that it incorporates a gas cap, if required. In the Campbell plot, the withdrawal is plotted against withdrawal over total expansion, while the water influx term is neglected. If there is no water influx, the data plots as a horizontal line. If there is water influx into the reservoir, the withdrawal over total expansion term increases proportionally to the water influx over total expansion. The Campbell plot can be more sensitive to the strength of the aquifer. In this version of the material balance, using only E_T neglects the water and formation compressibility (compaction) term. The Campbell plot is shown below.
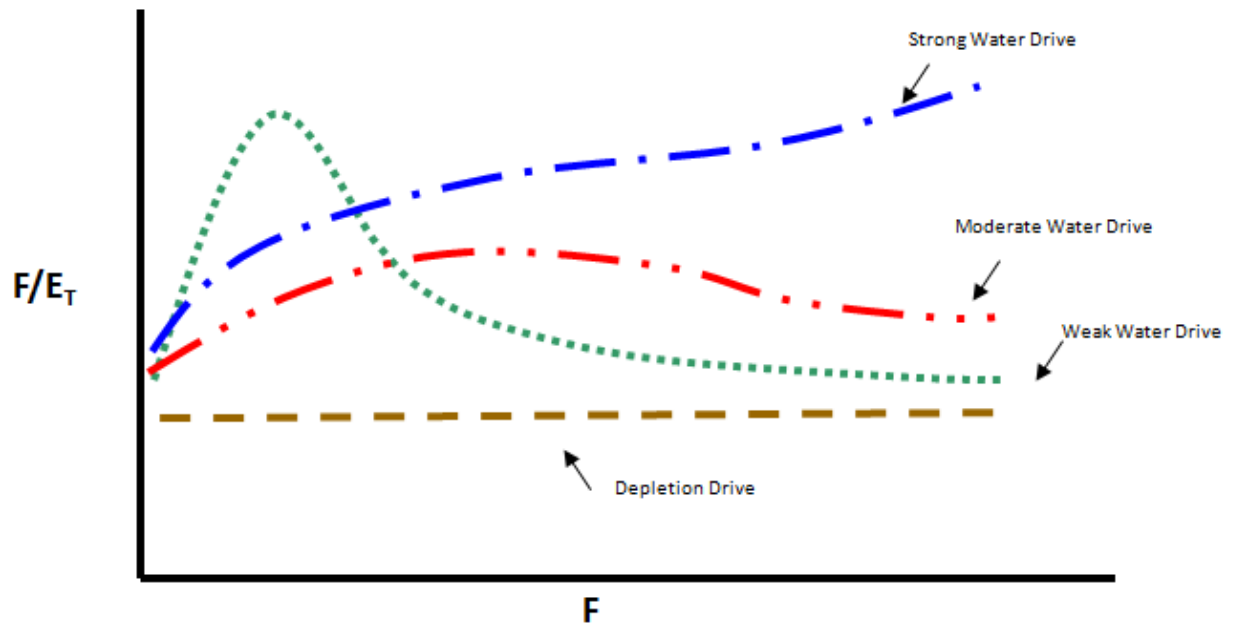
Voidage replacement ratio

Water injection is a secondary recovery technique that is often used as a means for pressure maintenance to re-energize a reservoir. There are many easy-to-use techniques for monitoring a water injection / waterflood project (Hall plot, WOR).
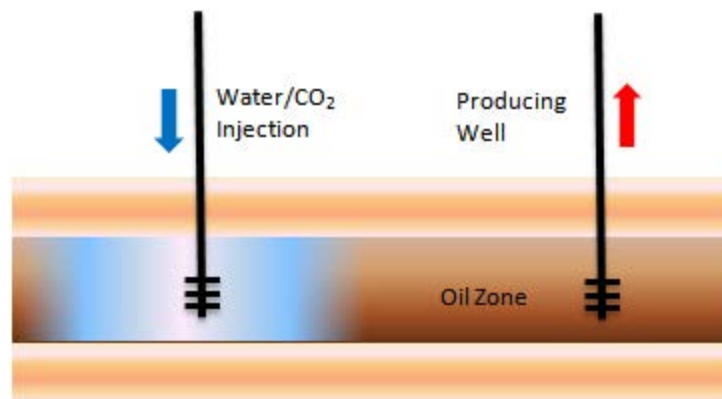
The voidage replacement ratio (VRR) is defined as the ratio of injected reservoir volume to produced reservoir volume.

$$Instantaneous \; VRR = \frac{q_{winj}B_{winj} + q_{ginj}B_{ginj}}{q_oB_o + q_o(R_p - R_s)B_g + q_wB_w}$$

$$Cumulative \; VRR = \frac{W_{inj}B_{winj} + G_{inj}B_{ginj}}{N_pB_o + N_p(R_p - R_s)B_g + W_pB_w}$$

Typically, waterflooding commences after a period of primary production. The purpose of waterflooding is to enhance recovery by maintaining reservoir pressure, or when necessary, increasing reservoir pressure so that it approaches the bubble point pressure to maintain solution gas. Consequently, the instantaneous voidage replacement ratio often commences at values greater than one, and then declines gradually to one as the target reservoir pressure is achieved.
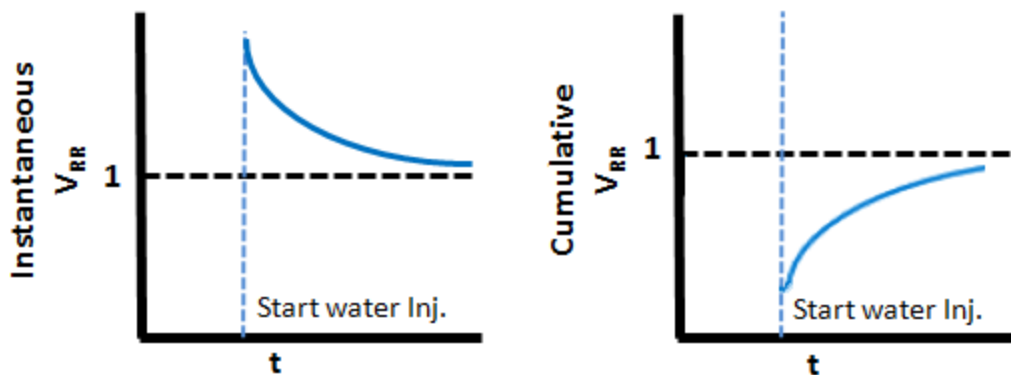
Voidage replacement calculations are often conducted on the entire reservoir. Since reservoirs are more heterogenous than homogenous, even though the voidage replacement may be unity for the reservoir, some areas may be greater than unity, and others much less than unity. Most analysts consequently perform voidage replacement calculations on a pattern basis, matching each injector with a group of nearby producing wells. In this way, areas not receiving enough water to replace voidage can be revised by adding more injectors, or by shutting in producers. Likewise, areas receiving too much water can have the injection rates reduced.

Use of voidage replacement calculations is an excellent way to better understand connectivity within a reservoir.

Volatile oil — Walsh formulation

Volatile oil is also called high shrinkage crude oil, or near-critical oil. It contains relatively fewer heavy molecules and more intermediates than black oils. It has a higher API (typically greater than 44), and is

typically lighter in color.

A small reduction in pressure below the bubble point causes the release of a large amount of gas in the reservoir. An additional property is used to the describe volatile oil – the volatile oil ratio Rv. The volatile oil ratio describes the amount of volatilized oil in the reservoir gas phase and is typically expressed in stb/ MMscf. The volatile oil ratio is often described as "the liquid content in the gas" or the "oil vapor in the gas". An oil reservoir can be described as volatile, if the gas in the gas cap or the gas that comes out of solution contains significant quantities of volatile liquids. Volatile oils normally contain more than 500scf/ stb of dissolved gas and the liquid content of the gas phase, the volatile oil ratio, would be more than 20stb/ MMscf.

Regular material balance does not account for volatile oil. In a reservoir containing volatile oil, the Walsh formulation is used to calculate original oil-in-place. The equations which are modified from standard material balance are shown below.

Terms	Description
$$F = N_p \left(\frac{B_o - B_g R_s}{1 - R_v R_s} \right) + G_p \left(\frac{B_g - R_v B_o}{1 - R_v R_s} \right) + W_p B_w - W_{inj} B_{winj} - G_{inj} B_{ginj}$$	Modified withdrawal term for volatile oil.
$$E_o = \frac{(B_o - B_{oi}) + B_g (R_{si} - R_s) + R_v (B_{oi} R_s - B_o R_{si})}{1 - R_v R_s}$$	Modified oil expansion term for volatile oil.
$$E_g = \frac{(B_g - B_{gi}) + B_o (R_{vi} - R_v) + R_s (B_{gi} R_v - B_g R_{vi})}{1 - R_v R_s}$$	Modified gas expansion term for volatile oil.

Probabilistic theory

In the presence of uncertainty re: input data required for determining the best estimate of a value, probabilistic methods are used. For example, there may be uncertainty in net pay or drainage area while estimating OGIP using volumetric calculations.

Probabilistic analysis is a technique to quantify the impact of these uncertainties on output variables, and to determine a range of possible outcomes, as opposed to a single deterministic solution. The uncertainty in the output also provides a measure of the validity of the model.

The Monte Carlo simulation (using Latin hypercube sampling) is an established approach of performing a probabilistic analysis. The Monte Carlo analysis involves a large number of runs, each of which is a deterministic calculation. The inputs to these deterministic calculations are randomly drawn from probability density functions (PDFs) that describe the likely values of an input parameter. The more realistic these PDFs are, the more realistic the estimate of the output parameter, as calculated by the Monte Carlo simulation.

Probability distribution types

In this section, we define the different probability distribution types used as part of the probabilistic analysis. The definitions include the equations for the PDF, cumulative distribution function (CDF), mean, median, and mode for each of the probability distribution types.

Normal distribution
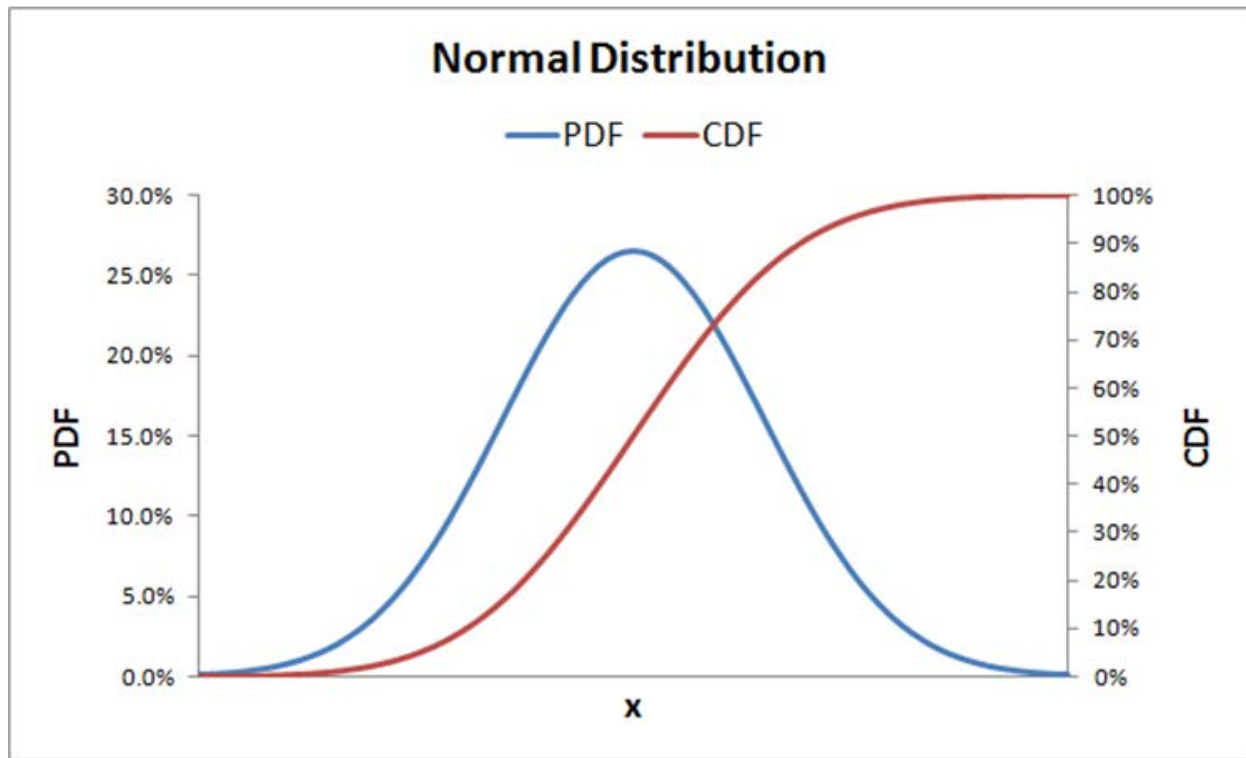
PDF: $f(x) = \dfrac{1}{\sigma\sqrt{2\pi}}\, e^{-(x-\mu)^2/(2\sigma^2)}$

CDF: $F(x) = \dfrac{1}{2}\left[1 + \mathrm{erf}\left(\dfrac{x-\mu}{\sigma\sqrt{2}}\right)\right]$

$$\text{Mean} = \text{Median} = \text{Mode} = \mu = \frac{1}{n}\sum_{i=1}^{n} x_i$$

$$\text{Variance} = \sigma^2 = \frac{1}{n-1}\sum_{i=1}^{n}(x_i - 1)^2$$

Log-normal distribution
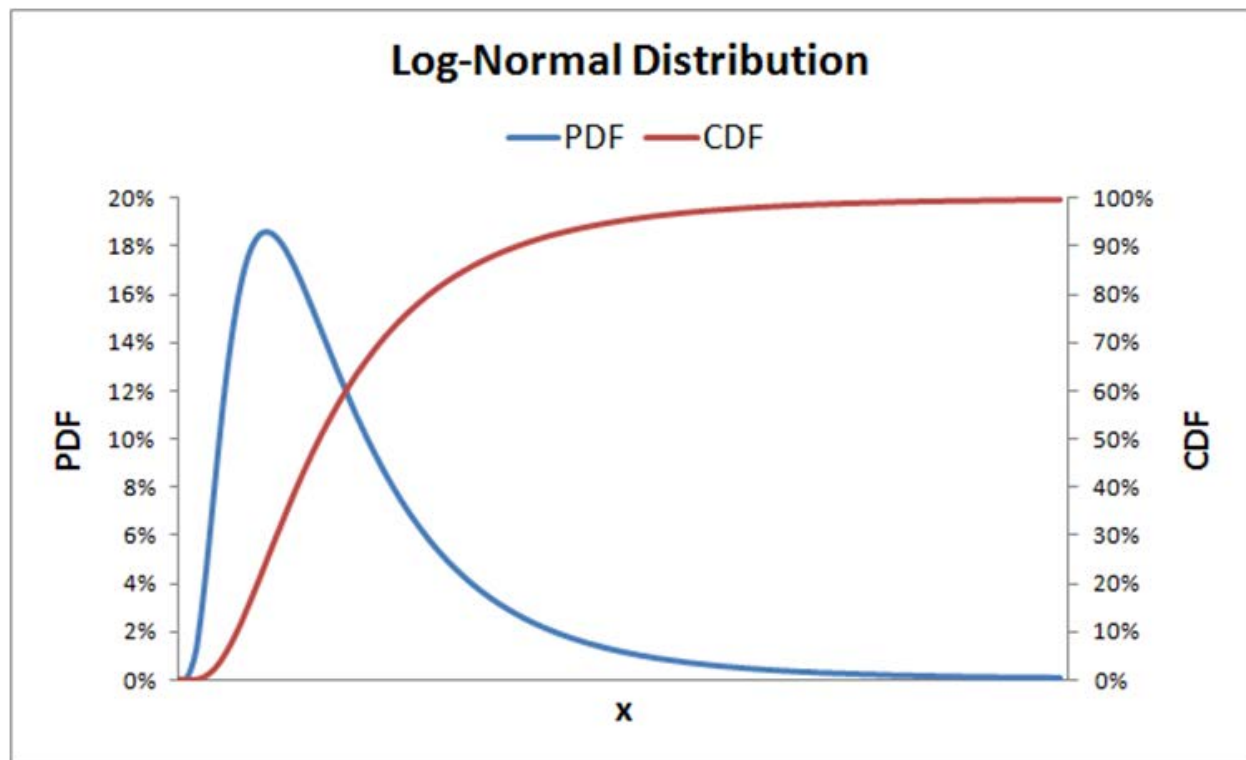
PDF: $f(x) = \dfrac{1}{x\sigma\sqrt{2\pi}}e^{-(\ln(x)-\mu)^2/(2\sigma^2)}$

CDF: $F(x) = \dfrac{1}{2} + \dfrac{1}{2}\left[1 + \mathrm{erf}\left(\dfrac{\ln(x)-\mu}{\sigma\sqrt{2}}\right)\right]$

$\text{Mean} = e^{\mu+\sigma^2/2}$

$\text{Mode} = e^{\mu-\sigma^2}$

$\text{Median} = e^{\mu}$

$\text{Variance} = \left(e^{\sigma^2}-1\right)e^{\sigma^2+2\mu}$

A log-normal distribution is the probability distribution of a random variable whose natural logarithm follows a normal distribution. The log of a set of data that follows a log-normal distribution follows a normal distribution. As such, it should be noted that μ is the mean of the natural log of the dataset, and σ is the standard deviation of the natural log of the dataset (that is, the mean and standard deviation of the underlying normal distribution).

Triangular distribution
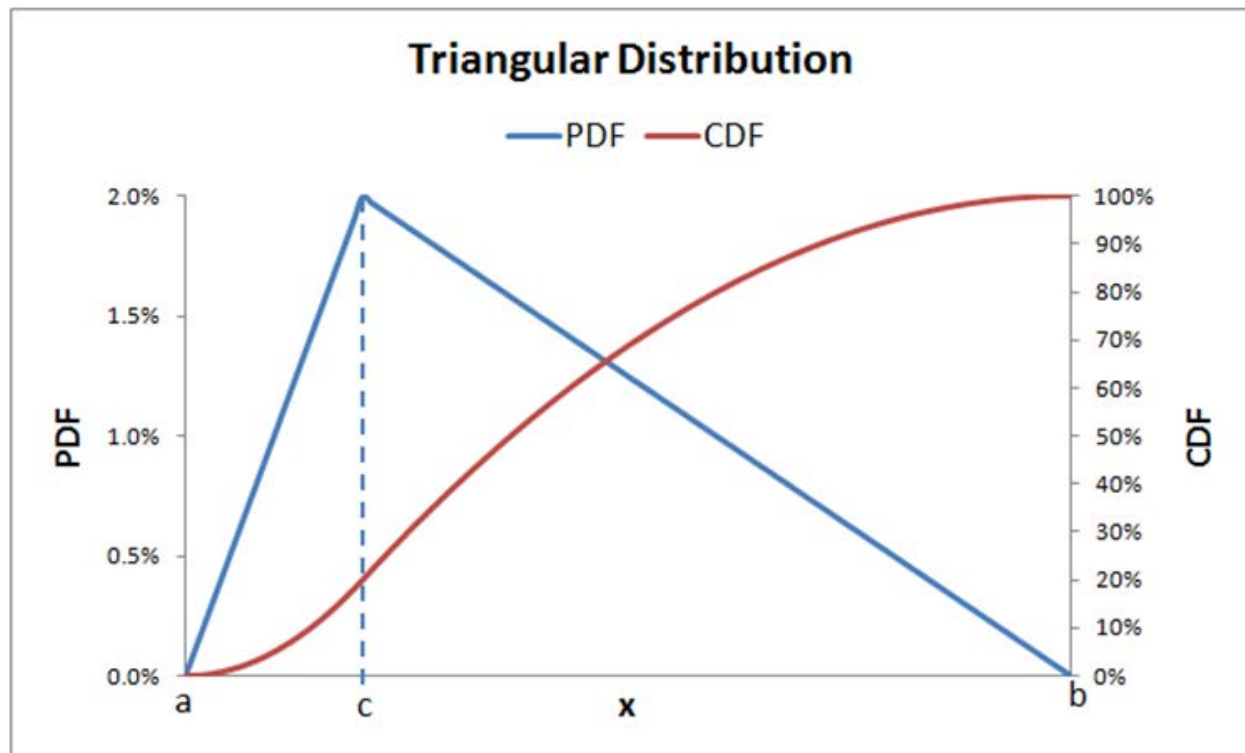
$$\text{PDF: } f(x) = \begin{cases} 0 & x < a \\[2mm] \dfrac{2(x-a)}{(b-a)(c-a)} & a \leq x \leq c \\[2mm] \dfrac{2(b-x)}{(b-a)(b-c)} & c < x \leq b \\[2mm] 0 & b < x \end{cases}$$

$$
\text{CDF: } F(x) = \begin{cases} 0 & x < a \\[2mm] \dfrac{(x-a)^2}{(b-a)(c-a)} & a \le x \le c \\[3mm] 1 - \dfrac{(b-x)^2}{(b-a)(b-c)} & c < x \le b \\[3mm] 1 & b < x \end{cases}
$$

$$
\text{Mean} = \frac{1}{3}(a+b+c)
$$

$$
\text{Median} = \begin{cases} a + \dfrac{\sqrt{(b-a)(c-a)}}{\sqrt{2}} & c \ge \dfrac{a+b}{2} \\[4mm] b - \dfrac{\sqrt{(b-a)(b-c)}}{\sqrt{2}} & c \le \dfrac{a+b}{2} \end{cases}
$$

$$
\text{Mode} = c
$$

$$
\text{Variance} = \frac{a^2 + b^2 + c^2 - ab - ac - bc}{18}
$$

Uniform distribution
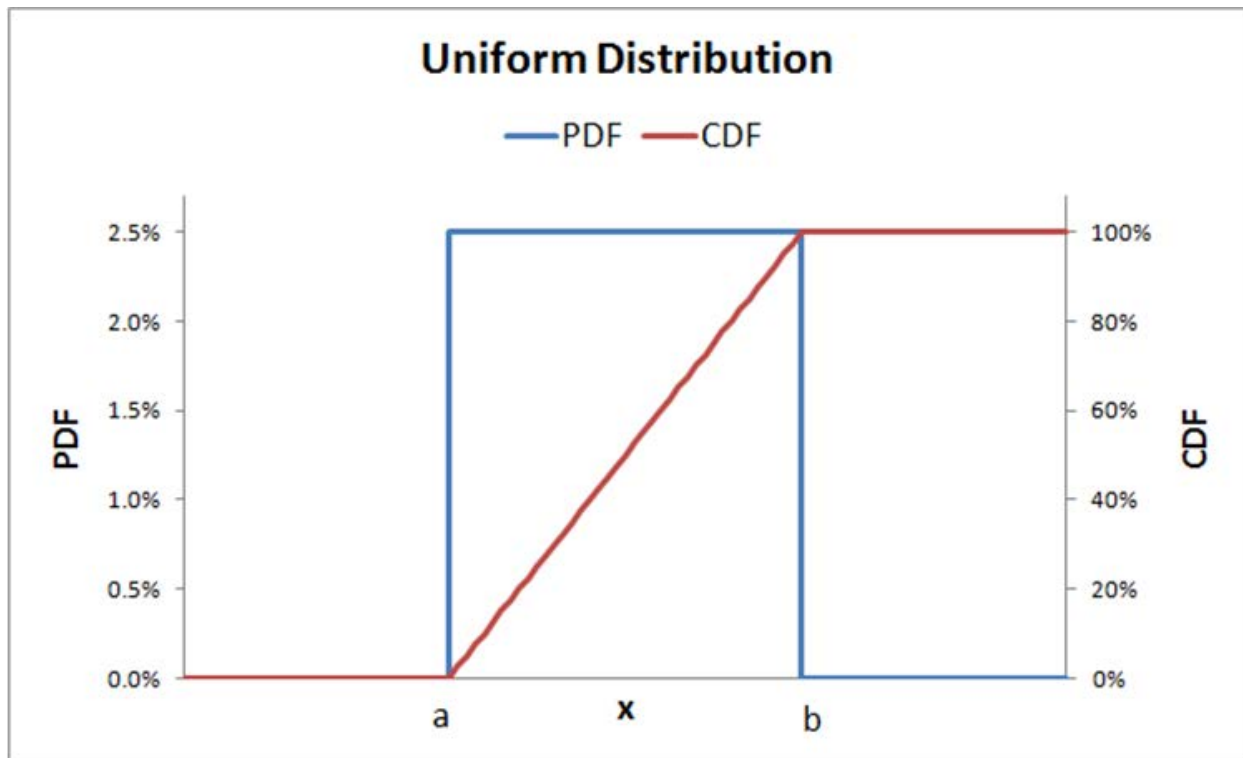
PDF: $f(x) = \begin{cases} \dfrac{1}{b-a} & a \leq x \leq b \\ \\ 0 & \text{otherwise} \end{cases}$

CDF: $F(x) = \begin{cases} 0 & x \leq a \\ \dfrac{x-a}{b-a} & a < x < b \\ 1 & x \geq b \end{cases}$

$\text{Mean} = \text{Median} = \dfrac{1}{2}(a+b)$

$\text{Mode} = \text{any value in } a \leq x \leq b$

$$\text{Variance} = \frac{1}{12}(b-a)^2$$

Calculation methods

Calculation methods are described below.

Monte Carlo simulation

The Monte Carlo simulation is a stochastic modeling method to simulate real-world situations where there is uncertainty in the input variables. This uncertainty cannot be directly modeled using analytical solutions. While conceptually very simple, a trivial example provides the easiest route to developing an understanding of the Monte Carlo simulation procedure.

Consider the simple estimation of prospect reserves (*EUR*, stbo) calculated as the product of the prospect area (*A*, acres), average net hydrocarbon thickness (*h*, feet), and recovery factor (*RF*, stbo/acre-ft). The algebraic expression of this simple model is:

EUR = A × h × RF

The deterministic approach would simply multiply the "best estimate" for each of these quantities to obtain a single value of EUR. The deterministic approach assumes that the most likely value of every input is encountered simultaneously, which is generally very unrealistic.

Suppose that for each of the three input variables, *A*, *h*, and *RF*, independent cumulative probability distributions can somehow be defined, thereby describing the uncertainty in each of these variables. The Monte Carlo method can make use of these distributions to arrive at an overall cumulative probability distribution (overall uncertainty) for EUR. This analysis approach is superior to the single-valued deterministic approach because of the valuable insight gained into the "upside," "downside," "most likely outcome," and the "mean" level of reserves that would result from drilling a large number of similar prospects.

The following describes one pass in the Monte Carlo simulation procedure:

1. Generate a random number between zero and one (representing the value of the cumulative probability) for each of the three input variables.

2. Enter the cumulative probability distribution for each input variable at their respective random number to determine the "sampled" value for each input.

3. Multiply the three independent variable sampled values to yield a sample reserve estimate.

An individual calculation or run to estimate a prospect size in this fashion is known as a "pass". By itself, the individual value of EUR generated by a pass is meaningless. However, when repeated a large number of times, a cumulative distribution for the EUR emerges.

The minimum number of passes required depends on the number of input variables that are risked. Generally, enough runs are needed to ensure that the entire domain of input variables is examined. The larger the number of input variables, the larger the minimum number of passes required.

Typically, 1000 or more passes comprise a single Monte Carlo simulation. As a qualitative rule, a smooth CDF of output variables is an indication of an appropriate number of runs.

After a Monte Carlo simulation run is finished, an analysis of the results follows. Assuming a 1,000 pass simulation run, results are processed as follows:

1. Arrange EUR results in ascending order.

2. Number the sorted EUR values from 1 to the total number of samples (for example, 1,000).

3. Calculate the cumulative probability of each value by dividing the sample number by the total number of samples (in this case, 1000).

4. Plot the resultant cumulative probability function (Cumulative Probability vs. EUR) to ascertain the smoothness of the distribution. Lacking a smooth distribution necessitates re-running the simulation with a larger number of passes.

5. Calculate the mean, variance, P10, P50, P90, and any other desired statistical parameters.

This analysis yields the statistical parameters desired for the prospect analysis. Expect the values of these parameters to vary slightly with each simulation. An unacceptably large variation warrants an increase in the number of passes.

Latin hypercube sampling

Selecting random values for model parameters can require a large number of simulation passes to generate a smooth cumulative probability distribution. Latin hypercube sampling, also known as stratified sampling, is a process applied to multiple variables to reduce the required number of passes in a Monte Carlo simulation.

First, stratified sampling is used to force randomly generated numbers to conform to the CDF represented by their statistical distribution. Normally, you could generate a random number between zero and one representing the cumulative probability a number of times, and use those numbers to read the CDF. Instead, the span of zero to one is split between the number of samples to be taken, and points within those smaller spans are randomly selected. Each of the samples is generated by:

$$\frac{n-1}{N} + \frac{r}{N}$$

where n is the interval index, N is the number of non-overlapping intervals, and r is a randomly generated number between zero and one (newly generated for each sample).

The effects of stratified sampling can be dramatic. The figure below compares the Cumulative Frequency Plot of 100 random samples with 100 stratified samples.
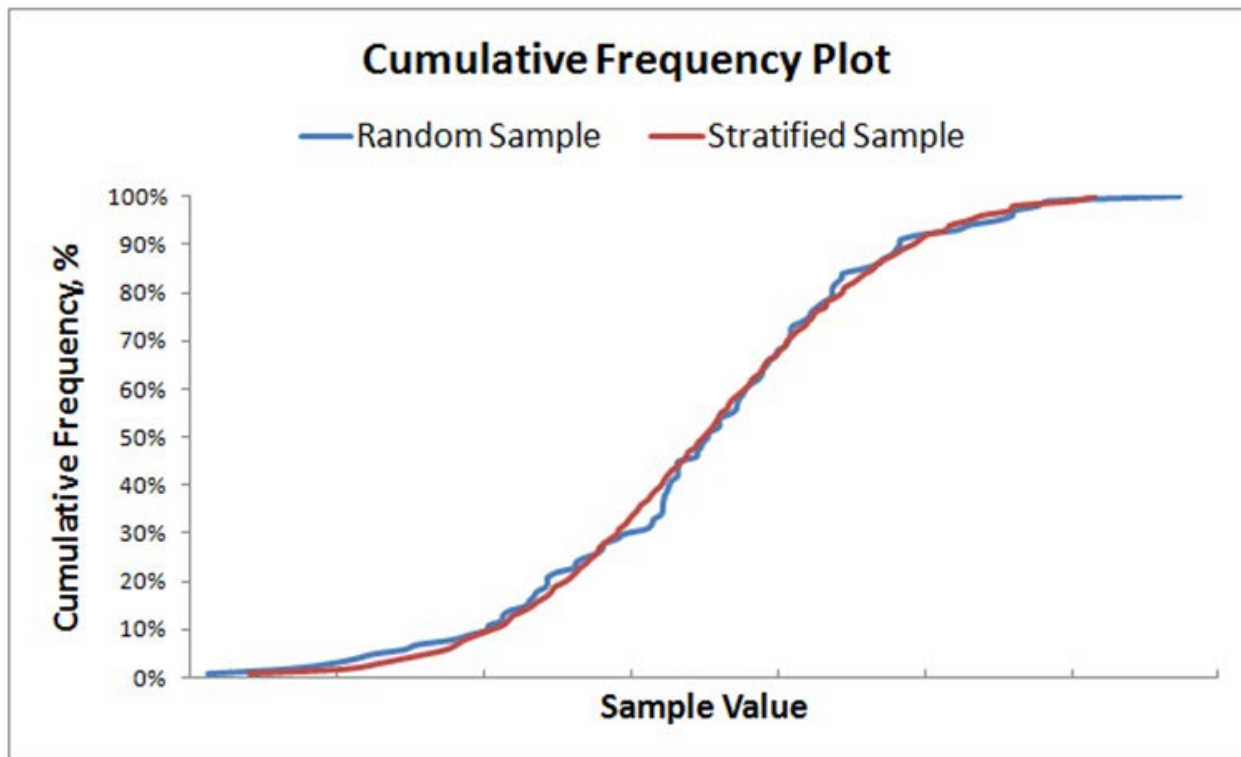
After the stratified sampling is performed on all variables, the samples are randomly grouped together to generate the parameters to be entered into the model for each simulation pass. Each value must only be used once.

Correlated sampling

This section describes methods for generating multiple sequences of correlated random variables. In other words, the values sampled in one distribution are correlated to the values sampled in another distribution, given the correlation coefficients between the two samples.

These screenshots show examples of two sequences of uncorrelated and correlated random data.

Two sequence of uncorrelated data: **Two sequence of correlated data:**
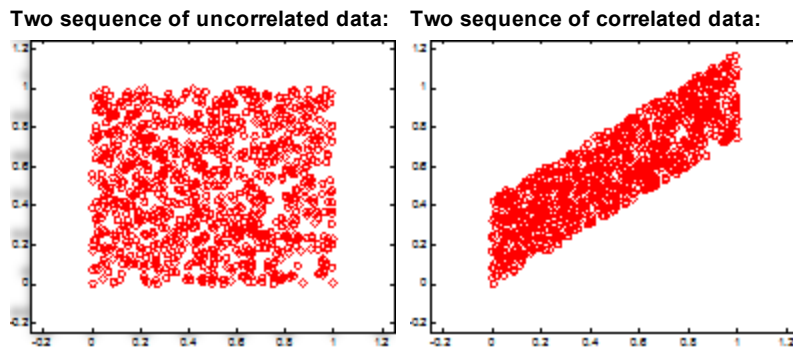
Creation of correlated random variables

The rank-order correlation approach of Spearman as presented by Iman and Conover (Iman & Conover, 1982) is used to create a set of multi-variable correlated random variables.

This approach is based on using rank correlations to define dependencies among input variables. By ranking the values and using them as opposed to the actual values, the Spearman rank correlation of the input values are kept as close as possible to the target rank correlation coefficient matrix, as specified.

Because this approach is distribution-free:

- it preserves the exact form of the probability distribution functions
- it may be used with any type of distribution function

Auto-correction to user-input correlation coefficient matrix

To generate a sequence of multi-variable correlated random numbers, we need to specify the applicable matrix of correlation coefficients. This matrix is required to be positive and definite (that is, all the eigenvalues of this matrix are to be greater than zero).

If the user-specified matrix of correlation coefficients fails to qualify as a positive-definite matrix, "The Method of Eigenvalues" is used to auto-correct the matrix. Through application of slight perturbation to negative or zero eigenvalues, this method attempts to repair the correlation coefficient matrix, and make it a positive-definite one, while introducing the smallest possible changes to the matrix.

Truncated distributions

Truncated distributions are described below.

Definitions and concept

A truncated distribution is a conditional distribution that results from restricting the domain of some other distribution. In practical statistics, a truncated distribution arises from situations where the ability to record, or even know about, occurrences is limited to values which lie above or below a given threshold, or specific range.

Assuming that a random variable x has a probability density function of $f(x)$ and a cumulative distribution function of $F(x)$, which both have infinite support ($-\infty < x < \infty$), then the probability density function after truncating the support to $a < x \le b$ can be expressed as:

$$f(x|a < x \le b) = \frac{g(x)}{F(b) - F(a)} = Tr(x)$$

where:

$$g(x) = \begin{cases} f(x) & a < x \le b \\ 0 & \text{everywhere else} \end{cases}$$

Note that $Tr(x)$ itself is a distribution such that:

$$F(x|a < x \le b) = \frac{1}{F(b) - F(a)} \int_a^b g(x)d(x) = 1$$

In general, the PDF of a truncated distribution function can be calculated as:

$$TrPDF(x) = \frac{g(x)}{F(b) - F(a)} \quad a < x \le b$$

$$TrPDF(x) = \frac{g(x)}{1 - F(a)} \quad a < x$$

$$TrPDF(x) = \frac{g(x)}{F(b)} \quad x \le b$$

The CDF of a truncated distribution function can be calculated as:

$$TrCDF(x) = \frac{\int_a^x g(x)dx}{F(b) - F(a)} \quad a < x \le b$$

$$TrCDF(x) = \frac{\int_a^x g(x)dx}{1 - F(a)} \quad a < x$$

$$TrCDF(x) = \frac{\int_{-\infty}^x g(x)dx}{F(b)} \quad x \le b$$

The mean of the truncated distributions are calculated as:

$$\text{mean}(x) = \frac{\int_a^x xg(x)dx}{F(b) - F(a)} \quad a < x \le b$$

$$\text{mean}(x) = \frac{\int_a^x xg(x)dx}{1 - F(a)} \quad a < x$$

$$\text{mean}(x) = \frac{\int_{-\infty}^x xg(x)dx}{F(b)} \quad x \le b$$

Special case: truncated normal distributions

Defining:

$$\phi(x) = \frac{1}{2\pi} e^{-\frac{1}{2}x^2}$$

$$\Phi(x) = \frac{1}{2}\left[1 + \text{erf}\left(\frac{x}{\sqrt{2}}\right)\right]$$

The PDF of a truncated normal distribution can be calculated as:

$$TrPDF(x) = \frac{\frac{1}{\sigma}\phi\left(\frac{x-\mu}{\sigma}\right)}{\Phi\left(\frac{b-\mu}{\sigma}\right) - \Phi\left(\frac{a-\mu}{\sigma}\right)} \quad a \leq x \leq b$$

$$TrPDF(x) = \frac{\frac{1}{\sigma}\phi\left(\frac{x-\mu}{\sigma}\right)}{1 - \Phi\left(\frac{a-\mu}{\sigma}\right)} \quad a \leq x$$

$$TrPDF(x) = \frac{\frac{1}{\sigma}\phi\left(\frac{x-\mu}{\sigma}\right)}{\Phi\left(\frac{b-\mu}{\sigma}\right)} \quad x \leq b$$

The mean of a truncated normal distribution can be calculated as:

$$\text{mean}(x) = \mu + \frac{\phi\left(\frac{a-\mu}{\sigma}\right) - \phi\left(\frac{b-\mu}{\sigma}\right)}{\Phi\left(\frac{b-\mu}{\sigma}\right) - \Phi\left(\frac{a-\mu}{\sigma}\right)}\sigma \quad a \leq x \leq b$$

$$\text{mean}(x) = \mu + \frac{\phi\left(\frac{a-\mu}{\sigma}\right)}{1 - \Phi\left(\frac{a-\mu}{\sigma}\right)}\sigma \quad a \leq x$$

$$\text{mean}(x) = \mu + \frac{\phi\left(\frac{b-\mu}{\sigma}\right)}{\Phi\left(\frac{b-\mu}{\sigma}\right)}\sigma \quad x \leq b$$

The variance of a truncated normal distribution can be calculated as:

$$\text{variance}(x) = \sigma^2 \left[1 + \frac{\left[\left(\frac{a-\mu}{\sigma}\right)\phi\left(\frac{a-\mu}{\sigma}\right)\right] - \left[\left(\frac{b-\mu}{\sigma}\right)\phi\left(\frac{b-\mu}{\sigma}\right)\right]}{\Phi\left(\frac{b-\mu}{\sigma}\right) - \Phi\left(\frac{a-\mu}{\sigma}\right)} - \left[\frac{\phi\left(\frac{a-\mu}{\sigma}\right) - \phi\left(\frac{b-\mu}{\sigma}\right)}{\Phi\left(\frac{b-\mu}{\sigma}\right) - \Phi\left(\frac{a-\mu}{\sigma}\right)}\right]^2\right] \quad a \leq x \leq b$$

$$\text{variance}(x) = \sigma^2 \left[1 + \frac{\left(\frac{a-\mu}{\sigma}\right)\phi\left(\frac{a-\mu}{\sigma}\right)}{1 - \Phi\left(\frac{a-\mu}{\sigma}\right)} - \left[\frac{\phi\left(\frac{a-\mu}{\sigma}\right)}{1 - \Phi\left(\frac{a-\mu}{\sigma}\right)}\right]^2\right] \quad a \leq x$$

$$\text{variance}(x) = \sigma^2 \left[1 + \frac{\left(\frac{b-\mu}{\sigma}\right)\phi\left(\frac{b-\mu}{\sigma}\right)}{\Phi\left(\frac{b-\mu}{\sigma}\right)} - \left[\frac{\phi\left(\frac{b-\mu}{\sigma}\right)}{\Phi\left(\frac{b-\mu}{\sigma}\right)}\right]^2\right] \quad x \leq b$$

Stretched exponential decline theory

One of the benefits of a <u>stretched exponential decline</u> is that for positive n, τ, q_i, the model gives a finite value of <u>EUR</u>, even if no abandonment constraints are used in time or rate.

The Stretched Exponential Production Decline Model		
$\frac{dq}{dt} =$	$-n\left(\frac{t}{\tau}\right)^n \frac{q}{t}$	Defining the differential equation of the model
q =	$q_o \exp\left[-\left(\frac{t}{\tau}\right)^n\right]$	Rate expression as a function of time
Q =	$\frac{q_o \tau}{n}\left\{\Gamma\left[\frac{1}{n}\right] - \Gamma\left[\frac{1}{n}, \left(\frac{t}{\tau}\right)^n\right]\right\}$	Cumulative production as a function of time
EUR =	$\frac{q_o \tau}{n}\Gamma\left[\frac{1}{n}\right]$	EUR in terms of model parameters
Reference <u>SPE</u> papers: 134231, 143666, 137414, 144311, and 135616.		

Typecurve theory

Typecurve theory includes the following:

- Agarwal-Gardner
- Blasingame
- Compound Linear
- Fetkovich
- NPI
- Transient
- Wattenbarger

Agarwal-Gardner typecurve theory

Agarwal and Gardner have compiled and presented decline typecurves for analyzing production data. Their methods build upon the work of Fetkovich, Palacio, and Blasingame, using the concepts of the equivalence between constant rate and constant pressure solutions. Agarwal and Gardner present typecurves with dimensionless variables based on the conventional welltest definitions, as opposed to the Fetkovich dimensionless definitions used by Blasingame et al. They also include primary and semi-log pressure derivative plots (in inverse format for decline analysis). Furthermore, they present their decline curves in additional formats to the standard normalized rate vs. time plot. These include the rate vs. cumulative, and cumulative vs. time analysis plots.

Rate-cumulative production analysis

Dimensionless typecurves

Agarwal et al. propose the use of rate-cumulative typecurves for estimating gas- or oil-in-place. Dimensionless rate (q_D) is plotted against dimensionless cumulative production (Q_{DA}), which is defined as follows

$$Q_{DA} = \frac{t_{DA}}{p_D} = q_D t_{DA}$$

The resulting typecurves are straight lines on a Cartesian graph, which are anchored at the point 0.159, as shown in the following figure. A plot of dimensionless rate vs. dimensionless cumulative production yields a straight line that passes through Q_{DA} = 0.159 at q_D = 0, provided that fluid-in-place has been estimated correctly.

Rate-cumulative production decline-type curves
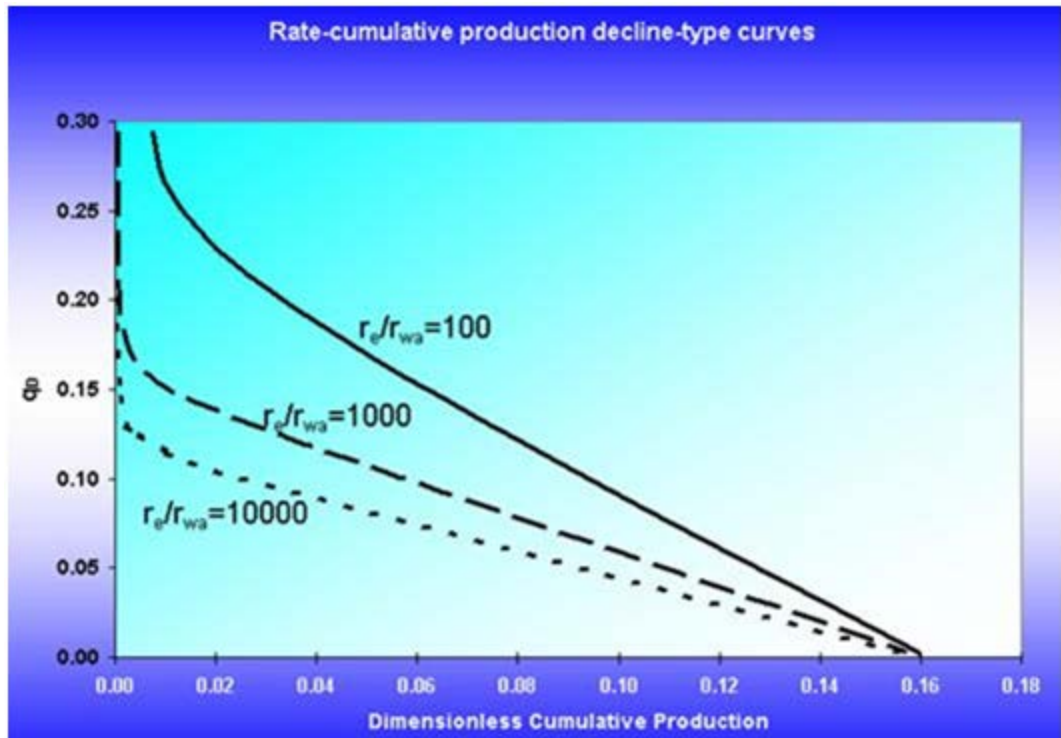
Modifications in RTA

The presentation of rate-cumulative analysis in rate transient analysis (RTA) is modified significantly from that of Agarwal and Gardner. See methodology: r ate-cumulative.

Data Preparation

The rate vs. cumulative production analysis is performed to estimate the hydrocarbons-in-place.

Oil wells

Plot pressure-drop normalized flow rate (q / Δp) vs. modified cumulative production on Cartesian coordinates, where:

$$Q_m = \frac{N_p}{c_t \left(p_i - p_{wf}\right)}$$

Gas wells

Estimate original gas-in-place (a lower bound estimate can be obtained by performing a straight line extrapolation on a rate vs. cumulative production plot. Another estimate is the volumetric gas-in-place).

Plot pressure-drop normalized flow rate vs. modified cumulative production on Cartesian coordinates, where:

$$Q_m = \frac{G\left(p_{pi} - \bar{p}_p\right)}{\left(p_{pi} - p_{wf}\right)} = \frac{2q t_{ca} p_i}{\left(c_t \mu Z\right)_i \left(p_{pi} - p_{pwf}\right)}$$

Analysis

Oil wells

Perform a straight line extrapolation of the data. The value where the extrapolated line crosses the x-axis is the original oil-in-place.

Gas wells

Perform a straight line extrapolation of the data. If the extrapolated line crosses the x-axis short of the estimated gas-in-place, choose a smaller gas-in-place input value. If the extrapolated line crosses the x-axis beyond the estimated gas-in-place, choose a larger gas-in-place input value. Then, re-calculate the material balance pseudo-time function and re-plot the data.

Rate-time production analysis

Dimensionless typecurves

The Agarwal-Gardner rate-time analysis plot includes dimensionless typecurves, based on the constant rate solution. Unlike Blasingame, these typecurves are graphed using the well-test variables dimensionless rate and dimensionless time. Agarwal and Gardner also include typecurves for the primary pressure derivative and semi-logarithmic (well-test) derivative (plotted as an inverse). The result is a diagnostic analysis that clearly shows the transition point from transient to boundary-dominated flow. The dimensionless pressure for standard well-test analysis is defined as:

$$p_D = \frac{kh\left(p_i - p_{wf}\right)}{141.2 q B \mu}$$

The dimensionless flow rate is simply the inverse of the previous equation (note that in the well-test literature, dimensionless rate has a slightly different definition):

$$q_D = \frac{1}{p_D}$$

The primary and semi-log (inverse) derivative typecurves are as follows:

$$\frac{\partial p_D}{\partial t_D} \; and \; \frac{\frac{1}{\frac{\partial p_D}{\partial \ln t_D}}}{}$$

The resulting dimensionless typecurve plot is shown below.
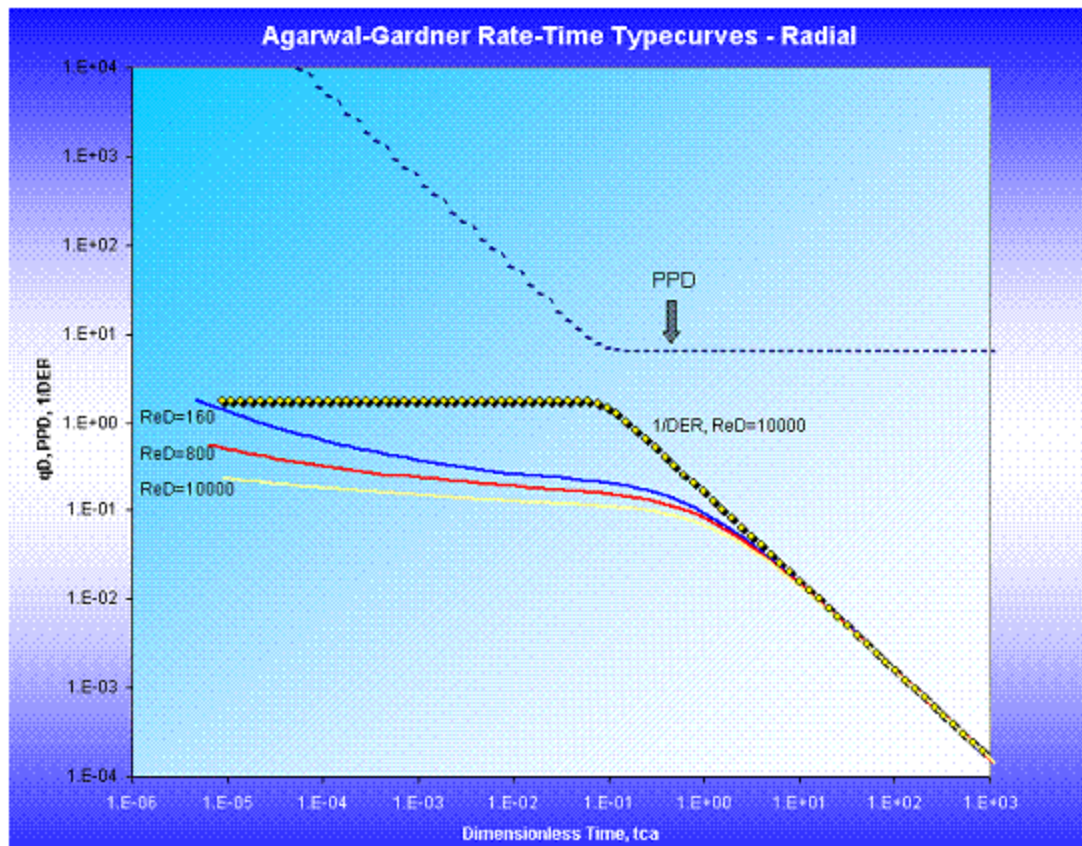
Modifications in RTA

In RTA, this analysis has been modified slightly; In addition to the semi-log derivative, a semi-log *integral* derivative curve is included. The advantage of the integral derivative curve is that the data has far

less scatter, while retaining a shape identical to the semi-log derivative, only offset in the time scale.

The RTA rendition of the Agarwal-Gardner Rate-Time plot is shown below. Note that the primary pressure derivative plot is not included in the RTA presentation.

Agarwal-Gardner Typecurve Analysis
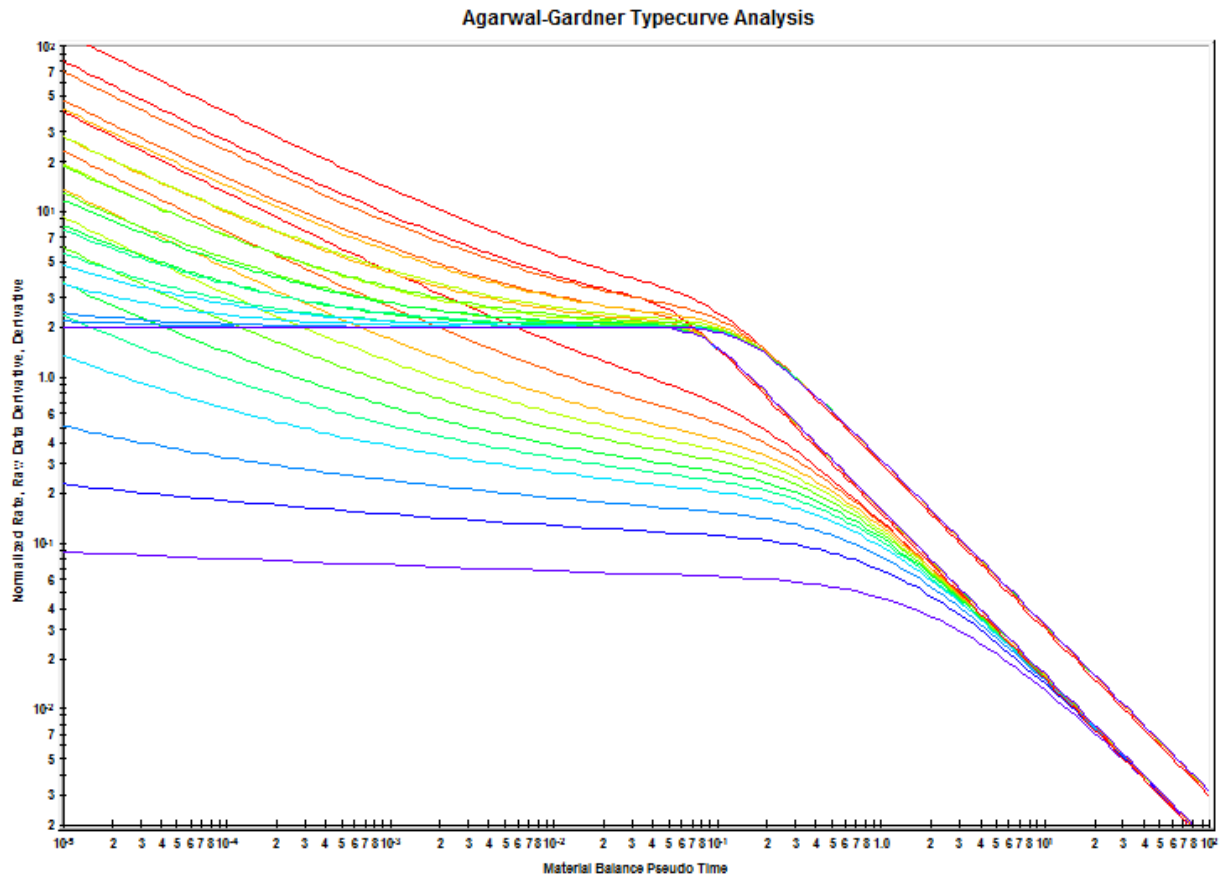
Data preparation

The horizontal axis is material balance time (pseudo-time for gas); the vertical axis is either normalized rate or inverse of semi-log derivative.

Oil wells

$$t_c = \frac{N_p}{q}$$

$$\frac{q}{\Delta p} = \frac{q}{p_i - p_{wf}}$$

$$\frac{1}{\partial} = \frac{1}{\left(\dfrac{\partial \frac{\Delta p}{q}}{\partial \ln t_c}\right)}$$

Gas wells

$$t_{ca} = \frac{\mu_i c_{ti}}{q(t)} \int_0^t \frac{q(t)}{\mu(\bar{p})c_t(\bar{p})}\, dt$$

$$\frac{q}{\Delta p_p} = \frac{q}{p_{pi} - p_{pwf}}$$

$$\frac{1}{\partial} = \frac{1}{\left(\dfrac{\partial \frac{\Delta p_p}{q}}{\partial \ln t_{ca}}\right)}$$

Analysis

The normalized rate and inverse semi-log derivative data are plotted against material balance time on a log-log scale of the same size as the typecurves. This plot is called the "data plot". Any convenient units can be used for normalized rate or time because a change in units simply causes a uniform shift of the raw data on a logarithmic scale. It is recommended that daily operated-rates be plotted, and not the monthly rates; especially when transient data sets are analyzed.

The data plot is moved over the typecurve plot, while the axes of the two plots are kept parallel, until a good match is obtained. Several different typecurves should be tried to obtain the best fit of all the data. The typecurve that best fits the data is selected and its r_e/r_{wa} (r_e/x_f for fractured case) value is noted.

Typecurve analysis is done by selecting a match point, and reading its coordinates off the data plot $(q/\Delta p$ and $t_c)_{match}$, and the typecurve plot $(q_D$ and $t_{DA})_{match}$. At the same time the stem value r_e/r_{wa} (r_e/x_f for fracture typecurves) of the matching curve is noted. To create a forecast, the selected type-curve is traced on to the data plot, and extrapolated. The future rate is read from the data plot, off the traced typecurve.

In the modified (RTA) plot, the inverse pressure integral derivative is also included.

Calculation of parameters

Radial typecurves

Oil wells

Using the definition of dimensionless rate:

$$q_D = \frac{141.2 q B \mu}{k h (p_i - p_{wf})}$$

Permeability is calculated as follows, where pressure-drop normalized flow rate and dimensionless rate are read off each of the raw data and typecurve graphs at a selected match point:

$$k = \frac{141.2 B \mu}{h} \left(\frac{q/\Delta p}{q_D} \right)_{match}$$

From the definition of dimensionless time based on area (t_{DA}):

$$t_{DA} = \frac{0.00633 k t_c}{\pi \phi \mu c_t r_e{}^2}$$

Reservoir radius is calculated as follows:

$$r_e = \sqrt{\frac{0.00633 k}{\pi \phi \mu c_t} \left(\frac{t_c}{t_{DA}} \right)_{match}}$$

Substituting the equation for permeability into the above:

$$r_e = \sqrt{\frac{0.00633}{\pi \phi c_t} \left(\frac{141.2 B}{h} \right) \left(\frac{q/\Delta p}{q_D} \right)_{match} \left(\frac{t_c}{t_{DA}} \right)_{match}}$$

Additional reservoir parameters are now calculated:

$$r_{wa} = \frac{r_e}{(r_e / r_{wa})_{match}}$$

$$A\,[acres] = \frac{\pi r_e{}^2}{43560}$$

$$s = \ln \frac{r_w}{r_{wa}}$$

$$N\left[Mbbls\right] = \frac{\pi r_e{}^2 \phi s_o h}{B_o}\left(\frac{1}{5615}\right) = \frac{0.00633}{c_t}\left(\frac{141.2 s_o}{5615}\right)\left(\frac{q/\Delta p}{q_D}\right)_{match}\left(\frac{t_c}{t_{DA}}\right)_{match}$$

Gas wells

For gas wells, dimensionless rate is defined as follows:

$$q_D = \frac{1.417 {*} 10^6 T}{kh}\left(\frac{q}{\Delta p_p}\right)$$

According to this equation, the permeability can be calculated as:

$$k = \frac{1.417 {*} 10^6 T}{h}\left(\frac{q/\Delta p_p}{q_D}\right)_{match}$$

From the definition of dimensionless time based on area:

$$t_{DA} = \frac{0.00633 k t_{ca}}{\pi \phi \mu_i c_{ti} r_e{}^2}$$

Reservoir radius is calculated as follows:

$$r_e = \sqrt{\frac{0.00633 k}{\pi \phi \mu_i c_{ti}}\left(\frac{t_{ca}}{t_{DA}}\right)_{match}}$$

Substituting the equation for permeability into the above:

$$r_e = \sqrt{\frac{0.00633}{\pi \phi \mu_i c_{ti}}\left(\frac{1.417 {*} 10^6 T}{h}\right)\left(\frac{q/\Delta p_p}{q_D}\right)_{match}\left(\frac{t_{ca}}{t_{DA}}\right)_{match}}$$

Additional reservoir parameters are now calculated:

$$r_{wa} = \frac{r_e}{(r_e/r_{wa})_{match}}$$

$$A\,[acres] = \frac{\pi r_e^2}{43560}$$

$$s = \ln\frac{r_w}{r_{wa}}$$

$$G\,[bcf] = \left[\frac{\pi r_e^2 \phi h S_g p_i T_{sc}}{Z_i T\,p_{sc}}\right] * 10^{-9}$$

$$= \left[\frac{0.0633 * 1.417 * 10^6\,S_g p_i T_{sc}}{\mu_i c_{ti} Z_i p_{sc}}\left(\frac{q/\Delta p_p}{q_D}\right)_{match}\left(\frac{t_{ca}}{t_{DA}}\right)_{match}\right] * 10^{-9}$$

Fracture typecurves

Oil wells

Using the definition of dimensionless rate:

$$q_D = \frac{141.2qB\mu}{kh(p_i - p_{wf})}$$

Permeability is calculated as follows, where pressure-drop normalized flow rate and dimensionless time are read off each of the raw data and typecurve graphs at a selected match point:

$$k = \frac{141.2B\mu}{h}\left(\frac{q/\Delta p}{q_D}\right)_{match}$$

From the definition of dimensionless time based on area:

$$t_{DA} = \frac{0.00633k t_c}{\pi\phi\mu c_t r_e^2}$$

Reservoir radius is calculated as follows:

$$r_e = \sqrt{\frac{0.00633k}{\pi\phi\mu c_t}\left(\frac{t_c}{t_{DA}}\right)_{match}}$$

Substituting the equation for permeability into the above:

$$r_e = \sqrt{\frac{0.00633}{\pi\phi c_t}\left(\frac{141.2B}{h}\right)\left(\frac{q/\Delta p}{q_D}\right)_{match}\left(\frac{t_c}{t_{DA}}\right)_{match}}$$

Additional reservoir parameters are now calculated:

$$x_f = \frac{r_e}{(r_e/x_f)_{match}}$$

$$A\,[acres] = \frac{\pi r_e^2}{43560}$$

$$N\,[Mbbls] = \frac{\pi r_e^2 \phi S_o h}{B_o}\left(\frac{1}{5615}\right) = \frac{0.00633}{c_t}\left(\frac{141.2S_o}{5615}\right)\left(\frac{q/\Delta p}{q_D}\right)_{match}\left(\frac{t_c}{t_{DA}}\right)_{match}$$

Gas wells

For gas wells, dimensionless rate is defined as follows:

$$q_D = \frac{1.417*10^6 T}{kh}\left(\frac{q}{\Delta p_p}\right)$$

The permeability is calculated from above, as follows:

$$k = \frac{1.417*10^6 T}{h}\left(\frac{q/\Delta p_p}{q_D}\right)_{match}$$

From the definition of dimensionless time based on area:

$$t_{DA} = \frac{0.00633k t_{ca}}{\pi\phi\mu_i c_{ti} r_e^2}$$

Reservoir radius is calculated as follows:

$$r_e = \sqrt{\frac{0.0633k}{\pi \phi \mu_i c_{ti}} \left(\frac{t_{ca}}{t_{DA}}\right)_{match}}$$

Substituting the equation for permeability into the above, we get:

$$r_e = \sqrt{\frac{0.00633}{\pi \phi \mu_i c_{ti}} \left(\frac{1.417*10^6 T}{h}\right) \left(\frac{q/\Delta p_p}{q_D}\right)_{match} \left(\frac{t_{ca}}{t_{DA}}\right)_{match}}$$

Additional reservoir parameters are now calculated:

$$x_f = \frac{r_e}{(r_e/x_f)_{match}}$$

$$A\,[acres] = \frac{\pi r_e^2}{43560}$$

$$G\left[bcf\right] = \left[\frac{\pi r_e^2 \phi h S_g p_i T_{sc}}{Z_i T \, p_{sc}}\right] * 10^{-9}$$

$$= \left[\frac{0.00633*1.417*10^6 S_g p_i T_{sc}}{\mu_i c_{ti} Z_i p_{sc}} \left(\frac{q/\Delta p_p}{q_D}\right)_{match} \left(\frac{t_{ca}}{t_{DA}}\right)_{match}\right] * 10^{-9}$$

Methodology: rate-cumulative

Cumulative-time typecurves have a similar purpose to the rate-time typecurves, but have the added advantage of smoothing noisy production data. As such, they often help to provide a more unique type curve match, when used in conjunction with the other Agarwal-Gardner typecurves. The following figure is an example of a cumulative-time typecurve for an unfractured well in a circular reservoir:

Cumulative Production vs. Time Typecurves - Radial
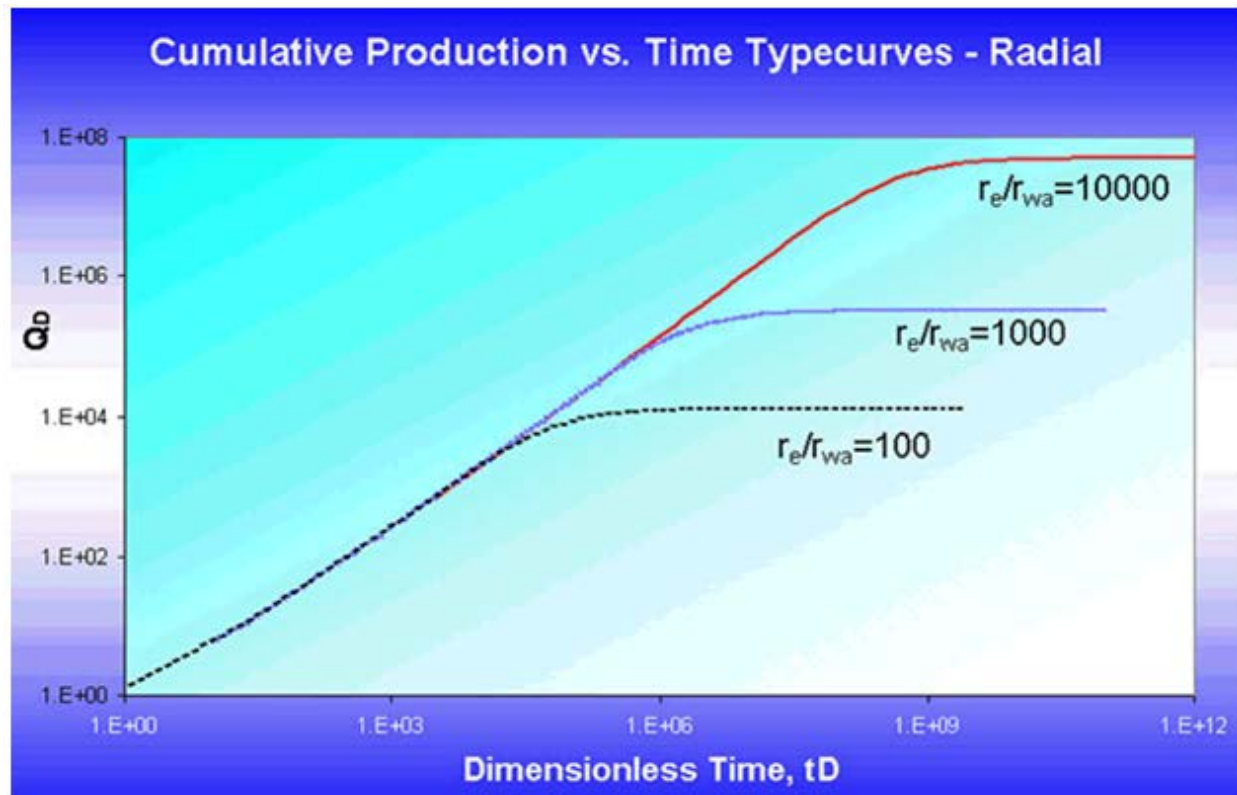
Plotting rate vs. cumulative production is a widely accepted and simple method for estimating movable reserves. In the absence of more sophisticated decline analysis techniques, many analysts use this method as a quick and effective way of estimating reserves. A straight-line extrapolation is equivalent to fitting the data to the exponential (b = 0) stem of the Arps decline typecurves. This method will almost always give a lower-bound estimate of recoverable hydrocarbons (this can be clearly seen when looking at the Arps decline typecurves, as the exponential stem has the steepest slope). A more rigorous decline analysis can be performed by fitting data to one of the full set of Arps decline typecurves. This type of analysis provides an empirical fit of the data to estimate the recoverable reserves.

There are two main limitations of the Arps decline analysis technique:

- The analysis does not account for changing production conditions, and thus cannot always provide a reliable estimate of recoverable hydrocarbons-in-place.

- Changing gas properties with time (reservoir pressure) are not accounted for; thus gas reserves are usually underestimated.

These limitations can be overcome through modification of the rate vs. cumulative production plotting functions. Changing production conditions are accommodated by incorporating variations in flowing

pressure as well as production rate, and by normalizing the production data using material balance time. Changing gas properties are handled using gas pseudo-time.

Blasingame typecurve theory

Background

The production decline analysis techniques of Arps and Fetkovich are limited in that they do not account for variations in sandface flowing pressure in the transient regime, and only account for such variations empirically during boundary-dominated flow (by means of the empirical depletion stems). In addition, changing pressure, volume, and temperature (PVT) properties with reservoir pressure are not considered for gas wells.

Blasingame and his colleagues have developed a production decline method that accounts for these phenomena. The method uses a form of superposition time function that only requires one depletion stem for typecurve matching - the harmonic stem. One important advantage of this method is that the typecurves used for matching are similar to those used for Fetkovich decline analysis, without the empirical depletion stems. When the typecurves are plotted using Blasingame's superposition time function, the analytical exponential stem of the Fetkovich typecurve becomes harmonic. The significance of this may not be readily evident until considering that, if the inverse of the flowing pressure is plotted against time, pseudo-steady state depletion at a constant flow rate follows a harmonic decline trend. In effect, Blasingame's typecurves allow depletion at a constant pressure to appear as if it were depletion at a constant flow rate. In fact, Blasingame et al. have shown that boundary-dominated flow with both declining rates and pressures appear as pseudo-steady state depletion at a constant rate, provided the rate and pressure decline monotonically.

Blasingame's improvements on the Fetkovich style of production decline analysis are further enhanced by the introduction of two additional typecurves which are plotted concurrently with the normalized rate typecurve. These 'rate integral' and 'rate integral derivative' typecurves aid in obtaining a more unique match. The derivation of these will be discussed in a later section.

Blasingame in RTA

Recall that the Fetkovich typecurves are based on combining the analytical solution to transient flow of a single-phase fluid at a constant wellbore flowing pressure with the empirical Arps equations for boundary-dominated flow. Fetkovich believed the exponent 'b' could vary between zero and one, and that it was correlatable with fluid properties as well as recovery mechanism. For example, single-phase oil flow would result in a 'b' value of zero, while single-phase gas flow would exhibit 'b' > 0 because of changes in gas properties. Later, Fraim and Wattenbarger showed that if the changes in gas fluid properties were taken into account (i.e., with the use of pseudo-time), boundary-dominated gas flow against a constant back pressure exhibits the same behavior that an oil reservoir would; the

decline would follow the exponential curve, in which 'b' = 0. These findings relate to flow at constant wellbore pressure. The subsequent development by Blasingame et al. was to account for changing wellbore flowing pressures by defining a superposition time function, which they called material balance time. They showed that if the material balance time were used instead of actual producing time, what was previously an exponential decline would follow the harmonic decline stem instead.
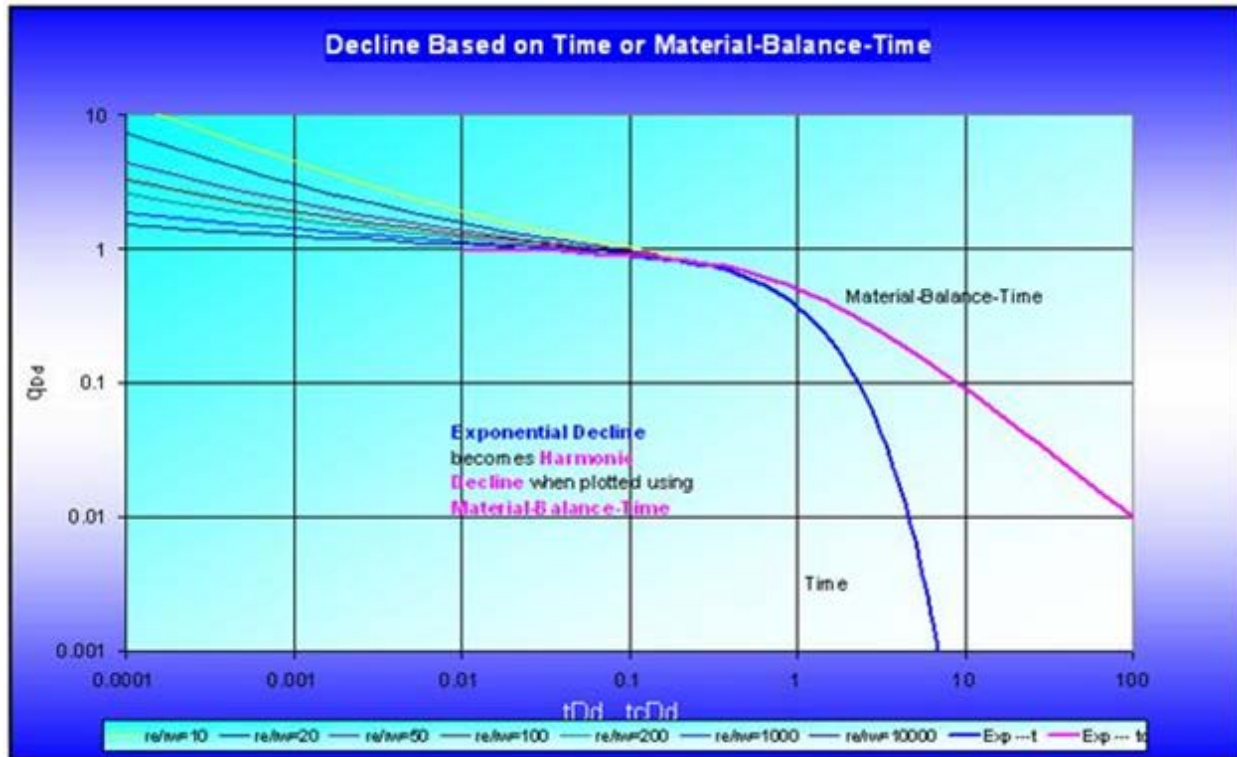
More importantly, data obtained when both the rate and the flowing pressure are varying can now be analyzed if material balance time is used. For example, if the production rate from a well is monotonically declining, and at the same time, its flowing sandface pressure is on continuous decline, a plot of pressure-drop normalized flow rate (q / Δp) vs. Q(t) / q(t) would follow the harmonic curve (for a gas well, the changing gas properties should also be accounted for by using pseudo-time).

Blasingame, McCray, and Palacio developed typecurves which show the analytical transient stems along with the analytical harmonic decline (but with the rest of the empirical hyperbolic stems absent). In addition, they introduced two other functions; the rate integral function, and the rate integral derivative function, which help in smoothing the often noisy character of production data, and in obtaining a more unique match.

The Blasingame suite of typecurves are similar to the Fetkovich typecurves for constant pressure production. The only real difference is the absence of the empirical depletion stems on the Blasingame

typecurves. These are not required because the usage of material balance time forces the boundary-dominated data to fall only on the analytical harmonic stem.

Blasingame Typecurves (Vertical Well - Radial Flow Model)
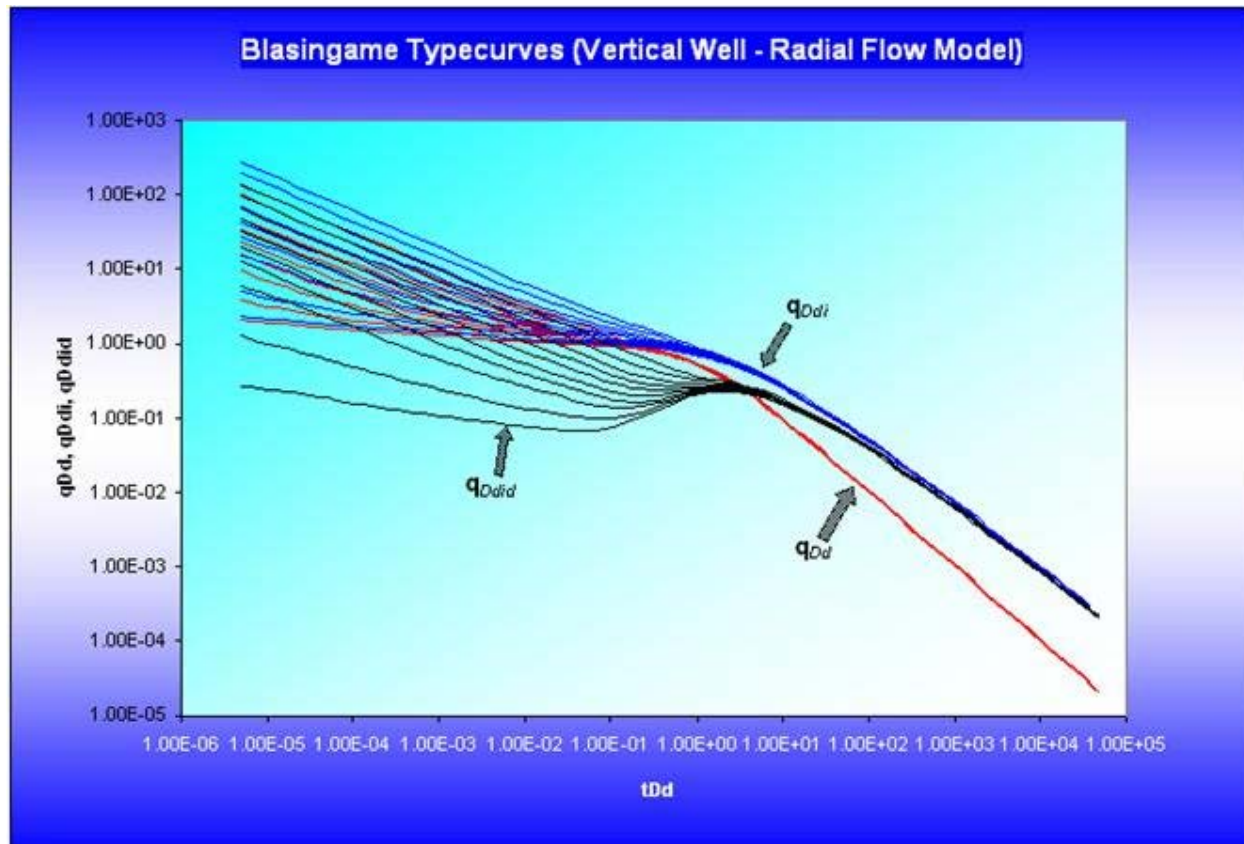
Models

The Blasingame suite of typecurves consists of a number of different models:

- Vertical well; radial flow model

- Vertical well; hydraulic fracture model (Infinite conductivity)

- Vertical well; hydraulic fracture model (Finite conductivity)

- Vertical well; hydraulic fracture model (Elliptical flow)

- Horizontal well model

- Waterflood model

- Well interference model (declining reservoir pressure)

All models assume a circular outer boundary, with the exception of Elliptical flow and Horizontal well typecurves, which assume an elliptical and a square outer boundary, respectively.

Methodology

In Blasingame typecurve analysis, three rate functions (normalized rate, rate integral, and rate integral derivative) can be plotted against Material Balance Time.

Normalized rate

Normalized rate is the primary plotting variable. It is very useful for production analysis where flowing pressures and rates change through time. It is defined as the rate divided by flowing pressure drop.

Oil

$$\frac{q}{\Delta p} = \frac{q}{p_i - p_{wf}}$$

Gas

$$\frac{q}{\Delta p_p} = \frac{q}{p_{pi} - p_{pwf}}$$

Rate integral

Conceptually, the rate integral may be thought of as the average rate at which the well has produced until any particular moment in time. The definition of the normalized rate integral is the cumulative average of the normalized rate when plotted against material balance time.

Surface (and even bottomhole) measured flowing rate and pressure data inherently contain a significant noise component. This noise often masks or distorts the sought after "reservoir signal". As a result, it is advantageous to have a way to remove this noise from the production data response.

Blasingame has identified a powerful method for removing noise from a production response, by using integration. The rate integral (the inverse of this is the pressure integral) is referred to as an auxiliary function, and is derived by integrating the normalized production rate response through time. Any discontinuities in the raw data are effectively removed through the integration process, yielding a smooth decline curve. The resulting curve resembles the original production decline response, but is much smoother. It can be used to perform a secondary typecurve match (simultaneously with the raw data). Furthermore, it may be used as base data for a well-test style semi-log derivative plot.

Conceptually, the rate integral function can be thought of as a cumulative average of the flow rate with time. The purpose of plotting a rate integral function is to smooth noisy rate data. This concept is most easily understood graphically:

Concept of Rate Integral

$$qi = \frac{\int_0^t q\,dt}{t} = \frac{Q}{t}$$

at time t, actual rate is q, rate integral is q_i

q_i makes areas A and B equal
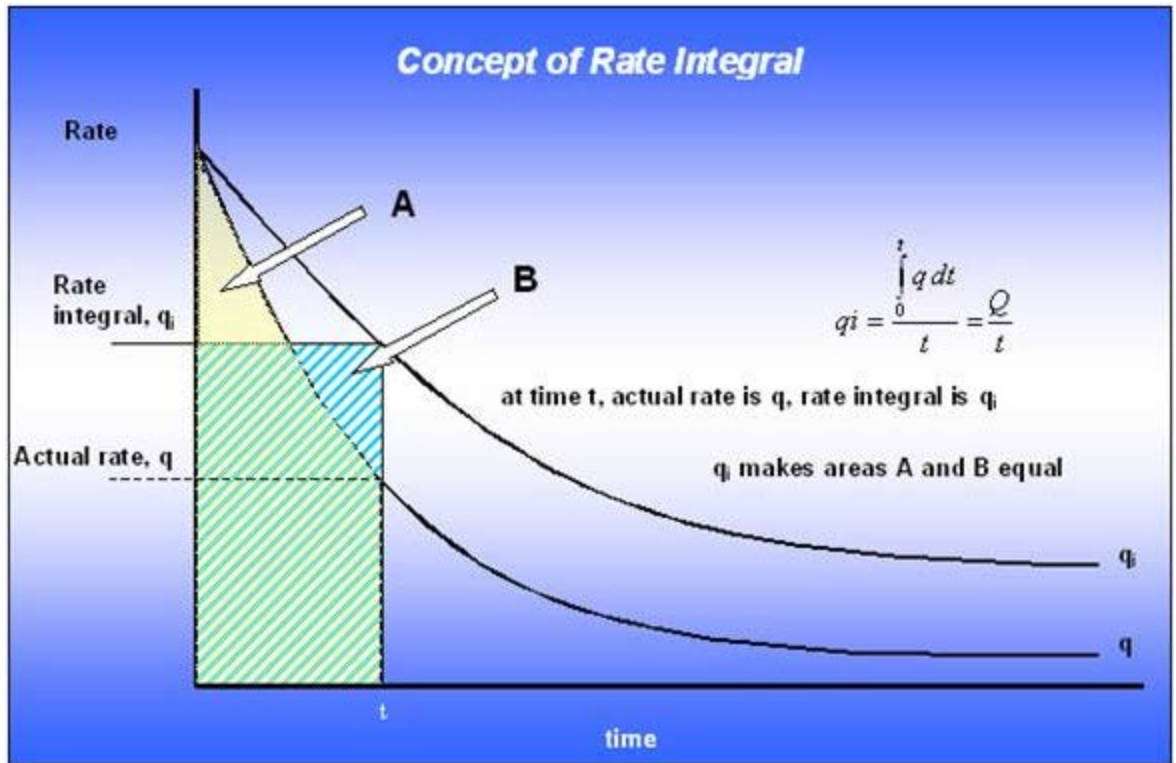
In terms of Blasingame typecurve analysis, the definition of the rate integral must account for two additional complications:

- Normalization of flow rate using pressure (for oil) or pseudo-pressure (for gas)

- Usage of material balance time (for oil) or material balance pseudo-time (for gas), instead of time

Blasingame's Rate Integral
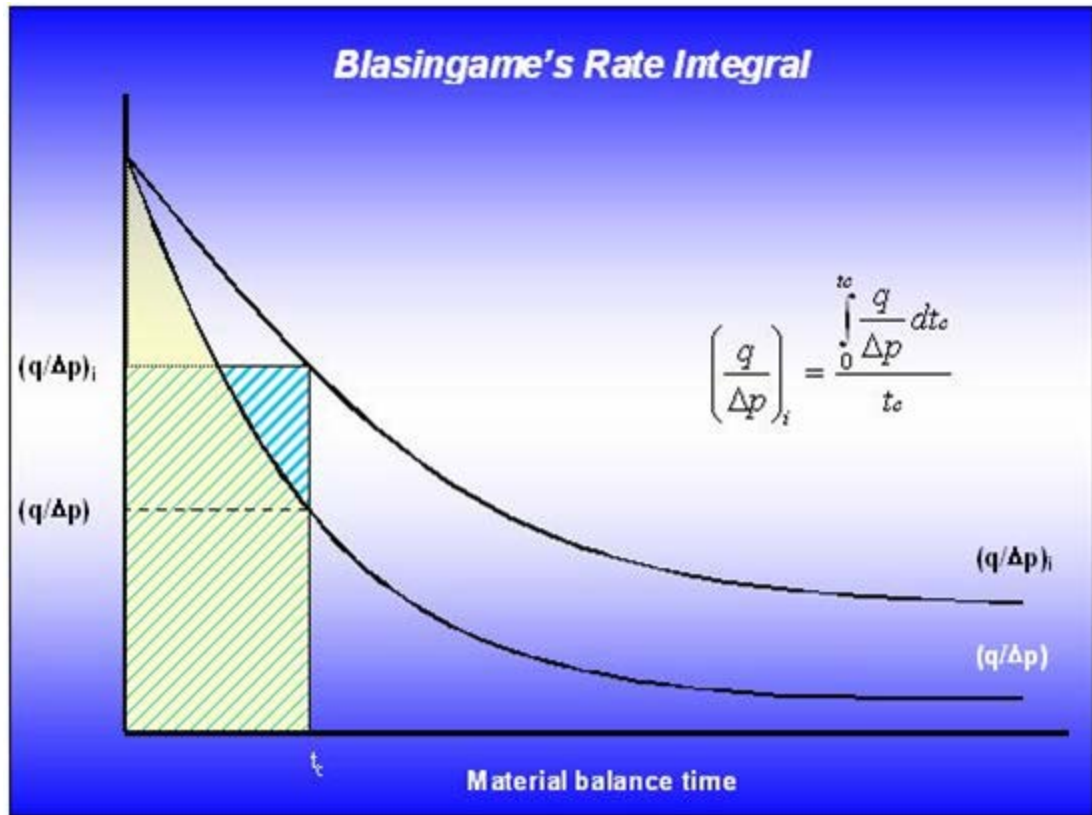
Oil

$$\left(\frac{q}{\Delta p}\right)_i = \frac{\int_0^{t_c} \frac{q}{\Delta p} dt_c}{t_c}$$

Gas

$$\left(\frac{q}{\Delta p_p}\right)_i = \frac{\int_0^{t_c} \frac{q}{\Delta p_p} dt_{ca}}{t_{ca}}$$

Rate integral derivative

The rate integral derivative is defined as the semi logarithmic derivative of the rate integral function, with respect to material balance time.

Oil

$$\left(\frac{q}{\Delta p}\right)_{id} = -\frac{d\left(\frac{q}{\Delta p}\right)_i}{d \ln t_c} = -\frac{d\left(\frac{q}{\Delta p}\right)_i}{dt_c} t_c$$

Gas

$$\left(\frac{q}{\Delta p_p}\right)_{id} = -\frac{d\left(\frac{q}{\Delta p_p}\right)_i}{d \ln t_{ca}} = -\frac{d\left(\frac{q}{\Delta p_p}\right)_i}{dt_{ca}} t_{ca}$$

Calculation of parameters

The actual normalized rate, rate integral, and rate integral derivative are plotted vs. material balance time data on a log-log scale of the same size as the typecurves. This plot is called the data plot. Any convenient units can be used for normalized rate or time because a change in units simply causes a uniform shift of the raw data on a logarithmic scale. It is recommended that daily operated-rates be plotted, and not the monthly rates, especially when transient data is analyzed. Any one of the curves can be used individually but often using more than one curve helps in achieving a more unique match of the data with the typecurves.

Move the data plot over the typecurve plot, while the axes of the two plots are kept parallel, until a good match is obtained. The rate, rate integral, and rate integral derivative data should all fit the same corresponding typecurve. Try several different transient typecurves to obtain the best fit of all the data. Select the typecurve that best fits the data, and note and its re / rwa value.

Typecurve analysis is done by selecting a match point and reading its coordinates off the data plot (q / ΔP and t_c for oil, q / Δp_p and t_{ca} for gas) $_{match}$; and off the typecurve plot (q_{Dd} and t_{Dd}) $_{match}$. Note the stem value r_e / r_{wa} of the matching curve.

Given a curve match, the following reservoir parameters can be obtained if reservoir thickness, total compressibility, and wellbore radius are known:

- Permeability

- Skin

- Fracture half length

- Dimensionless fracture conductivity

- Area

- Original oil- or gas-in-place

To create a forecast, the selected typecurve is traced on to the data plot, and extrapolated beyond the last data points. The future rate is read from the data plot, off the traced typecurve.

Note: The above calculation parameters reflect a vertical well with a radial flow model. Selection of other typecurve models for matching requires some adjustments. For information on other model calculation parameters, see transient typecurve matching equations.

Boundary-dominated flow

Harmonic stem of decline curves

Recall from the derivation of Material Balance Time:

$$\frac{\Delta p}{q} = m\, t_c + b_{pss}$$

Taking the reciprocal and rearranging provides the same form as the harmonic branch of Arps typecurve:

$$b_{pss}\, \frac{q}{\Delta p} = \frac{1}{\left(1 + \frac{m\, t_c}{b_{pss}}\right)}$$

To further show the similarity to the harmonic equation, the equation above can be written as follows:

$$q_{Dd} = \frac{1}{1 + t_{Dd}}$$

where:

$$q_{Dd} = \frac{q/\Delta p}{(q/\Delta p)_i}$$

$$\left(\frac{q}{\Delta p}\right)_i = \frac{1}{b_{pss}}$$

$$t_{Dd} = a_i t_c$$

$$a_i = \frac{m}{b_{pss}}$$

The rearranged material balance time equation is significant; if the pressure-drop normalized flow rate is plotted vs. material balance time, the data will follow the harmonic branch of the Fetkovich or Arps typecurve (regardless of whether production is constant or variable flow rate, or constant or variable sandface pressure).

The relations that are used to compute oil-in-place and reservoir properties are given by Equations A14-A16 of Palacio and Blasingame (1993).

$$b_{pss} = \frac{(q_{Dd})_{match}}{\left(\frac{q_o}{(p_i - p_{wf})} \right)_{match}} \quad (A14)$$

$$m = \frac{1}{N_{c_{ti}}} = b_{pss} \frac{(t_{Dd})_{match}}{(t_c)_{match}} \quad (A15)$$

$$N = \frac{1}{c_{ti}} \frac{(t_c)_{match}}{(t_{Dd})_{match}} \frac{\left(\frac{q_o}{(p_i - p_{wf})} \right)_{match}}{(q_{Dd})_{match}} \quad (A16)$$

Data preparation

In Blasingame typecurve analysis, boundary-dominated flow is represented by a single harmonic stem, into which all the transient stems converge.

To calculate original gas-in-place and original oil-in-place, the plotted data are matched against the harmonic stem, which is defined mathematically as follows:

$$q_{Dd} = \frac{1}{1 + t_{Dd}} \quad (1)$$

Oil

where:

$$q_{Dd} = \frac{\left(\frac{q}{\Delta p}\right)}{\left(\frac{q}{\Delta p}\right)_i}$$

and:

$$t_{Dd} = a_i t_c \quad (2)$$

The pseudo-steady-state equation for oil in decline form is as follows:

$$\frac{q}{\Delta p} = \frac{\frac{1}{b}}{\frac{1}{c_e \, N \, b} t_c + 1} \quad (3)$$

Through comparison of (1) and (3), it is clear that a graph of normalized rate vs. material balance time will follow the trend of the dimensionless harmonic stem.

From equations (1), (2), and (3) we get the following:

$$\frac{q}{\Delta p} = \frac{\left(\frac{q}{\Delta p}\right)_i}{1 + a_i \, t_c} \quad (4)$$

where:

$$\frac{q}{(\Delta p)_i} = \frac{1}{b}$$

$$a_i = \frac{1}{c_e \, N \, b}$$

Solving for N, we get:

$$N = \frac{1}{c_e \left(\frac{t_{Dd}}{t_c}\right)\left[\frac{q_{Dd}}{\left(\frac{q}{\Delta p}\right)}\right]} = \frac{1}{c_e}\left[\frac{t_c}{t_{Dd}}\right]\left[\frac{\frac{q}{\Delta p}}{q_{Dd}}\right] \quad (5)$$

Gas

The development for gas is similar to that of oil. However, pseudo-pressure and pseudo-time must be used in place of pressure and time.

The definitions of the dimensionless variables are as follows:

$$q_{Dd} = \frac{\left(\frac{q}{\Delta p_p}\right)}{\left(\frac{q}{\Delta p_p}\right)_i}$$

and:

$$t_{Dd} = a_i\, t_{ca} \quad (6)$$

The pseudo-steady-state equation for gas is as follows:

$$\frac{q}{\Delta p_p} = \frac{\frac{1}{b}}{\frac{2 p_i}{(Z\,\mu\,c_t)_i\,G\,b}\, t_{ca} + 1} \quad (7)$$

Combining equations (1), (6) and (7):

$$\frac{q}{\Delta p_p} = \frac{\left(\frac{q}{\Delta p}\right)_i}{1 + a_i\, t_c}$$

where:

$$\left(\frac{q}{\Delta p_p}\right)_i = \frac{1}{b}$$

and:

$$a_i = \frac{2\, p_i}{(Z\,\mu\,c_t)_i\, G\, b} \quad (8)$$

Solving for G, we get:

$$G \;=\; \frac{2\,p_i}{\left(\dfrac{t_{Dd}}{t_{ca}}\right)(\,Z\,\mu\,c_t)_i\left(\dfrac{q_{Dd}}{\dfrac{q}{\Delta p_p}}\right)} \;=\; \frac{2p_i}{(\,Z\,\mu\,c_t)_i}\left[\frac{t_{ca}}{t_{Dd}}\right]\left[\frac{\dfrac{q}{\Delta p_p}}{q_{Dd}}\right] \quad (9)$$

Transient typecurve matching equations

The evaluation of transient parameters is accomplished using the transient stems of the dimensionless typecurve model. Unlike the boundary-dominated flow case, the definition of the characteristic dimensionless variables changes according to the chosen transient model. Presented in this section are the typecurve matching equations for five different transient models:

- Radial (Vertical Well)

- Infinite Conductivity Fracture

- Finite Conductivity Fracture

- Horizontal Well

- Elliptical Flow Typecurves

The typecurves are plotted using the dimensionless decline rate q_{Dd} and dimensionless decline time t_{Dd}, which are defined as follows:

$$q_{Dd} \;=\; q_D\, b_{Dpss}$$

where:

$$q_D \;=\; \frac{141.2\,B\,\mu}{k\,h}\,\frac{q}{\Delta p} \quad \text{for oil wells}$$

$$q_D \;=\; \frac{1.417 \times 10^6\,T}{k\,h}\,\frac{q}{\Delta p_p} \quad \text{for gas wells}$$

$$t_{Dd} \;=\; \frac{2\,\pi}{b_{Dpss}}\,t_{DA}$$

where:

$$t_{DA} \;=\; \frac{0.00633\,k\,t_c}{\varphi\,\mu\,c_t\,A} \quad \text{for oil wells}$$

$$t_{DA} = \frac{0.00633 \, k \, t_{ca}}{\varphi \, \mu_i \, c_{ti} \, A} \text{ for gas wells}$$

The dimensionless pseudo-steady state constant b_{Dpss} is defined differently for each model.

Radial

The radial model simulates a vertical well in the center of a cylindrical reservoir.
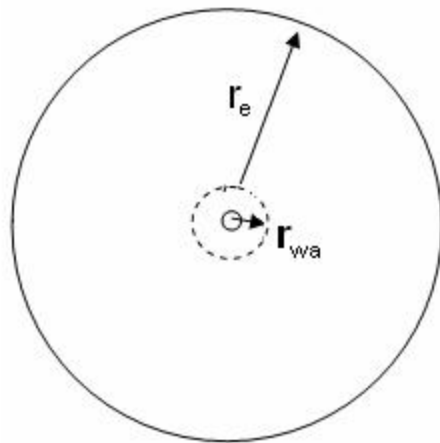
The characteristic dimensionless parameter $r_{eD} = r_e \, / \, r_{wa}$ represents the ratio of the external reservoir radius to the apparent wellbore radius.

The dimensionless pseudo-steady state constant b_{Dpss} is defined as follows for the radial model:

$$b_{Dpss} = \ln \left(\frac{r_e}{r_{wa}} \right)_{match} - \frac{1}{2}$$

Oil

Permeability is obtained by rearranging the definition of dimensionless decline rate:

$$q_{Dd} = \frac{q}{\Delta p} \left(\frac{141.2 \, B \, \mu}{k \, h} \right) b_{Dpss}$$

$$k = \left(\frac{\frac{q}{\Delta p}}{q_{Dd}} \right)_{match} \left(\frac{141.2 \, B \, \mu}{h} \right) b_{Dpss}$$

Solve for apparent wellbore radius from the definition of dimensionless decline time:

$$t_{Dd} \frac{0.00633 \, k \, t_c}{\frac{1}{2} \, \varphi \, \mu \, c_t r_{wa}^2 \left[\left(\frac{r_e}{r_{wa}} \right)^2_{match} - 1 \right] b_{Dpss}}$$

$$r_{wa} = \sqrt{\left(\frac{t_c}{t_{Dd}} \right)_{match} \frac{0.00633 \, k}{\varphi \, \mu \, c_t \, \frac{1}{2} \left[\left(\frac{r_e}{r_{wa}} \right)^2_{match} - 1 \right] b_{Dpss}}}$$

Skin is calculated as follows:

$$s = \ln \left(\frac{r_w}{r_{wa}} \right)$$

Gas

Permeability is obtained by rearranging the definition of dimensionless decline rate:

$$q_{Dd} = \frac{q}{\Delta p_p} \left(\frac{1.417 \times 10^6 \, T}{k \, h} \right) b_{Dpss}$$

$$k = \frac{1.417 \times 10^6 \, T}{h} \left[\frac{\frac{q}{\Delta p_p}}{q_{Dd}} \right]_{match} b_{Dpss}$$

Solve for apparent wellbore radius from the definition of dimensionless decline time:

$$t_{Dd} = \frac{0.00633 \, k \, t_{ca}}{\frac{1}{2} \, \varphi \, \mu_i \, c_{ti} \, r_{wa}^2 \left[\left(\frac{r_e}{r_{wa}} \right)^2_{match} - 1 \right] b_{Dpss}}$$

$$r_{wa} = \sqrt{\left(\frac{t_{ca}}{t_{Dd}} \right)_{match} \frac{0.00633 \, k}{\varphi \, \mu_i c_{ti} \, \frac{1}{2} \left[\left(\frac{r_e}{r_{wa}} \right)^2_{match} - 1 \right] b_{Dpss}}}$$

Skin is calculated as follows:

$$s = \ln \left(\frac{r_w}{r_{wa}} \right)$$

Infinite conductivity fracture

The fractured model simulates an infinite conductivity hydraulic fracture (vertical) in the center of a cylindrical reservoir.
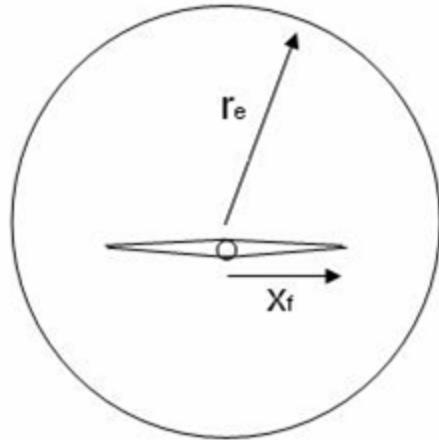
The characteristic dimensionless parameter r_{eD} = r_e / x_f represents the ratio of external reservoir radius to fracture half-length.

The dimensionless pseudo-steady state constant is defined as follows for the infinite conductivity fracture model:

$$b_{Dpss} = \ln\left(r_{eD}\right) - 0.049298 + 0.434645\left(r_{eD}\right)^{-2}$$

Oil

Permeability is obtained by rearranging the definition of dimensionless decline rate:

$$q_{Dd} = \frac{q}{\Delta p}\left(\frac{141.2\,B\,\mu}{k\,h}\right)b_{Dpss}$$

$$k = \left(\frac{\frac{q}{\Delta p}}{q_{Dd}}\right)_{match}\left(\frac{141.2\,B\,\mu}{h}\right)b_{Dpss}$$

Solve for effective radius from the product of dimensionless decline rate and dimensionless decline time:

$$r_e = \sqrt{\left(\frac{t_c}{t_{Dd}}\right)_{match}\frac{2}{b_{Dpss}}\frac{0.00633\,k}{\varphi\,\mu\,c_t}} = \sqrt{\left(\frac{t_c}{t_{Dd}}\right)_{match}\left(\frac{\frac{q}{\Delta p}}{q_{Dd}}\right)_{match}\frac{2\times0.00633\times141.2\,B}{\varphi\,h c_t}}$$

Solve for fracture half-length from the definition of dimensionless effective radius:

$$x_f = \frac{r_e}{\left(r_{eD}\right)_{match}}$$

Gas

Permeability is obtained by rearranging the definition of dimensionless decline rate:

$$q_{Dd} = \frac{q}{\Delta p_p} \left(\frac{1.417 \times 10^6 \, T}{k \, h} \right) b_{Dpss}$$

$$k = \left(\frac{\frac{q}{\Delta p_p}}{q_{Dd}} \right)_{match} \left(\frac{1.417 \times 10^6 \, T}{h} \right) b_{Dpss}$$

Solve for effective radius from the product of dimensionless decline rate and dimensionless decline time:

$$r_e = \sqrt{0.00633 \left(\frac{1.417 \times 10^6 \, T}{\frac{1}{2} \, h \, \varphi \, \mu_i c_{ti}} \right) \left(\frac{t_{ca}}{t_{Dd}} \right) \left(\frac{\frac{q}{\Delta p_p}}{q_{Dd}} \right)_{match}}$$

Solve for fracture half-length from the definition of dimensionless effective radius:

$$x_f = \frac{r_e}{(r_{eD})_{match}}$$

Finite conductivity fracture

A fracture with finite conductivity is defined as a planar crack penetrated by a well or propagated from a well by hydraulic fracturing having a non-zero pressure drop in the fracture during production. A fracture with finite conductivity is characterized by dimensionless fracture conductivity which is defined as:

$$F_{CD} = \frac{k_w \, w_f}{k \, x_f}$$

For $F_{CD} > 50$, the fracture is assumed to have infinite conductivity. The finite conductivity fracture model in RTA simulates a vertical fracture in the center of a cylindrical reservoir. The characteristic parameter $r_{eD} = r_e / x_f$ represents the ratio of external reservoir radius to fracture half length.
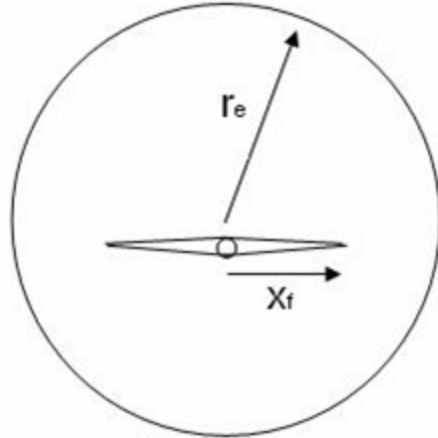
The dimensionless pseudo-steady state constant b_{Dpss} is defined as follows for the finite conductivity fracture model:

$$b_{Dpss} = \ln\left(r_{eD}\right) - 0.049298 + 0.43464\, r_{eD}^{-2} + \frac{a_1 + a_2\, u + a_3\, u^2 + a_4\, u^3 + a_5\, u^4}{1 + b_1\, u + b_2\, u^2 + b_3\, u^3 + b_4\, u^4}$$

where:

u = ln(FCD)

a1 = 0.936268

a2 = -1.00489

a3 = 0.319733

a4 = -0.0423532

a5 = 0.00221799

b1 = -0.385539

b2 = -0.0698865

b3 = -0.0484653

b4 = -0.00813558

Oil

Permeability is obtained by rearranging the definition of dimensionless decline rate:

$$q_{Dd} = \frac{q}{\Delta p} \frac{141.2\, B\, \mu}{k\, h}\, b_{Dpss}$$

$$k = \left[\frac{\left(\frac{q}{\Delta p} \right)}{q_{Dd}} \right]_{match} \frac{141.2\, B\, \mu}{h}\, b_{Dpss}$$

Solve for effective radius from the product of dimensionless decline rate and dimensionless decline time:

$$r_e = \sqrt{\left(\frac{t_c}{t_{Dd}} \right)_{match} \frac{2}{b_{Dpss}} \frac{0.00633\, k}{\varphi\, \mu\, c_t}} = \sqrt{\left(\frac{t_c}{t_{Dd}} \right)_{match} \left[\frac{\left(\frac{q}{\Delta p} \right)}{q_{Dd}} \right]_{match} \frac{2 \times 0.00633 \times 141.2\, B}{\varphi\, c_t\, h}}$$

Solve for fracture half-length from the definition of dimensionless effective radius:

$$x_f = \frac{r_e}{(r_{eD})_{match}}$$

Additional parameters are then calculated using the following equations:

$$N = \frac{0.00633}{c_t} \frac{141.2\, S_o}{5.615 \times 10^3} \left(\frac{t_c}{t_{Dd}} \right)_{match} \quad (\text{Mbbl})$$

$$A = \frac{\pi\, r_e^2}{43560} \quad (\text{Acres})$$

Radial flow skin factor:

$$s \approx \ln \frac{r_w}{x_f} + \frac{1.648546 - 3.002711 \times 10^{-1}\, u + 1.506532 \times 10^{-1}\, u^2}{1 + 2.136604 \times 10^{-1}\, u + 9.513761 \times 10^{-2}\, u^2 + 8.276998 \times 10^{-3}\, u^3}$$

where:

$$u = \ln(F_{CD})$$

Gas

Permeability is obtained by rearranging the definition of dimensionless decline rate:

$$q_{Dd} = \frac{q}{\Delta p_p} \frac{1.417 \times 10^6\, T}{k\, h}\, b_{Dpss}$$

$$k = \left[\frac{\left(\frac{q}{\Delta p_p} \right)}{q_{Dd}} \right]_{match} \frac{1.417 \times 10^6 \, T}{h} \, b_{Dpss}$$

Solve for effective radius from the product of dimensionless decline rate and dimensionless decline time:

$$r_e = \sqrt{\left(\frac{t_{ca}}{t_{Dd}} \right)_{match} \frac{2}{b_{Dpss}} \frac{0.00633 \, k}{\varphi \mu c_t}} \qquad = \sqrt{\left(\frac{t_{ca}}{t_{Dd}} \right)_{match} \left[\frac{\left(\frac{q}{\Delta p_p} \right)}{q_{Dd}} \right]_{match} \frac{2 \times 0.00633 \, (1.417 \times 10^6)}{\varphi c_t h}}$$

Solve for fracture half-length from the definition of dimensionless effective radius:

$$x_f = \frac{r_e}{(r_{eD})_{match}}$$

Additional parameters are then calculated using the following equations:

$$G = \frac{(1.417 \times 10^6) \times 0.00633 \times 2\pi}{(\mu c_t)_i} \left(\frac{t_{ca}}{t_{Dd}} \right)_{match} \left(\frac{\frac{q}{\Delta p_p}}{q_{Dd}} \right)_{match} S_{gi} \times \frac{519.668}{Z_i} \frac{p_i}{14.65} \times E - 9 \; (\text{Bscf})$$

$$A = \frac{\pi r_e^2}{43560} \; (\text{Acres})$$

Radial flow skin factor:

$$s \approx \ln \frac{r_w}{x_f} + \frac{1.648546 - 3.002711 \times 10^{-1} \, u + 1.506532 \times 10^{-1} \, u^2}{1 + 2.136604 \times 10^{-1} \, u + 9.513761 \times 10^{-2} \, u^2 + 8.276998 \times 10^{-3} \, u^3}$$

where:

u = ln(FCD)

$$u = \ln(F_{CD})$$

Horizontal well

The horizontal well's typecurve-matching procedure is based on a square-shaped reservoir with uniform thickness (h), and the well is assumed to penetrate the center of the pay zone. Note that the horizontal well typecurve does *not* include any options for including hydraulic fractures.

The procedure for matching horizontal wells is similar to that of vertical wells. However, for horizontal wells, there is more than one choice of model. Each model presents a suite of typecurves representing a different penetration ratio ($L / 2x_e$) and dimensionless wellbore radius (r_{wD}). The definition of the penetration ratio is illustrated in the following diagram:
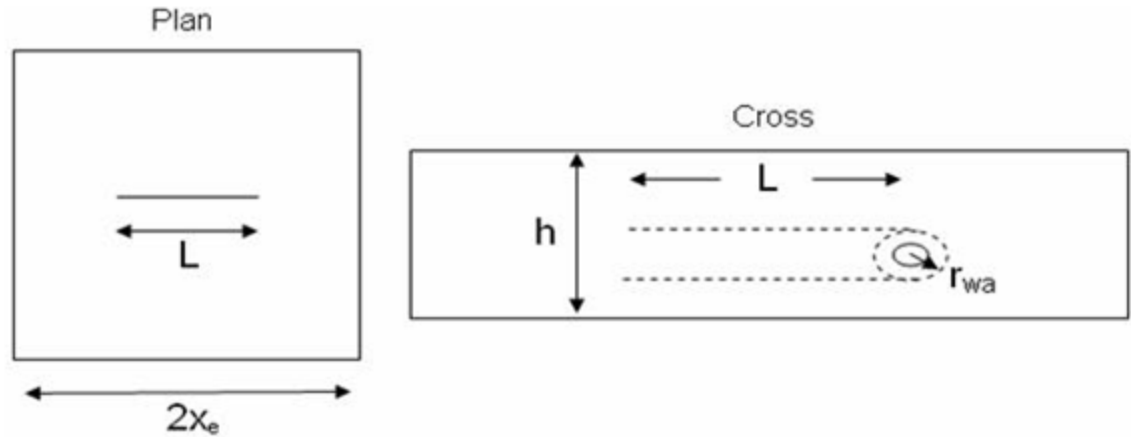
$$r_{wD} = \frac{2\,r_{wa}}{L}$$

The characteristic dimensionless parameter for each suite of horizontal typecurves is defined as follows:

$$L_p = \frac{L}{2\,\beta\,h}$$

where β is the square root of the anisotropic ratio:

$$\beta = \sqrt{\frac{k_h}{k_v}}$$

The dimensionless pseudo-steady state constant b_{Dpss} is defined as follows for the horizontal well model:

$$b_{Dpss} = \left[\frac{1}{2}\,\ln\left(\frac{16}{e^\gamma}\,\frac{1}{C_{Ah}}\,\frac{4A}{\left(\frac{L}{2\,x_e}\right)^2}\right)\right]$$

where:

γ = Euler's constant = 0.57721

Oil

Dimensionless decline rate is defined differently for horizontal oil wells, than for the radial or fractured cases:

$$q_{Dd} = \frac{q}{\Delta p} \left(\frac{141.2 \, B \, \mu}{k \, h} \right) b_{Dpss}$$

Horizontal permeability (k_h) is obtained by rearranging the above definition of dimensionless decline rate:

$$k_h = \left(\frac{\frac{q}{\Delta p}}{q_{Dd}} \right)_{match} \left(\frac{141.2 \, B \, \mu}{h} \right) b_{Dpss}$$

Vertical permeability (k_v) is calculated using the anisotropic ratio:

$$k_v = \frac{k_h}{\beta^2}$$

Gas

Dimensionless decline rate is defined differently for horizontal gas wells, than for the radial or fractured cases:

$$q_{Dd} = \frac{q}{\Delta p_p} \left[\frac{\left(1.417 \times 10^6 \right) B \, \mu}{k \, h} \right] b_{Dpss}$$

Now, permeability is obtained by rearranging the above definition of dimensionless decline rate:

$$k = \left(\frac{\frac{q}{\Delta p_p}}{q_{Dd}} \right)_{match} \left[\frac{\left(1.417 \times 10^6 \right) B \, \mu}{h} \right] b_{Dpss}$$

Vertical permeability is calculated exactly the same as for the oil case, using the anisotropic ratio.

Elliptical flow typecurves

Elliptical flow is considered to be the governing flow regime for low permeability gas reservoirs when the reservoir has some sort of an elliptical outer or inner boundary. Cases such as production from an elliptical wellbore, an elliptical fracture, or a circular wellbore in an anisotropic reservoir system can be considered to be examples of an elliptical inner boundary. An elliptic reservoir surrounded by an elliptic aquifer is the example of an elliptical outer boundary.

The elliptical flow typecurves in RTA are generated for a hydraulically fractured well in the center of a reservoir with a closed elliptical boundary.
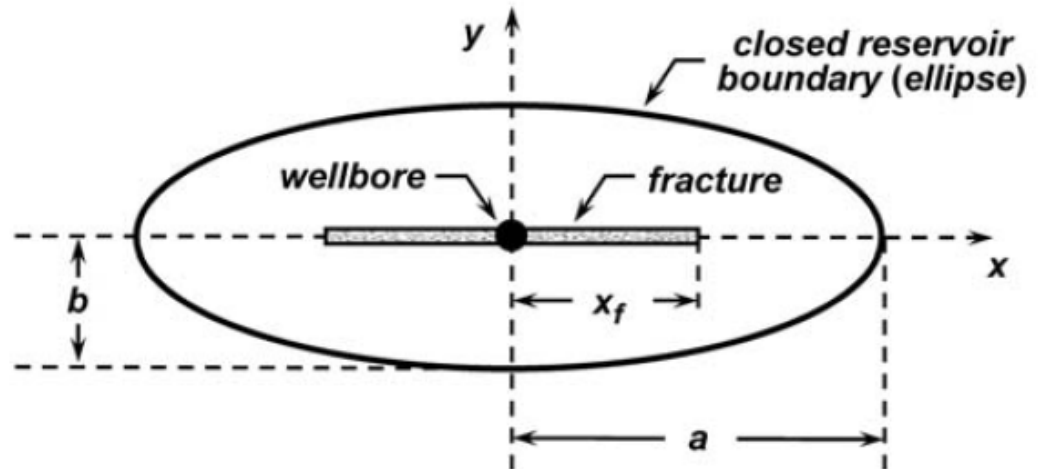
Schematic of the elliptical reservoir model (Amini et al. 2007).

The following assumptions are made in order to develop these typecurves (Amini et al. 2007):

- The reservoir is assumed to be a single-layer system that is isotropic, horizontal, and uniform thickness with constant reservoir characteristics.

- The fracture is assumed to have elliptical shape. It is also assumed that the fracture is very narrow compared to length of the fracture.

- The elliptical outer boundary is assumed to have a focal length equal to fracture half length.

In the case of infinite conductivity fracture, we do not need to consider the flow in the fracture because of constant pressure along the fracture. However, when we are dealing with a finite conductivity fracture, the flow through fracture should be considered, as the pressure drop within the fracture becomes significant compared to the total pressure drop of the fracture and reservoir. In this case, we should solve the diffusivity equations for reservoir and fracture. However, these equations cannot be solved separately and they are coupled together. In the following sections the diffusivity equation, as well as initial and boundary conditions for reservoir and fracture domains are presented.

Calculation of parameters

Oil wells

Using the definition of dimensionless rate for oil wells:

$$q_D = \frac{141.2 \, B \, \mu}{k \, h} \frac{q}{\Delta p}$$

Permeability is calculated as follows:

$$k = \frac{141.2 \, B \, \mu}{h} \left[\frac{\left(\frac{q}{\Delta p} \right)}{q_D} \right]_{match}$$

From the definition of area-based dimensionless time (t_{DA}) for oil wells:

$$t_{DA} = \frac{0.00633 \, k \, t_c}{\varphi \, \mu \, c_t \, A}$$

Area is calculated as follows:

$$A = \frac{0.00633 \, k}{\varphi \, \mu \, c_t} \left(\frac{t_c}{t_{DA}} \right)_{match}$$

Substituting the equation for permeability into the above leads to:

$$A = \left(\frac{t_c}{t_{DA}} \right)_{match} \left[\frac{\left(\frac{q}{\Delta p} \right)}{q_D} \right]_{match} \frac{0.00633 \times 141.2 \, B}{\varphi \, c_t \, h} \times \frac{1}{43560} \, (\text{Acres})$$

Additional parameters are then calculated using the following equations:

$$N = \left(\frac{t_c}{t_{DA}} \right)_{match} \left[\frac{\left(\frac{q}{\Delta p} \right)}{q_D} \right]_{match} \frac{0.00633 \times 141.2}{c_t} \frac{S_{oi}}{5.615 \times 10^3} \, (\text{Mbbls})$$

$$x_f = \sqrt{\frac{2A}{\pi \, \sin(h) \, (2 \, \zeta_o)_{match}}} = \sqrt{\frac{2}{\pi \, \sin(h) \, (2 \, \zeta_o)_{match}} \times \left(\frac{t_c}{t_{DA}} \right)_{match} \left[\frac{\left(\frac{q}{\Delta p} \right)}{q_D} \right]_{match} \frac{0.00633 \times 141.2 \, B}{\varphi \, c_t \, h}}$$

$$a = x_f \, \cos(h) \, (\zeta_o)_{match}$$

$$b = x_f \, \sin(h) \, (\zeta_o)_{match}$$

$$\textbf{Drainage Aspect Ratio} = \frac{a}{b} = \cot(h) \, (\zeta_o)_{match}$$

$$\textbf{Penetration Ratio} = \frac{x_f}{a} \frac{1}{\cos(h) \, (\zeta_o)_{match}}$$

$$\text{Where}(\zeta_o)_{match} = \sin(h)^{-1}\left(\frac{b}{x_f}\right)_{match}$$

Gas wells

Using the definition of dimensionless rate for gas wells:

$$q_D = \frac{1.417 \times 10^6\, T}{k\,h}\, \frac{q}{\Delta p_p}$$

Permeability is calculated as follows:

$$k = \frac{1.417 \times 10^6\, T}{h}\left[\frac{\left(\frac{q}{\Delta p_p}\right)}{q_D}\right]_{match}$$

From the definition of area-based dimensionless time for gas wells:

$$t_{DA} = \frac{0.00633\, k\, t_{ca}}{\varphi\,\mu\,c_t\,A}$$

Area is calculated as follows:

$$A = \frac{0.00633\, k}{\varphi\,\mu\,c_t}\left(\frac{t_{ca}}{t_{DA}}\right)_{match}$$

Substituting the equation for permeability into the above leads to:

$$A = \left(\frac{t_{ca}}{t_{DA}}\right)_{match}\left[\frac{\left(\frac{q}{\Delta p_p}\right)}{q_D}\right]_{match}\frac{0.00633 \times (1.417 \times 10^6)\, T}{(\varphi\,\mu\,c_t)_i\,h} \times \frac{1}{43560}\ \text{(Acres)}$$

Additional parameters are then calculated using the following equations:

$$G = \left(\frac{t_{ca}}{t_{DA}}\right)_{match}\left[\frac{\left(\frac{q}{\Delta p_p}\right)}{q_D}\right]_{match}\frac{0.00633 \times (1.417 \times 10^6)\, T}{(\varphi\,\mu\,c_t)_i\,h}\,\frac{S_{gi}}{5.615 \times 10^3} \times 10^{-9}\ \text{(Bscf)}$$

$$x_f = \sqrt{\frac{2A}{\pi\,\sin(h)\,(2\,\zeta_o)_{match}}} = \sqrt{\frac{2}{\pi\,\sin(h)\,(2\,\zeta_o)_{match}} \times \left(\frac{t_{ca}}{t_{DA}}\right)_{match}\left[\frac{\left(\frac{q}{\Delta p_p}\right)}{q_D}\right]_{match}\frac{0.00633 \times (1.417 \times 10^6)\, T}{(\varphi\,\mu\,c_t)_i\,h}}$$

$$a = x_f\,\cos(h)\,(\zeta_o)_{match}$$

$$b = x_f \sin(h) \left(\zeta_o \right)_{match}$$

Drainage Aspect Ratio $= \dfrac{a}{b} = \cot(h) \left(\zeta_o \right)_{match}$

Penetration Ratio $= \dfrac{x_f}{a} = \dfrac{1}{\cos(h) \left(\zeta_o \right)_{match}}$

Where $\left(\zeta_o \right)_{match} = \sin(h)^{-1} \left(\dfrac{b}{x_f} \right)_{match}$

Compound linear typecurve theory

The most popular well design for exploiting unconventional oil & gas resources is long horizontals with multiple hydraulic fractures. Liang et al (2012) proposed a new set of typecurves for analyzing horizontal multifrac wells with the following geometry:

Figure 1: Horizontal Well Geometry
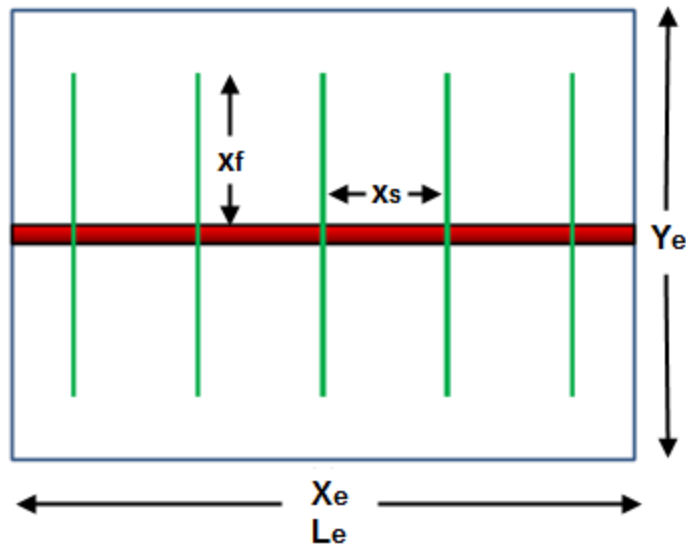
The following six flow regimes have been proposed for such a geometry:

1. Bi-linear flow caused by finite conductivity fractures

2. Primary linear flow from the formation into the fractures

Figure 2
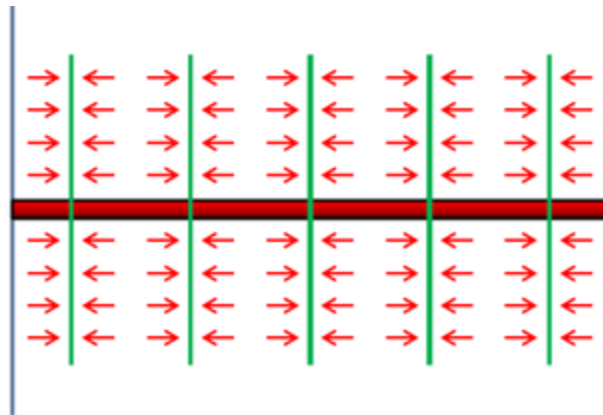
3. Transition period between primary linear flow and compound linear flow

4. Compound linear flow, which is perpendicular to the primary linear flow

Figure 3
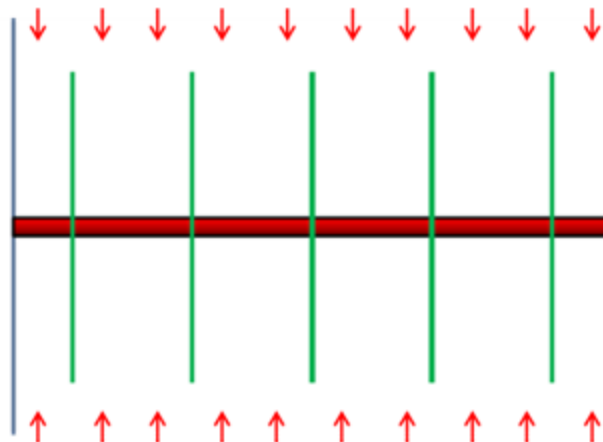
5. Transition between compound linear flow and boundary-dominated flow

6. Boundary-dominated flow

For unconventional reservoirs, the primary flow regimes of interest for rate-transient analysis are the primary linear flow into the fracture, the transition between primary linear and compound linear, and compound linear flow. The compound linear typecurves available in IHS RTA are based on these three flow regimes.

If the following assumptions are made regarding the horizontal multi-fractured well, Figure 1 can be reduced to a single fracture in an infinitely large reservoir:

- Fractures are equally spaced along the horizontal well

- Fractures have the same half-length and conductivity

- The horizontal well contributes negligible flow as compared to the fractures

- The reservoir is a single-layer, homogenous, isotropic system with single porosity and uniform thickness

- The fractures penetrate the entire formation thickness

- The spacing between horizontal wells is infinitely large

With these assumptions in mind, the following reservoir model was used to generate the typecurves:

Figure 4

The complete solution of the above reservoir model is based on Green's function method of Gringarten and Ramey (1974). The dimensionless variables are defined as follows:

$$t_{Dxf} = \frac{0.00633kt}{\emptyset \mu c_t x_f{}^2}$$

$$p_D = \frac{\Delta pkh}{141.2qB\mu}$$

The constant rate solution of the equation for various Xs/xf ratios results in the following set of type-curves for normalized pressure and semi-log derivative (DER):

Figure 5

Compound Linear Typecurve Analysis

Figure 6

Compound Linear Typecurve Analysis
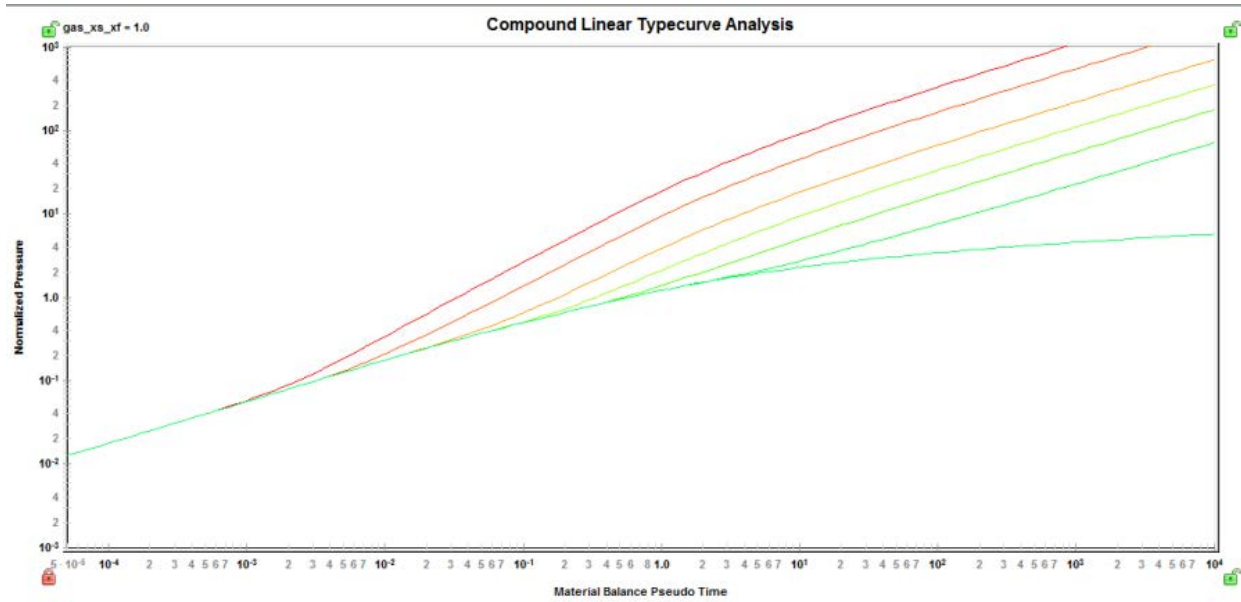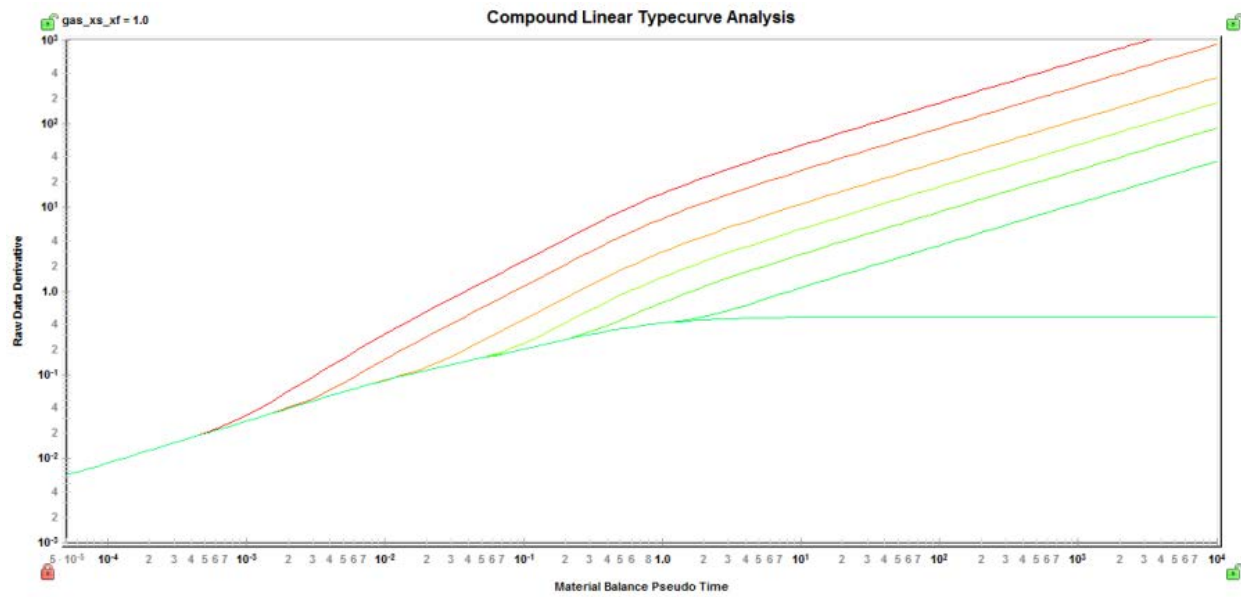
The square root derivative has also been introduced for the compound linear typecurve, and simply rotates the DER typecurve, resulting in a flat line during linear flow.
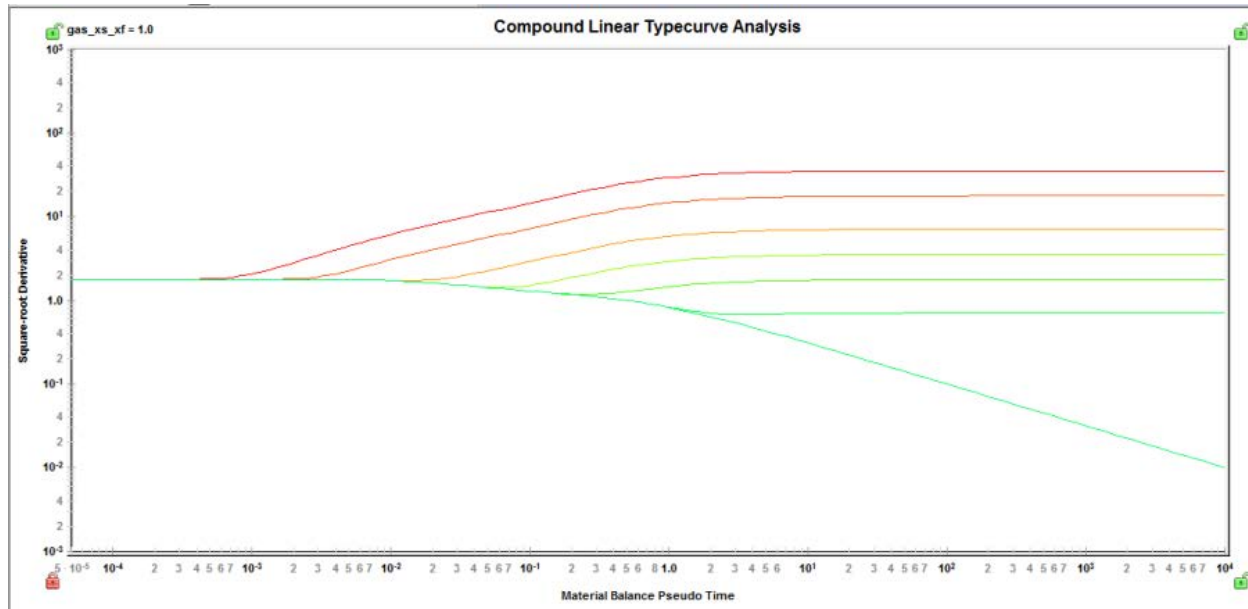
The typecurves presented above are based on an infinite conductivity fracture with no skin. In reality however, it is quite possible to experience a pressure drop caused by flow convergence, or finite conductivity of the hydraulic fractures. The existence of such a skin will change the shape of the data on a log-log plot, and can have a significant effect on typecurve matching if not accounted for properly. The figure below shows the effect of skin on the typecurve shape:

Figure 8
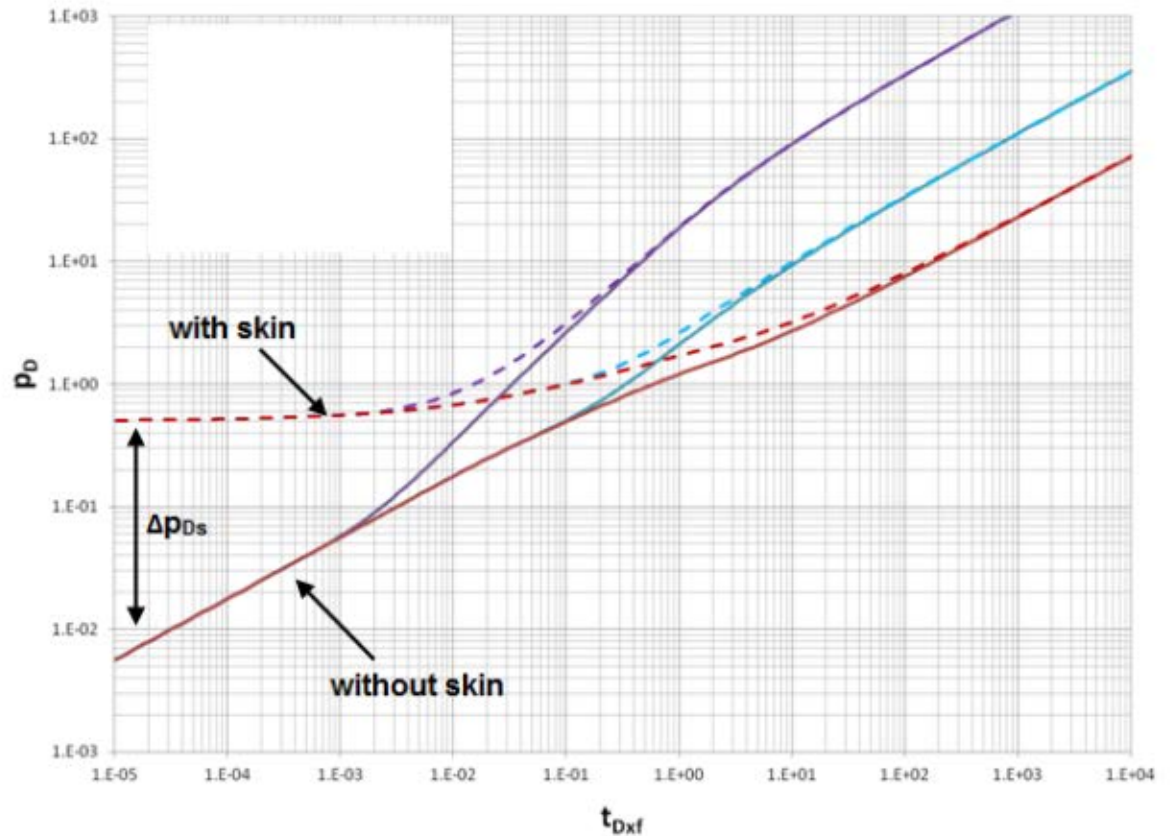
The dimensionless pressure drop illustrated in Figure 8 can be expressed as a total apparent skin using the following equation:

$$s' = \Delta p_{Ds} \times n_f \times \left(\frac{2x_f}{h}\right)$$

The same dimensionless pressure drop can be expressed in terms of an apparent FCD as follows:

$$FCD' = \frac{1}{\Delta p_{Ds}} \times \frac{1}{n_f} \times \left(1 + \frac{h}{x_f}\left(\ln\left(\frac{h}{2r_w}\right) - \frac{\pi}{2}\right)\right)$$

The actual pressure drop due to skin is estimated using the average flow rate of the last five data points ($q\_(@\Delta p\_Ds)$), and the following equation:

$$\Delta p_s = q@\Delta p_{Ds} \times \frac{141.2 B\mu(\Delta p_{Ds})}{kh}$$

Methodology

Data preparation

The horizontal axis is material balance time (pseudo-time for gas).

Pressure – time

For the Pressure - Time family of typecurves, the vertical axis plots are:

- Normalized pressure
- Semi-log pressure derivative
- Integral derivative
- Square root derivative

Normalized pressure

Oil wells

$$\frac{\Delta p}{q} = \frac{\left(p_i - p_{wf}\right)}{q}$$

Gas wells

$$\frac{\Delta p_p}{q} = \frac{\left(p_i - p_{pwf}\right)}{q}$$

Raw data derivative

Oil wells

$$DER = t_c \frac{\partial \left(\frac{\Delta p}{q}\right)'}{\partial (t_c)}$$

Gas wells

$$DER = t_{ca} \frac{\partial \left(\frac{\Delta p_p}{q} \right)'}{\partial (t_{ca})}$$

Derivative

Oil wells

$$t_c \frac{\partial \left(\frac{1}{t_c} \int \left(\frac{\Delta p}{q} \right)' dt \right)}{\partial (t_c)}$$

Gas wells

$$t_{ca} \frac{\partial \left(\frac{1}{t_{ca}} \int \left(\frac{\Delta p_p}{q} \right)' dt \right)}{\partial (t_{ca})}$$

Square-root pressure derivative

Oil wells

$$2\sqrt{t_c} \frac{\partial \left(\frac{\Delta p}{q} \right)'}{\partial (t_c)}$$

Gas wells

$$2\sqrt{t_{ca}} \frac{\partial \left(\frac{\Delta p_p}{q} \right)'}{\partial (t_{ca})}$$

Calculation of parameters

Oil wells

Once a satisfactory match is achieved, the match point is defined as follows:

$$X_{Match} = \frac{t_c}{t_{Dxf}}$$

$$Y_{Match} = \frac{n_f\left(\frac{\Delta p}{q}\right)'}{(p_D)}$$

Using the dimensionless variable definitions:

$$p_D = \frac{\Delta pkh}{141.2qB\mu}$$

$$t_{Dxf} = \frac{0.00633kt}{\emptyset\mu c_t x_f^2}$$

along with the match point, the following variable can be calculated:

$$k = \frac{141.2B\mu}{h(Y_{Match})}$$

$$x_f = \sqrt{\frac{0.00633k}{\emptyset\mu c_t}\left(X_{Match}\right)}$$

$$x_s = x_f \times \left(\frac{x_s}{x_f}\right)_{Typecurve}$$

$$L_e = x_s \times n_f$$

Gas wells

Once a satisfactory match is achieved, the match point is defined as follows:

$$X_{Match} = \frac{t_{ca}}{t_{Dxf}}$$

$$Y_{Match} = \frac{n_f \left(\frac{\Delta p_p}{q} \right)'}{p_D}$$

Using the dimensionless variable definitions:

$$p_D = \frac{\Delta p k h}{141.2 q B \mu}$$

$$t_{Dxf} = \frac{0.00633 k t}{\emptyset \mu c_t x_f{}^2}$$

along with the match point, the following variable can be calculated:

$$k = \frac{1.417 E6 T}{h(Y_{Match})}$$

$$x_f = \sqrt{\frac{0.00633 k}{\emptyset \mu c_t} \left(X_{Match} \right)}$$

$$x_s = x_f \times \left(\frac{x_s}{x_f} \right)_{Typecurve}$$

$$L_e = x_s \times n_f$$

Rate – time

For the Rate - Time family of typecurves, the vertical axis plots are:

- Normalized rate

- Semi-log pressure derivative

- Integral derivative

- Square root derivative

Normalized rate

Oil wells

$$\frac{q}{\Delta p} = \frac{q}{\left(p_i - p_{wf}\right)}$$

Gas wells

$$\frac{q}{\Delta p_p} = \frac{q}{\left(p_{pi} - p_{pwf}\right)}$$

Raw data derivative

Oil wells

$$DER = \frac{1}{t_c \dfrac{\partial\left(\frac{\Delta p}{q}\right)'}{\partial(t_c)}}$$

Gas wells

$$DER = \frac{1}{t_{ca} \dfrac{\partial\left(\frac{\Delta p_p}{q}\right)'}{\partial(t_{ca})}}$$

Derivative

Oil wells

$$\cfrac{1}{t_c \cfrac{\partial\left(\frac{1}{t_c} \int \left(\frac{\Delta p}{q}\right)' dt\right)}{\partial(t_c)}}$$

Gas wells

$$\cfrac{1}{t_{ca} \cfrac{\partial\left(\frac{1}{t_{ca}} \int \left(\frac{\Delta p_p}{q}\right)' dt\right)}{\partial(t_{ca})}}$$

Square-root pressure derivative

Oil wells

$$\cfrac{1}{2\sqrt{t_c} \cfrac{\partial\left(\frac{\Delta p}{q}\right)'}{\partial(t_c)}}$$

Gas wells

$$\cfrac{1}{2\sqrt{t_{ca}} \cfrac{\partial\left(\frac{\Delta p_p}{q}\right)'}{\partial(t_{ca})}}$$

Calculation of parameters

Oil wells

Once a satisfactory match is achieved, the match point is defined as follows:

$$X_{Match} = \frac{t_c}{t_{Dxf}}$$

$$Y_{Match} = \frac{\left(\frac{q}{\Delta p}\right)'}{(n_f q_D)}$$

Using the dimensionless variable definitions:

$$q_D = \frac{1}{p_D}$$

$$t_{Dxf} = \frac{0.00633kt}{\emptyset \mu c_t x_f{}^2}$$

along with the match point, the following variable can be calculated:

$$k = \frac{141.2B\mu}{h)} \left(Y_{Match}\right)$$

$$x_f = \sqrt{\frac{0.00633k}{\emptyset \mu c_t} \left(X_{Match}\right)}$$

$$x_s = x_f \times \left(\frac{x_s}{x_f}\right)_{Typecurve}$$

$$L_e = x_s \times n_f$$

Gas wells

Once a satisfactory match is achieved, the match point is defined as follows:

$$X_{Match} = \frac{t_{ca}}{t_{Dxf}}$$

$$Y_{Match} = \frac{\left(\frac{q}{\Delta p_p}\right)'}{n_f q_D}$$

Using the dimensionless variable definitions:

$$q_D = \frac{1}{p_D}$$

$$t_{Dxf} = \frac{0.00633kt}{\emptyset \mu c_t x_f{}^2}$$

along with the match point, the following variable can be calculated:

$$k = \frac{1.417E6T}{h}\left(Y_{Match}\right)$$

$$x_f = \sqrt{\frac{0.00633k}{\emptyset \mu c_t}\left(X_{Match}\right)}$$

$$x_s = x_f \times \left(\frac{x_s}{x_f}\right)_{Typecurve}$$

$$L_e = x_s \times n_f$$

Boundary-dominated flow

The compound linear typecurves described above were developed for an infinitely large reservoir. Most unconventional reservoirs will, however, experience boundary-dominated flow eventually. The time at which this happens will generally depend on well spacing.

Boundary-dominated flow will appear as a straight line with a unit slope on a log-log plot, and can be expressed by the following equation using the raw data derivative:

$$RawData\,DER = \left(2\pi\frac{x_f{}^2}{X_eY_e}\right)t_{Dxf}$$

This boundary-dominated flow line is represented by a dotted line intersecting the compound linear flow curve, and will be displayed only when a valid area or reservoir length has been entered.

Figure 9
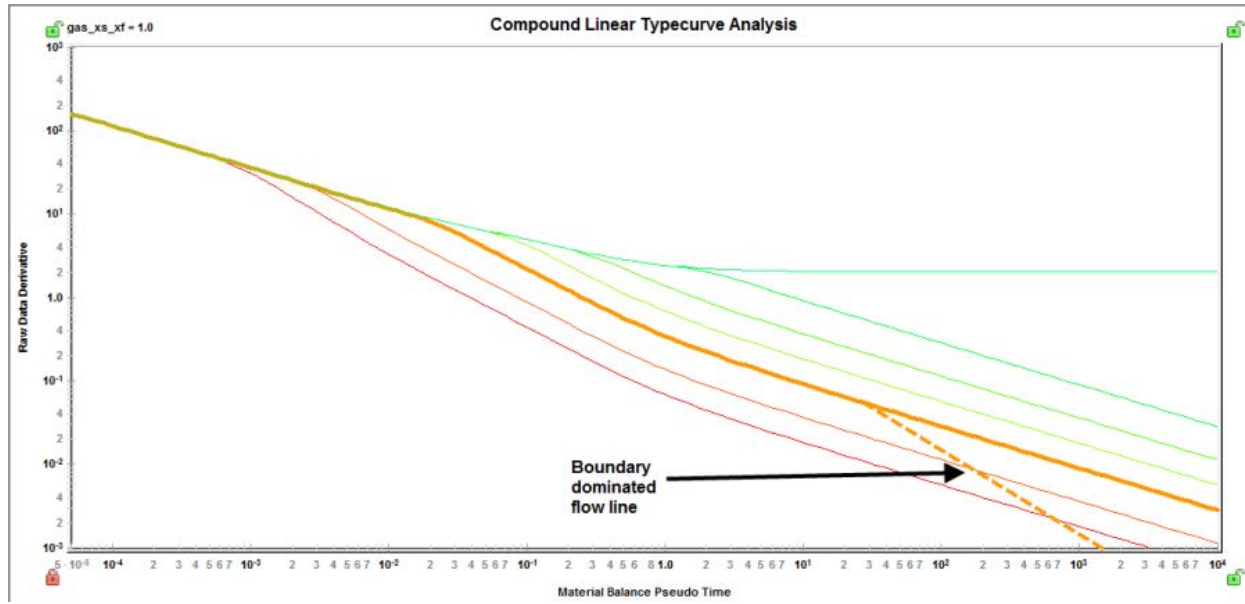
Fetkovich typecurve theory

Fetkovich recognized that decline curve analysis was only applicable during the depletion period (ie. when production is in boundary-dominated flow), and thus the early production life of a well (ie. when production is in transient flow) was not analyzable by the conventional decline curve methods. Fetkovich used analytical flow equations to generate typecurves for transient flow, which he combined with the empirical decline curve equations originally documented by J.J. Arps. For more information, see decline analysis theory. In doing so, Fetkovich presented a new set of typecurves that extended the Arps typecurves into the transient flow region.

Typecurve derivation

The Fetkovich typecurve graph consists of the following two sections which have been blended to be continuous and thereby encompass the entire production life, from transient to boundary-dominated flow:

- Early-time curves (left-side)

- Late-time curves (right-side)

The early-time portion is derived from transient flow equations which come from the field of well-test analysis, whereas the late-time portion consists simply of the Arps typecurve. The common link between the two sections is the exponential decline curve. It is the limiting behavior of all the transient curves when they reach boundary-dominated flow. It is also the first curve in the Arps family of hyperbolic decline curves (b = 0).

Early-time curves

The reservoir that Fetkovich considered in developing the transient flow equations was that of a closed circular reservoir with a well at the center, producing at a constant sandface flowing pressure. The mathematical model has the same standard assumptions as those used when describing reservoirs in the field of well-testing:

- Homogeneous reservoir

- Constant thickness

- Single-phase fluid of constant and small compressibility

- No-flow outer boundary

- Constant flowing pressure at the wellbore

The problem was originally solved by Van Everdingen and Hurst (1949).

The transient portion of the flow rate equations can be represented by numerical curve fit equations (Edwardson et al., 1961). These are given by:

$$q_D = \frac{26.7544 + 43.5537\ t_D^{0.5} + 13.3818\ t_D + 0.492949\ t_D^{1.5}}{47.421\ t_D^{0.5} + 35.5372\ t_D + 2.60967\ t_D^{1.5}},\ t_D < 200$$

$$q_D = \frac{3.90086 + 2.02623 \cdot t_D \cdot (\ln\ t_D - 1)}{t_D \cdot (\ln\ t_D)^2},\ t_D > 200$$

Note: These definitions of dimensionless time (t_D) and dimensionless rate (q_D) are based on well-test applications. For the definitions of these variables as they apply to decline curve analysis, see late-time curves.

Fetkovich modified the definitions of dimensionless rate and time as follows:

$$q_{Dd} = q_D \left[\ln\left(\frac{r_e}{r_{wa}}\right) - \frac{1}{2} \right]$$

$$t_{Dd} = \frac{t_D}{\frac{1}{2}\left[\left(\frac{r_e}{r_{wa}}\right)^2 - 1\right]\left[\ln\left(\frac{r_e}{r_{wa}}\right) - \frac{1}{2}\right]}$$

The early-time behavior of the solution to the reservoir problem (transient flow) is the basis of transient well-test analysis, and represents the condition when the reservoir is infinite-acting; when the boundary has not been felt. Obviously transient flow is, by definition, independent of reservoir size; and this would be clearly evident if the flow rate were plotted as dimensionless rate vs. dimensionless time. As shown below, all reservoirs would follow the same curve at early-time and would only deviate at later times, when the reservoir boundary is felt. As the reservoir size increases, transient flow lasts longer, and the deviation to boundary-dominated flow occurs later.

Transient Flow is a single curve;
Boundary-Dominated Flow is a family of curves

Same Transient for all re/rw 's

Different re/rw 's

q_D

t_D
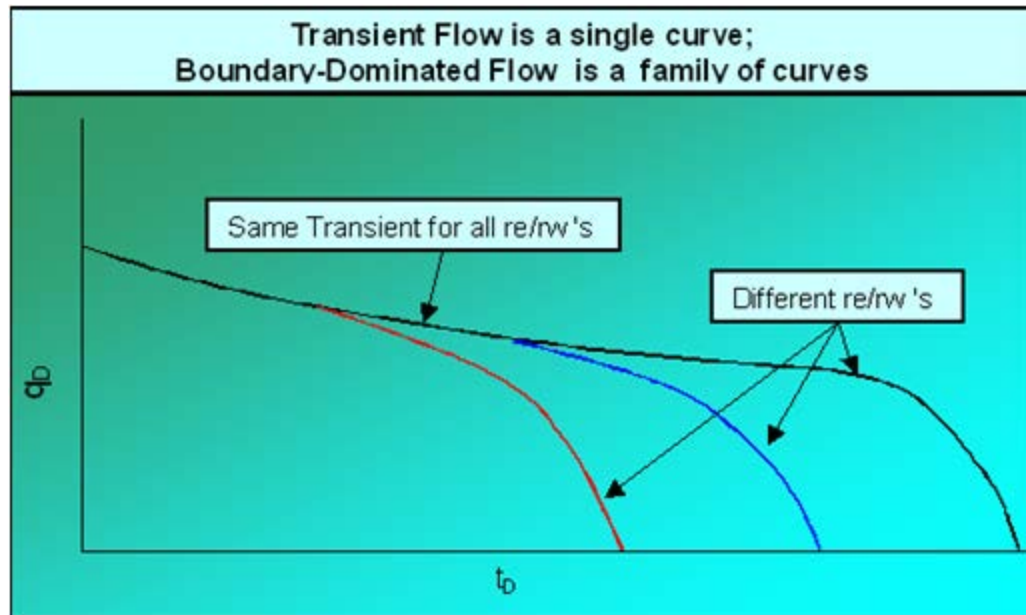
If the same curves were re-plotted on different axes, the shapes would vary significantly. A particularly useful format is to plot dimensionless decline time (t_{Dd}) on the x-axis, and dimensionless decline rate (q_{Dd}) on the y-axis (see the sub-section late-time curves for definitions of dimensionless decline rate and time). This merges all of the late-time branches into a single curve, because the variable dimensionless reservoir size (r_e/r_w) is now incorporated into the axes. As a result however, the transient data, instead of forming a single line, now becomes a family of lines, with dimensionless reservoir size as a variable as seen below: (Note that this figure represents the early-time portion of the collective Fetkovich typecurves.)
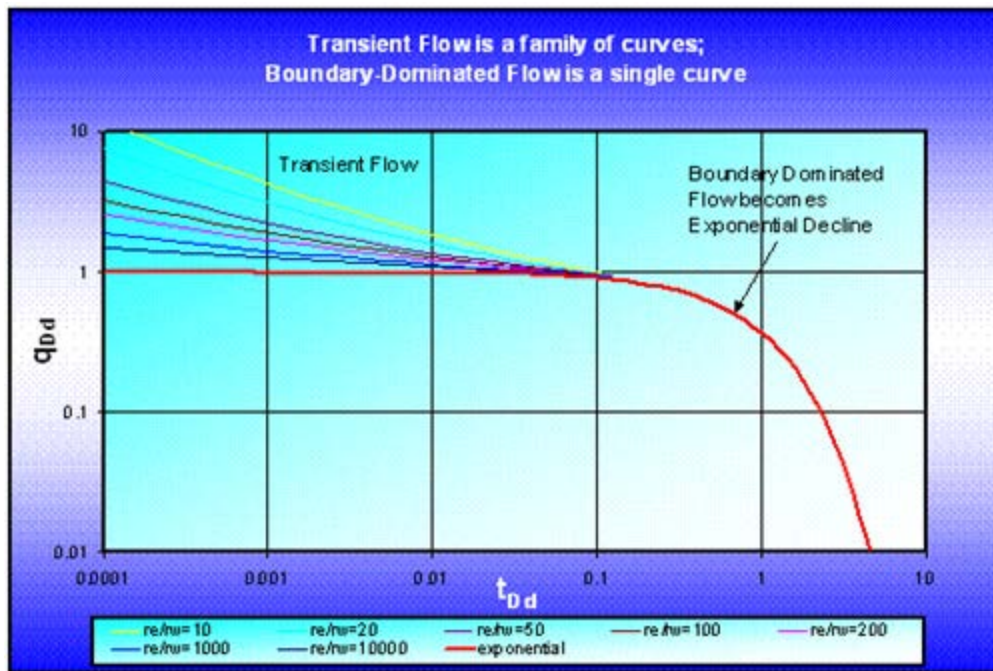
The above figure shows that for all sizes of reservoirs, when transient flow ends, the boundary-dominated flow can be represented by an exponential decline. A well producing at constant pressure will follow one of these curves. One reason for the success of Fetkovich typecurves is that most oil wells are produced at wide-open conditions (ie. at the lowest possible constant pressure). In addition, the above early-time plot gives the impression that by matching the early-time data on one of these curves, it is possible to identify the dimensionless reservoir size. Hence by implication, if the wellbore radius were known, the reservoir size could be determined. However this is a false impression which occurs because of the axes used for plotting. Keep in mind at all times, that the early-time curves represent transient flow, and by definition, the reservoir size cannot be determined from this data alone. If the only data available were in the early-time regime, a unique match could not be obtained. What appears as a possible match on one dimensionless reservoir size curve will also match another dimensionless reservoir size curve at a different location (note that the curves extend to earlier times). An example of a non-unique match of transient data is shown below.

Non-Uniqueness Of Matching When Only Early-time Data Are Available
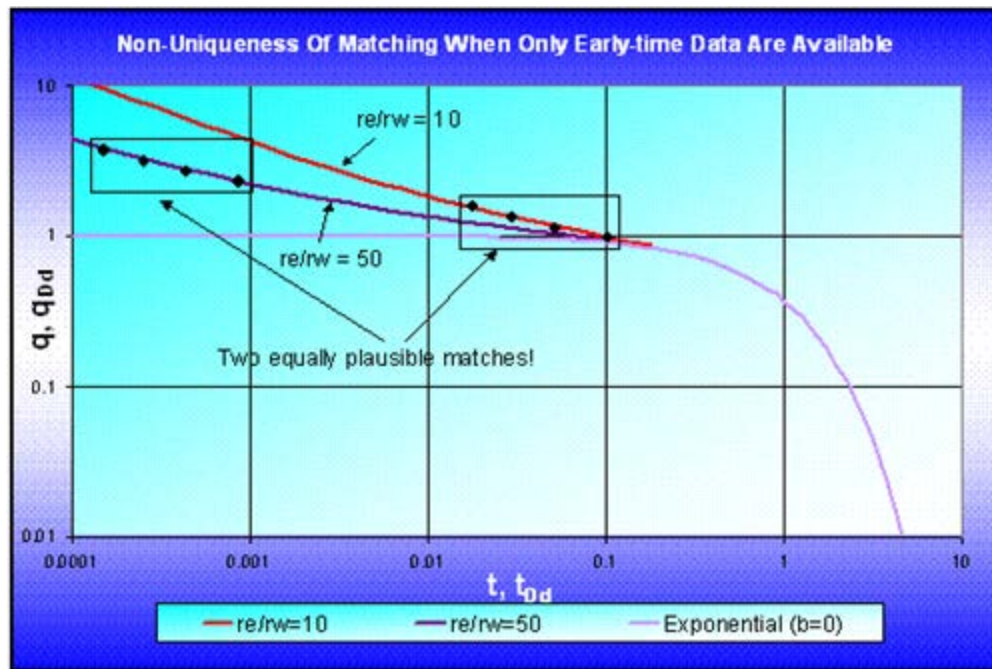
It is only when the production data extends into the boundary-dominated flow region that the different dimensionless reservoir size branches can be used to determine the actual reservoir size. Matching of the data to the typecurves becomes much more unique. Matching of the late-time data gives an indication of the reserves, which in turn is a direct function of the reservoir size. With the knowledge of reservoir size and the match of the transient data, the dimensionless reservoir size parameter can then be used to calculate the effective wellbore radius (r_{we}), from which the skin factor (s) can be obtained using the following equation:

$$r_{we} = r_w \, e^{-s}$$

Late-Time Curves

The boundary-dominated equations, which are used when dimensionless decline time exceeds 0.3, are obtained from the Arps decline equations. The dimensionless quantities used in the Arps dimensionless decline curve are defined differently from those used in the well-test literature. This section will relate the two sets of dimensionless definitions.

In the well-testing domain, dimensionless rate and dimensionless time are defined as follows:

$$q_D = \frac{141.2 \, q \, \mu \, B}{k \, h \, (p_i - p_{wf})}$$

and:

$$t_D = \frac{0.00633\, k\, t}{\phi\, \mu\, c_t\, r_w^2}$$

Fetkovich used van Everdingen and Hurst's solution (1949) to show that during boundary-dominated flow (i.e. when the reservoir boundary has been felt and the reservoir is in depletion), the dimensionless flow rate can be expressed as an exponential function of dimensionless time and dimensionless reservoir size. This equation can be written in terms of the Arps dimensionless exponential decline equation, which is defined as follows:

$$q_{Dd} = e^{-t_{Dd}}$$

where:

$$q_{Dd} = q_D \left[\ln\left(\frac{r_e}{r_{wa}}\right) - \frac{1}{2} \right]$$

and:

$$t_{Dd} = \frac{t_D}{\frac{1}{2}\left[\left(\frac{r_e}{r_{wa}}\right)^2 - 1\right]\left[\ln\left(\frac{r_e}{r_{wa}}\right) - \frac{1}{2}\right]}$$

Using the definitions of dimensionless decline rate and dimensionless decline time in combination with the exponential decline equation, it can be shown that the exponential decline rate (a) is given by:

$$a = \frac{\dfrac{0.00633\, k}{\phi\, \mu\, c_t\, r_w^2}}{\frac{1}{2}\left[\left(\frac{r_e}{r_{wa}}\right)^2 - 1\right]\left[\ln\left(\frac{r_e}{r_{wa}}\right) - \frac{1}{2}\right]}$$

Thus, Fetkovich has demonstrated that Arps' empirical exponential decline curve has a solid theoretical basis, as the late-time solution to the "constant wellbore flowing pressure" case. From the above equations, the decline coefficient (a) is seen to be a function of rock and fluid properties as well as drainage size, and is independent of the wellbore flowing pressure (for slightly compressible fluids).

The constant q_i for use in the exponential decline equation at t = 0, (q_{Dd} = 1) can be calculated from:

$$q = q_i = \frac{k\,h\left(p_i - p_{wf}\right)}{141.2\,\mu\,B\left[\ln\left(\frac{r_e}{r_{wa}}\right) - \frac{1}{2}\right]}$$

If the hyperbolic decline equation:

$$q = \frac{q_i}{\left(1 + b\,a_i\,t\right)^{\frac{1}{b}}}$$

is presented in graphical form it can be seen to encompass the whole range of conditions from exponential decline (b = 0) to harmonic decline (b = 1), where each value of initial rate (q_i), initial nominal decline rate (a_i), and decline exponent (b) will produce its own unique curve. Fetkovich generalized these curves by making the equation dimensionless.

He defined a dimensionless decline rate as:

$$q_{Dd} = \frac{q(t)}{q_i}$$

and a dimensionless decline time as:

$$t_{Dd} = a_i\,t$$

The resulting dimensionless equation is:

$$q_{Dd} = \frac{1}{\left(1 + b\,t_{Dd}\right)^{\frac{1}{b}}}$$

If this equation is plotted using dimensionless decline time and rate as the axes, a unique set of curves is obtained that represents all decline conditions for all wells. Notice that the obtained curves are independent of initial nominal decline rate and initial flow rate when plotted on these dimensionless coordinates.

Arps Dimensionless Rate-Time Decline
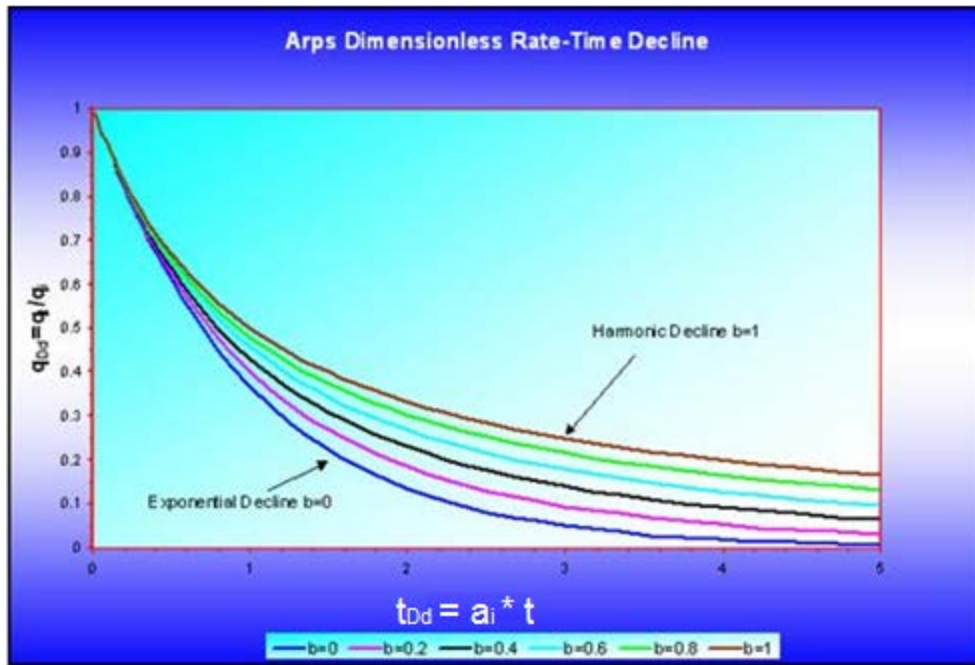
When these dimensionless curves are plotted on log-log scales as shown below, they are called type-curves, and can be used for graphical analysis of actual production data. (Note that these typecurves represent the late-time portion of the collective Fetkovich typecurves.)

Arps Dimensionless Type Curves for Empirical Rate-Time Decline Equations

$$\frac{q}{q_i} = \frac{1}{e^{\alpha t}}$$

$$\frac{q}{q_i} = \frac{1}{(1 + b\, a_i\, t)^{1/b}}$$
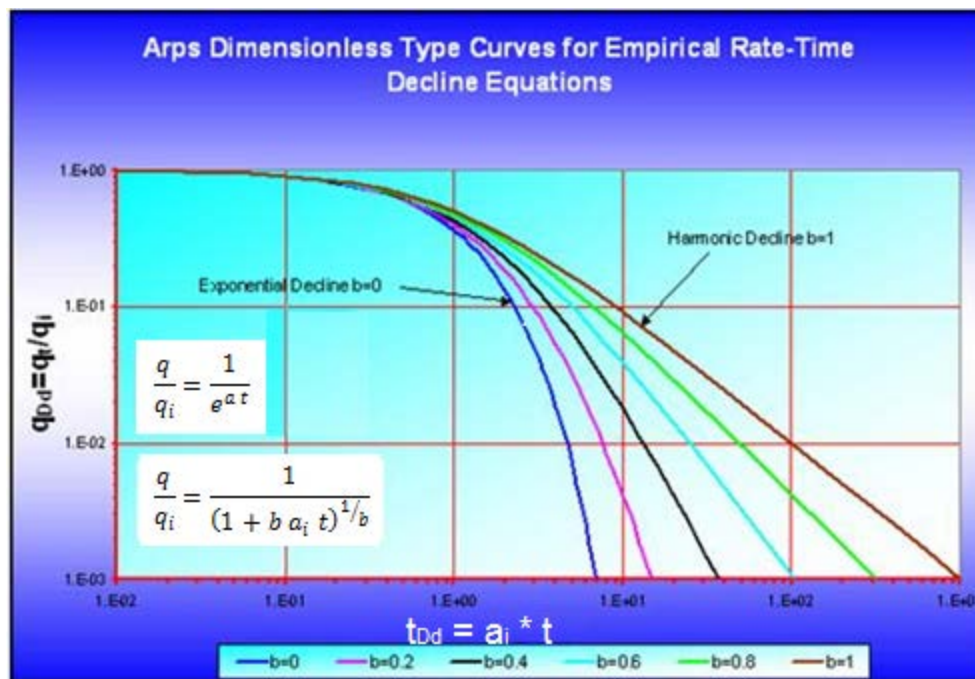
Typecurves can be used for graphical interpretation of a well's production decline. The production rate of the well is plotted on transparent graph paper of the same scale as the typecurve, and overlain on the typecurve (keeping the axes parallel). The data plot is moved over the typecurves until the best fitting curve is determined. This gives the value of the decline exponent. The values of initial flow rate and initial nominal decline rate are determined by selecting any point on the data plot and the corresponding point on the typecurve. The value of initial flow rate is obtained by dividing the "match point" values off the data plot and the typecurve, $q_i = (q_t / q_{Dd})_{match}$. The value of initial nominal decline rate is obtained by dividing the "match point" values off the typecurve and the data plot, $a_i = (t_{Dd} / t)_{match}$. The production forecast is obtained by tracing the matched curve onto the data plot and extrapolating.

Fetkovich typecurves – combined early and late-time portions

Combining the Fetkovich transient curves (early-time portion) with the Arps decline curves (late-time portion), and blending them where the two sets of curves meet results in the Fetkovich decline typecurves, shown below.
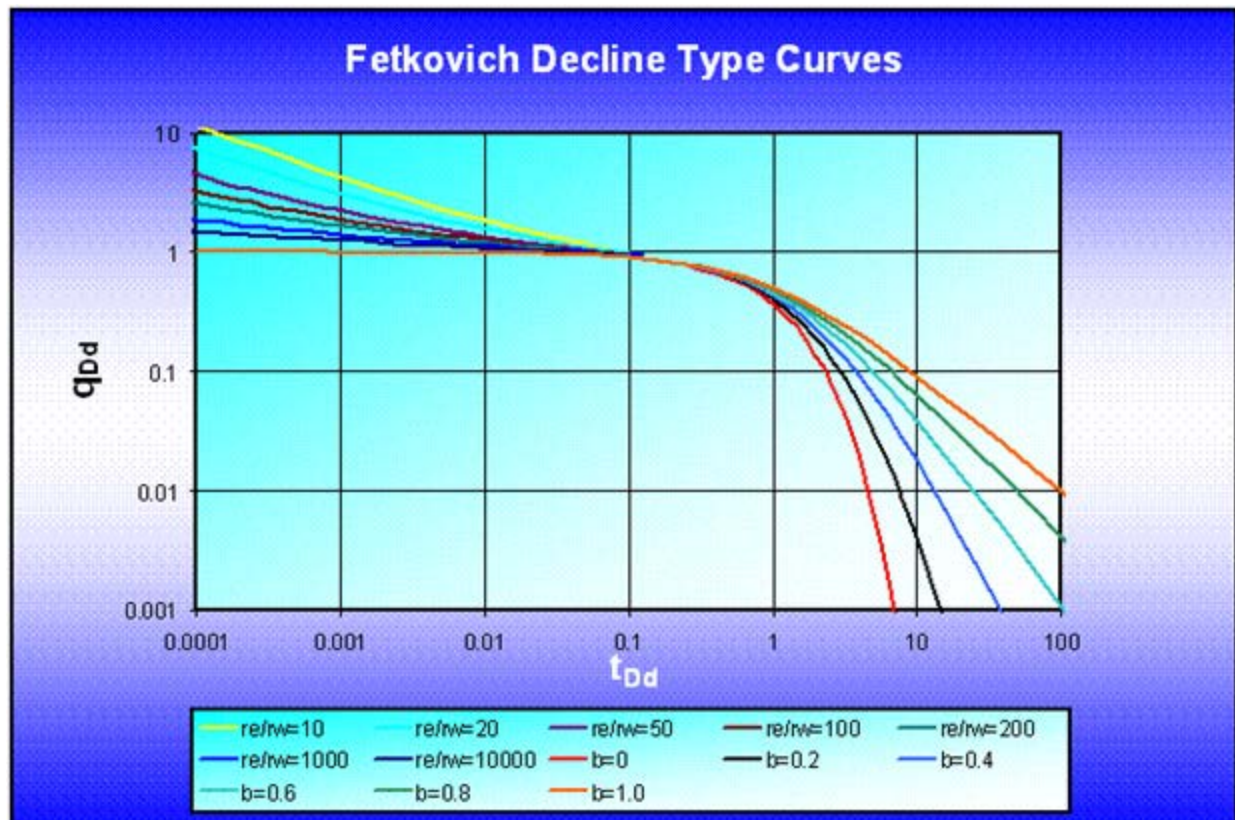
From the Fetkovich typecurve plot it is evident that the transition from transient to depletion behavior occurs at a dimensionless time of 0.1. Until the dimensionless time exceeds 0.1, it is impossible to know the type of decline that ultimately develops.

Fetkovich noted that sometimes the hyperbolic decline coefficient 'b', as determined using the Arps decline curves, was larger than 1 (it is normally expected to be between 0 and 1). The explanation that he postulated for this was that the data being analyzed was still in the transient regime, and had not reached the boundary-dominated regime. If data still in the transient flow regime is forced to match a hyperbolic decline, then b-values larger than 1 will result.

Typecurve calculations

Typecurve calculations are described below.

Rate – time typecurves

The actual rate-time data are plotted on a log-log scale of the same size as the typecurves. This plot is called the "data plot". Any convenient units can be used for rate or time because a change in units simply causes a uniform shift of the raw data on a logarithmic scale. It is recommended that daily operated-rates be plotted, and not the monthly rates; especially when transient data are analyzed. However, for very noisy and cyclic data, Fetkovich suggests 6-month averaging of the data. In addition, a log-log plot of the cumulative production data vs. time, if matched simultaneously with the rate data, should help in achieving a more unique match of the data with the typecurves.

The data plot is moved over the typecurve plot, while the axes of the two plots are kept parallel, until a good match is obtained. The rate and the cumulative data should both fit the same corresponding typecurve. Several different typecurves should be tried to obtain the best fit of all the data. The typecurve that best fits the data is selected and its "r_e/r_{wa}" and "b" vales are noted.

To make a forecast, the selected typecurve is traced on to the data plot, and extrapolated beyond the last data points. The future rate is then read from the data plot off the traced typecurve.

Typecurve analysis is done by selecting a match point and reading its co-ordinates off the data plot (q and t)$_{match}$, and off the typecurve plot (q_{Dd} and t$_{Dd}$)$_{match}$. At the same time the stem values ("r_e/r_{wa}" and "b") of the matching curve are noted.

From the right-hand-set of typecurves, the following decline curve parameters can be obtained:

$$q_i = \frac{q(match)}{q_{Dd}(match)}$$

$$a_i = \frac{t_{Dd}(match)}{t(match)}$$
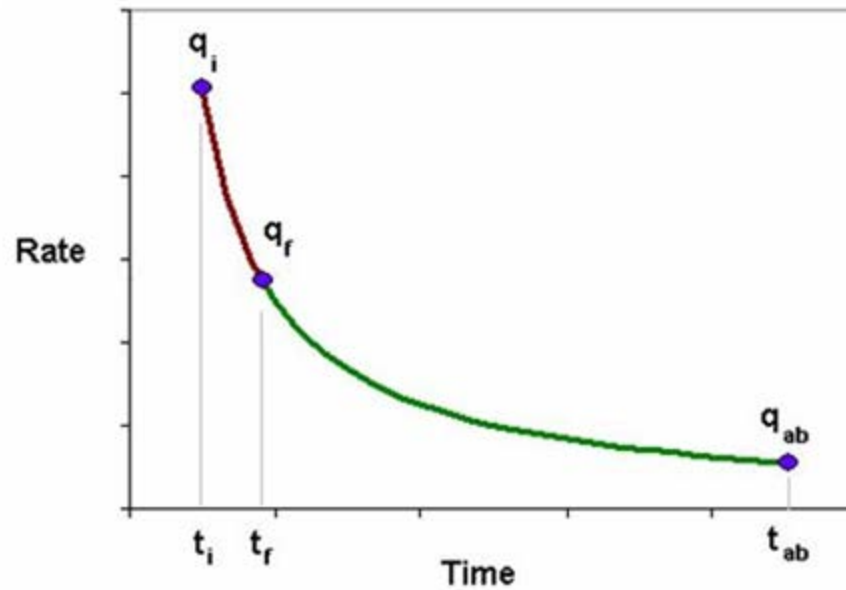
The subscript 'f' denotes conditions at the beginning of the forecast period.

With these, we can now calculate the expected ultimate recovery.

Exponential

$$EUR = Q_f + \frac{q_f - q_{ab}}{a}$$

$$q_f = q_i\, e^{(-a\, t_f)}$$

Hyperbolic

$$EUR = Q_f + \frac{q_i^b}{(1-b)a_i}\left(q_i^{1-b}\left(1 + b\, a_i\, t_f\right)^{\left(1-\frac{1}{b}\right)} - q_{ab}^{1-b}\right)$$

$$q_f = q_i\left(1 + b\, a_i\, t_f\right)^{-\frac{1}{b}} \text{ (b not equal to 0)}$$

$$a_f = a_i\left(1 + b\, a_i t_f\right)^{-1}$$

Harmonic

$$EUR = Q_f + \frac{q_i}{a_i}\left(\frac{q_i}{q_{ab}\left(1 + a_i\, t_f\right)}\right)$$

$$q_f = q_i\left(1 + a_i\, t_f\right)^{-1}$$

$$a_f = a_i\left(1 + a_i\, t_f\right)^{-1}$$

Now, we can estimate fluid-in-place and drainage area.

Oil

$$N = \frac{EUR}{c_t\left(p_i - p_{wf}\right)} \text{ (Mbbls)}$$

$$A = \frac{N\, B_o}{\phi\, h\, S_o\,(43560)} \text{ (Acres)}$$

Gas

$$G = \frac{EUR * p_i\, Z_{wf}}{p_i\, Z_{wf} - p_{wf}\, Z_i} \text{ (bcf)}$$

$$A = \frac{Z_i \, T \, p_{sc} \, G}{\phi \, h \, S_g \, p_i \, T_{sc}(43560)} \quad \text{(Acres)}$$

From the left-hand set of typecurves, the reservoir parameters can be obtained if initial reservoir pressure, wellbore flowing pressure, net pay, total compressibility, and wellbore radius are known.

$$\left(\frac{r_e}{r_{wa}}\right)_{match} = \text{value of typecurve stem (left-hand set of curves)}$$

Permeability is obtained by rearranging the definition of dimensionless decline rate:

$$q_{Dd} = q\left(\frac{141.2 \, B \, \mu}{k \, h(p_i - p_{wf})}\right)\left(\ln\left(\frac{r_e}{r_{wa}}\right)_{match} - \frac{3}{4}\right)$$

$$k = \left(\frac{q}{q_{Dd}}\right)_{match}\left(\frac{141.2 \, B \, \mu}{h(p_i - p_{wf})}\right)\left(\ln\left(\frac{r_e}{r_{wa}}\right)_{match} - \frac{3}{4}\right)$$

Permeability can be also obtained by rearranging the definition of dimensionless decline rate as follows:

$$q_{Dd} = q\left(\frac{1.417 * 10^6 \, T}{k \, h(p_{pi} - p_{pwf})}\right)\left(\ln\left(\frac{r_e}{r_{wa}}\right)_{match} - \frac{3}{4}\right)$$

$$k = \left(\frac{q}{q_{Dd}}\right)_{match}\left(\frac{1.417 * 10^6 \, T}{h(p_{pi} - p_{pwf})}\right)\left(\ln\left(\frac{r_e}{r_{wa}}\right)_{match} - \frac{3}{4}\right)$$

Solve for apparent wellbore radius from the definition of dimensionless decline time:

$$t_{Dd} = \frac{0.00633 \, k \, t}{\frac{1}{2}\phi \, \mu \, c_t \, r_{wa}^2\left(\left(\frac{r_e}{r_{wa}}\right)_{match}^2 - 1\right)\left(\ln\left(\frac{r_e}{r_{wa}}\right)_{match} - \frac{3}{4}\right)}$$

$$r_{wa} = \sqrt{\left(\frac{t}{t_{Dd}}\right)_{match} \frac{0.00633\,k}{\phi\,\mu\,c_t\,\frac{1}{2}\left(\left(\frac{r_e}{r_{wa}}\right)^2_{match} - 1\right)\left(\ln\left(\frac{r_e}{r_{wa}}\right)_{match} - \frac{3}{4}\right)}}$$

Skin factor is calculated as follows:

$$s = \ln\left(\frac{r_w}{r_{wa}}\right)$$

Cumulative – time typecurves

Production data is often quite noisy, and thus difficult to analyze. To reduce the effect of this noise, the cumulative production can be used. It is a smoother curve than production data and can make the analysis more reliable. Fraim and Lee developed cumulative typecurves of dimensionless cumulative decline production (Q_{Dd}) vs. dimensionless decline time (t_{Dd}); where the dimensionless cumulative decline production is defined as the ratio of cumulative production to the ultimate movable fluid.

Oil

$$Q_{Dd} = \frac{B\,N_p\,1.787}{c_t\,h\,\phi(r_e^2 - r_w^2)(p_i - p_{wf})} = \frac{N_p}{N_{p,n}}$$

Gas

$$Q_{Dd} = \frac{637.8\,p_{sc}\,T\,G_p}{T_{sc}\,h\,\phi\,\overline{\mu c_t}(r_e^2 - r_w^2)(\Psi_i - \Psi_{wf})} = \frac{G_p}{G_{p,n}}\,s$$

where (oil and gas):

$$Q_{Dd} = \int_0^{t_{Dd}} q_{Dd}\,dt_{Dd} = \frac{\int_0^{t_D} q_D\,dt_D}{\frac{1}{2}\left[\left(\frac{r_e}{r_w}\right)^2 - 1\right]} = \frac{Q_D}{\frac{1}{2}\left[\left(\frac{r_e}{r_w}\right)^2 - 1\right]}$$

$$t_{Dd} = \cfrac{t_D}{\frac{1}{2}\left[\left(\frac{r_e}{r_w}\right)^2 - 1\right]\left[\ln\left(\frac{r_e}{r_w}\right) - \frac{3}{4}\right]}$$

From the Fetkovich typecurves, the rate can be integrated to determine the cumulative production, and plotted in typecurve format.
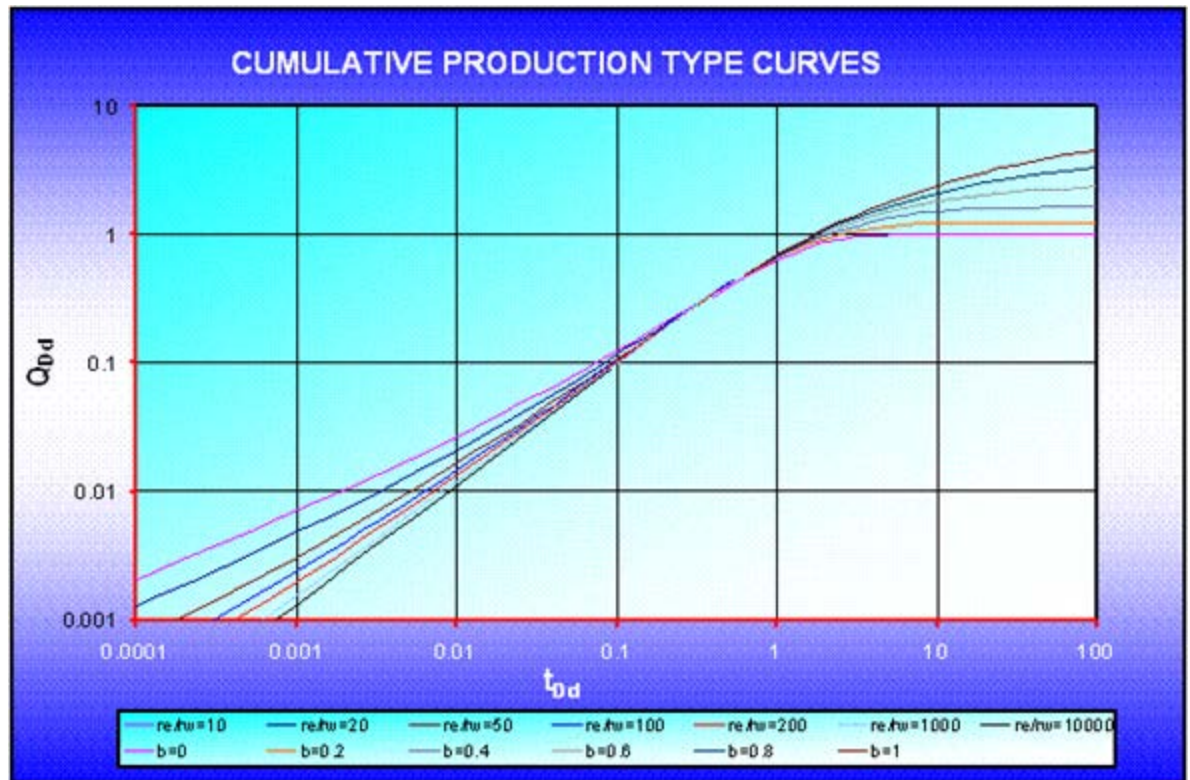
Cumulative graphs show that, at dimensionless decline time (t_{Dd}) = 100, harmonic decline leads to five times more cumulative production as compared to exponential decline.

The authors indicated that the dimensionless decline time-function used for the cumulative plots above has 3/4 in the denominator, whereas in the Fetkovich type curves, the dimensionless decline time-function has 1/2 in the denominator. The factor 3/4 appears in the inflow equation when the drawdown is referenced to the average reservoir pressure, and the factor 1/2 appears when the reference is the initial pressure at reservoir radius (r_e). Fetkovich tried using 1/2, 5/8, and 3/4; and found that using 1/2 reduced the discontinuity between the transient stems and the hyperbolic stems.

Typecurve equations

Typecurve equations are described below.

Cumulative typecurves

Fraim and Lee (1987), and Spivey et al. (1992) provide detailed equations for generating the transient and the boundary-dominated stems of the cumulative production typecurves. Transient flow rate and cumulative production are reported as functions of time by Edwardson et al. (1961). The cumulative values are given by:

$$Q_D = \frac{1.12838\, t_D^{0.5} + 1.19328\, t_D + 0.269872\, t_D^{1.5} + 0.00855294\, t_D^2}{1 + 0.616599\, t_D^{0.5} + 0.0413008\, t_D}, t_D < 200$$

$$Q_D = \frac{-4.29881 + 2.02566\, t_D}{(\ln t_D)}, \qquad t_D > 200$$

The well test-based dimensionless cumulative production (Q_D) and dimensionless time (t_D) are converted to decline-based dimensionless cumulative production (Q_{Dd}) and decline-based dimensionless time (t_{Dd}) by:

$$Q_{Dd} = \int_0^{t_{Dd}} q_{Dd}\, t_{Dd} = \frac{\int_0^{t_D} q_D\, t_D}{\frac{1}{2}\left[\left(\frac{r_e}{r_w}\right)^2 - 1\right]} = \frac{Q_D}{\frac{1}{2}\left[\left(\frac{r_e}{r_w}\right)^2 - 1\right]}$$

$$t_{Dd} = \frac{t_D}{\frac{1}{2}\left[\left(\frac{r_e}{r_w}\right)^2 - 1\right]\left[\ln\left(\frac{r_e}{r_w}\right) - \frac{3}{4}\right]}$$

The transition from transient equations to boundary-dominated flow equations for cumulative production occurs at $t_{Dd} = 0.6$.

Boundary-dominated flow is obtained from the following equations:

Exponential

$$Q_{Dd} = 1 - e^{-t_{Dd}} = 1 - q_{Dd}$$

Hyperbolic

$$Q_{Dd} = \frac{1}{1-b}\left[1 - (1 + b\, t_{Dd})^{1-\frac{1}{b}}\right] = \frac{1 - q_{Dd}^{1-b}}{1-b}$$

Harmonic

$$Q_{Dd} = \ln(1 + t_{Dd}) = \ln\left(\frac{1}{q_{Dd}}\right)$$

Cumulative / derivative typecurves

Spivey et al. showed that typecurves of cumulative production can be combined with their (semi-log) derivative to give a set of typecurves that uses only cumulative production data and not rate. Because cumulative production tends to be much smoother than the original rate data, these plots tend to have less scatter than the traditional Fetkovich typecurves. The derivative typecurves are obtained from:

$$Derivative = \frac{d(Q)}{d(\ln t)}$$

This can be shown to be mathematically equivalent to:

$$Derivative = q * t$$

and, in dimensionless form:

$$Derivative = q_{Dd} * t_{Dd}$$

Simply multiplying the rate by time gives the semi-log derivative of cumulative production. The type-curve plot of cumulative production and its derivative are shown in the following plot.

Cumulative / Derivative Type Curves
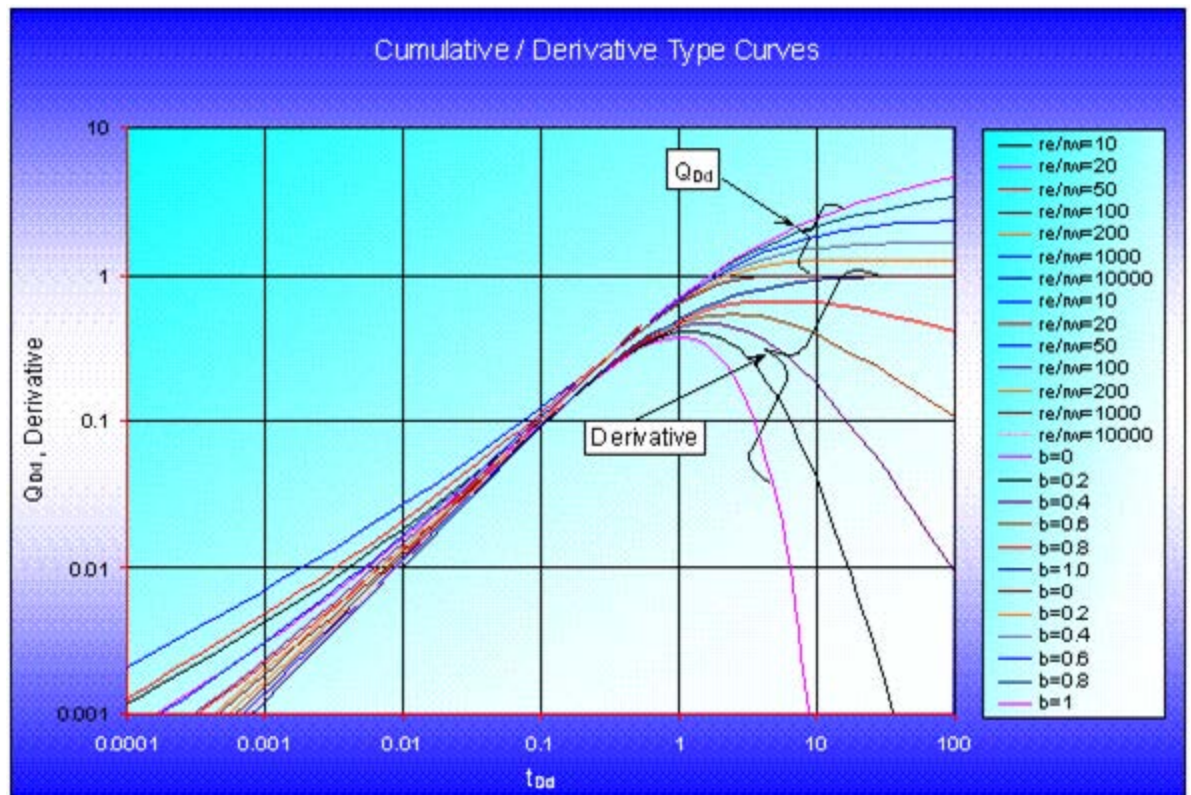
Rate-integral typecurves

Blasingame et al. (1989) introduced the concept of integral typecurves in the field of well testing. Spivey et al. (1992) extended the concept to decline curve analysis, and they state that as production data is usually very noisy, plotting a rate-integral or cumulative production should reduce the noise and make the data much more analyzable. The rate-integral is related to the cumulative production, and is defined as:

$$q_{integral} = \frac{Q}{t}$$

and, in dimensionless form:

$$q_{Dd,integral} = \frac{Q_{Dd}}{t_{Dd}}$$

The rate-integral is obtained by dividing the cumulative production by the time of flow, as seen in the equations above. The direct physical interpretation of the rate-integral is the average production rate,

from the beginning of production to the current time. The relationship between rate and rate-integral is shown in the following diagram:

Rate and Rate-Integral Type Curves
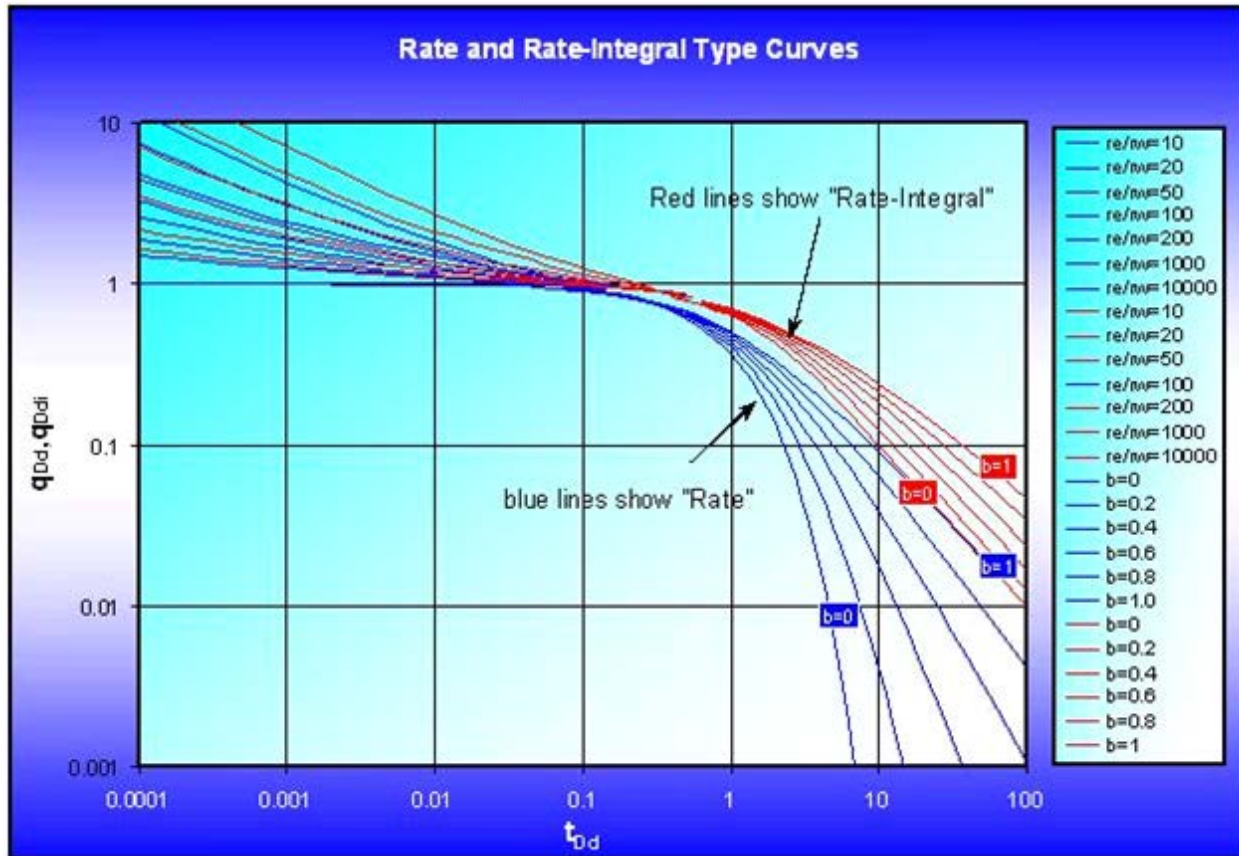
It is seen above that the rate and the rate-integral have very similar characteristics. The advantage of the rate-integral is that it tends to be smoother and less noisy than the rate data. This is consistent with the fact that the rate-integral is essentially a time-dependent average rate, and like all averaging, is less noisy than the original data.

Matching equations (variable flowing pressure)

Matching equations are described below.

Oil

The Fetkovich typecurve matching equations can be extended for use with production at variable flowing pressure. Instead of simply plotting production rate, normalized rate ($q / \Delta p$) is plotted.

Permeability is obtained by rearranging the definition of dimensionless decline rate:

$$q_{Dd} = \frac{141.2\, q\, B\, \mu}{k\, h\, \Delta p} \left[\ln\left(\frac{r_e}{r_{wa}}\right) - \frac{3}{4} \right]$$

$$k = \frac{141.2\, B\, \mu}{h} \left[\frac{\left(\frac{q}{\Delta p}\right)}{q_{Dd}} \right]_{match} \left[\ln\left(\frac{r_e}{r_{wa}}\right)_{match} - \frac{3}{4} \right]$$

where q / Δp and q$_{Dd}$ are read off the raw data and typecurve graphs at a selected match point.

Solve for apparent wellbore radius from the definition of dimensionless decline time:

$$t_{Dd} = \frac{0.00633\, k\, t}{\frac{1}{2}\phi\, \mu\, c_t\, r_{wa}{}^2 \left[\left(\frac{r_e}{r_{wa}}\right)^2 - 1 \right]\left[\ln\left(\frac{r_e}{r_{wa}}\right) - \frac{3}{4} \right]}$$

$$r_{wa} = \sqrt{ \left(\frac{t}{t_{Dd}}\right)_{match} \frac{0.00633\, k}{\frac{1}{2}\phi\, \mu\, c_t \left[\left(\frac{r_e}{r_{wa}}\right)^2_{match} - 1 \right]\left[\ln\left(\frac{r_e}{r_{wa}}\right)_{match} - \frac{3}{4} \right]} }$$

Finally, skin factor can be calculated as follows:

$$s = \ln\left(\frac{r_w}{r_{wa}}\right)$$

For exponential, hyperbolic and harmonic, expected ultimate recovery is calculated as follows:

Exponential

$$EUR = Q_f + \frac{\left(\frac{q}{\Delta p}\right)_f (\Delta p)_{forecast} - q_{ab}}{a}$$

$$\left(\frac{q}{\Delta p}\right)_f = \left(\frac{q}{\Delta p}\right)_i e^{(-a_i t_f)}$$

$$\left(\frac{q}{\Delta p}\right)_i = \left[\frac{\left(\frac{q}{\Delta p}\right)}{q_{Dd}}\right]_{match}$$

$$a = \left(\frac{t_{Dd}}{t}\right)_{match}$$

It is assumed that the flowing pressure is constant during the forecast period, and this constant flowing pressure $(p_{wf})_{forecast}$ should be entered for analysis.

Hyperbolic

$$EUR = Q_f + \frac{\left(\frac{q}{\Delta p}\right)_f^b (\Delta p)_{forecast}^b}{(1-b)a_f}\left[\left(\frac{q}{\Delta p}\right)_f^{1-b} (\Delta p)_{forecast}^{1-b} - q_{ab}^{1-b}\right]$$

$$\left(\frac{q}{\Delta p}\right)_f = \left(\frac{q}{\Delta p}\right)_i (1+b\,a_i\,t_f)^{-\frac{1}{b}}$$

$$\left(\frac{q}{\Delta p}\right)_i = \left[\frac{\left(\frac{q}{\Delta p}\right)}{q_{Dd}}\right]_{match}$$

$$a_i = \left(\frac{t_{Dd}}{t}\right)_{match}$$

$$a_f = a_i(1+b\,a_i\,t_f)^{-1}$$

Harmonic

$$EUR = Q_f + \frac{\left(\frac{q}{\Delta p}\right)_f (\Delta p)_{forecast}}{a_f} - \ln\left[\frac{\left(\frac{q}{\Delta p}\right)_f (\Delta p)_{forecast}}{q_{ab}}\right]$$

$$\left(\frac{q}{\Delta p}\right)_f = \left(\frac{q}{\Delta p}\right)_i (1 + a_i\, t_f)^{-1}$$

$$\left(\frac{q}{\Delta p}\right)_i = \left[\frac{\left(\frac{q}{\Delta p}\right)}{q_{Dd}}\right]_{match}$$

$$a_i = \left(\frac{t_{Dd}}{t}\right)_{match}$$

$$a_f = a_i(1 + a_i\, t_f)^{-1}$$

Gas

Permeability is obtained by rearranging the definition of dimensionless decline rate:

$$q_{Dd} = \frac{1.417 * 10^6\, T}{k\, h\, \Delta p_p}\left[\ln\left(\frac{r_e}{r_{wa}}\right) - \frac{3}{4}\right]$$

$$k = \frac{1.417 * 10^6\, T}{h}\left[\frac{\left(\frac{q}{\Delta p_p}\right)}{q_{Dd}}\right]_{match}\left[\ln\left(\frac{r_e}{r_{wa}}\right)_{match} - \frac{3}{4}\right]$$

Where $q\,/\,\Delta p_p$ and q_{Dd} are read off the raw data and typecurve graphs at a selected match point.

Solve for apparent wellbore radius from the definition of dimensionless decline time:

$$t_{Dd} = \frac{0.00633 \, k \, t}{\frac{1}{2} \, \phi \, \mu \, c_t \, r_{wa}^2 \left[\left(\frac{r_e}{r_{wa}}\right)^2 - 1\right]\left[\ln\left(\frac{r_e}{r_{wa}}\right) - \frac{3}{4}\right]}$$

$$r_{wa} = \sqrt{\left(\frac{t}{t_{Dd}}\right)_{match} \frac{0.00633 \, k}{\frac{1}{2}\phi \, \mu \, c_t \left[\left(\frac{r_e}{r_{wa}}\right)^2_{match} - 1\right]\left[\ln\left(\frac{r_e}{r_{wa}}\right)_{match} - \frac{3}{4}\right]}}$$

Finally, skin factor can be calculated as follows:

$$s = \ln\left(\frac{r_w}{r_{wa}}\right)$$

For exponential, hyperbolic and harmonic, expected ultimate recovery is calculated as follows:

Exponential

$$EUR = Q_f + \frac{\left(\frac{q}{\Delta p_p}\right)_f \left(\Delta p_p\right)_{forecast} - q_{ab}}{a_i}$$

$$\left(\frac{q}{\Delta p_p}\right)_f = \left(\frac{q}{\Delta p_p}\right)_i e^{(-a_i t_f)}$$

$$\left(\frac{q}{\Delta p}\right)_i = \left[\frac{\left(\frac{q}{\Delta p}\right)}{q_{Dd}}\right]_{match}$$

$$a_i = \left(\frac{t_{Dd}}{t}\right)_{match}$$

It is assumed that the flowing pressure is constant during the forecast period, and this constant flowing pressure $(p_{wf})_{forecast}$ should be entered for analysis.

Hyperbolic

$$EUR = Q_f + \frac{\left(\frac{q}{\Delta p_p}\right)_f^b (\Delta p_p)_{forecast}^b}{(1-b)a_f} \left[\left(\frac{q}{\Delta p_p}\right)_f^{1-b} (\Delta p_p)_{forecast}^{1-b} - q_{ab}^{1-b} \right]$$

$$\left(\frac{q}{\Delta p_p}\right)_f = \left(\frac{q}{\Delta p_p}\right)_i (1 + b \, a_i \, t_f)^{-\frac{1}{b}}$$

$$\left(\frac{q}{\Delta p}\right)_i = \left[\frac{\left(\frac{q}{\Delta p}\right)}{q_{Dd}} \right]_{match}$$

$$a_i = \left(\frac{t_{Dd}}{t}\right)_{match}$$

$$a_f = a_i (1 + b \, a_i \, t_f)^{-1}$$

Harmonic

$$\left(\frac{q}{\Delta p}\right)_f = \left(\frac{q}{\Delta p}\right)_i (1 + a_i \, t_f)^{-1}$$

$$EUR = Q_f + \frac{\left(\frac{q}{\Delta p_p}\right)_f (\Delta p_p)_{forecast}}{a_f} \ln \left[\frac{\left(\frac{q}{\Delta p_p}\right)_f (\Delta p_p)_{forecast}}{q_{ab}} \right]$$

$$\left(\frac{q}{\Delta p_p}\right)_f = \left(\frac{q}{\Delta p_p}\right)_i (1 + a_i \, t_f)^{-1}$$

$$\left(\frac{q}{\Delta p}\right)_i = \left(\frac{\left(\frac{q}{\Delta p}\right)}{q_{Dd}}\right)_{match}$$

$$a_i = \left(\frac{t_{Dd}}{t}\right)_{match}$$

$$a_f = a_i (1 + a_i \, t_f)^{-1}$$

Matching equations (normalized data)

In this analysis, normalized rate and normalized cumulative production are used for analysis instead of rate and cumulative production. The same typecurves are used for analysis as for Fetkovich analysis but the equations to calculate reservoir parameters and reserves are slightly different.

Normalized rate and normalized cumulative production are defined as follows:

Normalized rate: oil

$$\frac{q}{\Delta p} = \frac{q}{p_i - p_{wf}}$$

Normalized rate: gas

$$\frac{q}{\Delta p_p} = \frac{q}{p_{pi} - p_{pwf}}$$

Normalized cumulative production: oil

$$Q_n = \int_0^t \frac{q}{\Delta p} \, dt$$

Normalized cumulative production: gas

$$Q_n = \int_0^t \frac{q}{\Delta p_p} \, dt$$

NPI typecurve theory

The normalized pressure integral (NPI) was initially developed by Blasingame et al. (1989). The objective of the method was to present a robust diagnostic method for drawdowns that did not suffer from noise and data scatter, as is typical of the standard well-test derivative. The solution involves using a pressure integral curve as the base curve for noisy drawdown analysis.

The dimensionless pressure integral is defined as follows:

$$p_{Di} = \frac{1}{t_{DA}} \int_0^{t_{DA}} p_D(t)\,dt$$

where:

$$p_D = \frac{k\,h\,\Delta p}{141.2\,q\,B\,\mu}$$

Conceptually, the pressure integral is a "cumulative average flowing pressure drop" (see also rate integral). The distinguishing characteristic of the pressure integral is its smoothness. Thus, it is an ideal base curve for the standard pressure derivative if the raw data contains any degree of noise or scatter.

The dimensionless pressure integral derivative is defined as follows:

$$p_{Did} = t_{DA}\frac{dp_{Di}}{dt_{DA}} = p_D - p_{Di}$$

Below is a graph of the three dimensionless typecurves (that is, p_D, p_{Di} and p_{Did}), representing the solution for a vertical well in the center of a bounded reservoir (circle).

NPI Typecurve Analysis
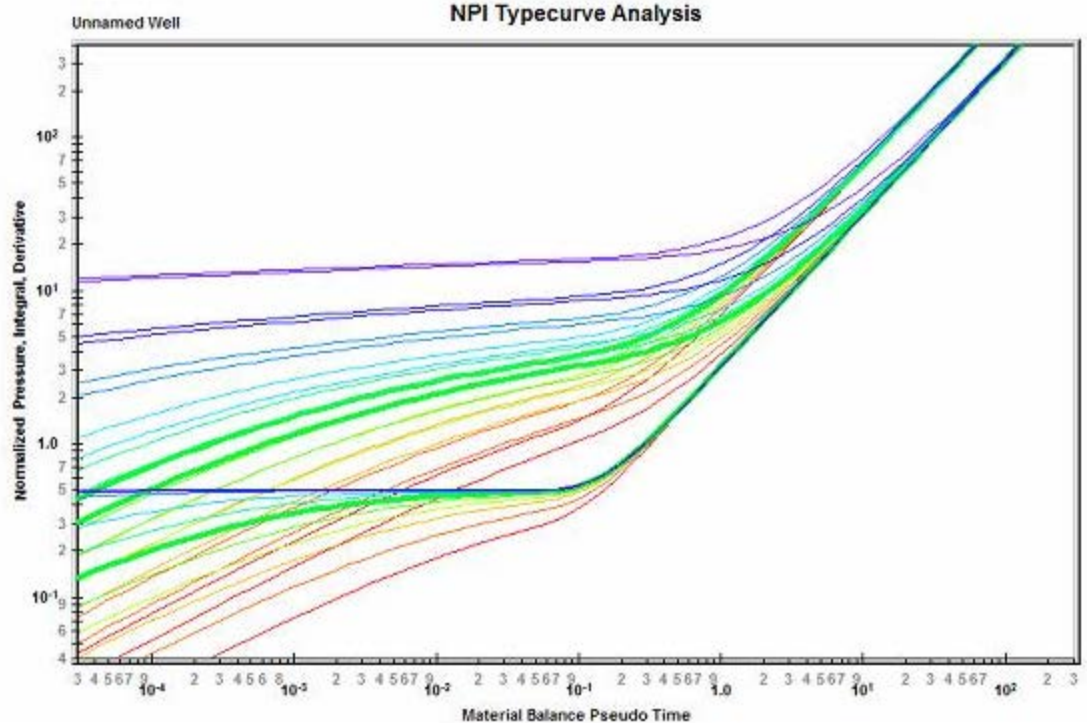
Methodology

Modifications in RTA

The original development of pressure integral typecurves was for pressure transient analysis. However, the theory can be extended to production data analysis (Rate Transient Analysis), using the following concepts:

- Equivalence of constant rate and pressure
- Material balance time

As a production data analysis method, the normalized pressure integral has the advantage of blending seamlessly with transient well-test interpretation. In fact, the diagnostic plot is equivalent to that of an extended drawdown test. The perspective is quite different from decline curves, and provides a useful benchmark for comparison of results.

Data preparation

In normalized pressure integral typecurve analysis, the following three rate functions can be plotted against material balance time.

Normalized pressure

Oil wells

$$\frac{\Delta p}{q}$$

Gas wells

$$\frac{\Delta p_p}{q}$$

Normalized pressure integral

The pressure integral is defined at any point in the producing life of a well, as the average normalized flowing pressure drop at which the well has produced until that moment in time. The normalized pressure integral is defined as follows:

Oil wells

$$\left(\frac{\Delta p}{q}\right)_i = \frac{1}{t_c} \int_0^{t_c} \frac{\Delta p}{q} \, dt_c$$

Gas wells

$$\left(\frac{\Delta p_p}{q}\right)_i = \frac{1}{t_{ca}} \int_0^{t_{ca}} \frac{\Delta p_p}{q} \, dt_{ca}$$

Pressure integral derivative

The pressure integral derivative is defined as the semi-logarithmic derivative of the pressure integral function, with respect to material balance time. It is defined as follows:

Oil wells

$$\left(\frac{\Delta p}{q}\right)_{id} = t_c \frac{d\left(\frac{\Delta p}{q}\right)_i}{dt_c}$$

Gas wells

$$\left(\frac{\Delta p_p}{q}\right)_{id} = \frac{t_{ca}\, d\left(\frac{\Delta p_p}{q}\right)_i}{dt_{ca}}$$

Analysis

The actual normalized pressure, pressure integral, and pressure integral derivative are plotted vs. material balance time data on a log-log scale of the same size as the typecurves. This plot is called the "data plot". Any convenient units can be used for normalized rate or time because a change in units simply causes a uniform shift of the raw data on a logarithmic scale. It is recommended that daily operated-rates be plotted, and not the monthly rates, especially when transient data are analyzed. Any one of the curves can be used individually but often using more than one curve helps in achieving a more unique match of the data with the typecurves.

The data plot is moved over the typecurve plot, while the axes of the two plots are kept parallel, until a good match is obtained. The pressure, pressure integral, and pressure integral derivative data should all fit the same corresponding typecurve. Several different typecurves should be tried to obtain the best fit of all the data. The typecurve that best fits the data is selected and its r_e / r_{wa} (r_e / x_f for fractured case) value is noted.

Typecurve analysis is done by selecting a match point, and reading its co-ordinates off the data plot $(\Delta p / q$ and $t_{ca})_{match}$, and the typecurve plot $(p_D$ and $t_{DA})_{match}$. At the same time the stem value r_e / r_{wa} (r_e / x_f for fracture typecurves) of the matching curve is noted. To create a forecast, the selected typecurve is traced on to the data plot, and extrapolated. The future rate is read from the data plot, off the traced typecurve.

Given a curve match, the following reservoir parameters can be obtained if net pay, total compressibility, and wellbore radius are known: permeability, skin (or fracture half length, depending on which model is chosen), area, and original fluids-in-place.

Calculation of parameters

Radial typecurves

Oil wells

$$p_D = \frac{k \, h \, \Delta p}{141.2 \, q \, B \, \mu}$$

$$t_{DA} = \frac{0.00633 \, k \, t_c}{\pi \, \phi \, \mu \, c_t \, r_e^2}$$

$$k = \frac{141.2 \, B \, \mu}{h} \left(\frac{p_D}{\frac{\Delta p}{q}} \right)_{match}$$

$$r_e = \sqrt{\frac{0.00633 \, k}{\pi \, \phi \, \mu \, c_t} \left(\frac{t_c}{t_{DA}} \right)_{match}}$$

$$r_{wa} = \frac{r_e}{\left(r_e / r_{wa} \right)_{match}}$$

$$s = \ln \left(\frac{r_w}{r_{wa}} \right)$$

$$N = \frac{0.00633}{c_t}\left(\frac{141.2\,S_o}{5.615*10^3}\right)\left(\frac{p_D}{\frac{\Delta p}{q}}\right)_{match}\left(\frac{t_c}{t_{DA}}\right)_{match} \quad \text{(Mbbls)}$$

Gas wells

$$p_D = \frac{k\,h\,\Delta p_p}{1.417*10^6\,T\,q}$$

$$t_{DA} = \frac{0.00633\,k\,t_{ca}}{\pi\,\phi\,\mu_i\,c_{ti}\,r_e^2}$$

$$k = \frac{1.417*10^6\,T}{h}\left(\frac{p_D}{\frac{\Delta p_p}{q}}\right)_{match}$$

$$r_e = \sqrt{\frac{0.00633\,k}{\pi\,\phi\,\mu_i\,c_{ti}}\left(\frac{t_{ca}}{t_{DA}}\right)_{match}}$$

$$r_{wa} = \frac{r_e}{\left(r_e/r_{wa}\right)_{match}}$$

$$s = \ln\left(\frac{r_w}{r_{wa}}\right)$$

$$G = \frac{(0.00633)(1.417 * 10^6) S_g \, p_i \, T_{sc}}{\mu_i \, c_{ti} \, Z_i \, p_{sc}} \left(\frac{t_{ca}}{t_{DA}}\right)_{match} \left(\frac{p_D}{\frac{\Delta p_p}{q}}\right)_{match} * 10^9 \ \text{(Bscf)}$$

Fracture typecurves

The NPI fracture typecurves are the inverse of the Agarwal-Gardner rate-time fracture typecurves.

Transient typecurve theory

The transient typecurve analysis method provides an alternative perspective that is ideal for analysis of very short (early) production periods, and/or analysis of very low permeability reservoirs.

In the Blasingame, Agarwal-Gardner and Normalized Pressure Integral methods, the typecurves are scaled such that there is convergence onto a single boundary-dominated stem (unit slope). This is achieved through the use of a dimensionless time that is based on area (t_{DA} or t_{Dd}). One consequence of this type of scaling is that there are numerous transient stems. If a dimensionless time based on well radius (t_D) is chosen instead, there will be a single transient stem with a series of boundary-dominated curves. When viewing a single typecurve (e.g., $re_D = 28$) there is no difference between these two scaling formats (see figure below). However, when viewing all the typecurves together, the transient presentation provides a more convenient base for analysis of transient data. This follows from the fact that selection of an appropriate transient stem is not required.
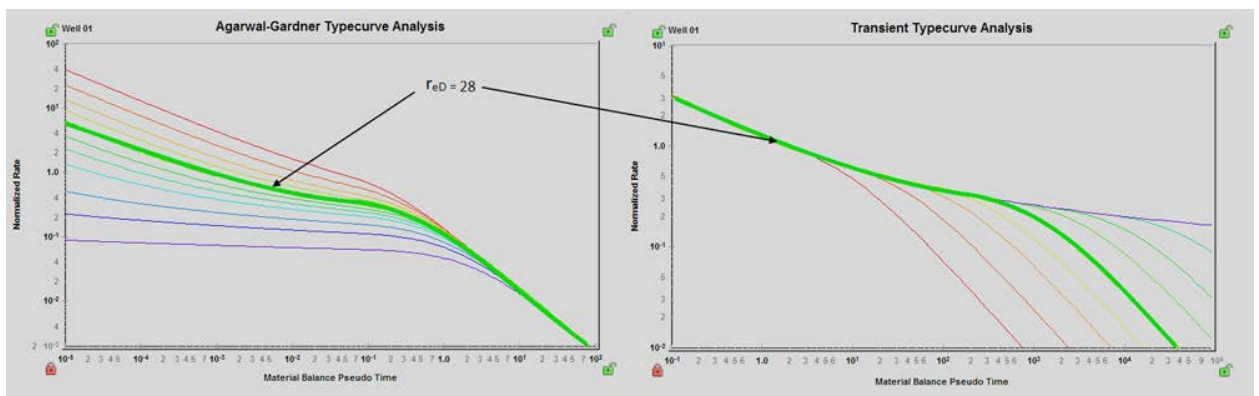
Consider a transient production data set (either very low permeability, or limited production life). A comparison of the typecurve match using Agarwal-Gardner Rate-Time analysis with that of the Transient format is shown below.
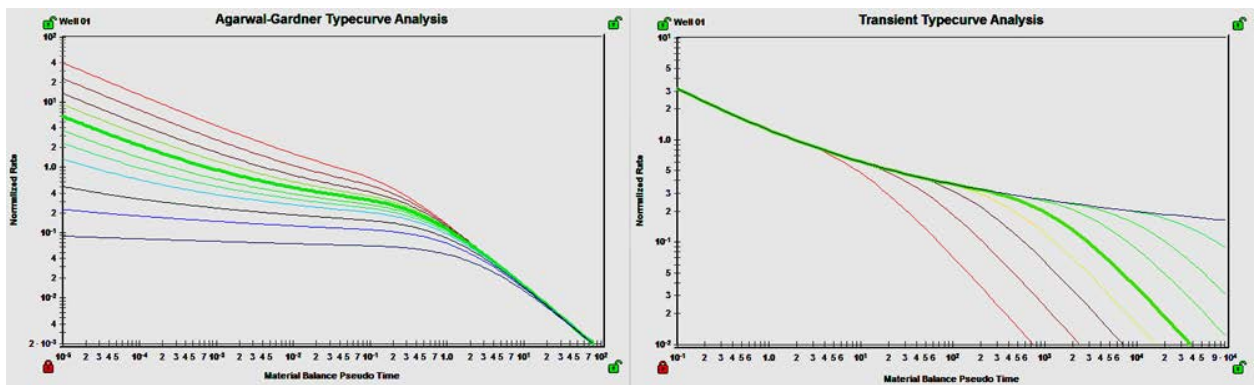
It is clear from this example that the transient presentation of the typecurves provides a more unique typecurve match. For the same reason that transient data works better with the transient format (q_D vs. t_D), it should be noted that boundary-dominated flow analysis is not advised using this method.

The accepted time-superposition function for Rate Transient Analysis is material balance time. Since material balance time is rigorous for boundary-dominated flow, it is a natural standard for evaluating variable rate production data. However, when dealing with transient data, it is clearly not the best option. The standard time-superposition for transient flow (pressure transient analysis) is radial-superposition time. When using the transient typecurves in RTA, both the radial and linear superposition time options are available.

Inverse pressure integral derivative

This derivative can make typecurve matching easier by exaggerating features in the data. In most cases, the inverse pressure derivative was found to be too sensitive to be useful. The inverse pressure integral derivative is less sensitive and so can be interpreted more handily, while still providing detail about the character of the data.

We start with dimensionless pressure:

$$q_D = \frac{1}{p_D}$$

Next we define the dimensionless pressure integral:

$$p_{Di} = \frac{1}{t_D} \int p_D \, dt_D$$

This is used to define the inverse pressure integral derivative:

$$\frac{1}{p_{Did}} = \frac{1}{\left(\dfrac{dp_{Di}}{d\ln(t_D)}\right)}$$

This can also be written as:

$$\frac{1}{p_{Did}} = \frac{1}{\left(t_{DA} \frac{dp_{DI}}{dt_D}\right)}$$

Data preparation

The horizontal axis is material balance time (pseudo-time for gas).

On the vertical axis, two variables are plotted:

- Normalized Rate vs. Material Balance Time

- Inverse of Semi-log Derivative vs. Material Balance Time

Normalized rate

Oil wells

$$\frac{q}{\Delta p} = \frac{q}{p_i - p_{wf}}$$

$$\frac{1}{DER} = \frac{1}{\left[\dfrac{\partial \frac{\Delta p}{q}}{\partial \ln(t_c)}\right]}$$

Gas Wells

$$\frac{q}{\Delta p_p} = \frac{q}{p_{pi} - p_{pwf}}$$

$$\frac{1}{DER} = \frac{1}{\left[\dfrac{\partial \dfrac{\Delta p_p}{q}}{\partial \ln(t_{ca})}\right]}$$

Note: In the modified (RTA) plot, the $1 / DER_i$ (inverse pressure integral derivative) is also included.

Analysis

The normalized rate and inverse semi-log derivative data are plotted against material balance time on a log-log scale of the same size as the typecurves. This plot is called the "data plot". Any convenient units can be used for normalized rate or time because a change in units simply causes a uniform shift of the raw data on a logarithmic scale. It is recommended that daily operated-rates be plotted, and not the monthly rates; especially when transient data are analyzed.

The data plot is moved over the typecurve plot, while the axes of the two plots are kept parallel, until a good match is obtained. Several different typecurves should be tried to obtain the best fit of all the data. The typecurve that best fits the data is selected and its "r_e / r_{wa}" (r_e / x_f for fractured case) value is noted.

Typecurve analysis is done by selecting a match point, and reading its coordinates off the data plot (q / Δp and t_c) $_{match}$, and off the typecurve plot (q_D and t_D) $_{match}$. At the same time the stem value "r_e / r_{wa}" (r_e / x_f for fracture typecurves) of the matching curve is noted.

To create a forecast, the selected typecurve is traced on to the data plot, and extrapolated. The future rate is read from the data plot, off the traced typecurve.

Calculation of parameters: radial typecurves

Oil wells

Permeability is obtained by rearranging the definition of dimensionless rate:

$$q_D = \frac{141.2 \, q \, B \, \mu}{k \, h \, (p_i - p_{wf})}$$

$$k = \frac{141.2\,B\,\mu}{h}\left(\frac{q/\Delta p}{q_D}\right)_{match}$$

$$t_D = \frac{0.00633\,k\,t_c}{\phi\,\mu\,c_t\,r_{wa}{}^2}$$

Solve for apparent wellbore radius from the definitions of dimensionless time and permeability:

$$r_{wa} = \sqrt{\frac{0.00633}{\phi\,c_t}\left(\frac{141.2\,B}{h}\right)\left(\frac{q/\Delta p}{q_D}\right)_{match}\frac{\left(t_c\right)}{\left(t_D\right)_{match}}}$$

Skin factor is calculated as follows:

$$s = \ln\left(\frac{r_w}{r_{wa}}\right)$$

Volume and area parameters are calculated as follows:

$$N = \pi\,\frac{S_o}{c_t}\left(\frac{0.00633 * 141.2\,B}{h}\right)\left(\frac{q/\Delta p}{q_D}\right)_{match}\left(\frac{t_c}{t_D}\right)_{match}\left(\frac{(r_{eD})^2}{5.615 * 10^3}\right)\quad\text{(Mbbls)}$$

$$A = \frac{5.615 * 10^3\,N\,B_o}{\phi\,S_o\,h}\frac{1}{43560}\quad\text{(Acres)}$$

Gas wells

Permeability is obtained by rearranging the definition of dimensionless rate:

$$q_D = \frac{1.417 * 10^6 \, T_R}{k \, h} \frac{q}{\Delta p_p}$$

$$k = \frac{1.417 * 10^6 \, T_R}{h} \left(\frac{q/\Delta p_p}{q_D}\right)_{match}$$

$$t_D = \frac{0.00633 \, k \, t_{ca}}{\phi \, \mu_i \, c_{ti} \, r_{wa}^2}$$

Solve for apparent wellbore radius from the definitions of dimensionless time and permeability:

$$r_{wa} = \sqrt{\frac{0.00633}{\phi \, \mu_i \, c_{ti}} \left(\frac{1.417 * 10^6 \, T_R}{h}\right)\left(\frac{t_{ca}}{t_D}\right)_{match}\left(\frac{q/\Delta p_p}{q_D}\right)_{match}}$$

Skin factor is calculated as follows:

$$s = \ln\left(\frac{r_w}{r_{wa}}\right)$$

Volume and area parameters are calculated as follows:

$$G = \frac{\pi \, (0.00633)(1.417 * 10^6) \, S_g \, p_i \, T_{sc}}{\mu_i \, c_{ti} \, Z_i \, p_{sc}}\left(\frac{t_{ca}}{t_D}\right)_{match}\left(\frac{q/\Delta p_p}{q_D}\right)_{match}(r_{eD})_{match}^2 * 10^{-9} \; \text{(Bcf)}$$

$$A = \frac{G \, Z_i \, T \, p_{sc}}{\phi \, h \, S_g \, p_i \, T_{sc}} \frac{1}{43560} \; \text{(Acres)}$$

Calculation of parameters: finite conductivity fracture typecurves

The finite conductivity fracture typecurves are based on a square-shaped reservoir with a hydraulic fracture in the center. They are plotted using dimensionless time format, and are therefore categorized as transient format curves. The transient stems represent three different dimensionless fracture conductivity (FCD) values (0.5, 5, and 500). The boundary dominated stems diverge at each of four (1, 2, 5, 25) dimensionless reservoir length (x_{eD}) values.
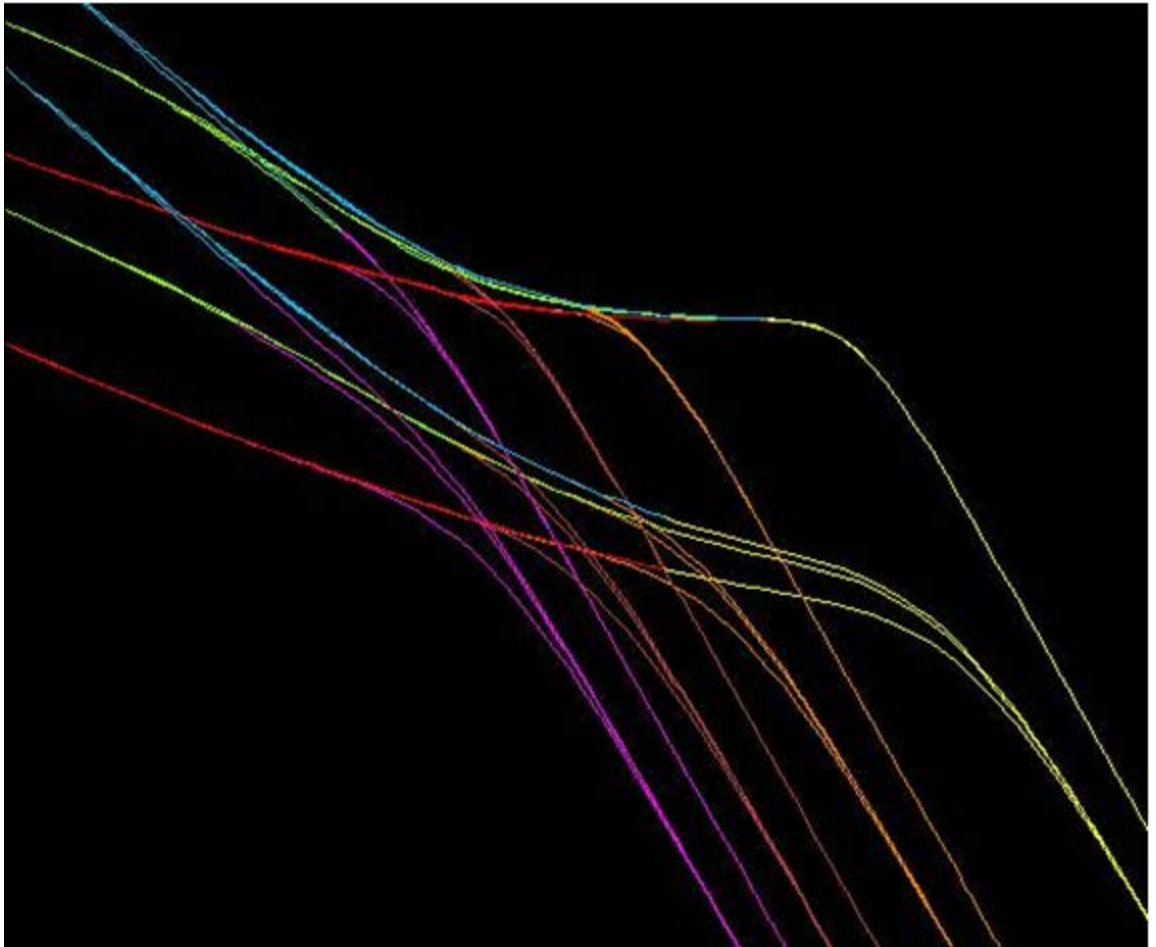
Definitions

Dimensionless fracture conductivity:

$$F_{CD} = \frac{k_f\,w}{k\,x_f}$$

Dimensionless reservoir length / width:

$$X_{eD} = \frac{X_e}{x_f}$$

Where $2X_e$ = primary reservoir dimension

Oil wells

Permeability is obtained by rearranging the definition of dimensionless rate:

$$q_D = \frac{141.2\, q\, B\, \mu}{k\, h\, (p_i - p_{wf})}$$

$$k = \frac{141.2\, B\, \mu}{h} \left(\frac{q/\Delta p}{q_D} \right)_{match}$$

$$t_D = \frac{0.00633\, k\, t_c}{\phi\, \mu\, c_t\, x_f{}^2}$$

Solve for fracture half-length from the definitions of dimensionless time and permeability:

$$x_f = \sqrt{ \frac{0.00633}{\phi\, c_t} \left(\frac{141.2\, B}{h} \right) \left(\frac{q/\Delta p}{q_D} \right)_{match} \left(\frac{t_c}{t_D} \right)_{match} }$$

Volume and area parameters are calculated as follows:

$$N = \frac{S_o}{c_t} \left(\frac{0.00633 * 141.2\, B}{h} \right) \left(\frac{q/\Delta p}{q_D} \right)_{match} \left(\frac{t_c}{t_D} \right)_{match} \left(\frac{(2\, X_{eD})^2}{5.615 * 10^3} \right) \text{ (Mbbls)}$$

$$A = \frac{5.615 * 10^3\, N\, B_o}{\phi\, S_o\, h} \frac{1}{43560} \text{ (Acres)}$$

Gas wells

Permeability is obtained by rearranging the definition of dimensionless rate:

$$q_D = \frac{1.417 * 10^6\, T_R}{k\, h} \frac{q}{\Delta p_p}$$

$$k = \frac{1.417 * 10^6\, T_R}{h} \left(\frac{q/\Delta p_p}{q_D} \right)_{match}$$

$$t_D = \frac{0.00633\, k\, t_{ca}}{\phi\, \mu_i\, c_{ti}\, x_f{}^2}$$

Solve for fracture half-length from the definitions of dimensionless time and permeability:

$$x_f = \sqrt{ \frac{0.00633}{\phi\, \mu_i\, c_{ti}} \left(\frac{1.417 * 10^6\, T_R}{h} \right) \left(\frac{t_{ca}}{t_D} \right)_{match} \left(\frac{q/\Delta p_p}{q_D} \right)_{match} }$$

Volume and area parameters are calculated as follows:

$$G = \frac{(0.00633)(1.417 * 10^6)\, S_g\, p_i\, T_{sc}}{\mu_i\, c_{ti}\, Z_i\, p_{sc}} \left(\frac{t_{ca}}{t_D}\right)_{match} \left(\frac{q/\Delta p_p}{q_D}\right)_{match} (2\, X_{eD})_{match}^{2} * 10^{-9} \ \ (\text{Bcf})$$

$$A = \frac{G\, Z_i\, T\, p_{sc}}{\phi\, h\, S_g\, p_i\, T_{sc}} \frac{1}{43560} \ \ (\text{Acres})$$

Wattenbarger typecurve theory

Extended periods of linear flow have been observed in many gas wells. These wells are usually in very tight gas reservoirs with hydraulic fractures designed to extend to the drainage boundary of the well. Wattenbarger et al. (1998) presented new typecurves to analyze the production data of these gas wells.

They assumed a hydraulically fractured well in the center of a rectangular reservoir. The fracture is assumed to be extended to the boundaries of the reservoir.
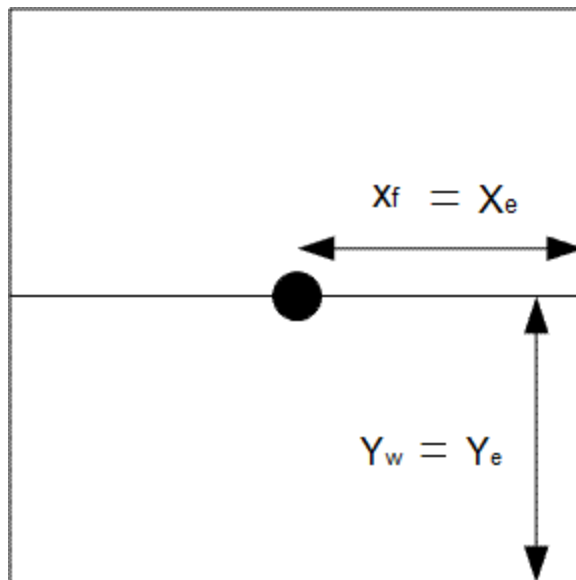
They showed that the solution in case of constant rate production and closed reservoir is:

$$p_D = \frac{\pi}{2}\left(\frac{Y_e}{x_f}\right)\left[\frac{1}{3} + \left(\frac{x_f}{Y_e}\right)^2 t_{Dxf}\right] - \frac{2}{\pi^2}\left(\frac{Y_e}{x_f}\right)\sum_{n-1}^{\infty}\frac{1}{n^2} e\left[-n^2\pi^2\left(\frac{x_f}{Y_e}\right)^2 t_{Dxf}\right]$$

Where dimensionless variables are defined as:

$$p_D = \frac{k\,h\,(p_i - p_{wf})}{141.2\,q\,B\,\mu}$$

$$t_{Dxf} = \frac{0.00633\,k\,t}{\phi\,\mu\,c_t\,x_f^2}$$

The typecurves based on this equation are shown below. Wattenbarger et al. (1998) showed that there are different typecurves for different values of x_f / Y_e.
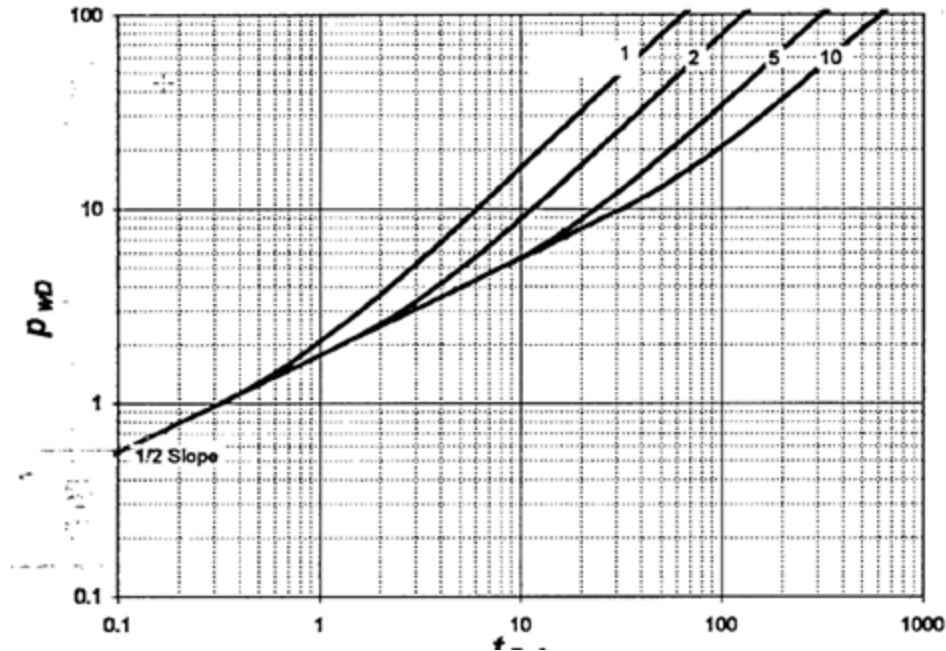
The solution for linear flow can be rewritten as:

$$\left(\frac{x_f}{Y_e}\right) p_D = \frac{\pi}{2}\left[\frac{1}{3} + t_{Dye}\right] - \frac{2}{\pi^2}\sum_{n-1}^{\infty}\frac{1}{n^2}\,e\left[-n^2\,\pi^2\,t_{Dye}\right]$$

where:

$$t_{Dye} = \frac{0.00633\,k\,t}{\phi\,\mu\,c_t\,Y_e^2} = \left(\frac{x_f}{Y_e}\right)^2 t_{Dxf}$$

This equation shows that plotting $[(x_f / Y_e) * p_D]$ against t_{Dye} gives only one curve for any rectangular geometry, rather than families of typecurves with different values of x_f / Y_e.

In RTA, this analysis has been modified as follows:

- $[(Y_e / x'_e) * q_D]$ is plotted against t_{Dye} instead of $[(x_f / Y_e) * p_D]$.

- The typecurves are generated for cases where the well is not in the center of the reservoir (different values for Y_e / Y_w).

- In addition to dimensionless rate, the inverse of semi-log pressure derivative curve is included.

Methodology

Data preparation

The horizontal axis is material balance time (pseudo-time for gas).

On the vertical axis, two variables are plotted:

- Normalized rate

- Inverse of semi-log pressure derivative

Normalized rate

Oil wells

$$\frac{q}{\Delta p} = \frac{q}{p_i - p_{wf}}$$

Gas wells

$$\frac{q}{\Delta p_p} = \frac{q}{p_{pi} - p_{pwf}}$$

Inverse of semi-log pressure derivative

Oil wells

$$\frac{1}{DER} = \frac{1}{\left[\dfrac{\partial \dfrac{\Delta p}{q}}{\partial \ln(t_c)}\right]}$$

Gas wells

$$\frac{1}{DER} = \frac{1}{\left[\dfrac{\partial \dfrac{\Delta p_p}{q}}{\partial \ln(t_{ca})}\right]}$$

Analysis

The normalized rate and inverse semi-log pressure derivative are plotted against the material balance time on a log-log scale of the same size as the typecurves. This plot is called the "data plot". Any convenient units can be used for normalized rate or time because a change in units simply caused a uniform shift of the raw data on a logarithmic scale. It is recommended that daily operated-rates be plotted, and not the monthly rates; especially when transient data are analyzed.

The data plot is moved over the typecurve plot, while the axes of the two plots are kept parallel until a good match is obtained. Several different typecurves should be tried to obtain the best fit of all the data. The typecurve that best fits the data is selected and Y_e / Y_w value is noted.

Calculation of parameters

Oil wells

Using the definition of $[q_D (Y_e / X_e)]$:

$$q_D \frac{Y_e}{X_e} = \frac{141.2\, B\, \mu}{k\, h} \frac{q}{\Delta p} \frac{Y_e}{X_e}$$

$k\, X_e / Y_e$ is calculated as follows:

$$\frac{k\, X_e}{Y_e} = \frac{141.2\, B\, \mu}{h} \left[\frac{\left(\frac{q}{\Delta p} \right)}{q_D \frac{Y_e}{X_e}} \right]_{match}$$

where $(q / \Delta p)$ and $[q_D\, (Y_e / X_e)]$, are read off from each of the raw data and typecurve graphs at a selected match point.

From the definition of dimensionless time based on reservoir width (t_{Dye}):

$$t_{Dye} = \frac{0.00633\, k\, t_c}{\phi\, \mu\, c_t\, Y_e^2}$$

$(Y_e / \sqrt{k})$ is calculated as follows:

$$\frac{Y_e}{\sqrt{k}} = \sqrt{\frac{0.00633}{\phi\, \mu\, c_t} \left(\frac{t_c}{t_{Dye}} \right)_{match}}$$

Substituting the equation for $[(k\, X_e / Y_e)]$ into the above, we get:

$$\sqrt{k}\, X_e = \sqrt{\frac{0.00633}{\phi\, \mu\, c_t}} * \frac{141.2\, B\, \mu}{h} * \left[\frac{\left(\frac{q}{\Delta p} \right)}{q_D \frac{Y_e}{X_e}} \right]_{match} * \sqrt{\left(\frac{t_c}{t_{Dye}} \right)_{match}}$$

Additional reservoir parameters are now calculated:

$$A = 4\,X_e\,Y_e = 4 * \left(\sqrt{k}\,X_e\right)\frac{Y_e}{\sqrt{k}}\frac{1}{43560}$$

$$= \frac{4 * 0.00633}{\phi\,c_t} * \frac{141.2\,B}{h} * \left[\frac{\left(\frac{q}{\Delta p}\right)}{q_D\frac{Y_e}{X_e}}\right]_{match} * \left(\frac{t_c}{t_{Dye}}\right)_{match} * \frac{1}{43560}$$

(Acres)

$$N = \frac{4\,X_e\,Y_e\,h\,\phi\,S_{oi}}{B} * \frac{1}{5.615 * 10^3}$$

$$= \frac{4 * 0.00633 * 141.2}{c_t} * \left[\frac{\left(\frac{q}{\Delta p}\right)}{q_D\frac{Y_e}{X_e}}\right]_{match} * \left(\frac{t_c}{t_{Dye}}\right)_{match} * \frac{S_{oi}}{5.615 * 10^3}$$

(Mbbl)

Gas wells

Using the definition of $[q_D(Y_e / X_e)]$:

$$q_D\frac{Y_e}{X_e} = \frac{1.417 * 10^6\,T}{k\,h}\frac{q}{\Delta p_p}\frac{Y_e}{X_e}$$

$(k\,X_e / Y_e)$ is calculated as follows:

$$\frac{k\,X_e}{Y_e} = \frac{1.417 * 10^6\,T}{h}\left[\frac{\left(\frac{q}{\Delta p_p}\right)}{q_D\frac{Y_e}{X_e}}\right]_{match}$$

where $(q / \Delta p_p)$ and $[q_D (Y_e / X_e)]$ are read off from each of the raw data and typecurve graphs at a selected match point.

From the definition of t_{Dye},

$$t_{Dye} = \frac{0.00633\,k\,t_{ca}}{\phi\,\mu\,c_t\,Y_e^2}$$

$(Y_e / \sqrt{k})$ is calculated as follows:

$$\frac{Y_e}{\sqrt{k}} = \sqrt{\frac{0.00633}{\phi \, \mu \, c_t} \left(\frac{t_{ca}}{t_{Dye}}\right)_{match}}$$

Substituting the equation for $(k \, X_e / Y_e)$ into the above, we get:

$$\sqrt{k} \, X_e = \sqrt{\frac{0.00633}{\phi \, \mu \, c_t}} * \frac{1.417 * 10^6 \, T}{h} * \left[\frac{\left(\frac{q}{\Delta p_p}\right)}{q_D \frac{Y_e}{X_e}}\right]_{match} * \sqrt{\left(\frac{t_{ca}}{t_{Dye}}\right)_{match}}$$

Additional reservoir parameters are now calculated:

$$A = 4 \, X_e \, Y_e = 4 * \left(\sqrt{k} \, X_e\right) * \frac{Y_e}{\sqrt{k}} * \frac{1}{43560}$$

$$= \frac{4 * 0.00633}{\phi \, \mu \, c_t} * \frac{1.417 * 10^6 \, T}{h} * \left[\frac{\left(\frac{q}{\Delta p_p}\right)}{q_D \frac{Y_e}{X_e}}\right]_{match} * \left(\frac{t_{ca}}{t_{Dye}}\right)_{match} * \frac{1}{43560}$$

(Acres)

$$G = \frac{4 \, X_e \, Y_e \, h \, \phi \, S_{gi}}{B_{gi}} * 10^{-9}$$

$$= \frac{4 * 0.00633 * 1.417 * 10^6 \, T}{\mu \, c_t} \left[\frac{\left(\frac{q}{\Delta p_p}\right)}{q_D \frac{Y_e}{X_e}}\right]_{match} * \left(\frac{t_{ca}}{t_{Dye}}\right)_{match} * \frac{S_{gi}}{B_{gi}} * 10^{-9}$$

(Bscf)

Typewell theory

The distribution of rates is used to generate the range of production history lines corresponding with P90, P50, P10 cases. (For example, for each period, the P90 point is determined as the value for which 90% of the data points are higher—or for the more common description, the value for which 10% of the values are smaller.) The data points in this case are the rates for each well at a specific period. If a group of groups is selected, the aggregate rates for each group are used.

To determine this value, all data points for a period must be sorted in ascending order. N is the number of data points in the period. P is the percentile. (In the P90 example P is 10.) The position of the percentile value is n.

$$n = \frac{P}{100}(N-1) + 1$$

The value of n is split into its integer (k) and decimal (d) components such that n = k + d

The percentile value (v_p) is calculated by:

$$v_p = v_k + d(v_{k+1} - v_k)$$

The production volume for each period is calculated in the same way as the rate.

The cumulative production track is calculated by summing the calculated volumes for each period.

For example:

We have the following dataset:

1.18	1.28	0.95	2.49	1.35	1.82	1.46	3.96	1.33	1.40
3.72	3.11	2.32	2.20	1.75	4.57	2.22	4.12	2.79	3.95

The values are set to ascending order:

0.95	1.18	1.28	1.33	1.35	1.40	1.46	1.75	1.82	2.20
2.22	2.32	2.49	2.79	3.11	3.72	3.95	3.96	4.12	4.57

The percentile to be found is 10 (P90). N=20.

Next, n is determined:

$$n = \frac{10}{100}(20-1) + 1 = 2.9$$

From n = 2.9, k = 2 and d = 0.9.

Then we find v_2 is 1.18 and v_3 is 1.28.

Finally $v_k + d(v_{k+1} - v_k) = 1.18 + 0.9(1.28 - 1.18) = 1.27$.

The P90 rate for this period is 1.27.

Unconventional reservoir theory

Production behavior of unconventional reservoirs

The term "unconventional" refers to production from very low-permeability formations. This often includes shale and very tight sands. When the permeability of a formation is very low, an enormous amount of surface area is required between the well completion and the reservoir to be able to produce at economic rates. This required area is achieved through multiple stages of massive fracture stimulations. The flow regime most often observed in these wells is linear flow. Linear flow may last several years and is often the only flow regime observed in the analysis. In addition to fractures created in the reservoir, linear flow can be caused by natural fracturing or enhancements to the natural fractures. For more information see fracture properties.

The effective drainage boundaries for these wells often coincide with the fracture length. In other words, drainage beyond the stimulated region is not significant and in the analysis method presented, this contribution is neglected. The base reservoir geometry used to develop this method is that of a single fracture centered in a rectangular reservoir, where the fracture width extends to the reservoir boundary. In this geometry, linear flow is observed until the reservoir width (Y_e) boundary is reached, and the well enters boundary-dominated flow. The reservoir geometry is shown below:
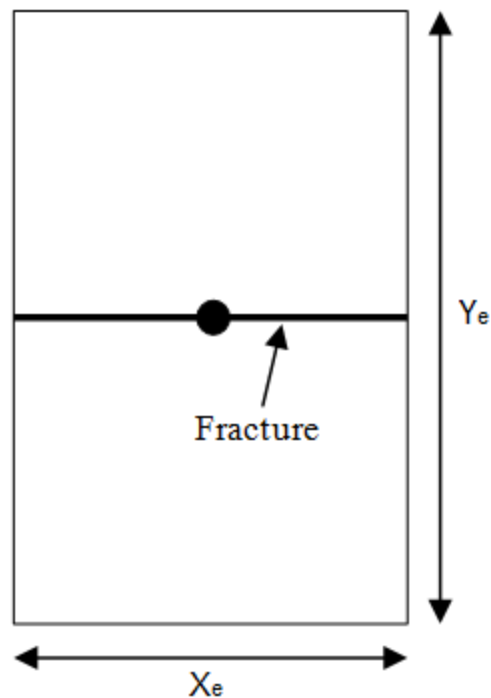
Constant flowing pressure

Current analysis techniques in the industry use material balance time. Since material balance time is actually boundary-dominated flow superposition time, these analyses may appear to show boundary-dominated flow even when the reservoir is still exhibiting transient flow. In the method presented, no superposition functions are used, which avoids a bias towards any flow regimes. The production data is analyzed using a plot of reciprocal rate versus square-root time. In this plot, linear flow appears as a straight-line trend. The basic assumption is of infinite conductivity in the fracture; finite conductivity manifests itself as a positive intercept on the plot. The equations presented are based on the assumption of a constant flowing pressure at the well. This is a reasonable simplification for tight gas and shale production, where wells are typically produced under high drawdown.

Based on the straight-line behavior of the square root time plot, the simplest form of the linear flow equation is:

Equation 1

$$\frac{1}{q} = m\sqrt{t} + b'$$

In this equation, the intercept captures a number of near well effects, such as skin and finite fracture conductivity, and the slope is given by:

For oil:

Equation 2a

$$m = \frac{31.3\,B}{h\,x_f\,\sqrt{k}}\,\sqrt{\frac{\mu}{\varphi\,c_t}} \times \frac{1}{p_i - p_{wf}}$$

For gas:

Equation 2b

$$m = \frac{315.4\,T}{h\,\sqrt{\left(\varphi\,\mu_g\,c_t\right)_i}} \times \frac{1}{p_{pi} - p_{wf}} \times \frac{1}{x_f\,\sqrt{k}}$$

From the slope of the equation, fracture half-length and permeability are determined as a single product. To determine either explicitly, the other parameter must be known.

To determine the skin effect, the intercept of the line is used with the following:

For oil:

Equation 2c

$$s' = \frac{b' \left(p_i - p_{wf} \right) k \left(2 x_f \right)}{141.2 \, B \, \mu}$$

Equation 2d

$$F'_{CD} = \frac{141.2 \, B \, \mu}{b' \left(p_i - p_{wf} \right) k \, h \, n_f} \times \left(1 + \frac{h}{x_f} \left(\ln\left(\frac{h}{2 \, r_w} \right) - \frac{\pi}{2} \right) \right)$$

For gas:

Equation 2e

$$s' = \frac{b' \left(p_{pi} - p_{pwf} \right) k \left(2 x_f \right)}{1.417 \times 10^6 \, T}$$

Equation 2f

$$F'_{CD} = \frac{1.417 \times 10^6 \, T}{b' \left(p_{pi} - p_{pwf} \right) k \, h \, n_f} \times \left(1 + \frac{h}{x_f} \left(\ln\left(\frac{h}{2 \, r_w} \right) - \frac{\pi}{2} \right) \right)$$

Duration of linear flow

When a well is producing under constant flowing pressure, the distance of investigation can be obtained from the following equation during the linear flow period:

Equation 3

$$Y = 0.159 \sqrt{\frac{k \, t}{\left(\varphi \, \mu \, c_t \right)_i}}$$

Combining this equation with the reservoir geometry detailed in the diagram presented previously, the end of linear flow is given by the following:

Equation 4

$$\frac{Y_e}{2} = 0.159 \sqrt{\frac{k\, t_{elf}}{(\varphi\, \mu\, c_t\,)_i}}$$

Equation 4 can be rearranged as follows:

Equation 5

$$t_{elf} = \left(\frac{Y_e \sqrt{(\varphi\, \mu\, c_t\,)_i}}{2 \times 0.159 \sqrt{k}} \right)^2$$

This is not a practical form of the equation, since permeability (k) and reservoir width (Y_e) are usually not explicitly known. The permeability is tied into the ($x_f\sqrt{k}$) term and reservoir width is related to the drainage area (A); however, both of these are related to fracture half-length (x_f). Using the definition of drainage area (A = 2 * x_f * Y_e), equation 5 becomes:

Equation 6a

$$t_{elf} = \left(\frac{A \sqrt{(\varphi\, \mu\, c_t\,)_i}}{4 \times 0.159} \times \frac{1}{x_f \sqrt{k}} \right)^2$$

The ($x_f\sqrt{k}$) term is determined from the slope of the square-root time plot using a rearranged form of equation 2. For unconventional gas reservoirs, $x_f\sqrt{k}$ departs from its analytical value as the pressure drawdown, D_D, becomes higher. To correct for this drawdown effect, a correction factor, f_{cp}, is implemented in the gas constant pressure module, which allows for a more accurate determination of $x_f\sqrt{k}$.

D_D and f_{cp} are defined as follows:

Equation 6b

$$D_D = \frac{[p_{pi} - p_{pwf}]}{p_{pi}}$$

Equation 6c

$$f_{CP} = 1 - 0.0852\, D_D - 0.0857\, D_D^2$$

$x_f\sqrt{k}$ can be determined by using following equations:

For oil:

Equation 7a

$$x_f = \sqrt{k} = \frac{31.3\,B}{m\,h} \times \frac{1}{p_i - p_{wf}} \times \sqrt{\frac{\mu}{\varphi\,c_t}}$$

For gas:

Equation 7b

$$x_f\sqrt{k} = f_{cp}\,\frac{315.4\,T}{m\,h\,(p_{pi} - p_{pwf})}\,\sqrt{\frac{1}{(\varphi\,\mu\,c_t)_i}}$$

Substituting equation 7 into equation 6a, the duration of linear flow (and hence the beginning of boundary-dominated flow) is determined using the following equation:

For oil:

Equation 8a

$$t_{elf} = \left[\frac{A\,h\,(\varphi\,c_t)\,m\,(p_i - p_{wf})}{19.9\,B}\right]^2$$

For gas:

Equation 8b

$$t_{elf} = \left[\frac{A\,h(\varphi\,\mu_g\,c_t)\,m\,(p_{pi} - p_{pwf})}{200.6\,T}\right]^2$$

An approximation of the gas equation can be obtained by replacing pseudo-pressure terms with:

Equation 8c

$$\frac{p_i^2 - p_{wf}^2}{\left(\mu_g \, Z\right)_i}$$

and c_{ti} by the inverse of p_i

The major unknown in determining the end of linear flow is the effective drainage area. Analog wells can be used to determine an appropriate range of drainage areas for the subject well. Well spacing can provide an upper bound on drainage area in high-density developments. Interpretation of flowing material balance can be used to determine a minimum area based on the current production data.

Boundary-dominated flow

Given the geometry of the reservoir considered, linear flow is followed directly by boundary-dominated flow. There are two ways to represent this flow regime for purposes of forecasting: (a) pseudo-steady state equations, material balance time, and pseudo-time; (b) traditional (Arps) hyperbolic decline. In the interest of keeping the method simple and practical, the hyperbolic decline method is used. Hyperbolic decline is defined in the following equation:

Equation 9

$$q = \frac{q_i}{\left[\, 1 + b \, a_i \, t \,\right]^{\frac{1}{b}}}$$

In this equation, q_i and a_i are flow rate and decline rate (respectively) at the start of the forecast period; and t is the time that has elapsed since the start of the forecast. Since the hyperbolic decline forecast starts at the end of linear flow, the flow rate, decline rate, and time will be with respect to time at the end of linear flow (t_{elf}). The decline exponent (b) is selected to be between 0 and 0.5, which are typical values for boundary-dominated flow in gas. Equation 9 is then rewritten to represent this:

Equation 10

$$q = \frac{q_{elf}}{\left[\, 1 + b \, a_{elf} \, (\, t - t_{elf} \,) \,\right]^{\frac{1}{b}}}$$

Equation 1 is rewritten to show how rate at the end of linear flow (q_{elf}) is determined based on the interpretation of the square-root time plot:

Equation 11

$$q_{elf} = \frac{1}{m\sqrt{t_{elf}} + b'}$$

Decline rate from the hyperbolic decline equation is defined as:

Equation 12

$$a = -\frac{1}{q}\frac{dq}{dt}$$

In order to determine decline rate at the end of linear flow (a_{elf}), an expression is needed for decline rate during linear flow. This is obtained by combining Equation 1 and Equation 12:

Equation 13

$$a = \frac{1}{m\sqrt{t} + b'}\frac{m}{2\sqrt{t}}$$

This equation is now written to reflect the decline rate at the end of linear flow:

Equation 14

$$a_{elf} = \frac{1}{m\sqrt{t_{elf}} + b'}\frac{m}{2\sqrt{t_{elf}}}$$

From Equation 14, it is also apparent that if b is negligible, the equation reduces to:

Equation 15

$$a = \frac{1}{2t}$$

Once a decline exponent (b) is selected, Equation 10 can be used for any duration of forecast, and even to determine the production forecast based on an abandonment rate.

Variable flowing pressure

In the initial development of this interpretation technique, constant flowing pressure has been assumed. An additional case for variable flowing pressure may also be considered when interpreting

the square-root time plot. The standard y-axis of reciprocal rate is simply replaced with normalized pressure to account for changes in flowing pressure during the linear flow portion of the data. Transient linear flow appears to be a straight line in the normalized pressure versus square-root of time plot. The slope of the straight line, m, is used to calculate $x_f\sqrt{k}$ with the following:

For oil:

Equation 16a

$$x_f\,\sqrt{k}\;=\;\frac{19.927\,B}{m\,h}\sqrt{\frac{\mu}{\varphi\,c_t}}$$

For gas:

Equation 16b

$$x_f\,\sqrt{k}\;=\;f_{cp}\frac{200.8\,T}{m\,h}\sqrt{\frac{1}{(\,\varphi\,\mu\,c_t\,)_i}}$$

As stated earlier, the observation has been that most unconventional wells are produced at very high drawdown rates to maximize recovery. Because of this common practice, the forecasting approach in the variable pressure module uses hyperbolic decline with the assumption of constant pressure for the duration of the forecast.

Superposition time

Superposition is a mathematical tool. You can use simple solutions (such as constant rates) to produce complex ones (such as variable rates). Superposition uses the theory that a rate that changes from q_1 at time t to a new rate q_2 is equivalent to q_1 continuing forever, superposed, or added on (q_2 - q_1) starting at time t and continuing forever.
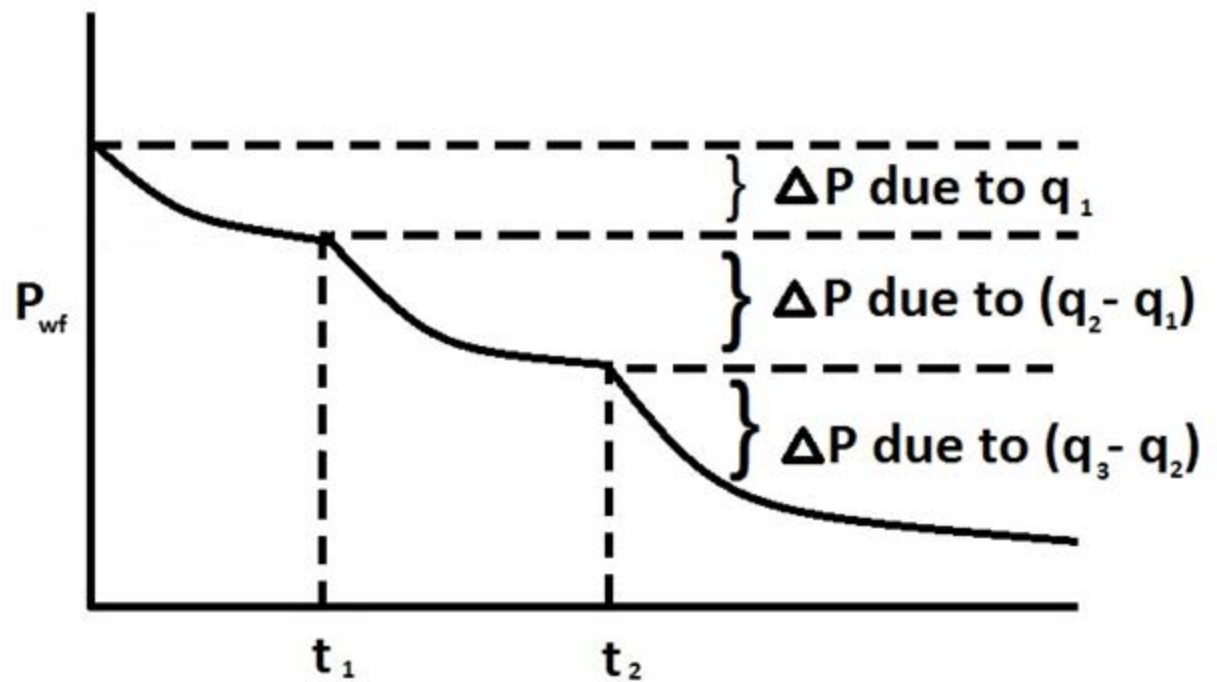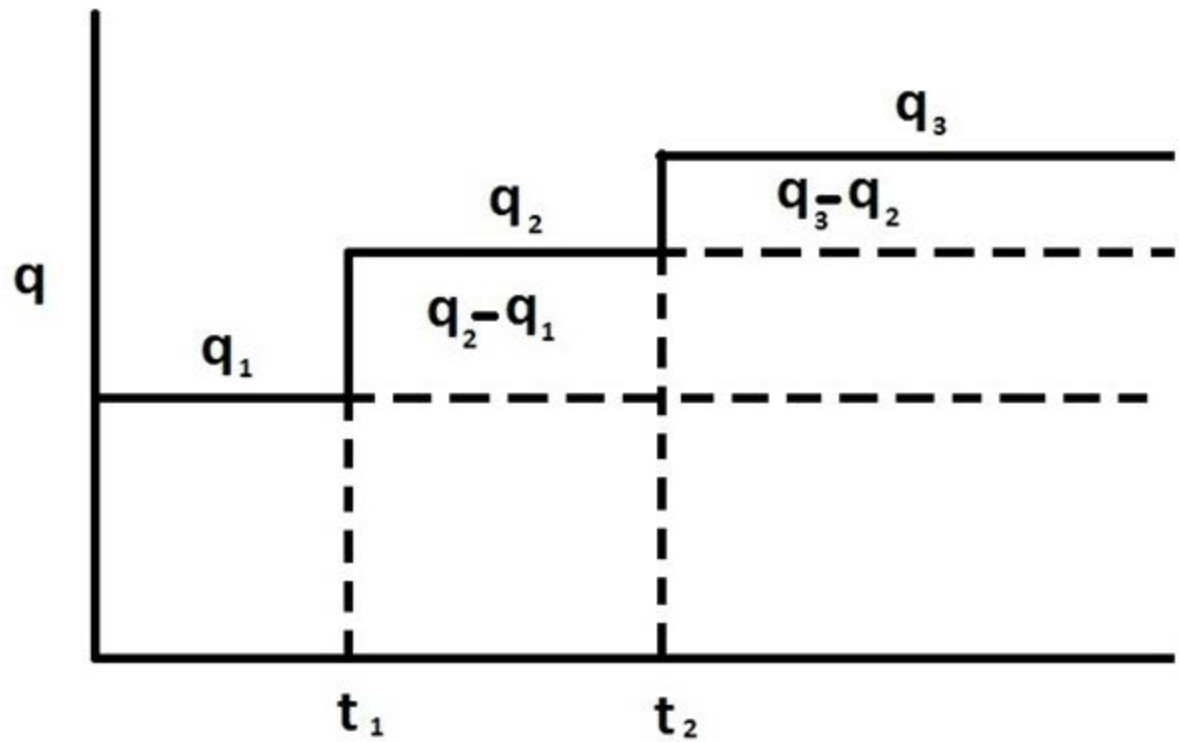
For unconventional reservoirs, two superposition time functions are commonly used in production analysis: linear superposition time and material balance time.

Linear superposition time is given by:

Equation 17a

$$t_n = \sum_{j=1}^{n} \frac{q_j - q_{j-1}}{q_n} \sqrt{t - t_{j-1}}$$

Material balance time is given by:

Equation 17b

$$t_c = \frac{Q_n}{q_n}$$

Both two superposition time functions can effectively convert variable rates to their equivalent constant rates solutions. Therefore, the plot of $\frac{p_i - p_{wf}}{q}$ versus linear superposition time (or square root of material balance time) on a Cartesian graph results in a straight line. The slope of this line (m') can be used to calculate $x_f \sqrt{k}$:

For oil:

Equation 17c

$$x_f \sqrt{k} = \frac{19.927 \, B}{m' \, h} \sqrt{\frac{\mu}{\varphi \, c_t}}$$

For gas:

Equation 17d

$$x_f \sqrt{k} = \frac{200.8 \, T}{m' \, h} \sqrt{\frac{1}{(\varphi \, \mu \, c_t)_i}}$$

Using pseudo-time

The above derivations used for the unconventional reservoir model (URM) analysis do not account for variation in total compressibility. It is possible to account for variation in total compressibility and fluid

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viscosity by using pseudo-time.

Pseudo-time is defined as follows:

For oil:

$$t_a\left(t\right) \;=\; \frac{\mu_o(p_i)\,c_t(p_i)}{k(p_i)}\;\int\limits_0^t\;\frac{k(\bar{p}_{inv})}{\mu_o(\bar{p}_{inv})\,c_t(\bar{p}_{inv})}\;dt$$

For gas:

$$t_a\left(t\right) \;=\; \frac{\mu_g(p_i)\,c_t(p_i)}{k(p_i)}\;\int\limits_0^t\;\frac{k(\bar{p}_{inv})}{\mu_g(\bar{p}_{inv})\,c_t(\bar{p}_{inv})}\;dt$$

In these equations, $\bar{p}_{inv}$, is average pressure over the volume investigated at a given time t.

Note: The correction factor, f_{CP}, (defined in *Equation 6c*) is another way to account for variation in gas compressibility. Therefore, when pseudo-time is used, there is no need to use the correction factor, f_{CP}, in calculations.

Accounting for variation in rock and fluid properties in the oil URM

In the descriptions above, URM analysis for gas is done in terms of pseudo-pressure, and URM analysis for oil is done in terms of pressure. This is done because for the oil case, a variation of oil properties (such as viscosity, compressibility, and the formation volume factor) is considered to be negligible, and formation compressibility and permeability are assumed to be constant (no geomechanical effects).

However in some cases, it is important to account for a variation in oil and formation properties. This can be done similarly to how it is done for gas cases, by introducing oil pseudo-pressure:

$$p_{po}\left(p\right) \;=\; \frac{B_o(p_i)\,\mu_o(p_i)}{k(p_i)}\;\int\limits_0^p\;\frac{k(p)}{B_o(p)\mu_o(p)}\;dp$$

When the oil URM calculation is modified to use pseudo-pressure, the FMB plot within the URM dashboard is also modified. For information on modifications for the oil FMB plot, see accounting for variation in oil properties (FMB).

Note: This approach is used and described in literature, including Behmanesh et al. (2015), Stalgorova and Mattar (2016).

Application to horizontal wells

The majority of wells in unconventional gas production are horizontal wells with multiple stage fracturing. The approach first considered with the development of this method is to treat the horizontal wellbore as a fracture, and incorporate fracture stimulation in this well as part of the effective permeability interpreted on the square-root time plot. An additional method has been incorporated using the same process as that developed for a single fracture. If the horizontal well is cased, or contributes very little production compared to the fractures, the well can be treated as a series of fractures in the reservoir. In a well with n equally spaced and identically sized fractures, the single fracture model can be multiplied by n fractures to represent the whole well. The linear flow into the fractures is followed by boundary-dominated flow when no-flow boundaries are formed between adjacent fractures. This layout is displayed below with its relationship to the single-fracture model.
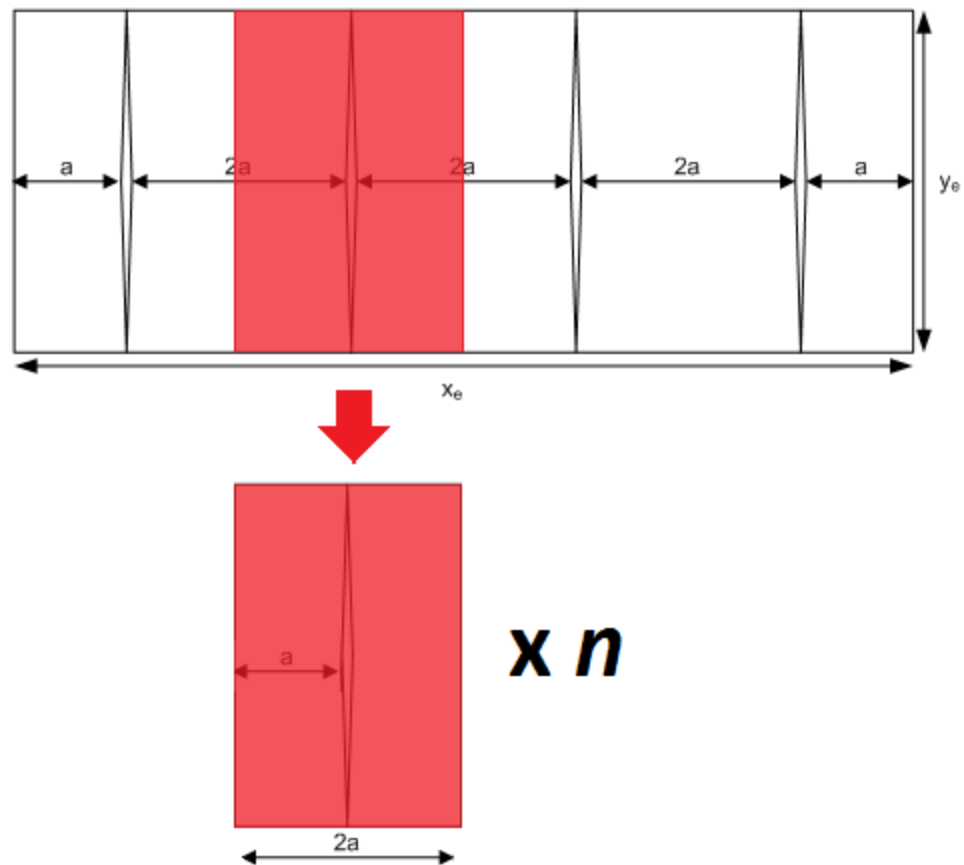
Applying this theory to Harmony Reservoir™

This theory applies to using production data to identify the linear flow parameter and interpret the linear flow parameter for different completion types.

Using production data to identify the linear flow parameter

Equations 16a and 16b can be rewritten as:

For oil:

Equation 18a

$$4hx_f \sqrt{k} = 4 \cdot \frac{19.927\,B}{m} \sqrt{\frac{\mu}{\varphi\,c_t}}$$

For gas:

Equation 18b

$$4hx_f \sqrt{k} = 4 \cdot \frac{200.8T}{m} \sqrt{\frac{1}{(\varphi\mu c_t)_i}}$$

Note: Equations 17c and 17d can be rewritten in a similar way.

These equations are derived for the case where the well is being produced through a single fracture.

For this case, the total area to flow ($^A c$) can be calculated as:

Equation 19

$$A_c = 4\,h\,x_f$$
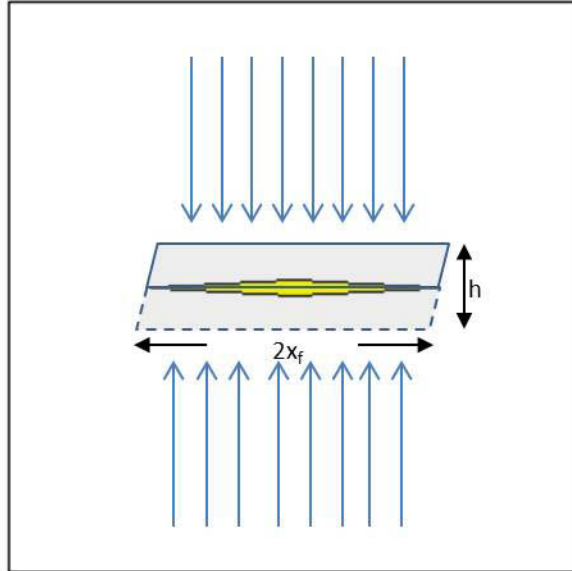
Therefore, equations 20a and 20b can be rewritten in a general form:

For oil:

Equation 20a

$$A_c \sqrt{k} = 4 \cdot \frac{19.927\,B}{m} \sqrt{\frac{\mu}{\varphi\,c_t}}$$

For gas:

Equation 20b

$$A_c \sqrt{k} = 4 \cdot \frac{200.8T}{m} \sqrt{\frac{1}{(\varphi\mu c_t)_i}}$$

Where A_c is total area to flow.

In equations 20a and 20b, the right-side of the equation is known: m, and is defined by production data (the slope of the line for normalized pressure plotted against a $\sqrt{t}$ function), and the remaining parameters are known for reservoir and fluid properties. Therefore, we can calculate the linear flow parameter $A_c\sqrt{k}$ using the top-left plot on the unconventional reservoir model (URM) dashboard.
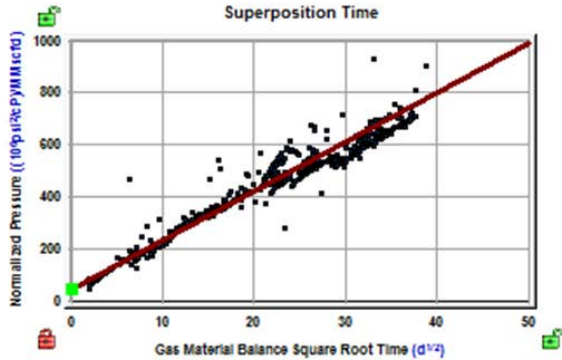
slope of the line $\longrightarrow$ $A_c\sqrt{k}$

Note: A_c represents the total area to flow, without any assumptions whether the well is producing through a single fracture, through multiple fractures, or through a non-fractured horizontal well-bore.

Interpreting the linear flow parameter for different completion types

Once the value for the linear flow parameter $A_c\sqrt{k}$ is calculated, it can be interpreted differently depending on the type of completion. With URM analysis, three types of completion are selectable from the Model Type drop-down list.
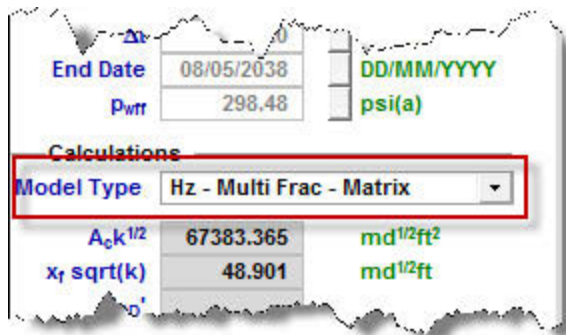
The following sections describe how the linear flow parameter is interpreted for each model type.

Vertical – single frac model type

In this case, it is assumed that the well is being produced through a single fracture. We can observe linear flow towards the fracture from both sides. The total area to flow (A_c) can be calculated as:

Equation 21

$$A_c = 4\,h\,x_f$$

Where h is the known net pay. Once $A_c\sqrt{k}$ is calculated, $x_f\sqrt{k}$ is also calculated and reported.

If you enter the value for permeability, x_f will be calculated based on the known value of permeability, and the previously calculated $x_f\sqrt{k}$.
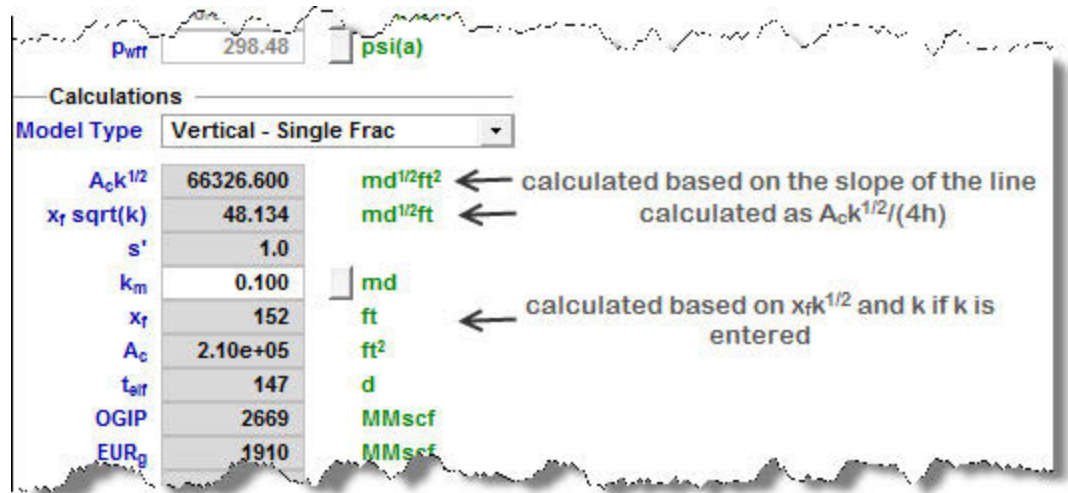
Horizontal multifrac – effective k model type

In this case, it is assumed that the well is being produced through a horizontal wellbore without fractures. This model can also be used when the well is fractured, but we do not model each individual fracture; instead we account for all the fractures by using higher effective permeability. Then, we can observe linear flow towards the wellbore.

Total area to flow (A_c) can be calculated as:

Equation 22

$$A_c = 2\,h\,L_e$$
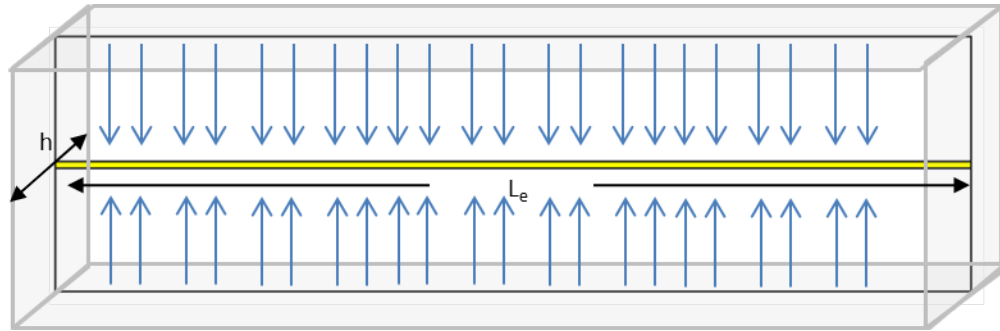
Where h is the known net pay. Once $A_c\sqrt{k}$ is calculated, $L_e\sqrt{k}$ can also be calculated.

Note: As there is no x_f in this model type, the parameter $x_f\sqrt{k}$ should be interpreted as $\left(L_e/2\right)\sqrt{k}$.

If you enter the value for effective horizontal wellbore length, L_e, effective permeability k_e will be calculated based on the known L_e and the previously calculated $L_e\sqrt{k}$.
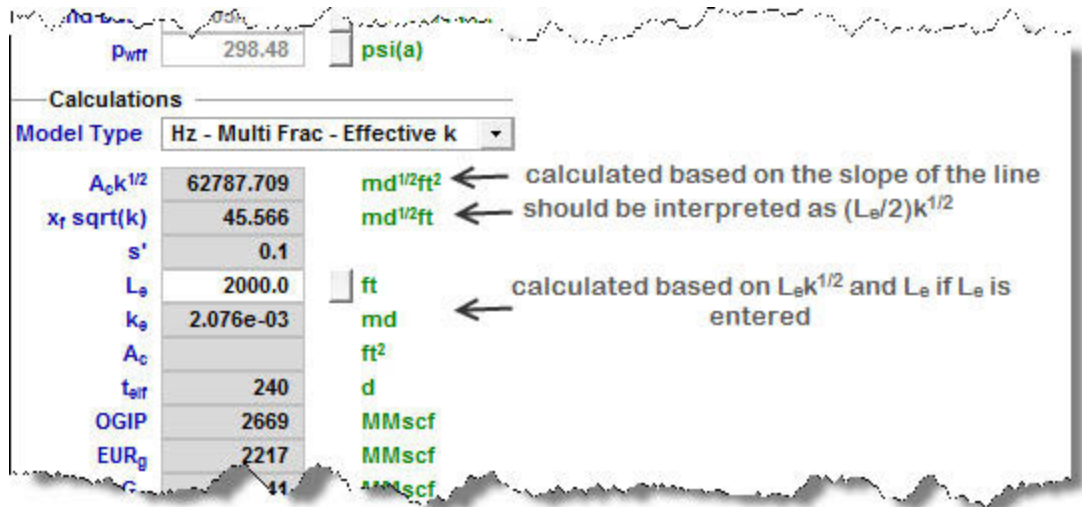
Horizontal multifrac – matrix model type

In this case, it is assumed that the well is being produced through multiple fractures (n_f = number of fractures). Then, we can observe linear flow towards each fracture.

The total area to flow (A_c) can be calculated as:

Equation 23

$$A_c = 4\,n_f\,x_f\,h$$
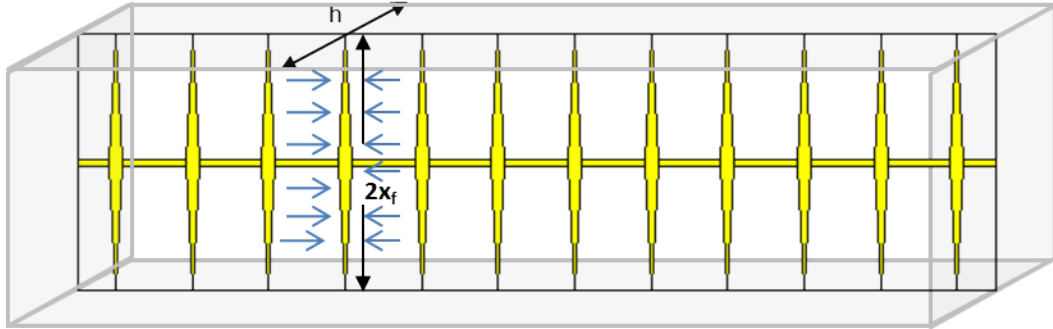
Where *h* is the known net pay. Once $A_c\sqrt{k}$ is calculated, $n_f\ x_f\ \sqrt{k}$ can also be calculated.

For this completion type, there is another relationship between model parameters:

Equation 24

$$OFIP = 2\,x_f \cdot L_e \cdot h \cdot \varphi \cdot S_{fi}\,/\,B_{fi}$$

Where:

OFIP: original fluid in place – this value can be obtained from the Flowing Material Balance plot

h: net pay; known reservoir property

φ: porosity; known reservoir property

S_{fi}: initial saturation of the modeled fluid (oil or gas); known reservoir property

B_{fi}: initial formation volume factor of the modeled fluid (oil or gas); known fluid property

L_e: effective horizontal well length

x_f: fracture half-length

In Equation 24, all parameters except for L_e and x_f are known. Therefore, if you enter the value for L_e, x_f can be calculated.

If you enter the value for n_f, permeability can be calculated based on the previously calculated $n_f x_f \sqrt{k}$, x_f, and the given n_f.
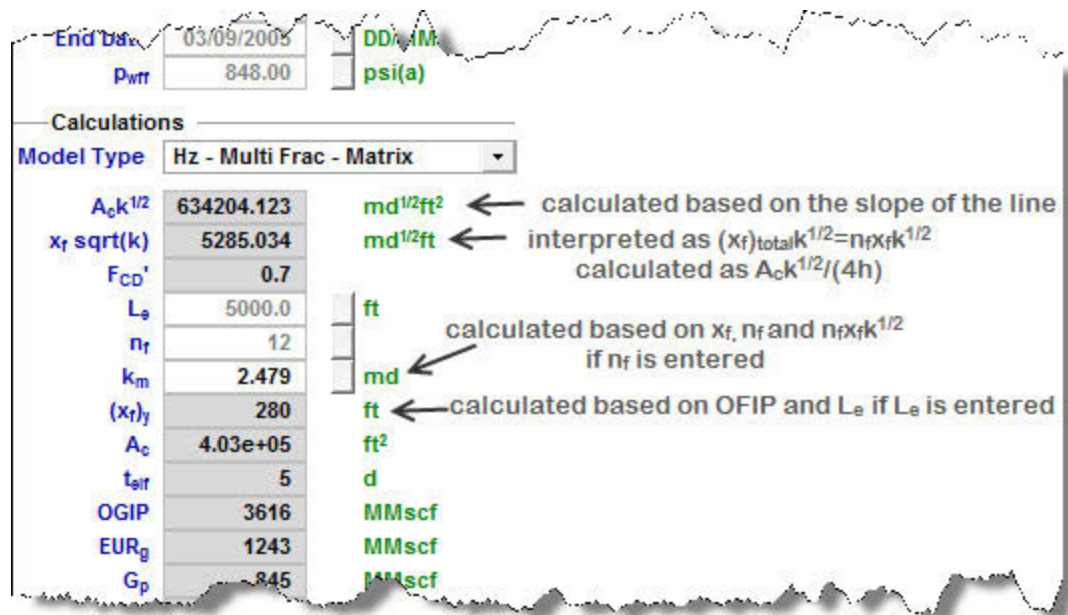
Most likely model

This model is a new methodology for identifying the possible range of stimulated reservoir volume (SRV) configurations based on specified well performance data, assumed system geometry, and known external system constraints.

The method is based on providing single values for known completion and petrophysical properties, and lower / upper limits for unknown parameters. The method is suitable for early well performance data, where transient linear flow is dominant.

The method is graphics-based with a plot of the exposed area of the fractures (A_x) versus drainage area of the reservoir (A_d). Based on user-defined constraints and limits, this plot defines a region that contains the full set of possible SRV configurations.
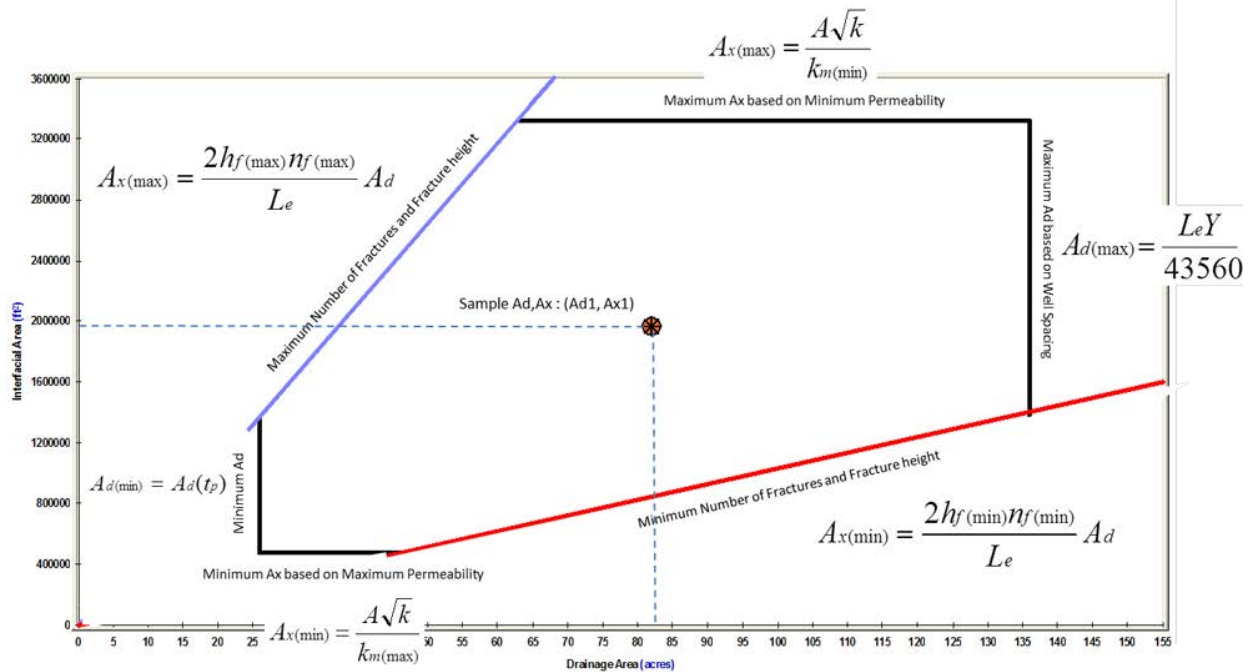
The definition of the allowable range of A_x versus A_d is identified in two parts.

Part 1: identify the region that defines minimum & maximum values for A_x and A_d

Limiting values for A_x are determined as follows:

Important: All of the equations below are referenced *earlier* in this topic.

Equation 18a

$$A_{x(\mathrm{min})} = \frac{A\sqrt{k}}{\sqrt{k_{m(\mathrm{max})}}}$$

Equation 18b

$$A_{x(\mathrm{max})} = \frac{A\sqrt{k}}{\sqrt{k_{m(\mathrm{min})}}}$$

Where $A\sqrt{k}$ is extracted from the slope of the square root straight line on the specialized plot, and $k_{m(min)}$ and $k_{m(max)}$ define the acceptable range of the unknown parameter, Stimulated Region Permeability.

The parameter k_m is considered to be an effective permeability, inclusive of any natural or induced fractures that have been activated (or are naturally active) and are connected to the primary hydraulic fracture network, but it does not include the primary fracture permeability. In other words, it is the permeability that acts directly on the primary hydraulic fracture system. A_x is defined as the total matrix area exposed to fractures. For a fracture of half-length (x_f), A_x is defined as:

Equation 18c

$$A_c = 4hx_f$$

Limiting values for A_d are determined as follows:

Equation 18d

$$A_{d(min)} = A_d\left(t_p\right)$$

Equation 18e

$$A_{d(max)} = L_e\,Y \text{ or } A_{d(max)} = \frac{L_e\,Y}{43560} \text{ if } A_d \text{ is in acres}$$

Where:

$A_d(t_p)$ equals the currently contacted drainage area, which is determined from a combined analysis of the square root straight line and the flowing material balance (Anderson et al. 2010).

Y equals the projected average distance between adjacent laterals once the field has been fully developed.

Based on the above, a box-shaped region can be defined on a plot of A_x versus A_d.

Part 2: identify the functional relationship between A_x and A_d

Assuming parallel transverse fractures (slab model) of uniform distribution and length, A_d is a linear function of A_x as follows:

Equation 19a

$$A_x = \frac{2 \, h_f \, n_f}{L_e} A_d$$

If the fracture network is assumed to be 2-dimensional (matchstick geometry), the coefficient in the above equation becomes 4. If the fracture network is assumed to be 3-dimensional (sugar cube geometry), the coefficient becomes 6.

Since h_f and n_f are unknowns, we can define the minimum and maximum functional relationship between A_x and A_d, assuming that we can provide allowable ranges for h_f and n_f.

Equation 19b

$$A_{x(\text{min})} = \frac{2 \, h_{f(\text{min})} \, n_{f(\text{min})}}{L_e} A_d$$

Equation 19c

$$A_{x(\text{max})} = \frac{2 \, h_{f(\text{max})} \, n_{f(\text{max})}}{L_e} A_d$$

The above equations plot as straight lines through the origin on the A_x versus A_d plot. The intersection of the previously defined rectangular region with these straight lines yields a region that contains all the possible A_d and A_x combinations.

Formulae for calculating reservoir / completion properties, given a sample configuration (A_{d1}, A_{x1}) from the A_x - A_d region, are shown as follows:

Equation 19d

$$x_{f(A_{d1} \, A_{x1})} = \frac{A_{d1}}{2 \, L_e}$$

Equation 19e

$$k_{m(A_{d1} A_{x1})} = \left(\frac{A \, \sqrt{k}}{A_{x1}} \right)^2$$

Equation 19f

$$h_f\, n_{f(A_{d1}\, A_{x1})} = \frac{A_{x1}\, L_e}{2\, A_{d1}}$$

Equation 19g

$$FCD'_{(A_{d1}\, A_{x1})} = \frac{1.417\, E6\, T}{b'\, k\, h_f\, n_f} \left(1 + \frac{h_f}{x_f} \left(\ln\left(\frac{h_f}{2\, r_w} \right) - \frac{\pi}{2} \right) \right)$$

The mass center of the Allowable A_x versus A_d region is used to calculate the "most likely" values.

Volumetrics theory

Volumetric analysis is a technique that uses geological observations and information to estimate original fluids-in-place. It is often referred to as a "static method" as it primarily sources its data from core samples, wireline logs, and geological maps. Volumetric calculations are typically used prior to production to estimate reserves, and after considerable production to determine the efficiency of recovery, the areal extent of the reservoir, and as a basis for advanced studies, such as reservoir simulations.

Volume Parameter Equations and Equalities	
Rock Volume	$V_R = A \times h$
Pore Volume	$V_P = V_R \times \phi = A \times h \times \phi$
Hydro-carbon Pore Volume	$V_{HCP} = V_P \times (S_{HC}) = A \times h \times \phi \times (S_{HC})$ Where $S_{HC} =$ the hydrocarbon saturation of interest (either S_o or S_g)

A comprehensive geologic study of the prospect is necessary to increase the confidence and reliability of determined reservoir properties, such as volume, porosity, and fluid saturations. In calculating the volume of the reservoir, accurate determinations of the areal extent and thickness must be made with respect to the geological structure and depositional environment. The use of isopach maps in combination with planimetering is a commonly used method in the determination of reservoir volume. Conclusions drawn concerning lithofacies and depositional settings are used to provide an assessment of porosity, while wireline log and core data provide the analyst with measurements of fluid saturations.

Oil reservoir calculations

Original Oil-in-Place (OOIP) Calculations		
Field Units [stb]	$OOIP = 7758 \times \dfrac{V_{HCP}}{B_{oi}}$ Or, in expanded form: $OOIP = 7758 \times A \times h \times \phi \times (S_{oi}) \times \dfrac{1}{B_{oi}}$	Where: A = acres h = feet φ = fraction S_{oi} = fraction B_{oi} = bbl/stb
Metric Units [m^3]	$OOIP = \dfrac{V_{HCP}}{B_{oi}}$ Or, in expanded form: $OOIP = A \times h \times \phi \times (S_{oi}) \times \dfrac{1}{B_{oi}}$	Where: A = square meters h = meters φ = fraction S_{oi} = fraction B_{oi} = m^3/m^3

Gas reservoir calculations

Historically, in a gas reservoir, only *free* gas-in-place was considered. Because of this, only one name was required: OGIP. However, with the increasing use of adsorbed gas reservoirs in the industry, Fekete / IHS has adopted the name "OGIP$_F$" to define the gas-in-place for a free-gas reservoir. Likewise, the name "OGIP$_A$" is used to define the gas-in-place in a reservoir. The name OGIP has been retained to describe the total original gas-in-place.

Free gas equations

Original Free Gas-in-Place (OGIP$_F$) Calculations		
Field Units [scf]	$OGIP_F = 43560 \times \frac{V_{HCP}}{B_{gi}}$ Or, in expanded form: $OGIP_F = 43560 \times A \times h \times \phi \times \left(S_{gi}\right) \times \frac{1}{B_{gi}}$	Where: A = acres h = feet φ = fraction S_{gi} =fraaction B_{gi} = ft^3/scf
Metric Units [m^3]	$OGIP_F = \frac{V_{HCP}}{B_{gi}}$ Or, in expanded form: $OGIP_F = A \times h \times \phi \times \left(S_{gi}\right) \times \frac{1}{B_{gi}}$	Where: A = square meters h = meters φ = fraction S_{gi} = fraction B_{gi} = m^3/m^3

Adsorbed gas equations – shale reservoirs

Shale gas reservoirs usually contain much more adsorbed gas than free gas. Therefore, OGIP calculations for shale reservoirs should also account for adsorption. For shale reservoirs, total gas in place is calculated as:

OGIP = OGIP$_F$ + OGIP$_A$

The following equations are used to calculate the original adsorbed gas-in-place (OGIP$_A$).

Original Adsorbed Gas-in-Place (OGIP$_A$) Calculations		
Field Units [scf]	$$OGIP_A = 43560 \times A \times h \times \rho_b \times \frac{V_{L\$} \times p}{p_{L\$} + p}$$	Where: A = acres h = feet ρ_b = ton/ft^3 p = psi(a) $V_{L\$}$ = scf/ton $p_{L\$}$ = psi(a)
Metric Units [m^3]	$$OGIP_A = A \times h \times \rho_b \times \frac{V_{L\$} \times p}{p_{L\$} + p}$$	Where: A = square meters h = meters ρ_b = g/cm^3 p = kPa(a) $V_{L\$}$ = cm^3/g $p_{L\$}$ = kPa(a)

Adsorption saturation option

Adsorbed gas may occupy a portion of the measured porosity. To account for this, you can use the Adsorption Saturation option. If this option is selected, the calculation for OGIP$_A$ remains unchanged, but the calculation for OGIP$_F$ uses a decreased value for gas saturation. For information on the calculation for this adjusted S$_g$, see the shale adsorption correction.

For adsorption theory, see shale properties.

Calculations for liquid-rich gas reservoirs

With liquid-rich gas, it is important to calculate the original dry gas-in-place (OGIP$_d$), as well as the original condensate-in-place (OCIP).

Original dry gas in-place comes from free gas and dissolved gas:

OGIP$_d$ = OGIP$_{dF}$ + OGIP$_S$

Original condensate in-place comes from free condensate and vaporized condensate:

OCIP = OCIP$_F$ + OCIP$_V$

The following equations are used to calculate OGIP$_{dF}$, OGIP$_S$, OCIP$_F$, and OCIP$_V$:

Calculations for Liquid-Rich Gas		
Field Units [scf, stb]	$$OGIP_{dF} = 43560 \times A \times h \times \emptyset \times S_{gi} \times \frac{1}{B_{gdi}}$$	Where: A = acres h = feet

Calculations for Liquid-Rich Gas		
	$OCIP_F = 7758 \times A \times h \times \emptyset \times S_{ci} \times \frac{1}{B_{ci}}$ $OGIP_S = OCIP_F \times R_{si}$ $OCIP_V = OGIP_{dF} \times R_{vi}$	ϕ = fraction S_{gi}, S_{ci} = fraction B_{gi} = ft^3/scf B_{ci} = bbl/stb R_{si} = stb/scf R_{vi} = scf/stb
Metric Units $[m^3, m^3]$	$OGIP_{dF} = A \times h \times \emptyset \times S_{gi} \times \frac{1}{B_{gdi}}$ $OCIP_F = A \times h \times \emptyset \times S_{ci} \times \frac{1}{B_{ci}}$ $OGIP_S = OCIP_F \times R_{si}$ $OCIP_V = OGIP_{dF} \times R_{vi}$	Where: A = square meters h = meters ϕ = fraction S_{gi}, S_{ci} = fraction B_{gi} = m^3/m^3 B_{ci} = m^3/m^3 R_{si} = m^3/m^3 R_{vi} = m^3/m^3

Note that the formation volume factor used to calculate the original dry gas-in-place is B_{dgi} — the formation volume factor for *dry* gas. It is different from B_{gi} — the formation volume factor for *recombined* gas displayed in the Properties editor. The dry gas formation volume factor (B_{gdi}) is defined as the ratio of the gas phase volume at reservoir conditions (V_g) to the equivalent volume of its gas component at standard conditions. The formation volume factor for recombined gas is the value obtained using given gas correlations based on the recombined gas gravity. For more information, see recombination.

WOR forecasting theory

Water-oil ratio (WOR) forecasting is a method of trending future water production for the purpose of forecasting oil production and determining expected ultimate recoverable s (EUR). Water-oil ratio forecasting is an empirical analysis method; there is no formal model or equations. Plots of both water-oil ratio and water-oil ratio +1 are used in forecasting, and the plots are typically semi-log with cumulative oil production as the x-axis. Water-oil ratio, water-oil ratio +1, and water cut are defined below:

$$WOR = \frac{q_w}{q_o}$$

$$WOR + 1 = \frac{q_w + q_o}{q_o}$$

$$Water\ cut = \frac{WOR}{WOR + 1}$$

Ratio interpretation in combination with rate interpretation (traditional decline analysis) can increase confidence in the forecasts. In exponential or harmonic rate decline, slope dependencies are often observed between the rate and ratio trends. By plotting a forecast on both rate and ratio data, the slope dependencies can be used to match historical data on both the rate and ratio trends. These interpretations are less likely to show personal bias, as the forecast would only look reasonable if it matched both trends. Exponential decline is best analyzed on a semi-log plot of a water-oil ratio or a water-oil ratio +1 vs. time. Harmonic decline is best analyzed on a semi-log plot of a water-oil ratio or a water-oil ratio +1 vs. cumulative oil. The plot below shows slope dependence (the rate slope is the inverse of the ratio slope) between the oil rate and the water-oil ratio +1, while the total fluid rate (oil + water) is constant.
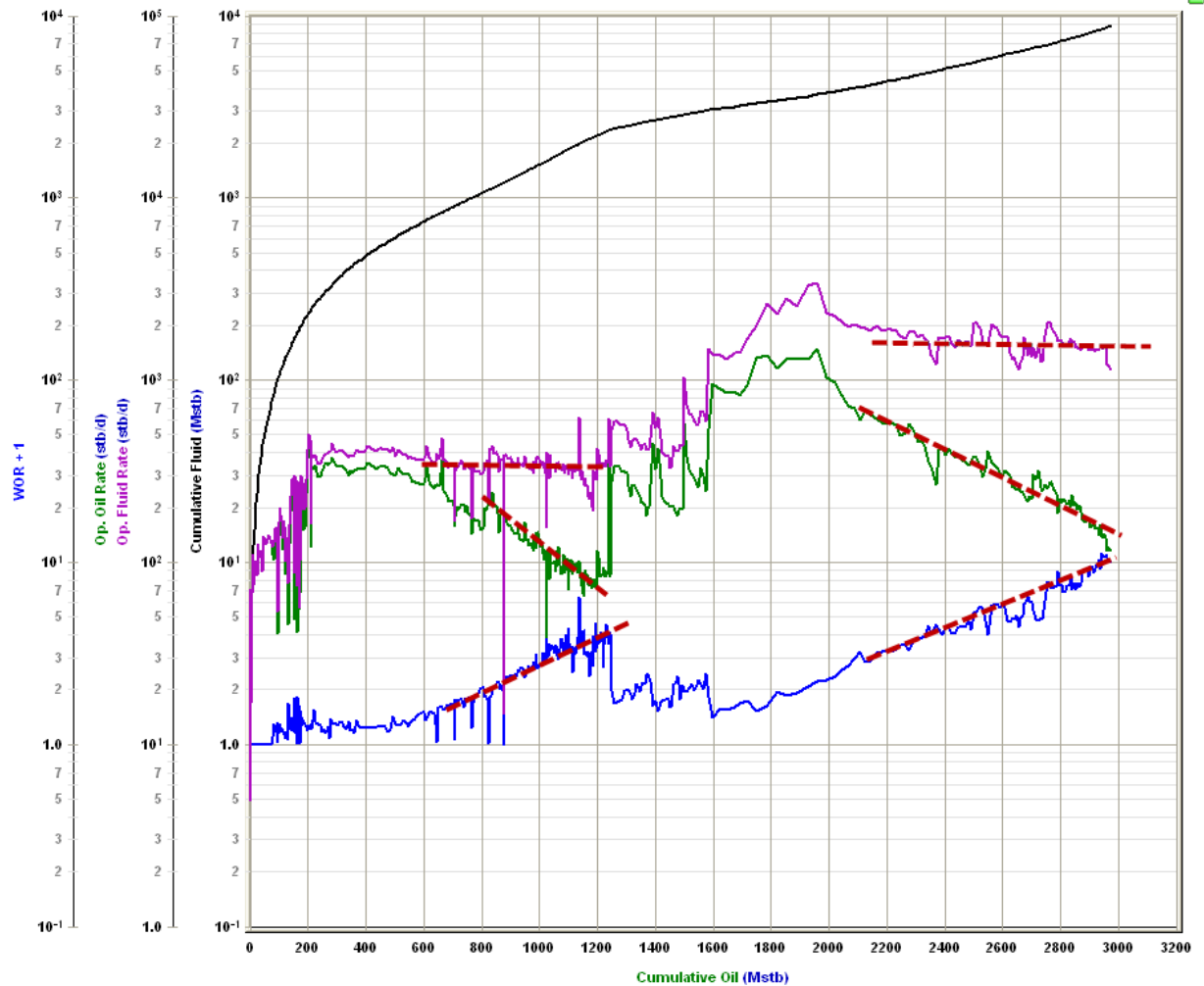
The WOR and WOR +1 are often used interchangeably. The advantage of WOR +1 in some situations is that periods with zero water production can be plotted. In some cases, the ratio trend appears more linear on WOR or WOR +1. It could be that the WOR behaves linearly when water rates are constant, and WOR +1 behaves linearly when total fluid rates are constant. This may guide you in determining which plot to select, but both should be considered uncertain. To create the forecast, a linear trend is placed on the WOR or WOR +1 semi-log plot, and a maximum WOR or water cut is used to truncate the forecast. An oil rate forecast is calculated by combining the ratio forecast with a total fluid rate.
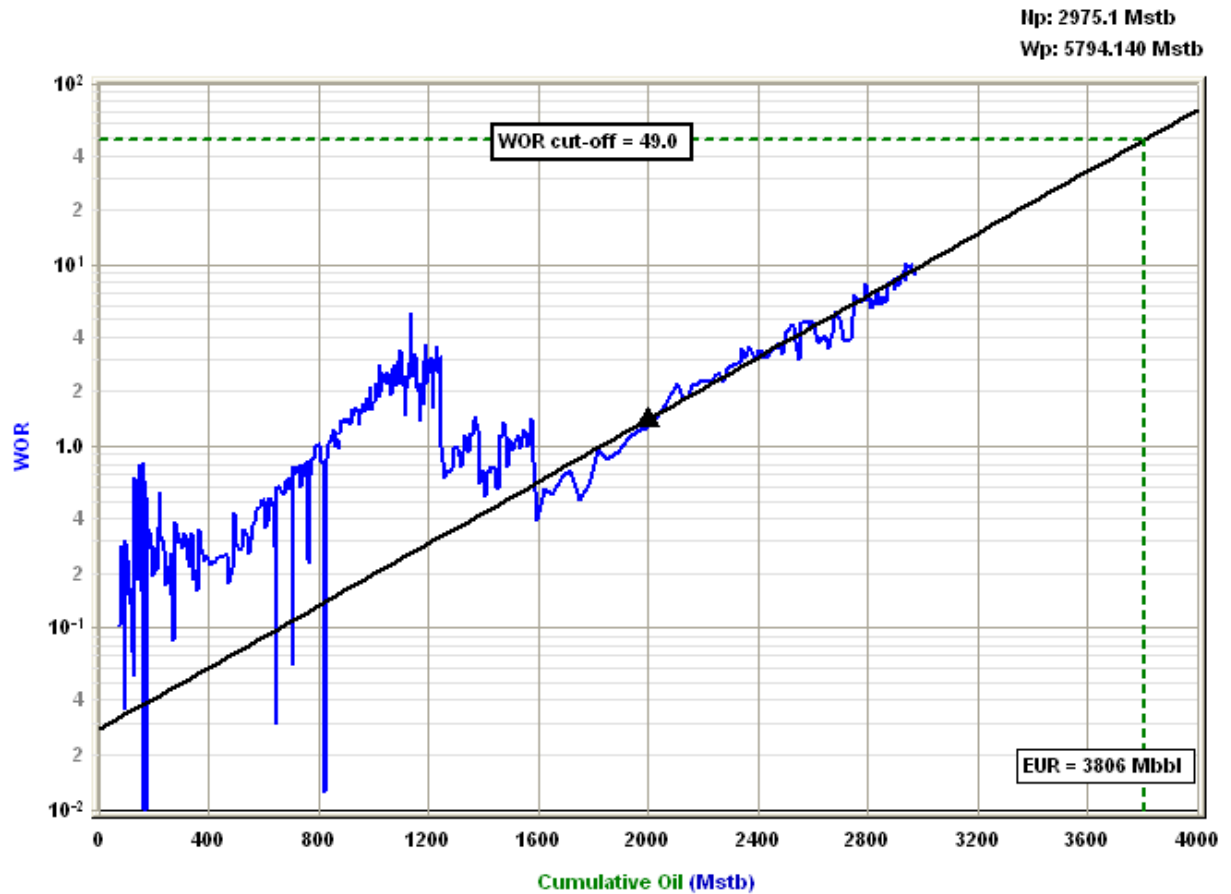
Water-oil ratio forecasting provides the most useful result in water drive or waterflood scenarios (for example, scenarios with high water production). However, linearizing the data removes the diagnostic aspects that may be desired for these reservoirs and production scenarios. Similar to decline forecasts, the trends created with WOR plots should be considered under constant operating conditions. Changing conditions, such as infill drilling or recompletions, often appear as changing the slope in the WOR trend.

Calculations & correlations

Calculations and correlations include the following:

- Annular diameters

- Average reservoir pressure calculations
- Capillary correlations
- Flow rate calculations

- Geomechanical correlations

- Liquid lift calculations

- Gas calculations & correlations
- Oil correlations
- Pressure loss calculations
- Recombination

- Relative permeability correlations
- Water correlations

Annular diameters

Pressure loss calculations for an annulus flow path require some extra steps to complete because the standard cylindrical tube model cannot be directly applied. Instead, the annular space is converted into a single cylindrical tube through the use of one of the following methods:

- Equivalent diameter method

- Hydraulic (or wetted) diameter method
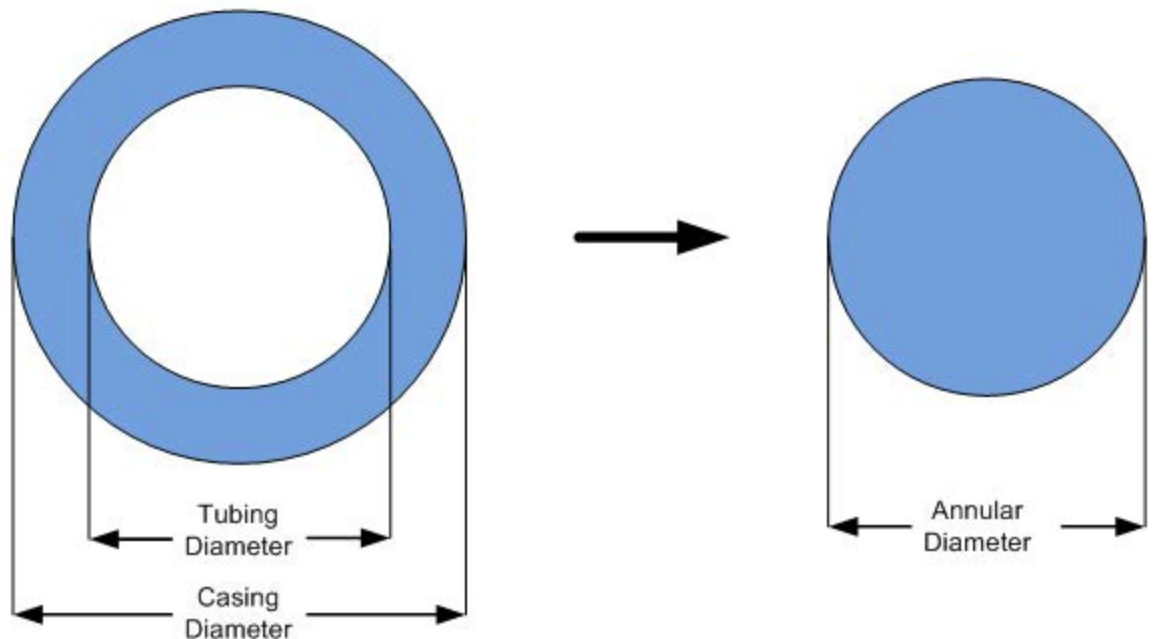
Equivalent diameter

With the equivalent diameter solution, the objective is to find a single tube that has the same cross-sectional area as the annulus. While this method seems logical at first glance, it does not account for frictional differences on both pipe walls (that is, the inside wall of the casing and the outside wall of the tubing).

$$Equivalent\ Diameter = \sqrt{D_2^2 - D_1^2}$$

where:

- D_1 = outer diameter of the tubing

- D_2 = inner diameter of the casing

Hydraulic (wetted) diameter

With the hydraulic diameter solution, the objective again is to find a diameter for a single tube that represents the annulus, but also accounts for the extra friction that annular flow would experience.

$$Hydraulic\ Diameter = \frac{4(Area)}{WettedPerimeter}$$

$$Hydraulic\ Diameter = \frac{4\left(\frac{\pi D_2^2}{4} - \frac{\pi D_1^2}{4}\right)}{\pi(D_2 + D_1)}$$

this simplifies down to $Hydraulic\ Diameter = D_2 - D_1$

where:

- D_1 = outer diameter of the tubing

- D_2 = inner diameter of the casing

Average reservoir pressure calculations

Average reservoir pressure at the end of the production period is calculated for oil and gas reservoirs provided that the original oil-in-place and original gas-in-place are known. The calculated average reservoir pressure value is reported under the calculations part for all the applicable typecurves.

Oil wells

Using the definition of compressibility, we can write:

$$c_t \;=\; \frac{1}{N} \cdot \frac{N_p}{(p_i - \bar{p})}$$

The above equation can be changed to:

$$\bar{p} = p_i - \frac{N_p}{c_t\,N}$$

Gas wells

For a gas reservoir, we can write:

$$\frac{\bar{p}}{\bar{Z}} = \frac{p_i}{Z_i}\left(1 - \frac{G_p}{G}\right)$$

Capillary correlations

Capillary pressure correlations

Analytical: Developed based on theory and generally applicable for calculating capillary pressures.

$$p_{cow} = p_{cgw} = a_o + a_1 \left(1 - S_{wn} \right) + a_2 \left(1 - S_{wn} \right)^2 + a_3 \left(1 - S_{wn} \right)^3$$

$$S_{wn} = \frac{(S_w - S_{wirr})}{(1 - S_{wirr})}$$

$$p_{cog} = a_o + a_1 \, S_{gn} + a_2 \, S_{gn}^{\,2} + a_3 \, S_{gn}^{\,3}$$

$$S_{gn} = \frac{S_g}{(1 - S_{org})}$$

where: a_0 = Coefficient 0, a_1 = Coefficient 1, ...

Brooks-Corey: An empirical approach to calculate capillary pressures and works satisfactorily in many cases. It requires residual wetting-phase saturation. Uses a lithology factor that allows the correlations to be generalized to any lithology.

$$p_{cow} = p_{cgw} = C_w \left(S_{wn} \right)^{-A_w}$$

$$A_w = 1/\lambda$$

$$S_{wn} = \frac{(S_w - S_{wirr})}{(1 - S_{wirr})} \; for \; drainage$$

$$S_{wn} = \frac{(S_w - S_{wirr})}{(1 - S_{wirr} - S_{orw})} \; for \; \text{imbibition}$$

$$A_o = 1/\lambda$$

$$S_{on} = \frac{(S_o - S_{org})}{(1 - S_{org})}$$

Custom Table: Allows you to enter laboratory measurements for capillary pressure values.

Analytical

Water-oil system

$$p_{cow} = Coeff0 + Coeff1\,(1 - S_{wn}) + Coeff2(1 - S_{wn})^2 + Coeff3(1 - S_{wn})^3$$

$$S_{wn} = \frac{S_w - S_{wirr}}{1 - S_{wirr}}$$

where:

Coeff0 = capillary pressure coefficient 0

Coeff1 = capillary pressure coefficient 1

Coeff2 = capillary pressure coefficient 2

Coeff3 = capillary pressure coefficient 3

Gas-oil system

$$p_{cgo} = Coeff0 + Coeff1\,(1 - S_{gn}) + Coeff2(1 - S_{gn})^2 + Coeff3(1 - S_{gn})^3$$

$$S_{gn} = \frac{S_g}{1 - S_{org}}$$

where:

Coeff0 = capillary pressure coefficient 0

Coeff1 = capillary pressure coefficient 1

Coeff2 = capillary pressure coefficient 2

Coeff3 = capillary pressure coefficient 3

Brooks Corey

The Brooks Corey model is widely accepted to calculate capillary pressure for relative permeability calculations. This model is a modified representation of Corey's model and represents the capillary pressure in a more general form.

Water-oil system

$$p_{cow} = (p_{ce})_{ow}^{-\frac{1}{\lambda_{ow}}}$$

$$S_{wn} = \frac{S_w - S_{wirr}}{1 - S_{wirr}}$$

where:

$(p_{ce})_{ow}$ = oil-water pore entry capillary pressure

λ_{ow} = oil-water pore size distribution index

Gas-oil system

$$p_{cgo} = (p_{ce})_{go}^{-\frac{1}{\lambda_{go}}}$$

$$S_{on} = \frac{S_o - S_{org}}{1 - S_{org}}$$

where:

$(p_{ce})_{go}$ = gas-oil pore entry capillary pressure

λ_{go} = gas-oil pore size distribution index

Flow rate calculations

When viewing production data and when using that data to generate forecasts of future production, it is critical that the method used to calculate the rates be known, understood, and used properly. Four commonly used terms used in this regard are "operated-day rate" (op-day), "calendar-day rate" (cal-day), "time on-production", and "load factor".

Note: The term "injection" can be substituted in all the definitions below where "production" is used.

Operated-day rate

Operated-day rate is defined as the volume of fluid produced or forecast over a period of time divided by the actual on-time during the period in days. For example, if a well produced 300 barrels of oil in a 30 day month, but was only actually producing for 15 days, then:

Operated-Day Rate = 300 Bbls / 15 days = 20 Bbls / day

Calendar-day rate

Calendar-day rate is defined as the volume of fluid produced or forecast over a period of time divided by the number of days in the period, regardless of actual on-time. For example, if a well produced 300 barrels of oil in a 30-day month, but was only actually producing for 15 days, then:

Calendar-Day Rate = 300 Bbls / 30 days = 10 Bbls / day

Time on-production

Time on-production is defined as the period of time a well is actually producing. It is typically expressed in hours or days.

Load factor

Load factor is defined as the ratio of the actual on-time and the period time. For example, if a well produced for 15 days in a 30-day period, then its load factor expressed as a percentage would be:

15/30 * 100 = 50%

Geomechanical correlations

There are two types of geomechanical correlations: permeability and compressibility.

Permeability correlations

Yilmaz and Nur: A generic correlation suitable for extremely low permeability reservoirs.

Dobrynin: A more detailed correlation designed for over-pressurized reservoirs that require porosity as an input. Valid in the pressure range of 0 – 20,000 psi.

Custom Table: Allows you to enter laboratory measurements for the permeability ratio.

Compressibility correlations

Dobrynin: A more detailed correlation designed for over-pressurized reservoirs that require porosity as an input. Valid in the pressure range of 0 – 20,000 psi.

Custom Table: Allows you to enter laboratory measurements for formation compressibility. The formation compressibility ratio is calculated using the formation compressibility entered for each pressure divided by the initial formation compressibility coming from the basic reservoir properties.

Liquid lift calculations

Liquid lift calculations use the Turner correlation, which determines the minimum gas velocity required to continuously lift liquids. The intent of these calculations is to determine the minimum gas rate for a given wellbore configuration and pressure, below which liquid loading problems may start to occur.

The Turner correlation is as follows:

$$v_g\left(water\right) = \frac{5.62\left(67 - kp\right)^{0.25}}{\left(kp\right)^{0.5}}$$

$$v_g\left(Oil/Condensate\right) = \frac{4.02\left(45 - kp\right)^{0.25}}{k\, p^{0.5}}$$

$$k = \frac{2.693\, G}{Z\, T}$$

$$q_g = \frac{3.06\, p\, v_g\, A}{Z\, T}$$

Gas calculations & correlations

Gas correlations

There are three types of gas correlations: pressure volume temperature (PVT), viscosity, and gas type.

PVT

B.W.R. (Table): The Benedict-Webb-Rubin is an empirical relationship that predicts the state of liquids and gases. Tables were developed for approximately fifty substances, mostly hydrocarbons that related gas density, formation volume factor, and temperature to pressure.

B.W.R. (8-constant): The Benedict-Webb-Rubin (8-constant) equation of state developed a set of generalized coefficients in order to permit widespread application to all types of gases.

B.W.R. (11-constant): The Benedict-Webb-Rubin (11-constant) equation of state is a further refined method to predict the state of liquids and gases. Used for all types of gases, it uses 11 empirical constants to achieve a more accurate interpolation of the data.

AGA8 Detail: Calculates the Z-factor based on the physical chemistry of the gas components at specified temperatures and pressures. It can be used when the exact composition (fraction mole percents) of the gas is available.

Carbon Dioxide: The Carbon Dioxide tables are for computing the Z factor for 100% CO_2 content.

Nitrogen: The Nitrogen tables are for computing the Z factor for 100% N_2 content.

Hydrogen Sulfide: The Hydrogen Sulfide tables are for computing the Z factor for 100% H_2S content.

Custom Table: Allows you to enter laboratory measurements for the gas Z-factor or formation volume factor. The Z factor is calculated from the formation volume factor or vice versa. Gas compressibility is subsequently calculated from these two values.

Viscosity

Carr et al: Developed to predict the viscosity of gas hydrocarbon mixtures for temperatures between 32ºF and 400ºF and pressures up to 12,000 psi. Applies to both sweet and sour gas and is designed to handle non-hydrocarbon components (CO_2, H_2S, N_2) in concentrations of up to 15% each.

Lee, Gonzalez, Eakin: Applies to sweet gas and does not account for the presence of non-hydro-carbon components. Applicable for pressure ranges of 100 - 8,000 psi and temperatures between 100ºF - 340ºF. Less accurate for gases with specific gravity above 1.0.

Optimized Lee et al: Developed using the Lee, Gonzalez, and Eakin method, but uses a optimized temperature history to achieve more accurate results, thus resulting in different coefficients in the equations. Less than 5% difference in extreme cases from original correlations.

Lucas et al: Uses the method of corresponding states to calculate gas viscosity. Better suited for higher density gases at lower pressures.

Custom Table: Choosing this correlation allows you to enter custom gas viscosity values from laboratory measurements.

Gas type

Selecting wet or dry gas changes the results obtained from gas correlations, as different coefficients have been developed for these gas types. The Liquid-rich Gas option allows for the recombination of gas and condensate into a single gas stream. For more information, see reservoir fluid types.

Ovalle et al.'s correlation for Rv

Ovalle et al.'s correlation is based solely on commonly available field data. Required field data is as follows: the initial producing gas / condensate ratio from the first separator, the initial stock tank liquid gravity in API, the specific gravity of initial reservoir gas, and reservoir temperature. This correlation does not need require the dew point pressure to calculate the "Rv" curve vs. pressure.

$$R_v = \exp\left[3.684 + 0.61967 \times Z + 0.015359 \times Z^2\right]$$

$$Z = \sum_{n=0}^{4} Z_n$$

n	Varn	C0n	C1n	C2n	C3n	C4n
1	In P, psi	20.809	-6.7095	0.5136	0	0
2	APId	11.175	-1.2965	0.042311	-0.0005438	2.49E-06
3	γg_{RD}	-13.365	27.652	-18.598	4.3658	0

n	Varn	COn	C1n	C2n	C3n	C4n
4	TR,°F	-1.5309	0.0058453	1.40E-06	0	0

API_d	Gravity of stock-tank liquid, oAPI, determined when P ≥ Pd
P	Pressure, psi
γg_{Rd}	Reservoir gas specific gravity at P≥Pd (This value is the recombined gas specific gravity
TR	Reservoir temperature, °F
RV	Vaporized oil ratio, Stb / MMscf

Calculation of the vaporized oil ratio

The vaporized oil ratio (R_v) can be calculated from the liquid drop-out (V_L / V_{sat}) measured in the lab.

$$R_v = \frac{(V_L/V_{sat})B_{gd,sat} - B_o CGR_i}{(V_L/V_{sat})B_{gd,sat}R_s - B_o}$$

where

(V_L/V_{sat}): the liquid drop-out of a liquid-rich gas, meaning the retrograde liquid volume at any pressure (below the dew point pressure) and reservoir temperature relative to the volume of the gas sample at the dew point pressure and reservoir temperature.

$B_{gd,sat}$: the dry gas formation factor at the dew point pressure (saturation pressure)

Oil correlations

Oil / condensate correlations

Oil condensate PVT correlations are described below.

PVT

Vasquez and Beggs: Developed from data obtained from fields all over the world and generally applicable for all oil types. Covers a wide range of pressures, temperatures, and oil properties.

Al-Marhoun: Developed for Saudi Arabian oils. Valid for all types of gas-oil mixtures ranging from 14 - 45 °American Petroleum Institute (API) gravity.

De Ghetto et al: Developed for heavy oils (10 < °API < 22.3) and extra-heavy oils (°API < 10) from the Mediterranean Basin, Africa, and the Persian Gulf. Requires separator pressure and temperature.

Glaso: Developed for North Sea oils and it is suitable for oil mixtures ranging from 22-48 °API. Valid for all types of oil and gas mixtures after correcting for non-hydrocarbons in the surface gases and the paraffinicity of the oil.

Hanafy et al: Developed for Egyptian oils gathered from the Gulf of Suez, Western Desert, and Sinai regions. Independent of oil gravity and reservoir temperature. Although authors claim that the correlations are applicable to a wide range of crude oils ranging from heavy to volatile oils (14.3 – 47 °API), it appears to be more applicable for light oils.

Petrosky and Farshad: Developed for Gulf of Mexico oils gathered from offshore regions in Texas and Louisiana. Applicable for oil mixtures ranging from 16 - 45 °API. Provides improved results for the Gulf of Mexico oils compared to Standing, Vasquez and Beggs, Glaso, and Al-Marhoun correlations.

Standing: Developed for California oils. Applicable for oil mixtures ranging from 16 - 64 °API.

Velarde et al: Developed for black oils, applicable for oil mixtures ranging from 12 - 55 °API.

Constant Properties: Allows you to enter values for oil compressibility, the solution gas-oil ratio, and the oil formation volume factor at initial reservoir conditions.

Custom Table: Allows you to enter laboratory measurements for oil compressibility, the solution gas-oil ratio, and the oil formation volume factor.

Viscosity

Beggs and Robinson: Developed from data obtained from fields all over the world and generally applicable for all oil types. Covers a wide range of pressures, temperatures, and oil properties.

De Ghetto et al: Developed for heavy oils (10 < °API < 22.3) and extra-heavy oils (°API < 10) from the Mediterranean Basin, Africa, and the Persian Gulf. Requires separator pressure and temperature.

Hanafy et al: Developed for Egyptian oils gathered from the Gulf of Suez, Western Desert, and Sinai regions. Independent of oil gravity and reservoir temperature. Although the authors claim that the correlations are applicable to a wide range of crude oils ranging from heavy to volatile oils (14.3 – 47 °API), it appears to be more applicable for light oils.

Khan et al: Developed using oil samples collected from Saudi Arabian reservoirs. Gives more accurate predictions for Saudi Arabian oils, compared to the Beggs and Robinson.

Ng and Egbogah: This correlation contains two methods for calculating dead oil viscosity using a modified Beggs and Robinson viscosity correlation and a correlation that uses the pour-point temperature, which is the lowest temperature at which the oil is observed to flow when cooled. The purpose of introducing the pour-point temperature into the correlation is to reflect the chemical composition of crude oil into the viscosity correlation. To obtain the viscosity for live oils, the dead oil correlations are used with the Beggs and Robinson viscosity correlation. This correlation is applicable for oil mixtures ranging from 5 - 58 °API.

Constant Properties: Allows you to enter the value for oil viscosity at initial reservoir conditions.

Custom Table: Allows you to enter laboratory measurements for oil viscosity.

Vasquez and Beggs (generally applicable)

Vasquez and Beggs is a generally applicable correlation containing equations for the solution gas oil ratio, oil formation volume factor, and oil compressibility. The correlation was developed from data obtained from over 600 laboratory pressure volume temperature (PVT) analyses gathered from fields all over the world. The data used in the development of the correlation covers a wide range of pressures, temperatures, and oil properties. The correlation divides the data into two groups: one for oil gravity over 30°API and one at and below 30°API.

Note: This is the default setting for oil correlations.

Bubble point pressure

$$p_{bp} = \left(\frac{R_{so}}{C_1 G \; e^{C_3\left(\frac{\gamma_o}{T + 460}\right)}} \right)^{\frac{1}{C_2}}$$

Coefficient	$\gamma_O \leq 30^O$ API	$\gamma_O > 30^O$ API
C_1	0.0362	0.0178
C_2	1.0937	1.1870
C_3	25.7240	23.9310

Solution gas oil ratio

$$R_{so} = C_1 \, G \, p^{c_2} \cdot e^{C_3\left(\frac{\gamma_o}{T + 460}\right)}$$

Oil formation volume factor (FVF) – saturated

$$B_o = 1 + A_1 \, R_{so} + A_2 \, (T - 60) \left(\frac{\gamma_o}{G}\right) + A_3 \, R_{so} \, (T - 60) \left(\frac{\gamma_o}{G}\right)$$

Coefficient	$\gamma_O \leq 30^O$ API	$\gamma_O > 30^O$ API
A_1	4.677E-04	4.670E-04
A_2	1.751E-05	1.100E-05
A_3	-1.811E-08	1.337E-09

Oil FVF – undersaturated

$$B_o = B_{ob} \cdot e^{c_o \left(p_{bp} - p\right)}$$

where B_{ob} is the formation volume factor at the bubble point pressure

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Compressibility – saturated

$$c_o = \frac{-1433 + 5\,R_{sob} + 17.2T - 1180G + 12.61\,\gamma_o}{10^5\,p} + \frac{\frac{B_g}{B_o} \cdot \frac{dR_{so}}{dp}}{5.615}$$

where R$_{sob}$ is the solution gas-oil ratio at the bubble point pressure

Compressibility – undersaturated

$$c_o = \frac{-1433 + 5R_{sob} + 17.2T - 1180G + 12.61\,\gamma_o}{10^5\,p}$$

Al-Marhoun (Middle East oil)

The Al-Marhoun correlation contains equations for estimating bubble point pressure, solution gas oil ratio, and oil formation volume factor for Middle East oils. 75 bottomhole fluid samples from 62 reservoirs in the Middle East were used in the development of these correlations. The author claims that the correlations should be valid for all types of gas-oil mixtures that share similar properties as those used in the derivation. According to the author, the average errors and standard deviations were lower with the Al-Marhoun correlation than with the Standing and Glaso correlations for Middle Eastern crude oils. Note that temperature is measured in Rankine.

Bubble point pressure

$$p_{bp} = -64.138910 + 0.702362 \cdot 10^{-2} \cdot x - 2.278475 \cdot 10^{-9} \cdot x^2$$

$$x = R_s^{0.722569} \cdot \gamma_g^{-1.879109} \cdot \gamma_o^{3.04659} \cdot T^{1.302347}$$

Solution gas oil ratio

$$R_s = \left(\frac{x}{\gamma_g^{-1.879109} \cdot \gamma_o^{3.04659} \cdot T^{1.302347}} \right)^{\frac{1}{0.722569}}$$

$$x = \frac{-b \pm \sqrt{b^2 - 4ac}}{2a}$$

where:

a = - 2.278475 * 10^{-9}

b = 7.02362 * 10^{-3}

c = - 64.13891 – p

Oil FVF – saturated

$$B_o = 0.574095 + 7.723532 \cdot 10^{-4} \cdot T + 2.454005 \cdot 10^{-3} \cdot y + 3.727676 \cdot 10^{-5} \cdot y^2$$

$$y = R_s^{0.501538} \cdot \gamma_g^{-0.145526} \cdot \gamma_o^{-5.220726}$$

Oil FVF – undersaturated

$$B_o = B_{ob} \cdot e^{(c_o(p_b - p))}$$

The oil compressibility used in this equation is obtained from the Vasquez and Beggs correlation.

Beggs and Robinson

Beggs and Robinson developed an empirical correlation for determining the viscosity of dead oil. The correlation originated from analyzing 460 dead oil viscosity measurements. The dataset from which the results were obtained ranged from 16°API to 58°API and 70°F to 295°F. The correlation tends to overstate the viscosity of the crude oil when dealing in temperature ranges below 100°F to 150°F.

Viscosity

$$\mu_{od} = 10^x - 1$$

where:

x = y T^{-1.163}

$$x = y\ T^{-1.163}$$

$$y = 10^z$$

$$z = 3.0324 - 0.02023\ G$$

De Ghetto et al. (heavy and extra-heavy oils)

The De Ghetto et al. correlation contains modified PVT correlations for estimating bubble point pressure, solution gas oil ratio, oil formation volume factor (FVF), oil compressibility, and oil viscosity for heavy (10° < API < 22.3°) and extra-heavy oils (API < 10°). The oils used for developing the correlation came from reservoir fluid samples taken from the Mediterranean Basin, Africa, and the Persian Gulf. When comparing published correlations, De Ghetto et al. decided that the Vasquez and Beggs correlation estimated the oil formation volume factor with minimal error, and therefore no further modification was needed. Note that in contrast with other correlations, the De Ghetto et al. correlation requires the pressure and temperature at the separator.

Heavy oils (10° < API < 22.3°)

Bubble point pressure

$$p_b = \left(\frac{56.434 \cdot R_s}{\gamma_g\left(p_{sp}\right) \cdot 10^{10.9267\left(\frac{\gamma_{API}}{T+459.67}\right)}} \right)^{\frac{1}{1.2057}}$$

$$\gamma_g\left(p_{sp}\right) = \gamma_g\left(1 + 0.5912\ \cdot \gamma_{API} \cdot T_{sp} \cdot \log\left(\frac{p_{sp}}{114.7}\right) \cdot 10^{-4}\right)$$

Solution gas oil ratio

$$R_s = \frac{\gamma_g\left(p_{sp}\right)\cdot p^{1.2057}}{56.434}\cdot 10^{10.9267}\cdot\left(\frac{\gamma_{API}}{T+459.67}\right)$$

Oil FVF – saturated

$$B_o = 1 + A_1\,R_s + A_2\left(T-60\right)\left(\frac{\gamma_{API}}{\gamma_g}\right) + A_3 R_s\left(T-60\right)\left(\frac{\gamma_{API}}{\gamma_g}\right)$$

where:

A_1, A_2, and A_3 are Vasquez and Beggs constants for API ≤ 30°:

$A_1 = 4.677*10^{-4}$

$A_2 = 1.751*10^{-5}$

$A_3 = -1.811*10^{-8}$

Oil FVF – undersaturated

$$B_o = B_{ob}\cdot e^{\left(c_o\left(p_b - p\right)\right)}$$

Compressibility – saturated

$$c_o = \frac{-2841.8 + 2.9646\cdot R_{sb} + 25.5439\cdot T - 1230.5\cdot\gamma_g\left(p_{sp}\right) + 41.91\cdot\gamma_{API}}{p\cdot 10^5} + \frac{B_g}{5.6145835\cdot B_o}\cdot\frac{dR_s}{dp}$$

Compressibility – undersaturated

$$c_o = \frac{-2841.8 + 2.9646\cdot R_{sb} + 25.5439\cdot T - 1230.5\cdot\gamma_g\left(p_{sp}\right) + 41.91\cdot\gamma_{API}}{p\cdot 10^5}$$

Viscosity – dead oil

$$\log\left(\mu_{od}+1\right) = 2.06492 - 0.0179\cdot\gamma_{API} - 0.70226\cdot\log(T)$$

Viscosity – saturated

$$\mu_{os} = -0.6311 + 1.078 \cdot x - 0.003653 \cdot x^2$$

$$x = \left(0.2478 + 0.6144 \cdot 10^{-0.000845 R_s}\right) \cdot \mu_{od}^{(0.4731 + 0.5158)}$$

$$y = 10^{-0.00081 \, R_s}$$

Viscosity – undersaturated

$$\mu_o = 0.9886 \cdot \mu_{os} + 0.002763(p - p_b)\left(-0.01153 \cdot \mu_{os}^{1.7933} + 0.0316 \cdot 0.0316 \cdot \mu_{os}^{1.5939}\right)$$

Extra heavy oils (API < 10°)

Bubble point pressure

$$p_b = \left(\frac{R_s}{\gamma_g}\right)^{\frac{1}{1.1128}} \cdot \frac{10.7025}{10^{\left(0.0169 \cdot \gamma_{API} - 0.00156T\right)}}$$

Solution gas oil ratio

$$R_s = \gamma_g \left(\frac{p}{10.7025} \cdot 10^{\left(0.0169 \cdot \gamma_{API} - 0.00156T\right)}\right)^{1.1128}$$

Oil FVF – saturated

$$B_o = 1 + A_1 \, R_s + A_2 \left(T - 60\right)\left(\frac{\gamma_{API}}{\gamma_g}\right) + A_3 R_s \left(T - 60\right)\left(\frac{\gamma_{API}}{\gamma_g}\right)$$

where:

A_1, A_2, and A_3 are Vasquez and Beggs constants for API ≤ 30°:

$A_1 = 4.677 \times 10^{-4}$

$A_2 = 1.751*10^{-5}$

$A_3 = -1.811*10^{-8}$

Oil FVF – undersaturated

$$B_o = B_{ob} \cdot e^{(c_o(p_b - p))}$$

Compressibility – saturated

$$c_o = \frac{-889.6 + 3.1374 \cdot R_{sb} + 20 \cdot T - 627.3 \cdot \gamma_g\left(p_{sp}\right) - 81.4476 \cdot \gamma_{API}}{p \cdot 10^5} + \frac{B_g}{5.6145835 \cdot B_o} \cdot \frac{dR_s}{dp}$$

Compressibility – undersaturated

$$c_o = \frac{-889.6 + 3.1374 \cdot R_{sb} + 20 \cdot T - 627.3 \cdot \gamma_g\left(p_{sp}\right) - 81.4476 \cdot \gamma_{API}}{p \cdot 10^5}$$

Viscosity – dead oil

$$\log\left(\mu_{od} + 1\right) = 1.090296 - 0.012619 \cdot \gamma_{API} - 0.61748 \cdot \log\left(T\right)$$

Viscosity – saturated

$$\mu_{os} = 2.3945 + 0.8927 \cdot x + 0.001567 \cdot x^2$$

$$x = \left(-0.0335 + 1.0785 \cdot 10^{-0.000845 R_s}\right) \cdot \mu_{od}^{(0.5798 + 0.3432 y)}$$

$$y = 10^{-0.00081 R_s}$$

Viscosity – undersaturated

$$\mu_o = \mu_{os} - \left(1 - \frac{p}{p_b}\right)\left(\frac{10^{-2.19} \cdot \mu_{od}^{1.055} \cdot p_b^{0.3132}}{10^{0.0099 \gamma_o}}\right)$$

Glaso (North Sea oil)

The Glaso correlation contains equations for estimating the bubble point pressure, solution gas oil ratio, and the oil formation volume factor for North Sea oils. The author claims that the correlation should be valid for all types of oil and gas mixtures after correcting for non-hydrocarbons in the surface gases and the paraffinicity of the oil. According to the author, the correlation more accurately predicts the oil properties of North Sea oils than the Standing correlation.

Bubble point pressure

$$\log\left(p_b\right) = 1.7669 + 1.7447 \cdot \log\left(x\right) - 0.30218 \cdot \log\left(x\right)^2$$

$$p_b = 10^{\log\left(p_b\right)}$$

$$x = \left(\frac{R_s}{\gamma_g}\right)^{0.816} \frac{T^{0.172}}{\gamma_{API}^{0.989}}$$

Solution gas oil ratio

$$R_s = \left(\frac{x \cdot \gamma_{API}^{0.989}}{T^{0.172}}\right)^{\frac{1}{0.816}} \gamma_g$$

$$\log\left(x\right) = \frac{-b \pm \sqrt{b^2 - 4ac}}{2a}$$

where:

$x = 10^{\log(x)}$

$a = -0.30218$

b = 1.7447

c = 1.7669 − log(p)

Oil FVF – saturated

$$\log\left(B_o - 1\right) = -6.58511 + 2.91329 \cdot \log\left(y\right) - 0.27683 \cdot \log\left(y\right)^2$$

$$y = R_s\left(\frac{\gamma_g}{\gamma_o}\right)^{0.526} + 0.968\,T$$

Oil FVF – undersaturated

$$B_o = B_{ob} \cdot e^{(c_o(p_b - p))}$$

Note: The oil compressibility used in this equation is obtained from the Vasquez and Beggs correlation.

Hanafy et al. (Egyptian oil)

The Hanafy et al. correlation contains equations for estimating the bubble point pressure, solution gas oil ratio, oil formation volume factor, oil compressibility, oil viscosity, and oil density for Egyptian oils. The compressibility correlation assumes constant compressibility after the bubble point. This correlation is independent of oil gravity and reservoir temperature. The pressure volume temperature (PVT) data used in the derivation of the correlations was gathered from the Gulf of Suez, Western Desert, and Sinai regions. The authors claim that the correlations can be used to estimate oil properties for a wide range of crude oils ranging from heavy to volatile oils. However, our observations are that it appears to be closer to the properties of light oils.

Bubble point pressure

$$p_b = 3.205 \cdot R_s + 157.27$$

Solution gas oil ratio

$$R_s = -49.069 + 0.312p$$

$R_s = 0$ when $p \leq 157.28$

Oil FVF – saturated

$$B_o = 0.0006 \cdot R_s + 1.079$$

Oil FVF – undersaturated

$$B_o = B_{ob} \, e^{(c_o \, (p_b - p))}$$

Density – saturated

$$p_o = \left(2.366 - \left(\frac{1.358}{B_o}\right)\right)^{-1}$$

Density – undersaturated

$$p_o = p_{ob} e^{(c_o(p - p_b))}$$

Compressibility – saturated

$$c_o = e^{\left(\frac{2.582}{p_o} - 0.99\right)} \cdot 10^{-6} + \frac{B_g}{5.6145835 \cdot B_o} \cdot \frac{dR_s}{dp}$$

Compressibility – undersaturated

$$c_o = e^{\left(\left(\frac{2.582}{p_{ob}}\right) - 0.99\right)} \cdot 10^{-6}$$

Oil viscosity

$$\mu_o = e^{\left(7.296 \cdot \rho_0^3 - 3.095\right)}$$

Khan et al. (Saudi Arabian oil)

The Khan et al. correlation contains equations for estimating oil viscosity at, above, and below the bubble point for Saudi Arabian oils. The study used data from 75 sandface samples, which were taken from 62 Saudi Arabian reservoirs. The authors claim that this correlation gives the most accurate predictions for Saudi Arabian crude oils, as compared to the Beggs and Robinson, Beal, and Chew and Connally correlations.

Oil viscosity

$p = p_b$

$$\mu_{ob} = \frac{0.09\sqrt{\gamma_g}}{\sqrt[3]{R_s \cdot \theta_r^{4.5} \ (1 - \gamma_0)^3}}$$

where:

$$\theta_r = \frac{T + 459.67}{459.67} = relative\ temperature$$

$p > p_b$

$$\mu_o = \mu_{ob}\, e^{\left(9.6 \cdot 10^{-5}\left(p - p_b\right)\right)}$$

$p < p_b$

$$\mu_{os} = \mu_{ob}\left(\frac{p}{p_b}\right)^{-0.14} e^{\left(-2.5 \cdot 10^{-4}\left(p - p_b\right)\right)}$$

Ng and Egbogah

The Ng and Egbogah correlation contains two methods for calculating dead oil viscosity using a modified Beggs and Robinson viscosity correlation and a correlation that uses the pour point temperature. Pour point temperature is the lowest temperature at which the oil is observed to flow when cooled and examined under conditions prescribed in ASTM D97. The purpose of introducing the pour point temperature into the correlation is to reflect the chemical composition of crude oil into the viscosity correlation. To obtain the viscosity for live oils, the dead oil correlations are used with the Beggs and Robinson viscosity correlation. The data used to derive the correlations was taken from the Reservoir Fluids Analysis Laboratory of AGAT Engineering Ltd., using a total of 394 oil systems.

Dead oil

$$\log(\mu_{od}+1) = -1.7095 - 0.0087917 \cdot T_{pp} + 2.7523 \cdot \gamma_o + (-1.2943 + 0.0033214 \cdot T_{pp} + 0.9581957 \cdot \gamma_o) \cdot \log(T - T_{pp})$$

-50°C < T_{pp} < 15°C

Live oil – saturated

$$\mu_{os} = x \cdot \mu_{od}^y$$

$$x = 10.715\,(R_s + 100)^{-0.515}$$

$$y = 5.44(R_s + 150)^{-0.338}$$

where μ_{od} is defined using the modified Beggs and Robinson correlation.

$$\log(\mu_{od} + 1) = 1.8653 - 0.025086 \cdot \gamma_o - 0.5644 \cdot \log(T)$$

Live oil - undersaturated

$$\mu_o = \mu_{ob}\left(\frac{p}{p_b}\right)^x$$

$$x = 2.6 p^{1.187} e^{\left(-11.513 - 8.98 \cdot 10^{-5} p\right)}$$

Petrosky and Farshad (Gulf of Mexico)

The Petrosky and Farshad correlation contains equations for estimating the bubble point pressure, solution gas oil ratio, oil formation volume factor, and oil compressibility for Gulf of Mexico oils. The correlation was developed using fluid samples taken from offshore regions in Texas and Louisiana (Galveston Island eastward through Main Pass). The authors claim that these correlations provide improved results over other correlations for the Gulf of Mexico, including those published by Standing, Vasquez and Beggs, Glaso, and Al-Marhoun.

Bubble point pressure

$$p_b = 112.727 \left(\frac{R_s^{0.5774}}{\gamma_g^{0.8439}} \cdot 10^x - 12.34 \right)$$

where:

$$x = 4.561 \cdot 10^{-5} \cdot T^{1.3911} - 7.916 \cdot 10^{-4} \cdot \gamma_{API}^{1.541}$$

Solution gas oil ratio

$$R_s = \left(\left(\frac{p}{112.727} + 12.34 \right) \cdot \gamma_g^{0.8439} \cdot 10^x \right)^{1.73184}$$

where:

$$x = 7.916 \cdot 10^{-4} \cdot \gamma_{API}^{1.541} - 4.561 \cdot 10^{-5} \cdot T^{1.3911}$$

Oil FVF – saturated

$$B_o = 1.0113 + 7.2046 \cdot 10^{-5} \cdot \left(R_s^{0.3738} \left(\frac{\gamma_g^{0.2914}}{\gamma_o^{0.6265}} \right) + 0.24626 \cdot T^{0.5371} \right)^{3.0936}$$

Oil FVF – undersaturated

$$B_o = B_{ob}\, e^{(c_o\,(p_b - p))}$$

Compressibility – saturated

$$c_o = 1.705 \cdot 10^{-7} \cdot R_{sb}^{0.69357} \cdot \gamma_g^{0.1885} \cdot \gamma_{API}^{0.3272} \cdot T^{0.6729} \cdot p^{-0.5906} + \frac{B_g}{5.6145835 \cdot B_o} \cdot \frac{dR_s}{dp}$$

Compressibility – undersaturated

$$c_o = 1.705 \cdot 10^{-7} \cdot R_{sb}^{0.69357} \cdot \gamma_g^{0.1885} \cdot \gamma_{API}^{0.3272} \cdot T^{0.6729} \cdot p^{-0.5906}$$

where $2.464 * 10^{-5} < c_o < 3.507 * 10^{-5}$

Standing (California oil)

The Standing correlation contains equations for estimating the bubble point pressure, solution gas oil ratio, and the oil formation volume factor for California oils. There were 105 experimentally determined data points on 22 different oil-gas mixtures from California used in the development of the correlations.

Bubble point pressure

$$p_b = 18.2\left(\left(\frac{R_s}{G} \right)^{0.83} \cdot \frac{10^{0.00091\,T}}{10^{0.0125\,\ \gamma_{API}}} - 1.4 \right)$$

Solution gas oil ratio

$$R_s = \left(\left(\frac{p}{18.2} + 1.4 \right) \cdot \frac{10^{0.0125\,\gamma_{API}}}{10^{0.00091\,T}} \right)^{\frac{1}{0.83}} \cdot G$$

Oil FVF – saturated

$$B_o = 0.972 + 1.47 \cdot 10^{-4} \left(R_s \left(\frac{G}{\gamma_o} \right)^{0.5} + 1.25 \cdot T \right)^{1.175}$$

Oil FVF – undersaturated

$$B_o = B_{ob} \, e^{(c_o \, (p_b - p))}$$

The oil compressibility used in this equation is obtained from the Vasquez and Beggs correlation.

Velarde et al. (reduced variable approach)

The Velarde et al. correlation contains equations for estimating the bubble point pressure, solution gas oil ratio, and the oil formation volume factor. The bubble point pressure correlation was based on 728 datasets. The solution gas oil ratio was based on 2097 datasets.

Bubble point pressure

$$p_b = 1091.47 \left(R_{sb}^{0.081465} \cdot \gamma_g^{-0.161488} \cdot 10^x - 0.740152 \right)^{5.354891}$$

$$x = 0.013098 \cdot T^{0.282372} - 8.2 \cdot 10^{-6} \cdot \gamma_{API}^{2.176124}$$

Solution gas oil ratio (p = p_b)

$$R_s = \left(\frac{\left(\frac{p_b}{1091.47} \right)^{\frac{1}{5.354891}} + 0.740152}{\gamma_g^{-0.161488} \cdot 10^x} \right)^{\frac{1}{0.081465}}$$

Solution gas oil ratio (p < p_b)

$$R_{sr} = a_1\, p_r^{a2} + (1 - a_1)\, p_r^{a3}$$

$$R_{sr} = \frac{R_s}{R_{sb}}$$

$$p_r = \frac{p}{p_b}$$

$$a_1 = A_o \gamma_g^{A1}\, \gamma_{API}^{A2}\, T^{A3}\, p_b^{A4}$$

$$a_2 = B_o \gamma_g^{B1}\, \gamma_{API}^{B2}\, T^{B3}\, p_b^{B4}$$

$$a_3 = C_o \gamma_g^{c1}\, \gamma_{API}^{c2}\, T^{c3}\, p_b^{c4}$$

Note: All pressures in the above equations are measured in p_{sig}.

Reduced variable approach

The reduced solution gas oil ratio is defined as the solution gas oil ratio divided by the solution gas oil ratio at the bubble point. The reduced pressure is defined as the pressure divided by the bubble point pressure. Using the above relationship, the reduced solution gas oil ratio and the solution gas oil ratio at the bubble point are used to solve for the actual solution gas oil ratio at any pressure below the bubble point.

A Coefficients	B Coefficients	C Coefficients
$A_0 = 9.73 \times 10\text{-}7$	$B_0 = 0.022339$	$C_0 = 0.725167$
$A_1 = 1.672608$	$B_1 = 1.004750$	$C_1 = 1.485480$
$A_2 = 0.929870$	$B_2 = 0.337711$	$C_2 = 0.164741$
$A_3 = 0.247235$	$B_3 = 0.132795$	$C_3 = 0.091330$
$A_4 = 1.056052$	$B_4 = 0.302065$	$C_4 = 0.047094$

Oil FVF – saturated

$$B_o = \frac{\rho_{st} + 0.01357 \cdot R_s \gamma_g}{\rho_{oR}}$$

$$\rho_{oR} = \rho_{bs} - \left(0.00302 + 1.505\rho_{bs}^{-0.951}\right)(T-60)^{0.938} + \left(0.0233\left(10^{-0.0161\cdot\rho_{bs}}\right)\right)(T-60)^{0.475}$$

$$\rho_{bs} = \rho_{po} + \left(0.167 + 16.181\left(10^{-0.0425\cdot\rho_{po}}\right)\right)\left(\frac{\rho}{1000}\right) - 0.01\left(0.299 + 263\left(10^{-0.0603\cdot\rho_{po}}\right)\right)\left(\frac{\rho}{1000}\right)^2$$

In the above equation, an initial estimate of ρ_{po} is calculated as follows:

$$\rho_{po} = 52.8 - 0.01 R_{sb}$$

After this initial value is known, ρ_{po} is calculated through a 10-step iteration process using the following equations. The values from the ninth and tenth iterations are averaged to yield a final value for ρ_{po}.

$$\rho_a = -49.893 + 85.0149 \cdot \gamma_g - 3.70373 \cdot \gamma_g \, \rho_{po} + 0.047981 \cdot \gamma_g \, \rho_{po}^2 + 2.98914 \cdot \rho_{po-0.035688} \cdot \rho_{po}^2$$

$$\rho_{po} = \frac{R_s \gamma_g + 4600 \cdot \gamma_o}{73.71 + \frac{R_s \gamma_g}{\rho_a}}$$

Oil FVF – undersaturated

$$B_o = B_{ob} \, e^{(c_o (p_b - p))}$$

The oil compressibility used in this equation is obtained from the Vasquez and Beggs correlation. All pressures in the above equations are measured in psia.

Correlation limits

Variable	Rs Correlation Limits	pbp Correlation Limits
T	70 - 307 °F	74 - 327 °F
p_b	106 - 5312 psia	70 - 6700 psia

Variable	Rs Correlation Limits	pbp Correlation Limits
B_{ob}	1.040 - 2.082 bbl/stb	N/A
R_s or R_{sb}	102 - 1808 scf/stb	10 - 1870 scf/stb
γ_g	0.561 - 1.101	0.556 - 1.367
γ_o	11.6 - 53.4 °API	12 - 55 °API

Oil correlation limits

Correlation	T (°F)	p (psia)	p_b (psia)	B_o (Rbbl/st-bbl)	R_s (scf/st-bbl)
Al-Marhoun (Middle East Oil)	75 - 240		107 - 4315	1.02 - 2.42	24 - 1901
De Ghetto et al. (Heavy and Extra-Heavy Oils)	131.4 - 250.7	1038.49 - 7411.54	208.86 - 4021.96	1.057 - 1.362	17.21 - 640.25
Glaso (North Sea Oil)	80 - 280	400 - 4000	150 - 7127	1.087 - 2.588	90 - 2637
Hanafy et al. (Egyptian Oil)	107 - 327		36 - 5003	1.032 - 4.35	7 - 4272
Khan et al. (Saudi Arabian Oil)	75 - 240	14.7 - 5015	107 - 4315		24 - 1901
Ng and Egbogah	70 - 295				
Petrosky and Farshad (Gulf of Mexico Oil)	114 - 288	1700 - 10692	1574 - 6523	1.1178 - 1.6229	217 - 1406
Standing (California Oil)	60 - 260 (p_{bp}) 100 - 260 (B_o)		200 - 6000	1.024 - 2.15	20 - 1425
Vasquez and Beggs (Generally Applicable)		140.7 - 9514.7			
Velarde et al. (Reduced Variable Approach)	See Velarde et al		See Velarde et al	See Velarde et al	See Velarde et al

Correlation	g_g	γ_o (°API)	μ_o (cp)	μ_{os} (cp)	μ_{od} (cp)
Al-Marhoun (Middle East Oil)	0.752 - 1.367	14.3 - 44.6			
De Ghetto et al. (Heavy and Extra-Heavy Oils)	0.623 - 1.517	6 - 22.3	2.4 - 354.6	2.1 - 295.9	7.7 - 1386.9
Glaso (North Sea Oil)	0.65 - 1.276	22.3 - 48.1	0.119 - 106.6		
Hanafy et al. (Egyptian Oil)	0.752 - 1.367	17.8 - 47.7	0.13 - 71		

Correlation	g$_g$	γ$_o$ (°API)	μ$_o$ (cp)	μ$_{os}$ (cp)	μ$_{od}$ (cp)
Khan et al. (Saudi Arabian Oil)		14.3 - 44.6		0.13 - 77.4	
Ng and Egbogah		5 - 58			
Petrosky and Farshad (Gulf of Mexico Oil)	0.5781 - 0.8519	16.3 - 45			
Standing (California Oil)	0.5 - 1.5	16.5 - 63.8			
Vasquez and Beggs (Generally Applicable)	0.511 - 1.351	15.3 - 59.5			
Velarde et al. (Reduced Variable Approach)	See Velarde et al	See Velarde et al			

Correlation	T$_{sp}$ (°F)	p$_{sp}$ (psia)
De Ghetto et al. (Heavy and Extra-Heavy Oils)	59 - 177.8	14.5 - 752.2

Correlation	ρ$_o$ (g/cm^3)	ρ$_{ob}$ (g/cm^3)
Hanafy et al. (Egyptian Oils)	0.648 - 1.071	0.428 - 0.939

Pressure loss calculations

In order to have flow in a pipe system, a pressure difference is needed, as fluids flow from a high pressure point to a low pressure point. You can identify three components that define this pressure difference:

1. Hydrostatic pressure loss

2. Frictional pressure loss

3. Kinetic pressure loss

For most applications, kinetic losses are minimal and can be ignored. Thus, the equation that describes the overall pressure losses can be expressed as the sum of two terms:

$$\Delta P_T = \Delta P_{HH} + \Delta P_f$$

Note: The phrases "pressure loss," "pressure drop," and "pressure difference" can be used interchangeably.

In upward (or "uphill" in the context of pipelines) flow, fluids must overcome the back-pressure exerted by the effective column of fluid acting against the direction of flow. Fluids must also overcome friction losses due to the interaction of the fluid with the pipe wall.

In downward (or "downhill" in the context of pipelines) flow, friction effects act against the direction of flow, but in this case, the effective hydrostatic column helps the fluid to overcome such friction losses.

Hydrostatic pressure losses are a function of the density of the fluid in the pipe. Frictional losses 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. The correlations that are included in Harmony™ are as follows:

Single-phase flow (internally used when single-phase flow is found):

- Fanning gas

- Fanning liquid

Multiphase flow:

- Beggs & Brill

- Gray

- Hagedorn & Brown

- Petalas and Aziz

Single-phase flow

Single-phase flow pressure calculations include the density, friction component, hydrostatic component, and flow correlations.

Density

Density (ρ) is used in hydrostatic pressure difference calculations. The method for calculating ρ depends on whether flow is compressible or incompressible (multiphase or single-phase). It follows that:

- For a single-phase liquid, calculating the density is easy, and ρ is simply the liquid density.

- For a single-phase gas, ρ varies with pressure (since gas is compressible), and the calculation must be done sequentially, in small steps, to allow the density to vary with pressure.

Friction component

During pipe flows, friction results from the resistance of the fluid to movement. Friction can be thought of as energy that is "lost" or "dissipated" (transformed into non-useful thermal energy) in the system. In single-phase flow scenarios, the frictional component can be found by the general Fanning equation:

$$\Delta P_f \;=\; \frac{2fpv^2 L}{144 g_c D}$$

This correlation can either be used for single-phase gas or for single-phase liquid pipe flows.

Osborne Reynolds (1842–1912) experimentally investigated the relationship between the pressure drop and flow rate in a pipe. He found that at low rates, the pressure drop was directly proportional to the flow rate. He also observed that as he increased the flow rate, the measured data started to behave erratically. It was only when he used extremely high rates that he was able to reproduce his experimental data again.

After introducing a dye into the flow, Reynolds observed that at low rates of flow, the dye described a smooth flow path (linear) along the pipe. After increasing the flow rate, the dye presented perturbations, and if the rate was increased even further, the dye fluctuated erratically throughout the

pipe. He named the smooth (stable) flow 'laminar flow regime', and the disturbed (unstable) flow 'turbulent flow regime'. Reynolds proposed to make use of the dimensionless ratio of inertia to viscous forces (now named after him) as an indication of the transition from flow regimes:

$$R_e = \frac{\rho v^2}{\mu v / D}$$

In field units, the Reynolds number can be rewritten as:

$$R_e = \frac{1488 \rho v D}{\mu}$$

Considering the interaction of the fluid with the pipe wall, the friction factor results from the analysis (momentum flux) of the wall shear stress, and the kinetic energy per unit volume due to the movement of the fluid inside the pipe:

$$f = \frac{2\tau g_c}{\rho v^2}$$

In other words, the friction factor depends on the fluid properties and flowing conditions in the system.

Blasius was the first to present a correlation between the Reynolds number and the friction factor for a very limited range of applications.

Nikuradse experimentally identified a relationship between the flow regimes (using the Reynolds number), the pipe roughness, and friction. Nikuradse found that pressure losses were higher for rougher pipes than for smooth ones due to frictional effects. He also observed that for small Reynolds numbers (in the laminar flow regime), the friction factor was the same for rough and smooth pipes. Several authors have since tried to relate the Reynolds number and the absolute roughness of the pipe to estimate the friction factor.

In Harmony, the Fanning friction factor for Reynolds numbers in the laminar flow regime (Re≤2000) is found by:

$$f = \frac{16}{R_e}$$

In the turbulent flow regime (Re ≥ 4000), the friction factor is obtained from the Chen (1979) equation.

Fanning Friction Factor - Chen
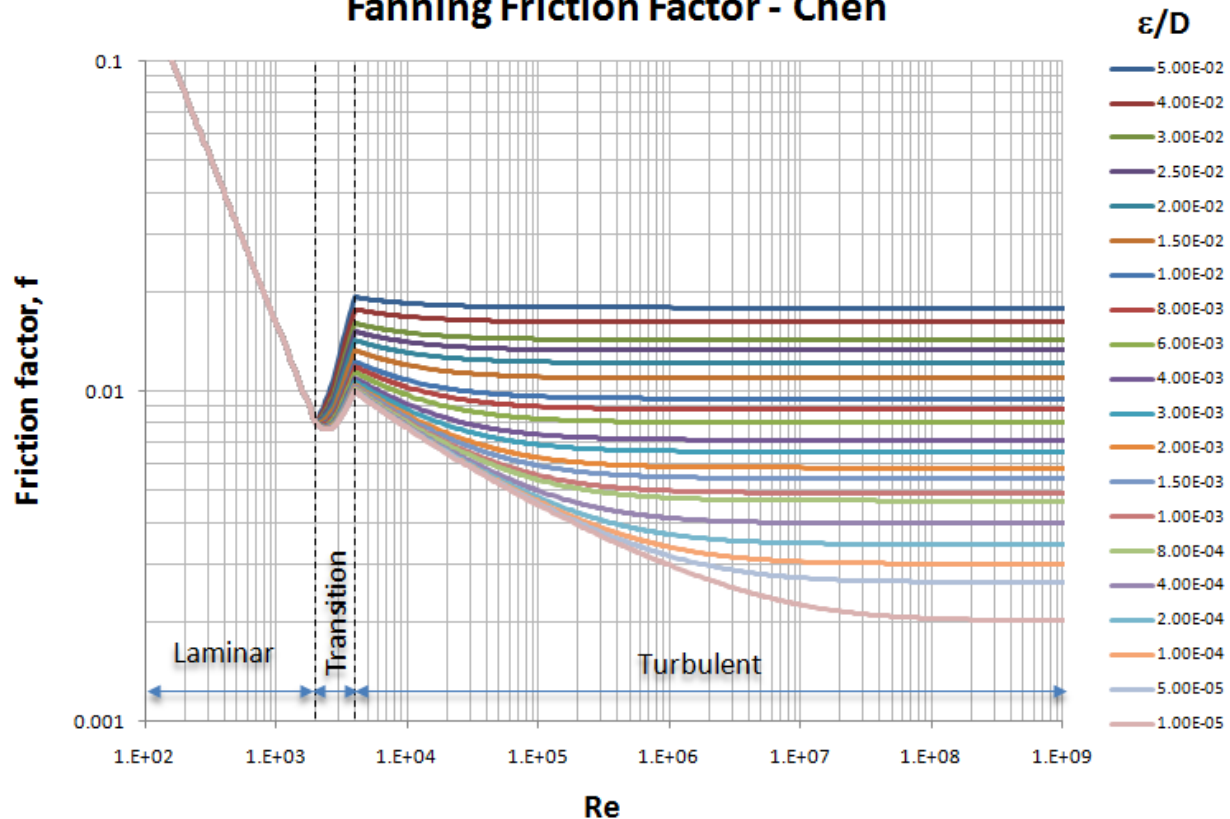
$$\frac{1}{\sqrt{f}} = -4.0\log_{10}\left[0.2698\left(\frac{\epsilon}{D}\right) - \frac{5.0452}{R_e}\log_{10}\left\{0.3539\left(\frac{\epsilon}{D}\right)^{1.1098} + \frac{5.8506}{R_e^{0.8981}}\right\}\right]$$

The friction factor in the transition from laminar to turbulent flow (2000<Re<4000) is approximated using the following expression:

$$f = \frac{f_{Lam}(4000 - R_e) + f_{Turb}(R_e - 2000)}{2000}$$

Hydrostatic component

This component is of importance only when there are differences in elevation from the inlet end to the outlet end of a pipe segment. (In horizontal pipes this component is zero.) The hydrostatic pressure difference (ΔP_{HH}) can be applied to all correlations simply by adding it to the friction component. The hydrostatic pressure drop (ΔP_{HH}) is defined for a vertical pipe as follows:

$$\Delta P_{HH} = \frac{\rho\,g}{144g_c} \cdot h$$

A generalized form accounting for pipe inclination (using the angle with respect to the horizontal) can be written as:
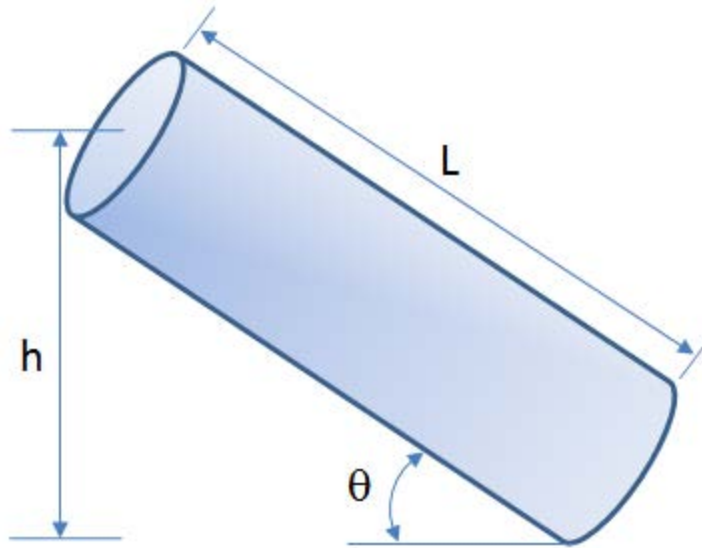
$$\Delta P_{HH} = \frac{\rho\,g}{144g_c}\,L \cdot \sin(\theta)$$

Note: To use the angle with respect to the vertical (for example, in well deviation surveys), change the trigonometric function to cosine.

For liquids, the density (ρ) is constant, and the above equation is easily evaluated.

For gases, density varies with pressure. Therefore, to evaluate the hydrostatic pressure loss or gain, the pipe (or wellbore) is subdivided into a sufficient number of segments, such that the density in each segment can be assumed to be constant. Note that this is equivalent to a Multi-Step Cullender and Smith calculation.

Flow correlations

Many single-phase correlations exist that were derived for different operating conditions or from laboratory experiments. Generally speaking, these only account for the friction component (that is, they are applicable to horizontal flow). Typical examples are:

- Fanning gas (also known as Multi-Step Cullender and Smith when applied to well-bores)

- Fanning liquid

In Harmony™, for cases that involve a single phase, the Gray, Hagedorn and Brown, Beggs and Brill and Petalas and Aziz methods revert to the Fanning single-phase correlations. For example, if the Gray correlation was selected, but there was only gas in the system, the Fanning gas correlation is used.

Note: Single-phase correlations can be used for vertical or inclined flow provided that the hydrostatic pressure drop is accounted for in addition to the friction component. Even though a particular correlation may have been developed for flow in a horizontal pipe, incorporation of the hydrostatic pressure drop allows the correlation to be used for flow in a vertical pipe. This adaptation is rigorous, and has been implemented into all of the correlations used in Harmony™. Nevertheless, for identification purposes, the correlation's name has been left unchanged.

Multiphase flow

Multiphase pressure loss calculations parallel single-phase pressure loss calculations. Essentially, each multiphase correlation makes its own specific modifications to the hydrostatic pressure difference and the friction pressure loss calculations, in order to make them applicable to multiphase situations.

The presence of multiple phases greatly complicates pressure drop calculations. This is due to the fact that the properties of each fluid present must be taken into account. Also, the interactions between each phase must be considered. Mixture properties must be used, and therefore the gas and liquid in-situ volume fractions throughout the pipe need to be determined. In general, multiphase correlations are essentially two-phase, and not three-phase. Accordingly, the oil and water phases are combined, and treated as a pseudo single-liquid phase, while gas is considered a separate phase.

The hydrostatic pressure difference calculation is modified by defining a mixture density. This is determined by a calculation of in-situ liquid holdup (amount of liquid in the pipe section). Some correlations determine holdup based on defined flow patterns.

The friction pressure loss is modified in several ways by adjusting the friction factor (f), the density (ρ), and velocity (v) to account for multiphase mixture properties.

The multiphase pressure loss correlations in Harmony™ are based on the Fanning friction pressure loss equation. They can be grouped as follows:

Do not account for flow patterns:

- **Gray** — Developed using data from gas and condensate wells.

- **Hagedorn and Brown** — Derived using a test well running different oils and air

Consider flow patterns:

- **Beggs and Brill** — Correlation derived from experimental data for vertical, horizontal, inclined uphill, and downhill flow of gas-water mixtures

- **Petalas and Aziz** — Mechanistic model combined with empirical correlations. This multi-purpose correlation is applicable for all pipe geometries, inclinations, and fluid properties.

These models can be used for gas-liquid multiphase flow, single-phase gas, or single-phase liquid, because in single-phase mode, they revert back to the Fanning equation, which is equally applicable to either gas or liquid.

Note: The Gray and Hagedorn and Brown correlations were derived for vertical wells and may not apply to horizontal pipes.

Flow fluid properties

Superficial Velocities

The superficial velocity of each phase is defined as the volumetric flow rate of the phase divided by the cross-sectional area of the pipe (as though that phase alone was flowing through the pipe). Therefore:

$$v_{sL} = \frac{Q_L}{\frac{\pi}{4} \cdot D^2}$$

$$v_{sG} = \frac{Q_G \cdot B_G}{\frac{\pi}{4} \cdot D^2}$$

Since the liquid phase accounts for both oil and water:

$$Q_L = Q_O B_O + (Q_W - Q_{WC} Q_G) B_W$$

and the gas phase accounts for the solution gas going in and out of the oil as a function of pressure:

$$Q_G = Q_G - Q_O R_S$$

the superficial velocities can be rewritten as:

$$v_{sL} = \frac{Q_o \cdot B_o + (Q_w - Q_{wc}\, Q_G)\, B_w}{\frac{\pi}{4} \cdot D^2}$$

$$v_{sG} = \frac{(Q_G - Q_o\, R_s)\, B_g}{\frac{\pi}{4} \cdot D^2}$$

The oil, water, and gas formation volume factors (B_O, B_W, and B_g) are used to convert the flow rates from standard (or stock tank) conditions to the prevailing pressure and temperature conditions in the pipe.

Since the actual cross-sectional area occupied by each phase is less than the cross-sectional area of the entire pipe, the superficial velocity is always less than the true in-situ velocity of each phase.

Mixture velocity

Mixture velocity is another parameter that is often used in multiphase flow correlations. The mixture velocity is given by:

$$v_m = v_{sL} + v_{sG}$$

Slippage and the liquid holdup effect

When two or more phases are present in a pipe, they tend to flow at different in-situ velocities. These in-situ velocities depend on the density and viscosity of each phase. Typically the phase that is less dense flows faster than the other. This causes a "slip" effect between the phases. As a consequence, the in-situ volume fractions of each phase (under flowing conditions) differ from the input volume fractions of the pipe.

If the slip condition is omitted, the in-situ volume fraction of each phase is equal to the input volume fraction.

In-situ volume fraction (liquid holdup with slip)

The in-situ volume fraction, E_L (or H_L), is often the value that is estimated by multiphase correlations. Because of slippage between phases, the liquid holdup (E_L) can be significantly different from the input liquid fraction (C_L). In other words, the liquid slip holdup (E_L) is the fraction of the pipe that is filled with liquid when the phases are flowing at different velocities. It can be defined as follows:

$$E_L = \frac{V_L}{V_p} = \frac{A_L}{A_p}$$

Input volume fraction (no-slip holdup)

The input volume fractions are defined as:

$$C_L = \frac{Q_L}{Q_L + Q_G\, B_g}$$

$$C_G = \frac{Q_G\, B_g}{Q_L + Q_G\, B_g}$$

We can also write them as a function of the superficial velocities as:

$$C_L = \frac{v_{sL}}{v_m}$$

$$C_G = \frac{v_{sG}}{v_m}$$

Note: Q_L is the liquid rate at the prevailing pressure and temperature. Similarly, $Q_G B_g$ is the gas rate at the prevailing pressure and temperature.

The input volume fractions, C_L and E_L, are known quantities, and are often used as correlating variables in empirical multiphase correlations. In the event that slip effects are neglected (gas and liquid traveling at the same velocity), the in-situ liquid fraction is equal to the input liquid fraction ($E_L = C_L$).

Actual velocities

Once the liquid holdup has been determined, the actual velocities for each phase can be determined as follows:

$$v_L = \frac{v_{sL}}{E_L}$$

$$v_G = \frac{v_{sG}}{1 - E_L}$$

Density

Density (ρ) is used in hydrostatic pressure difference calculations. The method for calculating ρ depends on whether flow is compressible or incompressible (multiphase or single-phase). For multiphase flow, the calculations become even more complicated than for single-phase flow because ρ is calculated from the in-situ mixture density, which in turn is calculated from the "liquid holdup." The liquid holdup, or in-situ liquid volume fraction, is obtained from one of the multiphase flow correlations, and depends on several parameters including the gas and liquid rates and the pipe diameter. Note that this is in contrast to the way density is calculated for friction pressure loss.

Mixture density

Mixture density is a measure of the in-situ density of the mixture, and is defined as follows:

$$\rho_m = \rho_L E_L + \rho_G E_G = \rho_L E_L + \rho_G (1 - E_L)$$

Note: Mixture density is defined in terms of in-situ volume fractions (E_L), whereas no-slip density is defined in terms of the input volume fractions (C_L).

No-slip density

"No-slip" density is the density that is calculated with the assumption that both phases are moving at the same in-situ velocity. No-slip density is therefore defined as follows:

$$\rho_{NS} = \rho_L C_L + \rho_G C_G = \rho_L C_L + \rho_G (1 - C_L)$$

Note: No-slip density is defined in terms of the input volume fractions (C_L), whereas the mixture density is defined in terms of the in-situ volume fractions (E_L).

Mixture viscosity

Mixture viscosity is a measure of the in-situ viscosity of the mixture and can be defined in several different ways. In general, unless otherwise specified, is defined as follows:

$$\mu_m = \mu_L E_L + \mu_G E_G = \mu_L E_L + \mu_G (1 - E_L)$$

Note: Mixture viscosity is defined in terms of in-situ volume fractions (E_L), whereas no-slip viscosity is defined in terms of input volume fractions (C_L).

No-slip viscosity

"No-slip" viscosity is the viscosity that is calculated with the assumption that both phases are moving at the same in-situ velocity. There are several definitions of "no-slip" viscosity. In general, unless otherwise specified, μ_{NS} is defined as follows:

$$\mu_{NS} = \mu_L\,C_L + \mu_G\,C_G = \mu_L\,CL + \mu_G\,(1 - C_L)$$

Surface tension

The surface tension (interfacial tension) between the gas and liquid phases has very little effect on two-phase pressure drop calculations. However, a value is required for calculating certain dimensionless numbers used in some of the pressure drop correlations. Empirical relationships for estimating the gas / oil interfacial tension and the gas / water interfacial tension were presented by Baker and Swerdloff, Hough and by Beggs.

Gas / oil interfacial tension

The dead oil interfacial tension at temperatures of 68°F and 100°F is given by:

$$\sigma_{68} = 39 - 0.2571\,(API)$$

$$\sigma_{100} = 37.5 - 0.2571\,(API)$$

If the temperature is greater than 100°F, the value at 100°F is used. If the temperature is less than 68°F, the value at 68°F is used. For intermediate temperatures, linear interpolation is used.

As pressure is increased and gas goes into solution, the gas / oil interfacial tension is reduced. The dead oil interfacial tension is corrected for this by multiplying by a correction factor:

$$C = 1.0 - 0.024 P^{0.45}$$

The interfacial tension becomes zero at miscibility pressure, and for most systems this is at any pressure greater than about 5000 psia. After the correction factor becomes zero (at about 3977 psia), 1 dyne/cm is used for calculations.

Gas / water interfacial tension

The gas / water interfacial tension at temperatures of 74°F and 280°F is given by:

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

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

If the temperature is greater than 280°F, the value at 280°F is used. If the temperature is less than 74°F, the value at 74°F is used. For intermediate temperatures, linear interpolation is used.

Friction component

In pipe flow, friction pressure loss is the component of total pressure loss caused by viscous shear effects. Friction pressure loss **always acts against the direction of flow**. It is combined with the hydrostatic pressure difference (which may be positive or negative, depending on whether the flow is upward (also known as uphill) or downward (downhill)) to give the total pressure loss.

Friction pressure loss is calculated from the Fanning friction factor equation as follows:

$$\Delta P_f \; = \; \frac{2fpv^2\,L}{144g_c\,D}$$

In the above equation, the variables f, ρ, and v are treated differently by each correlation.

Each multiphase flow correlation finds the friction factor differently. This calculation depends, in part, on the gas and liquid flow rates, but also on the standard Fanning (single-phase) friction factor chart. When evaluating the Fanning friction factor, there are many ways of calculating the Reynolds number depending on how the density, viscosity, and velocity of the two-phase mixture are defined. For example, the Beggs and Brill calculation of the Reynolds number uses mixture properties that are calculated by prorating the property of each individual phase in the ratio of the *input* volume fraction (and not of the *in-situ* volume fraction).

Hydrostatic component

Hydrostatic pressure difference is the component of pressure loss (or gain) attributed to the earth's gravitational effect. It is of importance only when there are differences in elevation from the inlet end to the outlet end of a pipe segment. This pressure difference can be positive or negative depending on the reference point (inlet higher vertically than outlet, or outlet higher than inlet). **Under ALL circumstances**, regardless of what sign convention is used, the contribution of the hydrostatic pressure calculation must be such that it tends to make the pressure at the vertically-lower end higher than that at the upper end.

The hydrostatic pressure difference is calculated as follows:

$$\Delta P_{HH} \; = \; \frac{p\,g}{144 g_c}\, L \cdot \, \sin\left(\theta\right)$$

In the equation above, the problem lies in finding an appropriate value for density, as discussed below:

- For a single-phase liquid, the density of the mixture is equal to the liquid density.

- For a single-phase gas, density varies with pressure, and the calculation must be done sequentially in small steps to allow density to vary with pressure.

- For multiphase flow, density is calculated from the in-situ mixture density, which in turn is calculated from the liquid holdup. The liquid holdup is obtained from multiphase flow correlations, such as Beggs and Brill, and depends on the gas and liquid rates, pipe diameter, etc.

- For a horizontal pipe segment, θ = 0.0, and there is NO hydrostatic pressure loss.

Flow correlations

Many of the published multiphase flow correlations are applicable for vertical flow only, while others apply for horizontal flow only. Other than the Beggs and Brill correlation and the Petalas and Aziz mechanistic model, there are not many correlations that were developed for the whole spectrum of flow situations that can be encountered in oil and gas operations — namely, uphill, downhill, horizontal, inclined, and vertical flow. However, we have adapted all of the correlations (as appropriate) so that they apply to all flow situations. This includes these multiphase flow correlations:

- **Beggs and Brill** — one of the few published correlations capable of handling all of the flow directions. It was developed using sections of pipeline that could be inclined at any angle.

- **Gray** — developed for vertical flow in wet gas wells. We have modified it, so that it applies to flow in all directions by calculating the hydrostatic pressure difference using only the vertical elevation of the pipeline segment, and the friction pressure loss based on the total length of the pipeline.

- **Hagedorn and Brown** — developed for vertical flow in oil wells. We have modified it, so that it applies to flow in all directions by calculating the hydrostatic pressure difference using only the vertical elevation of the pipe segment, and the friction pressure loss based on the total pipeline length.

- **Petalas and Aziz** — developed to overcome the limitations imposed by using previous correlations. It applies to all pipe geometries, fluid properties, and flow in all directions. A mechanistic approach is combined with empirical closure relationships to provide a model that is more robust than other models and can be to used predict pressure drop and holdup in pipes over a more extensive range of conditions.

Each of these correlations was developed for its own unique set of experimental conditions, or designed using a mechanistic modeling approach, and accordingly, results vary between them.

For multiphase flow in essentially vertical wells, the available correlations are Beggs and Brill, Petalas and Aziz, Gray and Hagedorn and Brown. If used for single-phase flow, these four correlations devolve to the Fanning gas or Fanning liquid correlation as needed.

When creating a new wellbore, Harmony sets a default multiphase correlation depending upon the type of well that exists in the Entity Viewer. This default correlation is based on our expected use cases, and thus may not apply to every wellbore. Of course, the correlation for the wellbore configuration can be changed at any time.

Note: The Gray and Hagedorn and Brown correlations were derived for vertical wells and may not apply to horizontal pipes. In Harmony, the Gray, the Hagedorn and Brown, the Beggs and Brill, and the Petalas and Aziz models revert to the appropriate single-phase Fanning correlation (Fanning liquid or Fanning gas).

Beggs and Brill correlation

The Beggs and Brill (1973) correlation is one of the few published correlations capable of handling all these flow 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.

The Beggs and Brill multiphase correlation deals with both friction pressure loss and hydrostatic pressure difference. First, the corresponding flow pattern for the particular combination of gas and liquid rates (segregated, intermittent, or distributed) is determined. The liquid holdup, and hence, the in-situ density of the gas-liquid mixture, is then calculated according to the identified flow pattern to obtain the hydrostatic pressure difference. A two-phase friction factor is calculated based on the input gas-liquid ratio and the Fanning friction factor. From this, friction pressure loss is calculated using input gas-liquid mixture properties.

In our implementation, whenever single-phase flow is encountered during pressure loss calculations, the Beggs and Brill correlation devolves to the Fanning gas or Fanning liquid correlation.

Flow pattern map

Unlike the Gray or Hagedorn and Brown correlations, the Beggs and Brill correlation needs to identify the flow pattern at the given flowing conditions in order to calculate the liquid holdup and friction. For this purpose, the Beggs and Brill correlation makes use of a horizontal flow-pattern map built based on the Froude number of the mixture (Fr_m) and input liquid content (no-slip liquid holdup, C_L).

In order to build the flow map, the observed flow patterns were grouped as: segregated (stratified, wavy, and annular flow), intermittent (plug and slug flow), distributed (bubble and mist flow), and transition (flow pattern included after a modification of the original publication that considers the region between the segregated and intermittent grouped patterns).

The boundaries between these groups of flow patterns appear as curves in a log-log plot in the original publication by Beggs and Brill. This was later revised so that straight lines could be used instead. We use this modified flow-pattern map in our calculations. The revised lines that define the boundaries are defined as follows (where * stands for the modification of the original curve to a straight line in a log-log plot):
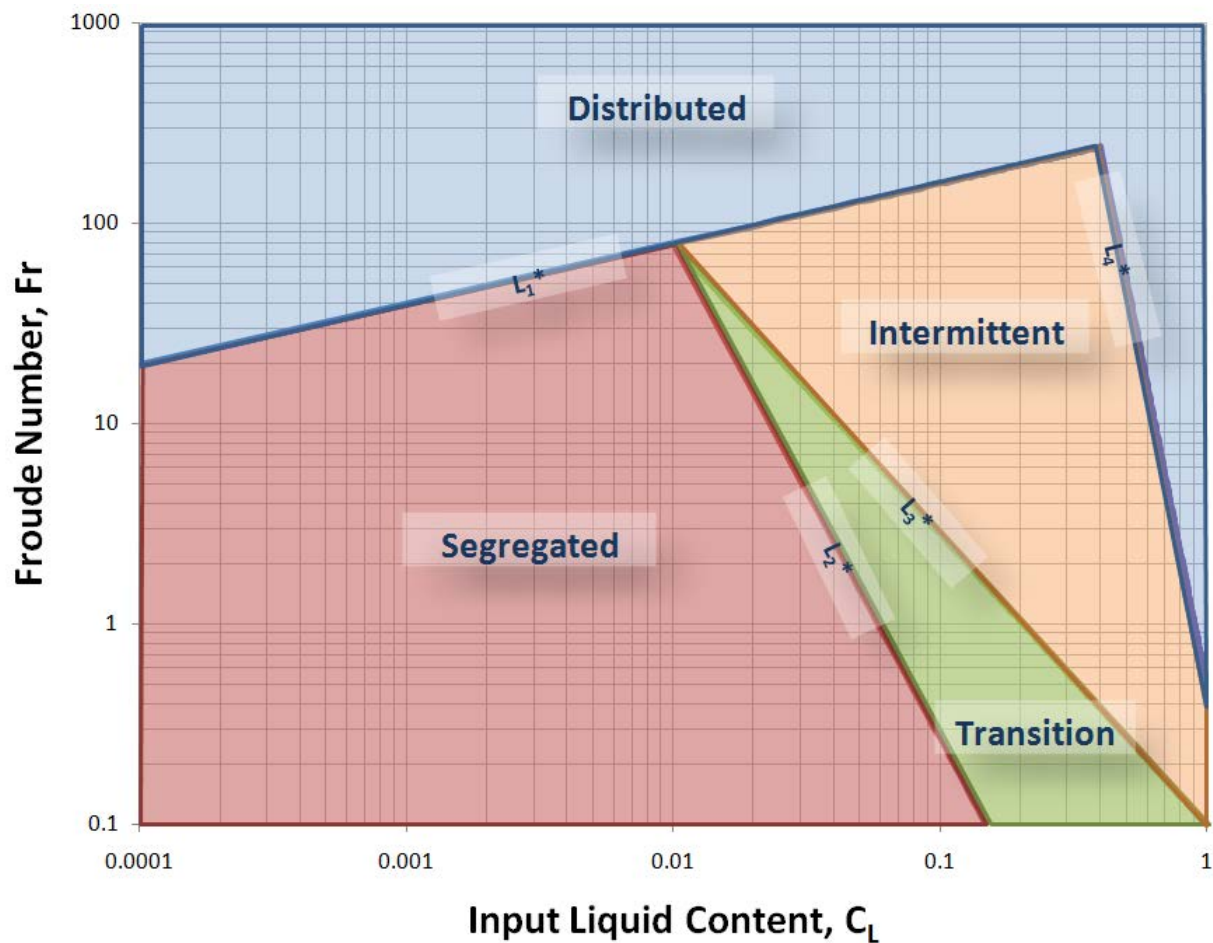
$$L_1^* = 316 C_L^{0.302}$$

$$L_2^* = 0.0009252 \; C_L^{-2.4684}$$

$$L_3^* = 0.1\ C_L^{-1.4516}$$

$$L_4^* = 0.5\ C_L^{-6.738}$$

The identified flow pattern is the one that would exist if the pipe were horizontal. Unless the pipe is actually in the horizontal position, the Beggs and Brill correlation is not able to recognize the actual flow pattern under the given conditions. Therefore, to calculate the liquid holdup, we first determine the liquid holdup for the horizontal flow, and this value is then corrected for the angle of interest.

The Froude number is a dimensionless number that relates the inertia with respect to the gravitational forces. For a mixture, it can be obtained by:

$$Fr_m = \frac{v_m^2}{gD}$$

Once the input liquid content (C_L) and Froude number of the mixture (Fr_m) are determined, the corresponding flow pattern is identified when the following inequalities are satisfied.

Segregated

$$_{\text{if}}\ C_L < 0.01\ and\ Fr_m < L_1^*$$

$$_{\text{or}}\ C_L \geq 0.01\ and\ Fr_m < L_2^*$$

Stratified

Wavy

Annular

Intermittent

$$_{if} \, 0.01 \leq C_L < 0.4 \, and \, L_3^* < Fr_m \leq L_1^*$$

$$_{or} \, C_L \geq 0.4 \, and \, L_3^* < Fr_m \leq L_4^*$$
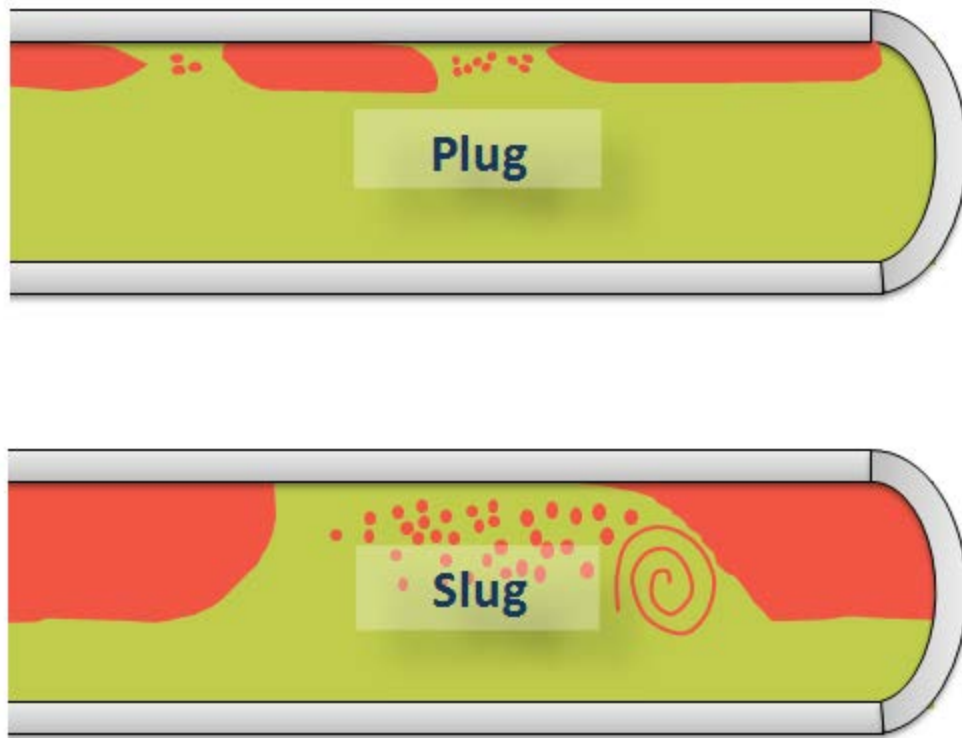
Distributed

$$_{if}\ C_L\ <\ 0.4\ and\ Fr_m\ \geq\ L_1^*$$

$$_{or}\ C_L\ \geq\ 0.4\ and\ Fr_m\ >\ L_4^*$$

Bubble

Mist

Transition

$$_{\text{if}} \; C_L \geq 0.01 \; and \; L_2^* < Fr_m < L_3^*$$

Hydrostatic Pressure Difference

Once the flow pattern has been determined, the liquid holdup is then calculated. Beggs and Brill divided the liquid holdup calculation into two parts. First, the liquid holdup for horizontal flow, $E_L(0)$, is determined. Afterward, this horizontal holdup is corrected for inclined flow to obtain the actual holdup, $E_L(\theta)$. The horizontal holdup must be $E_L(0) \geq C_L$. Therefore, in the event that $E_L(0) < C_L$, the horizontal holdup is set to $E_L(0) = C_L$. The expression used to calculate the horizontal holdup changes per flow pattern group as follows:

Segregated

$$E_L\left(0\right) = \frac{0.98 \; C_L^{0.4846}}{Fr_m^{0.0868}}$$

Intermittent

$$E_L\left(0\right) = \frac{0.845 \ C_L^{0.5351}}{F \ r_m^{0.0173}}$$

Distributed

$$E_L\left(0\right) = \frac{1.065 \ C_L^{0.5824}}{F \ r_m^{0.0609}}$$

Transition

$$E_L(0)_{transition} = A \ E_L(0)_{segregated} + B \ E_L(0)_{intermittent}$$

where:

$$A = \frac{L_3^* - Fr_m}{L_3^* - L_2^*}$$

$$B = 1 - A$$

Once the horizontal in-situ liquid volume fraction is determined, the actual liquid volume fraction is obtained by correcting $E_L(0)$ by an inclination factor $B(\theta)$:

$$E_L(\theta) = B(\theta) \cdot E_L(0)$$

where:

$$B\left(\theta\right) = 1 + \beta \left[\sin\left(1.8\,\theta\right) - \tfrac{1}{3}\sin^3\left(1.8\theta\right) \right]$$

β is a function of the flow pattern and is also related to the direction of inclination of the pipe (uphill or downhill flow).

For **uphill** flow

    Segregated

$$\beta = \left(1 - C_L\right) \ln \left[\frac{0.011 \, N_w^{3.539}}{C_L^{3.768} \, Fr_m^{1.614}}\right]$$

Intermittent

$$\beta = \left(1 - C_L\right) \ln \left[\frac{2.96 \, C_L^{0.305} \, Fr_m^{0.0978}}{N_w^{0.4473}}\right]$$

Distributed

β = 0

For **downhill** flow

ALL flow pattern groups

$$\beta = \left(1 - C_L\right) \ln \left[\frac{2.96 \, C_L^{0.305} \, Fr_m^{0.0978}}{N_w^{0.4473}}\right]$$

where Fr_m is the Froude number of the mixture and N_{Lv} is the liquid velocity number given by:

$$N_{Lv} = 1.938 \, v_{sL} \sqrt[4]{\frac{P_L}{\sigma}}$$

Note: β must always be ≥ 0. Therefore, if a negative value is calculated for β, β = 0.

Once the actual liquid holdup $E_L(\theta)$ is calculated, the mixture density ρ_m is obtained. Mixture density, in turn, is used to calculate the pressure change due to the hydrostatic head of the vertical component of the pipe or well.

$$\Delta P_{HH} = \frac{p_m \, g}{144 g_c} \, L \cdot \sin\left(\theta\right)$$

Beggs and Brill - Friction Pressure Loss

In order to calculate frictional losses, a normalizing friction factor (f_{NS}) is used. To determine f_{NS}, we use the Fanning friction factor calculated using the Chen equation. For this purpose, the no-slip

Reynolds number is used:

$$Re_{NS} = \frac{\rho_{NS} v_m D}{\mu_{NS}}$$

Based on experimental data, Beggs and Brill presented a correlation for the ratio of the two-phase friction factor (f_{tp}) and the normalizing (no-slip) friction factor resulting in the following exponential equation:

$$\frac{f_{tp}}{f_{NS}} = e^s$$

The value of S depends on the no-slip and the actual liquid holdup:

$$S = \frac{Ln\ y}{-0.0523 + 3.182 \left(Ln\ y \right) - 0.8725 \left(Ln\ y \right)^2 + 0.01853 (Ln\ y)^4}$$

where:

$$y = \frac{C_L}{(E_L)^2}$$

Severe instabilities have been observed when the equation for S is used as published. To solve for them, the following considerations are used:

- If y = 0, then S=0 (to ensure that the expression is reduced to single-phase liquid)
- If 1 < y < 1.2, then S = ln(2.2y − 1.2)

After a valid value for S has been found, you can solve for the two- phase friction factor:

$f_{tp} = f_{NS}e^s$

Finally, the expression for pressure loss due to friction is:

$$\Delta P_f = \frac{2 f_{tp}\ v_m^2\ \rho_{NS}\ L}{144 g_c\ D}$$

Gray Correlation

The Gray correlation was developed by H.E. Gray (1978) specifically for wet gas wells. Although this correlation was developed for vertical flow, we have implemented it to be used in both vertical and inclined pipe pressure-drop calculations. To correct pressure drop for situations with a horizontal

component, the hydrostatic head has only been applied to the vertical component of the pipe, while friction is applied to the entire length of pipe.

First, the in-situ liquid volume fraction is calculated. The in-situ liquid volume fraction is then used to calculate mixture density, which in turn is used to calculate the hydrostatic pressure difference. The input gas-liquid mixture properties are used to calculate an effective roughness of the pipe. This effective roughness is then used in conjunction with a constant Reynolds number of 10^7 to calculate the Fanning friction factor. The pressure difference due to friction is calculated using the Fanning friction pressure-loss equation.

Gray – Hydrostatic Pressure Difference

The Gray correlation uses three dimensionless numbers in combination to predict the in-situ liquid volume fraction. These three dimensionless numbers are:

$$N_1 = \frac{\rho_{NS}^2 \, v_m^4}{g \, \sigma_L^* \left(\rho_L - \rho_G \right)}$$

$$N_2 = \frac{g \, D^2 \left(\rho_L - \rho_G \right)}{\sigma_L^*}$$

$$N_3 = 0.0814 \left[1 - 0.0554 \ln \left(1 + \frac{730 \, R_v}{R_v + 1} \right) \right]$$

where:

$$R_v = \frac{v_{sL}}{v_{sG}}$$

$$\sigma_L^* = \alpha \frac{q_o \sigma_o + 0.617 q_w \sigma_w}{q_o + 0.617 q_w}$$

$$\alpha = \frac{0.00220462\left[\frac{lb_m}{s^2}\right]}{1\left[\frac{dyne}{cm}\right]}$$

The dimensionless numbers are then combined as follows:

$$E_L = 1 - (1 - C_L) \cdot (1 - e^{f_1})$$

where:

$$f_1 = -2.314\left[N_1\left(1 + \frac{205}{N_2}\right)\right]^{N_3}$$

Once the liquid holdup (E_L) is calculated, it is used to obtain the mixture density (ρ_m). Mixture density, in turn, is used to compute the pressure change due to the hydrostatic head of the vertical component of the pipe.

$$\Delta P_{HH} = \frac{p_m\, g}{144 g_c}\, L \cdot \sin(\theta)$$

Gray – Friction Pressure Loss

The Gray Correlation assumes that the effective (also known as apparent) roughness of the pipe (k_e) is dependent on the value of R_v. The conditions are as follows:

If Rv ≥ 0.007 then:

$k_e = k°$

if Rv < 0.007 then:

$$k_e = k + R_v\left[\frac{k^0 - k}{0.007}\right]$$

where:

$$k^o = \frac{28.5\,\sigma_L^*}{\rho_{NS}\,V_m^2}$$

$$R_v = \frac{v_{sL}}{v_{sG}}$$

and k is the absolute roughness of the pipe (single-phase dry gas flow). The resulting effective roughness (k_e) must be larger than or equal to 2.77×10^{-5}.

The relative roughness of the pipe is then calculated by dividing the effective roughness by the diameter of the pipe. The Fanning friction factor is obtained using the Chen equation and assumes a Reynolds number of 107. Finally, the expression for the friction pressure loss is:

$$\Delta P_f = \frac{2 f_{tp}\, v_m^2\, \rho_{NS}\, L}{144 g_c\, D}$$

Note: The original publication contains a misprint in the calculation of k_e: the constant should be 0.007 instead of 0.0007. We include this correction in our calculations. Additionally, the volume of water condensation is estimated using Bukacek's correlation (including the corrections by McKetta and Wehe) and is considered in the pressure-drop calculations.

Hagedorn and Brown

Experimental data obtained from a 1500 ft deep instrumented vertical test well was used in the development of the Hagedorn and Brown correlation. Pressures were measured for flow in tubing sizes of 1 ", 1 ¼" and 1 ½" OD. A wide range of liquid rates and gas / liquid ratios were used. As with the Gray correlation, our software calculates pressure drops for horizontal and inclined flow using the Hagedorn and Brown correlation, although the correlation was developed strictly for vertical wells. The software uses only the vertical depth to calculate pressure loss due to hydrostatic head, and the entire pipe length to calculate friction.

The Hagedorn and Brown method has been modified for the bubble flow regime (Economides et al, 1994). If bubble flow exists, the Griffith correlation is used to calculate the in-situ volume fraction. In such cases, the Griffith correlation is also used to calculate pressure drop due to friction. If bubble flow does not exist, then the original Hagedorn and Brown correlation is used to calculate the in-situ liquid volume fraction. Once the in-situ volume fraction is determined, it is compared with the input volume fraction. If the in-situ volume fraction is smaller than the input volume fraction, the in-situ fraction is set to equal the input fraction ($E_L = C_L$). Next, the mixture density is calculated using the in-situ volume fraction and used to calculate the hydrostatic pressure difference. The pressure difference due to friction is calculated using a combination of in-situ and input gas-liquid mixture properties.

Hagedorn and Brown - Hydrostatic Pressure Difference

The Hagedorn and Brown correlation uses four dimensionless parameters (based on the work of Duns and Ros) to correlate liquid holdup. These four parameters are:

$$N_{Lv} \; = \; 1.938 v_{sL} \sqrt[4]{\frac{\rho_L}{\sigma}}$$

$$N_{Gv} \; = \; 1.938 v_{sG} \sqrt[4]{\frac{\rho_L}{\sigma}}$$

$$N_d \; = \; 120.872 \, D \sqrt{\frac{\rho_L}{\sigma}}$$

$$N_d \; = \; 0.15726 \; \mu_L \sqrt[4]{\frac{1}{\rho_L \, \sigma^3}}$$

The method of calculation is based on the use of several plots where various combinations of these parameters are calculated and plotted against some correlated terms to determine the liquid holdup. For programming purposes, these curves were discretized into equations.

The first curve provides a value for a dimensionless parameter called N_{LC}, which is correlated with the dimensionless number N_{LL}. Therefore, once N_L is calculated, it is possible to obtain N_{LC} from the following plot:
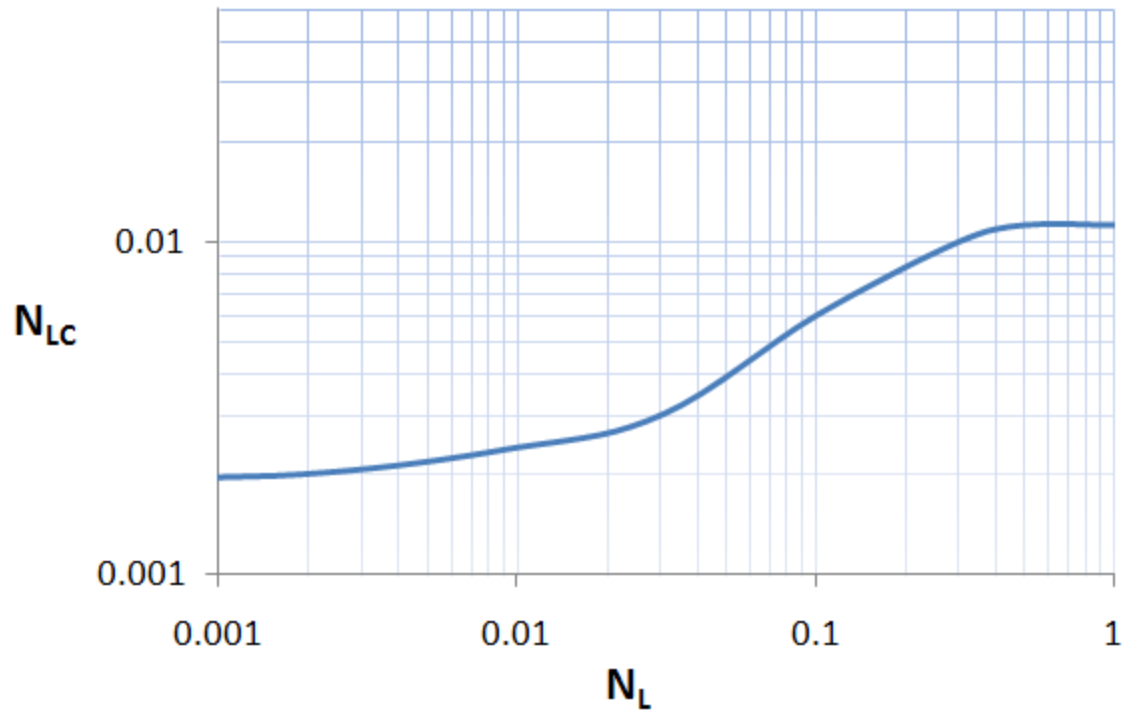
The value of N_{LC} is then used to calculate the dimensionless number, $\overline{X}_h$:

$$\overline{X_h} = \left(\frac{N_{Lv}}{N_{Gv}^{0.575}} \right) \left(\frac{\rho}{\rho_{sc}} \right)^{0.10} \left(\frac{N_{LC}}{N_d} \right)$$

The next plot contains a curve correlating the liquid holdup divided by a correction factor (E_L / Ψ) against the dimensionless group, $\overline{X}_h$. After $\overline{X}_h$ is calculated, you can then find the value of E_L / Ψ by making use of the following plot:
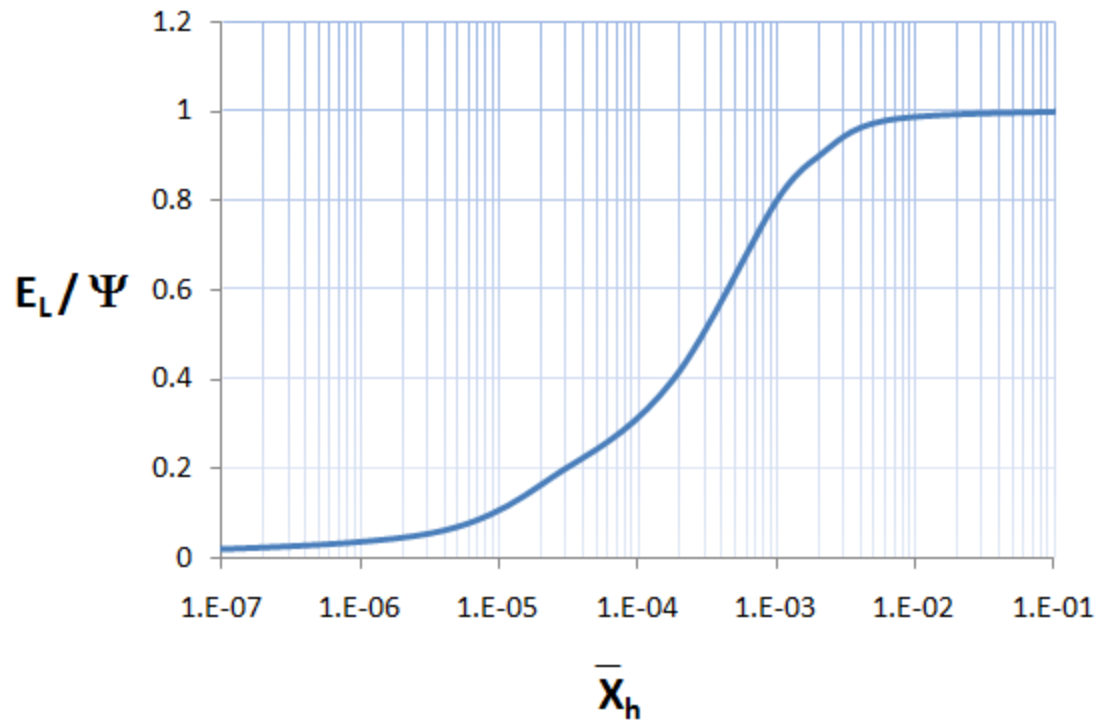
Finally, the third curve correlates the correction factor Ψ with the dimensionless number, $\overline{X}_\Psi$:

$$\overline{X}_\Psi = \frac{N_{Gv}\, N_L^{0.38}}{N_d^{2.14}}$$

A typical discretized curve to find Ψ can be as follows:
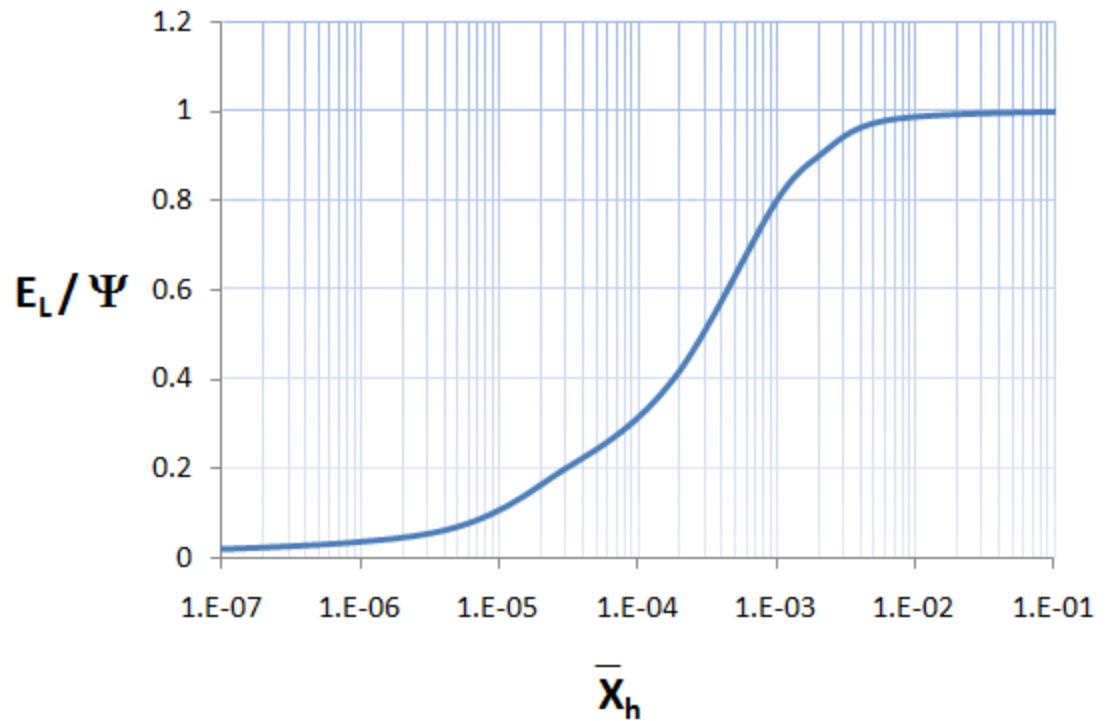
After finding Ψ, the in-situ liquid volume fraction (E_L) can be calculated taking the previously found E_L / Ψ:

$$E_L = \left(\frac{E_L}{\Psi}\right) \cdot \Psi$$

We have implemented a correction to replace the liquid holdup value with the "no-slip" (input) liquid volume fraction, if the calculated liquid holdup is less than the no-slip liquid volume fraction:

if $E_L < C_L$, then $E_L = C_L$

After finding E_L, the hydrostatic head is calculated by the standard equation:

$$\Delta P_{HH} = \frac{p_m\, g}{144 g_c} L \cdot \sin(\theta)$$

where:

$\rho_m = \rho_L\, E_L + \rho_G\, (1 - E_L)$

Hagedorn and Brown - Friction Pressure Loss

The friction factor is calculated using the Chen equation using a Reynolds number equal to:

$$R_e = \frac{\rho_{NS} V_m D}{\mu_m}$$

Note: In the Hagedorn and Brown correlation, mixture viscosity is given by:

$$\mu_m = \mu_L{}^{E_L} \mu_G{}^{(1-E_L)}$$

The pressure loss due to friction is then given by:

$$\Delta P_f = \frac{2f \rho_f v_m^2 L}{144 g_c D}$$

where:

$$\rho_f = \frac{\rho_{NS}^2}{\rho_m}$$

Modification to the Hagedorn and Brown Correlation: the Griffith Correlation for Bubble Flow

The Hagedorn and Brown correlation makes use of the Griffith correlation (1961) for the bubble flow regime. Bubble flow exists if $C_G < L_B$, where:

$$L_B = 1.071 - 0.2218 \left(\frac{v_m^2}{D} \right)$$

If the calculated value of L_B is less than 0.13, then L_B is set to 0.13. If the flow regime is found to be bubble flow, then the Griffith correlation is applied. Otherwise, the original Hagedorn and Brown correlation is used.

In the Griffith correlation, liquid holdup is given by:

$$E_L = 1 - \frac{1}{2} \left[1 + \frac{v_m}{v_s} - \sqrt{\left(1 + \frac{v_m}{v_s}\right)^2 - 4\left(\frac{v_{sg}}{v_s}\right)} \right]$$

Griffith suggested a constant value of v_s = 0.8 ft/s as a good average value, which is the one considered in our calculations.

The true in-situ liquid velocity is given by:

$$v_L = \frac{v_{sL}}{E_L}$$

The hydrostatic head is then calculated the standard way.

The pressure drop due to friction is also affected by the use of the Griffith correlation because E_L enters into the calculation of the Reynolds number via the in-situ liquid velocity. The Reynolds number is calculated using the following format:

$$Re_L = \frac{\rho_L \, v_L \, D}{\mu_L}$$

The single-phase liquid density, in-situ liquid velocity, and liquid viscosity are used to calculate the Reynolds number. This is unlike the majority of multiphase correlations, which usually define the Reynolds number in terms of mixture properties rather than single-phase liquid properties. The Reynolds number is used to calculate the friction factor using the Chen equation. The liquid density and the in-situ liquid velocity are then used to calculate the pressure drop due to friction:

$$\Delta P_f = \frac{2f \, \rho_f \, v_L^2 \, L}{144 g_c \, D}$$

Petalas and Aziz Mechanistic Model

The Petalas and Aziz mechanistic model (2000) was not built for a specific set of data or fluid properties. Instead, the authors applied first principles to the possible flow patterns that can be observed at different inclinations. For this reason, it is applicable to any 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 method could be summarized as follows:

- Assume the existence of a flow pattern
- Evaluate if this flow pattern is stable:
  - If the check fails, go back and select another flow pattern
  - If stable conditions are met, go ahead with the calculation of liquid holdup and the friction factor

- Calculate pressure losses using the found values for the friction factor and liquid hol-dup

With the continuous evaluation of the stability of the flow patterns, you can create the corresponding flow-pattern map to the given flowing conditions. This screenshot shows a typical flow-pattern map for vertical upward gas-oil flow:
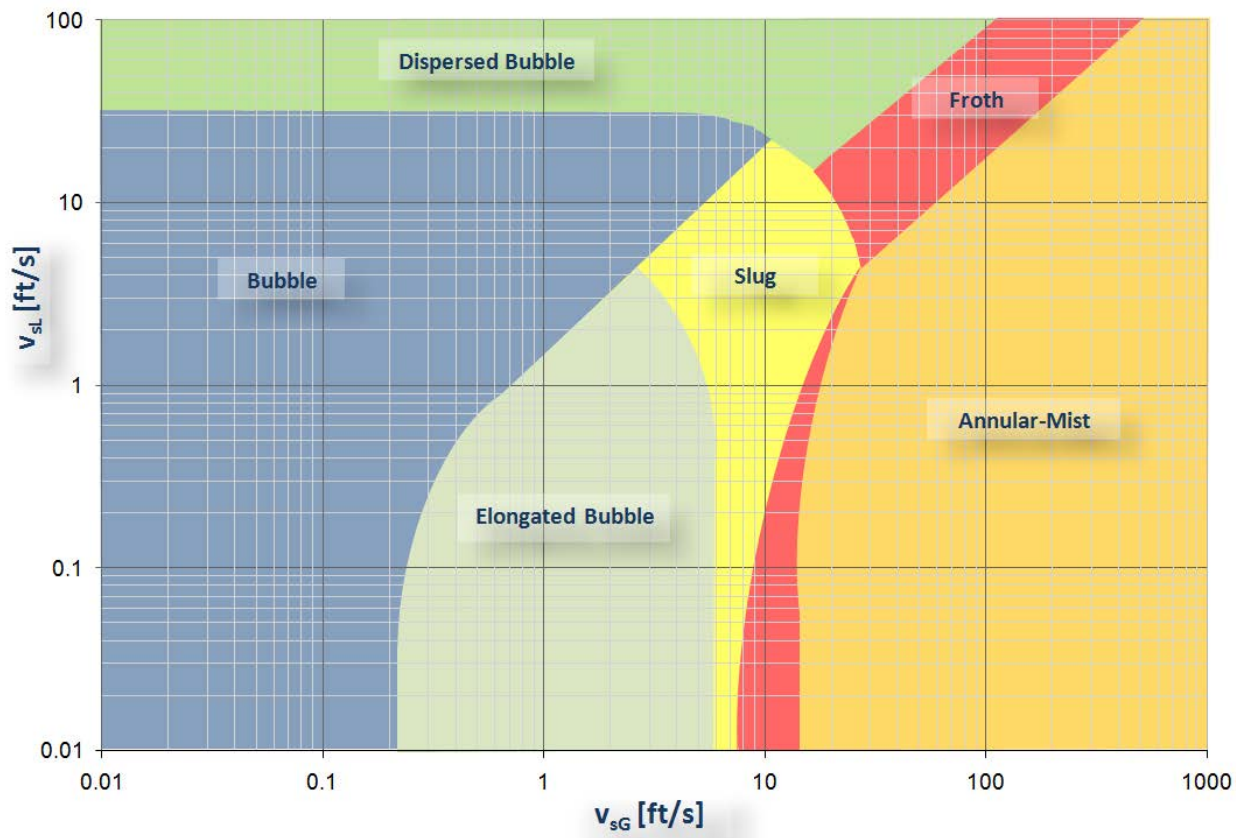
Flow Pattern Map

Dispersed Bubble flow

In order to have dispersed bubble flow, two requirements must be fulfilled.

The first criterion is based on Barnea's transition from dispersed to slug flow while using the slug liquid holdup calculation based on Gregory et al:

$$\frac{1}{1+\left(\frac{v_m}{8.66}\right)^{1.39}} < 0.48$$

where:

$$v_m = v_{sG} + v_{sL}$$

Also, to be able to sustain dispersed bubble flow, the ratio of the superficial gas velocity with respect to the mixture velocity should be:

$$\frac{v_{sG}}{v_m} > 0.52$$

Stratified Flow

The consideration here is that stratified flow can be possible only in downward (downhill) or horizontal flow. A momentum balance is obtained based on the one proposed by Taitel and Dukler. The first step consists in calculating $\tilde{h}_L$ (dimensionless liquid height) by solving:

$$-A_L \left(\frac{dp}{dL} \right) - \tau_{wL} S_L + \tau_i S_i - p_L A_L \left(\frac{g}{g_c} \right) \sin(\theta) = 0$$

$$-A_G \left(\frac{dp}{dL} \right) - \tau_{wG} S_G - \tau_i S_i - p_G A_G \left(\frac{g}{g_c} \right) \sin(\theta) = 0$$

where:

$$\tau_{wG} = \frac{f_G \, \rho_G \, v_G^2}{2 g_c}$$

$$\tau_{wL} = \frac{f_L \, \rho_L \, v_L^2}{2 g_c}$$

$$\tau_{wi} = \frac{f_i \, \rho_G \, v_i \, |v_i|}{2 g_c}$$

and

f_G is obtained from standard methods where:

$$Re_G = \frac{\rho_G \, v_G \, D_G}{\mu_G}$$

where the hydraulic diameter of the gas phase, D_G, is obtained by:

$$D_G = \frac{4 \, A_G}{S_G + S_i}$$

f_L from:

$$f_L = 0.452 \, f_{sL}^{0.731}$$

where f_{sL} is a friction factor based on the superficial velocity, which is calculated from standard methods using the pipe roughness and the Reynolds number:

$$Re_{sL} = \frac{\rho_L \, v_{sL} \, D}{\mu_L}$$

f_i from:

$$f_i = \left(0.004 + 0.5 \cdot 10^{-6} \, Re_{sL} \right) Fr_L^{1.335} \left(\frac{\rho_L \, D_G}{\rho_G \, v_G^2} \right)$$

using a liquid Froude number defined as:

$$Fr_L = \frac{v_L}{\sqrt{gh_L}}$$

use Lockhart-Martinelli parameters:

$$X^2 \, F_2 - F_1 - 4Y = 0$$

where:

$$X^2 = \frac{\left(\frac{\delta P}{\delta L} \right)_{sL}}{\left(\frac{\delta P}{\delta L} \right)_{sG}} = \frac{f_{sL} \, v_{sL}^2 \, \rho_L}{f_{sG} \, v_{sg}^2 \, \rho_G}$$

$$Y = \frac{(\rho_L - \rho_G)\, g\, \sin(\theta)}{\left(\frac{\delta P}{\delta L}\right)_{sG}} = \frac{(\rho_L - \rho_G)\, g\, \sin(\theta)}{2 f_{sG}\, v_{sG}^2 \rho_G}$$

$$F_1 = \left(\frac{f_G}{f_{sG}}\right) \tilde{v}_G^2 \left[\frac{\widetilde{S}_G}{\widetilde{A}_G} + \frac{f_i}{f_G} \frac{\tilde{v}_i \,|\, \tilde{v}_i\,|}{\tilde{v}_G} \left(\frac{\widetilde{S}_i}{\widetilde{A}_G} + \frac{\widetilde{S}_i}{\widetilde{A}_L} \right) \right]$$

$$F_2 = \frac{f_L}{f_{sL}} \tilde{v}_L^2 \frac{\widetilde{S}_L}{\widetilde{A}_L}$$

where:

$$\tilde{v}_i = \tilde{v}_G - \tilde{v}_L$$

with the geometric variables:

$$\tilde{h}_L = \frac{h_L}{D}$$

$$\widetilde{S}_L = \frac{S_L}{D}$$

$$\widetilde{A}_L = \frac{A_L}{D^2}$$

$$\widetilde{A}_G = \frac{A_G}{D^2}$$

$$\tilde{v}_L = \frac{v_L}{v_{sL}}$$

$$\tilde{v}_G = \frac{v_G}{v_{sG}}$$

$$\tilde{v}_L = \frac{\tilde{A}}{\tilde{A}_L}$$

Solve for h_L / D iteratively. Afterwards, we verify that stratified flow exists if:

$$v_G = \left(1 - \frac{h_L}{D}\right) \sqrt{\frac{(\rho_L - \rho_G)\ g\ A_G\ \cos(\theta)}{\rho_G \frac{d\ A_L}{dh_L}}}$$

and if:

$$v_L > \sqrt{\frac{g\ D(1 - \tilde{h}_L)\ \cos(\theta)}{f_L}}$$

Note: When cosθ ≤ 0.02, then, cosθ = 0.02.

To distinguish between stratified smooth and stratified wavy flow regimes:

stratified smooth flow exists if:

$$v_G \leq \sqrt{\frac{4\ \mu_L(\rho_L - \rho_G)\ g\ \cos(\theta)}{s\ \rho_L\ \rho_G\ v_L}}$$

where s=0.06, and if:

$$F_r = \frac{v_L}{\sqrt{g\,h_L}} > 1.4$$

Annular-Mist Flow

Calculate the dimensionless liquid film thickness ($\tilde{\delta}_L$), making the momentum balance on the liquid film and gas core with liquid droplets:

$$-A_f \left(\frac{dp}{dL} \right) - \tau_{wL} S_L + \tau_i S_i - p_L A_L \left(\frac{g}{g_c} \right) \sin(\theta) = 0$$

$$-A_c \left(\frac{dp}{dL} \right) - \tau_i S_i - p_c A_c \left(\frac{g}{g_c} \right) \sin(\theta) = 0$$

Annular-mist flow exists if:

$$\tilde{\delta}_L < \tilde{\delta}_{L, \min}$$

where $\tilde{\delta}_{L, \min}$ is determined from the following equations:

$$2 f_f \frac{\rho_L}{(\rho_L - \rho_c)} \frac{v_{sL}^2}{g D \sin(\theta)} = \frac{E_f^3 \left(1 - \frac{3}{2} E_f \right)}{2 - \frac{3}{2} E_f}$$

$$E_f = \frac{A_f}{A} = 4 \tilde{\delta}_L \left(1 - \tilde{\delta}_L \right)$$

Solve for $\tilde{\delta}_{L, \min}$ iteratively.

Bubble Flow

Bubble flow exists if:

$$D > 19 \left[\frac{(\rho_L - \rho_G)}{g \rho_L^2} \right]^{\frac{1}{2}}$$

and if:

$$\cos(\theta) \leq \frac{3}{4\sqrt{2}} v_b^2 \left(\frac{C_1 Y^2}{g\, d_b} \right)$$

where:

  $C_1 = 0.8$

  $Y = 1.3$

  $d_b = 7\text{mm}$

with:

$$v_b = 1.41 \left[\frac{g\,(\rho_L - \rho_G)\,\sigma}{\rho_L^2} \right]^{\frac{1}{4}} \sin(\theta)$$

Also, transition to bubble flow from intermittent flow occurs when:

  $E_L > 0.25$

where:

$$E_L = \frac{E_{LS}\, v_t + v_{Gdb}(1 - E_{LS}) - v_{sG}}{v_t}$$

Intermittent Flow

Note: The intermittent flow model used here includes slug and elongated bubble flow regimes.

Intermittent flow exists if:

  $E_L > 0.24$

where:

$$E_L = \frac{E_{LS} v_t + v_{Gdb}(1 - E_{LS}) - v_{sG}}{v_t}$$

If $E_L > 1$, then $E_L = C_L$.

and if:

$$E_L = \frac{1}{1 + \left(\dfrac{v_m}{8.66}\right)^{1.39}}$$

where:

$v_m = v_{sL} + v_{sG}$

- If $E_L L > 0.24$ and $ELs < 0.9$, then slug flow

- If $E_L > 0.24$ and $ELs > 0.9$, then elongated bubble flow

Froth Flow

If none of the transition criteria for intermittent flow are met, the flow pattern is then designated as froth. Froth flow implies a transitional state between the other flow regimes.

Recombination

Many gas-condensate systems exist as a single-phase liquid in the reservoir. Condensation generally takes place at the separator, in the wellbore, or in the reservoir very near the wellbore. When modeling gas condensate systems at reservoir conditions, gas and condensate rates measured at surface conditions are combined into a single-phase rich gas using recombination.

The recombination calculation takes the volume of condensate, vaporizes it, and adds it to the gas volume to obtain a single-phase rich gas as it exists in the reservoir. A recombined gas gravity is also calculated for use in analytical models.

Given the specific gravity of measured separator gas, the condensate gas ratio (CGR), and the specific gravity of the condensate, the recombined gas gravity can be calculated using the following equation:

$$G_{Rec} = \frac{\frac{10^6 * G}{CGR} + 4602\gamma_o + Q_{pa}}{\frac{10^6}{CGR} + V_{eq}}$$

Where:

$$Q_{pa} = 1.4599(p - 14.65)^{1.3394} G^{7.0943} \gamma_{API}^{1.1436} T^{-0.93446}$$

$$V_{eq} = 635.53 + 0.36182 p^{1.0544} G^{5.0831} \gamma_{API}^{1.5812} T^{-0.79130}$$

The recombined gas rate is calculated using the following equation:

$$q_{Recombined} = q_{Measured} \left(1 + \frac{V_{eq} CGR}{10^6} \right)$$

The recombined gas rate factor (RGRF) is defined as recombined gas rate divided by the measured gas rate:

$$RGRF = \frac{q_{Recombined}}{q_{Measured}}$$

Relative permeability correlations

Relative permeability correlations

There are two types of relative permeability correlations: 2-phase models and 3-phase models.

2-phase models

Corey: This model assumes the wetting and non-wetting phase relative permeabilities to be independent of the saturations of the other phases, and requires only a single suite of gas / oil relative permeability data.

Honarpour: Developed using data from oil and gas fields in the continental US, Alaska, Canada, Libya, Iran, Argentina, and the United Arab Republic.

Generalized-Corey: Similar to the Corey correlation, but developed for a wider range of rock and wettability characteristics.

Custom Table: Allows you to enter laboratory measurements for 2-phase relative permeability.

3-phase models

Stone 1: Based on the channel flow theory, and it is used widely in the industry as the benchmark for oil simulation. It is a better predictor than Stone 2 in low oil-saturation regions. More appropriate for water-wet systems, and not suited for intermediate wettability.

Stone 2: A modified version of Stone 1. It is a better predictor than Stone 1 in high-oil saturation regions. More appropriate for water wet-systems, and not suited for intermediate wettability.

Baker: Based on saturation-weighted interpolation between the 2-phase relative permeability values. Well suited for intermediate wettabilty or oil-wet systems.

Two-phase correlations

In a two-phase system, the fluids consist of oil and water, oil and gas, or gas and water. An example of an oil-water system is shown below:
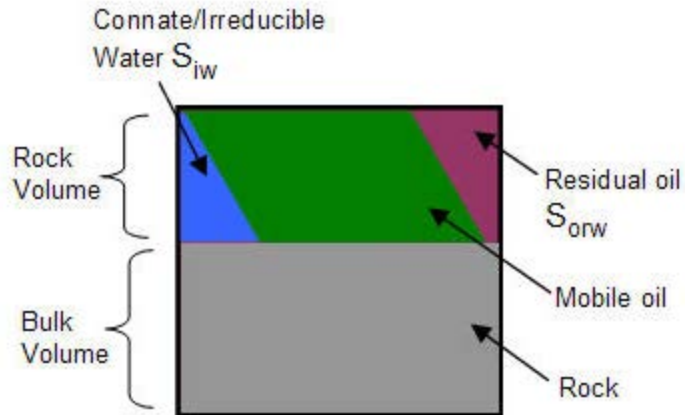
Corey

This model assumes the wetting and non-wetting phase-relative permeabilities to be independent of the saturations of the other phases and requires only a single suite of gas / oil relative permeability data.

Water / oil system

$$k_{ro} = \left[\frac{1-S_o}{1-S_{iw}}\right]^2 \left[1 - \left(\frac{S_o - S_{iw}}{1-S_{iw}}\right)^2\right]$$

$$k_{rw} = \left[\frac{S_w - S_{iw}}{1-S_{iw}}\right]^4$$

Gas / oil system

$$k_{rg} = \left[\frac{S_g}{1-S_{org}}\right]^2 \left[1 - \left(\frac{1-S_g - S_{org}}{1-S_{org}}\right)^2\right]$$

$$k_{ro} = \left[\frac{S_o - S_{org}}{1-S_{org}}\right]^4$$

Gas / Water System

$$k_{rg} = \left[\frac{S_g}{1-S_{iw}}\right]^2 \quad \left[1 - \left(\frac{1-S_g-S_{iw}}{1-S_{iw}}\right)^2\right]$$

$$k_{rw} = \left[\frac{S_w-S_{iw}}{1-S_{iw}}\right]^4$$

Honarpour

Developed using data from oil & gas fields in the continental US, Alaska, Canada, Libya, Iran, Argentina, and the United Arab Republic.

Sandstone

Water wet

$$k_{rw} = 0.035388\left[\frac{S_w-S_{iw}}{1-S_{iw}-S_{orw}}\right] - 0.0108074\left[\frac{S_w-S_{orw}}{1-S_{iw}-S_{orw}}\right]^{2.9} + 0.56556(S_w)^{3.6}\left(S_w - S_{iw}\right)$$

Intermediate wet

$$k_{rw} = 1.5814\left[\frac{S_w-S_{iw}}{1-S_{iw}}\right]^{1.91} - 0.58617\left[\frac{S_w-S_{orw}}{1-S_{iw}-S_{orw}}\right]^{2.9}\left(S_w - S_{iw}\right) + 1.2484\,\phi\left(1 - S_{iw}\right)\left(S_w - S_{iw}\right)$$

Any wettability

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

$$k_{rog} = 0.98372\left[\frac{S_o}{1-S_{iw}}\right]^4\left[\frac{S_o-S_{org}}{1-S_{iw}-S_{org}}\right]^2$$

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

Limestone

Water wet

$$k_{rw} = 0.0020525 \left[\frac{S_w - S_{iw}}{\phi^{2.15}} \right] - 0.051371 \left[\frac{S_w - S_{iw}}{k_{abs}^{0.43}} \right]$$

Intermediate wet

$$k_{rw} = 0.29986 \left[\frac{S_w - S_{iw}}{1 - S_{iw}} \right] - 0.32797 \left[\frac{S_w - S_{orw}}{1 - S_{iw} - S_{orw}} \right]^2 \left(S_w - S_{iw} \right) + 0.413259 \left[\frac{S_w - S_{iw}}{1 - S_{iw} - S_{orw}} \right]^4$$

Any wettability

$$k_{row} = 1.2624 \left[\frac{S_o - S_{orw}}{1 - S_{orw}} \right] \left[\frac{S_w - S_{iw}}{1 - S_{iw} - S_{orw}} \right]^2$$

$$k_{rog} = 0.93752 \left[\frac{S_o}{1 - S_{iw}} \right]^4 \left[\frac{S_o - S_{org}}{1 - S_{iw} - S_{org}} \right]^2$$

$$k_{rg} = 1.8655 S_g \left[\frac{S_g - S_{gc}}{1 - S_{iw}} \right] k_{rgro} + 8.0053 (S_{org})^2$$

$$\left[\frac{S_g - S_{gc}}{1 - S_{iw}} \right] - 0.025890 \left(S_g - S_{gc} \right) \left[\frac{1 - S_{iw} - S_{org} - S_{gc}}{1 - S_{iw}} \right]^2 \left[1 - \frac{1 - S_{iw} - S_{org} - S_{gc}}{1 - S_{iw}} \right]^2 \left[\frac{k_{abs}}{\phi} \right]^{0.5}$$

Generalized Corey

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

Gas / oil system

$$k_{rog} = k_{rocw} \left[\frac{S_o - S_{iw} - S_{org}}{1 - S_{iw} - S_{org}} \right]^{n_{og}}$$

$$k_{rgo} = k_{rgro} \left[\frac{S_g - S_{go}}{1 - S_{gc} - S_{iw} - S_{org}} \right]^{n_g}$$

Gas / water system

$$k_{rg} = k_{rgcw} \left[\frac{S_g - S_{gc}}{1 - S_{gc} - S_{iw}} \right]^{n_g}$$

$$k_{rw} = k_{rwgc} \left[\frac{S_w - S_{iw}}{1 - S_{iw}} \right]^{n_w}$$

Water / oil system

$$k_{ro} = k_{rocw} \left[\frac{1 - S_w - S_{orw}}{1 - S_{iw} - S_{orw}} \right]^{n_{ow}}$$

$$k_{rw} = k_{rwro} \left[\frac{S_w - S_{iw}}{1 - S_{iw} - S_{orw}} \right]^{n_w}$$

Three-phase correlations

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

Stone I

This probability model estimates three-phase permeability data from laboratory measured two-phase data. It uses the channel flow theory in porous media to obtain a simple result for determining the relative permeability to oil in the presence of water and gas flow. The model implies that water-relative permeability and water-oil capillary pressure in three-phase systems are functions of water saturation alone, regardless of the relative saturations of oil and gas. 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 as the benchmark for oil simulation. It is a better predictor than Stone 2 in low oil saturation regions, is more appropriate for water-wet systems, and is not suited for intermediate wet systems.

$$S_o^* = \frac{S_o - S_{orw}}{1 - S_{iw} - S_{orw}}$$

$$S_w^* = \frac{S_w - S_{iw}}{1 - S_{iw} - S_{orw}}$$

$$S_g^* = \frac{S_g}{1 - S_{iw} - S_{orw}}$$

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

Stone II

Stone's Model II is a modified version of Stone I. It is a better predictor than Stone 1 in high-oil saturation regions. It is more appropriate for water-wet systems, and is not suited for intermediate wet systems.

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

Baker

Baker's three-phase model is based on saturation-weighted interpolation between the two-phase relative permeability values. It is well suited for intermediate wet or oil-wet systems.

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

Water correlations

Correlations

Meehan: Generally applicable to calculate water properties while accounting for salinity.

Constant Properties: Allows you to enter values for the solution water gas ratio, water formation volume factor, water compressibility, and water viscosity at initial reservoir conditions.

Custom Table: Allows you to enter laboratory measurements for water properties.

Meehan (generally applicable)

Water compressibility is affected by the presence of solution gas, which evolves below the bubble point. The bubble point pressure of a gas-saturated brine is equal to the bubble point pressure of the co-existing oil. In a gas / water system, the water is considered to be at its bubble point at the initial reservoir pressure. Meehan presented an empirical correlation to determine the isothermal compressibility coefficient of gas-free water and gas-saturated water.

Compressibility

Gas-fee water

$$c_{T,wf} = 10^{-6} \left(A + BT + CT^2 \right)$$

where:

A = 3.8546 − 0.000134

B = -0.01052 + 4.77 * 10^{-7} p

B = $-0.01052 + 4.77 * 10^{-7}$ p

C = $3.9267 * 10^{-5} - 8.8 * 10^{-10}$ p

Gas-saturated water

$$c_{T,wg} = c_{T,wf}\left(1.0 + 8.9 + 10^{-3}\,R_{sw}\right)$$

where R_{sw} is the gas solubility in water

Saline solution

$c_{T,w} = c_{T,wg} * C_z$

$$C_z = 1.0 + \left(-0.052 + 2.7 \cdot 10^{-4}T - 1.14 \cdot 10^{-6}T^2 + 1.121 \cdot 10^{-9}T^3\right)S^{0.7}$$

where S is the salinity of saline solution (brine)

General concepts

General concepts include the following:
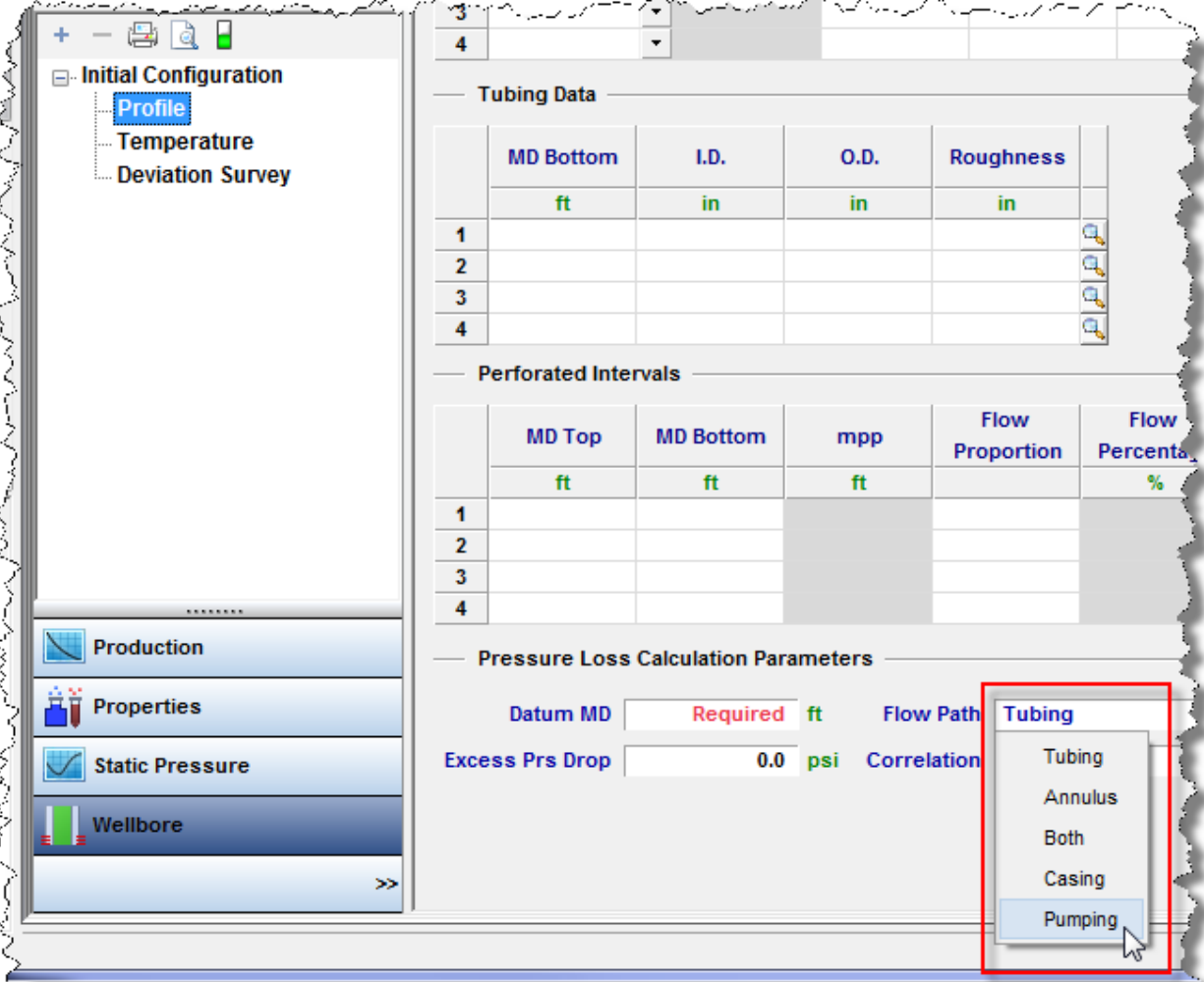
- Artificial lift
- Automatic parameter estimation theory
- Capillary pressure
- Continuous time track
- Data diagnostics theory
- Data diagnostics flowchart
- Equivalence of constant rate / pressure
- Fracture properties
- Geomechanical reservoir models
- GIS theory
- Interpolation theory

- Langmuir isotherm
- Material balance time theory
- Probabilistic
- Pseudo-pressure
- Pseudo-time
- Relative permeability
- Reserve evaluation
- Reservoir flow
- Reservoir fluid types
- Reservoir properties

- Shale properties
- Terminal / limiting decline rate
- Time-dependent skin
- Time to stabilization
- Water drive reservoir

Artificial lift

Pumping

For pumping wells with recorded liquid levels, use the Pumping flow path.

Open the <u>Wellbore editor</u>, and click **Profile**. Click the **Flow Path** drop-down menu in the Pressure Loss Calculation Parameters section, and select **Pumping**.

The Pumping flow path makes the assumption that all liquids are pumped up the tubing (the wellbore requires a tubing string), that all gas is produced up the annulus, and that the pump is at the end of tubing (EOT). The Pumping flow path ignores tubing pressures; only entered or imported casing pres-

sures are used to perform wellbore calculations. The final calculated sandface pressure is determined by breaking up the wellbore into individual sections.

A flowing row in the Production editor is a row that contains production information (gas or liquid). A non-flowing (shut-in) row has a value of "0" or null (that is, blank) for all volumes / rates.

With tubing landed below datum:

- The pressure drop is determined from the wellhead to the top of the liquid level using single-phase gas.

- Then, the hydrostatic pressure drop is determined from the top of the liquid level to the datum by multiplying the height of the liquid column by the liquid gradient.

With tubing landed above datum:

- The pressure drop is determined from the wellhead to the top of the liquid level using single-phase gas.

- The hydrostatic pressure drop is determined from the top of the liquid level to the end of tubing by multiplying the height of the liquid column by the liquid gradient.

- Finally, a multiphase flowing gradient is performed from the EOT to the datum.

The following columns are available in the Production editor:

- Liquid Level (MD)

- Liquid Level (TVD)

- Gas Gradient

- Water Gradient

- Oil Gradient

- Emulsion Gradient

- Average Liquid Gradient

Harmony Enterprise calculates and displays the average gradient for gas, oil, and water. Based on the water-oil ratio (WOR), it then calculates and displays an Emulsion Gradient (if applicable). Finally, Harmony Enterprise divides the entire hydrostatic pressure drop of the liquid column by the column height to determine the average liquid gradient. You can overwrite any and all gradients, with the exception of the emulsion gradient, which is a calculated value.

Calculated sandface pressure for a flowing row:

	Start Date	End Date	Gas Volume	Oil Volume	Water Volume	Casing Pressure	Pressure Source	Calculated Sandface Pressure	Liquid Level (MD)	Average Liquid Gradient	Gas Gradient	Oil Gradient	Water Gradient	Emulsion Gradient
	DD/MM/YYYY	DD/MM/YYYY	MMscf	stb	stb	psi(a)		psi(a)	ft	psi/ft	psi/ft	psi/ft	psi/ft	psi/ft
1	01/01/2012	02/01/2012	1.000	10.0	10.0	300.00	Casing Pressure ▾	583.54	9500.00	0.340	0.011	0.340		

In cases where oil and water rates are entered, Harmony Enterprise assumes that when the well is flowing, only the lightest liquid (oil) is present in the static liquid column. Therefore, a water and emulsion gradient is not displayed, and the Average Liquid Gradient value is identical to the Oil Gradient.

Calculated sandface pressure for a shut-in row:

	Start Date	End Date	Gas Volume	Oil Volume	Water Volume	Casing Pressure	Pressure Source	Calculated Sandface Pressure	Liquid Level (MD)	Average Liquid Gradient	Gas Gradient	Oil Gradient	Water Gradient	Emulsion Gradient
	DD/MM/YYYY	DD/MM/YYYY	MMscf	stb	stb	psi(a)		psi(a)	ft	psi/ft	psi/ft	psi/ft	psi/ft	psi/ft
1	01/01/2012	02/01/2012	1.000	10.0	10.0	300.00	Casing Pressure ▾	583.54	9500.00	0.340	0.011	0.340		
2	02/01/2012	03/01/2012	0.000	0.0	0.0	300.00	Casing Pressure ▾	616.32	9500.00	0.351	0.007	0.340	0.417	0.379
3	03/01/2012	04/01/2012	0.000	0.0	0.0	300.00	Casing Pressure ▾	814.67	9000.00	0.374	0.007	0.358	0.396	0.377
4	04/01/2012	05/01/2012	0.000	0.0	0.0	300.00	Casing Pressure ▾	995.70	8500.00	0.372	0.008	0.351	0.403	0.377
5	05/01/2012	06/01/2012	0.000	0.0	0.0	300.00	Casing Pressure ▾	1187.06	8000.00	0.376	0.007	0.357	0.400	0.379
6	06/01/2012	07/01/2012	1.000	10.0	10.0	300.00	Casing Pressure ▾	583.54	9500.00	0.340	0.011	0.340		

The first shut-in row sets the height of the static oil column. If the liquid level rises, the oil column also rises, followed by an emulsion. The WOR of the last producing row is used to calculate the emulsion gradient for all of the following shut-in rows in this period until the well begins to flow again.

Note: Gradients are not calculated when the pressure source is Gauge depth pressure.

Gas lift

For wells on gas lift, use the Gas Lift flow path. To select the Gas Lift flow path:

Open the Wellbore editor, and click **Profile**. Click the **Flow Path** drop-down menu in the Pressure Loss Calculation Parameters section, and select **Gas Lift**.
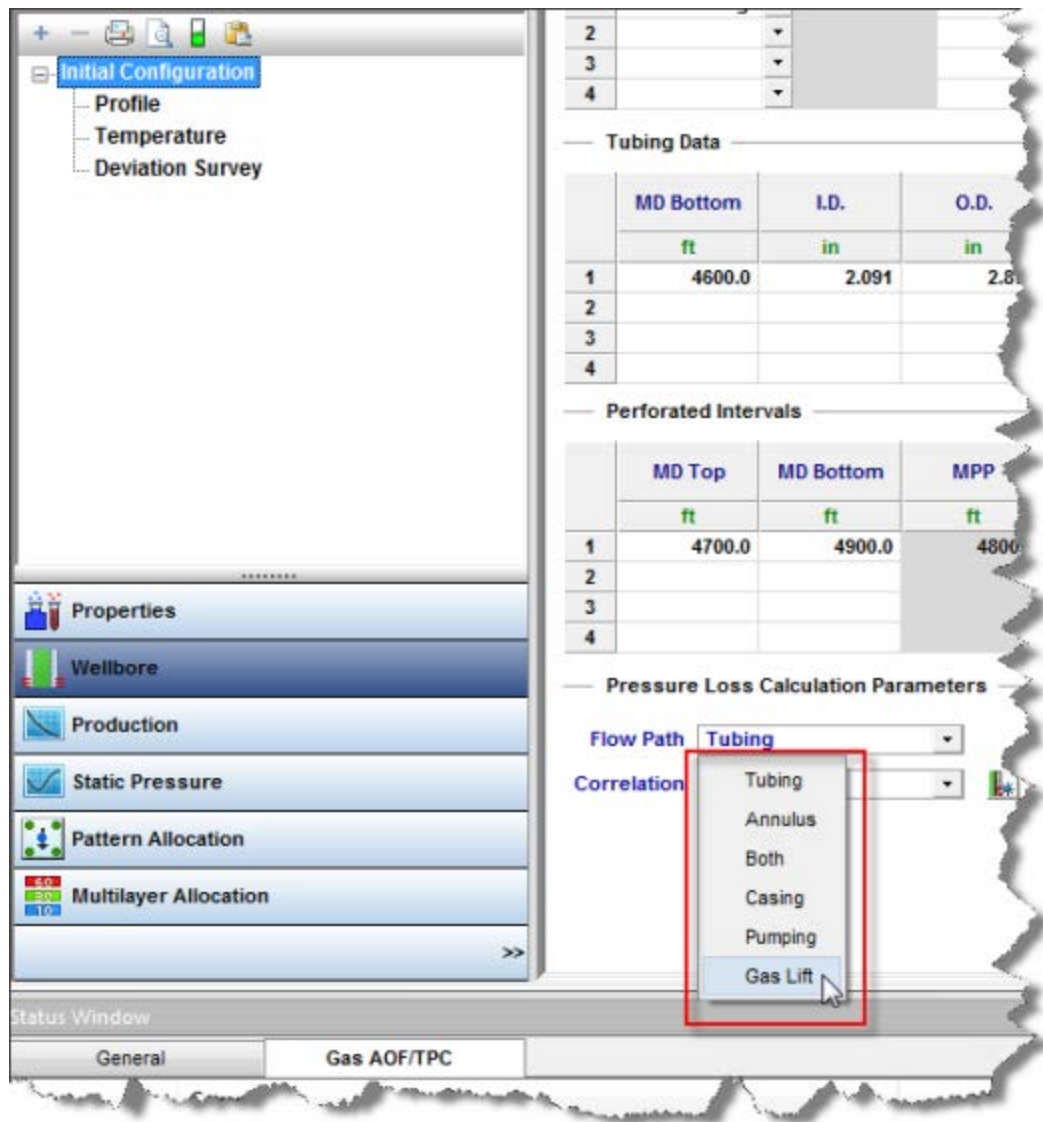
Additional options become available.
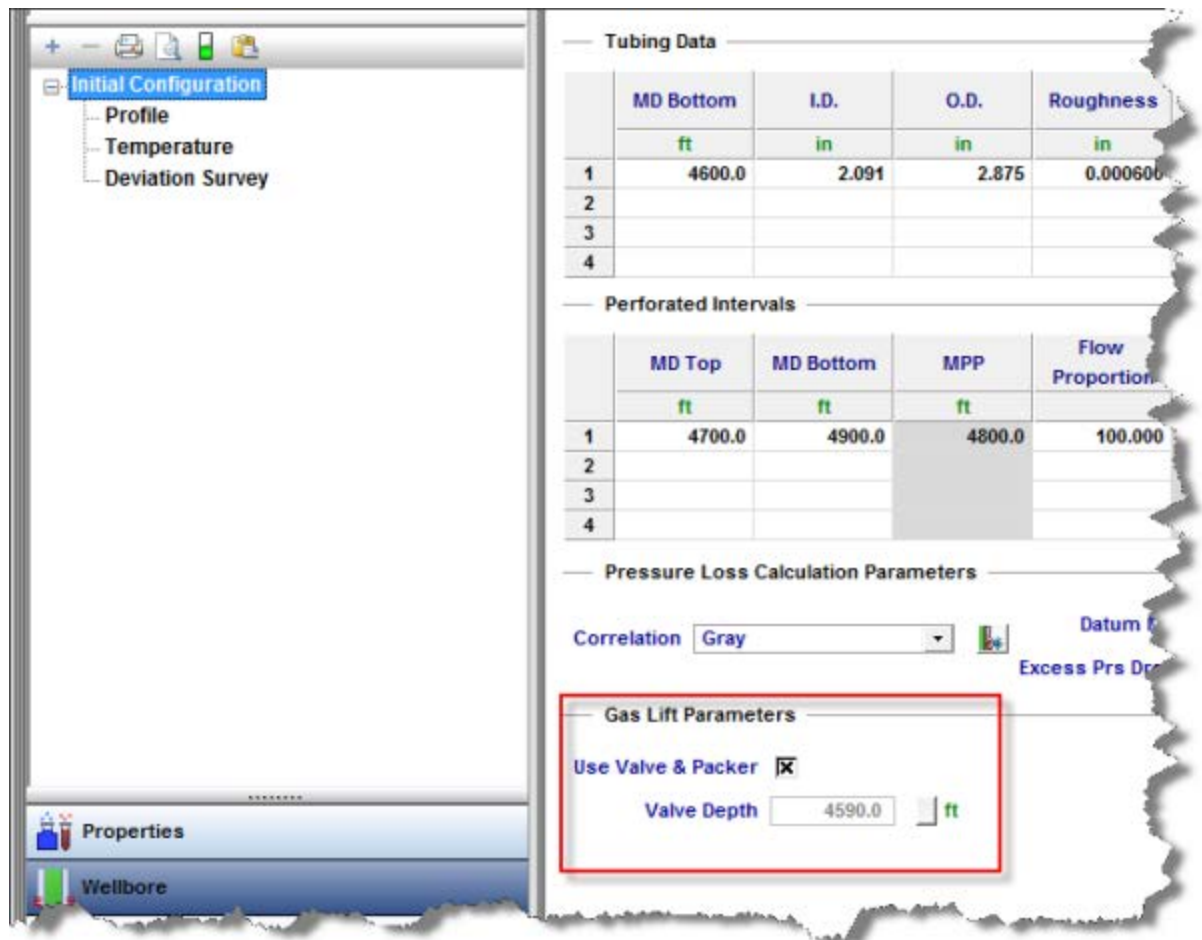
You can choose to model your gas lift system conventionally, with an operating valve and a packer, or as a "poor boy" system with no packer / valve.

Conventional gas lift

To model your gas lift system conventionally, click the **Use Valve & Packer** box. You must also specify the depth of the operating valve. If you do not specify a depth, Harmony Enterprise uses a default valve location 10 feet above EOT. With a packer in place, you must use tubing pressure as your pressure source. Sandface pressures cannot be calculated using the casing side pressure source.

The wellbore calculations assume that none of the injected gas is lost to the reservoir(s), and that all of it is returned up the tubing. Sandface pressure calculations occur as follows:

- The pressure drop from the surface to the operating valve is determined using the sum of all production rates, plus the rate of gas injection.

- The pressure drop from the operating valve to the datum(s) is determined using production rates only.

"Poor boy" gas lift

To model your gas lift system as "poor boy", deselect the **Use Valve & Packer**box. Because there is no packer in place, it is possible to use either casing or tubing as your pressure source in order to perform sandface pressure calculations.

Just as in the conventional case, the wellbore calculations assume that none of the injected gas is lost to the reservoir(s). Note that pressure calculations differ depending on your pressure source (that is, tubing or casing).

For tubing, the calculations occur as follows:

- The pressure drop from the surface to EOT is determined using the sum of the production rates, plus the rate of gas injection.

- The pressure drop from EOT to the datum(s) is determined using production rates only.

For casing side pressure, the calculations occur as follows:

- The pressure drop from the surface to EOT (or the most shallow layer above EOT, if applicable) is determined using only the gas injection rate.

- If there are layers above EOT, the pressure drop from the most shallow layer above EOT to EOT is determined using the gas injection rate, plus the rate of any fluids produced from the layer(s) above EOT.

- The pressure drop from EOT to the remaining datum(s) is determined using only the production rates from the layers below EOT.

Properties of injected gas

The properties of the injected gas may be different from the properties of the produced gas. You must enter your gas lift properties separately from produced gas properties in the Properties editor.

Note: In Harmony Enterprise, gas lift injection is treated differently than gas injection. If you want to model your well on gas lift, you must ensure that the injection rates (or volumes) are entered in the Production editor in the Gas Lift Injection fields, *not* the Gas Injection fields.

Entering rates into the production editor

Harmony Enterprise supports three natural gas streams:

1. Under the Production node, click **Gas**. This is gas produced from the reservoir. If you have gas lift operations, this is a "net produced gas"; which is gas produced from the well minus the gas injected for gas lift.

2. Under the Injection node, click **Gas Lift**. This is the gas injected into the wellbore for gas lift injection purposes only.

3. Under the Injection node, click **Gas Inj**. This is gas injected into the reservoir for pressure maintenance, enhanced oil recovery (EOR), or disposal. This gas injection has nothing to do with gas lift.

Therefore, in the following screenshot, the total gas received at the wellhead (gross produced gas) is the sum of Gas Volume and Gas Lift Inj Volume.

	Start Date	End Date	Gas Volume	Oil Volume	Gas Lift Inj Volume	Tubing Pressure	Casing Pressure	Active Pressure	Pressure Source	Calculated Sandface Pressure
	MM/DD/YYYY	MM/DD/YYYY	MMscf	stb	MMscf	psi(a)	psi(a)	psi(a)		psi(a)
1	05/15/2009	05/16/2009	5.000	500.0	0.000	1000.00	1500.00	1000.00	Tubing Pressure	2454.40
2	05/16/2009	05/17/2009	5.000	500.0	1.000	1000.00	1600.00	1000.00	Tubing Pressure	2572.90
3	05/17/2009	05/18/2009	5.000	500.0	2.000	1000.00	1700.00	1000.00	Tubing Pressure	2710.13
4	05/18/2009	05/19/2009	5.000	500.0	3.000	1000.00	1800.00	1000.00	Tubing Pressure	2860.28
5	05/19/2009	05/20/2009	5.000	500.0	4.000	1000.00	1900.00	1000.00	Tubing Pressure	3019.90

Automatic parameter estimation theory

Automatic parameter estimation (APE) is a mathematical process, known as multi-variable optimization, which automatically adjusts a specified set of function parameters to minimize error between the function and measured data. The mathematical function being minimized is called the objective function.

With analytical modeling in Harmony Enterprise, the objective function is calculated as follows:

- If Calculate Pressure mode is used:

$$E_{avg} = \frac{\sum_i \left(\frac{|(p_{calc})_i - (p_{hist})_i|}{(p_{hist})_i} w_i \right)}{\sum_i w_i}$$

- If Calculate Rate mode is used:

$$E_{avg} = \frac{\sum_i \left(\frac{|(q_{calc})_i - (q_{hist})_i|}{(q_{hist})_i} w_i \right)}{\sum_i w_i}$$

Where (summation is done for all history points, and *i* is the number of the point):

- $(p_{hist})_i$ — historical pressure for the *i*-th point
- $(p_{calc})_i$ — calculated pressure for the *i*-th point
- $(q_{hist})_i$ — historical rate for the *i*-th point
- $(q_{calc})_i$ — calculated rate for the *i*-th point
- w_i — weight for the *i*-th point

Note: $w_i = 0$ if the point is deselected; $w_i = 1$ if the point is selected; $w_i = 10$ if the point is weighted.

If Calculate Both mode is used, the objective function is calculated as the sum of the objective functions for Calculate Pressure and Calculate Rate modes.

E_{avg} reflects the difference between calculated and historical data; therefore a smaller E_{avg} indicates a better history match. The value of the objective function E_{avg} is displayed under the APE group in the Analytical Model pane.
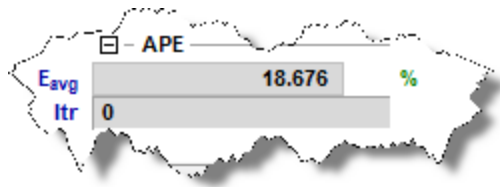
Over an iterative process, the selected modeling parameters are adjusted using the Mead (Simplex) optimization method to minimize the objective function.

Automatic parameter estimation should not be used exclusively because it is possible to find several sets of parameters that yield an acceptable model match. In other words, the solution can be non-unique. It is always recommended to start with parameters obtained from diagnostic analyses, and then fine-tune these parameters manually to obtain a close match. You can use APE for unknown parameters, or parameters which are not known with confidence. The more parameters that are selected for APE (or fitting), the longer the fitting process will take, with a greater chance of finding non-unique solutions. Note that if you include more data points in the fit, it will reduce performance.

Mead (Simplex)

This is a variation of the downhill Simplex method. The Simplex routine is a non-linear regression algorithm used for APE for reservoir and well parameters (k, s, C_D, etc.) when modeling pressure-transient data. The Mead method only requires function evaluations of the objective function, and not the derivatives.

To achieve greater convergence, the downhill Simplex method is modified by imposing constraints on the parameters during the search. Estimates of the parameters are always checked against preset maximum and minimum values for each parameter. Once the routine has converged on some parameters, it is restarted, with a slight perturbation away from the final values, and then it is allowed to converge again. This ensures that the parameter estimates are not the result of some local minimum in the residual, but rather a more global minimum.

Compared to other non-linear regression methods, this method is not always very efficient because it can require a large number of function evaluations. This tends to make it extremely slow in some cases. However, it is straightforward and not encumbered by the requirement of derivatives, and hence tends to be more robust under any conditions.

Capillary pressure

Capillary pressure (P_c) is the pressure difference across the interface between two immiscible fluids arising from capillary forces. These capillary forces are surface tension and interfacial tension. In porous media, the capillary pressure is the difference between the pressure in the non-wetting phase and the pressure in the wetting phase. It is defined by:

$$P_c = p_{non-wettingphase} - p_{wettingphase}$$

In oil-water systems, water is typically the wetting phase; while for gas-oil systems, oil is typically the wetting phase.

In a drop of water in oil, the interfacial tension is denoted by σ and has the following capillary pressure:
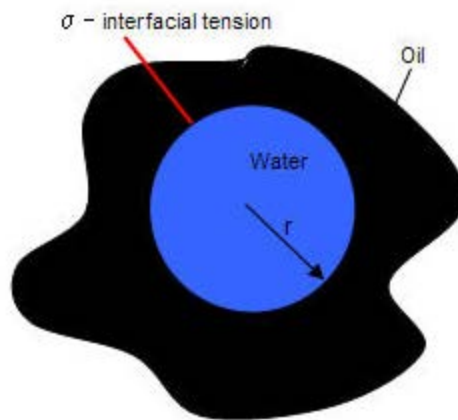
$$P_c = p_w - p_o = \Delta p = \frac{2\sigma}{r}$$

A drop of water on a surface with contact angle θ (where θ < 90° is water wet) has the following capillary pressure:
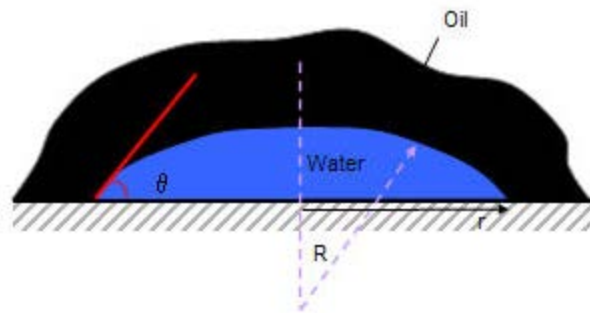
$$P_c = p_w - p_o = \Delta p = \frac{2 \sigma \cos(\theta)}{r}$$

Water in a capillary tube with contact angle θ, where h is the height the water rises, has the following capillary pressure:
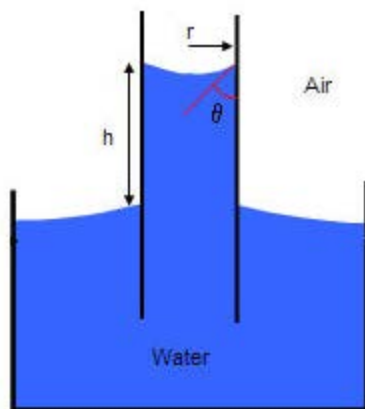
$$P_c = p_{air} - p_o = \Delta p = \frac{2 \sigma \cos(\theta)}{r} = \left(\rho_w - \rho_{air} \right)$$

The shape of the curve depends on pore sizes, size distribution, and fluid properties. The permeability of the reservoir rock can alter the capillary pressure curve. If the value of the permeability is lower, the pore size is smaller, and the capillary pressure is higher.

Water is immobile
In this regon
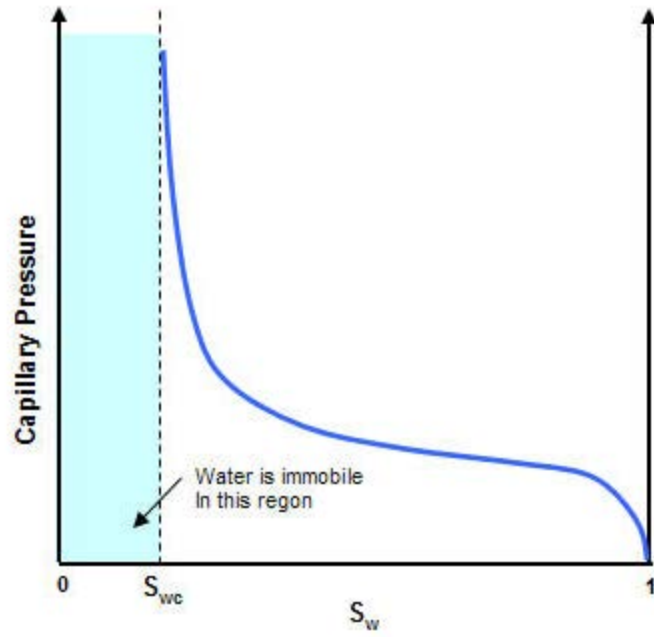
Continuous time track

This feature is used to adjust your data depending on your shut-in conditions. It is extremely important that you use this feature correctly, as your volume and rate data is influenced by this setting. The time track on import is interpreted based on the state of this setting:

- If this option is *selected*, no adjustment to the time track is made. The start dates in Harmony Enterprise match the data imported.

- If this option is *deselected*, Harmony Enterprise analyzes the time track. If the time between two reported dates is greater than a day, but less than a month, a day is assumed. If the time is greater than a month, but less than a year, a month is assumed.

The Continuous Time Track checkbox is located in the Import Options pane (Import Data dialog box) and the Select Wells to Import dialog box. By default, this option is selected for cumulative time.

Example: demonstrating the effect of the Continuous Time Track option

Given the following data, there are noticeable differences in the values Harmony Enterprise uses based on whether or not you select this feature:

Timestep (t)	Rate (q)
1	10
2	20
4	30
5	40

If you select the Continuous Time Track option, Harmony Enterprise uses the following values:

t_{start}	t_{end}	Rate (q)	Volume (V)	Cumulative Volume (Q)
1	2	10	10	10
2	4	20	40	50
4	5	30	30	80

t_{start}	t_{end}	Rate (q)	Volume (V)	Cumulative Volume (Q)
5	6	40	40	120

If you deselect the Continuous Time Track option, Harmony Enterprise uses the following values:

t_{start}	t_{end}	Rate (q)	Volume (V)	Cumulative Volume (Q)
1	2	10	10	10
2	3	20	20	30
3	4			30
4	5	30	30	60
5	6	40	40	100

Data diagnostics theory

The analysis of production data to determine reservoir characteristics, completion effectiveness, and hydrocarbons-in-place is becoming more prevalent. The methods of analysis have been documented and verified in numerous publications. The concepts underlying modern production data analysis are the same as pressure transient analysis. Even though both these domains use the same underlying theory of fluid flow through porous media and can determine the same variables (permeability, skin, reservoir size), it should not be assumed that they can replace each other. Pressure transient analysis and production data analysis must be viewed as complementary and not substitutes for each other. Pressure transient analysis deals mostly with "high frequency / high resolution" shut-in data, while production data analysis deals with "low frequency / low resolution" flowing data. This in itself, presents significant differences in data quality and interpretations.

Like all mathematical solutions, production data analysis methods are subject to numerous assumptions, which often can be justified. In this case, if the data is complete, consistent and of good quality, meaningful results can be obtained. However, if the quality of the data is questionable, then the production data analysis methods should be used with caution. In this case, the analyst's ability to filter out the bad data and extract the true reservoir signal becomes extremely important. As mentioned by Anderson et al. 2006, blind application of production data analysis methods without consideration of data quality issues can lead to misinterpretation of the reservoir characteristics. An analyst, who is not experienced in recognizing such inconsistencies, can obtain an answer that appears to be mathematically correct, yet be completely wrong because of using "bad data" for analysis.

There is no complete set of criteria that covers all of the challenges and pitfalls in production data analysis. Some inconsistencies in data measurement or reporting are more critical than others, while the same issue may be critical in one situation, but not in another. This makes data diagnostics complicated and very dependent on the expertise of the analyst. Nonetheless, there are some issues that are worse than others, and cause "bad" or inconsistent production data a lot of the time. Some of the more common issues are listed below:

- **Missing flowing pressures** — Even though the rate history is carefully obtained from daily records, the pressure history is infrequent, inaccurate, or often non-existent.

- **Missing flow rates** — Even though the flowing pressure of an individual well is obtained accurately and frequently from permanently installed downhole gauges, the corresponding flow rate is often non-existent, or has been pro-rated on a monthly basis from a group meter of several wells.

- **Rate or pressure averaging** — Often the flow rate and/or the flowing pressure are measured at high frequency (every minute), but for data storage efficiency, are

averaged to daily quantities. Depending on the rate variations during that period, this may result in meaningless numbers.

- **Wrong initial pressure** — The initial pressure is unknown or wrong, especially in tight gas or infill drilling.

- **Liquid loading** — The calculation of sandface pressures is wrong due to the unknown "standing liquid column" in the wellbore.

- **Wrong pressure source and flow path** — If the source of the wellhead pressure measurement or the flow path are specified incorrectly (tubing, annulus or both, or changing from one to the other) the calculated sandface pressures will be incorrect.

- **Wrong production data** — Rate allocations to individual wells based on group metering can be in error, as the distribution is based on infrequent tests.

- **Wrong production data** — The water production rate of individual wells is often poorly monitored or misreported. While small quantities of water may have little effect on the reservoir interpretation, they can have a significant effect on the wellbore performance and on the calculation of sandface pressures from wellhead data.

- **Significant increase in water / gas ratio** — When the water-gas ratio is high (>100 bbl/MMscf), the assumption of single-phase Darcy flow in the reservoir may not be valid, or the skin due to water coning may be variable, which affects the validity of the permeability and skin calculations.

  - Operational modifications:

    - Opening up of new perforations / shutting off old perforations

    - Refracturing of the well

    - Changing tubulars

    - Changing flow path

- **Wrong location of pressure gauge** — Often the only flowing pressure available is the pressure downstream of the choke. If the choke is wide open, this pressure is usable, but if the choke is being used to control the flow rate, then the downstream pressure is not of much value.

- **Wrong rate and pressure synchronization** — The original rate and pressure data often have different time tracks, and if they have not been synchronized properly, the interpretation may be invalid.

Sometimes a simple look at the reported production data (flowing pressure, gas and liquid flow rates and time) can reveal obvious or potential inconsistencies, or provide insight for interpretation. Here are some examples:

- If the flow rate suddenly increases, the flowing pressure should abruptly decrease correspondingly.

- If the flow rate is below the "critical liquid lift velocity" calculated using Turner correlation (Turner et al. 1969) or Coleman correlation (Coleman et al., 1991), there is the likelihood of liquid loading.

- If the tubing and casing pressure profiles are diverging, it is an indication of liquid load-up.

- The pressure is measured every minute but reported daily, along with the daily average rate. If there have been interruptions or significant rate changes during the 24-hour interval, an average daily rate is meaningful, but an average daily pressure is not.

- Sometimes the flow rate is pro-rated from a group-meter measurement instead of being measured at the individual well. The pro-rating formula honors the total production from all the wells, but may be completely incorrect at the individual well level, especially when there have been undocumented production disruptions at various wells.

- A rapid increase in the water-gas ratio could indicate water coning, and wellbore operational problems.

- A rapid decrease in the water-gas ratio or condensate-gas ratio could indicate liquid loading in the wellbore.

- A high frequency of scatter in production rates, pressures, the water-gas ratio, or condensate-gas ratio can indicate unstable flow in the well and/or unstable operating conditions.

- Flat (constant) liquid production rates, with large step changes, usually indicate infrequent measurement. The presence of this kind of data can make the quality of the calculated sandface pressures low, even if the wellhead pressures are of high quality.

- No liquid rates are reported, yet either the pressure data indicates "slugging", or it is a known fact that liquids are being produced. In this case, the quality of the calculated sandface flowing pressure may not be high, even if the wellhead pressures are of high quality.

- Flat (constant) pressures with step changes usually indicate infrequent pressure measurement. This means that one pressure is recorded per week or month, and then it is reported as a constant value until another reading is taken.

- Straight-line trends in pressures or rates usually indicate infrequent measurements and interpolation between them (rather than actual measurement).

Note: For additional data diagnostic examples, see the data diagnostics flowchart.

When an analysis is performed, the analyst must always review the interpretation to make sure it makes sense. This is the ultimate test and must never be avoided. Although it is preferable to identify and eliminate inconsistent data before the analysis is undertaken, sometimes inconsistencies do not become evident until after the analysis has been completed. For example, a sudden change in the slope of the flowing material balance plot (p/Z plot) is a diagnostic that depends on information about original-gas-in-place, which is obtained from interpretation.

Recognizing the fact that the analysis and interpretation of production data is influenced significantly by the quality and consistency of the data, it is the objective of this topic to develop a series of diagnostic plots and guidelines that can help analysts to identify "bad data" and prevent misleading answers resulting from analyzing poor-quality data. The diagnostic plots are independent of any interpretations as they are considered pre-analysis diagnostics.

To achieve the objective of this topic, a number of diagnostic plots are proposed. These plots are then used in a number of case studies using field examples. The intent was to investigate if these diagnostics plots could differentiate between "good data" and "bad data". The results of this study allow production engineers to recognize poor-quality data, and avoid being misled by their results, or at least to make a reasonable judgments as to the quality of their interpretations.

Production data diagnostics

There are four areas of investigation in production data diagnostics:

1. Outlier removal

2. Liquid loading in the wellbore

3. Single phase flow in the reservoir

4. Consistency (correlation) between rate and pressure

Outlier removal

The first step in production data diagnostics is the removal of outliers. Apart from adding extraneous noise to what is often an already confusing mass of data, these outliers can cause incorrect interpretation if they are not removed. For example, often outliers show a unit slope on typecurves. This unit slope may be easily misdiagnosed as reservoir depletion. It should *not* be used as an indication of original-gas-in-place or of boundary-dominated flow. A simple solution is to simply identify and remove the outliers from the analysis.

Liquid loading in the wellbore

In this step, the analyst should investigate if there is any issue with liquids loading up in the well, or if there is any unstable flow in the well. If liquid loading exists, and the sandface flowing pressure is being calculated from wellhead measurements, it is very easy to get the wrong answer, because multiphase flow calculations do not account for "stagnant" liquid columns in the wellbore. The following points should be considered in this step:

- If the pressure data is measured at the mid-point of perforations (MPP), then liquid loading or any other wellbore issues will not affect production data analysis. However, any correction from the gauge depth to the MPP can be a source of error (sometimes significant, depending on the distance between them).

- If the sandface pressure is being calculated from wellhead measurements, and the "quiet side" is being used (for example, the well is flowing through tubing and the pressure source is the annulus), the calculation down to end-of-tubing (EOT) is often very good. However, from the EOT to the MPP, there often exists a "stagnant" liquid column, which must be accounted for by estimating a "flowing" gradient (estimated at 0.2 - 0.3 psi/ft or 4-7 kPa/m for water).

- If the sandface pressure is being calculated from wellhead measurements, and the "flowing side" is being used, multiphase flow calculations must be used, and their accuracy (unless calibrated to similar flowing conditions) is questionable.

The following plots can be used to identify liquid loading. (Some of the plots can be used to identify productivity issues as well as liquid loading.)

- **Gas rate and sandface pressure versus time** — If there is a high degree of scatter in production rates and pressures, then it indicates unstable flow in the well, like slugging, and/or unstable operating conditions.

- **Difference between casing and tubing pressure versus time** — The tubing and casing pressure profiles should track each other if there is no problem in the wellbore. The plot shows that if the difference between casing pressure and tubing pressure is changing (diverging tubing and casing pressures with time), then there is possibility of liquid loading.

- **Water-gas-ratio or condensate-gas-ratio versus time** — A fluctuation or rapid decrease in the water-gas ratio and condensate-gas ratio is an indication of unstable flow in the well. Fluctuation is an indication of slug flow and a rapid decrease is an indication of liquid loading. If slug flow is indicated, yet no water rate is reported, then the quality of calculated sandface pressures may be questionable, even if the wellhead pressures are of high quality.

The water-gas ratio versus time plot has another practical importance. A rapid increase in the water-gas ratio could indicate possible productivity issues related to water (for example, water coning), as gas relative permeability decreases significantly at high water-gas ratios.

- **log (*q*) versus log (*t*)** — This plot has diagnostic value in cases where the gas rate is decreasing abnormally as a result of liquid loading or any other productivity issues. The log scale tends to compress the late-time data and accentuate the declining rate trend in the late-time data. This plot may also accentuate the fluctuation in gas rate, which can be useful to identify slug flow.

All the above indicators of wellbore liquid problems must be viewed together, as they are often complementary effects, but some of them may be more evident than others.

Single-phase flow in the reservoir

A plot of the water-gas ratio versus time is used in this step. If the water-gas ratio is high, the assumption of single-phase flow in the reservoir may not be acceptable. A threshold value for the water-gas ratio should be defined (suggested value of 100 bbl / MMscf), and the portion of the data with a water-gas ratio higher than the threshold value should not be used for analysis using typecurves and analytical models, as these analysis methods are developed assuming single-phase flow inside the reservoir.

Consistency (correlation) between rate and pressure

After removing the outliers, and the data which indicates liquid loading and productivity issues in the wellbore, and/or multiphase flow inside the reservoir, the analyst should look for consistency between pressure and rate data. If the rate and pressure data are inconsistent with each other, they should be identified and should *not* be used to interpret reservoir effects (permeability, skin or gas-in-place). The series of *Diagnostic Plots* described in the following section are recommended for use in identifying or accentuating any such inconsistency.

The concept of a diagnostic plot implies that a certain feature or behavior emerges from a given data profile. More specifically, diagnostic plots should highlight that the data is "bad" by indicating that a certain expected feature does not exist, or that the displayed profile deviates significantly from expectations. When this occurs, the apparent signal is potentially misleading and the wrong reservoir interpretation would be extracted, if the analyst proceeds. As explained by Anderson et al. 2006, a diagnostic plot for production data should:

- Highlight that there is something wrong with the production data.

- Identify the causes of misbehavior, if any exist.

- Show if the flow rate and flowing pressure are correlated or not.

The diagnostic plots for identifying inconsistent production data are described below:

- **Gas rate and sandface pressure versus time** — Visually check for a negative correlation between rate and pressure data. This means that if the flow rate suddenly increases (or decreases), then the flowing pressure should decrease (or increase) correspondingly. If that does not happen, the rate and pressure data are inconsistent with each other, which may be because the rate is wrong, or the pressure is wrong, or the completion has changed (for example, refrac, tubing change).

- If the rate changes by an order of magnitude, it is better to use log (q) instead of q.

- **Normalized rate versus time** — This is a plot of $q / \Delta p_p$ versus time. In the absence of step changes in rate and pressure, theory indicates that $q / \Delta p_p$ must decrease continuously with time. Therefore, an increasing trend in $q / \Delta p_p$ with time indicates that non-reservoir effects are present. Note that if there are different stems in the $q / \Delta p_p$ versus time plot and $q / \Delta p_p$ is decreasing with time in each stem, (see Figure 1a), the analyst should not conclude that the rate and pressure data are inconsistent, as these different stems can be caused by step changes in rate and/or pressure. However, it forces the analyst to ask the question: Is there any inconsistency between rate and pressure data?

- **Normalized pressure versus time** — This is a plot of $\Delta p_p / q$ versus time. The trend of the plot is the reverse of the $q / \Delta p_p$ versus time plot. However, the signature and diagnostic value tends to be the same. In general, whenever a plot of $q / \Delta p_p$ is used, pretty much the same information could have been obtained by plotting $\Delta p_p / q$ instead. The choice of one or the other is a personal preference.

- **Percentage drawdown versus time** — This plot shows [($\Delta p / p_i$) *100] versus time, and indicates the degree of drawdown. Knowing the degree of drawdown can be an important issue in production data diagnostics because theory indicates that the pressure variable to be used for analysis should be Dp (= pi - pwf). If Dp / pi is close to unity, then we are dealing with a well with high drawdown, and in this case, the effect of pi overshadows that of pwf, and makes the rate insensitive to variations in the flowing pressure. In other words, any discrepancies in flowing pressure will not have much of an effect on rate. For example, if there is a step change in flowing pressure, this step change may not be reflected in the rate (given normal data scatter). In the case of high drawdown, even if the flow rate and pressure are *not* correlated, the diagnostic plots which depend on Dp may not indicate that there is a problem.

- The fact that high drawdown yields pressure-insensitive rates is a diagnostic onto itself. This is very useful when public data is analyzed, as often, all or part of the pressure data is missing from the production file. If we know that the well is producing under high drawdown conditions, then the rate is insensitive to flowing pressure and any discrepancies in flowing pressure do not really matter.

- **Blasingame typecurve** — This is a log-log plot of normalized rate (q / Dp_p) versus material balance time, (that is, Gp / q), where Gp is the cumulative production of gas and q is the gas rate. Theoretically, normalized rate must decrease continuously with material balance time. Therefore, an increasing trend indicates that

non-reservoir effects are present. If there are step pressure or rate changes, they will cause a sudden deviation from the decreasing trend, but the general trend will be resumed if the data is consistent. However, if there are different stems in this plot, it is an indication of inconsistency between rate and pressure data (see Figure 1b).

- **NPI typecurve** — This is a log-log plot of normalized pressure (Dp_p / q) versus material balance time (Gp / q). This plot is the inverse of the Blasingame plot. Theoretically, the normalized pressure must increase continuously with material balance time. Therefore, a decreasing trend indicates that non-reservoir effects are present. If there are different stems in this plot, it is an indication of inconsistency between rate and pressure data.

- **FMB rate** — This is based on the flowing material b Balance (FMB) concept. It is a Cartesian plot of normalized rate (q / Dp_p) versus normalized cumulative (Gp / Dp_p). Theoretically, the normalized rate must decrease continuously with normalized cumulative. Therefore, an increasing trend indicates non-reservoir effects. If there are different stems in this plot, it is an indication of inconsistency between rate and pressure data.

- **FMB pressure** — This is the inverse of the FMB rate plot. It is a Cartesian plot of normalized pressure (Dp_p / q) versus material balance time (Gp / q) and should be increasing continuously. Therefore, a decreasing trend indicates that non-reservoir effects are present. If there are different stems in this plot, it is an indication of inconsistency between rate and pressure data.

- **Blasingame-Cartesian** — This is a Cartesian plot of normalized rate (q / Dp_p) versus material balance time (Gp / q). Theoretically, normalized rate must decrease continuously with material balance time. Therefore, an increasing trend in normalized rate with material balance time indicates that non-reservoir effects are present. If there are different stems in this plot, it is an indication of inconsistency between rate and pressure data.

Figure 1: Example of step change in rates or pressures in normalized rate versus time and Blasingame typecurve plots

a. Normalized Gas Rate vs Time

b. Blasingame Type Curve
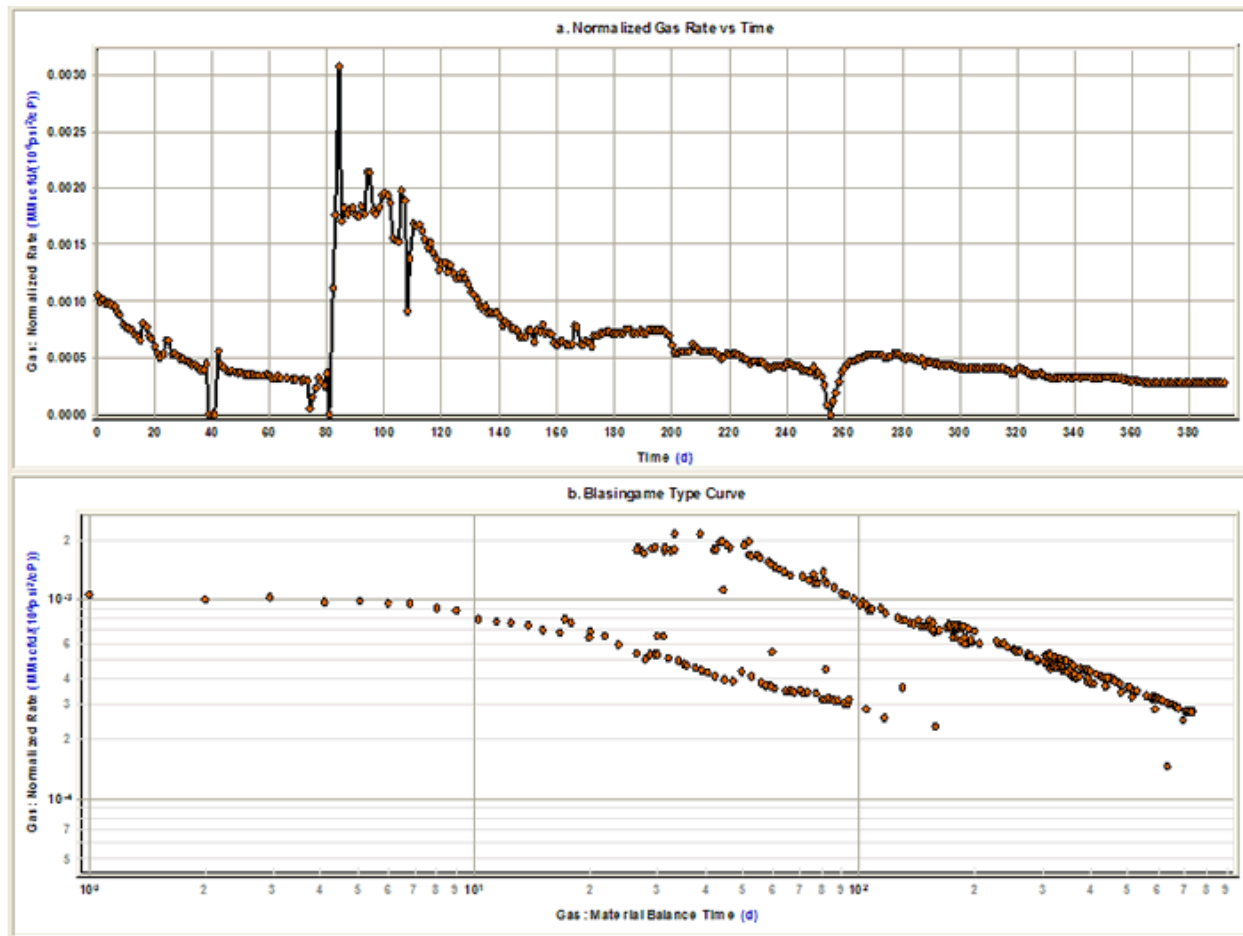
All of the above plots do not always show the same inconsistencies. Depending on the data quality, the variations in operating conditions, rate fluctuations, source of measurements, and the degree of drawdown, some plots highlight an inconsistency, while others may not. We therefore recommend that all these plots be drawn and inspected, and if any one of them shows an inconsistency, the data should be examined in detail to understand the cause and severity of the problem. The case studies below demonstrate how plots can be used.

Case studies

To demonstrate the performance of the proposed diagnostic plots in evaluating the quality of production data, we use relevant field examples to illustrate specific issues. In each example, all or some of the useful plots are presented. All of the diagnostics plots were constructed from raw data, with no interpretation required, and most often, using sandface flowing pressure calculated from wellhead measurements. It is worth noting that not all of the proposed plots provide diagnostic insight in every case. This is why the analyst should always look at a combination of the plots, in the hope that one or

more of them indicates an anomaly that is worth investigating, or highlights an inconsistency in the data.

Note: The term "sandface" is now used instead of "bottomhole".

Case 1

This case represents a well that was stimulated after three months of production. Some of the useful diagnostic plots are shown in Figure 2.

Figure 2a shows the rate and sandface flowing pressure versus time plot. From this plot, we can see that the well was shut in for two days in February 2005 and after that the rate and pressure increases rapidly. Looking at Figure 2b, it is evident from this plot that there are two stems in the typecurve. One stem is for data before February 2005 and one is for data after February 2005. It can also be seen that the productivity of the well ($q / \Delta p_p$) has increased after February 2005. This is due to the fact that the well was fractured on February 5, 2005. Figure 2c is a plot of $q / \Delta p_p$ versus $Gp / \Delta p_p$. Extrapolation of this plot to the x-axis gives an estimate of the original-gas-in-place. It is obvious from this plot that the frac not only improved the productivity of the well, but also added more reserves as shown by the increase from the original-gas-in-place to the ultimate-gas-in-place. Only data collected after February 5, 2005 should be used in any interpretation, as the reservoir model has changed.

Figure 2: Case 1 diagnostic plots

a. Gas Rate and Bottomhole Pressure vs Time

b. Blasingame Type Curve

c. RMB Rate

d. Blasingame-Cartesian
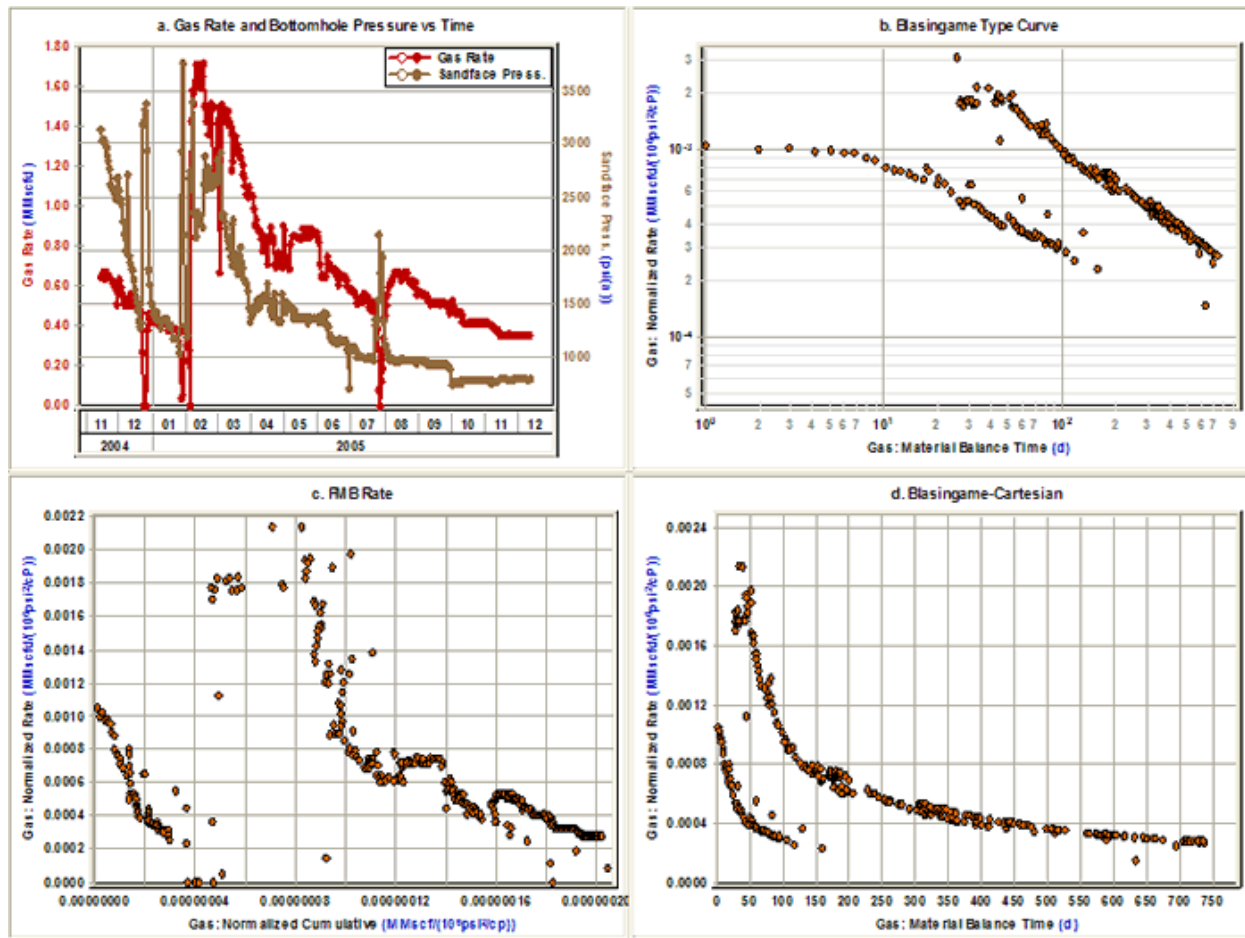
Case 2

Figure 3a shows the gas rate and sandface flowing pressure versus time. It can be seen from this plot that the sandface flowing pressure is almost a straight line from the beginning of March 2004 until the middle of April 2004. The same thing can be seen for tubing pressure in Figure 3b. In practice, it is not likely that the tubing pressure profile would be a straight line for a period of time. If the tubing pressure has a straight line profile for a period of time, it implies that it was not measured frequently and the data has been interpolated and not measured. This will be reflected in the reliability of the calculated sandface flowing pressure data.

This well also produced water and oil. Figure 3c shows the oil rate and water rate versus time plot. Looking at this plot, it is obvious that the oil rate and water rate have flat profiles with large step changes. This again means that oil rate and water rate were not measured frequently and this will have a significant effect on the quality of the calculated sandface flowing pressure data, because multiphase flow calculations depend directly on gas-liquid ratios.

Figure 3d shows the gas rate / critical-Turner-rate ratio versus time plot. This plot shows that the well may be loaded by liquid from the beginning of March 2004 to the end of August 2004. This is consistent with fluctuations in the gas rate during this period. This plot also shows that the gas rate is higher than the critical-Turner rate from the beginning of September 2004 to the end. The tubing pressure during this period is constant and equal to 13.0 psi (apparently a gauge pressure of 0, converted to absolute). This is not a valid pressure. Therefore, the calculated flowing sandface pressure and the critical-Turner-rate calculations after September 2004 are not valid, and should be discounted in any interpretation.

Figure 3: Case 2 diagnostic plots
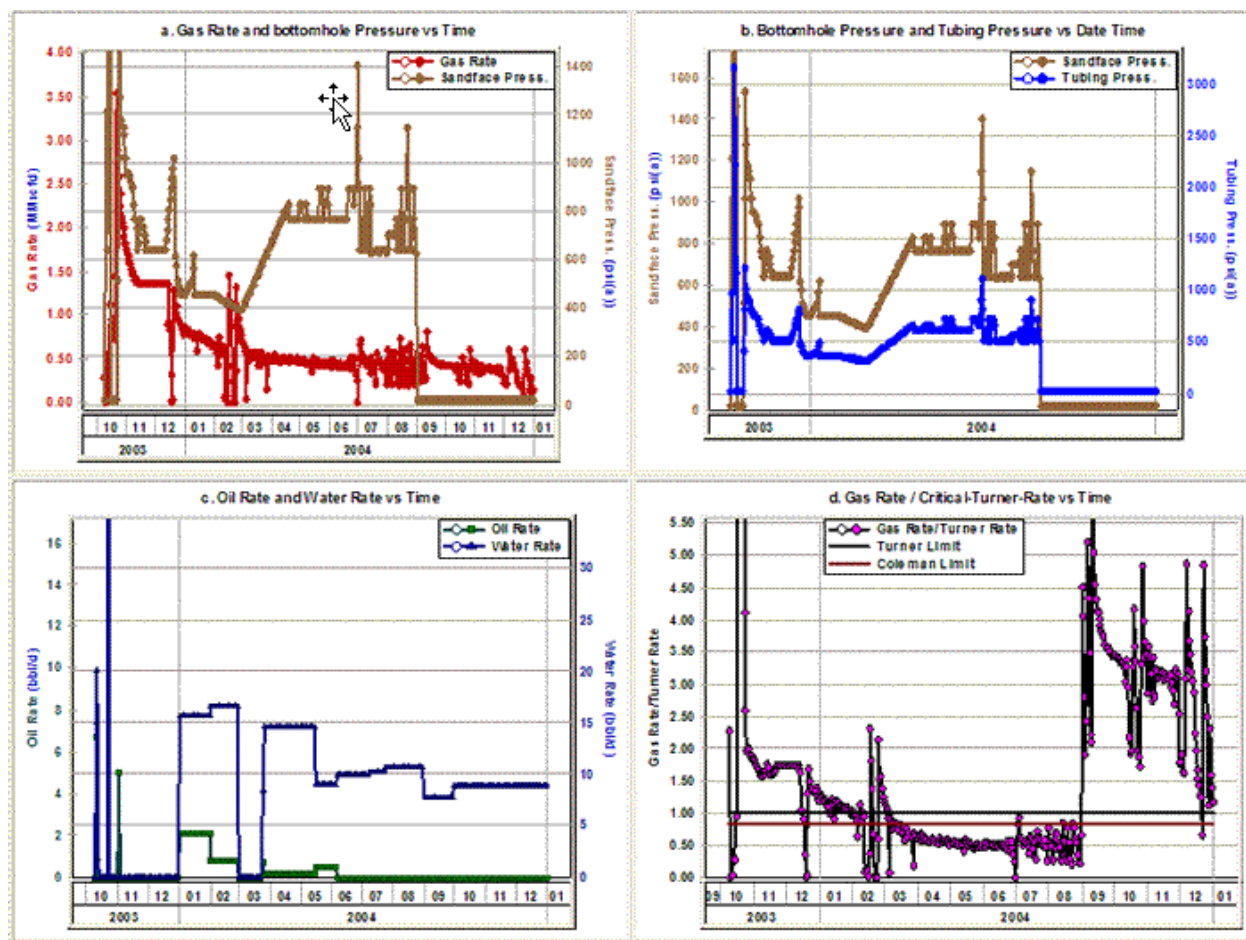
Case 3

Figure 4a shows the gas rate and calculated sandface flowing pressure versus time. Looking at this plot, everything seems to be normal. Figure 4b shows the ratio of gas-rate / critical-Turner-rate versus

time plot. According to this plot, the rate is less than both the Coleman and Turner critical lift rates, which indicates that the well is probably loaded with liquids. However, there is no liquid production reported at all. The gas rate is higher than 2 MMscfd and there is no indication of slugging or liquid loading in the trend of the gas rate and flowing pressure. The Blasingame typecurve and FMB rate plots are well behaved. The problem in this case is that the specified tubing ID was wrong. This directly affects the values for critical-Turner rate, but has little effect on the calculated flowing sandface pressure, as it only affects the friction component of the pressure loss inside the wellbore, which is very small compared to hydrostatic pressure loss. Therefore, the flowing sandface pressures calculated using the wrong tubing ID, in this case of dry gas production, can still be used for analysis.

Figure 4: Case 3 diagnostic plots
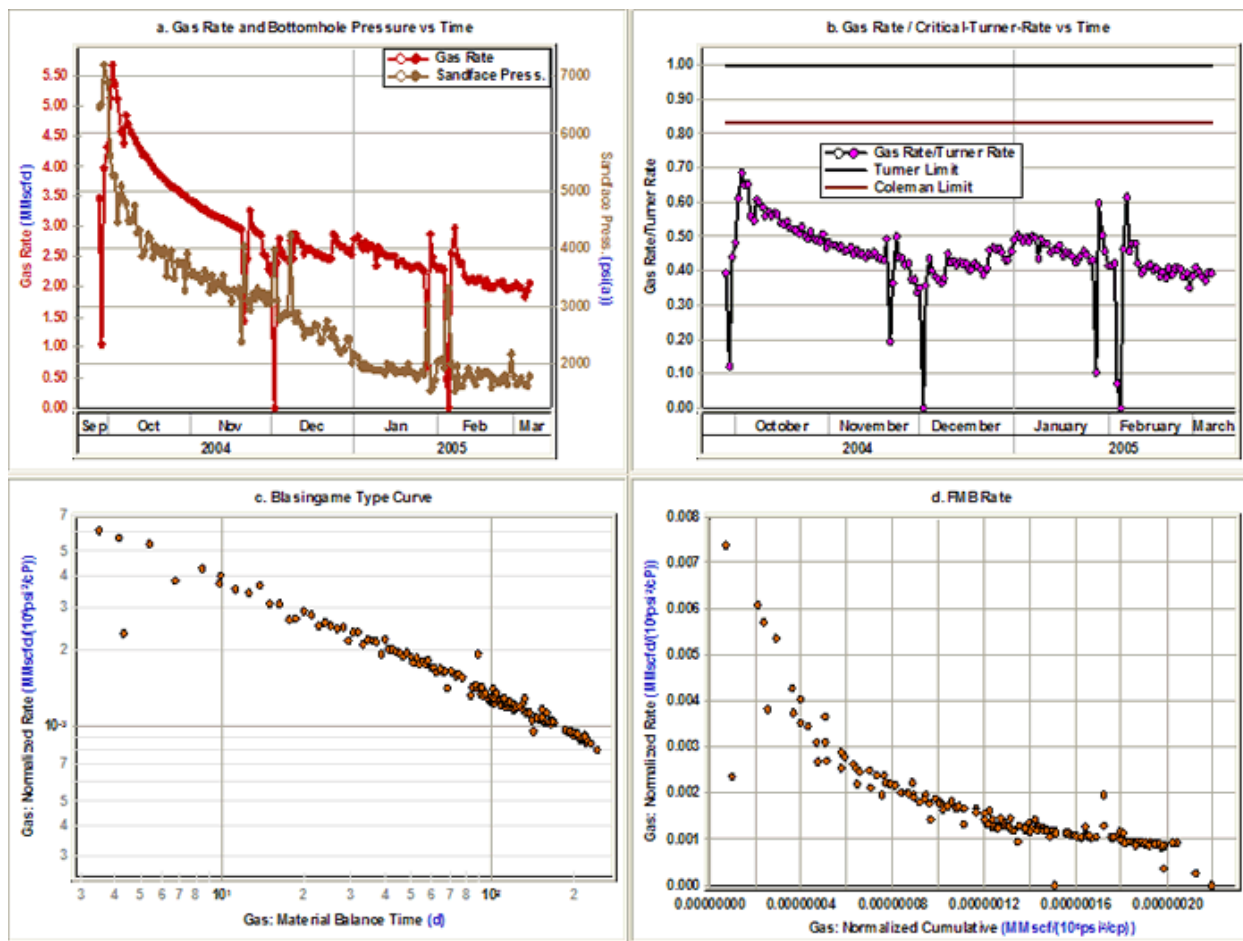
Case 4

Figure 5a shows the gas rate and sandface flowing pressure versus time for a high permeability gas well. Figure 5b shows the ratio of gas-rate / critical-Turner-rate versus time plot for this well. This plot shows that the gas rate is lower than the Turner rate before July 1, 2002. Looking at the gas rate and sandface flowing pressure versus time and water-gas ratio versus time plot shows that something happened on July 1, 2002. There is a step change in the rate and the flowing pressure, and a significant increase in the water-gas ratio (Figure 5c). This behavior is consistent with a tubing change-out (where tubing is replaced with a smaller diameter to lift liquids and eliminate the liquid lifting problem). This tubing change was not documented for this well.

Looking at the Blasingame typecurve and FMB rate plots also shows there is some inconsistency between rate and flowing pressure data, as there are two stems on these plots. One of the stems is for data before July 1, 2002 and the other stem is for the data after July 1, 2002. The main reason for having two stems is because of having "stagnant" liquid column in the wellbore before July 1, 2002. This liquid column was not considered when calculating the sandface pressure during this period, and therefore, the calculated sandface pressure data for this part of data is wrong. Only data collected after July 1, 2002 should be used in any interpretation, as the calculated flowing sandface pressure data is more reliable.

Figure 5: Case 4 diagnostic plots

Figure 6: Case 5 diagnostic plots
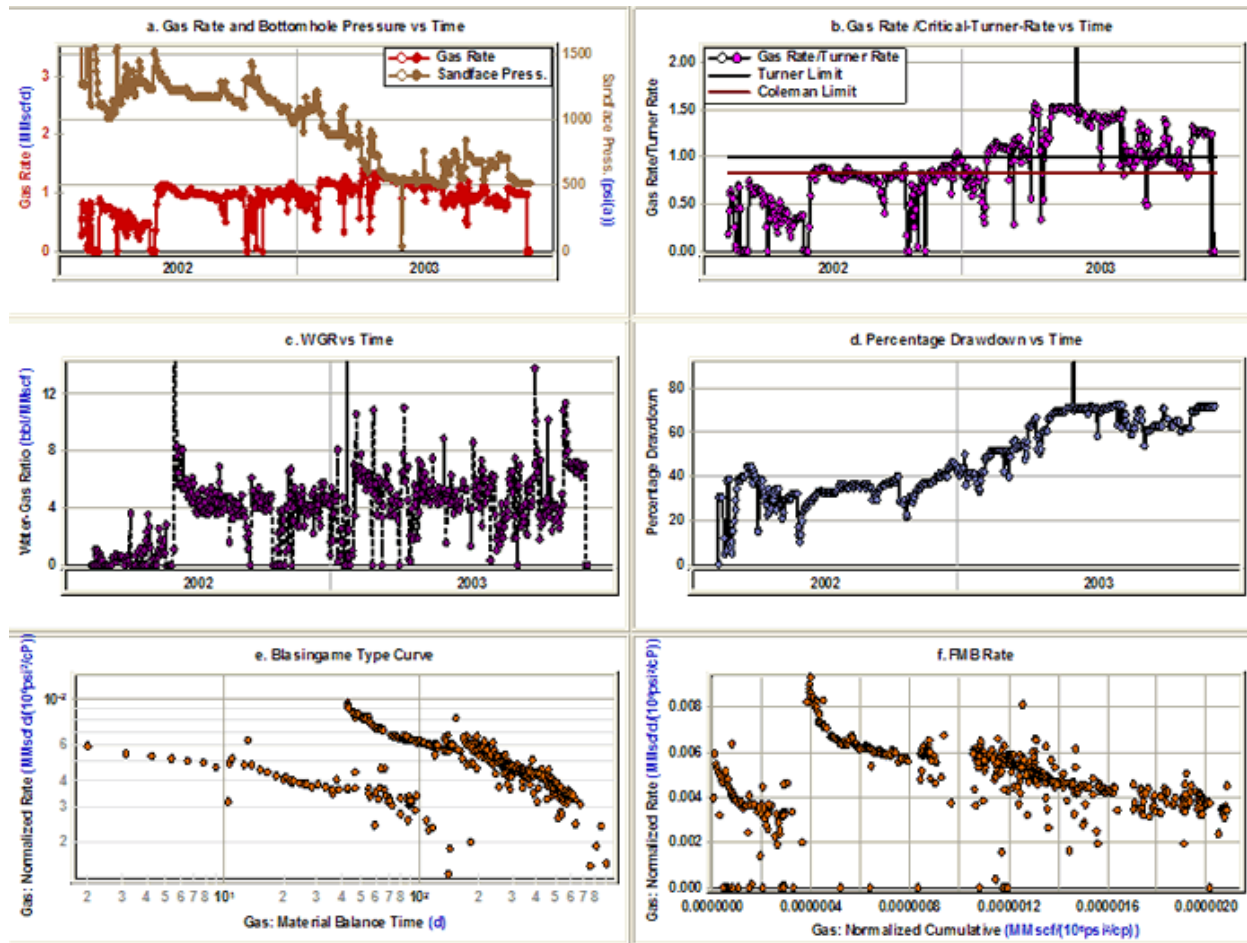
Case 5

Figure 6a shows the gas rate and sandface flowing pressure versus time for a hydraulically fractured well. Figure 6 (that is, plots b-to-e) shows some of the proposed diagnostic plots. These plots do not show any inconsistency between rate and pressure.

Figure 6f shows the ratio of gas-rate / critical-Turner-rate versus time plot. According to this plot, the gas rate is less than the critical liquid lift rate throughout the whole producing life. In addition, Figure 6a shows fluctuation in gas rate and this indicates that there is slug flow. Although there is indication of slug flow in Figure 6a and liquid loading in Figure 6f, no water production has been reported. Therefore, sandface pressure calculations from wellhead pressure are likely incorrect.

a. Gas Rate and Bottomhole Pressure vs Time
b. Blasingame Type Curve
c. RMB Rate
d. RMB Pressure
e. Blasingame-Cartesian
f. Gas Rate /Critical-Turner-Rate vs Time

Case 6

Figure 7a shows the gas rate and calculated sandface flowing pressure versus time for a horizontal gas well. Visual inspection of Figure 7a indicates some inconsistencies between pressure and rate. It can be seen from this plot that:

- The pressure profile is flat from July 2002 to December 2002.

- There is a step change in pressure at the end of July 2003, but this step change is not reflected in the gas- rate data.

Some of the proposed diagnostic plots are shown in Figures 7 b-f. There is no evidence of these inconsistencies in Figures 7 b-e. Figure 7f shows the plot of percentage drawdown [(Δp / p_i) * 100] versus time for this well. According to this plot, except for the first two months of production, the well is producing under almost 85% drawdown. This means that we are dealing with a high drawdown well, and that the rate is insensitive to flowing pressure and that any discrepancies in flowing pressure have very little effect on interpretation. This is the reason why no inconsistency was observed in Figures 7b-e.
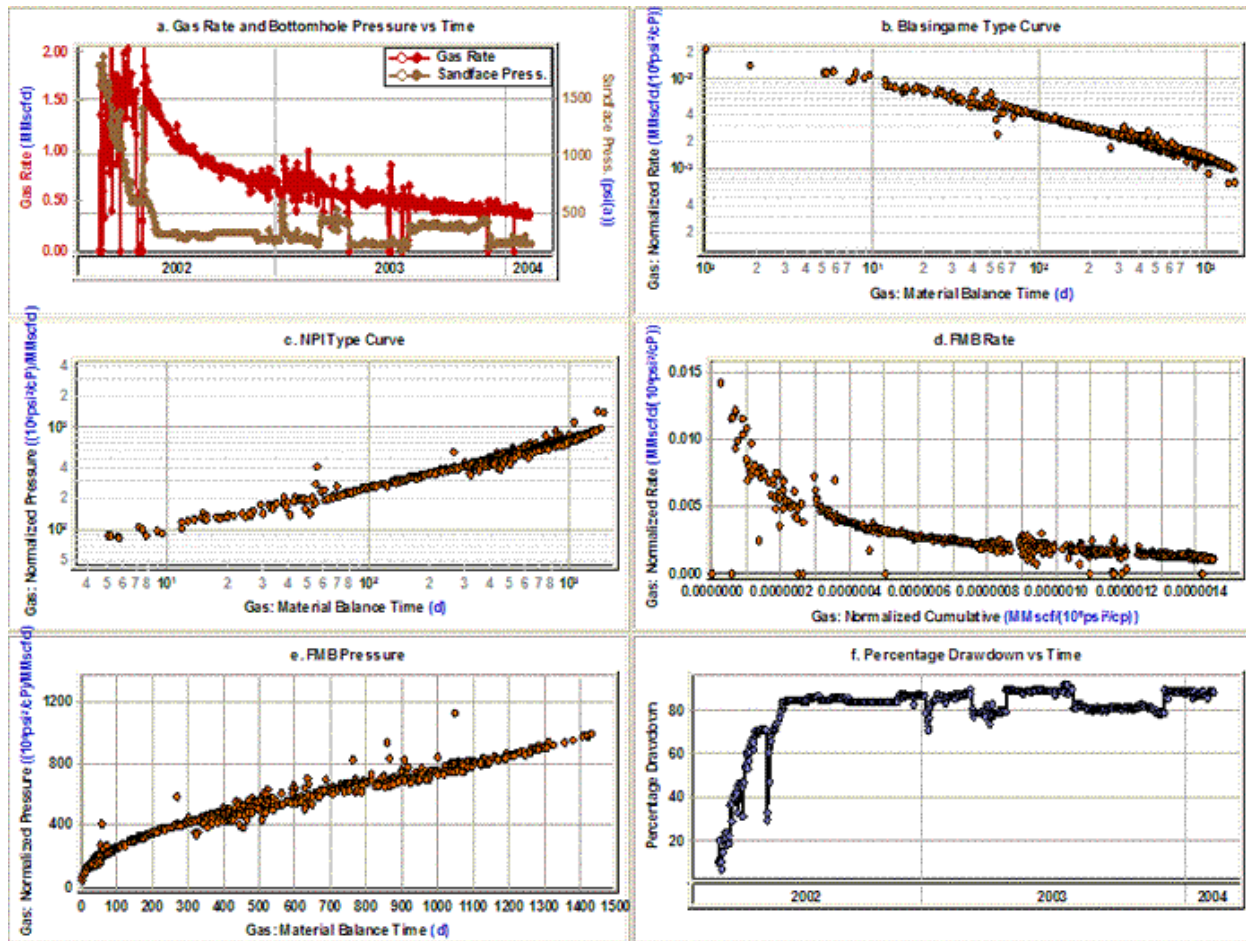
Case 7

This is a high-permeability gas well. This well is producing through tubing and only tubing pressure data is available. Figure 8a-f shows some of the diagnostic plots for this well. Figure 8a shows the gas rate and sandface flowing pressure versus time for this well. Everything seems normal except for the data between the beginning of May 2002 until the end of July 2002:

- The sandface flowing pressure suddenly decreases in early May 2002, but this step change is not reflected in gas-rate data.

- The gas rate suddenly decreases in late June 2002, but this step change is not reflected in the sandface flowing pressure data.

To find out why the rate and pressure are not consistent in this period, we reviewed at the water-rate data. The plot of water rate and sandface flowing pressure is shown in Figure 8b. This plot shows that the well was producing almost 50 bbl/d of water from the beginning of 2001 until the beginning of May

2002, and no water rate was reported from the beginning of May 2002 until the end of July 2002. The water rate affects both hydrostatic and friction pressure losses in the wellbore, and has a huge effect on the magnitude of the calculated sandface pressures. This can explain the inconsistency between rate and sandface pressure from the beginning of May 2002 until the end of July 2002, as the water rate is not reported. If the casing pressure had been available, the problem would have been less severe because the sandface pressure could have been calculated using casing pressure data instead. This would not have been affected by an incorrect liquid rate, as it involves a hydrostatic head calculation of a dry gas column to the end-of-tubing.

Figure 8c shows the plot of percentage drawdown versus time for this well. According to this plot, except for the first two months of production, the well is producing under almost 95% drawdown. This means that the diagnostic plots which use Δp or Δp_p may not show any inconsistency between rate and flowing pressure data even when they are not consistent. Looking at Figures 8d-f does not indicate any sign of inconsistency, which was expected because of high drawdown.

Figure 8: Case 7 diagnostic plots
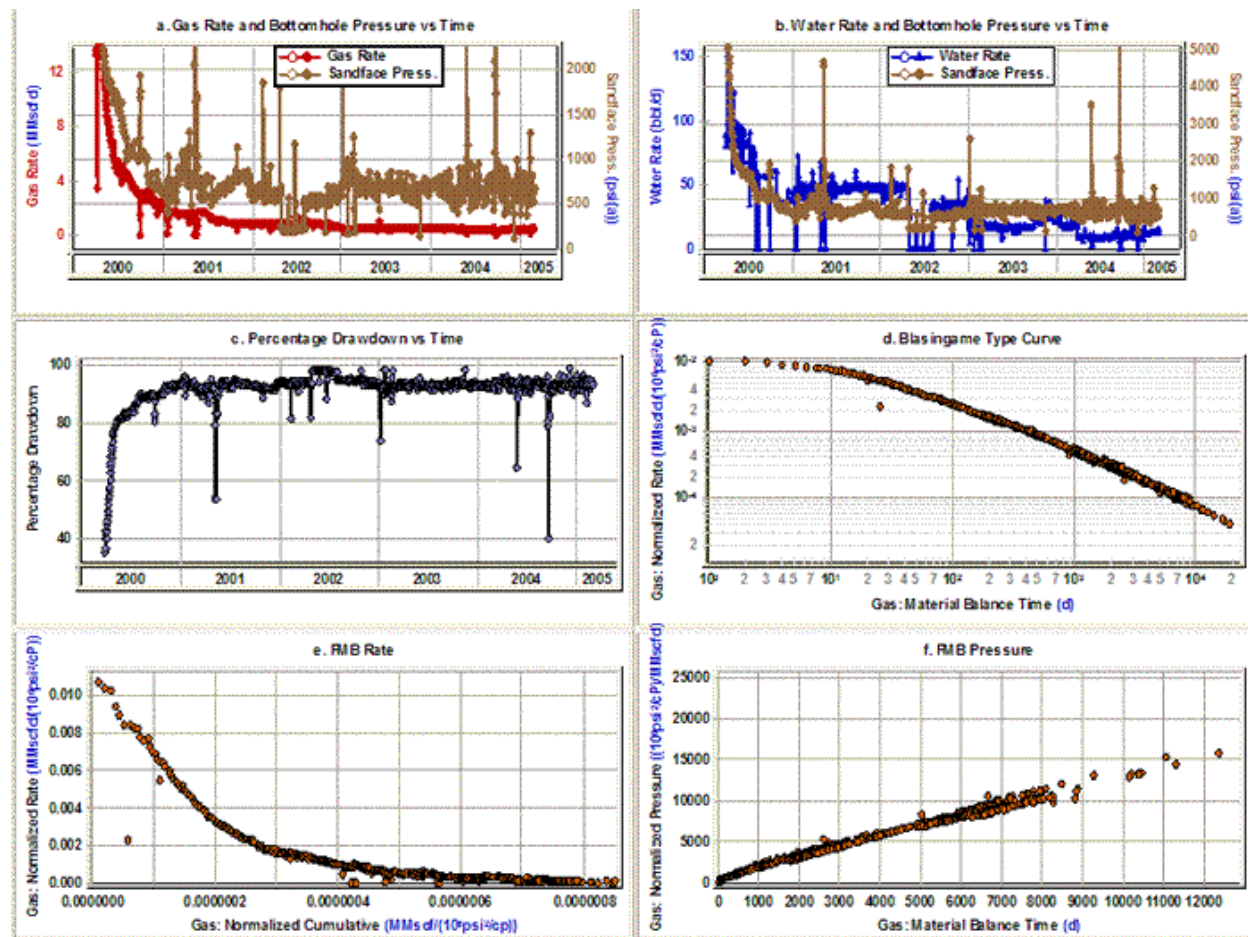
Case 8

This is a high-permeability gas well. In this example, we do not emphasize the consistency between pressure and rate data. We just want to point out the value of diagnostic plots for indicating reservoir productivity issues. The gas rate and flowing sandface pressure versus time is plotted in Figure 9a. It can be seen from this figure that there are two step changes in rate, which are not reflected in pressure data. This plot also shows that the rate declines rapidly from September 2004. Figure 9b shows log q versus log t for this well. As can be seen, this log-log plot accentuates the declining trend in rate, as it compresses the late-time data. Liquid loading can sometimes cause this abnormal decrease in gas rate.

To investigate the possibility of liquid loading, the ratio of gas-rate / critical-Turner-rate is plotted versus time and presented in Figure 9c. It can be seen from this figure that when the gas rate started to decline, the gas rate was much higher than the critical liquid lift rate. The rapid decline in rate therefore indicates a decrease in reservoir productivity and not liquid loading. Figure 9d shows the water-gas ratio versus time for this well. This plot shows a rapid increase in the water-gas ratio at the same time that rate declines rapidly. Therefore, the rapid decline in gas rate was because of water reaching the well inside the reservoir and not liquid loading, and in fact, it is a reservoir problem not a wellbore problem. The fact that this well is producing this much water could mean that we are dealing with an active water-drive reservoir, or that a secondary gas cap is pushing water ahead of it to the well. The well was shut in for six months, but after that, the same problem occurred very quickly (that is, a high water-gas ratio).

Figure 9: Case 8 diagnostic plots
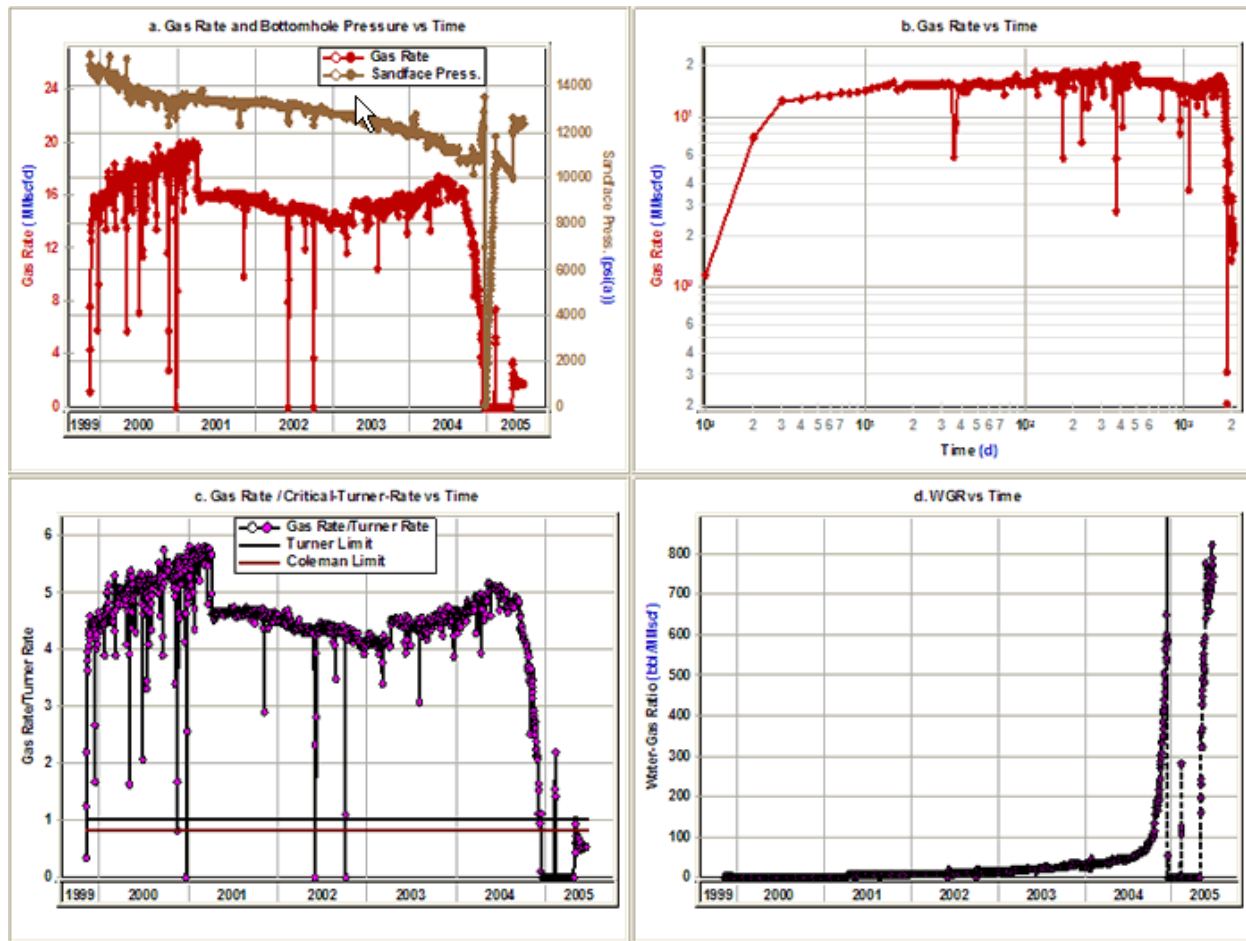
Case 9

As mentioned earlier, the first step in production data diagnostics is the removal of outliers to eliminate any incorrect interpretation caused by these outliers. It was also mentioned that often outliers show a unit slope on typecurves. In this example, we present a dataset that shows this problem. Figure 10a shows the gas rate and sandface flowing pressure versus time. The outliers are shown by hollow points, so they can be distinguished from the rest of the data. Figure 10b shows the Blasingame type-curve plot for this case. The outliers are also shown by hollow points in this plot. It can be seen from this plot that the unit slope on this typecurve is caused by outliers, not depletion. Therefore, this unit slope should not be used as an indication of original-gas-in-place or boundary-dominated flow.

Figure 10: Case 9 diagnostic plots

a. Gas Rate and Bottomhole Pressure vs Time

b. Blasingame Type Curve
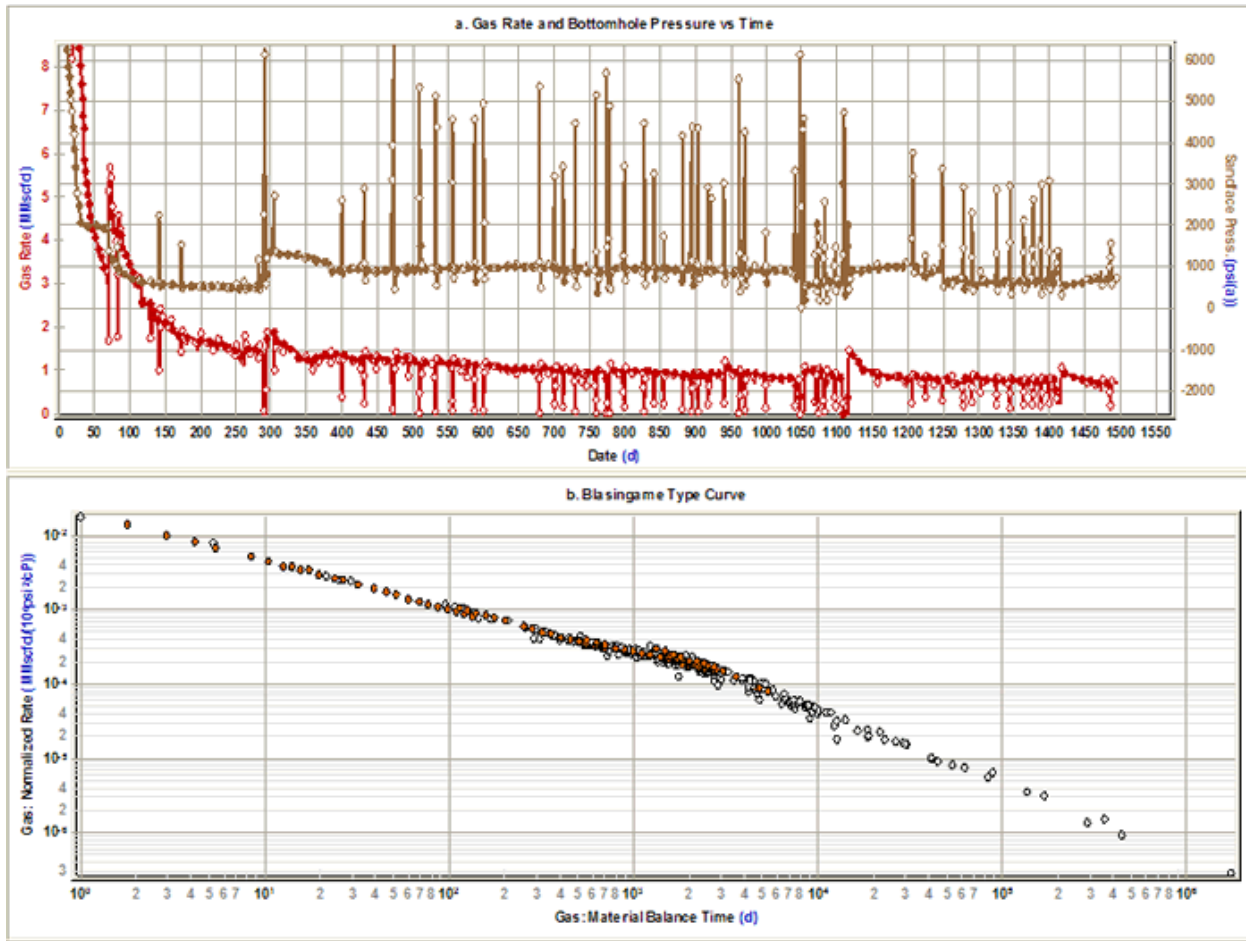
Data diagnostics flowchart

Common causes for data inconsistencies are as follows:

- Recompletion, reperf, refrac

- Fracture cleanup

- Wellbore cleanup

- Liquid loading

- Slugging

- Tubing change-out

- Changing flowpath

- Under-reported work-overs

- Incorrect pressure source and flow path

- Pressure or rate averaging

- Out of sync pressure and rate time-tracks

- Missing flowing pressures or rates

- Incorrect initial pressure

- Misreported water production

- Significant increase in water gas ratio (WGR)

Use the flowchart below to evaluate the quality of your data:

Start pre-analysis dia-gnostics here
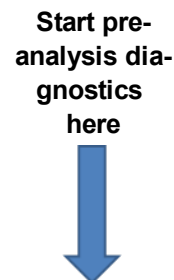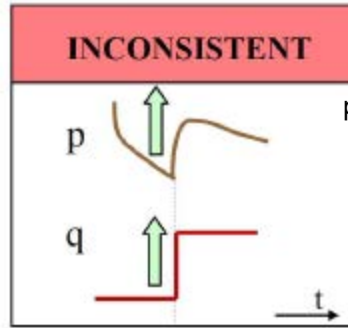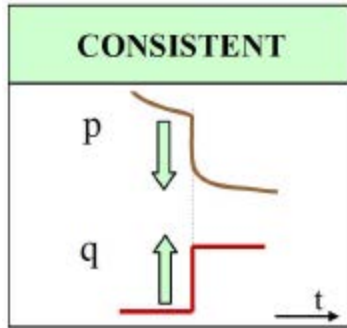
Do the instantaneous changes in pressure and rate correlate? — NO → See the step change correlation on the rate & pressure vs. time plot.

YES ↓
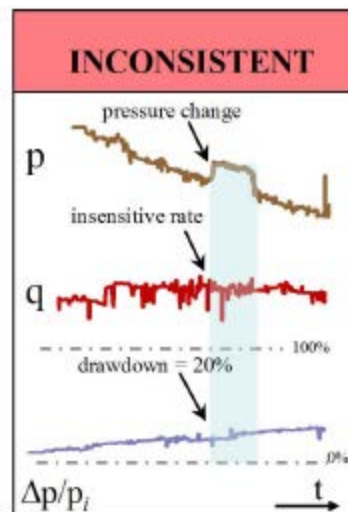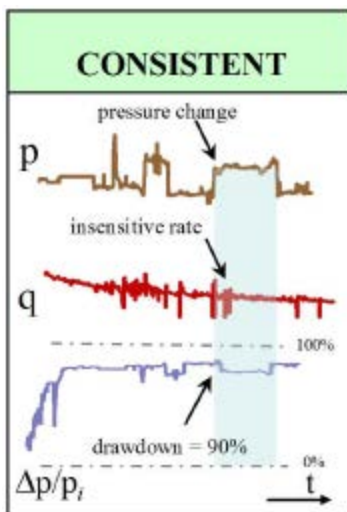
Is the well operating under high drawdown? — NO → See the drawdown plot.

YES ↓
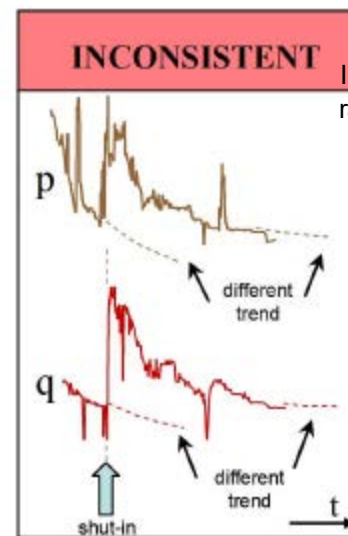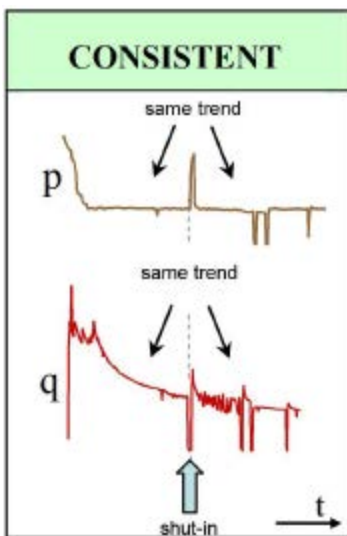
Is the trend in rate and pressure consistent? — NO → See the trend correlation on the rate & pressure vs time plot.

YES ↓

CONSISTENT

p

t

INCONSISTENT

p

incorrect point

missing

t

Is the data smooth? Is the data continuous?

NO → See the stable data and continuous smooth data plots on the rate & pressure vs time plot.

YES ↓

CONSISTENT

p

smooth

t

INCONSISTENT

p

scatter

t

Have the outliers been removed?

NO → See the continuous smooth data plot on the rate & pressure vs time plot.

YES ↓

CONSISTENT

$q/\Delta p_p$

step rate changes

declining trend

t_c

INCONSISTENT

$q/\Delta p_p$

inclining trend

t_c

Does the Blasingame graph continuously decline? Or, does the NPI graph continuously incline?

NO → See the Blasingame and NPI plots

CONSISTENT

$\Delta p_p/q$

inclining trend

step rate changes

t_c

INCONSISTENT

$\Delta p_p/q$

declining trend

t_c

YES ↓

| CONSISTENT | INCONSISTENT | Do the FMB rate or pressure plots have a single continuous stem? | | NO → See the FMB rate and FMB pressure plots |

single continuous stem — $q/\Delta p_p$ vs $Q/\Delta p_p$

two separate stems — $q/\Delta p_p$ vs $Q/\Delta p_p$

YES ↓

$\Delta p_r/q$ — single continuous stem — vs t_c

$\Delta p_r/q$ — two separate stems — vs t_c

| CONSISTENT | INCONSISTENT | Is the gas rate above the critical Turner rate? | | NO → See the Turner rate plot |

above Turner rate — Turner / Coleman — 1.0 — q/q_T vs t

Turner 1.0 / Coleman — below Turner rate — q/q_T vs t

YES ↓

| CONSISTENT | INCONSISTENT | Is the water rate reported? Does it appear to be correct? | | NO → See the WGR & water rate plot |

stable rate — q_w vs t

q_w — incorrect rates reported — vs t

YES ↓

Is the water rate free of rapid increases? — NO → See the WGR & water rate plot

YES ↓
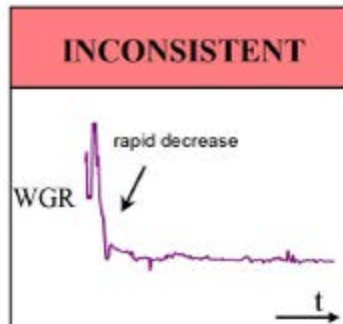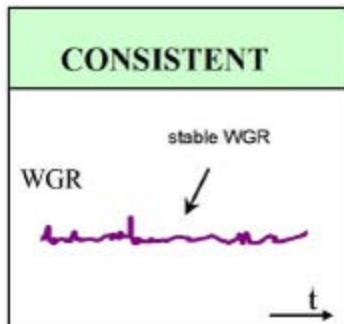
Is WGR free of rapid decreases? — NO → See the WGR & water rate plot

YES ↓
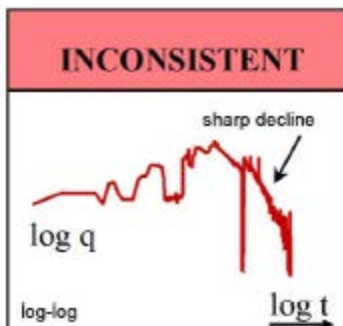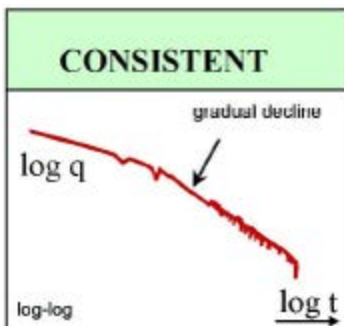
Is the gas rate on the log-log plot free of sharp declines? — NO → See the log gas rate plot

YES ↓

Finish. Proceed to analysis

Rate & pressure vs. time (Cartesian) plot

Examine the rate & pressure vs. time (Cartesian) plot to answer the following questions:

- Do step changes in pressure and rate correlate with each other?

- Is the general trend in the rate reflected in the pressure, and vice versa?

- Is the production rate and pressure data stable?

- Is the rate and pressure data smooth, continuous, and free of scatter?

Do step changes in pressure and rate correlate with each other?
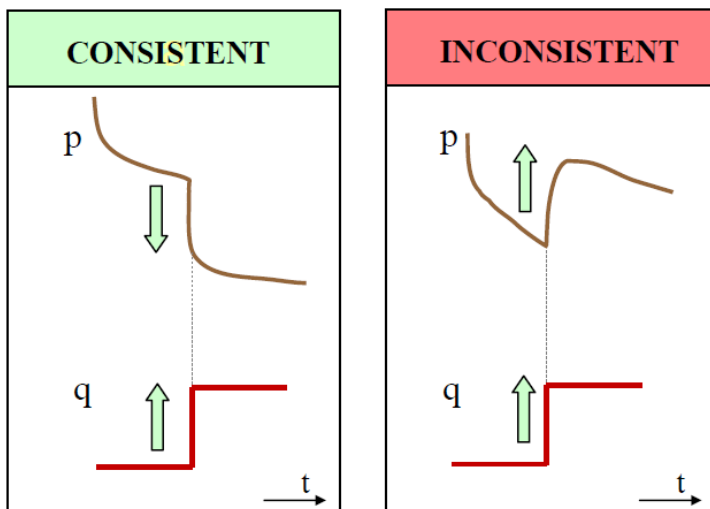
- A sharp *increase* in rate should correspond to a sharp *decrease* in pressure, and vice versa.

- The response to a step change should be immediate and not gradual.

Reasons for inconsistencies:

Incorrect pressure

- The pressure may have been measured on the other side of the choke / valve.

- A change in liquid holdup in the wellbore.

- At high drawdown, the rate becomes insensitive to pressure changes. For additional information, see the percentage drawdown plot. If changes in pressure are not reflected in the rate data, this may not be a cause for concern.

- Pressures may be measured every minute, but reported daily. An aver-

age daily rate is meaningful, but an average daily pressure is not.
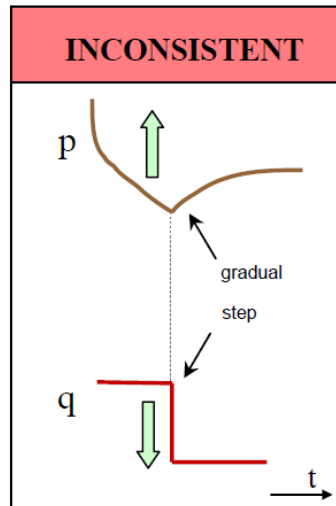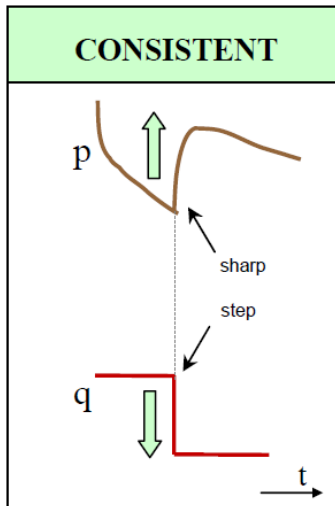
Incorrect rate

- The rate may be averaged from group metering.

- The rate may be a daily or monthly average.

- Unreported liquid production from a gas well.

Time periods

- If the data in different time periods is inconsistent, the data in the low-flow-rate region is more likely to be in error.

Is the general trend in the rate reflected in the pressure, and vice versa?
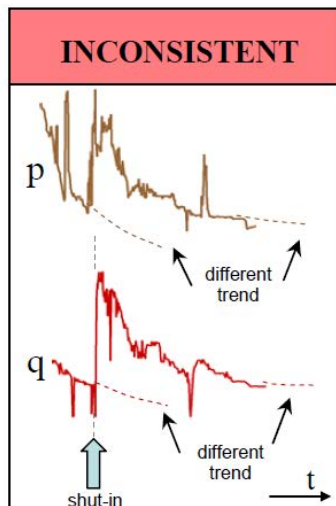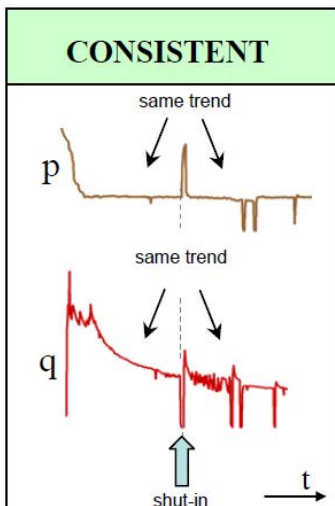
- If the rate is disrupted but comes back to the original trend, the pressure should also return to its original trend.

- If there is a change in the rate trend, the change in the pressure trend should be consistent with these bulleted items.)

Reasons for inconsistencies:

- A change in operations (for example, location of pressure measurement, metering, etc.).

- Tubing change-outs, hydraulic fractures, work-overs, recompletions, etc. The Blasingame, NPI, FMB rate, and FMB pressure plots tend to be better suited for this diagnosis.

Is the production rate and pressure data stable?
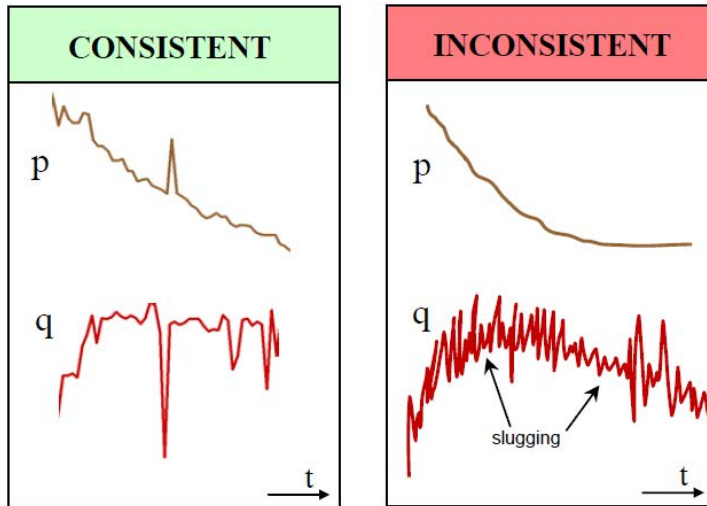
- Unstable rates indicate slugging, even though no water is reported.

- Sometimes rates are smoothed by reporting an average day rate.

- Sometimes pressure data is smoothed for supervisory control and data acquisition (SCADA) systems.

- These smoothing actions obscure fluctuations.

Reasons for inconsistencies:

- Liquid production may only be measured at the plant, and not at the well.

- Often water production is not properly reported.

- Liquid loading in the wellbore.

- The WGR & water rate plot provides further insight.

- The Turner rate plot is a valuable diagnostic tool.

- Sandface pressures can fluctuate, even though wellhead pressures are smooth. This is due to the multiphase calculations of sandface pressures.

Is the rate and pressure data smooth, continuous, and free of scatter?
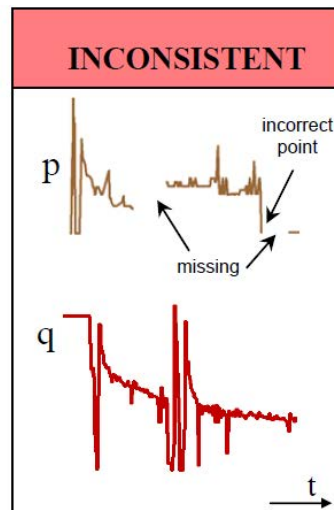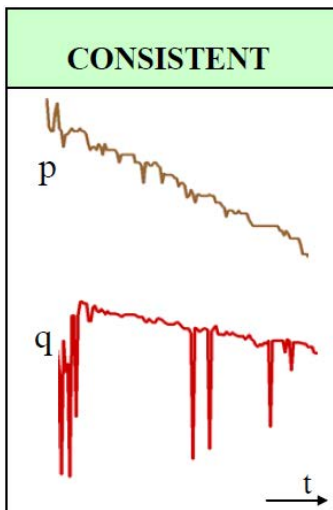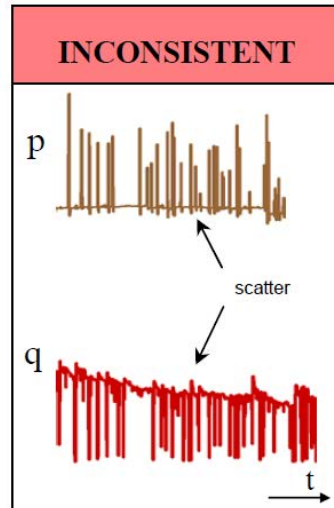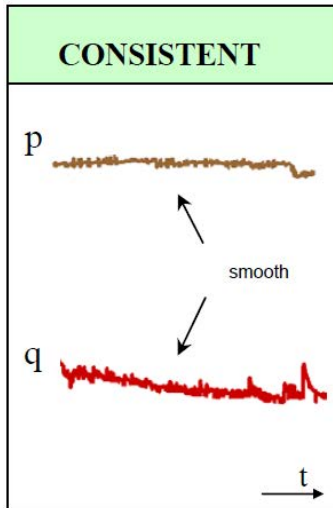
- Outliers can create a false unit slope (which suggests boundary-dominated flow) on typecurves that use the concept of "material balance time".

- Interpolation of missing pressures is often misleading.

- If the reported data appears too smooth, it is possible that interpolations are used, instead of measurements.

Reasons for inconsistencies:

- Pressure and rate data often contain outliers. This scatter can be removed from the production dataset using a median filter.

- Sometimes failing to exclude these outliers can result in false conclusions about the reservoir, because they tend to line up on a unit slope on a typecurve log-log plot. For additional information, see the Blasingame plot.

- These outliers can be recognized because they are sparse.

- Linear interpolation or averaging of pressures is not a true representation of reservoir characteristics.

- The rule of thumb is that if the data appears too straight, it is most likely incorrect, not measured, or interpolated.

Turner rate

These questions apply to the Turner rate:

- Is the gas rate above the critical Turner rate?

- Do the casing and tubing pressures track one another?

Is the gas rate above the critical Turner rate?
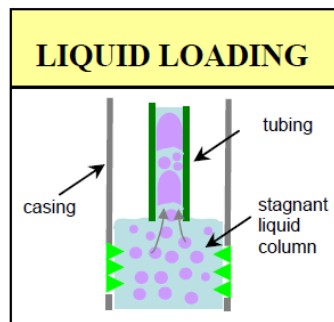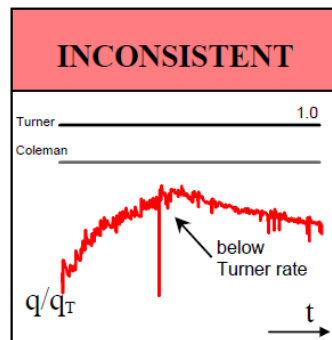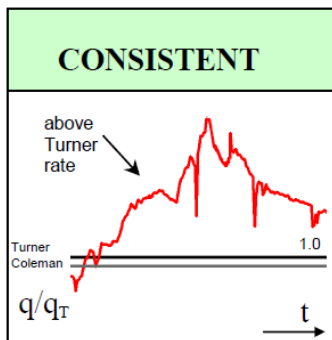
- The critical Turner rate is defined as the minimum rate required to lift liquids in the wellbore. The plot is the ratio of gas rate / critical-Turner rate (q/q_T).

- If the ratio < 1, there is a likelihood of liquid loading.

- The critical Coleman rate is an alternative to the Turner rate. The Turner rate is approximately 20% higher than the Coleman rate, and many operators prefer the Coleman calculation to that of Turner.

- If the ratio is < 1, calculations for sandface pressures from wellhead measurements are likely to be in error, due to not accounting for a "stagnant" liquid column. For additional information, see the WGR & water rate plot.

Reasons for inconsistencies:

- The gas rate below which liquid loading occurs depends on the diameter of the pipe and the pressure of the gas. Liquid loading occurs more often when producing through the casing.

- When liquid loading is indicated (ratio < 1), it is often accompanied by a reduced production of liquids,

or a reduced liquid / gas ratio. For additional information, see the WGR & water rate plot.

- Usually following the onset of liquid loading, the tubing is replaced with a smaller diameter tubing to increase the gas rate and lift the liquids. This event may not be recorded.

- If the specified tubing ID is incorrect, the Turner rate calculation may also be incorrect. This affects the value of the critical Turner rate, but has little effect on the calculated sandface flowing pressures.

Do the casing and tubing pressures track one another?
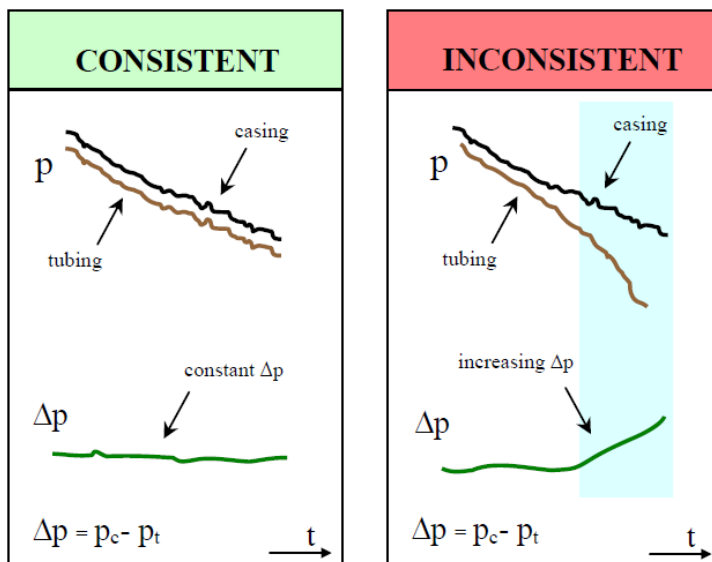
- Tubing and casing pressures track each other when there are no problems in the wellbore (for example, liquid loading, hydrating).

Reasons for inconsistencies:

- Diverging tubing (p_t) and casing (p_c) pressures are an indication of liquid loading or hydrating in the wellbore.

- To convert from wellhead to sandface pressure, use the quiet-side pressure (usually the casing) and assume the liquid level is at the end of tubing (EOT).

- If sandface pressure is being calculated from wellhead measurements, and the flowing side is being used, multiphase flow calculations must be used, and their accuracy is poor.

Log gas rate (log-log)

Does the rate have a sharp decline when plotted on a logarithmic scale?
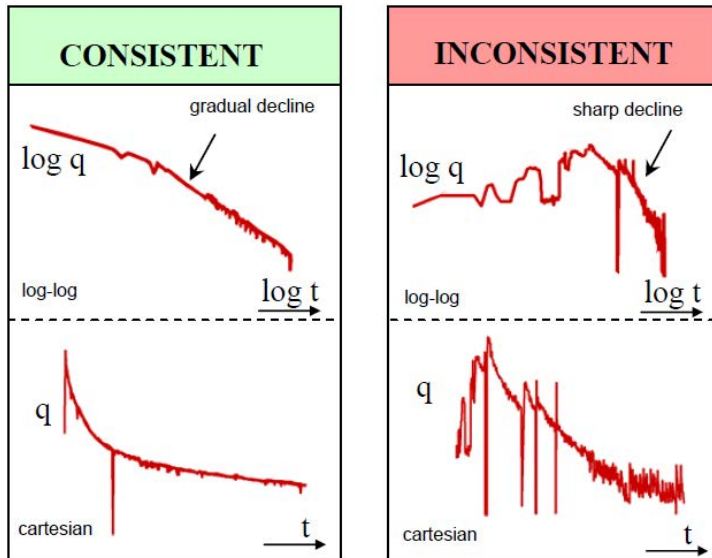
- The log scales tend to accentuate the problem, which may not be evident in Cartesian coordinates. The scale compression of large-time values accompanied by the scale expansion of low rates makes the problem more visible.

- A sharp decline on a log-log plot indicates a problem.

Reasons for inconsistencies:

- An abnormal decrease in the gas rate can indicate liquid loading.

- Often accompanied by the production of liquids.

- For additional information, see the WGR & water rate plot.

WGR & water rate

These questions apply to the water gas rate (WGR) and water rate:

- Are the water rate and WGR stable and relatively constant?

- Is the flow in the reservoir effectively single phase?

- Is there a rapid decrease in the WGR?

- Are there significant fluctuations in the WGR?

Are the water rate and WGR stable and relatively constant?
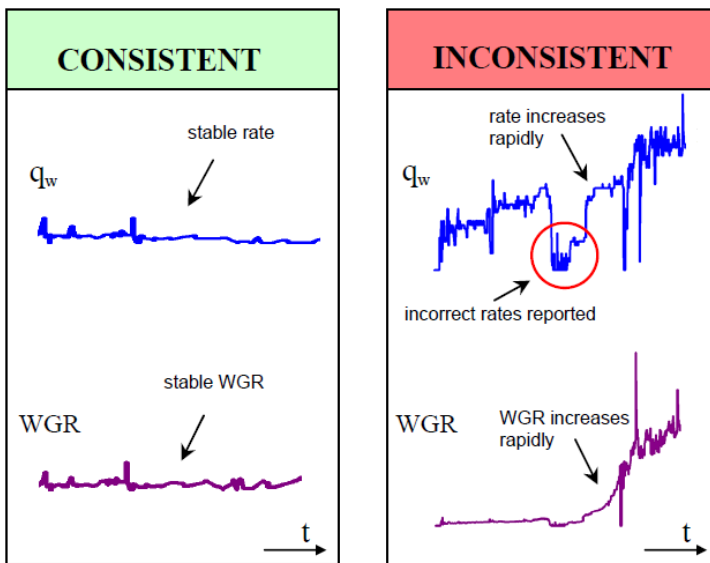
- A sudden increase in the water rate could indicate future productivity problems.

- The data following a rapid increase in WGR should be treated with caution, especially if the pressure measurements are at the wellhead.

- If pressure data is measured at the midpoint of perforations (MPP), then liquid loading or any other wellbore issues will not affect the production data analysis.

Reasons for inconsistencies:

- A sudden increase in the water rate could be due to coning, or a reservoir water influx. Either way, operating problems due to wellbore effects are likely to result in reduced productivity.

- The conversion of wellhead pressure to sandface pressure changes if water production is present (because of liquid hold-up in the wellbore).

- If the water rate is not reported, the quiet-side pressure data can be used instead, as it is not affected by an incorrect liquid rate at the end of tubing (EOT).

Is the flow in the reservoir effectively single phase?
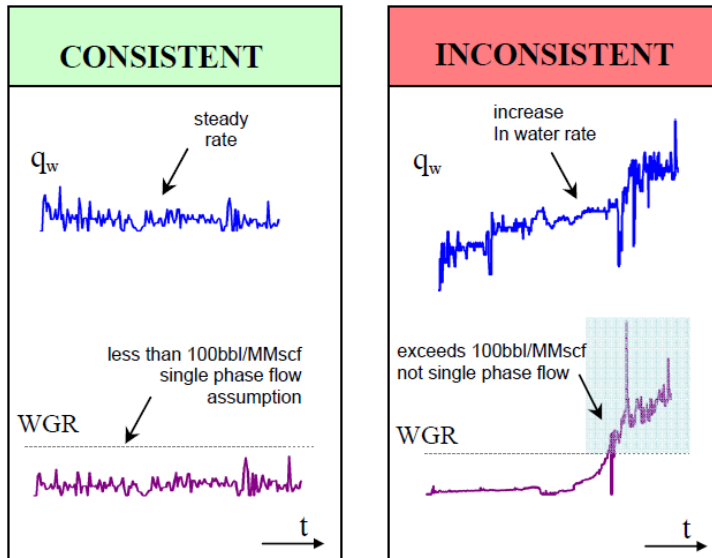
- For gas wells with low WGR, the assumption of single-phase gas flow may still be valid.

- For high WGR, the assumption of single-phase flow may not be valid. Data exceeding an approximate threshold value of 100 bbl / MMScf should be used with caution, as typecurves and analytical models assume single-phase flow.

Reasons for inconsistencies:

- Water coning results in a changing skin, which can invalidate the reservoir models in use.

- Saturation changes in the reservoir result in varying effective permeability.

Is there a rapid decrease in the WGR?
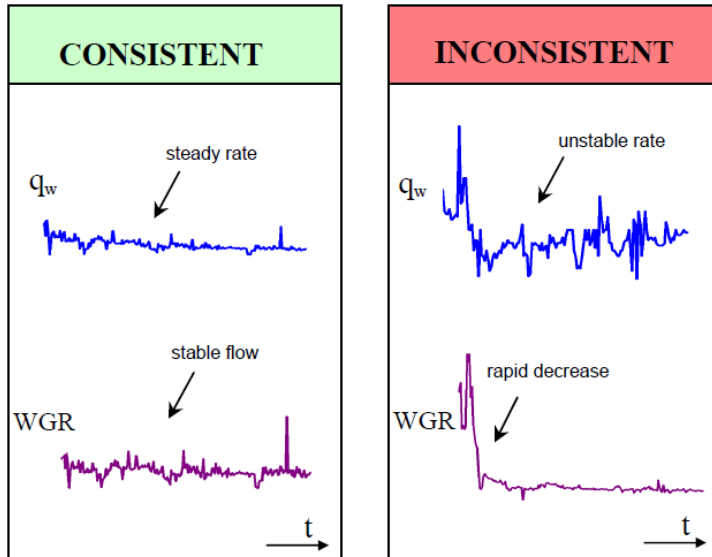
- A sudden decrease in WGR coupled with an unstable water rate could indicate liquid loading.

  Reasons for Inconsistencies:

- When the gas rate decreases below a certain value known as the critical rate, the gas can no longer lift the liquids in the wellbore, and liquids start to accumulate. This is known as liquid loading and can result in a decrease in apparent water production. For more information, see the Turner rate plot.

- If sandface pressures are being calculated from wellhead measurements, an additional pressure drop may need to be added to represent the "stagnant" column of liquid.

Are there significant fluctuations in the WGR?
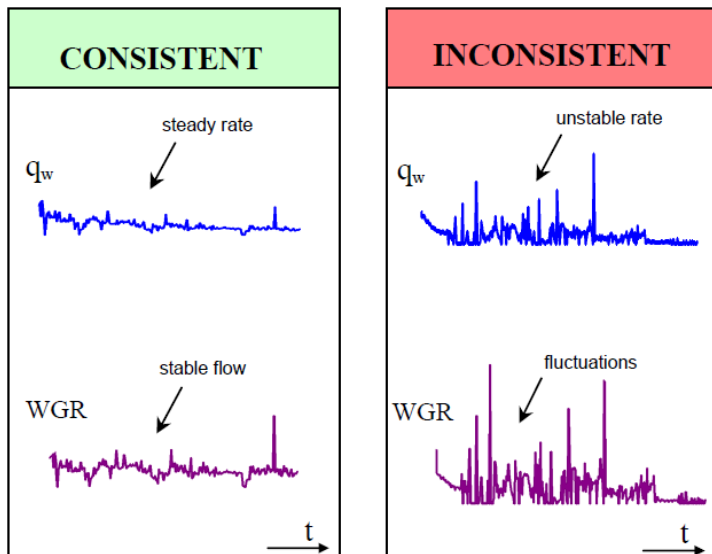
- Fluctuations in WGR are an indication of slug flow.

  Reasons for inconsistencies:

- If slug flow is indicated, yet no water rate is reported, then the quality of the calculated sandface pressures may be questionable, even if the wellhead pressures are of good quality.
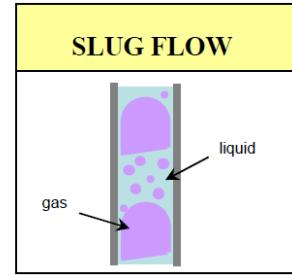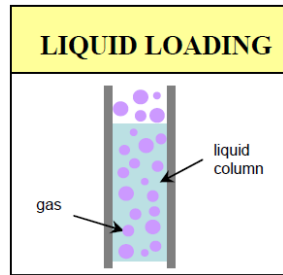
Drawdown %

Is the well producing under high drawdown conditions?

This is a plot of $\Delta p / p_i$ X 100% versus time. It indicates the degree of drawdown.

The shape of the inflow performance relationship (IPR) curve shows that in high drawdown situations, the rate becomes insensitive to pressure.

IPR CURVE

p

high drawdown region

q
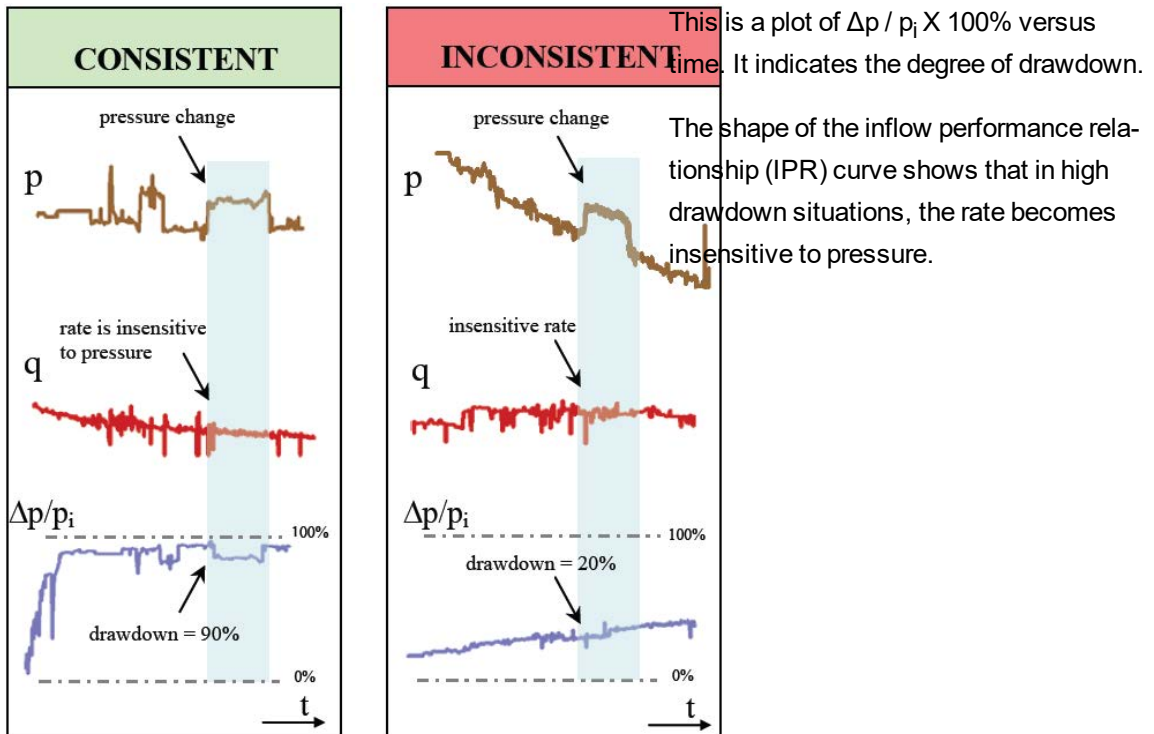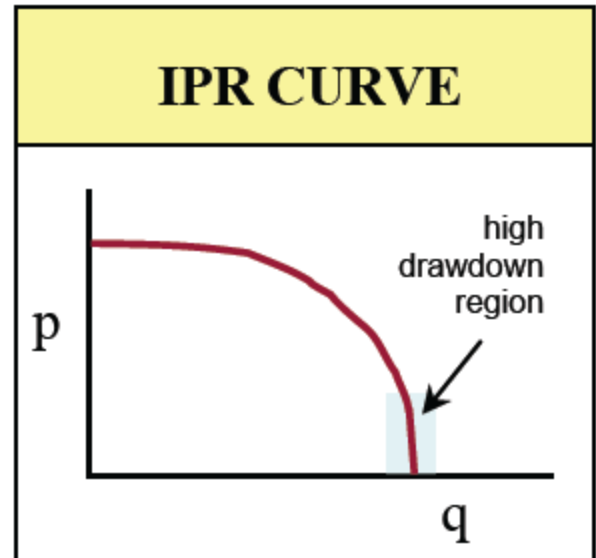
Reasons for inconsistencies:

- At low drawdown, if the flowing pressure decreases (increases), and the rate does not increase (decrease), it means that one or the other is incorrect.

- At high drawdown, the well is operating in the low pressure region of the IPR curve. If the flowing pressure changes but the flow rate does not, it is not a cause for concern.

- At high drawdown, a lack of correlation between rate and pressure is not a cause for concern.

CONSISTENT

pressure change

p

rate is sensitive
to pressure

q

$\Delta p/p_i$

100%

drawdown = 20%

0%

t
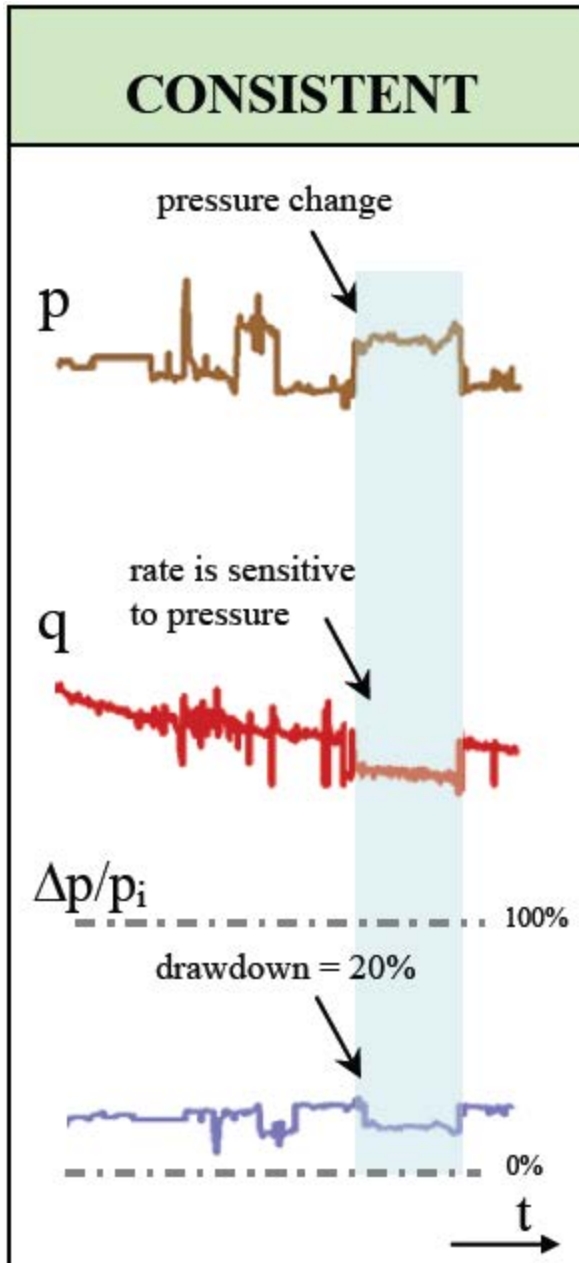
Blasingame (log-log)

These questions apply to Blasingame (log-log):

- Does the normalized rate continuously decline?

- Does the Blasingame plot have a single continuous stem?

- Are outliers being misinterpreted as boundary-dominated flow?

Does the normalized rate continuously decline?
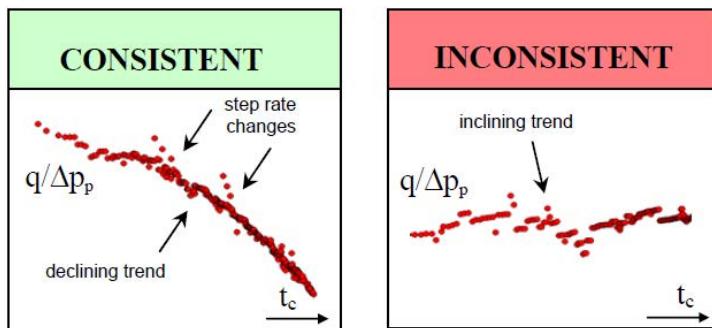
- The log-log plot of normalized rate ($q/\Delta p_p$) versus material balance time (G_p/q) should have a declining trend.

- A step change in rate causes a sudden deviation from the declining trend, but if the data is consistent, it reverts to the original declining trend.

Reasons for inconsistencies:

- An increasing trend indicates non-reservoir effects, such as near wellbore cleanup, improving skin, wellbore liquid unloading (if pressures have been calculated from wellhead data).

Does the Blasingame plot have a single continuous stem?
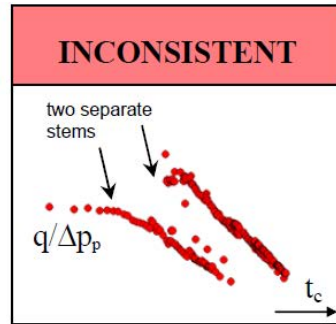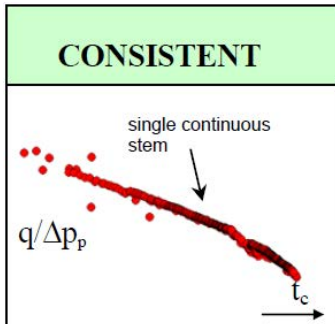
- Changes in rate or pressure are accounted for in the Blasingame plot, and should *not* cause it to develop multiple stems.

- In the case of multiple stems, the stem that represents the correct reservoir model should be used for analysis.

Reasons for inconsistencies:

- The reservoir model has changed (for example, work-over, recompletion, refrac, etc.).

- The wellhead pressures measurement location may have changed (for example, tubing, casing, before / after valve), or there may have been a change of flow path or tubulars.

Are outliers being misinterpreted as boundary-dominated flow?
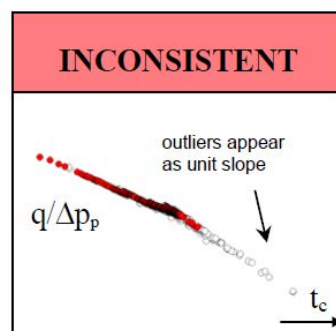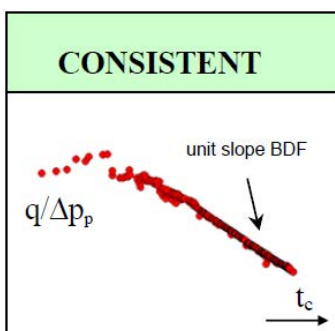
- Outliers often appear on a unit slope on the Blasingame plot. This can lead to an incorrect diagnosis of reservoir depletion or boundary-dominated flow (BDF).

Reasons for inconsistencies:

- Outliers have been included in the analyses. Apply the median filter to remove the outliers.

NPI (log-log)

These questions apply to the normalized pressure integral (NPI) – log-log:

- Does the normalized pressure continuously increase?

- Does the NPI plot have a single continuous stem?

- Are outliers being misinterpreted as boundary-dominated flow?

Does the normalized pressure continuously increase?
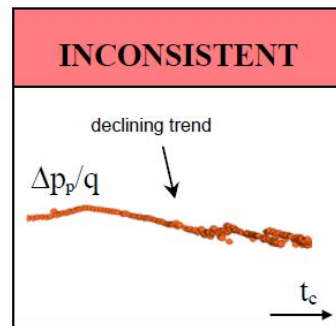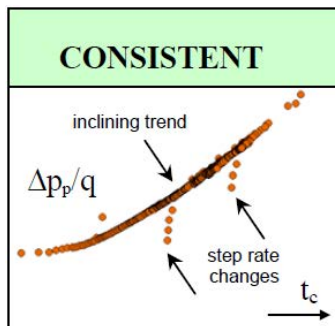
- The log-log plot of normalized pressure ($\Delta p_p/q$) versus material balance time (G_p/q) should have an increasing trend.

- A step change in rate causes a sudden deviation from the inclining trend, but if the data is consistent, it reverts to the original trend.

Reasons for inconsistencies:

- A decreasing trend indicates non-reservoir effects, such as near wellbore cleanup, improving skin, wellbore liquid unloading (if pressures have been calculated from wellhead data).

Does the NPI plot have a single continuous stem?
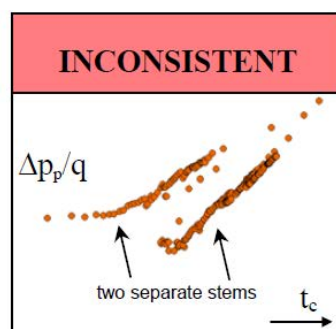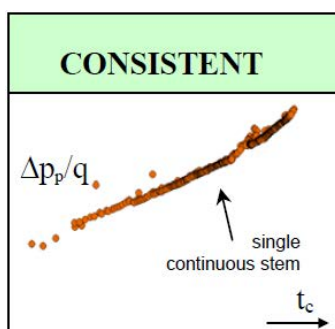
- Changes in rate or pressure are accounted for in the NPI plot, and should *not* cause it to develop multiple stems.

- In the case of multiple stems, the stem that represents the correct reservoir model should be used for analysis.

Reasons for inconsistencies:

- The reservoir model has changed (for example, work-over, recompletion, refrac, etc.).

- The wellhead pressures measurement location may have changed (for example, tubing, casing, before / after valve), or there may have been a change of flow path or tubulars.

Are outliers being misinterpreted as boundary-dominated flow?
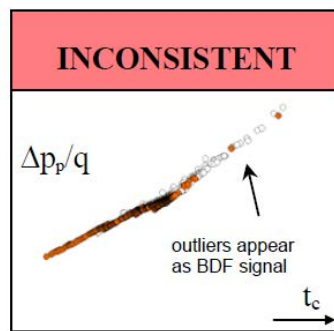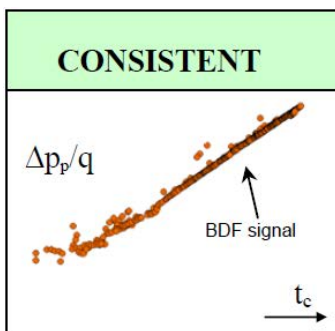
- Outliers often appear on a unit slope on the NPI plot. This can lead to an incorrect diagnosis of reservoir depletion, or boundary-dominated flow (BDF).

Reasons for inconsistencies:

- Outliers have been included in the analyses. Apply the median filter to remove outliers.

FMB rate (Cartesian)

These questions apply to the flowing material balance (FMB) rate – Cartesian:

- Does the normalized rate continuously decline?

- Does the FMB-Rate plot have a single continuous stem?

Does the normalized rate continuously decline?
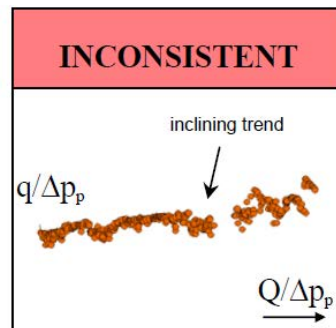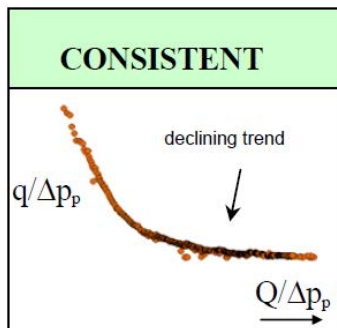
- The Cartesian plot of normalized rate ($q/\Delta p_p$) versus normalized cumulative production ($Q/\Delta p_p$) should have a declining trend, and tend towards a straight line.

Reasons for inconsistencies:

- An increasing trend indicates non-reservoir effects, such as near well-bore cleanup, improving skin, well-bore liquid unloading (if pressures have been calculated from wellhead data).

Does the FMB-Rate plot have a single continuous stem?
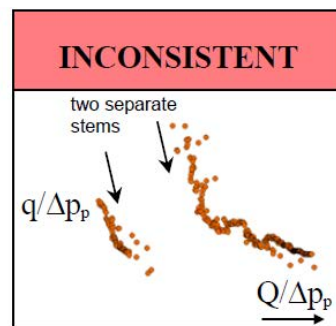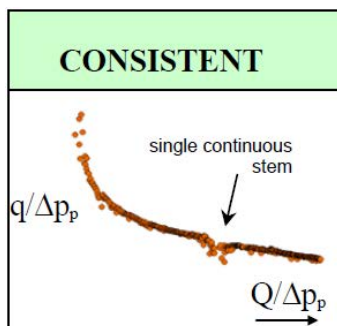
- Changes in rate or pressure are accounted for in the FMB-rate plot, and should *not* cause it to develop multiple stems.

- In the case of multiple stems, the stem representing the correct reservoir model should be used for the analysis.

Reasons for inconsistencies:

- The reservoir model has changed (for example, work-over, recompletion, refrac, etc.).

- The wellhead pressures measurement location may have changed (for example, tubing, casing, before / after valve), or there may have been a change of flow path or tubulars.

FMB pressure (Cartesian)

These questions apply to flowing material balance (FMB) pressure – Cartesian:

- Does the normalized pressure continuously increase?

- Does the FMB-Pressure plot have a single continuous stem?

Does the normalized pressure continuously increase?
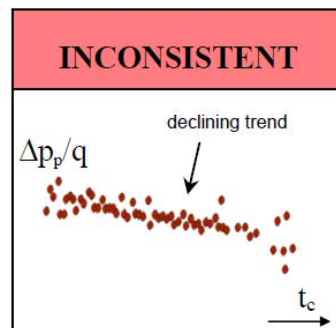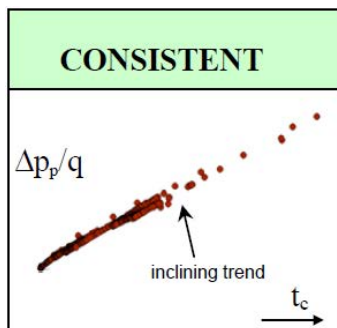
- The Cartesian plot of normalized pressure ($\Delta p_p/q$) versus material balance time (G_p/q) should have an inclining trend and tend towards a straight line.

   Reasons for inconsistencies:

- A decreasing trend indicates non-reservoir effects, such as near wellbore cleanup, improving skin, wellbore liquid unloading (if pressures have been calculated from wellhead data).

Does the FMB-Pressure plot have a single continuous stem?
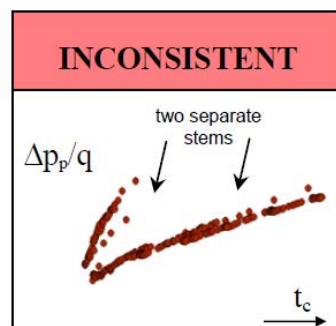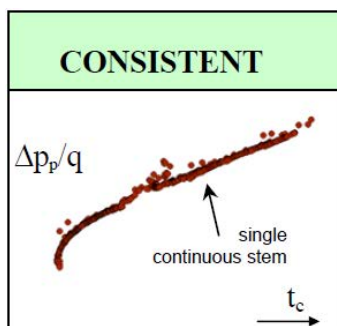
- Changes in rate or pressure are accounted for in the FMB-pressure plot, and should *not* cause it to develop multiple stems.

- In the case of multiple stems, the stem that represents the correct reservoir model should be used for the analysis.

   Reasons for inconsistencies:

- The reservoir model has changed (for example, work-over, recom-

pletion, refrac, etc.).

- The wellhead pressures measurement location may have changed (for example, tubing, casing, before / after valve), or there may have been a change of flow path or tubulars.

Equivalence of constant rate and constant pressure solutions

A well produced at a constant rate exhibits a varying (declining) sandface flowing pressure, whereas a well produced at a constant sandface pressure exhibits a varying decline rate. There is a strong symmetry between the two solutions, as both are obtained from the same equation, namely the equation that governs fluid flow in porous media. The symmetry is not exact, however, because the boundary conditions under which the two solutions are obtained are different.

The constant rate solution can be converted to a constant sandface pressure solution (and vice versa) using the principle of superposition. The constant sandface pressure solution is obtained by superposing a large number of very short constant rate solutions in time. When plotted against superposition time, the superposed constant rate solution is very similar to the constant pressure solution, provided the discretization intervals are sufficiently small. It turns out that the two solutions are quite similar during transient flow anyway, and therefore, superposition is not required to make one look like the other. However, they quickly diverge after boundary-dominated flow begins. The constant rate solution behaves like the harmonic stem of the Arps type curves, while the constant pressure solution declines exponentially. The figure below compares the two solutions by plotting the dimensionless typecurves of each.

Comparison of q_D with $1/p_D$
Cylindrical Reservoir with Vertical Well in Center
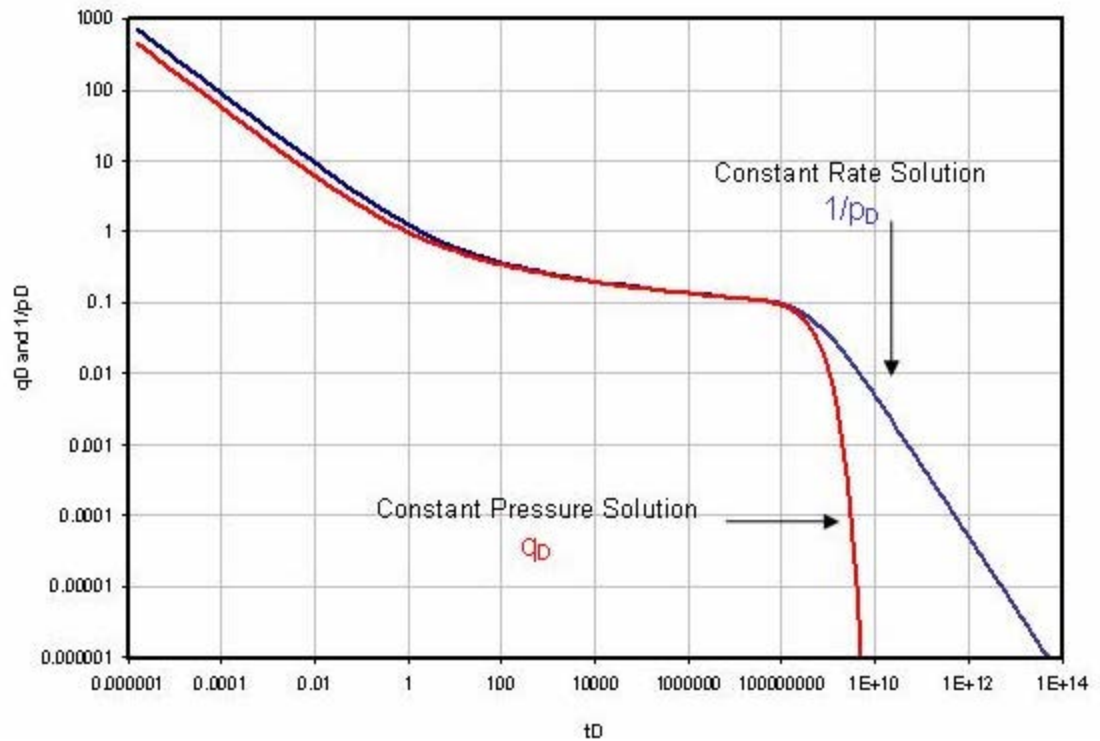
A method for forcing one solution to look like the other during boundary-dominated flow is useful because the necessity of using superposition in time would be avoided completely. Because of pressure transient analysis, diagnostic tools for analyzing the constant rate solution are widely known and understood. Therefore, there is value in being able to analyze other types of solutions using the same diagnostic tools. The concept of material balance time provides the normalization necessary to make constant pressure and constant rate solutions equivalent. Material balance time converts the boundary-dominated flow portion of the constant pressure solution into the pseudo-steady state portion of the equivalent constant rate solution. Plotting using material balance time also allows solutions with both declining rates and pressures to look like the equivalent constant rate solution.

Fracture properties

Fracture flow capacity ($k_f w_f$)

Fracture flow capacity is a measure of how conductive or how easily fluid moves through a fracture. It is defined as the product of fracture permeability (k_f) and fracture width (w_f), as shown below:
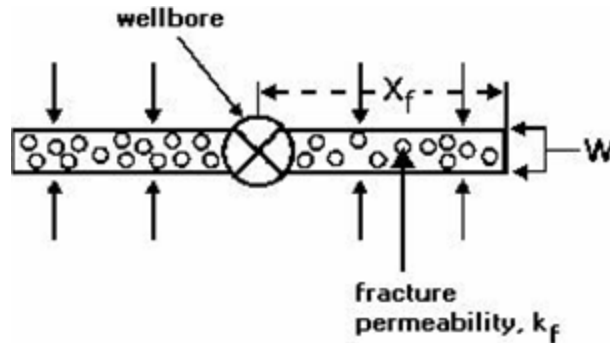
A large value of fracture flow capacity (>10,000 md ft) represents an infinite conductivity fracture, and yields a linear fracture flow response on the derivative. A small value of the fracture flow capacity (<10,000 md ft) represents a finite conductivity fracture and may yield a bilinear fracture flow response on the derivative. When the value of fracture flow capacity is divided by the product of formation permeability and fracture half-length, the result is known as the dimensionless fracture conductivity, defined as:

$$F_{CD} = \frac{k_f \, w_f}{k \, x_f}$$

This dimensionless form is a more common measure of fracture conductivity that is found in the literature.

Fracture half-length (x_f)

A hydraulic fracture is typically modeled by assuming it extends in a straight line equally on each side of the wellbore as shown in the following diagram.
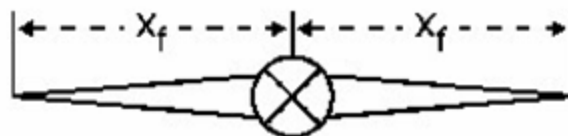
As shown, the fracture half-length is the distance from the well to the tip of the fracture.

The fracture half-length depends on the size of the fracture treatment and varies from a few feet to a few hundred feet. In pressure and rate transient analysis it is estimated from the linear fracture flow analysis.

Geomechanical reservoir models

Geomechanical models simulate changes in rock properties with time and pressure. In performance-based reservoir analysis, a geomechanical model may be coupled with a flowing material balance, typecurve, analytical, numerical, or unconventional reservoir module analysis. In addition, geo-mechanical models are useful for, and may be necessary additions to, analyses of overpressured reservoirs. The primary properties of interest are porosity, formation compressibility (pore compressibility), and permeability. The impact of these properties on the fluid flow model are discussed in the following sections.

Porosity and formation compressibility

Pore volume and pore volume compressibility are related through the following equation:

$$c_f \; = \; \frac{1}{V_p} \frac{d\, V_p}{d\, p}$$

In normally pressured reservoirs, the pore volume change with pressure is considered minimal, and thus the pore volume (formation) compressibility retains a very small, constant value. However, in overpressured reservoirs, the natural compaction process is incomplete, as a large portion of the over-burden remains supported by high internal pore pressure. As this pressure is released through fluid pro-duction, the pore space may reduce significantly. Thus, under overpressured conditions, formation compressibility is relatively large, and may have significant variation with pressure. This becomes important to the material balance equation, as pore compressibility is a significant energy term in over-pressured reservoirs.

In normally pressured gas reservoirs, the energy of the formation is usually negligible, compared to the energy of the gas. In oil reservoirs, the formation compressibility may be significant at any pressure. The graph below compares the energies (compressibilties) of formation and fluid (gas) over a large pressure range. In areas where they are near the same order of magnitude, the formation com-pressibility cannot be ignored.

Compressibility vs. Pressure (Typical Gas Reservoir)
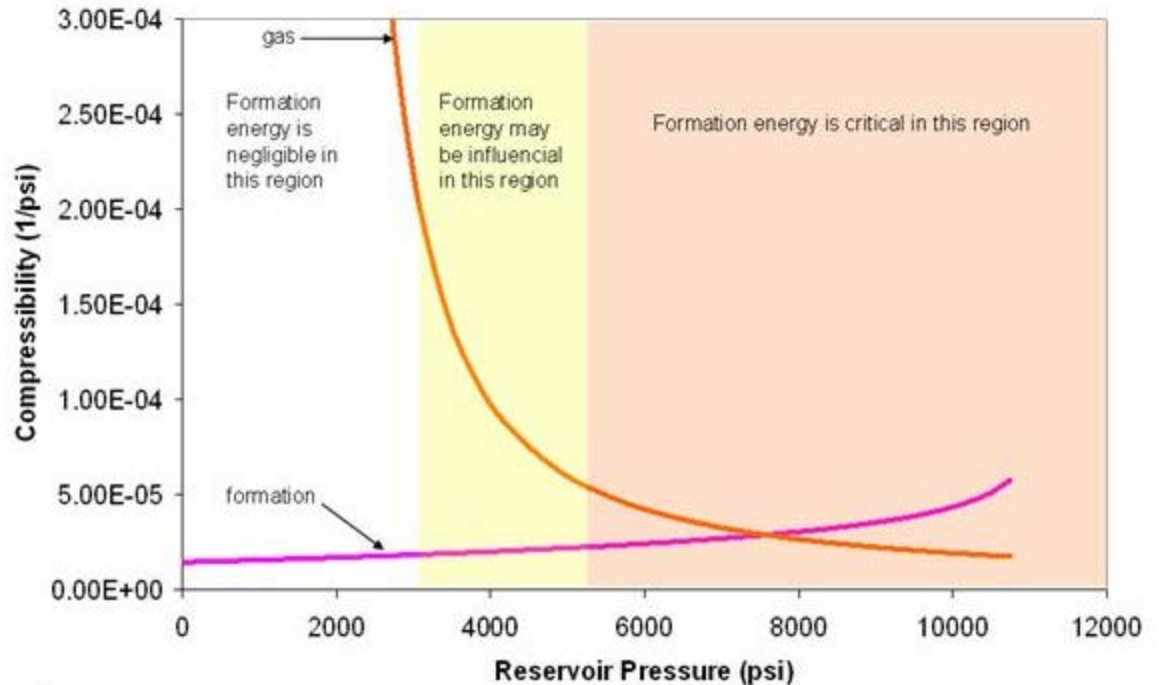
For overpressured reservoirs, there are very few published correlations. Most appear to be highly specific to area and rock type, and thus are not useful for universal application.

Hall

The most well-known and widely used correlation for formation compressibility was developed by Hall, and is a function of porosity. The Hall correlation is based on laboratory data and is considered reasonable for normally pressured sandstones. It tends to under-predict formation compressibility under high pressure conditions. This correlation is used when calculating initial formation compressibility on the Basic Reservoir Properties view.

$$c_f = 1.87 \cdot 10^{-6}\, \phi^{-0.415}$$

Dobrynin

The Dobrynin (1962) correlation can predict a relative change in formation compressibility over a range of net overburden pressures. It is designed for overpressured reservoirs. The correlation assumes a

semi-logarithmic relationship between formation compressibility and net overburden pressure between two limiting pressures, p_{min} and p_{max}. However, it does not predict the initial formation compressibility.

$$c_f = \frac{c_{f\ max}}{\log\left(\frac{p_{max}}{p_{min}}\right)}\ \log\left(\frac{p_{max}}{p_n}\right)$$

$$f_c = \frac{c_f}{c_{fi}} = \frac{\log\left(\frac{p_{max}}{p_n}\right)}{\log\left(\frac{p_{max}}{p_{ni}}\right)}$$

$$p_{max} = 30000\,psi$$

$$p_n = p_e + \alpha\,(p_i - p)$$

Laurent et al. (1993) propose an empirical correlation for Biot Coefficient (α):

$$\alpha = 1.75\,\phi^{0.51}$$

The Dobrynin correlation is considered a reasonable predictor of variation in formation compressibility, provided that the following conditions are met:

- Net overburden pressure must lie within the range of p_{min} and p_{max} (usually 150 to 30,000 psi)

- Overburden pressure must be higher than the product of the initial pressure and Biot's number (initial net overburden pressure must be greater than zero)

The Dobrynin correlation may be used to generate a continuous compressibility profile using a known formation compressibility value:

- Initial formation compressibility (usually between 10 and 80 microcips for over-pressured reservoirs)

- Overburden pressure gradient (Pgrd, psi/ft)

- Reservoir depth (ft)

Formation compressibility is then solved for any value of pressure.

Pressure-dependent permeability

In the standard pressure transient equations, permeability is usually considered to be constant. However, there are several situations in which this assumption may not be a valid:

- Compaction in overpressured reservoirs
- Very low permeability reservoirs (in general)
- Unconsolidated and/or fractured formations

Variable permeability is an important (and sometimes critical) consideration, with regards to the fluid flow model. As a result of pore volume reduction during fluid withdrawal, the available flow area is reduced, and thus the permeability decreases with pressure. As with formation compressibility, the variable permeability effect is greatest in overpressured conditions. The process of pore volume collapse in overpressured reservoirs is referred to as compaction.

One way to account for a variable permeability over time is to modify the definition of pseudo-pressure and pseudo-time. Another way to account for variable permeability is through the use of formation compressibility correlations.

Yilmaz and Nur

Yilmaz and Nur present a generic correlation, suitable for the pressure variable permeability observed in extremely low permeability reservoirs. The correlation introduces a "permeability modulus" (γ) which has a form identical to compressibility. The magnitude of the permeability modulus is a strong function of the formation compressibility.

$$\gamma = \frac{1}{k} \frac{d\,k}{d\,p}$$

$$\frac{k}{k_i} = e^{-\gamma\,(p_i - p)}$$

Dobrynin

Dobrynin presents a more detailed correlation, designed for overpressured reservoirs, which relates the fractional change in permeability due to formation compressibility, overburden pressure, and a dimensionless correlation factor (γ). Between a certain minimum and maximum pressure range (p_{min} and p_{max}), this correlation produces a semi-log straight line.

$$\frac{\Delta k}{k} = 2\left(1+\gamma\right) c_f^{\max}\left[p_{\min} + \frac{p_o}{\log\left(\frac{p_{\max}}{p_{\min}}\right)}\left[\log\left(\frac{p_{\max}}{p_o}\right) + 0.434 - \frac{p_{\min}}{p_o}\left[\log\left(\frac{p_{\max}}{p_{\min}}\right) + 0.434\right]\right]\right]$$

where:

γ is 0.33 for uniform pore distribution or very high pore compressibility, higher for poorly sorted sandstones with low pore compressibility.

The equation below relates the permeability at any pore pressure to that at conditions of zero net overburden pressure:

$$\frac{k_p}{k} = 1 - 2\left(1+\gamma\right) c_f^{\max}\left[p_{\min} + \frac{p_e - \alpha\overline{p}}{\log\left(\frac{p_{\max}}{p_{\min}}\right)}\left[\log\left(\frac{p_{\max}}{p_e-\alpha\overline{p}}\right) + 0.434 - \frac{p_{\min}}{p_e-\alpha\overline{p}}\left[\log\left(\frac{p_{\max}}{p_{\min}}\right) + 0.434\right]\right]\right]$$

It is more suitable to have an equation that relates permeability at any pressure to permeability at initial conditions, thus we rewrite the above as follows.

$$\frac{k_p}{k_i} = \frac{\frac{k_p}{k}}{\frac{k_i}{k}} = \frac{1-2(1+\gamma)c_f^{\max}\left[p_{\min}+\frac{p_e-\alpha\overline{p}}{\log\left(\frac{p_{\max}}{p_{\min}}\right)}\left[\log\left(\frac{p_{\max}}{p_e-\alpha\overline{p}}\right)+0.434-\frac{p_{\min}}{p_e-\alpha\overline{p}}\left[\log\left(\frac{p_{\max}}{p_{\min}}\right)+0.434\right]\right]\right]}{1-2(1+\gamma)c_f^{\max}\left[p_{\min}+\frac{p_e-\alpha p_i}{\log\left(\frac{p_{\max}}{p_{\min}}\right)}\left[\log\left(\frac{p_{\max}}{p_e-\alpha p_i}\right)+0.434-\frac{p_{\min}}{p_e-\alpha p_i}\left[\log\left(\frac{p_{\max}}{p_{\min}}\right)+0.434\right]\right]\right]}$$

where:

Biot's Number default: *0.85 to 1*

Maximum Formation Compressibility default: *30 to 80 microcips*

P_{max} = 30,000 psi

P_{min} = 150 psi

Geomechanical effects for oil analytical models

This content applies to water analytical models as well.

Background

Geomechanical effects are useful for (and may be necessary additions to) the analysis of over-pressured reservoirs. The major geomechanical effects are:

- Pressure-dependent permeability effect (Yilmaz and Nur correlation)
- Pressure-dependent formation compressibility effect (Dobrynin correlation)

Permeability changes are incorporated into a special formulation of pseudo-pressure for oil, but they also enter into the definition of pseudo-time. In addition, formation compressibility changes are incorporated into the definition of pseudo-time.

Implementation notes: 2014v2 release

For the limited scope of the 2014v2 release, only the pseudo-pressure aspect of pressure-dependent permeability has been implemented. To be consistent with standard analytical model formulations, the pseudo-pressure for oil assumes a constant formation volume factor and constant viscosity.

Pseudo-time (which is affected by both changing permeability and by compressibility) *has not been implemented*.

Consequences:

- By using regular time instead of pseudo-time for oil, forecasts tend to be more conservative. The degree of conservativeness is directly related to the combined effect of permeability, and formation compressibility variations with pressure.
- By using constant oil properties, slight changes in pressure, volume, temperature (PVT) are not be tracked (this is a relatively minor issue).

Recommended Usage:

- For oil reservoirs that stay above the bubble point
- For oil reservoirs that are at or below the bubble point, but with total compressibility that accounts for gas coming out of solution.

GIS theory

The geographic information system (GIS) is a system for gathering, processing, and presenting data based on geographical references.
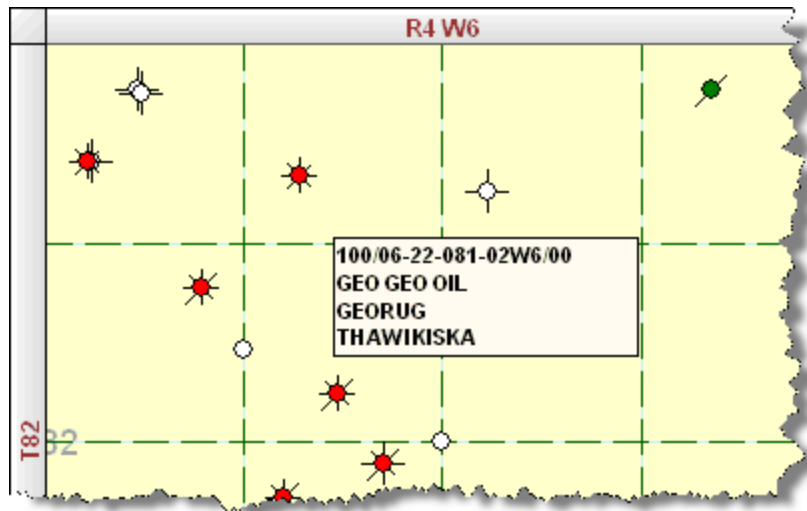
This section describes how locations are displayed using the different mapping systems. There are five grid display modes supported in Harmony Enterprise:

1. Cartesian

2. Dominion Land Survey (DLS)

3. Latitude / Longitude

4. National Topographic Map Numbering System (NTS)

5. Universal Transverse Mercator (UTM)

Cartesian

Cartesian coordinates describe a location in terms of distance from a defined reference point. The X axis, which represents longitude, increases in the east direction. The Y axis, which represents latitude, increases in the north direction.

Example location: -317 km, 6532 km

X Axis (East/West)	Y Axis (North/South)
317 km west	6532 km north

East / West: The negative sign indicates that the location is to the west of the defined reference point.

North / South: The location is to the north of the reference point. In most cases this reference will be the equator.

Dominion land survey

The Dominion Land Survey (DLS) system is used in the Canadian provinces of Alberta, Saskatchewan, Manitoba, and a small portion of British Columbia.

Areas in Canada where the DLS system is used:
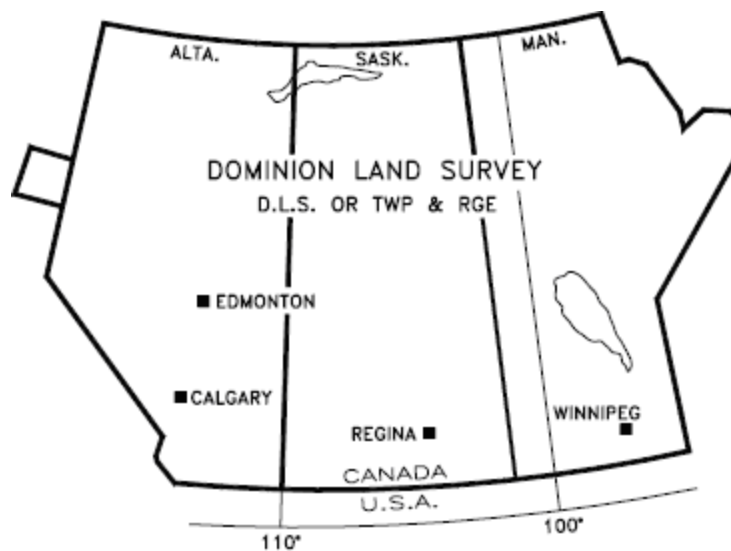
Example Location: 100/04-11-082-04W6/0

We can read the parts of the unique well identifier (UWI) as the following:

UWI Format	Location Exception	Legal Sub-division	Section	Township	Range	Meridian	Event Sequence Code
1	00	04	11	082	04	w6	0

UWI format

This number identifies the use of a DLS system.

Location exception code

This is used when there is more than one well drilled per legal subdivision. For more details on what can be included in the exception code, see Energy Resource Conservation Board's Guide 59.

Meridian

The meridians are 4 degrees of longitude wide that divide the DLS provinces. The First or Primary Meridian is located at 97º27' 28.41" west, which is just west of Winnipeg, Manitoba. Meridians west of the Primary Meridian are designated sequentially as "W1M", "W2M" to "W6M". Similarly, meridians east of the Primary Meridian are designated sequentially as "E1M", "E2M", etc. The fourth meridian west of the Primary (W4M) corresponds to 110 degrees west, and forms the Alberta-Saskatchewan border.

The meridians corresponding to Alberta, Canada:
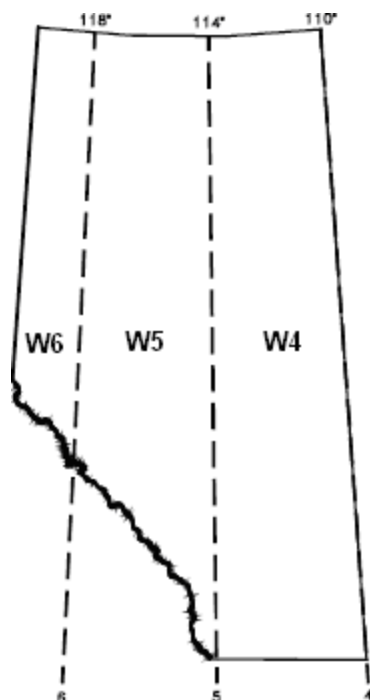
Range

The ranges further divide the meridians. At the southern edge of Alberta, there are 30 range lines per meridian. The number of ranges per meridian decreases as the latitude increases. Each range is 6 miles (9.7 kilometers) wide.

Ranges in Alberta:

W4
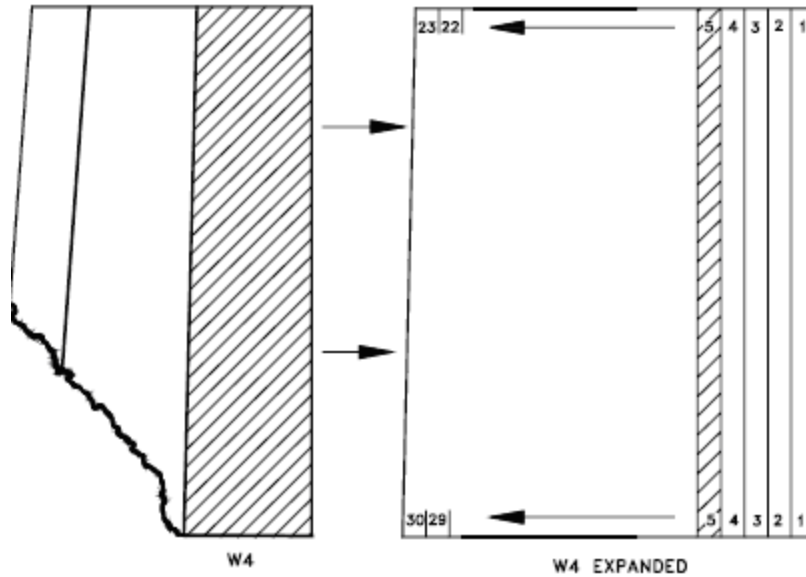
W4 EXPANDED

Townships

The townships divide the provinces up in the north-south direction from the Canada-USA border to the Arctic Circle. There are 126 township lines in Alberta. Each township is 6 miles (9.7 km) north-south.

Expanded view of ranges in Alberta:

W4

W4 EXPANDED
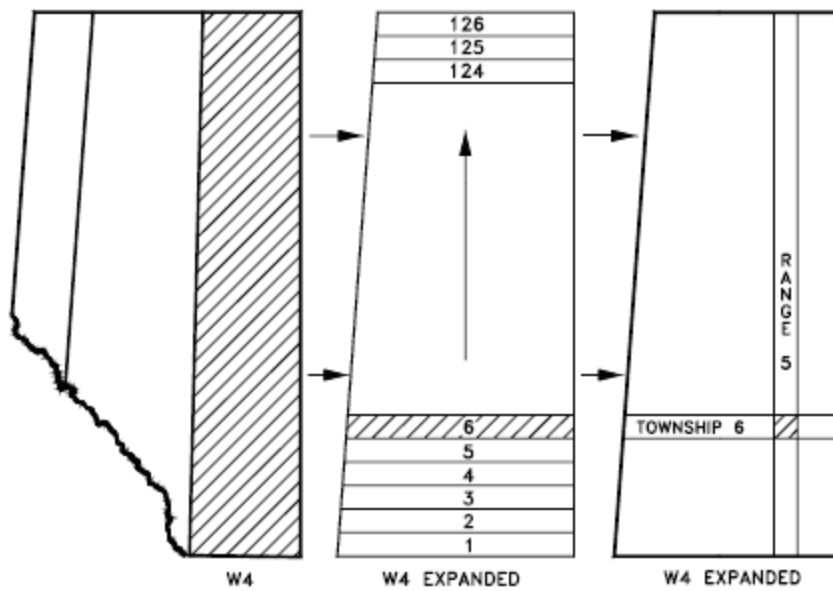
W4 EXPANDED

Sections

A square one range wide by one township north-south contains 36 sections. Each section is 1 mile (1.6km) per side.

Expanded view of sections:
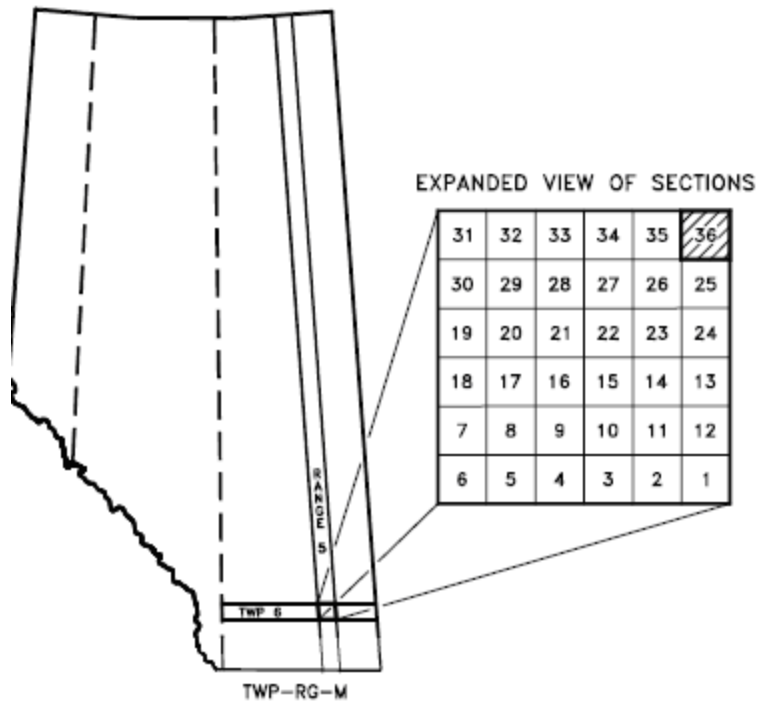
Legal subdivision

Each section is further divided into 16 legal subdivisions (LSD). An LSD is the smallest division in the DLS system. Each LSD is a square of one-quarter-mile, or 1320 ft (402m) per side.

Expanded view of LSD:

LEGAL SUBDIVISIONS

13	14	15	16
12	11	10	9
5	6	7	8
4	3	2	1

SECTIONS

31	32	33	34	35	36
30	29	28	27	26	25
19	20	21	22	23	24
18	17	16	15	14	13
7	8	9	10	11	12
6	5	4	3	2	1

SECTION 36 EXPANDED

SC-TWP-RG-M
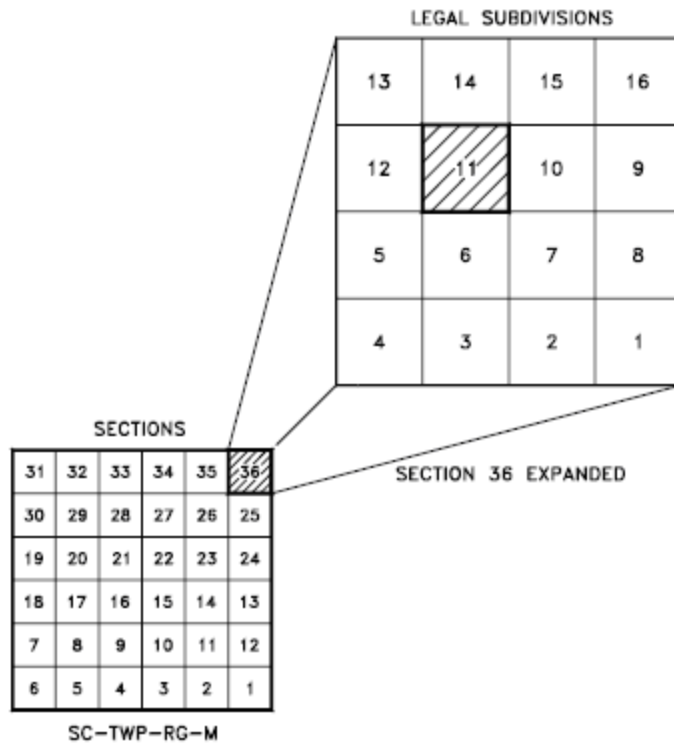
Event sequence

Indicates chronological sequence of drilling or completion activities.

Latitude / longitude

Latitude is a measure of how far a point is from the Earth's equator. Latitudes may vary from 0 to 90 in both north and south directions. Latitude lines are all parallel. There is a constant distance separating latitude lines of about 110 km (69 miles) per degree.
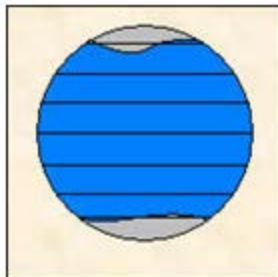
Longitude is an angular distance that is measured using the prime meridian as a reference. The prime meridian is an imaginary line that connects the North and South poles while passing through Greenwich, England. The ranges for longitudes are 0 - 180 East and West. Longitude lines are not parallel. The distance between two points that are separated by a fixed longitude depends on their latitude. Longitude varies from about 110 km (69 miles) per degree at the equator to a few meters (or feet) per degree at the poles.
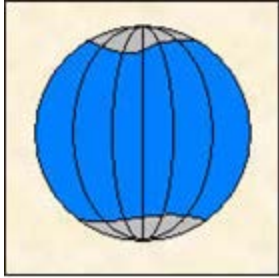
To further divide degrees of latitude and longitude seconds and minutes are used:

- 1 degree = 1º = 60 minutes

- 1 minute = 60 seconds

Since Harmony Enterprise only accepts a decimal notation for latitude and longitude, you need to convert your values. You can use an online calculator. Or convert by hand, by dividing the minutes by 60 and the seconds by 3600 (60 x 60), followed by adding these values together with the degrees. If you attempt to bring in latitude / longitude, Harmony Enterprise does not read the directional script typically given at the end of a coordinate pair (e.g., N for "Northing", etc.). Instead, Harmony Enterprise reads whether the number is positive or negative.
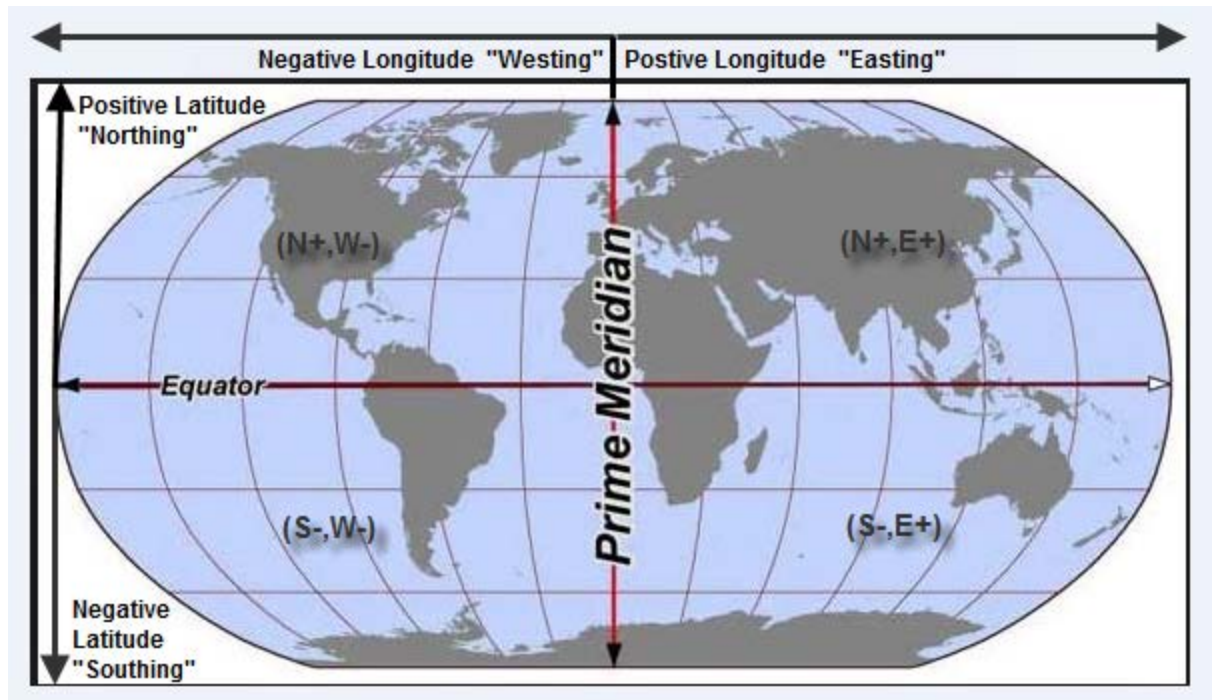
As an example of latitude and longitude, here are the approximate locations of a few cities around the world:

Location	Latitude	Longitude	Notes
Greenwich, England	51º, 29 min N	0º, 0 min	This is the reference point for longitude.
Calgary, Canada	51º, 3 min N	114º, 3 min W	This city is located north of the Equator and to the west of Greenwich.
Perth, Australia	31º, 57 min S	115º, 52 min E	This city is located south of the Equator and to the east of Greenwich.

National topographic map numbering system

The National Topographic Map Numbering System (NTS) is a system used by Canada to provide general purpose maps of the country.
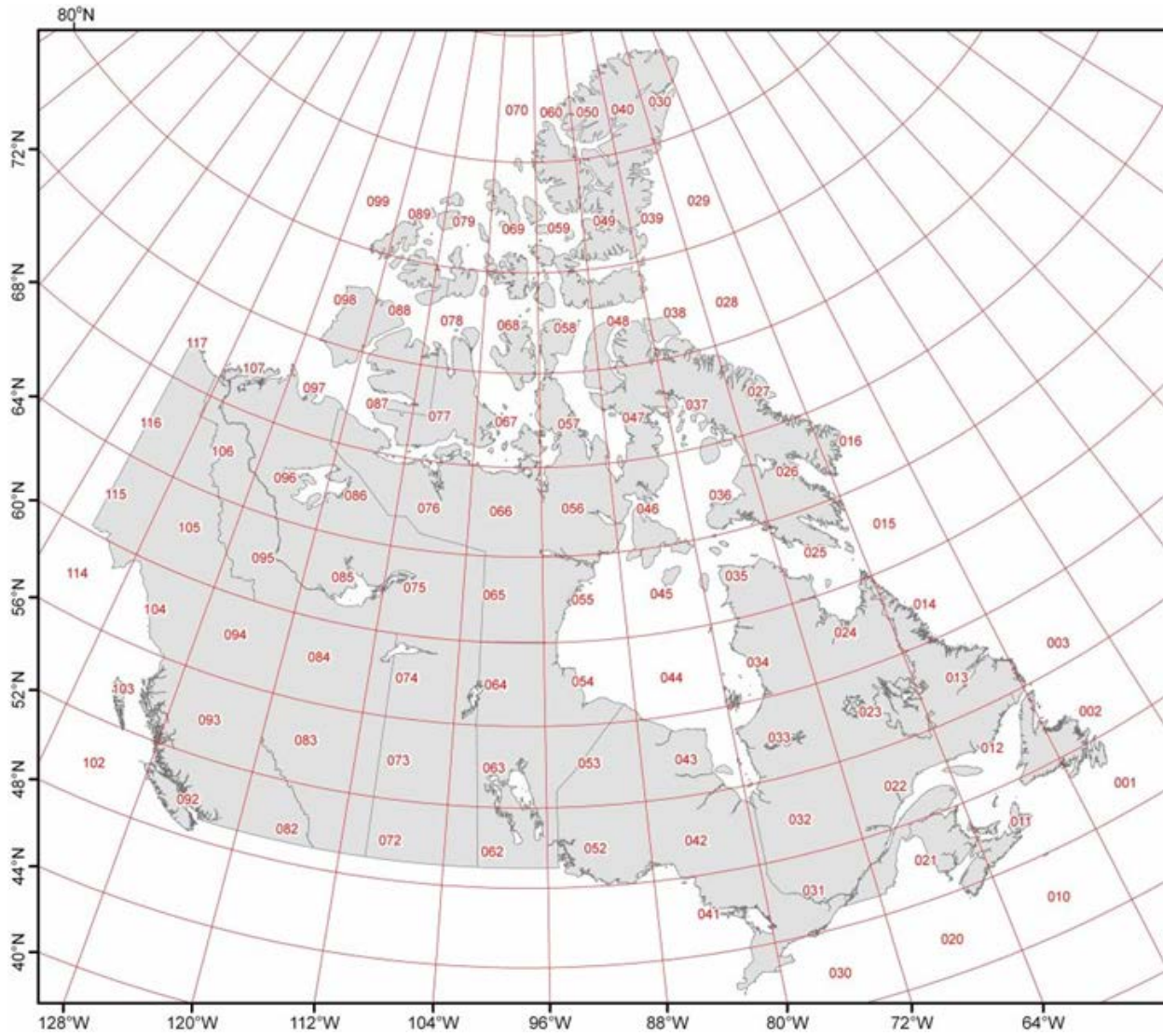
Example Location: a-10-D-93-P-2

Quarter Units	Units	Blocks	Series Numbers	Map Areas	Map Sheets
a	10	1	93	P	8
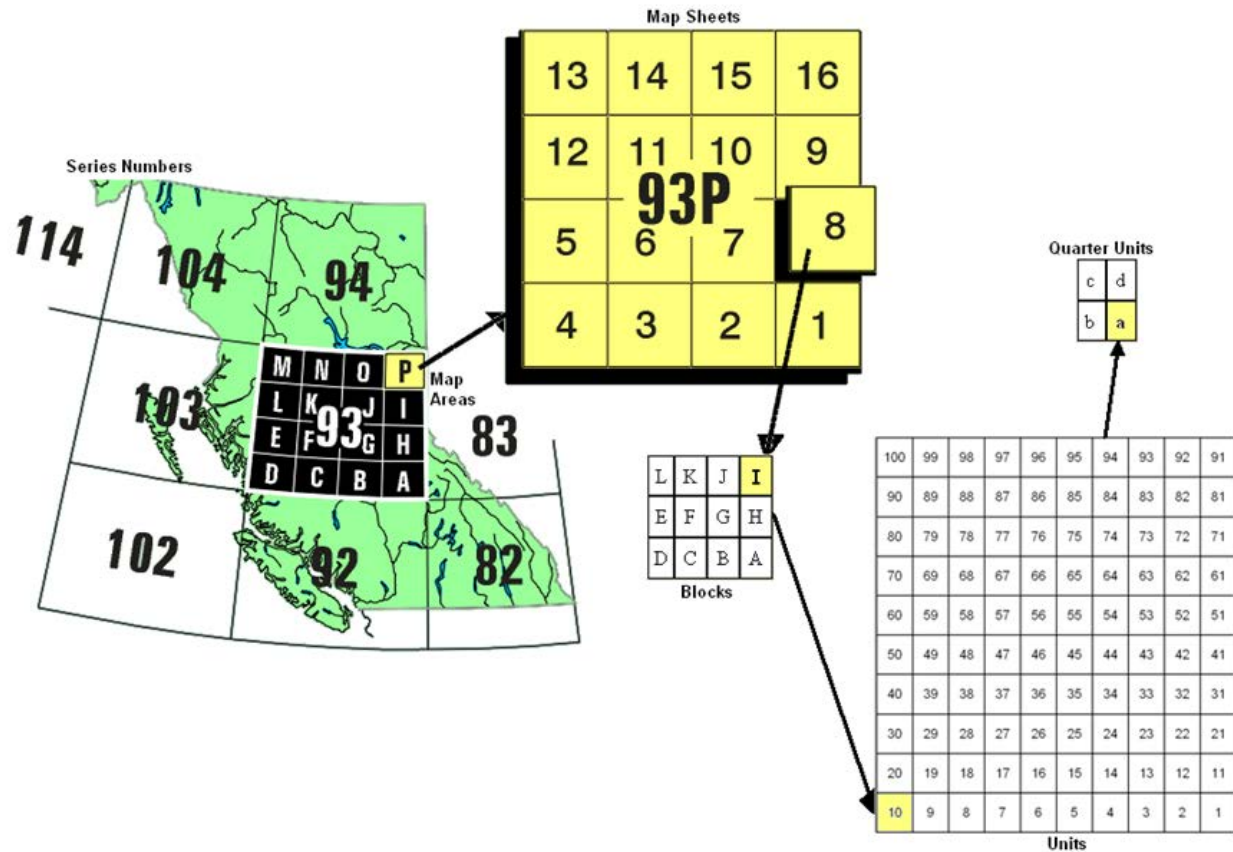
Series numbers

The series numbers identify rectangular areas that have a width of 8 degrees of longitude (width) and 4 degrees of latitude (north south). Series number 93 is located in the province of British Columbia.

Map areas

The map areas divide the series numbers into 16 pieces that are labeled A to P. Each map area is 2 degrees of longitude (width) and 1 degrees of latitude (north south).

Map sheets

Each map area is divided into 16 numbered map sheets.

Blocks

The map sheets are divided into 12 blocks that are labeled from A to L.

Units

The blocks are subdivided into 100 units. The direction of the numbers is always towards the left, unlike the numbering of map sheets.

Quarter units

Each block is subdivided into quarter units labeled a to d.

Universal transverse mercator

The universal transverse mercator (UTM) grid is an attempt to draw the earth on a cylindrical projection. The word transverse implies that the cylinder is "wrapped" around the earth in a north-south direction, as shown in the following figure.

The equator is used as the reference point in the north/south direction. The east/west reference is decided upon by the user. Caution should be used in using coordinates that are very far apart as UTM zones are intended to be only 6 degrees longitude in width.

Example location: 317km W, 6532km N

East/West	North/South
317 km west	6532 km north

East / West: The location is 317 km (198 miles) to the west (W) of longitudinal reference point.

North / South: The location is that the well is 6532 km (4083 miles) to the north (N) of the equator.

Interpolation theory

Values should be interpolated using the following equation:

$$y = y_1 + \frac{(y_2 - y_1)(t - t_1)}{(t_2 - t_1)}$$

Where:

y = Interpolated value

y_1 = Known lower-bound value

y_2 = Known upper-bound value

t = Mid-period time at the interpolate value

t_1 = Mid-period time at the known lower-bound value

t_2 = Mid-period time at the known upper-bound value

Langmuir isotherm

Adsorption

Shale reservoirs have immense capacity for methane storage. The mechanism by which this occurs is called *adsorption*. In adsorption, molecules of gas become attached to the surface of organic material in shale. Nearly all the gas stored by adsorption exists in a condensed, near-liquid state. Adsorption can be visualized by imagining a magnet attached to a metal surface, or lint attached to a sweater. This is different from *ab*sorption where one substance becomes trapped inside another, such as a sponge soaking up water. Adsorption is a reversible process, because it involves weak attraction forces.

Typically, shale reservoirs can store far more gas in the adsorbed state than conventional reservoirs can hold by compression at pressures below 1000 psia. Since the volume of a cleat or fracture system is small when compared to the volume of the reservoir, free gas only accounts for a small portion of the gas stored in shale. As a result, the pressure volume relationship is often described by the desorption isotherm only.

Langmuir isotherm formulation

The release of adsorbed gas is commonly described by a pressure relationship called the Langmuir isotherm. The Langmuir adsorption isotherm assumes that the gas attaches to the surface of the shale, and covers the surface as a single layer of gas (a monolayer). At low pressures, this dense state allows greater volumes to be stored by sorption than is possible by compression.

The typical formulation of the Langmuir isotherm is:

$$C_g = \frac{V_L p}{p_L + p}$$

where C_g is the gas content measured in scf / ton of shale.

Langmuir volume

The Langmuir volume is the maximum amount of gas that can be adsorbed at infinite pressure. The following plot of a Langmuir isotherm demonstrates that gas content asymptotically approaches the Langmuir volume as pressure increases to infinity.
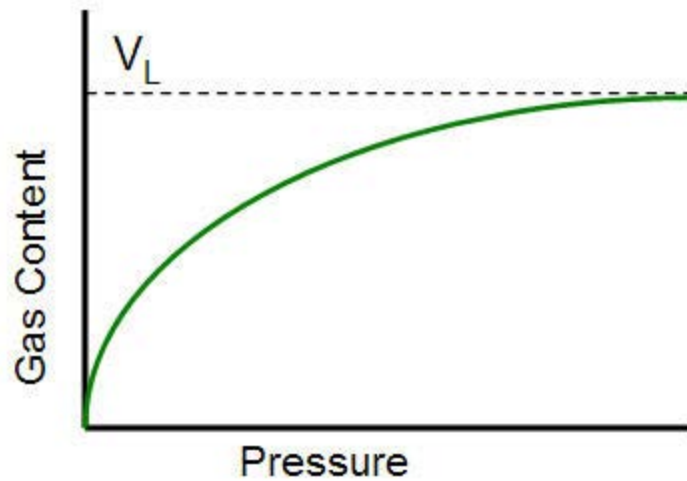
The units for Langmuir volume are scf / ton (volume gas per mass of shale). This can be converted to scf/ft^3 (volume of gas per volume of shale) by multiplying it by the bulk density.

Langmuir pressure

The Langmuir pressure, or critical desorption pressure, is the pressure at which one half of the Langmuir volume can be adsorbed. As seen in the figure below, it changes the curvature of the line and thus affects the shape of the isotherm.
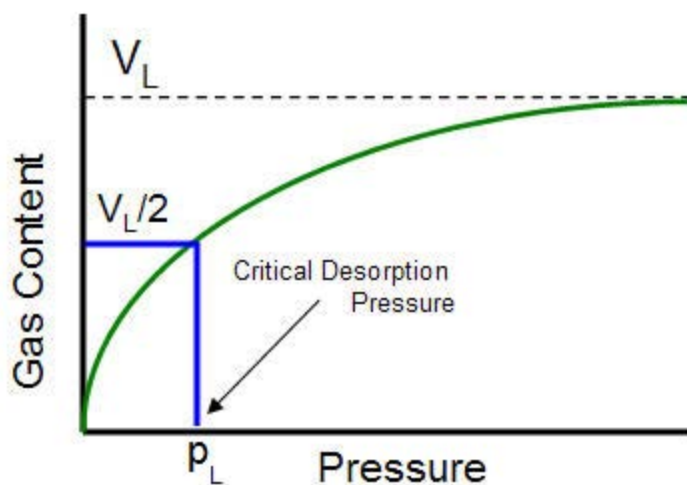
Isotherm variability

An isotherm is based on the assumption that the temperature is constant. The adsorption capacity decreases as temperature increases. When doing any analysis on shale, it is important to use the isotherm based on the reservoir temperature.

Material balance time theory

The Fetkovich typecurves are applicable to wells that produce at constant sandface pressure. Many wells, particularly gas wells, experience a decline in sandface pressure during their life. Blasingame and his students / co-workers (McCray, Palacio) developed a time function that enables the matching of production rate data on Fetkovich typecurves, even when the flowing pressure is varying. After developing different time functions, they came up with a simple function they called "material balance time" which works very well when the change in sandface pressure is smooth, as is often the case in production operations. They, and Agarwal-Gardner et al., also demonstrated that using material balance time converts the constant pressure solution into the constant rate solution, which is the solution widely used in the field of well testing.

Conceptually, material balance time is defined as the ratio of cumulative production to instantaneous rate:

$$t_c = \frac{Q}{q} \quad (1)$$

The symbol t_c has been adopted as it represents a corrected time based on cumulative production. It is also similar to the corrected "Horner" time that is used in build-up analysis in well testing, for correcting the effect of a varying flow rate. It is the value of time that a well has to flow at the current rate in order to produce the same amount of fluid (and hence honor the material balance principle). In the figure below, the cumulative production is represented by the area under the graph. The definition of material balance time makes these areas the same.

Material-Balance-Time

Graph A

Actual Rate Decline

q_1

$Q = Q_1 =$ Cumulative Production at a given time.

t_1

Actual Time

Graph B

Constant Rate

$t_{c1} = \dfrac{Q_1}{q_1}$

$Q = Q_1$

t_{c1}

Material-Balance-Time

$$t_c = \dfrac{Q}{q}$$

On Graph A, at time (t_1) the cumulative production is Q_1.

The rate, (q) at that time is used in Graph B and is assumed to be constant.

The time taken in Graph B for the well to flow at the constant rate to get the same cumulative production as in Graph A, is t_{c1} or material balance time.

Graphs C and D below demonstrate the same principle, using a different time (t_2) and the corresponding material balance time t_{c2}.

Graph C

Actual Rate Decline

q_2

$Q = Q_2 =$ Cumulative Production at a given time.

t_2

Actual Time

Graph D

Constant Rate

$t_{c2} = \dfrac{Q_2}{q_2}$

$Q = Q_2$

t_{c2}

Material-Balance-Time

Derivation of material balance time for slightly compressible systems focuses on the flow of liquids, and does not address the pseudo-time issues for gas reservoirs. It is fundamental to two basic ideas, namely the equivalence of constant pressure and constant rate solutions, and the harmonic stem of decline curves. Material balance pseudo-time for gas accounts for changing pressure-volume-temperature (PVT) properties with reservoir pressure.

Constant compressibility fluids

Consider an oil reservoir. A comparison of the constant rate (declining pressure) and constant pressure (declining rate) typecurves obtained when plotting against dimensionless time (based on area) shows the equivalence of the two solutions during the transient period, and their divergence during boundary-dominated flow.

Figure 1
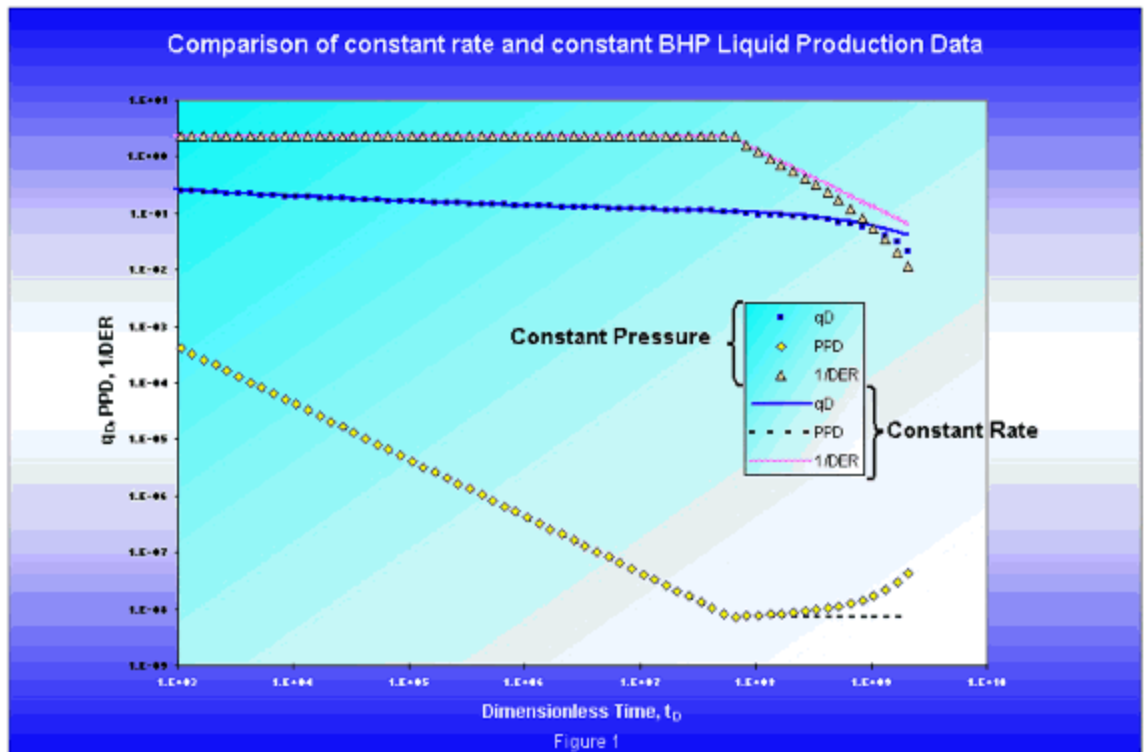
Material balance time also normalizes production histories in which both the rate and the pressure decline, provided that both sets of data decline monotonically.

Another way to state the functionality of material balance time is to say that it is effective in normalizing any rate / pressure history, so that it looks like the constant rate solution, provided that the rate / pressure history does not contain any disturbances large enough to disrupt boundary-dominated flow. A disturbance that is large enough to disrupt boundary-dominated flow, such as a sudden (and significant) decrease in back pressure, would introduce a new transient flow period. Since material balance time is designed to normalize boundary-dominated flow only, it loses its effectiveness if a new transient is introduced.

When the same typecurves (in figure 1) are plotted against dimensionless material balance time, the late time portion of the constant pressure overlays the constant rate solution precisely. This is an

important result because it illustrates that the same diagnostic plots used in pressure transient analysis can be inverted and used for rate transient analysis, provided that the material balance time function is used.
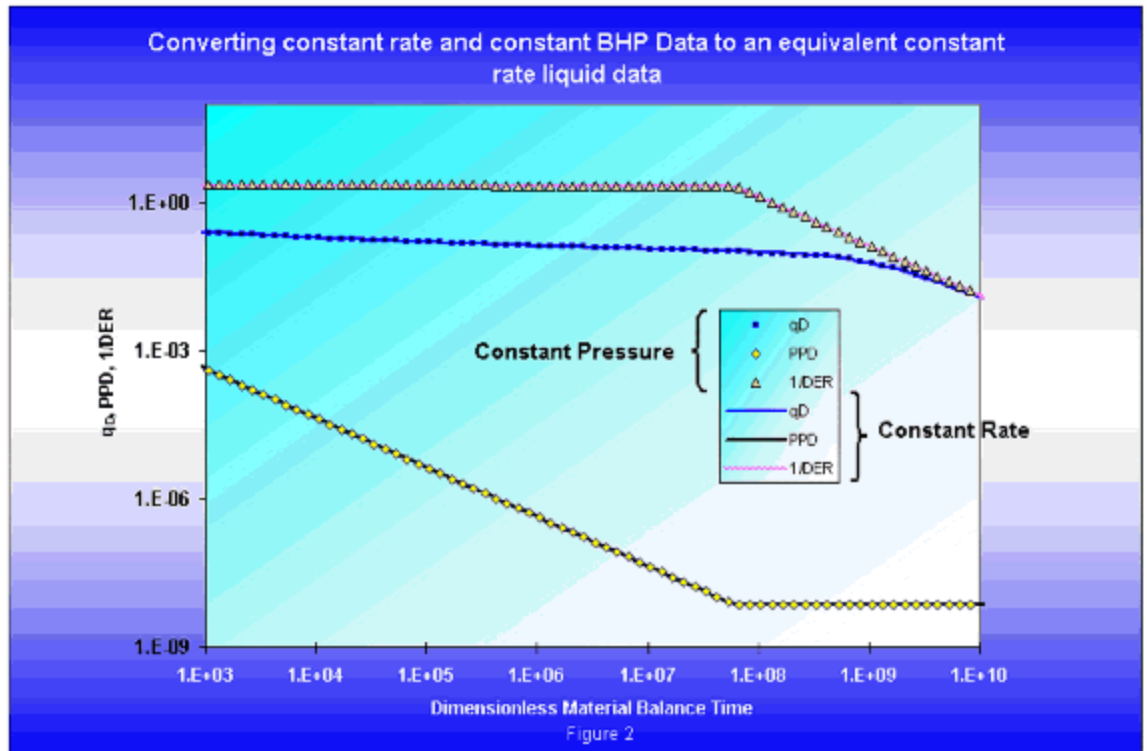
From the above figure, it can be seen that the inverse logarithmic derivative behaves very similarly to the logarithmic derivative on a welltest typecurve. During transient (radial) flow, it has a constant value of 2 (1 divided by ½). Upon reaching boundary-dominated flow, the inverse logarithmic derivative falls off with a constant slope of 1 on the log-log plot. The primary pressure derivative has the opposite behavior to the inverse log derivative, in that it exhibits a slope of negative 1 during transient flow, and becomes constant during boundary-dominated flow. This follows from the fact that the pressure decline for a well produced at a constant rate has a constant slope on log-log paper, during pseudo-steady state.

The $1/p_D$ (q_D) data, for different combinations of r_e / r_w, exhibit a fan of transient stems that converge into one harmonic depletion stem when plotted against dimensionless time based on area. If the data is plotted against a dimensionless time based on effective wellbore radius rather than reservoir area, the transient stems merge together while the depletion stems fan out.

The main difference in appearance between Agarwal-Gardner (A-G) typecurves and Fetkovich typecurves is that the depletion stems for A-G typecurves all collapse to the harmonic case. This follows

from the fact that the A-G typecurve normalizes all rate and pressure solutions, so that they behave like the constant rate solution for slightly compressible fluids. Figure 3 shows the A-G typecurves for a vertical, unfractured well.

Figure 3
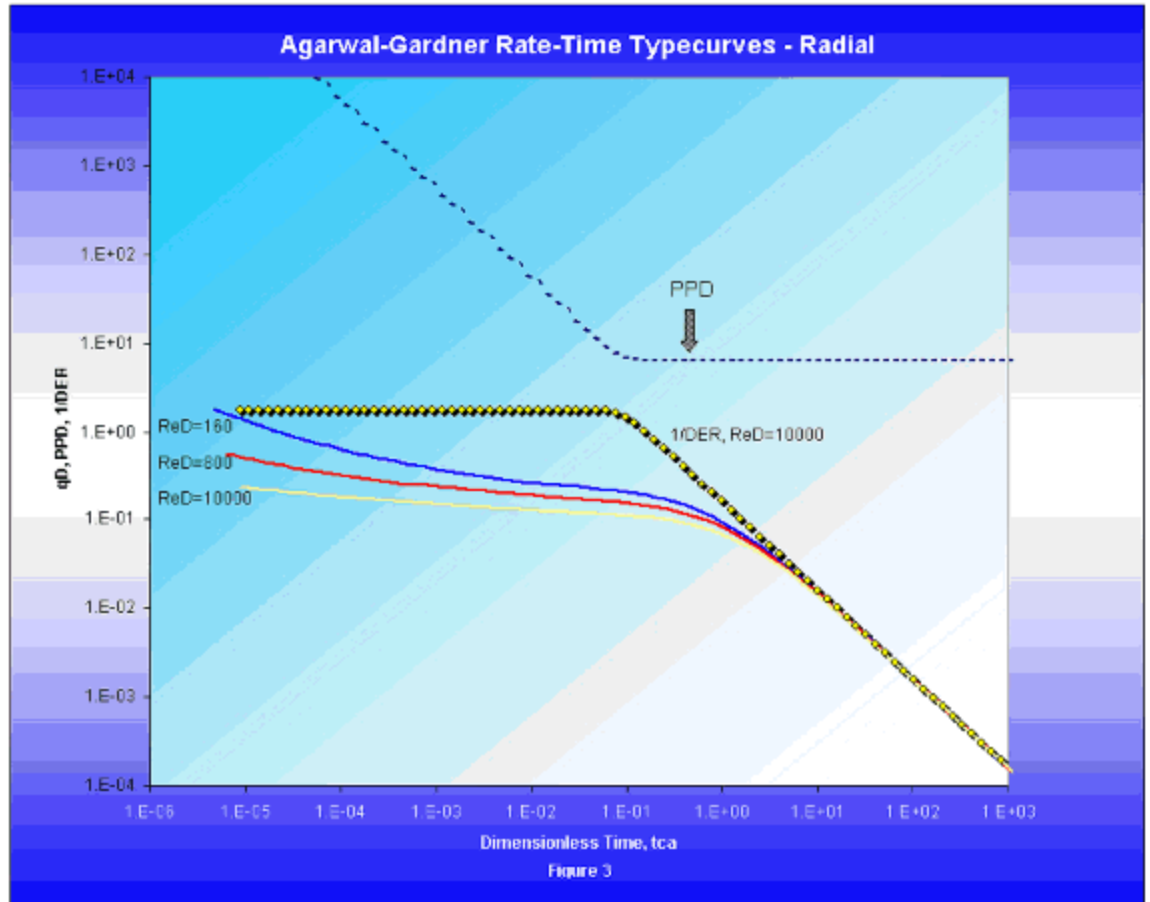
The presence of the inverse log derivative and pressure derivative plots on the A-G typecurve aids in the identification of transient and boundary- dominated flow regimes, in the same way that the logarithmic pressure derivative aids in flow regime identification on welltest typecurves.

Material balance time for oil

When analyzing oil wells:

$$t_c = \frac{N_p}{q_o} \quad (1a)$$

The following development (see Palacio and Blasingame, 1993) applies rigorously to a system with constant compressibility, such as an undersaturated oil reservoir.

Using the definition of compressibility, the oil production from a reservoir is related to the drop in average reservoir pressure, as follows:

$$c = -\frac{1}{V}\frac{\partial V}{\partial p}$$

$$c_t = \frac{5.615}{A\,h\,\phi}\frac{(q\,B)dt}{d\bar{p}} \quad (2)$$

Separating the variables and integrating:

$$\int_0^t q\,dt = -\frac{A\,h\,\phi\,c_t}{5.615\,B_o}\int_{p_i}^{\bar{p}} d\bar{p} \quad (3)$$

Recognizing that the left side is the cumulative oil production, the average reservoir pressure can be calculated from:

$$\bar{p} = p_i - \frac{1}{N\,c_t}N_p \quad (3a)$$

The important characteristic of equation (3a) is that it is always valid — regardless of time, flow regime, or production scenario (constant or variable flow rate). This is because equation (3a) is a material balance equation.

Note that if p is plotted vs. N_p, then a straight line of slope $1/N_{ct}$ and intercept p_i is obtained. Of course, p is typically not available in practice, so we must use an alternate approach to applying this concept. Before doing so, we recast equation (3a) by including the definition of t_c, as in Equation (1a):

$$\frac{p_i - \bar{p}}{q} = \frac{1}{N\,c_t}t_c \quad (3b)$$

The second equation to be used is the steady-state solution for single-phase liquid flow in a rectangular reservoir containing a vertical well:

$$\frac{k\,h}{141.2\,q\,B\,\mu}\,(\bar{p} - p_{wf}) = \frac{1}{2}\ln\left(\frac{4}{e^{\gamma}}\,\frac{A}{C_A r_w^2}\right) \quad (4)$$

where:

γ = Euler's constant = 0.57721

Although equation (4) was derived for constant rate (variable p_{wf}), Blasingame and Lee (1986) showed that it is also valid when the sandface pressure is constant (variable rate). Combining the material balance equation (3b) and the steady-state flow equation (4) gives:

$$\frac{p_i - p_{wf}}{q} = \frac{\Delta p}{q} = m\,t_c + b_{pss} \quad (5)$$

where:

$$m = \frac{1}{N\,c_i}$$

and:

$$b_{pss} = \frac{141.2\,B\,\mu}{k\,h}\frac{1}{2}\ln\left(\frac{4}{e^{\gamma}}\,\frac{A}{C_A r_w^2}\right)$$

Equation (5), called the pseudo-steady state equation, suggests that a plot of $\Delta p / q$ as a function of material balance time yields a straight line. If we assume q is constant, then equation (5) reduces to:

$$\Delta p = m\,q\,t_c + q\,b_{pss}$$

and a plot of Δp vs t_c yields a straight line.

Blasingame and Lee state that the importance of equation (5) is that it is also valid for moderately changing flow rate and sandface pressure conditions, so long as the transients caused by the changing inner boundary condition do not obscure the boundary-dominated flow behavior. In particular, equation

(5) is directly related to two concepts: the equivalence of the constant pressure and constant rate solutions, and the harmonic stem of decline curves.

Material balance pseudo-time for gas

The application of material balance time to gas is more complex than it is for oil because of the varying PVT properties of gas. Accordingly, the simple concept of material balance time given by:

$$t_c = \frac{G_p}{q_g} \quad \text{(1b)}$$

has limited application, and is considered to be only an approximation of the more rigorous formulation, which must be defined in terms of pseudo-time, t_a. Material balance pseudo-time, t_{ca}, is defined as follows:

$$t_{ca} = \frac{(\mu_g c_g)_i}{q_g} \int_0^t \frac{q_g}{\bar{\mu}_g \, \bar{c}_g} dt \quad \text{(6)}$$

Equation (6) can be coupled with the steady-state flow equation for the flow of single-phase gas (which is the gas equivalent of equation (4) of this section), to give:

$$\frac{\bar{p}_p - p_{pwf}}{q} = \frac{1.417 * 10^6 \, T}{k \, h} \frac{1}{2} \ln\left(\frac{4}{e^\gamma} \frac{A}{C_A \, r_{wa}^2}\right) \quad \text{(7)}$$

where:

γ = Euler's constant = 0.57721

Addition of equations (6) and (7) results in the following equation:

$$\frac{\Delta p_p}{q} = m_a \, t_{ca} + b_{a,pss} \quad \text{(8)}$$

where:

$$m_a = \frac{2 \, p_i}{(\mu \, c_t \, Z)_i \, G}$$

and:

$$b_{a,pss} = \frac{1.417 * 10^6\, T}{k\,h}\, \frac{1}{2}\, \ln\frac{4}{e^\gamma}\, \frac{A}{C_A\, r_{wa}^2}$$

Total compressibility

The definition of material balance pseudo-time described in equation (6) accounts only for the compressibility of gas. This is often a reasonable approximation as gas compressibility is typically much larger than that of liquid or rock. However, in some cases, the compressibilities of other fluids cannot be ignored. Thus, we require a more general definition of pseudo-time that accounts for the total system compressibility. Total compressibility includes gas compressibility, as well as water influx and production, formation and residual fluids compressibilities, and gas desorption.

$$t_{ca} = \frac{(\mu_g\, c_t)_i}{q_g} \int_0^t \frac{q_g}{\bar{\mu}_g\, \bar{c}_t}\, dt \quad (6)$$

The following is a derivation for total compressibility in a general form.

Material balance equation

Refer to material balance analysis theory - gas material balance for the general gas material balance equation. The general gas material balance equation can be expanded to include water influx and production, formation and residual fluids compressibilities, and desorption of gas (ΔV_{wip}, ΔV_{ep} and ΔV_d, respectively) as follows:

$$G_f\, B_{gi} = \left(G_f - G_p\right) B_g + \Delta V_{wip} + \Delta V_{ep} + \Delta V_d \quad (9)$$

where:

$$\Delta V_{wip} = 5.615\, (W_e - W_p\, B_w)$$

$$\Delta V_{ep} = \frac{B_{gi}\, G_f}{S_{gi}} \left[\left(1 - e^{-\int_p^{p_i} c_f\, dp}\right) + S_{wi}\left(e^{\int_p^{p_i} c_w\, dp} - 1\right) + S_{oi}\left(e^{\int_p^{p_i} c_o\, dp} - 1\right) \right]$$

$$\Delta V_d = \rho_B \, B_g \, \frac{B_{gi} \, G_f}{S_{gi} \, \phi} \left(\frac{V_L \, p_i}{p_L + p_i} - \frac{V_L \, p}{p_L + p} \right)$$

The relative change of the pore volume due to water influx and production, formation and residual fluid expansion, and desorption of gas (c_{wip}, c_{ep}, and c_d, respectively), can then be defined as:

$$c_{wip} = \frac{\Delta V_{wip}}{B_{gi} \, G_f \Big/ S_{gi}} = \frac{5.615 \, (W_e - W_p \, B_w)}{B_{gi} \, G_f \Big/ S_{gi}}$$

$$c_{ep} = \frac{\Delta V_{ep}}{B_{gi} \, G_f \Big/ S_{gi}} = \left(1 - e^{-\int_p^{p_i} c_f \, dp} \right) + S_{wi} \left(e^{\int_p^{p_i} c_w \, dp} - 1 \right) + S_{oi} \left(e^{\int_p^{p_i} c_o \, dp} - 1 \right)$$

$$c_d = \frac{\Delta V_d}{B_{gi} \, G_f \Big/ S_{gi}} = \frac{\rho_B \, B_g}{\phi} \left(\frac{V_L \, p_i}{p_L + p_i} - \frac{V_L \, p}{p_L + p} \right)$$

If the adsorption saturation correction has been enabled, c_d is modified as follows:

$$c_d{'} = \frac{\rho_b \left(B_g - \frac{1.38x10^{-6} M}{\rho_s} \right)}{\phi} \left[\frac{V_L p_i}{p_i + p_L} - \frac{V_L p}{p + p_L} \right]$$

For more information, see material balance analysis theory - advanced gas material balance.

Solving for total compressibility (c_t)

The solution for total compressibility comes from the definition of pseudo-time:

$$t_a = \int_0^t \frac{k_r \, dt}{\mu \, c_t}$$

By taking the partial derivative of pseudo-time with respect to time, total compressibility is exposed:

$$\frac{\partial t_a}{\partial t} = \frac{k_r}{\mu\, c_t} \quad (10)$$

The following chain rule of derivatives is applied:

$$\frac{\partial t_a}{\partial t} = \frac{\partial t_a}{\partial p_p} \frac{\partial p_p}{\partial p} \frac{\partial p}{\partial t}$$

Therefore, equation (10) may be expressed as:

$$\frac{k_r}{\mu\, c_t} = \frac{\partial t_a}{\partial p_p} \frac{\partial p_p}{\partial p} \frac{\partial p}{\partial t} \quad (11)$$

Note that the inclusion of a permeability term in the above definition of pseudo-time accounts for a pressure-dependent permeability. For more information on theory and equations, see geomechanical reservoir models.

Solving for ∂t_a / ∂p_p

Defining pseudo-pressure:

$$p_p = 2 \int_{p_o}^{p} \left(\frac{k_r\, p}{\mu\, Z} \right) dp$$

Relating pseudo-pressure to pseudo-time (Rahman et al., 2006):

$$\frac{\partial p_p}{\partial t_a} = \frac{-2\; k_r\, q\, p_i\, S_{gi}}{Z_i\, G_f}$$

$$\frac{\partial t_a}{\partial p_p} = \frac{Z_i\, G_f}{-2\; k_r\, q\, p_i\, S_{gi}} \quad (12)$$

Solving for ∂p_p / ∂p

From the above definition of pseudo-pressure:

$$\frac{\partial p_p}{\partial p} = \frac{2\,k_r\,p}{\mu\,Z} \quad (13)$$

Solving for ∂p / ∂t

Dividing both sides of equation (9) by ($G_f\,B_{gi}$ / S_{gi}) and recalling that B_g = ($p_{sc}\,Z\,T$) / ($T_{sc}\,P$):

$$\frac{p}{Z}\left(S_{gi} - c_{wip} - c_{ep} - c_d\right) = \frac{p_i}{Z_i}\left(\frac{G_f - G_p}{G_f}\right)S_{gi}$$

Letting c equal the summation of c_{wip}, c_{ep}, and c_d; and rearranging:

$$\frac{p}{Z} = \frac{p_i\,S_{gi}}{Z_i\,G_f}\left(\frac{G_f - G_p}{S_{gi} - c}\right) \quad (14)$$

$$\frac{\partial}{\partial t}\frac{p}{Z} = \frac{\partial}{\partial t}\frac{p_i\,S_{gi}}{Z_i\,G_f}\left(\frac{G_f - G_p}{S_{gi} - c}\right)$$

$$\frac{\partial}{\partial p}\frac{p}{Z}\frac{\partial p}{\partial t} = \frac{p_i\,S_{gi}}{Z_i\,G_f}\frac{\partial}{\partial t}\left(\left(G_f - G_p\right)\left(S_{gi} - c\right)^{-1}\right)$$

Where: $\quad \dfrac{\partial}{\partial t}G_p = q\,, \quad \dfrac{\partial}{\partial t}c = \dfrac{\partial c}{\partial p}\dfrac{\partial p}{\partial t}\,, \quad c_g = \dfrac{1}{p} - \dfrac{1}{Z}\dfrac{\partial Z}{\partial p}$

$$\frac{p}{Z}\left(\frac{1}{p} - \frac{1}{Z}\frac{\partial Z}{\partial p}\right)\frac{\partial p}{\partial t} = \frac{p_i\,S_{gi}}{Z_i\,G_f}\left[\frac{-q}{\left(S_{gi} - c\right)} - \frac{\left(G_f - G_p\right)\left(-\frac{\partial c}{\partial p}\frac{\partial p}{\partial t}\right)}{\left(S_{gi} - c\right)^2}\right]$$

$$\frac{p}{Z} c_g \frac{\partial p}{\partial t} = \frac{p_i S_{gi}}{Z_i G_f} \left[\frac{-q}{(S_{gi} - c)} - \frac{(G_f - G_p)\left(-\frac{\partial c}{\partial p} \frac{\partial p}{\partial t}\right)}{(S_{gi} - c)^2} \right] \quad (15)$$

Rearranging equation (14) such that:

$$\frac{p \, Z_i \, G_f}{Z \, p_i \, S_{gi}} = \left(\frac{G_f - G_p}{S_{gi} - c}\right)$$

Equation (15) can now be written as:

$$\frac{p \, Z_i \, G_f}{Z \, p_i \, S_{gi}} \left(c_g - \frac{\frac{\partial c}{\partial p}}{(S_{gi} - c)} \right) \frac{\partial p}{\partial t} = \frac{-q}{(S_{gi} - c)}$$

And then solved for $\partial p / \partial t$:

$$\frac{\partial p}{\partial t} = \frac{-q \, Z \, p_i \, S_{gi}}{p \, Z_i \, G_f} \frac{1}{c_g (S_{gi} - c) - \frac{\partial c}{\partial p}} \quad (16)$$

Substitution

Equations (12), (13), and (16) are substituted into the chain rule of derivatives from equation (11) and simplified:

$$\frac{k_r}{\mu \, c_t} = \frac{1}{\mu \left(c_g (S_{gi} - c) - \frac{\partial c}{\partial p} \right)}$$

$$c_t = k_r \left(c_g (S_{gi} - c) - \frac{\partial c}{\partial p} \right)$$

As c equals the summation of c_{wip}, c_{ep}, and c_d:

$$c_t = k_r \left(c_g \left(S_{gi} - c_{wip} - c_{ep} - c_d \right) - \frac{\partial c_{wip}}{\partial p} - \frac{\partial c_{ep}}{\partial p} - \frac{\partial c_d}{\partial p} \right)$$

Probabilistic

The probabilistic analysis is designed to address uncertainty in well performance in the following areas:

- Expected performance and recovery in new wells (that is, proven, and undeveloped locations)

- True analytical probabilistic forecasting for wells with established production history

The probabilistic module uses Monte Carlo simulation to generate stochastic outputs for reservoir parameters such as OFIP, EUR, linear flow parameters (when applicable), and the production forecast. The model can be constrained to a known well history using automatic parameter estimation, which optimizes key input parameters to ensure there is a minimum level of conformance with production history. Dependencies between input parameters can be specified using a correlation matrix. Results are displayed with histograms, shaded plots, and cross-plots of statistical outputs.

Pseudo-pressure (ψ)

Pseudo-pressure is a mathematical pressure function that accounts for the variable compressibility and viscosity of gas viscosity (μ_g) with respect to pressure.

Note: If there is geomechanical reservoir behavior, see the modification for geomechanical models.

The equation for the flow of gas in the reservoir is very similar to that for liquid flow. In well testing and rate transient analysis, analytical equations are solved after making certain assumptions. In particular, five assumptions are very important.

1. Total system compressibility (c_t) is constant

2. Fluid density ($\rho \propto p / Z$) is constant

3. Fluid viscosity (μ) is constant

4. Total porosity (ϕ) is constant

5. Fluid saturations are constant

For liquids, these assumptions are reasonable because liquid compressibility, density, and viscosity do not vary significantly with pressure, and the equations can be solved analytically. These analytical solutions are referred to as the liquid-flow solutions, and form the basis of all well test and rate transient analysis. The result is an analytical relationship between pressure and time. Liquid-flow solutions for different wellbore and reservoir configurations are available in the literature. For example, for the case of an infinite-acting reservoir and a vertical well producing at a constant rate, pressure can be calculated as:

Pressure ≈ Constant * log(time)

For gas, most of the assumptions listed above are no longer valid because gas density ($\rho \propto p / Z$) can vary significantly with pressure. Gas viscosity (μ_g) also varies with pressure, but not to the same degree. To deal with these changing gas properties, the concept of pseudo-pressure (ψ) was developed by Al-Hussainy et al. (1966) and is defined as follows:

$$\psi\left(p\right) = 2 \int_0^p \frac{p}{\mu Z}\, dp$$

This transformation of pressure to pseudo-pressure is an exact transformation, which accounts for variation of gas density and viscosity. If we assume that changes of total compressibility (c_t), porosity,

and fluid saturations are insignificant, 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 rate transient analysis provided pressure is replaced by pseudo-pressure. For the above mentioned example, pseudo-pressure can be calculated as:

Pseudo-Pressure ≈ Constant * log (time)

Modification for geomechanical models

If there is geomechanical reservoir behavior, where rock permeability is changing with pressure, you can account for this behavior in the pseudo-pressure.

Changing permeability can be expressed as $k_{effective}(p) = k \cdot k_m(p)$ where k is the permeability at the initial pressure, and $km^{(p)}$ is a (dimensionless) permeability multiplier.

To incorporate a variation of permeability with pressure into the pseudo-pressure term, the definition of pseudo-pressure is modified as follows:

$$\psi\left(p\right) = 2 \int_0^p \frac{p \cdot k_m(p)}{\mu Z} dp$$

Note: In some sources, pseudo-pressure is also referred to as the real gas potential (m(p)).

Pseudo-time

Pseudo-time is a mathematical time function that accounts for the variable total compressibility (c_t) and viscosity (μ_g) of gas, as well as the variable porosity (φ) with respect to time and pressure.

The equation for flow of gas in the reservoir is very similar to that for liquid flow. In well testing and rate transient analysis, analytical equations are solved after making certain assumptions. In particular, five assumptions are very important.

1. Total system compressibility (c_t) is constant

2. Fluid density ($\rho \propto p/Z$) is constant

3. Fluid viscosity (μ) is constant

4. Total porosity (ϕ) is constant

5. Fluid saturations are constant

For liquids, these assumptions are reasonable, since liquid compressibility and viscosity do not vary significantly with pressure, and the equations can be solved analytically. These analytical solutions are referred to as the liquid flow solutions, and form the basis of all well test and rate transient analysis. The result is an analytical relationship between pressure and time. For example, for the case of an infinite-acting reservoir and a vertical well producing at a constant rate, pressure can be calculated as:

$$\text{Pressure} \approx \text{Constant} * \log(\text{time})$$

For gas, most of the assumptions listed above are no longer valid, since gas density ($\rho \propto p/Z$), viscosity (μ_g) and total compressibility (c_t) can vary significantly with pressure. Pseudo-pressure (ψ) and pseudo-time (t_a) are used to deal with these changing properties and linearize the flow equations for gas. With the introduction of pseudo-pressure and 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. For the above mentioned example, pseudo-pressure can be calculated as:

$$\text{Pseudo-pressure} \approx \text{Constant} * \log(\text{pseudo-time})$$

Development of pseudo-time

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, because the gas properties change with pressure, not time.

Pseudo-time was developed by Agarwal (1980) and he defined pseudo-time in terms of the viscosity (μ_g) and compressibility (c_t) at the wellbore (see buildup pseudo-time). This definition accounted for the large change in total compressibility (c_t) that occurs at low pressures (early time in a buildup). It had little effect on late time data, and was generally used for buildups only.

In the 90s, 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, was inappropriate for boundary dominated flow (depleting systems). Palacio and Blasingame (1993) introduced a new definition of pseudo-time to account for the 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 (see drawdown pseudo-time). This pseudo-time is appropriate for boundary dominated flow.

Anderson and Mattar (2005) found that, in a reservoir with significant transient flow, it was more appropriate to define pseudo-time in terms of the average pressure within the region of investigation rather than the average reservoir pressure (see corrected pseudo-time).

Different pseudo-time formulations are needed for buildup, for drawdown in a boundary dominated flow regime, and for a transient flow regime. The equations look similar, but they are radically different from each other.

Buildup pseudo-time

Pseudo-time for use in buildup analysis is defined in terms of pressure at the wellbore:

$$t_a\left(t\right) = \left(\mu_g c_t\right)_i \int_0^t \frac{dt}{\mu_g(p_{wb})c_t(p_{wb})}$$

If the wellbore has significant storage, a difference in the early time behavior will be noted, since pressure and thus compressibility and viscosity are changing most near the wellbore. Late time behavior is not typically affected by buildup pseudo-time since the pressure, viscosity, and compressibility become constant at the wellbore and in the reservoir.

Drawdown pseudo-time

Pseudo-time for use in drawdown analysis is defined in terms of average reservoir pressure:

$$t_a\left(t\right) = \left(\mu_g c_t\right)_i \int_0^t \frac{dt}{\mu_g(\bar{p})c_t(\bar{p})}$$

Note that the gas in place (GIP) must be known in order to perform the material balance calculations necessary to determine the average reservoir pressure.

Corrected pseudo-time

In the conventional definition of pseudo-time, the compressibility and viscosity terms are evaluated at average reservoir pressure conditions. Clearly, the average reservoir pressure is only a function of Original-Gas-In-Place (OGIP) and cumulative production. During the transient flow period, before any boundary effects are observed, the flow behavior of two different-sized reservoirs should be similar, and independent of the OGIP – they are both infinite-acting reservoirs. However using the conventional definition of pseudo-time, the result would be that the producing rates would be different because their average reservoir pressures are different due to the different OGIPs.

If a well is producing under boundary-dominated conditions, the average reservoir pressure is a very reasonable datum at which to establish fluid properties such as cg. However, if the well production is still in transient flow and no reservoir boundaries have been observed, the average reservoir pressure based on total reservoir volume is not an appropriate datum to use. Consequently, pseudo-time can cause anomalous model responses under certain conditions.

Anderson and Mattar (2005) proposed that the average reservoir pressure used in the pseudo-time calculation during the transient flow period should be calculated based on the gas-in-place of the investigated volume at that time.

$$
t_a\left(t\right) = \left(\mu_g c_t\right)_i \int_0^t \frac{dt}{\mu_g(\bar{p_{ir}})c_t(\bar{p_{ir}})}
$$

This way, during transient flow, pseudo-time is independent of OGIP. As soon as the reservoir enters boundary-dominated flow, the conventional definition of pseudo-time is automatically resumed, because at that time the region of investigation is the whole reservoir.

The volume of investigation is calculated based on the radius of investigation formula:

$$
r_{inv} = \sqrt{\frac{kt}{948 \cdot \phi \mu c_t}}
$$

This volume is adjusted for the effect of the reservoir boundaries and the coalescence of regions of influence caused by interference between wells.

Modification for geomechanical models

If there is geomechanical reservoir behavior, where rock permeability and formation compressibility are changing with pressure, you can account for this behavior in the pseudo-time.

Changing permeability can be expressed as $k_{effective}(p)=k \cdot k_m(p)$ where k is the permeability at the initial pressure, and $km^{(p)}$ is a (dimensionless) permeability multiplier.

To incorporate a variation of permeability with pressure into the pseudo-time term, the definition of pseudo-time is modified as follows:

$$t_a\left(t\right) = \left(\mu_g c_t\right)_i \int\limits_0^t \frac{k_m(\bar{p})dt}{\mu_g(\bar{p})c_t(\bar{p})}$$

Note: Variation of the formation compressibility with pressure is incorporated in the $c_t(p)$ term.

Relative permeability

Relative permeability is a concept used to convey the reduction in flow capability due to the presence of multiple mobile fluids. It is dependent upon pore geometry, wettability, fluid distribution, and the fluid saturation history. Relative permeability measurements are conducted on core samples in a laboratory, and are both time-consuming and expensive to produce. Consequently, relative permeability measurements are most often requested for projects where secondary and/or tertiary recovery is being considered.

In a single-phase system such as a dry-gas or an under-saturated oil reservoir, the effective permeability of flow of the mobile fluid through the reservoir varies little during production because the fluid saturations do not change. However, when more than one phase is mobile, the effective permeability to each mobile phase will change as the saturations of the fluids change in the reservoir.
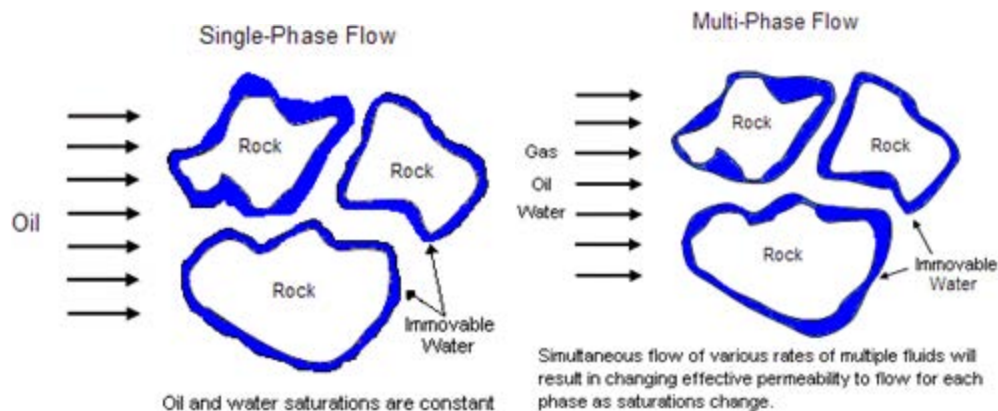
In a two-phase system, the fluids might consist of oil and water, or oil and gas. In a three-phase system, all three fluid phases occur. Each fluid, as it flows through the porous media, interferes with the fluids because capillary forces exist that reduce the flow rate of each individual phase in a non-linear fashion. Consequently, the sum of the relative permeabilities of each phase is always less than one.

$$k_{ro} + k_{rw} + k_{rg} < 1$$

Relative permeability terms and equations

Typical phases in a reservoir are oil, water, and gas; and the effective permeability of each is designated as k_o, k_w, and k_g, respectively. The relative permeability for each phase is calculated by dividing the effective permeability to flow by the absolute permeability. The absolute permeability is the "Klinkenberg" or theoretical "air" permeability, which is measured by cleaning and completely drying a

core sample, and then measuring the effective permeability of flow to air. The units of relative permeability are dimensionless.

$$k_{ro} = \frac{k_o}{k}, k_{rw} = \frac{k_w}{k}, k_{rg} = \frac{k_g}{k}$$

Wettability

Wettability in a reservoir is a measurement of the ability of a fluid to coat the rock surface. Wettability and heterogeneity have a significant impact on the shape of the relative permeability curves. The wetting fluid relative permeability curve is concave upwards, whereas the non-wetting fluid has an "s" shape. In the case where there is no interfacial tension between the fluid phases, the relative permeability curves simplify to straight lines between the endpoints.

Water-wet relative permeability curves (oil and water)

A schematic of oil-water relative permeability curves in a water-wet reservoir is shown below. In water-wet rock, a water layer wets the rock surface and acts like a lubricant for the oil located in the central parts of the pores.

- S_{wc} is the connate or irreducible water saturation. This is the water saturation below which water is not mobile because of capillary forces. The relative permeability of water at water saturations below S_{wc} is zero.

- S_{orw} is the residual oil saturation or critical oil saturation. This is the oil saturation below which the oil is immobile, that is, its relative permeability is zero.

Figure: Water-wet rock relative permeability curves. The plot shows k_{rel} on the vertical axis and saturation on the horizontal axis (from 0 to 1). The green "Oil" curve begins at k_{rocw} and declines; the blue "Water" curve rises to k_{rwro}. "Water is immobile in this regon" labels the left region; "Oil is immobile in this regon" labels the right region. The lower axis markers indicate S_{wc}, $1-S_{orw}$, S_w (increasing right) and S_o (increasing left).

Oil-wet relative permeability curves (oil and water)

The figure below displays a schematic of water-oil relative permeability curves in an oil-wet reservoir rock. In oil-wet rock, oil wets the pore surfaces and water occupies the central regions of the pores. Typically, the irreducible water saturation in oil-wet reservoir rock is lower than that in water-wet rock.
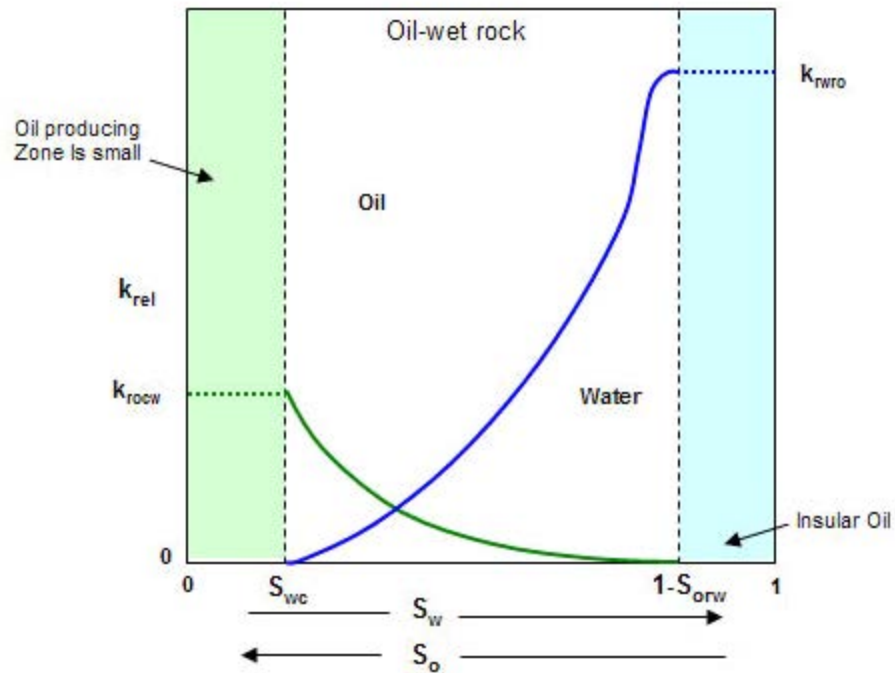
Gas-oil relative permeability curves

The schematic below displays a set of gas-oil relative permeability curves. In this case, the wetting phase (the oil phase) impedes the flow of gas. The water saturation in the reservoir rock is taken to not exceed its irreducible value. This means that the water is not mobile, but exists in the pore space and simply reduces the available pore space that the gas and oil can occupy.

- S_{gc} is the critical gas saturation. This is the minimum saturation for gas to become mobile.

- S_{org} is the residual oil saturation to gas. This is the immobile oil when gas is the displacing fluid.

- k_{rogc} is the relative permeability of oil at the critical gas saturation.

- k_{rgc} is the relative permeability of the gas at the residual oil saturation.
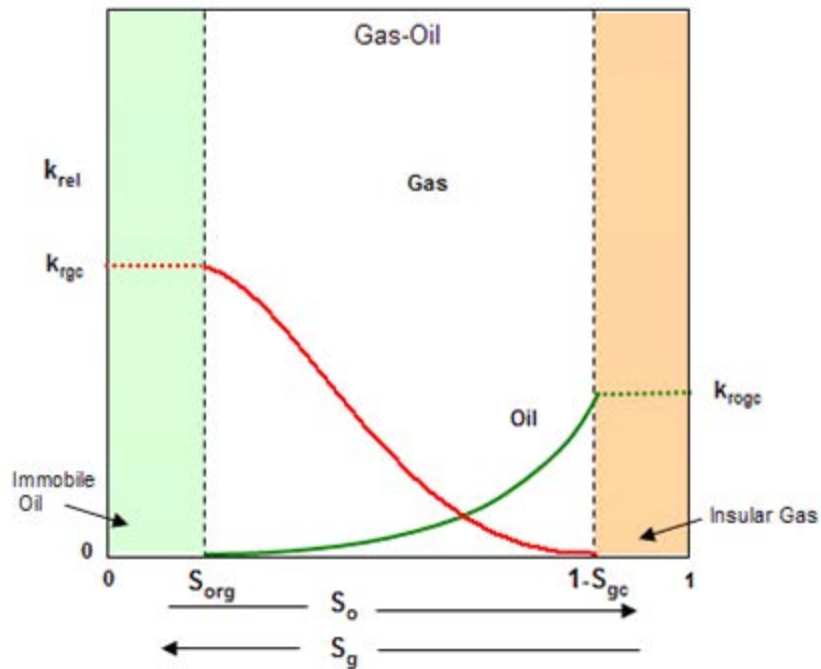
Normalized relative permeability

When using water-oil relative permeability, there is a second term that is often encountered. This is "normalized" relative permeability. Normalized relative permeability defines the oil relative permeability at the critical water saturation (where water becomes mobile) as a value of one (1.0). Normalized relative permeability defines the absolute permeability as the effective permeability at the critical water saturation.

Reserve evaluation

Reserve evaluation is the process of forecasting the production of existing and planned wells and using these forecasts in combination with economic data to estimate monetary value. This value can be used for determining whether to develop a reservoir, buy or sell a field, or to try and attract investment in a company. In order to provide consistent comparisons between projects, properties, and total companies, evaluation of current and future production values use a classification system. This classification system is used to categorize the uncertainty of production forecasts. Generally, the desired result of the evaluation is to obtain the net present value (NPV) of the project, property, or company.

The process of conducting a reserve evaluation entails the application of a consistent set of rules across several disciplines. Key elements of a reserve evaluation include:

- Estimation of remaining reserves

- Generation of production forecasts

- Categorization of risk and designation of current production status

- Summary of interests and burdens

- Estimation of future capital costs

- Fixed and variable operating costs

- Generation of cash flow analysis to evaluate for net present value and other key economic parameters, such as payout and rate of return on investment.

Purpose

Two useful products of a reserve evaluation are the net present value and the production forecasts used to generate net present value. These two estimates can be used in different ways depending on the purpose and required information. The table below shows examples of typical parties who have an interest in reserves evaluations.

Party	Reserves and Production Forecasts	Reserves and Net Present Value
Accountants	--	Creation of financial reports, ceiling tests and depletion calculations
Banks / lending institutions	--	Act as a basis for securing loans
Financial institutions and investors	--	Evaluate the performance of a company

Party	Reserves and Production Forecasts	Reserves and Net Present Value
Gas Marketers	Contracts for how much can be produced and pipeline transportation services	--
Governments	Resource development policy decision making	--
Investors and others	Rely on producer information to determine supply and demand	--
Lawyers	--	Used to settle disputes over reserves and values, estates
Pipeline companies	Planning for pipeline capacity	--
Producers	Development decisions, allocation of future capital Equipment sizing calculations	Determining the market value of a company Making investment decisions
Securities Commissions (SEC, ASC, etc.)	--	Require reserves and cashflow statements of publicly traded companies

Reserve Classifications

The oil / gas in a reservoir can be divided into two categories: reserves and resources. Reserves refer to oil / gas in a reservoir that has been confirmed to exist and is economically recoverable with current technology. Resources refer to oil/gas in a reservoir that is believed to exist but part or all of this volume has not been demonstrated to be productive or commercially recoverable. The volume classified as reserves can be contained within the resource volume.

Further classifications divide these volumes based on their certainty. The classifications from most to least certain are:

- **Proved (1P)** — "Those quantities of petroleum, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate."

- **Probable (2P)** — "Those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated *Proved plus Probable Reserves* (2P or PP). In this context, when

probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate."

- **Possible (3P)** — "Those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of *Proved plus Probable plus Possible* (3P or PPP) Reserves, which is equivalent to the high estimate scenario. In this context, when probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate."

The certainty can also be referred to in a probabilistic form as well. P90, P50, P10 are often used in place of 1P, 2P, 3P, even in situations where deterministic methods are used to estimate reserves volumes. P50 represents the quantity for which there is a 50% probability the quantities actually recovered will match or exceed the estimated recovery value. The same definition applies to P90 (90%) and P10 (10%).

The status of reserves is another classification type used. It describes the current ability of a well to produce. There are three status types used:

- **Developed / Producing** — The wells and facilities required for production are in place. Expected to be recovered from completion intervals that are open and producing at the time of the estimate.

- **Developed / Non-producing** — The wells and facilities required for production are in place. The well or zone is not currently producing, but requires little or no capital expenditure to be brought on production.

- **Undeveloped** — Significant capital expenditure is required for the well to come on production.

The following acronyms are typically used to define reserve classifications:

Acronym	Definition
PDP	Proved Developed Producing
PPDP	Proved plus Probable Developed Producing
PPPDP	Proved plus Probable plus Possible Developed Producing
PNP	Proved Developed, Non-Producing
PPNP	Proved plus Probable Developed, Non-Producing
PPPNP	Proved plus Probable plus Possible Developed, Non-Producing
PUD	Proved Undeveloped
PPUD	Proved plus Probable Undeveloped
PPPUD	Proved plus Probable plus Possible Undeveloped

Acronym	Definition
TP	Total Proved
TPP	Total Proved plus Probable
TPPP	Total Proved plus Probable plus Possible

Reservoir flow

Flow in a reservoir is often characterized as being one of two types: transient or boundary-dominated.

Transient flow takes place during the early life of a well, when the reservoir boundaries have not been felt, and the reservoir is said to be infinite-acting. During this period, the size of the reservoir has no effect on the well performance, and reservoir size cannot be determined except to deduce minimum contacted volume. Since the boundary of the reservoir has not been contacted during the transient flow period, static pressure at the boundary remains constant.

Pressure transient analysis / well testing theory relies heavily on the assumption that the well flows at a constant rate. Several terms are often used when describing flow from a well at constant rate:

- **Transient Flow** — The pressure transient migrates outward from the well without encountering any boundaries.

- **Steady State Flow** — The pressure transient has reached all of the boundaries but the static pressure at the boundary does not decline. This is often called "constant pressure boundary".

- **Pseudo-Steady State Flow** — The pressure transient has reached all of the boundaries and the static pressure is declining at the boundary and declining uniformly throughout the reservoir.

- **Boundary-Dominated Flow** — The pressure transient has reached all of the boundaries and the static pressure is declining at the boundary, but not uniformly because the flow rate is not constant. This is also often called "tank-type flow".

The following schematic chart shows the pressure distribution in the reservoir for a constant flow rate. The red lines represent the transient portion and the blue lines the pseudo-steady-state portion. The yellow line indicates the transition from transient to a pseudo-steady state. Note that the vertical distance between each line is uniform from near wellbore to the boundary.
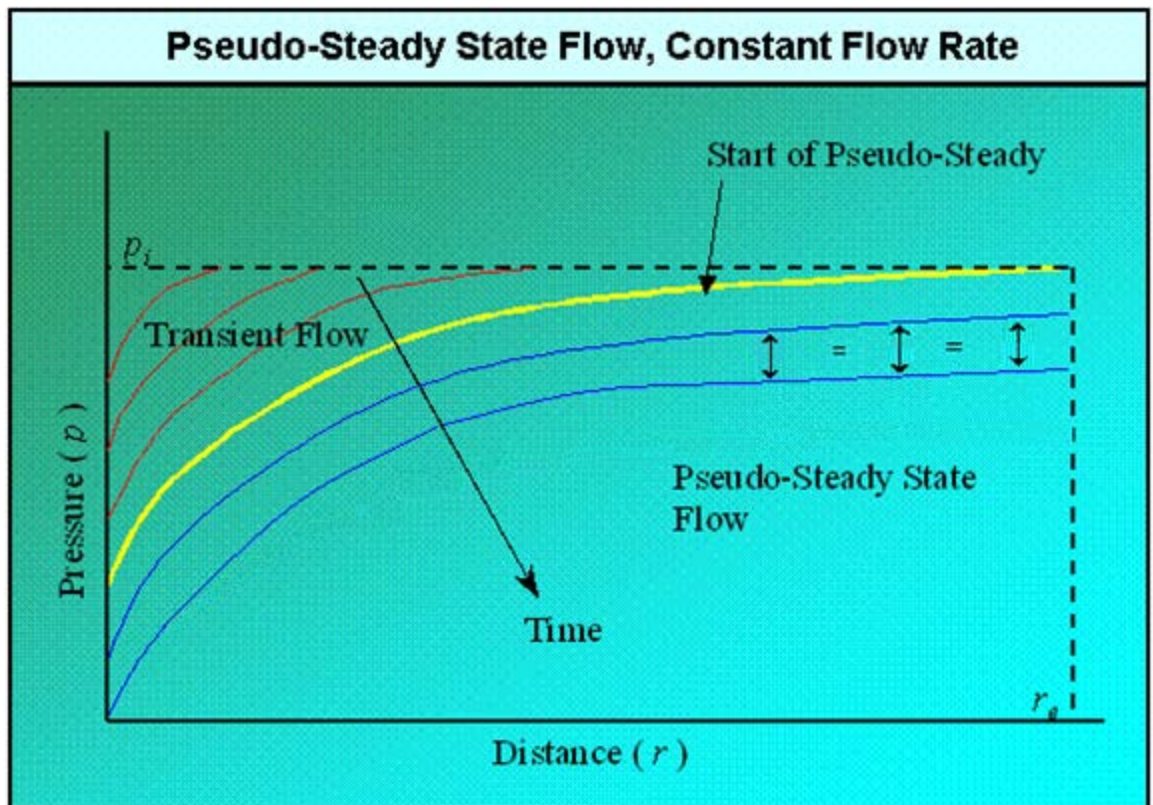
Pseudo-Steady State Flow, Constant Flow Rate

The following schematic chart shows the pressure distribution in the reservoir for a constant-flowing pressure solution. Note that the flowing pressure of the wellbore is constant and the pressure distribution through the reservoir is not uniform.

Boundary-Dominated Flow, Constant Flowing Pressure
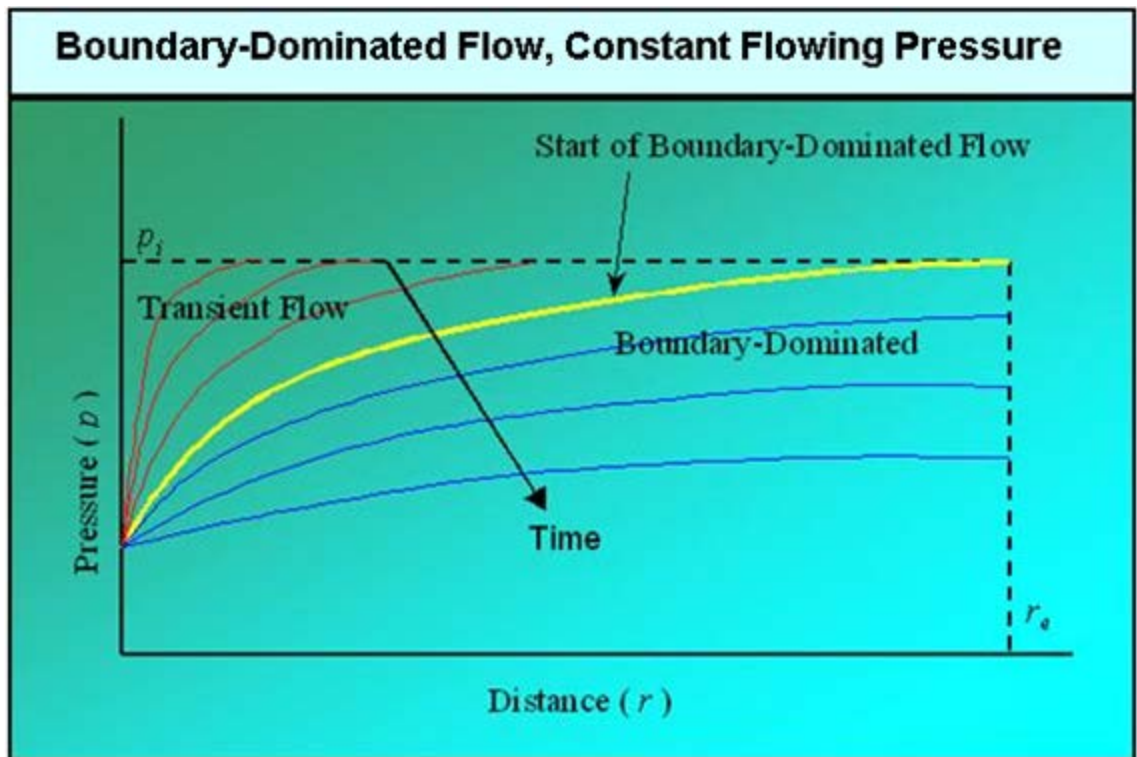
The constant rate and constant-pressure solutions are boundaries that the actual walls approach, but never really achieve. Early production and formal production tests often very closely approach the constant-rate solution, whereas late time production generally very closely approaches the constant-pressure solution. Constant-rate solutions are important for conducting pressure transient analysis (PTA) for determination of key reservoir parameters such as permeability and damage, whereas the constant-pressure solutions are important for determination of original in-place volumes and recoverable reserves.

Reservoir fluid properties

Gas

A gas can be defined as a homogenous fluid of low density and low viscosity, which has neither independent shape nor volume. It expands to completely fill the vessel in which it is contained. The properties of gases differ from liquids mainly because the molecules in gases are much further apart than liquids. The ideal gas law states:

$$pV = nRT$$

This equation has limited practical value because no known gas behaves as an ideal gas. However, this equation does describe the behavior of most real gases at low pressures, and it serves as a starting point to develop equations of states for real gases at elevated pressures. Furthermore, the behaviors of most real gases do not deviate drastically from the behavior predicted by this equation. By inserting a correction factor (Z) into the ideal gas equation, real gas behavior can be accurately predicted.

$$pV = ZnRT$$

The correction factor is called the gas compressibility factor; and represents the deviation from ideal gas behavior.

Gravity

Gas gravity is the molar mass (molecular weight) of the natural gas divided by the molar mass of air (28.94 kg / kmol). It ranges from 0.55 for dry sweet gas to approximately 1.5 for wet sour gas. Petroleum gases typically have a gravity of about 0.65.

The gas gravity affects the calculations of gas viscosity, compressibility, compressibility factor, and solution gas-oil-ratio.

Compressibility factor

The gas compressibility factor of a natural gas is a measure of its deviation from ideal gas behavior. The gas compressibility factor is the ratio of the volume actually occupied by a gas at a given pressure and temperature to the volume the gas would occupy at the same pressure and temperature, if it behaved like an ideal gas.

$$Z = \frac{V_{actual}}{V_{ideal}}$$

The gas compressibility factor is usually between 0.8 and 1.2, but it can be as low as 0.3 and as high as 2.0. It is used in the calculation of gas pseudo-pressures, and in converting gas volumes and rates from standard conditions to reservoir conditions (and vice-versa). It is sometimes called the super-compressibility factor, and is often confused with the term "compressibility", which is the change in volume per unit change in pressure. The gas compressibility factor directly affects the gas compressibility.

Compressibility

Gas compressibility is the relative change in volume per unit change in pressure. The gas compressibility should not be confused with the gas compressibility factor. The gas compressibility is a very strong function of pressure and increases as the pressure decreases.

Gas compressibility, when plotted versus pressure, shows a discontinuity at the dew point pressure. When the gas is undersaturated (that is, the pressure is greater than the dew point pressure), mathematically it can be expressed as:

$$c_g = -\frac{1}{B_{gd}} \frac{dB_{gd}}{dp}$$

or

$$c_g = \frac{1}{p} - \frac{1}{Z} \frac{dZ}{dp}$$

Where p is the specified pressure, B_{gd} is the dry gas formation volume factor, and Z is the gas compressibility factor at that pressure. Thus, the magnitude of gas compressibility is of the order of 1/p.

When the gas is saturated (that is, pressure is less than the dew point pressure), it is expressed as:

$$c_g = -\frac{1}{B_{gd}} \frac{dB_{gd}}{dp} + \frac{1}{B_{gd}} \frac{B_o - B_{gd} R_s}{1 - R_s R_v} \frac{dR_v}{dp}$$

Where B_o is the oil formation volume factor, R_s is the solution gas ratio, and R_v is the vaporized oil ratio.

Formation volume factor

The gas formation volume factor is the gas volume at reservoir conditions divided by gas volume at standard conditions. It is used to convert surface measured volumes to reservoir conditions, assuming that the fluid is in a single-gas phase despite temperature and pressure changes. Defined below, it is a function of the fluid composition and the pressure / temperature ratio between reservoir (in-situ) and standard conditions (14.65 psia and 519.67 °R or 60 °F):

$$B_g = \frac{V_{reservoir}}{V_{surface}} = \frac{14.65TZ}{519.67p}$$

It is a very strong function of pressure, and a weak function of temperature and gas composition.

The dry gas formation volume factor is the gas volume at reservoir conditions divided by the gas volume at standard conditions. It is used to describe the gas volume change from the reservoir to the surface, taking into account the phase change between gas and liquid.

$$B_{gd} = \frac{V_{reservoir}}{V_{surface}}$$

Vaporized oil ratio (R$_v$)

For condensate gas and volatile oil reservoirs with a gas cap, the liquid component in the reservoir gas needs to be considered. This is described by the vaporized oil rRatio (R_v). R_v is defined as the ratio of the volume of produced stock tank condensate or oil to the volume of produced separator gas (commonly used unit is stb/MMscf). It is used in the modified black oil (MBO) models.

Viscosity

Gas viscosity is a measure of the resistance to flow exerted by the gas and is given in units of centipoises (cp). Higher values indicate more resistance to flow. For gas, the viscosity increases with increasing temperature and pressure. As pressure decreases, gas viscosity decreases. The molecules are simply further apart at lower pressure and move past each other more easily.

Experimental determination of gas viscosity is difficult. Usually it is not measured but obtained from correlations, which include corrections for H_2S, CO_2, and N_2. Gas viscosity is used in numerous equations, most notably in the definitions of pseudo-pressure and pseudo-time. Typically, gas viscosity is in the range of 0.015 to 0.03 cp or 15 to 30 micro-Pa-s.

Critical temperature

Gases can be converted to liquids by compressing the gas at a suitable temperature. As the temperature increases, the kinetic energies of the particles that make up the gas also increase, and the gases become more difficult to liquefy. The critical temperature of a substance is the temperature at and above which vapor of the substance cannot be liquefied, no matter how much pressure is applied. For example, the critical temperature of water is 374°C and carbon dioxide is 31.2°C.

Critical temperature represents the temperature above which distinct liquid and gas phases do not exist. As the critical temperature is approached, the properties of the gas and liquid phases become the same, resulting in one phase known as supercritical fluid. The critical temperature value is used in the definition of reduced temperature ($T_r = T / T_c$), which in turn is used directly in correlations or equations of state to determine various PVT properties of natural gases (for example, viscosity, compressibility, gas compressibility factor, etc.).

Critical pressure

The critical pressure of a substance is the pressure required to liquefy a gas at its critical temperature. For example, the critical pressure of water is 217.7 atm and carbon dioxide is 73.0 atm.

Critical pressure represents the pressure above which distinct liquid and gas phases do not exist. As the critical pressure is approached, the properties of the gas and liquid phases become the same, resulting in one phase known as supercritical fluid. The critical pressure value is used in the definition of reduced pressure ($p_r = p / p_c$), which in turn is used directly in correlations or equations of state to determine various PVT properties of natural gases (for example, viscosity, compressibility, gas compressibility factor, etc.).

Oil

Correlations of physical properties of reservoir crude oils are more complicated than those for natural gas because of the many different components they contain. Although most components are hydrocarbons, the larger molecule components can be different chemical classes. These larger, heavier components can strongly influence the behavior of the mixture. Also the mixing rules for liquids are considerably different than those for gases because of the complex nature of hydrocarbon liquids.

There are three main sources for developing key oil properties.

1. Subsurface sampling of the produced fluid at reservoir conditions. This is the best method because the complex mixtures of hydrocarbons make each oil unique. The individual properties can then be determined empirically in a laboratory.

2. Surface sampling at a separator where the rate of flow for each fluid, gas and liquids, is measured along with their respective compositions. These fluids are then recombined in the laboratory at reservoir conditions, and the resulting fluid is used to empirically determine key oil properties.

3. Correlations are often used when only key parameters, such as the density of the produced oil and the volume of solution-gas evolved, are known. Correlations should be used only after being proved / tuned with laboratory measurements for subsurface samples of analogous oils.

Gravity

Oil gravity relates the density of oil to that of the density of water. The oil gravity has a very strong effect on the calculated oil viscosity and solution gas-oil ratio. It has an indirect effect on the oil compressibility and the oil formation volume factor because these variables are affected by the solution gas-oil ratio.

The American Petroleum Institute (API) developed a specific gravity scale that measures the relative density of various petroleum liquids. API gravity is gradated in degrees on a hydrometer instrument and was designed so that most values would fall between 10° and 70° API.

Usually the oil gravity is readily known. It ranges from 45 °API (light oil) through 20 °API (medium density) to 10 °API (heavy oil). The conversion from API gravity (oil field units) to relative gravity (relative to water) is:

$$\gamma_o = \frac{141.5}{°API + 131.5}$$

The conversion of oil relative gravity to oil density is:

$$\rho_o = \gamma_o \cdot \rho_w$$

where:

$\rho_w \approx 62.37$ lb·m / ft^3 or 1000 kg / m^3

Formation volume factor

The oil formation volume factor (FVF) is defined as the ratio of the volume of oil and dissolved gas at reservoir (in-situ) conditions to the volume of oil at stock tank (surface) conditions. Since most measurements of oil and gas production are made at the surface, and the fluid flow takes place in the

formation, volume factors are needed to convert measured surface volumes to reservoir conditions. It is defined as:

$$B_o = \frac{V_{res}}{V_{surface}}$$
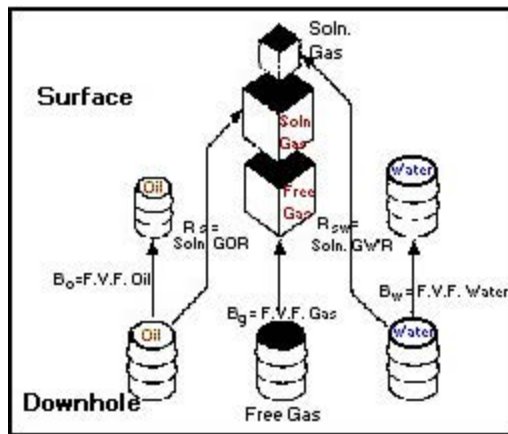
Note: F.V.F. → Formation Volume Factor

The oil formation volume factor is influenced by two main factors: solution gas and the compressiblity of oil. The dominant factor is solution gas. As pressure increases, the amount of solution gas that the oil can dissolve increases such that the oil swells, and so the formation volume factor exceeds 1.0. After there is no remaining free gas available to dissolve in the oil, further increases in pressure result in a decline in formation volume factor due to the second influencing factor – the compressibility of oil. As shown in the diagram below, the oil formation volume factor is dominated by swelling below the bubble point pressure (due to dissolved gas), and by compressibility above the bubble point pressure (because all available gas is now dissolved).
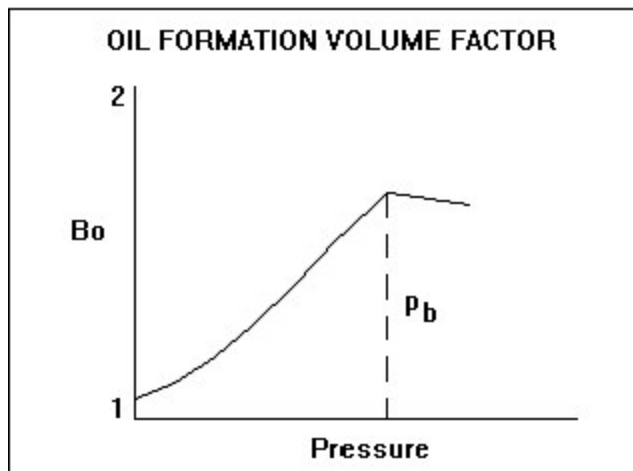
Shrinkage

Shrinkage is the inverse of the formation volume factor for oil, and represents the difference between the volume of oil in the reservoir and its volume when produced to the surface (standard pressure and temperature). The value of shrinkage is generally between 0.5 and 1, and the change in volume is due to solution gas coming out of the oil as the pressure decreases.

Compressibility

Oil compressibility is defined as the relative change in oil volume per unit change in pressure. Oil compressibility is a source of energy for fluid flow in a reservoir. In an undersaturated reservoir, it is a dominant drive mechanism, but for a saturated reservoir, it is overshadowed by gas compressibility effects due to the evolution of dissolved gas. Oil compressibility is a component of total compressibility, which is used in the determination of skin, dimensionless time, and material balance.

Oil compressibility, when plotted versus pressure, shows a significant discontinuity at the bubble point pressure. Above this pressure (undersaturated condition), the oil is a single-phase liquid consisting of oil and dissolved gas. The compressibility of this liquid can be measured in the laboratory, and it is a weak function of pressure. Mathematically, it can be expressed as:

$$c_o = -\frac{1}{B_o}\frac{dB_o}{dp}$$

Where B_o is oil formation volume factor.

Below the bubble point pressure (saturated condition), gas comes out of solution causing a sharp increase in compressibility, which causes the discontinuity shown in the plot. While below the bubble point pressure, oil compressibility becomes a much stronger function of pressure. It can be expressed as:

$$c_o = -\frac{1}{B_o}\frac{dB_o}{dp} + \frac{1}{B_o}\frac{B_{gd}-B_o R_v}{1-R_s R_v}\frac{dR_s}{dp}$$

Where B_{gd} is the dry gas formation volume factor, R_s is the solution gas ratio, and R_v is the vaporized oil ratio.

OIL COMPRESSIBILITY
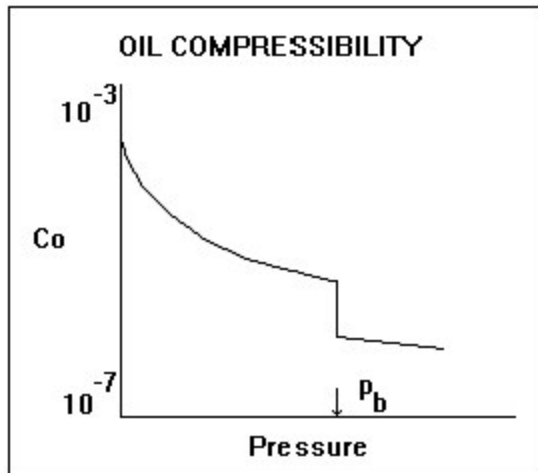
Solution gas-oil ratio

The solution gas-oil ratio is the amount of gas dissolved in the oil at any pressure. It increases approximately linearly with pressure and is a function of the oil and gas composition. A heavy oil contains less dissolved gas than a light oil. In general, the solution gas-oil ratio varies from 0 (dead oil) to approximately 2000 scf/bbl (very light oil). The solution gas-oil ratio increases with pressure until the bubble point pressure is reached, after which it is a constant, and the oil is said to be undersaturated.

SOLUTION GAS-OIL RATIO
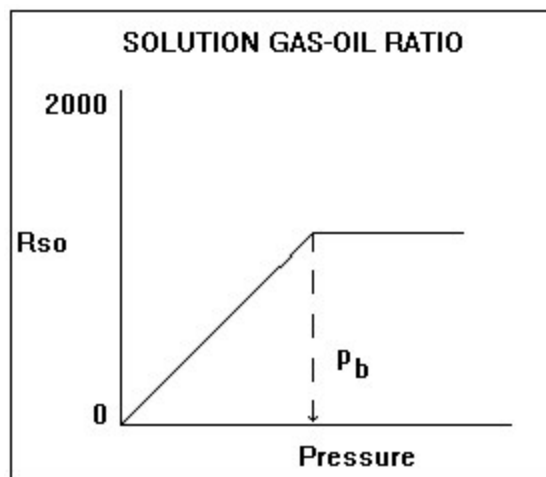
The solution gas-oil ratio is a significant component of the PVT correlations. It has a very significant influence on the oil formation volume factor, the oil viscosity, and the oil compressibility.

Viscosity

Oil viscosity is a measure of the resistance to flow exerted by the oil, and is given in units of centi-poises (cP). Higher values indicate greater resistance to flow. For oil, the viscosity decreases with increasing temperature and pressure (up to the bubble point). Above the bubble point pressure, oil viscosity increases minimally with increasing pressure as shown below. It is a very strong function of reservoir temperature, oil gravity, and the solution gas-oil ratio.
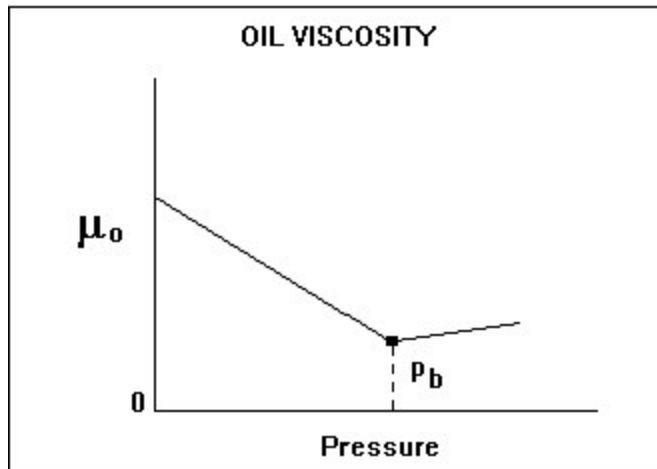
Oil viscosity is measured as a function of pressure in most PVT laboratory measurements. Occasionally, a routine oil analysis report quotes the oil viscosity (and the kinematic viscosity). These measurements are at stock tank conditions and should not be used as the in-situ oil viscosity. Dead-oil viscosity is defined as the viscosity of crude oil at atmospheric pressure (no gas in solution) and system temperature. There are several correlations available for estimating oil viscosity at reservoir conditions, but great care must be taken since they are very sensitive to the oil gravity and solution gas-oil ratio inputs. The oil viscosity at reservoir conditions can vary from 10,000 cP for a heavy oil to less than 1 cP for a light oil.

Bubble point pressure

The bubble point pressure is defined as the pressure at which the first bubble of gas comes out of solution. At this point, we can say the oil is saturated – it cannot hold anymore gas. Above this pressure, the oil is undersaturated, and the oil acts as a single-phase liquid. At and below this pressure, the oil is saturated, and any lowering of the pressure causes gas to be liberated resulting in two-phase flow.
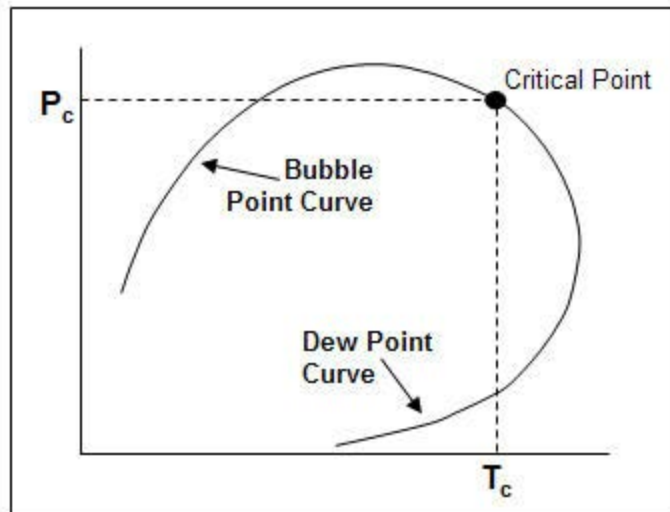
Water

Estimating reservoir water properties is important for reservoir engineering calculations, specifically for those with water influx. Also, water is often a very important liquid component of an oil and gas production system. The physical properties of water play an important role in multiphase flow calculations.

Because water composition is only generally affected by dissolved solids, correlating water properties is relatively simple. Also, changes in the physical properties of water as a function of temperature and pressure are relatively small and usually can be predicted.

Water-specific gravity

Water-specific gravity is defined as the density of the water divided by the density of water at standard conditions (62.3 lb / ft^3). Water contained in a reservoir is saline and usually has a specific gravity greater than 1.0. Water-specific gravity has no effect on calculated properties such as water compressibility, formation volume factor, and viscosity. It is used however, in the wellbore pressure-drop calculations when converting pressures from wellhead to sandface.

Salinity

Salinity is the quantity of dissolved salt in water, and is usually expressed as the mass of dissolved salt in a unit volume solution, in mg / L, or parts per million (ppm). Salinity is often reported as total dissolved solids (TDS).

Viscosity

Water viscosity is a measure of the resistance to flow exerted by water. Higher values indicate more resistance to flow. For water, the viscosity decreases with increasing temperature, and increases with increasing pressure. Water viscosity is a very weak function of pressure. Water at room temperature is approximately equal to 1 cP. In a reservoir, it is typically between 0.5 to 1 cP. This is due to the higher temperature, salinity, and the solution-gas content of water.

Compressibility

The compressibility of any substance is the change in volume per unit volume per unit change in pressure. Water compressibility is a source of energy for fluid flow in a reservoir, but it is only significant when there is no free gas present in the reservoir. The value of water compressibility can be obtained from laboratory PVT measurements, or it can be determined from correlations. The magnitude is approximately between 1.0×10^{-6} and $9.0 \times 10^{-6} \text{psi}^{-1}$. It is a weak function of pressure, temperature, and salinity.

Formation volume factor

The water formation volume factor is defined as the ratio of the volume of water at reservoir (in-situ) conditions to that at stock tank (surface) conditions. This factor is used to convert the flow rate of water (at stock tank conditions) to reservoir conditions.

$$B_w \; = \; \frac{V_{res}}{V_{surface}}$$

The water formation volume factor can be measured in the laboratory, or it can be determined from correlations. In most situations, the water formation volume factor is very close to one, and so most practitioners tend to set it to one. It is a very weak function of pressure, temperature, and salinity.

Dissolved gas / water ratio

The solution gas / water ratio is the amount of gas dissolved in the water. It increases approximately linearly with pressure, and is a function of the water and gas composition. Quantitatively, the solubility of gas in water is considerably less than that of gas in oil.

Reservoir fluid types

Typically, there are five main types of reservoir fluids: black oil, volatile oil, condensate (retrograde gas), wet gas, and dry gas. Each of these fluid types require different approaches when analyzing the reservoir, so it is important to identify the correct fluid type early on in the reservoir's life. Laboratory analysis is our primary method for determining and quantifying fluid type, but production information such as initial production gas-oil ratio (GOR), gravity of the stock-tank liquid, and the color of the stock-tank liquid are also useful indicators.

Black oils

Black oils are made up of a variety of components including large, heavy, and non-volatile hydro-carbons. The phase diagram is shown below. When the reservoir pressure lies anywhere along line 1 → 2, the oil is said to be undersaturated - meaning the oil could dissolve more gas if more gas were present. If the pressure is at 2, the oil is at its bubble point, and is said to be saturated - meaning the oil contains the maximum amount of dissolved gas and can't hold any more gas. A reduction in pressure at this point will release gas to form a free gas phase inside the reservoir. Additional gas evolves from the oil as it moves from the reservoir to the surface. This causes some shrinkage of the oil. Black oil is often called low shrinkage crude oil or ordinary oil.
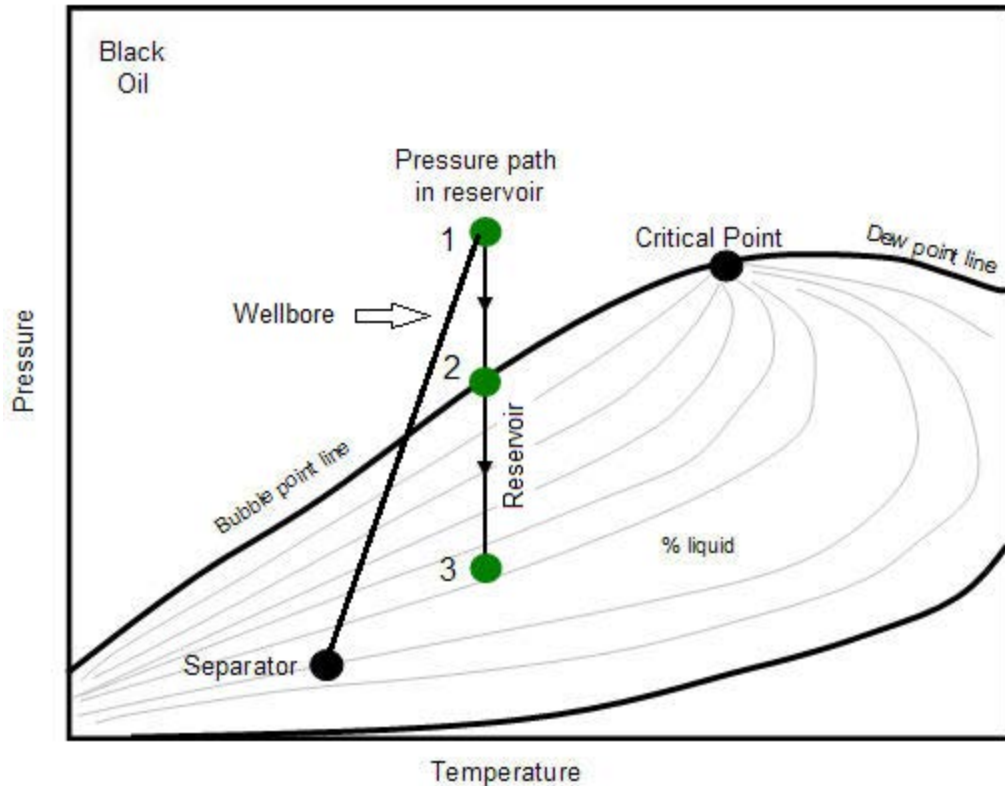
Black oils are dark in color indicating the presence of heavy hydrocarbons. It is characterized as having initial gas-oil ratios of 2000 scf/stb or less. Producing GOR will increase during production when reservoir falls below bubble point pressure, 2 → 3 as the gas evolves from the solution inside the reservoir and flows preferentially to the oil.

Volatile oils

Volatile oils contain fewer heavy molecules and more intermediate components (ethane through hexane) than black oils. Volatile oils generally have initial gas-oil ratios in the 2000 to 3300 scf/Bbl range, and the stock tank gravity is usually 40° API or higher. The color is generally lighter than black oil – brown, orange, or green. Gas associated with volatile oils tends to be very rich and similar to retrograde condensate gas.

The phase envelope for a volatile oil tends to cover a much narrower temperature range when compared to a black oil; but like a black oil, the reservoir temperature is always lower than the critical temperature for the fluid. As the reservoir temperature approaches the critical temperature a volatile oil will become more gas-like such that with even moderate depletion, a volatile oil reservoir can flash mainly to gas and have a relatively low liquid content.
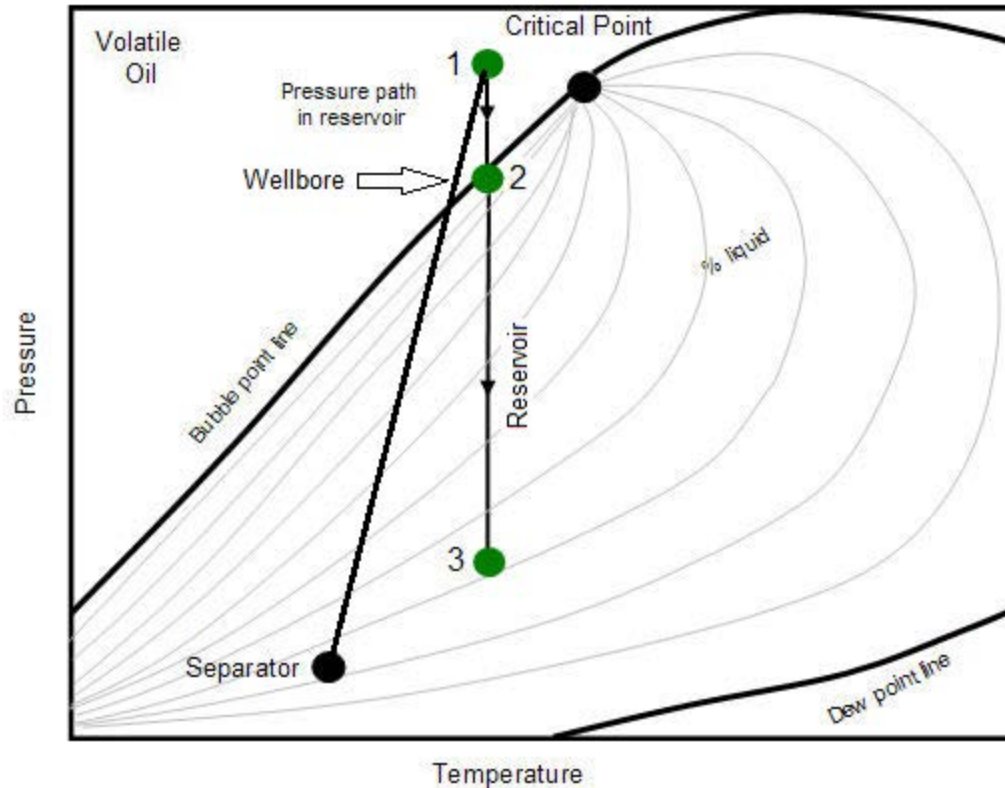
Condensate (retrograde gas)

Condensate gas is very similar to volatile oils in terms of the color (green, orange, brown, even clear) and gravity (40° to 60° API) of the produced oil. However, the reservoir temperature of a condensate gas reservoir is greater than the critical temperature of the fluid, and so where a volatile oil is a liquid at original reservoir pressure and temperature, a condensate gas is a gas.

As pressure is reduced in a condensate gas reservoir, the fluid will pass through the dew point and large volumes of liquid will condense in the reservoir. Since the gas flows preferentially to oil, much of this oil will be unrecoverable. Consequently, it is important to recognize that a reservoir contains a condensate gas and re-inject dry gas to maintain reservoir pressure above the dew point to maximize recovery of the liquids. In the diagram below, the retrograde gas exists completely in a gaseous state inside the reservoir at point 1. As the pressure decreases, the condensate exhibits a dew point at point 2. As the reservoir further depletes and the pressure drops, liquid condenses from the gas to form a free liquid *inside* the reservoir.
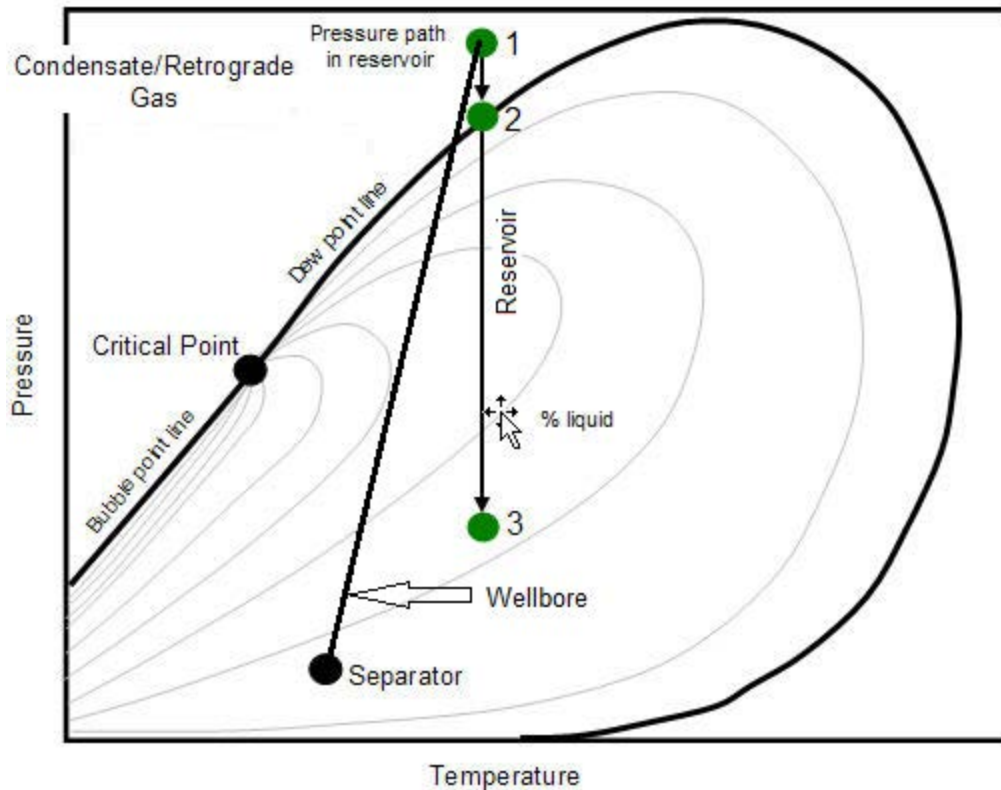
Wet gas (rich gas)

Natural gas that contains significant heavy hydrocarbons such as propane, butane and other liquid hydrocarbons is known as wet gas or rich gas. The general rule of thumb is if the gas contains less methane (typically less than 85% methane) and more ethane, and other more complex hydrocarbons, it is labeled as wet gas.

Wet gas exists solely as a gas in the reservoir throughout the reduction in reservoir pressure. Unlike retrograde condensate, no liquid is formed inside the reservoir. However, separator conditions lie within the phase envelope, causing some liquid to be formed at the surface. This surface liquid is normally called condensate, and the reservoir gas is sometimes called condensate-gas, which leads to a lot of confusion between wet gasses and retrograde condensate.

The entire phase diagram of a wet gas will lie below the reservoir temperature. Note that the pressure path line does not enter the phase envelope, meaning no liquid is ever formed inside the reservoir.
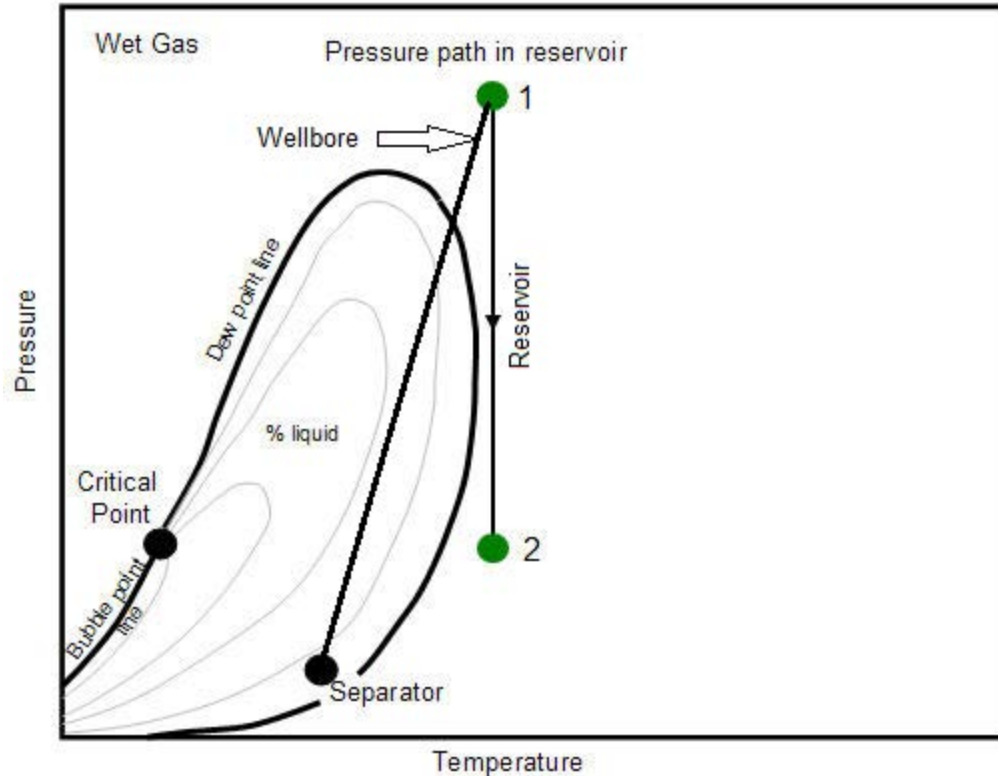
Wet gases produce stock tank liquid with the same range of gravities as the liquids from retrograde gases. However, the gravity of the stock tank liquid does not change during the life of the reservoir. Also, producing GOR are very high (> 50000 scf/stb) for wet gases and remains constant.

Dry gas

Natural gas that occurs in the absence of condensate or liquid hydrocarbons, or gas that had condensable hydrocarbons removed, is called dry gas. It is primarily methane with some intermediates. The hydrocarbon mixture is solely gas in the reservoir and there is no liquid (condensate surface liquid) formed either in the reservoir or at surface. The pressure path line does not enter into the phase envelope in the phase diagram, thus there is only dry gas in the reservoir. Note, the surface separator conditions also fall outside the phase envelope (in contrast to wet gas); hence no liquid is formed at the surface separator.

Dry Gas

Pressure path in reservoir 1

Wellbore ➡

Pressure

Dew point line

% liquid

Reservoir

2

Separator

Temperature
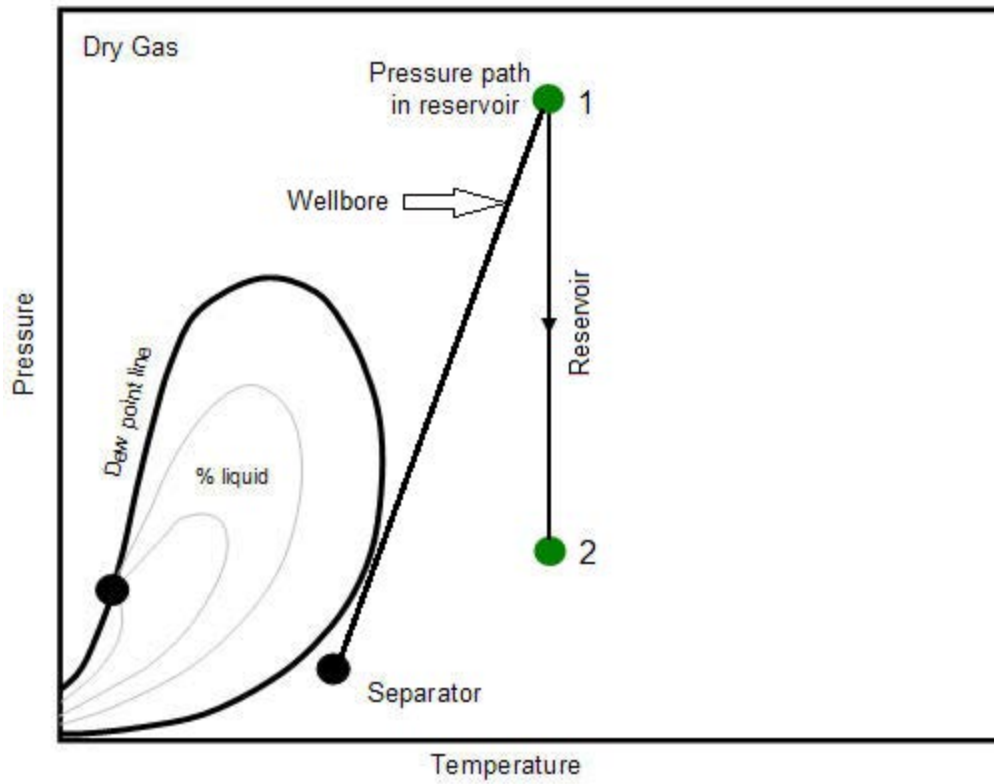
Reservoir properties

This topic describes the key terminology for reservoir properties.

Drainage area

This is the areal extent of the reservoir. It is most often determined from geological information about the formation / region, but it can also be estimated from performance studies such as material balance, interference analysis, and simulation studies.

Expected ultimate recovery

The expected ultimate recovery (EUR) is the amount of oil or gas that can be economically recovered from a reservoir under current operating and economic conditions.

Formation compressibility

Formation compressibility is the change in pore volume per unit of pore volume per unit change in pressure. Even though the formation is a solid material, it is compressible. The formation compressibility is used in the calculation of total compressibility. It is of the same order of magnitude as the oil compressibility, or the water compressibility, approximately 10^{-6} psi^{-1}.

Thus, in the absence of gas saturation, the formation compressibility is relatively significant and must not be ignored. However, when there is gas present in the pores, the gas compressibility is often one or two orders of magnitude higher, and so the formation compressibility is relatively small and may be ignored.

The formation compressibility may be measured in the laboratory, but it is usually derived from correlations. It is obvious that the nature of the formation, its degree of consolidation, its stress field, etc. all affect the formation compressibility, yet the correlations that exist do not take all of these factors into account. They are very simplified and relate the formation compressibility to the total porosity. The correlation used in Harmony Enterprise is derived from laboratory measurements [Hall, 1953], and is applicable to sandstones and carbonates. For overpressured reservoirs, the formation compressibility can be 10 times larger than suggested by the Hall correlation. In practice, it has been found that formation compressibility for overpressured reservoirs is approximately equal to 10^{-5} psi^{-1}.

Gas saturation

Gas saturation is the fraction of the pore space occupied by gas. Most gas reservoirs also contain some connate (non-movable) water. If the gas reservoir is part of a gas cap in a saturated oil reservoir, the space may contain gas, oil, and water. Thus, the gas saturation is rarely 100% but varies from 30% to 90%.

Gas saturation is used directly in the calculation of the reserves, and also in the calculation of total compressibility.

Note that the gas saturation has a significant effect on the total compressibility because the gas compressibility is much higher than the fluid compressibility of oil and water.

Initial pressure

Reservoir pressure is the pressure of fluids within the pores of a reservoir measured at a specific point in time. The initial reservoir pressure is the average reservoir pressure measured in a discovery well before any fluid is produced. This value is necessary for many reservoir engineering calculations, such as reserve determination. Units are typically psi (field units) or kilopascals (SI).

For well testing, the initial pressure is the average reservoir pressure before the start of a test. For a new well, a well that has not been put on production, the initial pressure equals the virgin or original pressure and corresponds to a drillstem test pressure. For a well that has been on production for a long time, the initial pressure may or may not be equal to the original reservoir pressure. The following example illustrates this concept.
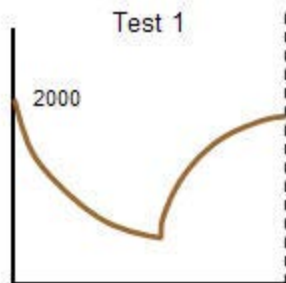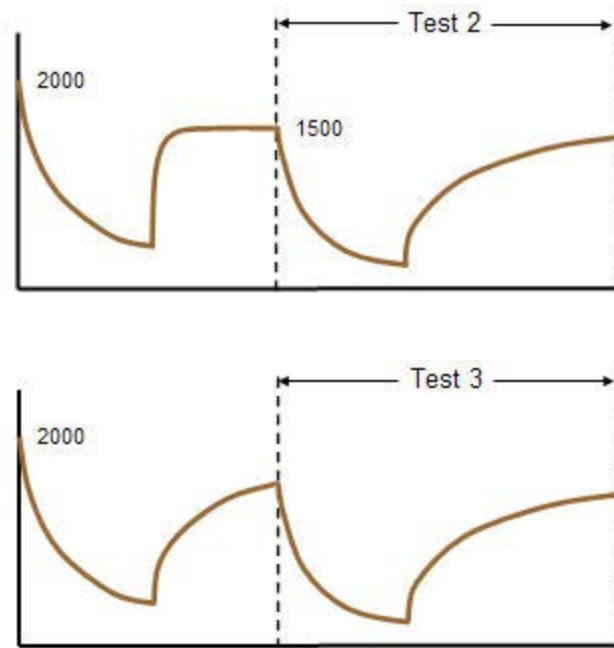
- If Test 1 is being analyzed, the initial pressure is 2000.

- If Test 2 is being analyzed, the initial pressure is 1500 because the reservoir pressure is fully built up before this test, and the historical pressure prior to Test 2 does not apply. Thus, it behaves like a new well with an initial pressure 1500.

- If Test 3 (which is a combination of Test 2 and some production prior to Test 2) is being analyzed, the initial pressure is 2000, because it must reflect the reservoir pressure before the production that is being analyzed during the test.

Mid-point of perforations

Perforations are the communication tunnel created from the casing or liner into the reservoir formation through which the oil or gas is produced. The mid-point of perforations is the measured depth from the surface to the mid-point of the perforated interval of the formation.

Net pay

Net pay is the thickness of the formation that contributes to the flow of fluids, or the sum of the productive intervals of a reservoir. It is determined from core or log analysis, and can be different from the gross pay or the perforated interval. In the case of an inclined or deviated wellbore in a declining formation, the net pay is measured perpendicular to the angle of decline. Several examples of net pay are shown below.

net pay = h

net pay = h

net pay = h₁+h₂+h₃

net pay = h₁+h₃

net pay = h
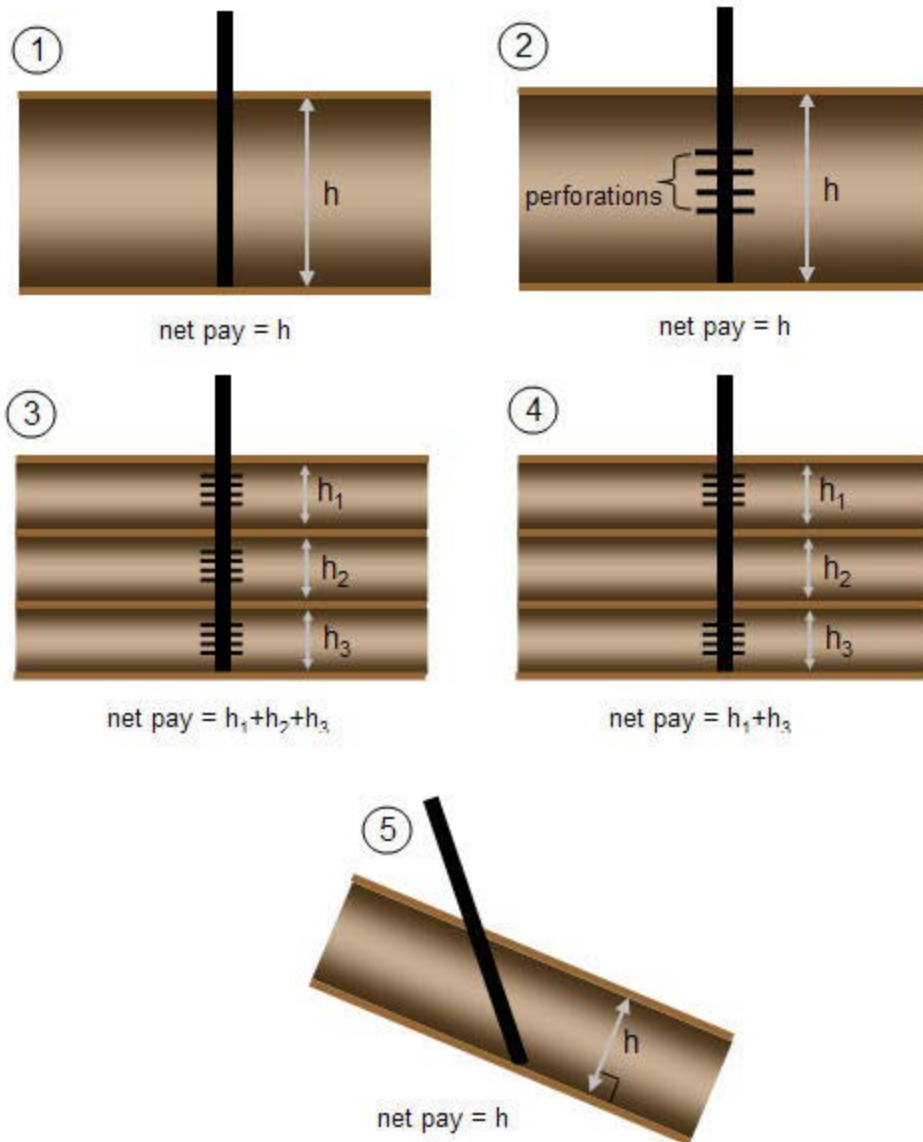
Oil saturation

Oil saturation is the fraction of the pore space occupied by oil. Most oil reservoirs also contain some connate (non-movable) water. Thus, the oil saturation is rarely 100% and usually ranges from 10% to 90% (in the oil / water transition zones). The oil saturation affects the oil and gas reserves, and is also used in the calculation of total compressibility.

Original fluid-in-place

Original fluid-in-place (OFIP) is the amount of fluid contained in a reservoir at standard conditions, as calculated from the reservoir and fluid properties. It is a general term that refers to the calculation of original gas-in-place (OGIP) and/or original oil-in-place (OOIP).

Porosity

The total porosity is the percentage volume occupied by the pore space, regardless of the type of fluids contained in the pore space. It is obtained from core or log analysis. Total porosity is used to calculate volumetric reserves and formation compressibility, and is used in the pressure transient flow equations.

The total porosity has only a small effect during the transient flow period (it occurs within the log term in the skin calculation equation for radial flow), but it has a significant effect during pseudo-steady state (PSS) flow, as it directly affects the reserves contained in the reservoir.

Rock volume

The total volume of reservoir rock, often referred to as the bulk volume.

Pore volume

The total volume of pore space within the reservoir as determined by the porosity of the rock.

Hydrocarbon pore volume

The total pore volume containing hydrocarbons. This is generally the product of pore volume and water saturation.

Recovery factor

The recovery factor (RF) is the ratio of the expected ultimate recovery and original gas/oil-in-place. It indicates how much of the original gas/oil-in-place can be recovered under current operating and economic conditions.

Reservoir temperature

The reservoir temperature represents the temperature of the formation. It increases with reservoir depth and differs widely depending on the reservoir location's geothermal gradient. The geothermal gradient is the rate of increase in temperature per unit depth in the earth. Although the gradient is variable depending on location, a typical average value is 15°F / 1000 ft.

In the analysis of gas wells, the reservoir temperature is used directly in the pressure transient analysis calculations, as well as calculating all the gas fluid properties, such as the gas formation volume factor, gas viscosity, and gas compressibility.

In the analysis of oil wells, the reservoir temperature does not enter into the pressure transient analysis equations directly; rather it is used in calculating oil fluid properties such as the oil formation volume factor, oil viscosity, oil compressibility, and solution gas-oil ratio.

Units are typically Rankine (field units) or Kelvin (SI).

Total compressibility

The compressibility of a substance is the change in volume per unit volume per unit change in pressure. In a reservoir that consists of rock and pore space occupied by oil, water, and gas, the total compressibility is defined as follows:

$$c_t = c_g S_g + c_o S_o + c_w S_w + c_f$$

From this definition, the total compressibility takes into account the compressibility and saturation of gas, oil, and water, as well as the (rock) formation compressibility. Note that the gas saturation has a significant effect on the total compressibility because the gas compressibility is much higher than the other fluid compressibility (oil and water). Thus, if there is any gas present in the reservoir, the total compressibility is dominated by the gas compressibility component.

In well testing and rate transient analysis, the analysis of pressure and production data is based on the solution of the diffusivity equation. The analytical solution of this equation assumes that the total compressibility is constant. This assumption is valid for single-phase liquid systems. In gas systems, because compressibility of gas is highly dependent on pressure, the assumption of a constant value of total compressibility can lead to serious errors, especially when the reservoir has started to deplete (that is, during boundary-dominated flow). To account for this changing gas compressibility, the concept of pseudo-time is invoked. It accounts for the variation with pressure of compressibility, viscosity, and permeability.

The units of compressibility are 10^{-6} psi^{-1}. ($1 * 10^{-6}$ psi^{-1} (sometimes referred to as 1 Microsip.)

- $c_o \approx c_w \approx c_f \approx 10^{-6}$ psi^{-1}

- $c_g \approx 10^{-3}$ psi^{-1} @ 500 psi

- $c_g \approx 10^{-3}$ psi^{-1} @ 1000 psi

- $c_g \approx 10^{-4}$ psi^{-1} @ 2500 psi

- $c_g \approx 10^{-4}$ psi^{-1} @ 5000 psi

- $c_g \approx 10^{-5}$ psi^{-1} @ 10,000 psi

- $c_g \approx 10^{-5}$ psi^{-1} @ 15,000 psi

Water saturation

Water saturation is the fraction of the pore space occupied by water. Most reservoirs are water wet and contain connate water. Water saturation may range from 10% to 50% for an oil or gas reservoir, and it is 100% for an aquifer. The water saturation obviously affects oil and gas reserves, and it is also used in the calculation of total compressibility.

Wellbore radius

The wellbore radius is half of the measured inside diameter of the borehole at the point of perforation. This is not to be confused with the effective wellbore radius, which accounts for changing skin during production or after stimulation. The wellbore radius and effective wellbore radius are equivalent when the skin is equal to zero.

Shale properties

Tight / shale gas reservoirs have very low matrix permeability, and in some instances contain organic-rich rocks where gas can also be adsorbed. For additional information, see shale adsorption correction. Production from these reservoirs requires long horizontal wells with multiple- staged hydraulic fracture treatments to create extensive artificial fracture networks near the wellbore.

To estimate original gas-in-place in tight / shale gas reservoirs, you require:

- Conventional volumetric calculations using rock volume, porosity, fluid saturations, and pressure.
- Use of Langmuir isotherms to estimate the volume of adsorbed gas.

Typically, all water in a tight / shale gas reservoir is not moveable, so the reported water production is almost always attributable to production of load fluids (completion / fracture treatment fluid).
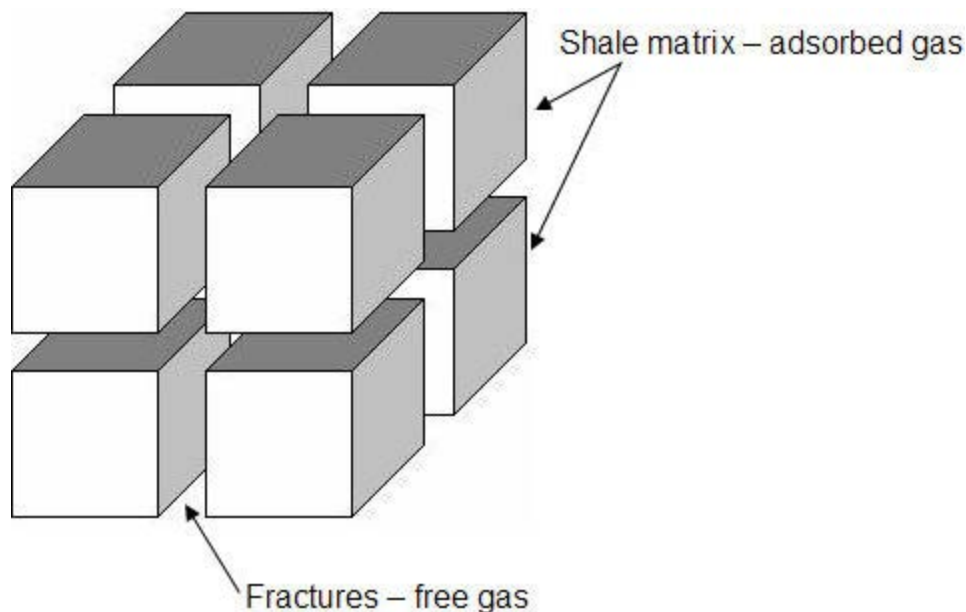
Conventional vs. tight / shale gas reservoirs

A comparison of conventional and tight / shale gas reservoirs is shown below:

Characteristic	Conventional	Shale
Gas Generation	Gas is generated in the source rock and then migrates into the reservoir.	Gas is generated and trapped within the source rock.
Gas Storage Mechanism	Compression.	Compression and adsorption.
Gas Pro-	Free gas only.	Free and adsorbed gas.

Characteristic	Conventional	Shale
duced		
Production Performance	Minimal transient period followed by a long boundary-dominated flow period. Production rates are mainly related to permeability and declining reservoir pressure. From a traditional decline perspective, 'b' values typically range from 0 to 0.5 but can be somewhat larger if there are commingled layers. Recovery factor = 50% − 90%	Very long transient (linear) flow period that can extend many years. In some cases, it is debatable if boundary-dominated flow will ever be fully realized. Production rates are mainly related to the success of creating a large fracture network around a long horizontal wellbore and to the matrix permeability. From a traditional decline perspective, 'b' values initially equal 2.0 (indicating linear flow), and then transition to <1.0 as boundary-dominated flow becomes prevalent. Recovery factor = 5% − 20%

A comparison of conventional vs. tight / shale gas rate-time plots is shown below:

Conventional Reservoir

Tight/Shale Reservoir
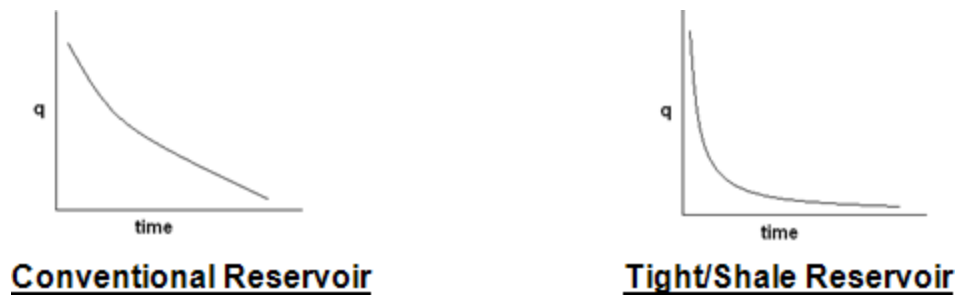
Shale adsorption correction

The shale adsorption correction is based on SPE paper 131772 by R. Ambrose et al.

In shale reservoirs that display adsorption, it has traditionally been thought that the adsorbed gas resides in the matrix of the organic-rich portion of the rock, which does not contribute significantly to the porosity of the rock. New evidence (Ambrose et al.) suggests that this organic-rich portion of the shale does, in fact, contain the majority of the porosity, as well as the adsorbed gas. If this assumption is valid, it is possible that the adsorbed gas is occupying a portion of the measured porosity, thus decreasing the pore space available to free gas. The volume occupied by the adsorbed gas must therefore be subtracted from the measured pore volume when calculating the volume available for free gas storage. The **Ads. Sat.** (Adsorption Saturation) option in Harmony Enterprise performs this correction.

When gas is adsorbed, the molecules are so close to each other that they exist in a near liquid phase. The adsorption volume correction in Harmony Enterprise converts the measured adsorbed gas content

into a liquid, and subsequently treats this phase as an extra saturation term, similar to water saturation.

When the correction is enabled, an Adsorbed Saturation, "S_{ads}" is calculated, and gas saturation is calculated as follows:

$$S_g = (1 - S_w - S_o - S_{ads})$$

To calculate adsorbed saturation, define:

$$\phi = \frac{PoreVolume}{RockVolume} \ and \ \phi_{ads} = \frac{AdsorbedVolume}{RockVolume} \ and S_{ads} = \frac{AdsorbedVolume}{PoreVolume}$$

The adsorbed saturation can therefore be calculated as follows:

$$S_{ads} = \frac{\phi_{ads}}{\phi}$$

From SPE 131772, ϕ_{ads} is defined as:

$$\phi_{ads} = 1.318x10^{-6} M \left[\frac{V_L p_i}{p_i + p_L}\right] \frac{\rho_b}{\rho_{ads}}$$

where

    ϕ_{ads} = Fractional volume occupied by adsorbed phase

    M = Molecular weight of the gas (lbm/lbmole)

    V_L = Langmuir Volume (scf/ton)

    p_L = Langmuir Pressure (psi(a))
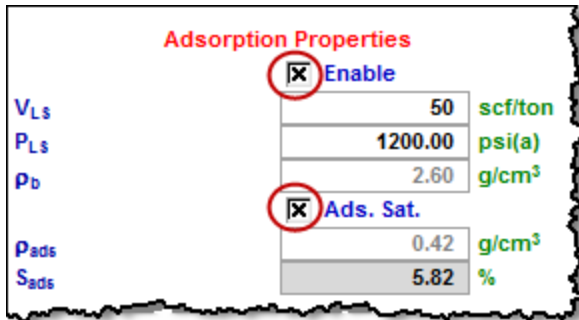
    p_i = Initial reservoir pressure (psi(a))

    ρ_b = Bulk density of the rock (g/cm^3)

    ρ_{ads} = Density of the adsorbed phase (g/cm^3)
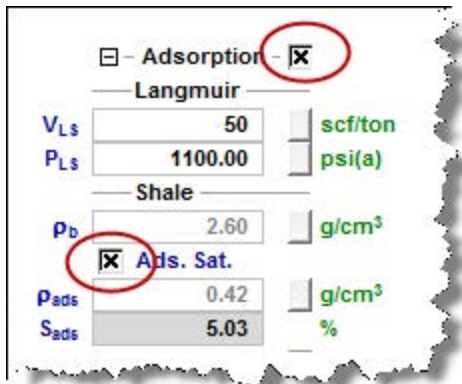
Note: ρ_{ads} is the density of the adsorbed "liquid" phase. The default in Harmony Enterprise for this value corresponds to the liquid methane density of 0.42 g/cm³.

The adsorption saturation correction is available for gas volumetric and gas analytical models. In gas volumetric analyses, the correction is available under Adsorption Properties. To use the correction, click the **Enable** checkbox and then the **Ads. Sat.** checkbox.

In gas analytical models, click the **Adsorption** checkbox, then click the **Ads. Sat.** checkbox.
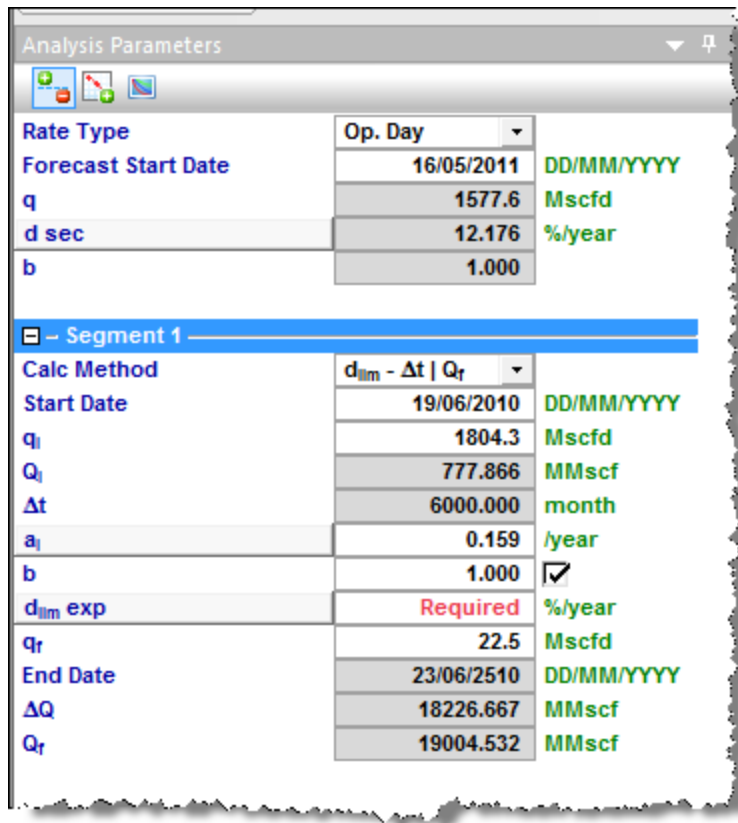
Enabling the Ads. Sat. correction results in an adsorbed saturation (S_{ads}) being calculated, which in turn is subtracted from the original gas saturation (S_g). This corrected gas saturation is now used in the volumetric calculations to calculate a new free-gas OGIP.

Terminal / limiting decline rate

The terminal / limiting decline rate begins as a hyperbolic decline curve and transitions into an exponential decline curve at a specified limiting effective decline rate, dlim. When the **Terminal / Limiting Decline Rate** option is selected in the **Calc Method** drop-down menu, a d_{lim} value is required.

There are two options for the d_{lim} value: "d_{lim}exponential" and "d_{lim}hyperbolic". When you click

d_{lim} exp , it toggles to d_{lim} hyp ; clicking the option again

selects "d_{lim}exponential".

When using the "d_{lim}exponential" option, the decline transitions such that the exponential portion of the decline has an effective decline rate of the d_{lim}value specified. When using the "d_{lim}hyperbolic" option, the decline transitions when the hyperbolic portion reaches the specified dlim value. The exponential portion then has an effective decline rate that is different from the dlim value.
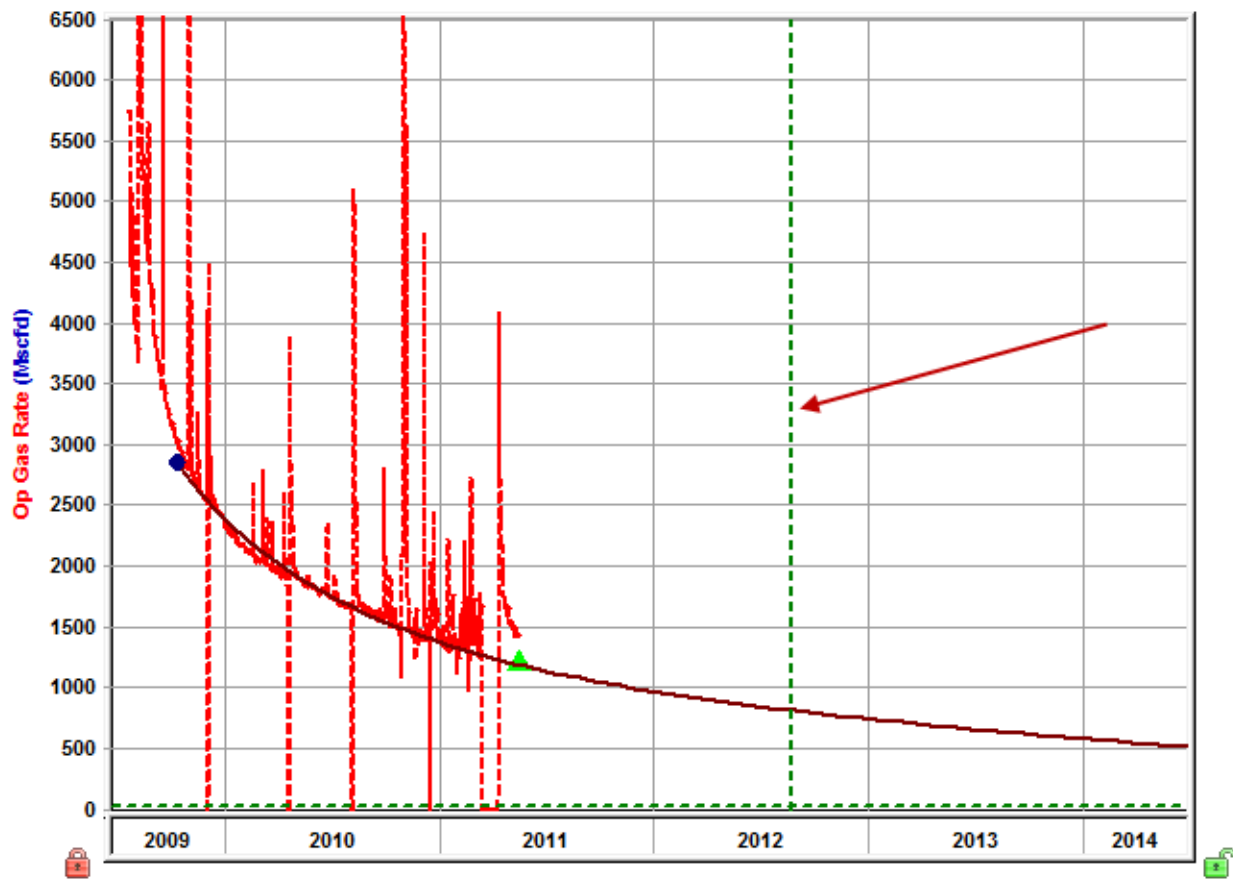
Note: The vertical dashed green line in the screenshot above indicates the transition from hyperbolic to exponential.

Terminal decline calculation methods

There are two ways to calculate the effective decline rate:

1. Secant

2. Tangent

All of the calculations go from your point of interest to a year ahead, but the difference is whether you are drawing a chord segment (secant line) or tangent line.

Note: The most common way to calculate the effective decline rate is by using the secant line, and because of this, references to the effective decline rate mean that the secant line is used.
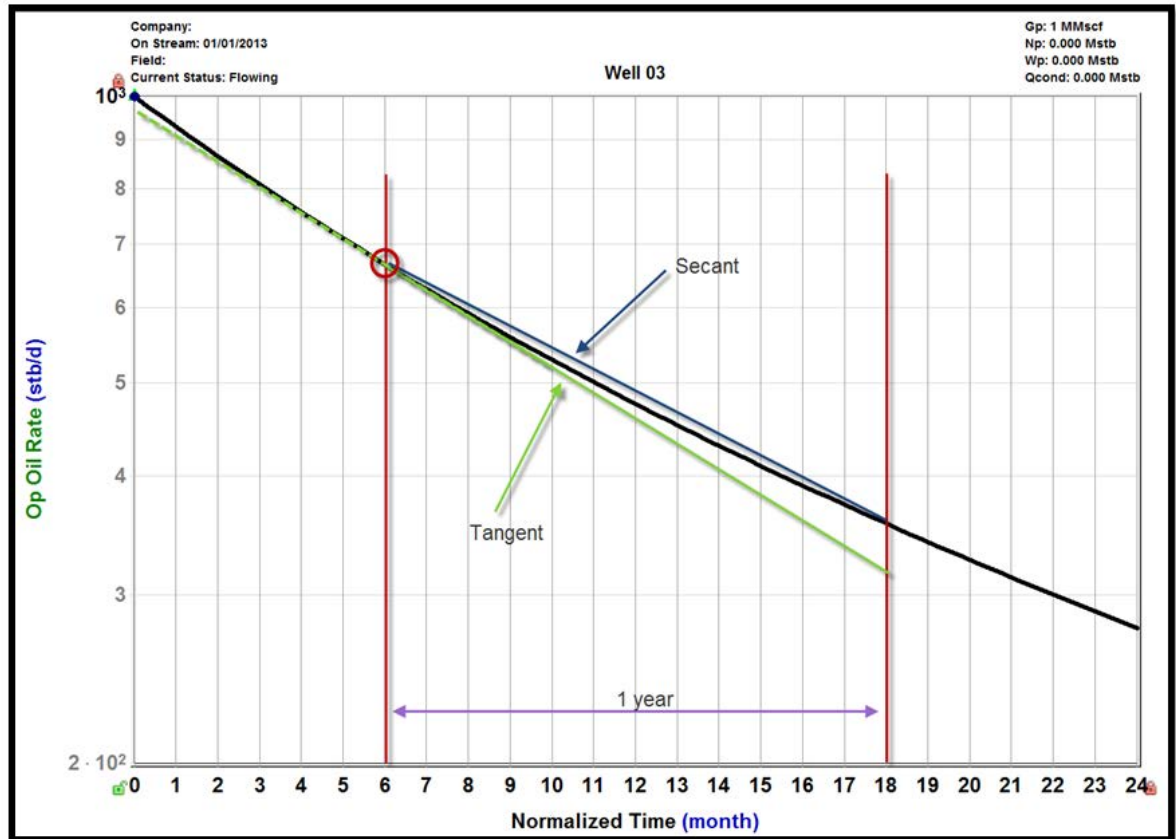
A d_{lim} hyperbolic uses the secant line to calculate the effective decline rate. If you want a d_{lim} hyperbolic of 10%, find where the 10% is calculated, and then switch from a hyperbolic decline to an exponential decline.
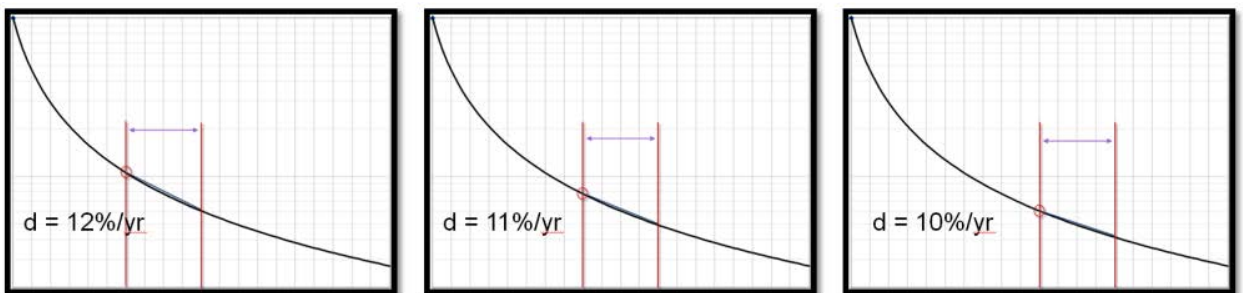
However, you cannot go from the hyperbolic to that chord segment line and expect a reasonable result. You need a smooth transition, so even though we used the chord segment to calculate the 10%, we need to use the tangent line to create the exponential section, which is not even 10%. This section is 10.4% for the remainder of the forecast.

d$_{lim}$ Hyperbolic will transition when d$_{sec}$ = 10%/yr. Therefore the exponential portion of the line will have an effective decline rate of 10.4%/yr

d$_{sec}$ = 10%/yr

d$_{tan}$ = 10.4%/yr
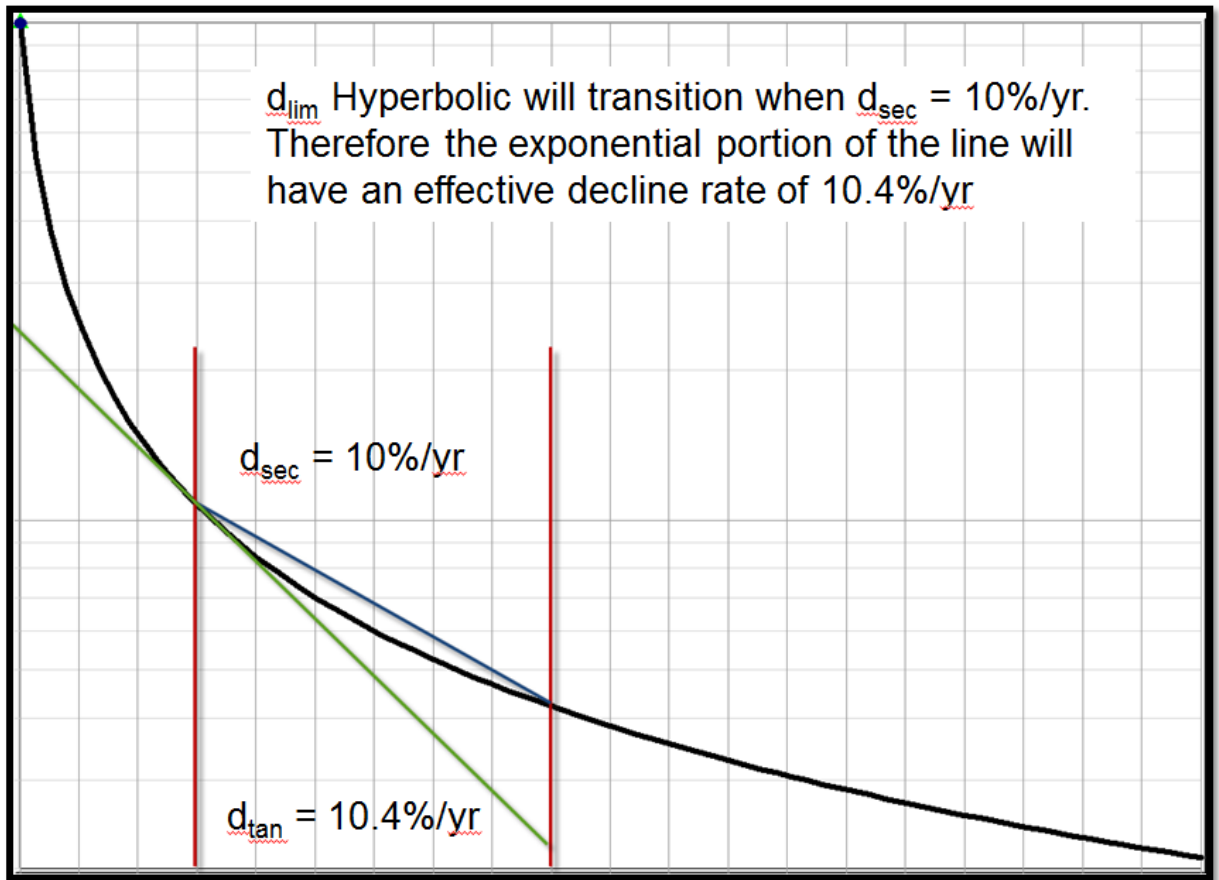
The method described above used to be the default way of calculating terminal decline. Even though the secant / chord segment is how the effective decline rate is almost always calculated, when doing a d$_{lim}$, we use the tangent line.

d = 12%/yr

d = 11%/yr

d = 10%/yr
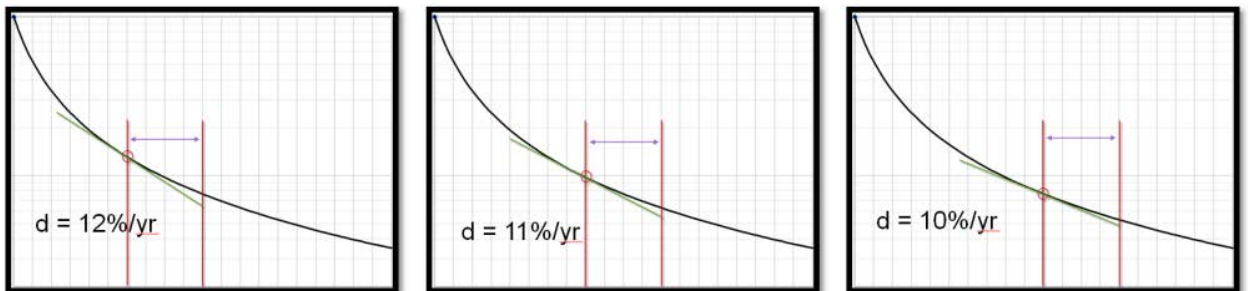
The transition from hyperbolic to exponential is smooth, with an exponential portion that is actually 10%. This is now the default way to calculate terminal decline.
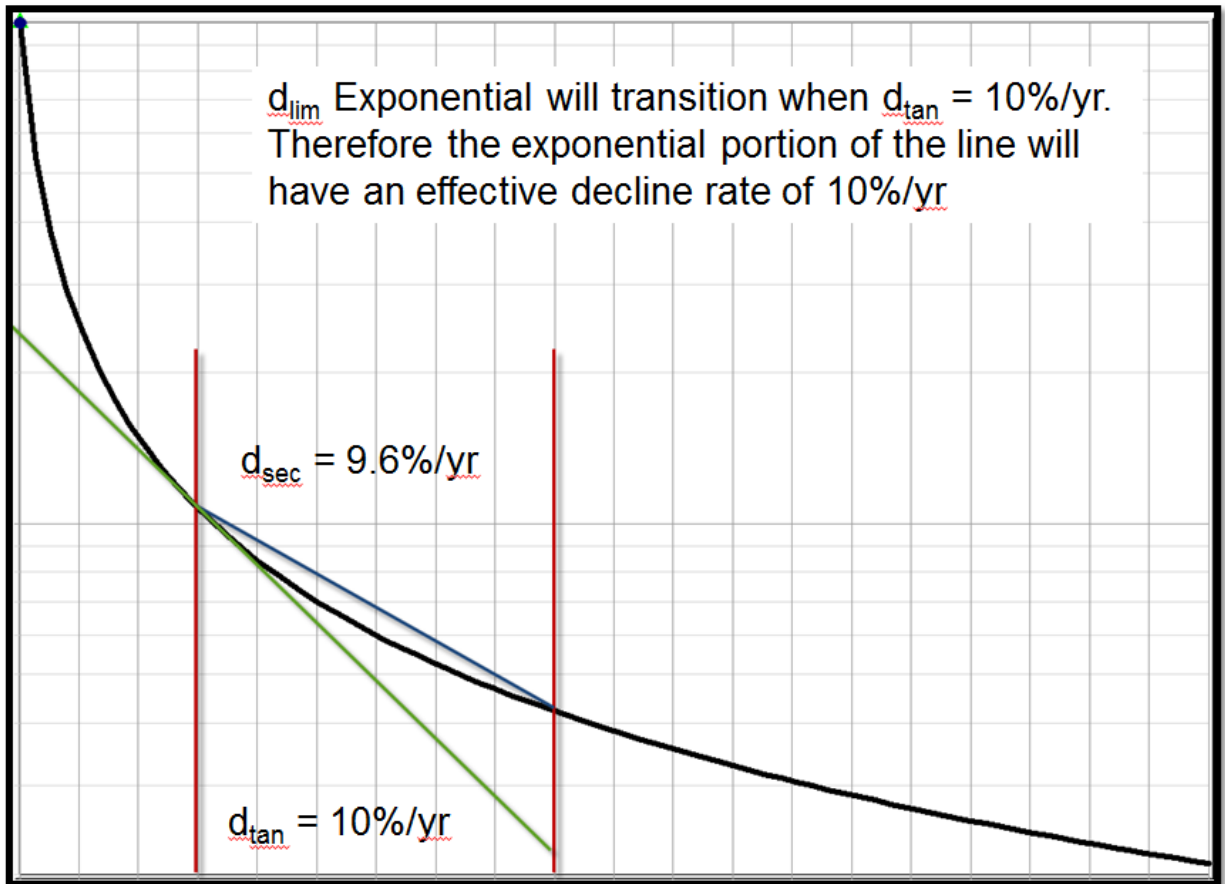
Time-dependent skin

Time-dependent skin accounts for wellbore skin changes with time, which can include a wide range of near-wellbore phenomena in production data, or pressure transient analysis. Some of these phenomena include:

- Pressure-dependent permeability (can also be handled explicitly using the modified pseudo-pressure method)

- Fracture closure over time

- Migration of fines through a fracture

- Condensate drop-out near the well

- Scale / wax deposition near perforations

- Well cleanup (decreasing skin damage)

- Gradual loss of formation integrity near the wellbore

The processes occurring during these phenomena may be very complex and difficult to model analytically. The changing skin model is a suitable approximation because it "lumps" all the contributors of pressure loss into a single term, occurring at a discrete point (and thus, it is independent of the geometrical or fluid-flow complexities).

Time-dependent skin should be thought of as a "tuning parameter" during the history-matching phase of numerical modeling. It is designed to be a catch-all for any changing fluid or reservoir property over time that is *not* accommodated by the analytical model. In order to obtain a unique result, a simultaneous match on flowing and shut-in pressures is almost always required. In other words, flowing data on its own rarely shows a clear trend of changing well productivity (especially, if it is a decreasing damage over time). This is because the effect is usually masked by depletion. However, if shut-in pressures are used in conjunction with flowing data, the changing productivity can be clearly identified, as no "static" reservoir model is able to honor both datasets.

The time-dependent skin has the following inputs:

- s or s_f (skin, or damage skin on fracture face) = the starting value of skin

- t_{sds} (skin damage start date) = the start date of changing skin

- t_{sde} (skin damage end date) = the end date of changing skin

- s_{lim} (skin damage limit) = the limit of changing skin (on and after the end date of changing skin)

For example, if the skin is initially 0.5, and the skin increases on t_{sds} = 01/01/2015 linearly to s_{lim} = 2 on 31/12/2016, and then the skin remains at 2, the numerical simulator takes into account such skin change as a function of time.
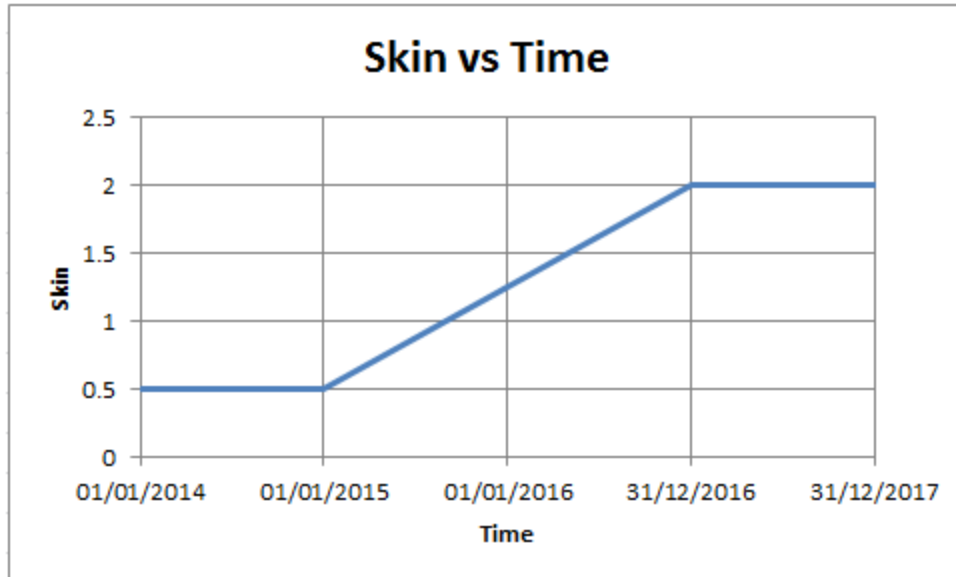
Time to stabilization

Time to stabilization (t_{stab}) is defined as the time it takes for the radius of investigation to reach all of the reservoir boundaries.

$$t_{stab} = \frac{(dist\,an\,ce\ to furthest\ \ boundary)^2 \cdot 948 \cdot \phi\mu\,c_t}{k}$$

Stabilization originated as a practical consideration and reflected the point at which pressure no longer changed significantly with time: that is, it had *stabilized*. With high-permeability reservoirs, this point was not difficult to observe. However, in tight formations, it takes a very long time for pressure to stabilize — often months, or even years. Moreover, except where there is a pressure maintenance mechanism acting on the pool, a true steady state is never achieved and pressure never becomes constant.

Water drive reservoir

Some gas reservoirs may be connected to aquifers that provide pressure support to the gas reservoir as it is depleted. In this case, the pressure decrease in the gas reservoir is balanced by water encroaching into the reservoir. As this happens, the pore volume of gas is decreasing and the average reservoir pressure is maintained. Often this reservoir will show a flat pressure trend after some depletion. An example of this behavior on a p/Z plot is shown below.

The change in reservoir volume due to net encroached water can be determined from the following equation:

$$\Delta V_{wip} = 5.615(W_e - W_\rho B_w)$$

To use this in the material balance, the change in pore volume is taken relative to the initial pore volume, shown below.

$$c_{wip} = \frac{5.615\,(W_e - W_\rho B_w)}{B_{gi}\,G\,/\,S_{gi}}$$

When dealing with this equation, the major unknown value to be determined is water encroachment from the aquifer (W_e). Two aquifer models are provided to determine net encroached water: Schilthuis Steady-State Model and Fetkovich Model.

Schilthuis steady-state model

This is the simplest aquifer model and assumes that the rate of water influx is proportional to pressure drawdown. In this model, it is assumed that the aquifer volume is much larger than the gas reservoir and remains at the initial pressure.

$$W_e = K \int_0^t (p_i - p)\,dt = K \sum_{j=0}^{n} \left(p_i - \frac{p_j + p_{j-1}}{2} \right) \left(t_j - t_{j-1} \right)$$

Using this model, the only parameter to solve for is the transfer coefficient (J).

Fetkovich

In the Fetkovich aquifer, the aquifer is assumed to be in pseudo-steady state and depleted according to the material balance equation. In this model, both the aquifer volume and transfer coefficient must be determined. The equations are shown below.

$$W_e = K \int_0^t (p_i - p)\,dt = K \sum_{j=0}^{n} \left(p_i - \frac{p_j + p_{j-1}}{2} \right) \left(t_j - t_{j-1} \right)$$

$$W_{ei} = c_w p_{aqi} V_{aq}$$

$$J = \frac{k\,h}{141.2\mu \left(\ln \frac{r_e}{r_o} - \frac{3}{4} \right)} \frac{\theta}{360}$$

While the transfer coefficient is defined, the required inputs to calculate the transfer coefficient are often not known. More commonly the transfer coefficient is determined as part of matching the p/Z plot.

Nomenclature

The table below outlines key nomenclature in Harmony Enterprise.

Variable	Description
a	Nominal (instantaneous) decline rate
a_{elf}	Decline rate at end of linear flow
a_f	Final nominal (instantaneous) decline rate
a_i	Initial nominal (instantaneous) decline rate
a_{lim}	Limiting nominal (instantaneous) decline rate
A	Area
A_D	Areal extent of reservoir
A_o	Gas-oil pore size distribution index
A_{SRV}	Area of stimulated reservoir volume
A_w	Oil-water pore size distribution index
APE	Automatic parameter estimation
API	American Petroleum Institute number
API	Application programming interface
b	Decline exponent
$b_{a,pss}$	Pseudo-steady state constant in the flow equation using material balance pseudo-time (gas)
b_{Dpss}	Dimensionless pseudo-steady state constant
b_{pss}	Pseudo-steady state constant in the flow equation using material balance time (oil)
B	Formation volume factor
B_g	Formation volume factor for gas
B_{gd}	Dry gas formation volume factor, ft3/scf, m3/m3
B_{gi}	Formation volume factor for gas at initial reservoir pressure and temperature
B_{ginj}	Formation volume factor for injected gas
B_o	Formation volume factor for oil, bbl/stb, m3/m3
B_{ob}	Formation volume factor for oil at bubble point
B_{oi}	Formation volume factor for oil at initial reservoir pressure and temperature
B_w	Formation volume factor for water
B_{wi}	Formation volume factor for water at initial reservoir pressure and temperature
B_{winj}	Formation volume factor for injected water

Variable	Description
BOE	Barrel of oil equivalent
c	Compressibility
c_d	Relative change in pore volume due to desorption of gas
c_e	Effective compressibility. For oil systems, includes oil, water, and formation compressibilities. For gas systems, includes gas, water, and formation compressibilities.
c_{ep}	Relative change in pore volume due to formation and residual fluid expansion
c_f	Formation / pore compressibility
$c_{f,max}$	Formation compressibility at zero net overburden pressure
c_{fi}	Initial formation compressibility
c_g	Gas compressibility
$\overline{c_g}$	Average gas compressibility
c_i	Initial compressibility
c_{ma}	Matrix compressibility
c_o	Oil compressibility
c_t	Total compressibility
$c_{\overline{t}e}$	Total compressibility at average reservoir pressure including net gas compressibility due to water influx
c_{ti}	Total initial compressibility
c_T	Isothermal compressibility
$c_{T,w}$	Isothermal compressibility of water
$c_{T,wf}$	Isothermal compressibility of gas-free water
$c_{T,wg}$	Isothermal compressibility of gas-saturated water
c_{ti}	Total system compressibility at original reservoir pressure
c_w	Water compressibility
c_{wip}	Relative change in pore volume due to water influx and production
C	Transfer coefficient related to flow capacity of the formation
CCA	Custom calculated attributes
CD	Storage coefficient
CDF	Cumulative distribution function
CDI	Formation and connate water compressibility d rive index
CF	Casing flange (reference point for depth measurements)
CGR	Condensate gas ratio, bbl/MMscf, m3/103m3

Variable	Description
Ca	Ash content (Langmuir isotherm)
CA	Reservoir shape factor
CaD	Dimensionless apparent wellbore storage
CAh	Shape factor for horizontal wells
CD	Dimensionless wellbore storage
Cg	Gas content
$C_{g,abdn/CO2}$	Gas content at abandonment pressure or CO2 concentration
C_{gi}	Initial gas content
C_G	Input gas volume fraction
C_L	Liquid input volume fraction
C_m	Matrix swelling coefficient
C_o	Gas-oil entry capillary pressure
C_p	Mechanical compliance coefficient
C_{pD}	Dimensionless storage pressure parameter
C_w	Oil-water entry capillary pressure. Moisture content. (Langmuir isotherm)
Cal rate	Calendar rate — does not account for time on production.
d	Effective decline rate
di	Initial effective decline rate
d_{lim}	limiting effective decline rate
D	Turbulence factor
DDI	Depletion drive index
DLS	Dominion land survey
DSN	Data source name
E	Young's modulus of elasticity
ENERDEQ®	IHS's Energy Information Access & Integration Platform is an information access and integration platform that directly connects you to global energy data
Entity	A well or scenario. Groups can include various entities (that is, wells and scenarios).
EUR	Expected ultimate recovery
E_{avg}	Average error
E_{fw}	Formation expansion factor
E_g	Gas expansion factor
E_{gi}	Gas expansion factor at initial conditions

Variable	Description
E_L	In-situ liquid volume fraction (liquid holdup)
E_{L0}	Horizontal liquid holdup
$E_{L\theta}$	Inclined liquid holdup
E_o	Oil expansion factor
E_t	Total expansion factor
f	Decimal fraction
f_c	Compressibility modifier
F	Reservoir voidage from production
FDBC	Fekete database connection tool
Forecast	Used to predict future production
FMB	Flowing material balance
FSD	Forecast start date
F_{CD}	Dimensionless fracture conductivity
g_g	Geothermal gradient
G	Original gas-in-place
G	Separator gas specific gravity (for fluid properties)
GHV	Gross heating value
GMB	Gas material balance
GOR	Producing gas-oil ratio
GWR	Gas water ratio
G_f	Free gas-in-place
G_{inj}	Cumulative gas injected
G_p	Cumulative gas production
G_{pa}	Additional gas production
$G_{p,n}$	Ultimate recoverable gas
G_{pn}	Cumulative gas production at time 'n'
G_r	Remaining gas
G_T	Cumulative transferred gas volume in a connected reservoir
h	Net pay
h_p	Perforated interval
HCPV	Hydrocarbon pore volume
History	History matching is the process of evaluating your model against known production data

Variable	Description
matching	(rate and pressure vs. time). For example, in an Analytical model, the inputs are measured sandface pressures and rates, along with a set of fixed parameters like permeability, initial reservoir pressure, saturations, etc. Since a model is just a complex equation that relates pressure to rate, then the measured rates can be applied to a given model in order to synthesize a set of sandface pressures (or vice versa). The history-matching process then consists of changing the model parameters until the synthesized data overlaps the measured data to a reasonable degree.
I	Incline rate
IHDC	Information hub direct connect — the Canadian-specific portion of IHS web services
IWIP	Initial water-in-place
j	Time interval / timestep
J	Transfer coefficient
k	Permeability
k_{abs}	Absolute permeability
k_{aq}	Aquifer permeability
k_e	Effective roughness of pipe
k_f	Fracture permeability
k_g	Effective permeability of gas
k_h	Horizontal permeability
k_i	Initial permeability
k_{matrix}	Matrix (outer zone) permeability
k_o	Effective permeability of oil
k_r	Pressure-dependent permeability ratio: kr = k / ki
k_{res}	Reservoir permeability
k_{rg}	Gas-relative permeability
k_{rgc}	Gas-relative permeability at residual oil saturation
k_{rgcw}	Gas-relative permeability at connate water saturation
k_{rgro}	Gas-relative permeability at residual oil saturation
k_{ro}	Oil-relative permeability
k_{rocw}	Oil-relative permeability at connate water saturation
k_{rog}	Oil-relative permeability with respect to gas
k_{rogc}	Oil-relative permeability at critical gas saturation
k_{row}	Oil-relative permeability with respect to water
k_{rw}	Water-relative permeability

Variable	Description
k_{rwgc}	Water-relative permeability at critical gas saturation
k_{rwro}	Water-relative permeability at residual oil saturation
k_{srv}	SRV (inner zone) permeability
k_v	Vertical permeability
k_w	Effective permeability of water
k_x	Permeability in the x-direction
k_y	Permeability in the y-direction
k_z	Permeability in the z-direction
KB	Kelly bushing (reference point for depth measurements)
L	Horizontal wellbore length
L_D	Dimensionless horizontal wellbore length
L_e	Effective horizontal wellbore length
m	Slope from the flow equation using material balance time (oil)
m_a	Slope from the flow equation using material balance pseudo-time (gas)
M	Mobility ratio (analytical models) (water-drive typecurves)
MD	Measured depth (CF or KB)
MPP	Mid-point of perforations
M_{aq}	Aquifer mobility
M_o	Molecular weight of stock tank liquid
M_{res}	Reservoir mobility
n	Moles of gas (ideal g as law equation)
n_f	Number of fractures
n_g	Gas exponent
n_{og}	Oil-gas system exponent
n_{ow}	Oil-water system exponent
n_w	Water exponent
N	Original oil-in-place
NAD 27	North American Datum, created in 1927
NAD 83	North American Datum, modified in 1983
NGL	Natural gas liquids
NTS	National topographic (map numbering) system
N_p	Cumulative oil production

Variable	Description
$N_{p,n}$	Ultimate recoverable oil
N_{VL}	Liquid velocity number
ODBC	Open database connectivity
OCIP	Original condensate-in-place, Mstb, 103m3
$OCIP_{SRV}$	Original condensate-in-place in a stimulated region, Mstb, 103m3
ODBC	Open database compliant
OFIP	Original fluid-in-place
OGIP	Original gas-in-place, MMscf, 106m3
$OGIP_A$	Original adsorbed gas-in-place, MMscf, 106m3
OGIPF	Original free gas-in-place, MMscf, 106m3
$OGIP_{SRV}$	Original gas-in-place in a stimulated region, MMscf, 106m3
OMB	Oil material balance
OOIP	Original oil-in-place, Mstb, 103m3
$OOIP_{SRV}$	Original oil-in-place in a stimulated region, Mstb, 103m3
OWIP	Original water-in-place, Mstb, 103m3
$OWIP_{SRV}$	Original water-in-place in a stimulated region, Mstb, 103m3
Op Rate	Operated rate — accounts for time on production.
p	Pressure
$\bar{p}$	Average reservoir pressure
p_{ab}	Abandonment pressure
p_{air}	Air pressure
p_{aq}	Aquifer pressure
p_{aqi}	Initial aquifer pressure
p_{bp}	Bubble point pressure, psi(a), kPa(a)
p_c	Critical pressure
$(pce)_{go}$	Gas-oil pore entry capillary pressure, psi(a), kPa(a)
$(pce)_{ow}$	Oil-water pore entry capillary pressure, psi(a), kPa(a)
p_{cgo}	Gas-oil system capillary pressure, psi(a), kPa(a)
p_{cow}	Oil-water system capillary pressure, psi(a), kPa(a)
p_d	Desorption pressure
p_{dew}	Dew point pressure, psi(a), kPa(a)
p_D	Dimensionless pressure

Variable	Description
p_{Di}	Dimensionless pressure integral
p_{Did}	Dimensionless pressure integral derivative
p_e	Bulk overburden pressure
p_{flow}	Specified flowing pressure
p_{grd}	Overburden pressure gradient
p_i	Initial reservoir pressure
p_j	Pressure at time "j"
p_L	Langmuir pressure
p_{max}	Maximum pressure
p_{min}	Minimum pressure
p_n	Net overburden pressure
p_{ni}	Initial net overburden pressure
p_o	Oil pressure
p_p	Pseudo-pressure
$\bar{p}_p$	Average pseudo-pressure
p_{pab}	Abandonment pseudo-pressure
$\bar{p}_{pab}$	Average abandonment pseudo-pressure
p_{pi}	Initial pseudo-pressure
p_{pwf}	Wellbore flowing pseudo-pressure
p_r	Reduced pressure
$\bar{p}_R$	Current reservoir pressure
p_{sp}	Separator pressure
p_{sc}	Pressure at standard conditions (14.65 psia, 101.0 kPa(a))
p_w	Water pressure
p_{wf}	Sandface flowing pressure
p_{wff}	Sandface forecast pressure
p_ε	Reservoir pressure at 50% matrix strain
P10	For each time interval, the P10 point is determined as the value for which 10% of the data points are higher. The production volume for each period is based on the calculated rate, and the cumulative production track is calculated by summing the calculated volumes. The P10 curve can be considered a highly optimistic prediction.
P50	For each time interval, the P50 point is determined as the value for which 50% of the data points are higher. The production volume for each period is based on the calculated rate, and the cumulative production track is calculated by summing the calculated

Variable	Description
	volumes.
P90	For each time interval, the P90 point is determined as the value for which 90% of the data points are higher. The production volume for each period is based on the calculated rate, and the cumulative production track is calculated by summing the calculated volumes. A line is drawn through each P90 point to obtain the curve. The P90 curve is often considered as a conservative estimate of reserves.
PI	Productivity index
PVT	Pressure volume temperature
P_c	Capillary pressure SPE recommends Pc (P being the secondary symbol for pressure) to denote capillary pressure, whereas pc is used to denote critical pressure.
q	Rate
$\bar{q}$	Average rate
q_{ab}	Abandonment rate
q_D	Dimensionless rate
q_{Dd}	Dimensionless decline rate
qDde	Dimensionless decline rate accounting for total pool production
$q_{Dd, integral}$	Dimensionless rate integral
q_{elf}	Rate at end of linear flow
q_f	Final rate (abandonment rate) qf = (number of wells) * (qGas / 6 +qOil);
q_g	Instantaneous gas rate
q_{ginj}	Injected gas rate
q_i	Initial rate
$q_{integral}$	Rate integral
q_j	Rate at time "j"
q_o	Instantaneous oil rate
q_s	Gas flow rate from separator
q_{tot}	Pool total production rate
q_w	Instantaneous water rate
q_{we}	Rate of water influx
q_{winj}	Rate of water injection
Q	Cumulative production
Q_D	Dimensionless cumulative production
Q_{DA}	Area-based dimensionless cumulative production

Variable	Description
Q_{Dd}	Dimensionless cumulative decline production
Q_f	Final cumulative production
$Q_{g,dry}$	Cumulative surface gas production
$Q_{g,wet}$	Cumulative well stream gas produced at the sandface
Q_i	Initial cumulative production
Q_m	Modified cumulative production
Q_n	Normalized cumulative production
Q_{tot}	Pool cumulative production
r	Radius
r_{aq}	Aquifer exterior radius
r_e	Reservoir effective radius
r_{eD}	Dimensionless effective radius
r_o	Reservoir outer boundary radius (Water-drive Typecurves and Models) Distance to observation well from active well, for cylindrical reservoirs
r_w	Wellbore radius
r_{wa}	Apparent wellbore radius
r_{wD}	Dimensionless wellbore radius
r_{we}	Effective wellbore radius
R	Ideal gas law constant
RC	Rate vs cumulative production
RF	Recovery factor
RR	Remaining recoverable
RT	Rate vs time
R_p	Solution gas-oil ratio based on cumulative oil and gas production
R_s	Solution gas-oil ratio, scf/bbl, m3/m3
R_{sb}	Solution gas-oil ratio at bubble point
R_{si}	Initial solution gas-oil ratio
R_{sr}	Reduced solution gas-oil ratio
R_{sw}	Gas solubility in water
R_v	Vaporized oil ratio, bbl/MMscf, m3/103m3
s	Skin
s_d	Near-wellbore skin damage

Variable	Description
$s_{d\varphi}$	Interporosity skin
s_f	Fracture face skin
S	Salinity of water
SDI	Segregation (gas cap) Drive Index
SI	International system of units. For more information, see http://dictionary.reference.com/browse/si+units?s=t
SL	Surface losses
SPE	Society of petroleum engineers
SRV	Stimulated reservoir volume
S_g	Gas saturation
S_{gc}	Critical gas saturation
S_{gi}	Initial gas saturation
S_{gn}	Normalized gas saturation
S_{iw}	Irreducible water saturation (Relative Permeability Correlations)
S_o	Oil saturation
S_{oi}	Initial oil saturation
S_{on}	Normalized oil saturation
S_{or}	Residual oil saturation
S_{org}	Residual oil saturation to gas
S_{orw}	Residual oil saturation to water
S_w	Water saturation
S_{wc}	Critical water saturation (capillary pressure)
S_{wc}	Connate water saturation (relative permeability)
S_{wi}	Initial water saturation
S_{wirr}	Irreducible water saturation (capillary correlations)
S_{wn}	Normalized water saturation
$\bar{S}_w$	Average water saturation
t	Time
t_a	Pseudo-time
t_c	Material balance time
t_{ca}	Material balance pseudo-time
t_{cae}	Total material balance pseudo-time for gas

Variable	Description
t_{ce}	Total material balance pseudo-time for oil
t_{co}	Length of the first time period in material balance time
t_D	Dimensionless time
t_{DA}	Area-based dimensionless time
t_{Dd}	Dimensionless decline time
t_{Dde}	Dimensionless decline time accounting for total pool production
t_{Dxf}	Dimensionless time based on fracture half-length (xf)
t_{Dye}	Dimensionless time based on reservoir width (Ye)
t_{elf}	Time at end of linear flow
t_f	Time at start of forecast date
t_{flow}	Specified flow time
t_j	Time at the "jth" time period/timestep
t_{lim}	Limiting time
$t_{shut-in}$	Specified shut-in time
t_{stab}	Time to stabilization
T	Temperature
TVD	True vertical depth (CF or KB)
TPC	Tubing performance curve
T_c	Critical temperature
T_f	Formation temperature
T_i	Initial temperature
T_{pp}	Pour point temperature
T_r	Reduced temperature
T_{sp}	Separator temperature
T_{sc}	Temperature at standard conditions (60oF/15oC)
T_{sp}	Separator temperature
v_g	Gas velocity
v_L	In-situ liquid velocity
v_m	Mixture velocity
v_{sg}	Superficial gas velocity
v_{sl}	Superficial liquid velocity

Variable	Description
V	Volume
VR	Voidage replacement
VRR	Voidage replacement ratio
V_{aq}	Aquifer volume
V_{HCP}	Hydrocarbon pore volume
V_i	Initial volume
V_L	Langmuir volume
V_{Li}	Initial Langmuir volume
V_p	Pore volume
V_R	Volatile oil ratio Rock volume
V_{sc}	Volume at standard conditions
V_T	Total volume
V_w	Wellbore volume
w_f	Fracture width
WDI	Water drive index
WGR	Water gas ratio
WGS 84	World Geodetic System, modified in 1984
WOR	Water-oil ratio
W_e	Water encroachment from aquifer
W_{ei}	Initial water encroachment from aquifer
W_{inj}	Cumulative water injection
W_p	Cumulative water production
x_e	Reservoir length
x_{eD}	Dimensionless reservoir length
x_f	Fracture half-length
x_i	Half SRV width, or the distance from the fracture to the permeability boundary
x_w	Active well location in the x-direction
y	Distance of investigation at time t
y_e	Reservoir width
y_w	Active well location in the y-direction
y_e/y_w	Ratio of reservoir width to well location in the y-direction

Variable	Description
Z	Gas compressibility factor
Z^{**}	Modified gas compressibility factor
$\bar{Z}$	Average gas compressibility factor
Z_{ab}	Compressibility factor at reservoir abandonment pressure
Z_i	Compressibility factor at initial pressure and temperature
Z_i^{**}	Modified compressibility factor at initial pressure and temperature
z_o	Location of observation well from top of zone (z-direction) for rectangular reservoirs
Z_{sc}	Compressibility factor at standard conditions
z_w	Well location in the z-direction (only applicable to horizontal wells)
α	Biot's coefficient (Geomechanical Reservoir Models - Dobrynin Correlation) Separation factor/selectivity ratio (Langmuir Isotherm)
β	Square root of the anisotropic ratio kh/kv
β_D	Ratio of total pool production to individual well production
γ	Permeability modulus (Geomechanical Reservoir Models - Yilmaz & Nur Pressure-Dependent Permeability Correlation) Dimensionless correlation factor (Geomechanical Reservoir Models - Dobrynin Pressure-Dependent Permeability Correlation) Euler's constant = 0.57721
γ_{API}	Specific gravity of liquid hydrocarbons/condensate in oAPI
γ_g	Specific gravity of gas
$\gamma_{g(psp)}$	Specific gravity of gas at separator pressure conditions
γ_o	Specific gravity of liquid hydrocarbons / condensate
γ_t	Recombined gas gravity
γ_w	Specific gravity of water
Δk	Change in permeability
Δp_f	Change in pressure due to friction
Δp_{HH}	Change in pressure due to hydrostatic head
ΔQ	Forecast cumulative production
Δt	Forecast duration
ΔV_d	Change in reservoir volume due to desorption of gas
ΔV_{ep}	Change in reservoir volume due to formation and residual fluid expansion
ΔV_p	Reduction in hydrocarbon pore volume
ΔV_w	Expansion of initial water volume
ΔV_{wip}	Change in reservoir volume due to water influx and production
ΔX_o	Location of observation well from active well in the x-direction, for rectangular reservoirs

Variable	Description
ΔY_o	Location of observation well from active well in the y-direction, for rectangular reservoirs
ΔZ	Change in elevation
ε	Tensile strain
ε_{exp}	Net strain between overburden stress effect and matrix shrinkage as measured experimentally
ε_L	Langmuir strain
θ	Angle of inclination
θ_r	[(T + 459.67) / 459.67] = relative temperature
λ	Interporosity flow coefficient Pore size distribution index (Capillary Correlations - Brooks / Corey)
λ_{go}	Gas-oil pore size distribution index
λ_{ow}	Oil-water pore size distribution index
μ	Viscosity of primary fluid (gas/oil/water)
$\bar{\mu}$	Average viscosity
μ_{aq}	Aquifer viscosity
μ_g	Gas viscosity, cP, mPa.s
$\bar{\mu}_g$	Viscosity of gas at average pressure
μ_i	Viscosity at initial reservoir pressure
μ_L	Liquid viscosity
μ_m	Mixture viscosity
μ_{NS}	No-slip viscosity
μ_o	Oil viscosity, cP, mPa.s
μ_{ob}	Oil viscosity at bubble point
μ_{od}	Viscosity of dead oil
μ_{os}	Viscosity of saturated oil
μ_{res}	Reservoir viscosity
μ_w	Water viscosity, cP, mPa.s
v	Poisson's ratio
ξ	Reduced inverse viscosity
ρ	Density
ρ_a	Apparent density of surface gas
ρ_{air}	Air density
ρ_{bs}	Pseudo-liquid density at reservoir pressure and standard temperature

Variable	Description
ρ_B	Bulk density
ρ_G	Gas density
ρ_L	Liquid density
ρ_m	Mixture density
ρ_{mol}	Molar density
ρ_{NS}	No-slip density
ρ_o	Oil density
ρ_{ob}	Oil density at bubble point
ρ_{oR}	Oil density at reservoir conditions
ρ_{po}	Pseudo-liquid density at standard conditions
ρ_{st}	Stock tank oil density
ρ_w	Water density
σ	Interfacial tension (capillary pressure)
σ_i	Effective horizontal stress at initial reservoir pressure
φ	Porosity
φ_i	Initial porosity
φ_t	Total porosity
Ψ	Pseudo-pressure
$\overline{\Psi}$	Pseudo-pressure at average pressure
Ψ_i	Pseudo-pressure at initial reservoir pressure
Ψ_{wf}	Pseudo-pressure at sandface flowing pressure
ω	Storativity ratio

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