Statement of work for integration of advanced analytics into reservoir engineering operations

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OVERVIEW

Oil and gas companies are struggling with data integration. Is analytics the answer? What steps can companies take to turn data into insight and action? An Accenture report explored the barriers blocking companies from generating improved outcomes from analytics and provided case studies of how organizations have leveraged analytics for tangible gains. It also offered a road map to gauge maturity on the journey to becoming a business where analytics drive competitive essence. The report can be found at: https://www.accenture.com/us-en/insight-digitizing-energy-analytics-powered-performance

Below are key findings:

Summary of key challenges with analytics in oil and gas companies:

1. **No single, holistic data strategy, resulting in fragmented use of analytics**
2. Poor data quality and lack of integration
3. Patchy ownership of data across processes
4. Limited visibility of data across the breadth of processes
5. C-suite does not lead by example to mandate insight-based decisions

Accenture provided three recommendations for becoming analytically-powered:

1. Visualize the value and design for analytics outcomes
    a. Ask the right questions
    b. Develop a value-led road map
    c. Identify gaps and work diligently to close them
    d. Help the business visualize the value at speed
2. Adopt an end-to-end process view, integrating enterprise and operations analytics
    a. Define an organization-wide analytics strategy… and communicate
    b. Leverage existing investments while embracing big data platforms
    c. Close the loop defining the right metrics, across functions for insights that lead to action plans
3. Promote a cultural shift to an analytically astute, insight-driven enterprise
    a. Ensure leadership leads by example
    b. Select the right analytics operating model
    c. Get the most of the talent the company employs
    d. Attract, develop and retain analytics talent
    e. Foster new behaviors with a change enablement program

The Accenture solutions could be modified specifically to reservoir engineering in a following way:

1. Data framework that allows for a holistic approach to viewing different pre and post processed data from multiple data sources.
    a. Example
        i. Compare Different porosity values from different sources, such as, Material balance, Core analysis, Petrophysics, Well Testing etc
        ii. Permeability from multiple sources Core analysis, well testing, petrophysics

Such a structure would mean a very large and integrated approach towards all data, data discipline will be paramount and data science will be used to validate different interpretations which can prevent bad assumptions and ensure data consistency.

A data framework will allow us to solve challenges 1-4.

1. A holistic data framework in which all data (pre and post processed) can sit and be accessed allows for the continuous use of data analytics at every part of the fields life cycle.
2. With the holistic framework poor data can be flagged and ignored if it is not validated from other data sources. Once the data is integrated once again poor data quality become a smaller issue because one can either flag or ignore bad data or one can use the bad data and integrated framework to capture and use the uncertainty involved with that data.
3. The holistic approach should mitigate or eliminate the patchy data ownership. Extra bonus, now a lot of the processed data and knowledge will no longer remain (be internalized) with the engineer/geologist who processed it but can be accessed by the entire community.
4. Once there is a holistic approach to the data there is no longer the problem of data visibility across different domains and groups.
5. All data collected can be used. (No such thing as non-relevant data, the problem lies with the preferences/experiences/or company policy that the engineer follows/has, example an engineer who has done decline curve analysis may choose to ignore the pressure data that another engineer collected because he is more interested in the production data, this is literally a choice of experience and comfort or even company policy)
6. C-suite sets company policy advised by SME's if the SME's accept data analytics then C-suite will accept it as well.

RESERVOIR ENGINEERING GOALS

In order to comprise a road map for analytics into reservoir engineering operations, one must define reservoir engineering goals first. Below is a summary of reservoir engineering goals taken from: http://www.ausihem.org/21cp/

Reservoir engineering seeks to economically optimize the development and production of hydrocarbon reservoirs. This requires answers to three questions:

- How much hydrocarbon does the reservoir contain?
- How much of it can be recovered?
- How fast can it be recovered?

The answers to these questions give, respectively, the **hydrocarbon in place**, the **reserves,** and the **rate of production.** The determination of these three quantities is the heart of reservoir engineering. These three quantities are heavily tied to physics. For example, HCPV is based upon fluid properties (Bo is pressure dependent) and porosity (which is also pressure dependent due to compressibility). Both of these properties are dynamic and are also determined using multiple data sources. This provides key challenge to integrating analytics into reservoir engineering.

1.1 The Importance of Holistic Approach:

Applications in analytics adopted in real-time will find that there is a low tolerance of false alarms while engineering processes optimization would have to compete against successful traditional methods. To find acceptance in the industry, and more importantly, to be useful, analytics results must be in a form that can be combined with those from existing physical models. This approach has the potential of yielding better accuracy, stability and generalization capability than each method alone. It would also be in the spirit of Integrated Operations for us to integrate the experience inherent in analytics with the knowledge inherent in physical models.

Below is the general overview of physics-based applications used by reservoir engineers and possible developments or enhancements using advanced analytics.

RESERVOIR ENGINEERING PROCESSES

2.1 Calculation of Oil and Gas in Place

Hydrocarbon in place is a fixed quantity that has developed through geological time. It may be estimated using **volumetric** or **material balance** methods. The volumetric calculation of hydrocarbon in place requires knowing the areal extent of the reservoir, its average net thickness and porosity, the hydrocarbon saturation, and the hydrocarbon formation volume factor (i.e., the volume that one unit volume of hydrocarbon at surface pressure and temperature occupies at reservoir conditions). It is a static method that does not depend on the dynamic behavior of the reservoir, that is, the *pressure response to production.* The equations for calculating the initial hydrocarbon in place (for two-phase oil/water and gas/water reservoirs, respectively) are

Initial oil in place (N),

$$\frac{A_0 h \phi S_0}{5.61 B_0} \tag{1}$$

and Initial gas in place (G),

$$\frac{A_g h \phi S_g}{5.61 B_g} \tag{2}$$

where subscripts o, g, and w refer to oil, gas, and water, and

A = area of oil or gas reservoir

h = average net thickness

ϕ = average porosity, fraction

S_{wi} = average initial water saturation in the oil or gas zone

B_0 = oil formation volume factor, RB/STB

B_g = gas formation volume factor, RB/SCF

C is a constant whose value depends on the units in use, e.g.:

- For N in STB, A in acres and h in ft, C = 7758
- For G in SCF, A in acres and h in ft, C = 43560

The average quantities of h, ϕ, and S are normally determined from isopach maps constructed from geological, petrophysical, and log data.

The material balance method depends on the dynamic behavior of the reservoir. It requires accurate production and fluid properties data. Theoretically, the initial hydrocarbon in place (IHIP) determined by the material balance method should always be equal to or less than that determined volumetrically.

The advantages of the MBE are that it provides a method of calculating IHIP as well as valuable insight into the behavior of the reservoir. Its main disadvantage is that it is based on a zero-dimensional model, and thus we cannot calculate with it the distribution of hydrocarbons and pressure. The MBE only deals with averages.

How analytics can be used: MBE inputs validation and deviation determination

MBE calculation is usually conducted by Reservoir/Production engineers on monthly/yearly basis and is validated by Well Pressure Test. Using real-time data on well-by-well basis can provide early determination of the parameters used in MBE and will be able to validate real time with other data sources such as petrophysics, geology, well tests, cores, etc.

2.2 Estimation of Reserves

Reserves, unlike Initial Hydrocarbons in Place, are not invariant. Rather, they are affected by the production method planned for the reservoir. The most significant factor in determining the production method and hence the reserves is economics. The current oil price structure, the time value of investment capital, and the tax environment will determine how much oil can be economically recovered. Other factors that influence reserves are well location and spacing, production rates, and the **drive mechanism** of the reservoir.

Oil production can be said to take place in two phases: the *primary recovery,* and *improved recovery.* During the primary recovery phase, hydrocarbons are produced using only the natural energy contained in the reservoir. This primary recovery phase may be supplemented or followed by an improved recovery phase, in which energy is added to the reservoir by injecting water, gas or a combination of the two; or the addition of energy may involve more complex enhanced oil recovery (EOR) methods, such as miscible gas injection, chemical injection or thermal processes.

In the reservoir's primary recovery phase, several sources of internal energy may contribute to fluid production. The five basic **natural drive mechanisms** drive mechanisms are

- expansion drive
- solution gas drive
- gas cap drive
- natural water drive
- gravity drainage

In most cases, a combination of mechanisms is acting; we refer to this as a **combination drive.**

How analytics can be used: Depletion Map

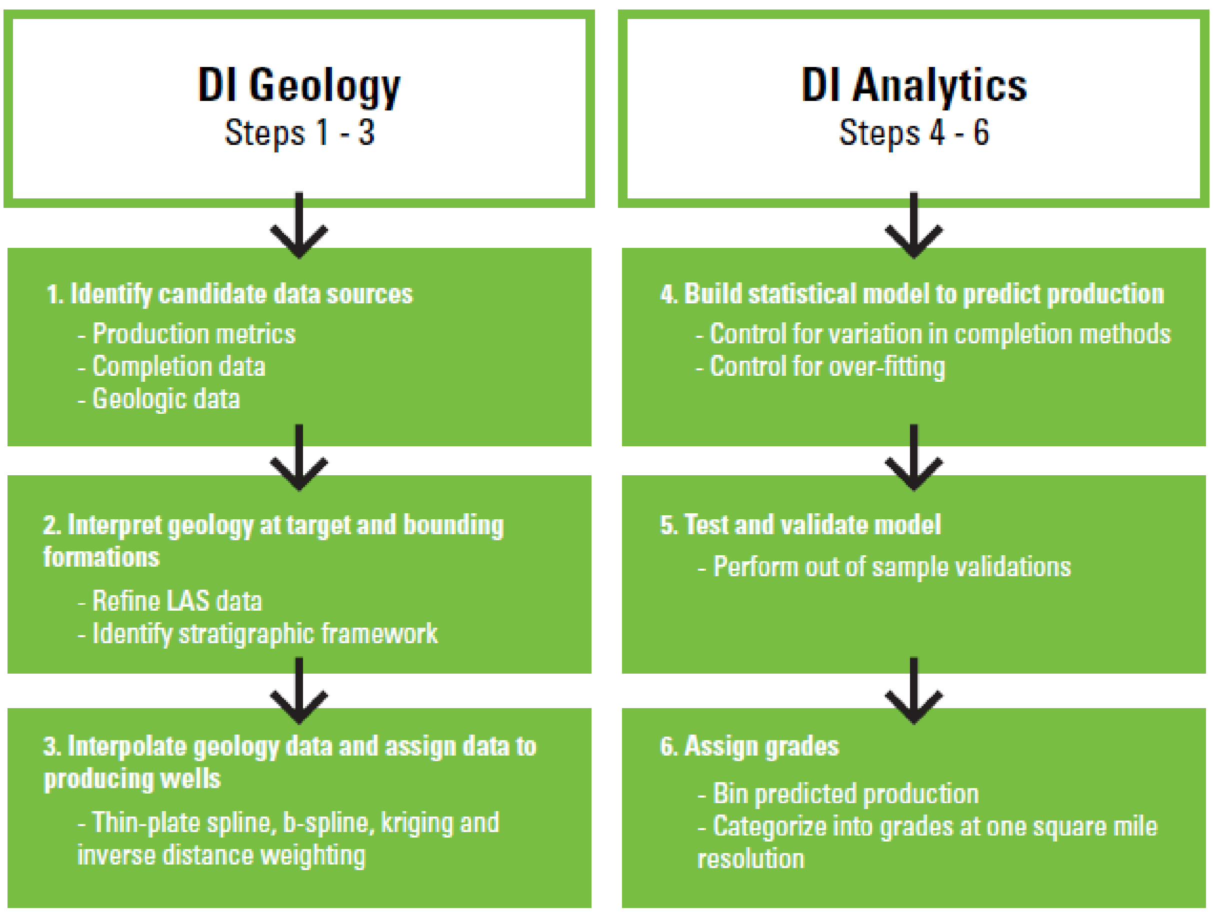
Depletion map has already been established. The input is local and IHS data, which dynamically updates with time. The depletion map uses Hadoop to process calculations and then map them onto the map of United States.

Further developments can be established with suggestions from reservoir engineering department.

An additional workflow is based on Drilling Info in order to improve processes in this area would be:

Graded Acreage Philosophy: Understanding Productive Quality of Reservoir Zones in Unconventional Hydrocarbon Plays.

Perform comprehensive subsurface analyses and advanced statistical modeling to qualify the productivity of the reservoir rock and assign grades to the acreage for each productive interval within play. This proposition has started using Moving Averages procedure programmed in SQL and needs to be standardized and modified. Drilling Info uses the following workflow:



2.3 Prediction of Performance Potential

Production rate, like reserves, is a function of the reservoir development strategy. Primarily, it depends on the number and location of wells, the flow potential of each well, the capacity of the surface facilities, and market demand. The number of wells and their locations influence the production rate and the uniformity of the drainage pattern in the reservoir, and thus ultimate recovery. The productive potential of a well is a function of the permeability, thickness, pressure, and homogeneity of the reservoir rock. The greater the permeability, thickness, and degree of homogeneity, the higher the well potential. The flow rate is also a strong function of the drilling and completion practices. Mud invasion or restricted flow at the wellbore that is caused by an inadequate number of perforations or plugging will reduce the well's overall potential.

Two main components of determining production performance potential are deliverability test and decline curve analysis.

Deliverability test (production testing) – tests in an oil or gas well to determine its flow capacity at specific conditions of reservoir and flowing pressures. The absolute open flow potential (AOFP) can be obtained from these tests, and then the inflow performance relationship (IPR) can be generated.

Decline curve analysis is a means of predicting future oil or gas well production based on past production history. Production decline curve analysis is a traditional means of identifying well production problems and predicting well performance and life based on measured oil well production.

How analytics can be used: Real-time production optimization – time series

Simulating oil and gas reservoirs deals with large scales of time and space but mainly numerical data. Prediction of the movement of gas, oil and water in the rock is a computing-intensive problem, made harder by sparse measurements.

Soft computing on time series here found in two niches. The first is as an aid in history-matching of the model. With many free parameters and much time spent on each run, it is tempting to use soft computing methods to optimize the parameter search. Efforts include evolutionary algorithms (reference) and ensemble Kalman filters (reference). This also allows us to used deterministic models while moving towards a probabilistic assessment of subsurface condition. This probabilistic viewpoint is another trend in the petroleum industry made possible by increased computing power.

The second application sees the time-consuming simulator replaced by a surrogate model, such as neural network. Trained on input and output from a traditional model, the neural network gives quicker predictions, allowing us to e.g. try out a larger number of different well placements, or explore more of the parameter space. This approach sometimes referred to as "neuro-simulation" in the literature (reference).

One of the main challenges of the production optimization is the existence of fracture inference. The following workflow is found at DrillingInfo website:

Calculate Well Inference and Optimize Well Spacing for Maximum Production

a. Generate variable plots that made it easy to identify important trends and gauge the impact of variables like:
    - Wellbore separation distance
    - Well age and production history
    - Engineering details such as proppant per foot and the extent of subsurface fracturing
    - Geological characteristics such as rock properties and fault location

b. Create a Production Prediction (Sweet-spot) Map That Takes Well Spacing Into Account

c. Calculate Impact of Existing Wells

d. Optimize Production

The challenge of the deliverability test is that it is done on a monthly basis. Implementing the real-time challenge to calculate the difference in pressure and optimize IPR curves would ultimately depend on SMEs and determination what is already has been done and completed by OFM and Petrel, and which additional elements could be used by analytics with suggestions from SMEs and help of IT team on how to improve deliverability test process.

2.4 Improved Recovery (Secondary and Enhanced Oil Recovery)

The improved recovery phase is primarily applicable to oil reservoirs. During this phase of production we are concerned with some type of artificial fluid injection rather than natural drive mechanisms. Thus, we talk about water injection or *water flooding, miscible flooding, steam injection, surfactant injection,* and the like. A common practice is to initiate the supplemental production phase with simple water or gas injection, which is commonly referred to as *secondary recovery* although it may be begun very early in the life of the reservoir. The water injection may then be followed with some type of miscible, chemical or thermal processes, which is known as **enhanced oil recovery (EOR)**.

Recovery during the primary and secondary phases of a reservoir's life seldom exceeds 50% of the original oil in place, so the potential recovery using EOR techniques is vast. Figure 1 presents a reservoir engineering functions diagram that summarizes the recovery techniques discussed.

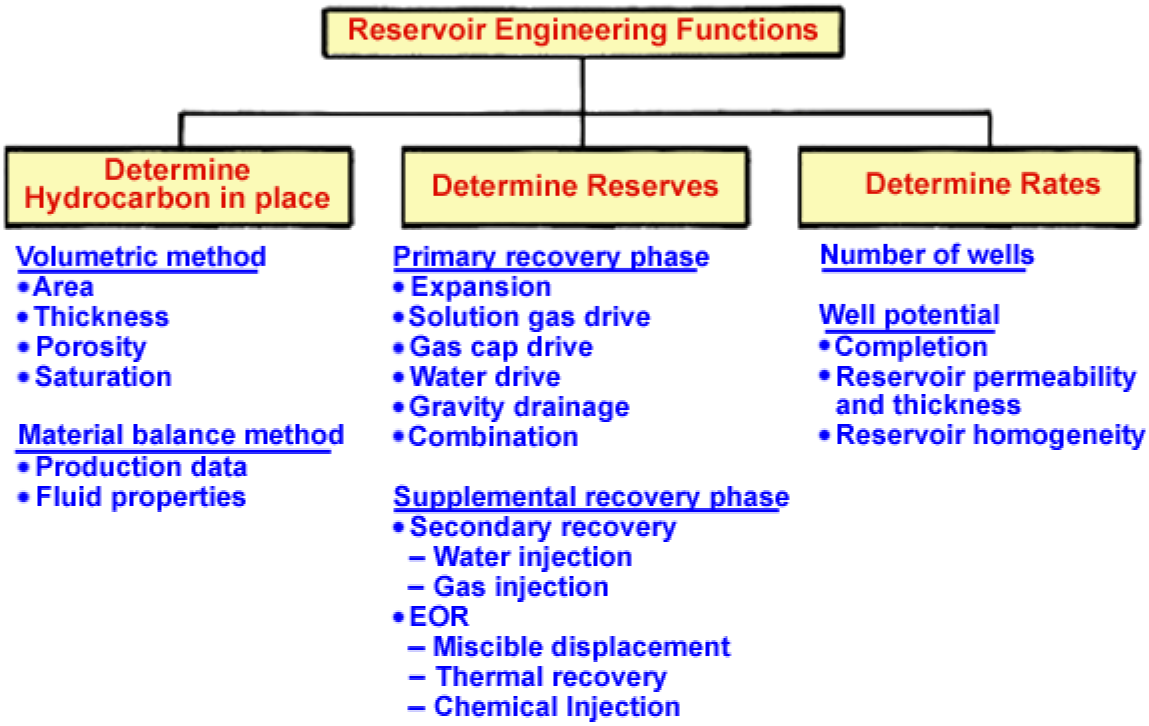


Figure 1

All of these functions are integrated in order to arrive at a plan for the development of the reservoir.

How analytics can be used: Monitoring GOR ratio to determine water break through

One of the potential applications using analytics would be monitoring GOR ratio in real-time to determine water break through.

2.5 Selection of the Best Development Plan

The objective of reservoir engineering is the *economic* optimization of hydrocarbon recovery, which means we need methods for calculating *production rate versus time* for various recovery schemes and cost scenarios. The important considerations will be the number of wells and their locations, the surface facility capacities, the offshore platform locations (if needed), and the feasibility of employing EOR methods. Models are available to the reservoir engineer to allow the calculation of recovery for a variety of situations. These models fall into two categories: the tank-type (zero-dimensional) approach and the numerical model (or reservoir simulation) approach.

How analytics can be used: Best Development Plan

Analytics can utilize various methods with a suggestion from reservoir/production engineers to provide strategic guidance in the best development plan using examples above.

RESERVOIR ENGINEERING DATA SOURCES

Several types of data are used in reservoir engineering calculations. The most important are

- data that pertain to the reservoir rock and its extent
- data that pertain to the properties of reservoir fluids
- production data

First we shall describe the four sources of data related to the reservoir rock and reservoir extent, which are

- geologic and seismic interpretations
- well log analyses
- well test analyses
- core analyses

3.1 Geologic and Seismic Interpretations

Reservoir geology helps the engineer to understand the external geometry of the reservoir as well as its internal architecture. Examples of the types of information it provides and possible analytics applications are

- the reservoir extent and its closure (the height of the crest above the lowest contour that completely closes the reservoir (to be determined)
- flow barriers, such as faults or pinchouts (time series applications)
- fluid contacts, (i.e., oil-water, oil-gas, and gas-water interfaces) (to be determined)
- aquifer size (to be determined)
- lithology variations (clustering and moving averages)
- continuity of the reservoir in the areal as well as in the vertical direction (to be determined)

3.2 Calculations from Well Logs

Logging provides *in-situ* information about the rock and its content from the immediate vicinity of the wellbore. There are over 30 types of logs, information from which may include:

- location of the productive stratum and its boundaries
- continuity of rock strata between adjacent wells
- net pay thickness
- oil, gas, and water saturations
- porosity of the reservoir rock
- other miscellaneous information, such as the condition of the hole, the temperature gradient in the wellbore, and the condition of the cement in a cased hole

3.3 Calculations from Well Tests

Well tests measure the pressure response of the well to short-term flow periods and the subsequent pressure buildup performance after shut-in. Various mathematical models can be used to determine the reservoir characteristics responsible for a particular pressure-flow rate behavior. In particular, permeability, the presence of nearby fault boundaries, or fluid contacts may be determined from an analysis of the well test data. Keep in mind that reservoir rock characteristics as determined from well tests are *averaged* values over the area of the reservoir that is contacted during the test.

3.4 Core Analyses

Cores provide petrophysical data essential to reservoir engineering. Basic core data, such as permeability, porosity, and fluid saturations help the engineer decide whether or not to complete the well and where to complete it. *Special core analyses* also help in evaluating reservoir performance, estimating hydrocarbons in place and reserves, evaluating the feasibility of EOR projects, and providing input data for reservoir simulation studies.

A second type of data used in reservoir engineering concerns the *properties of the reservoir fluids* and how they react to changes in pressure and temperature. Expressing the original hydrocarbons in place in surface volumes requires such data. Quantitative calculation of recoverable reserves requires estimates or laboratory determinations of formation volume factor, gas-oil ratio, and oil and gas compressibility, all as a function of pressure. Determining production rates of oil or gas requires knowledge of their respective viscosities at reservoir conditions. Any assessment of the practicality of EOR methods requires an understanding of the effects of the particular method employed on the behavior of the oil in the reservoir (i.e., oil viscosity reduction in a steam flood).

Reservoir fluid data is generally determined from a laboratory analysis performed on a carefully obtained representative sample of the original reservoir fluid. Where sampling is impossible, empirical correlations are available to estimate oil, gas, and water properties.

3.5 Production Data

This is another important type of data used in reservoir engineering calculations. By *production data*, we generally mean a careful accounting of the volumes of produced oil, gas, and water, as functions of time. *Pressure* as a function of time is also extremely important. The decline curve analysis and the material balance equation of oil or gas reservoirs require accurate production data in order to be of any value as predictive techniques.

The accuracy of production accounting can vary from field to field, particularly in large offshore developments where isolated wells and "satellite platforms" preclude the individual measurement of well production volumes on a regular basis. In such situations, individual well production is allocated from a total field production volume based on monthly well tests. In areas with high water-production rates the accuracy of measured water cuts also becomes a factor. Some estimate of the reliability of production data should be made by the engineer using such data in his or her calculations.

How Data Management can be used: To create a single framework that holds all data together for Reservoir Engineers to use.

Additional potential areas to use advanced analytics: description of physical processes in reservoir engineering

Advanced analytics has an untapped potential in using numeric methods to provide a more granular picture in all applications below:

Reservoir Description

Determination of hydrocarbon in place, reserves, and production potential requires an accurate physical description of the reservoir. The basic elements of such a description are depicted in Figure 1.

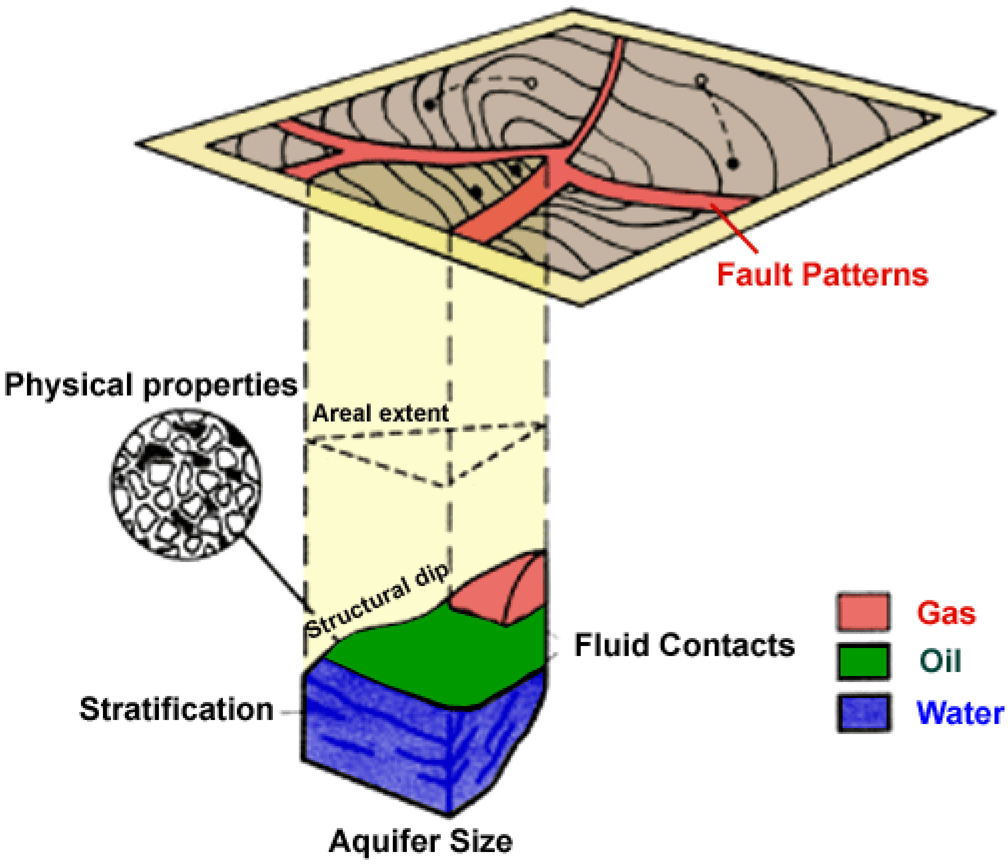


Figure 1

Areal Extent

The area of the reservoir is needed for calculating the hydrocarbon in place, for selecting the proper locations of wells, and as input data for reservoir simulation studies.

Physical Properties of the Productive Formation

Physical properties include formation thickness, porosity, water saturation, and permeability. These four parameters are needed in practically all aspects of reservoir engineering calculations. Preparation of *contour maps* for these properties constitutes the first and most important step in preparing a data base for reservoir engineering calculations.

Structural Dip

Reservoirs with a high angle of dip are good candidates for gravity drainage production. For secondary recovery projects in such reservoirs, one locates water-injection wells downdip and gas-injection wells updip for maxi mum recovery. Thus the angle of dip is an important factor in formulating a recovery plan.

Continuity of Strata and Stratification

Continuity or lack of continuity of the productive zone determines the pattern of depletion. Identification of separate zones or communicating zones, and the degree of communication, is necessary for establishing the optimum number of wells during primary production and EOR operations.

Fault Patterns

The location of faults and their effects as barriers to flow define the boundaries of the reservoir and help determine the locations of production and injection wells. Fault patterns strongly affect the design of the field development plan. The number and orientation of faults strongly influence the number of wells (and, in the case of offshore, the number of platforms) required for development.

Fluid Contacts

Determinations of oil-gas, oil-water, or gas-water contacts are needed for a complete description of the reservoir. Without such information, the hydrocarbon in place cannot be determined to a reasonable degree of accuracy and a proper recovery plan cannot be developed.

Aquifer Size

The size of the aquifer relative to the hydrocarbon reservoir is important in predicting recovery under primary depletion. Furthermore, this measurement has a strong bearing on the planning of a secondary or tertiary operation.

Reservoir Models

Reservoir engineering calculations require the formation of a *mathematical model* for the reservoir. This model should be based on the physical model that emerges from data obtained from the geological, geophysical, petrophysical, and log information. It is evident that in the majority of reservoirs the complexity is so great that it is not practical to expect a faithful mathematical description. Furthermore, it is impossible to obtain a physical description of the reservoir that is 100 percent accurate. One knows the physical properties of the reservoir to a high degree of accuracy only at well locations. In between the wells, or in the part of the reservoir for which no subsurface data are available, the physical description can only be deduced. The more drilling, the better the definition of the reservoir.

However, 3-D seismic and cross-well seismic tomography can provide information about the portions of the reservoir that lie between wells. 3-D seismics employs large amounts of closely spaced data and improved migration techniques to provide volumetric reservoir interpretation, while cross-well tomography applies high-frequency seismic waves, in which both source and receiver are located in existing wellbores. These tools give the geophysicist an active role to play in modeling the reservoir.

The mathematical representation of the reservoir can range from a very simple model, the *tank-type* (or *zero-dimensional)* model, to a highly complex set of equations that require numerical techniques and computers for their solution (the *reservoir simulation* approach). In the tank-type approach, the engineer assumes that the reservoir can be described with average values for properties such as thickness, porosity, and fluid saturations. While this approach may be satisfactory for simple problems, it may not be sufficient for other purposes. For instance, the tank-type model or a variation of it is normally used in volumetric estimation of the initial oil or gas in place. In some reservoirs it may also be satisfactory for material balance calculations. However, in other reservoirs such a model might be totally unsatisfactory and the engineer would have to resort to reservoir simulation. Generally speaking, as the heterogeneity of the reservoir increases, so too does the required complexity of the mathematical representation.

Reservoir Simulation

As the complexity of a reservoir increases, the need for a more complex mathematical representation arises. The engineer must use a *reservoir simulator* to predict the performance of the reservoir under various development schemes.

Modern reservoir simulation is based on the tank type model, which forms the basis of reservoir engineering. However, rather than considering the reservoir as *one* tank unit, the simulation divides the reservoir into *many tank units that interact with each other.* The number of tank units, or *cells*, depends on many factors, including the heterogeneity of the reservoir, the number of wells, and the field development scheme. Heterogeneous reservoirs require a larger number of cells.

The basic reservoir engineering equations that have been used to describe the reservoir when represented by one tank unit are used in reservoir simulation. In the single-cell representation, no oil or gas crosses the boundary of the tank (i.e., reservoir). However, in a simulation with many cells, each cell interacts with its neighbors. Fluids may enter a cell from adjacent cells or may leave a cell and go to the cell's neighbors. This fluid movement is governed by a well-established flow equation, known as Darcy's law. Keeping an inventory of the fluids in each cell is a rigorous bookkeeping operation, well suited to computers. The advent of the modern computer has increased the reservoir engineer's simulation capabilities.

The rock and fluid data required for reservoir studies using the one-tank model representation are required for *each* unit cell in a simulation study. The effort required to prepare such data and input it to the simulator is a significant part of the cost, which can range from tens to hundreds of thousands of dollars, depending on the size, complexity, and purpose of the model.

Reservoir Boundaries and Heterogeneities

Boundaries

A reservoir may have closed or open boundaries, or both. If the reservoir is completely bounded by sealing faults or pinchouts, it is closed. Some reservoirs are completely surrounded by an aquifer, thus their boundaries are open to water movement into the hydrocarbon zone. Still other reservoirs may be bounded by faults or pinchouts along part of their boundary and by an aquifer along the remaining part. Most reservoir engineering calculations require an accurate knowledge of the boundary conditions of the reservoir. This knowledge may establish the possible existence and extent of an aquifer activity in the reservoir.

Heterogeneities

All reservoirs are heterogeneous, varying only in their degree of heterogeneity. This means that the physical properties of the rock change with a change in location. One of the very important heterogeneities that needs to be considered in reservoir engineering calculations is stratification. Many reservoirs contain layers (strata) of productive rock that can be communicating or non-communicating. These layers can vary considerably in permeability and in thickness. A good description of the layers and their respective properties is critical in planning many EOR operations.

Fault System

Another common heterogeneity in reservoirs is the fault system. Faults can be completely or partially sealing. Well locations for both production and injection are affected by the fault pattern and its effect on fluid communication. Faults are normally defined from geological, geophysical, and production data.

Permeability

Permeability is another directional property. When permeability measurements vary depending on the direction in which they're measured, we say that the reservoir is anisotropic with respect to permeability. Permeability anisotropy is important in determining well spacing and configuration, as well as in considering the option of horizontal wells.

Reservoir Pressure

Reservoir pressure is one of the most important parameters of reservoir engineering calculations. Whether the calculations involve the tank type model or a more sophisticated reservoir simulator, accurate pressure values are required. However, there is an important difference between the requirements of the two models. The unit tank model relies on material balance equation calculations, and requires the *average* pressure for the whole reservoir as a function of time or production. In reservoir simulation studies, however, it is strongly desirable to have available buildup pressure values for individual wells as a function of time. These values represent the average pressure for the drainage volumes of the wells, and are needed for the history-matching phase of the simulation study, which is performed to validate the accuracy of the model built to represent the reservoir (Matthews et al. 1954). History matching is an essential step in "tuning" a reservoir model before conducting a predictive study.

Reservoir engineering calculations require a value for the pressure in the reservoir, away from the wellbore. To obtain this value, the well must be shut in and the pressure increase with shut-in time must be recorded. We refer to this as a pressure buildup test (Matthews and Russell 1967). From these data the average pressure value is calculated.

Another way of obtaining average values is to record the pressure in a well in which Production has been suspended. If such a well exists, and it is not very close to a producer or an injector, a pressure-measuring device can be used to continuously record the pressure, without interrupting production or injection operations.

For the single-tank model, an average value for the whole reservoir is required. This is normally obtained by a volumetric averaging of the pressure values from different wells. The equation for this purpose is

$$\bar{p}_R = \frac{\sum p_i V_i}{\sum V_i} \tag{3}$$

where:

$\bar{p}_R$ = average pressure for reservoir

P_i = average pressure for Well i

V_i = the drainage volume of Well i

Thus, if there are three wells with pressures p_1, p_2, and p_3, and drainage volumes V_1, V_2, and V_3, then Equation 3 becomes:

$$\bar{p}_R = \frac{p_1V_1 + p_2V_2 + p_3V_3}{V_1 + V_2 + V_3}$$

Matthews et al. (1954) and Matthews and Russell (1967) have shown that the well-drainage volume V_i is proportional to its flow rate, q_i Substituting q_i for V_i in Equation 3 gives

$$\bar{p}_R = \frac{\sum p_i q_i}{\sum q_i} \tag{4}$$

Equation 4 is the more Practical equation because the flow rate is usually available, while it may be more difficult to estimate the drainage volume.

A very useful plot is that of the average pressure values obtained on several wells versus the total oil production of an oil reservoir, or total gas production of a gas reservoir. The pressures are plotted on the Y-axis. If there is continuity in the reservoir the Pressures from the various wells should plot close to each other. If the pressures for a well plot are consistently higher or lower than the other values, it may indicate that the well is not in good communication with the reservoir or that it is in a separate reservoir. This may point out the need for more wells to effectively drain the isolated portion of the reservoir. Furthermore, the data from the isolated well should not be lumped in with the data from other wells in material balance engineering calculations.

Before comparing the pressure values measured in wells at various depths in a reservoir (very thick and/or steeply dipping reservoirs), they should be referred to a *datum* depth (Figure 1).

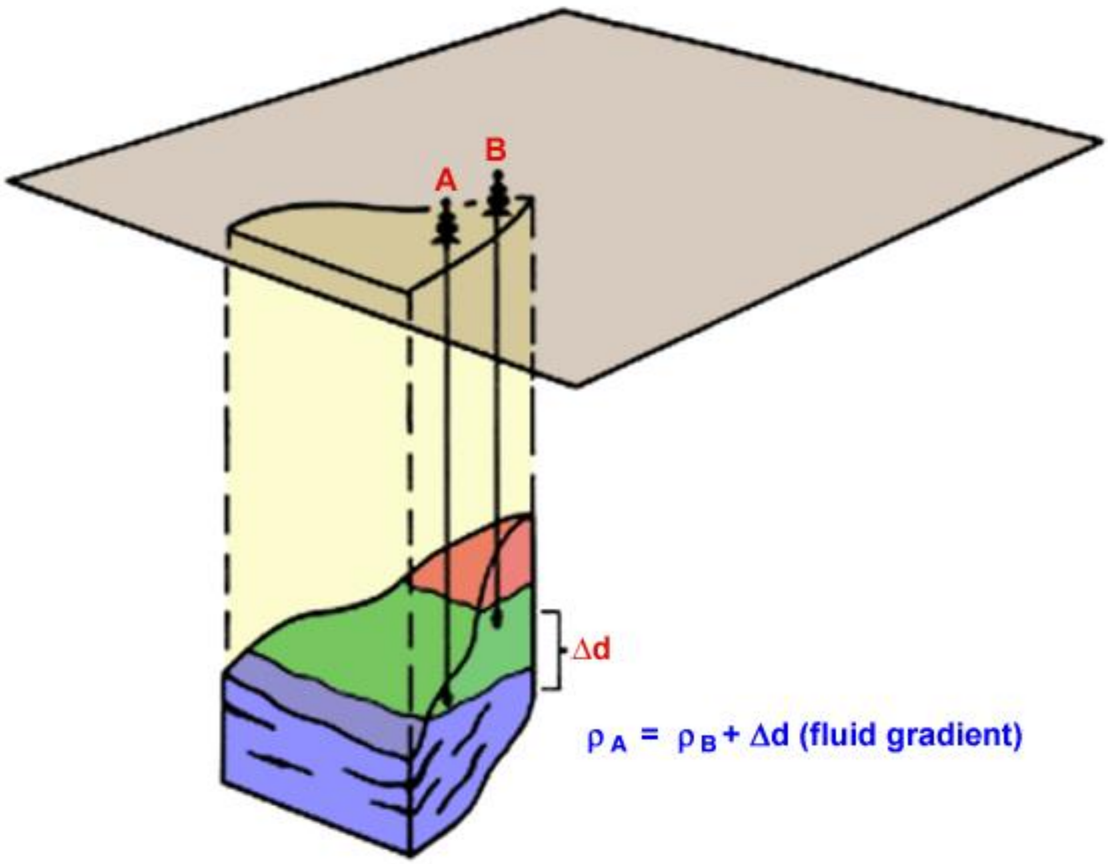


Figure 1

Normally the depth of the *volumetric midpoint* of the reservoir is taken as the datum depth. This is determined by constructing a plot of depth versus cumulative pore volume (Figure 2).

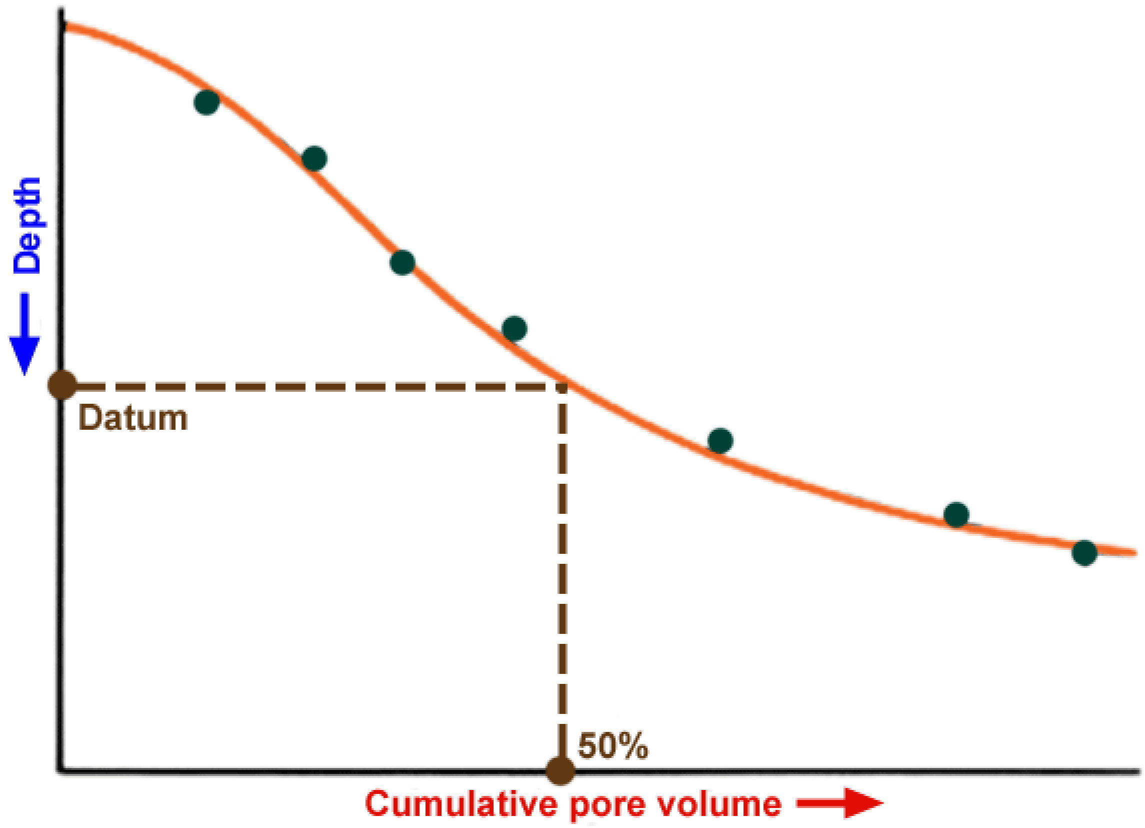


Figure 2

The depth corresponding to 50% pore volume is the volumetric midpoint depth. If a particular pressure value is obtained at a different depth than the datum, it is adjusted to the datum by

$$P_{adj} = p + 0.433\ \gamma \Delta H \qquad (5)$$

$$P_{adj} = p - 0.433\ \gamma \Delta H \qquad (6)$$

where:

p = the pressure at any elevation, psi

γ = specific gravity of fluid

ΔH = the vertical distance between the point at which the pressure was measured and the datum depth, ft

Equations 5 and 6 apply when the point at which the Pressure was determined is, respectively, above and below the datum depth.

When an aquifer is associated with the reservoir, the Pressure behavior as a function of time at the hydrocarbon-water contact (or as close as possible to it) is needed for water influx calculations. If this is not available, one usually uses the average reservoir Pressure and adjusts it to the hydrocarbon-water contact depth.

The average reservoir pressure is needed in many reservoir engineering calculations. In the case of miscible EOR techniques, for example, the average reservoir pressure determines whether miscibility will occur when CO_2 or other gases are injected. This in turn affects overall recovery and the economic feasibility of the project.

Reservoir pressure is a topic of significance in reservoir engineering because it is one of the critical pieces of data required by the reservoir engineer for an effective analysis of a reservoir. Obtaining reliable pressure data should be a primary goal of any reservoir management program.

Reservoir Temperature

The calculation of primary recovery relies on the reasonable assumption that the reservoir temperature stays constant. Thus, hydrocarbon recovery during this phase is considered to be an isothermal process. This is so because as fluids are produced any change in temperature due to production is compensated for by heat from the cap or base rocks, which are considered to *be* heat sources of infinite capacity.

The average reservoir temperature is needed for laboratory analyses that are made at reservoir conditions. Determining fluid properties, such as viscosity, density, formation volume factor, and gas in solution, requires a value for reservoir temperature. Reservoir temperature is usually measured at the bottom of the well or wells in a reservoir using a wireline temperature gauge. If a variation in temperature is detected across a reservoir after correcting for depth, an average value can be used for the constant reservoir temperature.

For EOR techniques such as chemical and miscible processes, temperature affects the phase behavior of injected and produced fluids, and thus the recovery. The feasibility of these processes must be determined by laboratory tests carried out at reservoir temperature. In EOR processes that employ heat injection, such as steam or *in-situ* combustion, the reservoir temperature is not constant and hydrocarbon recovery is not an isothermal process. Therefore, in mathematical formulations of such processes, it is necessary to write an energy balance over the entire reservoir. From an operations standpoint, reservoir temperatures need to be measured continuously at monitoring wells. These measurements indicate the heat front’s pattern of movement. Normally, a uniform movement is desired, but the heat-front pattern can be altered by changes in injection and/or production schedules.

Porosity, Permeability, and Saturation

Porosity is defined as the ratio of the pore space in the rock to the bulk volume of the rock. It is expressed as a fraction or as a percent of the bulk volume. In equation form,

$$\phi = \frac{V_p}{V_b}$$

where:

ϕ = porosity (fraction)

V_p = pore volume

V_b = bulk volume

V_p and V_b can be in any consistent units.

Two types of porosity can exist in the rock: *total* and *effective*. **Total porosity** comprises all of the pore spaces, including connected spaces, isolated spaces (e.g., vugs or fractures) and, in shaly formations, water which is bound to clay minerals. **Effective porosity** refers only to the interconnected pore spaces. While it is effective porosity that is of primary interest to reservoir engineers, a knowledge of total porosity is also important with respect to reservoir description and characterization. In some reservoirs (e.g., clean, unfractured sandstones), the difference between the toal and effective porosity will be negligible; in others (e.g., highly vuggy carbonates or very shaly sands), the difference may be significant.

Various methods exist for measuring porosity. Some are based on measurements of a rock sample's bulk volume and solid volume, and obtain the pore volume by subtracting the solid from the bulk volume. Thus: [pore volume = bulk volume - solid volume]. Other methods are based on measuring the pore volume directly in addition to the bulk volume. Such methods utilize gas expansion, fluid saturation, or mercury injection. Porosity measured by these techniques is the effective porosity.

Permeability is a measure of the ability of porous rock to transmit fluid. The quantitative value for this characteristic is the permeability. The permeability may be *absolute* or *effective.*

Absolute permeability occurs when only one fluid is present in the rock. It is a property of the rock and should be independent of the fluid used in the measurement. This assumes that the fluid does not interact with the rock. Absolute permeability is calculated by Darcy's law using laboratory-measured data. The unit of the permeability is the darcy. The permeability of one darcy may be defined as that permeability which will allow the flow of one cm^3/s of a fluid of viscosity one centipoise through a rock sample of one cm^2 in cross-sectional area under a pressure gradient of one atmosphere per cm. A permeability of one darcy is a large value, and we normally use the unit of millidarcy (0.001 darcy) to describe the permeability of most reservoirs. In some reservoirs the permeability may be as low as a fraction of a millidarcy, while in others it may be several darcies. The well-flow rate is directly proportional to permeability. Thus, wells with very low permeabilities are normally marginally productive, and may require stimulation and remedial action to improve their production.

Effective permeability occurs when more than one fluid is present: it is a function of the fluid saturation. Therefore, one speaks of effective permeability to oil, water, and gas. Effective permeability cannot be higher than specific permeability. The ratio of effective to specific permeability is termed *relative permeability*.

Saturation is a measure of the relative volume of each fluid in the pores. Thus the oil saturation is defined as the ratio of the volume of the oil in a porous rock to the pore volume of the same rock. It is expressed in fraction or in percent, and ranges from 0 to nearly 100%. Water is always present in all reservoirs, and its saturation is always greater than zero. In contrast, the oil saturation is zero in gas reservoirs, and the gas saturation is zero in oil reservoirs when the pressure is above the bubble-point. The water saturation is normally obtained in *situ* from log data. The oil or gas saturation is then calculated by subtracting the water saturation from unity (in two-phase reservoirs).

Sometimes the fluid content and saturations are measured directly in the laboratory on fresh core samples. These cores are obtained using an oil-base drilling fluid, and considerable care will have been exercised during the coring operation.

Oil or gas saturations are needed to volumetrically calculate the initial oil or gas in place.

Darcy's Law

Darcy's law is an empirical relation that describes the fluid flow in porous media as a function of pressure gradient and the viscosity of the fluid. It is basically an extension of the principles of fluid dynamics to flow of fluids in porous media. It thus represents the equation of motion in reservoir engineering.

In 1856, Henry Darcy, a French civil engineer, published his experimental results on water flowing through sand-filter beds. The results showed that the rate of flow through the sand bed was proportional to the pressure head above the bed and to the cross- sectional area of the filter, and inversely proportional to the viscosity of the water and the thickness of the bed. Later, other investigators extended Darcy's law to fluids other than water, and the constant in Darcy's equation was written as a ratio of permeability to viscosity.

These relations are expressed mathematically in the following equation:

$$q = -A\frac{k}{\mu}\frac{dp}{dx} \quad (8)$$

where:

q = flow rate in cm^3/s

k = permeability in direction of flow, darcies

μ= viscosity in centipoise

dp/dx = pressure gradient in atm/cm

A = cross-sectional area in cm^2

Note that the negative sign in front of the equation is needed to obtain a positive q, since dp/dx is negative. The most common application of Darcy's law is to linear and radial flow geometries.

Linear Flow

In a linear flow, A is constant

(Figure 1).

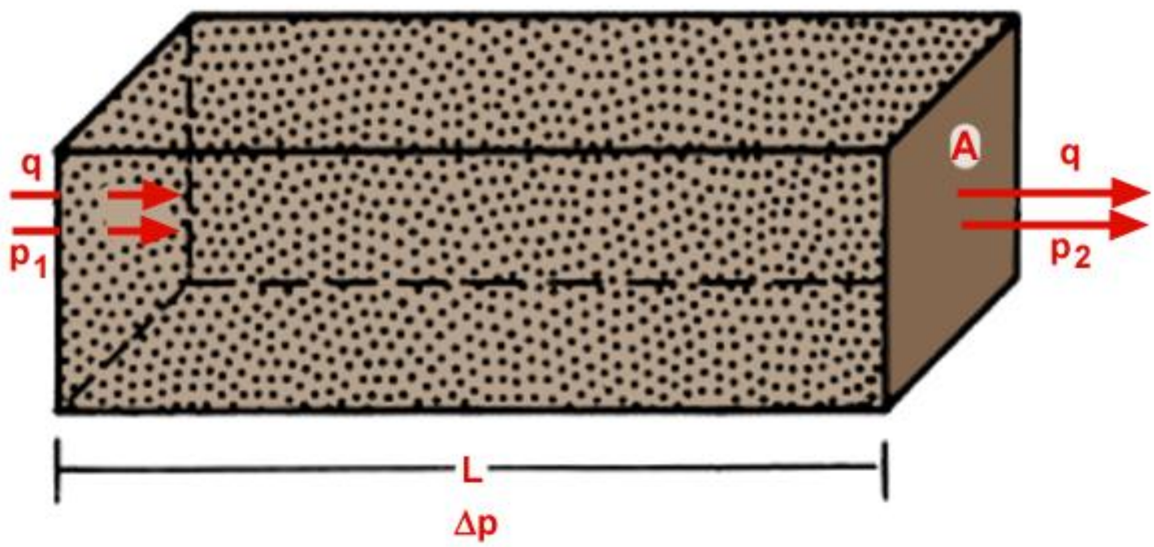


Figure 1

Re arranging Equation 8 gives

$$q\,dx = -\frac{Ak}{\mu}dp$$

Integrating between X = 0 and X = L gives

$$q\,L = -\frac{Ak}{\mu}(p_2 - p_1)$$

or

$$q = -\frac{Ak}{\mu}\frac{(p2 - p1)}{L}$$

In engineering units, the above equation becomes

$$q = \frac{1.127 \times 10^{-3} Ak(p_1 - p_2)}{\mu L}$$

where:

q = flow rate in reservoir bbl/day

A = area in ft^2

k = permeability in direction of flow, (md)

p_1= pressure at the inlet end, psi

P_2= pressure at the outlet end, psi

µ = viscosity in centipoise (cp)

L = length, ft

Radial Flow

In radial flow, which represents the flow pattern around a well, A=2 □rh (Figure 2).Substituting in Equation 8,

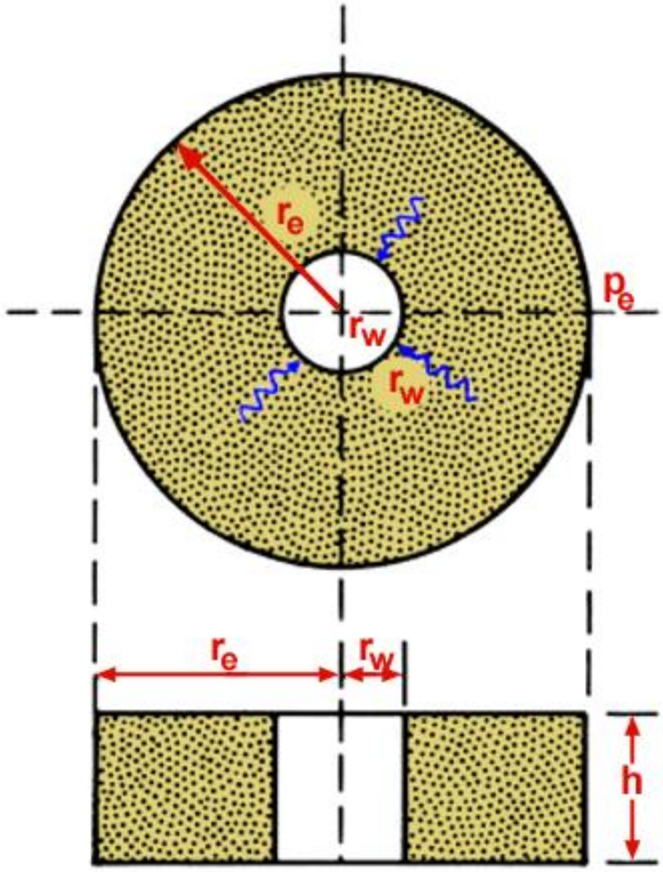


Figure 2

rearranging and integrating gives

$$q\int_{r_w}^{r_e}\frac{dr}{r} = -\frac{2\pi kh}{\mu}\int_{p_w}^{p_e} dp$$

This yields

$$q = \frac{2\pi kh\left(p_e - p_w\right)}{\mu \ln {r_e}/{r_w}}$$

and in engineering units

$$q = \frac{7.08\times 10^{-3}\, kh\left(p_e - p_w\right)}{\mu \ln {r_e}/{r_w}} \qquad (10)$$

where:

h = thickness of bed, ft

p_e = pressure at outer boundary, $r = r_e$

p_w = pressure at the inner boundary, $r = r_w$

r_e = radius of the outer boundary, ft

r_w = radius of the inner boundary, ft and the rest of the symbols are as defined previously.

In the case of a well, rwand re represent, respectively, the wellbore radius and the radius of its drainage area.

The assumptions underlying Darcy's law require that the flowing fluid be incompressible, and that the flow be laminar. Strictly speaking, while reservoir fluids *are compressible,* Darcy's law is still a very good approximation of the flow of oil and water. In the case of gas, it is used if the gas production is associated with the oil, and a modified form of it is used for gas wells. The modified form is

$$q = \frac{703 \times 10^{-6} kh\left(p_e^2 - p_w^2\right)}{\mu z T_R \left(\ln {r_e}/{r_w} - 0.5\right)} \quad (11)$$

where:

q = flow rate in MSCF/Dat standard conditions of temperature and pressure

k = permeability in dirction of flow, millidarcies

z = gas deviation factor (evaluated at average pressure)

μ = viscosity in centipore (cp) (evaluated at average pressure)

T_R = reservoir temperature,°R = 460+°F

h = thickness of bed in ft

Relative Permeabilities

All of these equations assume that only one fluid saturates the porous media; thus k is the absolute permeability. However, as mentioned previously, water is always present. Furthermore, in oil reservoirs, oil, gas, and water exist together, below the bubble-point. In such cases, one must use the effective permeability to the phase of interest in place of the specific permeability. Normally, one replaces the effective permeability by

$k_{eff} = k_r k$

where:

k_r = the relative permeability

Effect of Saturation on Fluid Flow

Relative permeability is a function of saturation. The relative permeability behavior for an oil-water system is illustrated in Figure 3.

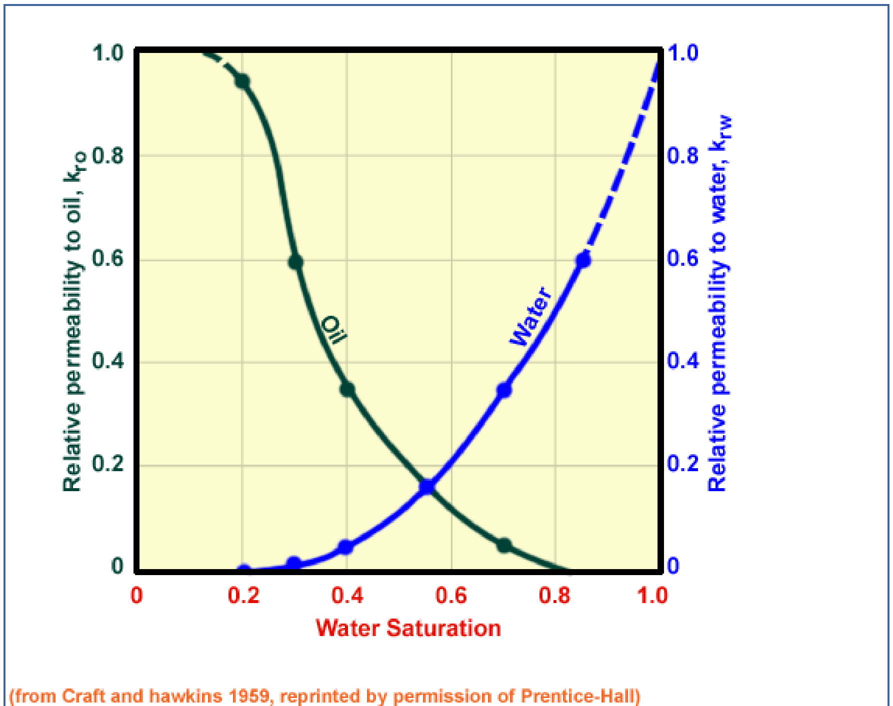


Figure 3

Note that the figure shows that relative permeability values equal to zero exist for saturation values greater than zero. This means that a critical saturation value must occur before relative permeability exceeds zero, that is to say, before the fluid starts to flow.

Gas-Oil Ratio (GOR) Equation

Gas production associated with the oil may come from two sources. These are:

- the flow of the free gas in the oil zone, which occurs when the pressure in the oil zone is below the bubble-point and the gas saturation is above its critical value;

- the gas that is liberated from the oil during its trip to surface because of the drop from reservoir pressure to surface pressure. This portion of gas is expressed in standard cubic feet/stock tank bbl (SCF/STB) or cubic meters per cubic meter (m^3/m^3), and is indicated by Rs.

The ratio of the flow of free gas to the flow of oil at standard condition is calculated by means of Darcy's law and is given by

$$\frac{k_{rg}\mu_0 B_0}{k_{ro}\mu_g B_g}$$

The ratio of the rate of gas to oil production, GOR, is

$$GOR = \frac{k_{rg}\mu_0 B_0}{k_{ro}\mu_g B_g} + R_s \quad (12)$$

where:

GOR = gas-oil ratio, SCF/STB

k_{rg} = relative permeability to gas, fraction

B_0 = oil formation volume factor, RB/STB

k_{ro} = relative permeability of oil, fraction

B_g = gas formation volume factor, RB/scf

R_s = the gas in solution, SCF/STB.

Fractional Flow Equation

When there is a natural influx of water from an aquifer, or when water is injected into an oil reservoir, a simultaneous flow of oil and water occurs. The oil and water fractions in the flowing stream may be calculated by means of Darcy's law. The oil and water fractions, f_o and f_w, are defined by

$$f_0 = \frac{q_0}{q_0 + q_w}, \text{ and } \quad f_w = \frac{q_w}{q_0 + q_w} \quad (13)$$

but, in linear systems,

$$q_0 = \frac{Ak\, k_{ro}}{B_0\, \mu_0}\, \frac{dp}{dx}, \text{ and } \quad q_w = \frac{Ak\, k_{rw}}{B_w\, \mu_w}\, \frac{dp}{dx}$$

substituting in (13) and simplifying gives

$$f_0 = \frac{\dfrac{k_{ro}}{B_w \mu_0}}{\dfrac{k_{ro}}{B_0 \mu_0} + \dfrac{k_{rw}}{B_w \mu_w}} \quad (14) \text{ and } \quad f_w = \frac{\dfrac{k_{rw}}{B_w \mu_w}}{\dfrac{k_{ro}}{B_0 \mu_0} + \dfrac{k_{rw}}{B_w \mu_w}} \quad (15)$$

Material Balance Equation

Expansion, Production, and Influx Terms

The material balance equation is an expression of the *conservation of the mass* of oil, gas, and water in the reservoir. The application of the conservation principle to the gas phase, for example, requires that the mass of gas in the reservoir at any time be equal to the mass of gas initially in place minus the mass of gas that has been produced. The mass of gas is calculated by

mass of gas = volume at standard conditions X $\square_{gs}$

where:

$\square_{gs}$ = the density of gas at standard conditions.

The statement of the conservation of the mass of gas may be written as

$$G_t \square_{gs} = G \square_{gs} - G_p \square_{gs}$$

or

$$G_t = G - G_p \qquad (16)$$

where:

G_t, G, and G_p are, respectively, the gas in the reservoir at any time, the initial gas, and the produced gas, all in standard volumes.

Because of the form of Equation 16, some authors refer to the MBE as a volumetric balance. This is misleading, since Equation 16 was derived from a mass balance equation. The complete derivation of the MBE requires expressing the three terms G_t, G, and G_p in Pertinent parameters. The resulting equation is

$$N_p [B_t + (R_p - R_{si}) B_g] + B_w W_p = N (B_t - B_{ti}) +$$

$$\frac{N m B_{ti}}{B_{gi}} \left(B_g - B_{gi}\right) + \frac{N B_{ti}}{1 - S_{wi}} \left(c_r + s_{wi} c_w\right) \Delta p + w_e \qquad (17)$$

Note: only the expansion of rock and its associated water in oil zone is considered in Equation 17.

where:

N_p = cumulative oil production, STB

B_t = two-phase formation-volume factor, RB/STB

R_p = cumulative produced GOR, SCF/STB

R_{si} = initial gas in solution, SCF/STB

B_g = gas formation-volume factor, RB/SCF

B_w = water formation-volume factor, RB/STB

W_p = total water produced in STB

N = initial oil in place, STB

B_{ti} = initial two-phase formation-volume factor

m = ratio of gas cap pore volume to oil leg pore volume

B_{gi} = initial gas formation-volume factor

S_{wi} = initial water saturation, fraction of pore volume

S_w = water saturation, fraction of pore volume

c_r = rock compressibility, vol/vol/psi

c_w = water compressibility, vol/vol/psi

$\Delta p = p_i - \bar{p}_R(t)$

p_i= initial reservoir pressure, Psi

$\bar{p}_R(t)$ = average reservoir pressure at the time of interest t, psi

W_e = cumulative water influx, RB

The two terms on the left-hand side indicate the total fluids production in reservoir volumes. The first three terms on the right-hand side are, respectively, the total expansion of the hydrocarbon in oil zone, the total expansion of the gas in gas cap, and the total expansion of the rock and its associated water. The last term is the water influx. Thus, a statement of the MBE which is simple and easy to remember is: total fluids produced in reservoir volumes equals total expansion of the hydrocarbon in the oil zone, the gas in the gas cap, and the rock and its associated water, plus the water influx in oil zone.

Compressibility of Rock and Water Terms

Normally one thinks of the water and rock as being incompressible. In fact, they are compressible. The rock compressibility is a function of its porosity and consolidation (Figure 1).

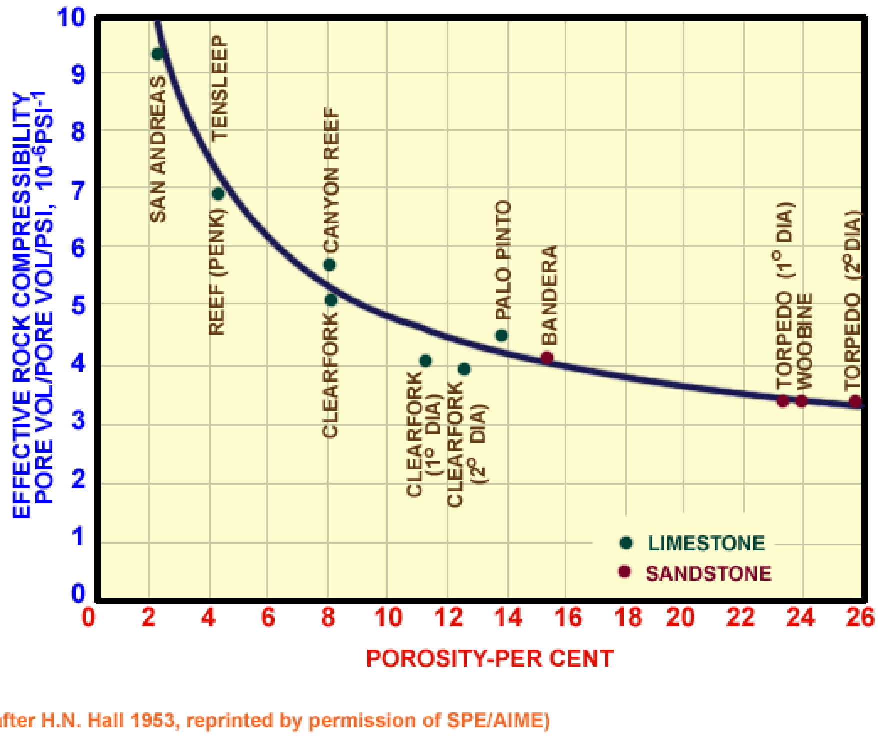


Figure 1

It can be as low as 3 × l0-6 vol/vol/psi and higher than 20 × l0-6 (Coats 1980). The water compressibility does not vary widely like the rock compressibility. It normally ranges between 3 and 6 × l0-6 vol/vol/psi.

To illustrate the meaning of compressibility and the unit vol/ vol/Psi consider two cubic feet of water that are under pressure. Assume the Pressure is decreased by 10 Psi and the water compressibility is 3 × 10-6 per psi. Since the pressure decreases by 10 psi, the two cubic feet of water expand by 210 × 3 × 10-6 = 6 × l0-5. The volume of water is now (2 + 6 × 10-5) cubic feet.

Advantages and Limitations of the MBE

The primary advantage of the material balance equation is that it provides a valuable insight into the behavior of the reservoir, and the contribution of the various drive mechanisms to recovery. In the case of reservoirs with reasonable reservoir-wide fluid communication, the MBE provides a method of calculating the initial oil or gas in place, as well as the expected aquifer effects, by using actual production and pressure data. The MBE is the only method that employs the dynamic response of the reservoir to production as a means of estimating the volume of original fluid. What the MBE calculates is the fluid volume in the reservoir that is affected by production.

The dynamic response of the reservoir fluid to production is manifested in the pressure change. Thus, the initial fluid in place calculated by the MBE is indicative of the fluid volume in communication with the wells. In contrast, the volumetric method of estimating the fluid in Place is a static method. It does not differentiate between connected and isolated areas. For this reason, the fluid in place calculated by the MBE *cannot be larger than that calculated volumetrically*, assuming an accurate volumetric estimate.

The main disadvantage of the MBE is that it is based on a tank model (i.e., a zero-dimensional model). Therefore, it deals with average values of rock and fluid properties for the whole reservoir. As a result, it cannot be used to calculate fluid or pressure distributions, nor can it be used to identify new well locations or the effect of well locations and production rates on recovery. The MBE cannot be used to predict water or gas channeling, and cannot account for the effect of heterogeneities on the behavior of the reservoir. When any of these factors is significant, reservoir simulation is required to predict precisely the behavior of the reservoir.

A. Derivation of the Material Balance Equation

We will derive the MBE based on the gas in the oil zone. The gas in scf in the oil zone at time, t, is given by Equation 16.

Thus:

$$G_t = G - G_p \qquad \text{(Al)}$$

Where:

G_t = the total gas in the oil zone at time t in scf,

G = the original gas in the oil zone, scf, and

G_p = the total gas produced at time t, scf.

G_t has two components: the gas in solution in the oil and the free gas in the oil zone.

The gas in solution in scf = $(N - N_p) R_s$

The free gas volume in the oil at time t, scf = [the oil zone volume occupied by the initial oil - the volume of oil at time t - the decrease in the oil zone volume due to the expansion of the gas cap gas and the oil zone rock plus its associated water, and due to the net water influx] $1/B_g$.

Note that all the terms between the brackets are in reservoir barrels.

The oil zone volume occupied by the initial oil = N Boi

The oil volume at time t = $(N - N_p) B_o$

Expansion of gas cap gas = $\frac{NmB_{oi}}{B_{gi}}$ $(B_g - B_{gi})$

Expansion of oil zone rock = $\frac{NmB_{oi}}{1 - S_{wi}}$ $c_r(p_i - P_{Rt})$

Expansion of the associated water = $\frac{NmB_{oi} c_w S_{wi}}{1 - S_{wi}}$ $(p_i - p_{Rt})$

Net water influx = $W_e - W_p B_w$

Thus:

$$G_t = (N - N_p)R_s + [N B_{oi} - (N - N_p) B_o - \frac{NmB_{oi}}{B_{gi}} (B_g - B_{gi})$$

$$- \frac{NmB_{oi}}{1 - S_{wi}} (c_r + c_w S_{wi}) (p_i - p_{Rt}) - (W_e - W_p B_w)] \frac{1}{B_g} \qquad \text{(A2)}$$

The original gas in the oil zone, $G = NR_{si}$ (A3)

The total gas produced, $G_p = N_p R_p$ (A4)

Substituting A2, A3, and A4 in A1 gives

$$(N + N_p)R_s + [N B_{oi} - (N - N_p) B_o - \frac{NmB_{oi}}{B_{gi}} \mathbf{(B_g} - B_{gi})$$

$$- \frac{NmB_{oi}}{1 - S_{wi}} (c_r + c_w S_{wi}) (p_i - p_{Rt}) - (W_e - W_p B_w)] \frac{1}{B_g} - N R_{si} - N_p R_p \qquad \text{(A5)}$$

Rearranging and collecting terms gives

$$N_p R_p B_g + N_p B_o N_p R_s B_g + W_p B_w = N(B_o + (R_{si} - R_s)B - B_{oi})$$

$$+ \frac{NmB_{oi}}{1 - S_{wi}} (c_r + c_w S_{wi}) (p_i - p R_t) + \frac{NmB_{oi}}{B_{gi}} (B_g - B_{gi}) - W_e$$

Adding and subtracting $N_pR_{si}B_g$ to the left hand side term gives

$$N_p \; [B_o + (R_{si} - R_s)B_g + (R_p \;\; R_{si})B_g] + W_pB_w = \text{right hand side}$$

However, $B_o + (R_{si} - R_s)\, B_g = B_t$; also at the bubble-point pressure P_i, $B_o = B_{oi} = B_{ti}$, since $R_{si} = R_s$. Substituting these relations in the previous equation gives

$$N_p \; [B_t + (R_p - R_{si})B_g] + B_wW_p = N(B_t - B_{ti}) +$$

$$\frac{NmB_{oi}}{B_{gi}} (B_g - B_{gi}) + \frac{NmB_{oi}}{1 - S_{wi}} (c_r + S_{wi}c_w) + \Delta p + W_e \qquad \text{(A6)}$$

THE BIGGEST CHALLENGE: EXISTING SOFTWARE

Questions to ask:

Before implementing any analytics modifications, the following questions should be asked:

a. Which reservoir engineering software is already present and performs all necessary functions?
b. Which data science software is present and has the potential to aid engineering processes?
c. Which reservoir engineering software could be easily replaced by analytics in order to save money on licenses?
d. Which reservoir engineering software cannot be replaced? For this software which analytics processes could be implemented to aid reservoir engineers? Should additional plug-ins for statistics or Big Data should be developed?
e. Which areas reservoir engineering software currently does not cover and how the analytics processes could be created to cover those areas?

The solution to above questions should be determined by collaboration of reservoir engineers and data analytics professionals. The rotation of analytics professionals in order to observe the daily activities of the reservoir engineers and how their processes are done could be a possible solution.

The List of Reservoir Engineering Software Tools:

Petrel

Petrel is a software platform used in the exploration and production sector of the petroleum industry. It allows the user to interpret seismic data, perform well correlation, build reservoir models, visualize reservoir simulation results, calculate volumes, produce maps and design development strategies to maximize reservoir exploitation. Risk and uncertainty can be accessed throughout the life of the reservoir.

OFM

OFM well and reservoir analysis software offers production surveillance visualization and forecasting tools to manage and improve performance. It allows users to do surveillance and analysis without complexity of creating these solutions from scratch. The current collection of solutions covers waterflooding, SAGD, WAG, CBM, shale, conventional oil, conventional gas, and many more.

GOHFER

GOHFER is multi-disciplinary, intergrated geomechanical fracture simulator that incorporates all the tools necessary for conventional and unconventional well completion design, analysis and optimization.

CMG

The software capable of reservoir simulator capabilities, model building and the refinement of advanced recovery processes through a combination of parallel processing, dynamic gridding and the multi-physics required to correctly model each process, including cross-disciplinary interactions like thermal effects, geochemistry, geomechanics, fluid and phase behavior as well as wellbore hydraulics and completions.

Harmony

HIS Harmony is a comprehensive desktop engineering application for analyzing oil and gas well performance and evaluating reserves.

PIPESIM steady-state multiphase flow simulator

A multiphase flow simulation to overcome fluid flow challenges and optimize production.

DATA SCIENCE TOOLS TO AID ENGINEERING PROCESSES

After what needs to be done is determined in reservoir engineering processes, the next step is to employ

SEMMA workflow and to determine which Data Science tools is applicable.

Examples include: Linear and non-linear modeling, Data Visualization, Machine Learning, Forecasting, Pattern Recognition.

To be continued…

CONCLUSION

The following text is taken from: Understanding the value of big data analytics in reservoir management (during low oil prices) by Luigi Saputelli – Reservoir Engineering Adviser

https://www.linkedin.com/pulse/understanding-value-big-data-analytics-reservoir-luigi-saputelli

Petroleum engineers are used to follow reservoir production data trends. This is, they collect vast amounts of production historic data and create production reports which show time-dependent trends. This "trendology" analysis (i.e. the science of relying on base case performance) only allow us to focus in a comparison of best performed days and downtime examination. This is a necessity but it is not sufficient. On the other side, operators with permanent well instrumentation complaint on the large amounts of data being generated with "little or no value" because there are no processes or skills to interpret those.

With continuous reservoir surveillance we can expect direct answers for the following questions:

- What is the production potential of our reservoirs today?
- What is the reason of the variance between the production plan and actual?
- What percentage of our decisions is supported by robust models?
- What is the most limiting factor of our production today? Is it well integrity or reservoir driven?
- …

The prime value of big data analytics is letting the reservoirs talk, i.e. providing awareness of their capacities and weaknesses. Reservoirs talk through information and knowledge derived from data analysis and integration. With limited data collection reservoirs are speechless. Every reservoir has specific challenges and languages to be decrypted. We shall implement the right technology to close the reservoir knowledge gap. Predictive data analytic with the right combination of physics modeling can discover patterns of data not detectable by traditional engineering analysis.

What is the value we can obtain from big data analytics in reservoir management?

- **Production excellence**: predict and understand reservoir production variances (loss/gains)
- **Optimize production**: continuously adjust operating settings to minimize bottlenecks
- **Maximize profit**: select most valuable action without detriment of long term goals
- **Increase recovery**: selecting the actions that prevent reserves loss and anticipating projects to prevent and recuperate by-passed oil

What challenges operators face for implementing big data surveillance in their reservoirs?