

Part 1

INTRODUCTION

COPYRIGHTED MATERIAL

Reservoir Characterization: Fundamental and Applications - An Overview

Fred Aminzadeh

FACT Inc., Santa Barbara, CA, USA

Abstract

This article provides a brief overview of reservoir characterization at different stages of a field from exploration to development to production and post primary production. It demonstrates the challenges associated with integration of different data types. It also shows how “Dynamic Reservoir Characterization” can assist in monitoring of the field for various well stimulation processes such as enhanced oil recovery as well as reservoir stimulation. Different sections of this entry attempt to highlight different aspects of reservoir characterization, as an exploration tool, development tool, production tool and monitoring tool. As reservoirs age, different measures are taken to extend their productive life. This includes different types of reservoir stimulation and enhanced oil (or gas) recovery.

Keywords: Reservoir characterization, data integration challenges, 3D/4D seismic, micro-seismic data, reservoir monitoring, dynamic reservoir characterization, rock physics and enhanced oil recovery (EOR)

1.1 Introduction to Reservoir Characterization?

As discussed in Aminzadeh and Dasgupta [2], Reservoir Characterization is to assess reservoir condition and its properties using the available data from core/log data to seismic and production data. This is done to assist in delineating or describing a reservoir. Reservoir characterization and modeling have become increasingly important for optimizing field development.

Email: fred.aminzadeh@fact-corp.com

Fred Aminzadeh (ed.) Reservoir Characterization: Fundamentals and Applications, (3–22) © 2022
Scrivener Publishing LLC

Reservoir valuation and producing from a field demands a realistic description of the reservoir, requiring an integrated reservoir characterization and modeling. An integrated approach for reservoir modeling bridges the traditional disciplinary divides and tears down interdisciplinary barriers, leading to better handling of uncertainties and improvement of the reservoir model for field development. Integrated reservoir management requires better characterization of the reservoir and it is imperative to a successful operation throughout the life of the reservoir. Dynamic reservoir characterization is to understand the changes in reservoir properties to monitor its performance as we produce from reservoir and/or stimulate the reservoir to enhance production. This is accomplished by the analysis of data from combination of different sources, to extract additional information about the *in-situ* conditions of the reservoir, including the formation temperature, pressure, and the properties of the oil, gas, and brine. Other reservoir properties that can affect measured data are density, hydrocarbon viscosity, stresses, and fractures. We start with the reservoir description process that generates models of reservoir architecture, lithologies and facies. The geometry of the flow units is established, physical rock properties such as porosities and permeabilities of flow layers. Three properties are related to the pore space: porosity--the fraction of the entire volume part occupied by pores, cracks and fractures, internal surface: the magnitude of the surface of pores as related to the rock mass pore volume and controls interface-effects at the boundary grain - pore fluid, permeability: the ability to flow fluid through rock pores. Porosity and specific internal surface are scalar properties, permeability is a tensor.

Figure 1.1 shows integration of reservoir structure or architecture and reservoir detailed properties from calibration with well data for the reservoir model. Reservoir description is an iterative process and need.

Different aspects of Figure 1.1, from the input data to the process (well data, seismic data, production data, etc.) will be discussed in Section 1.2 on the data requirements. The difficulties associated with the integration of different data sources will be addressed in Section 1.3, under "SURE Challenge". In Section 1.4 we discuss different aspects of reservoir characterizations in different stages of reservoir life. The exploration and development stage deal with preliminary determination of the reservoir structural model, stratigraphic and facies models. This is followed by the production phase with a focus on porosity, permeability and fluid saturation, involving reservoir/flow simulation and history matching. The recovery stages involve injection of water/CO₂ or steam to increase production. We discuss Dynamic Reservoir Characterization (DRC) in Section 1.5. We note that 4D seismic and microseismic data play an important role

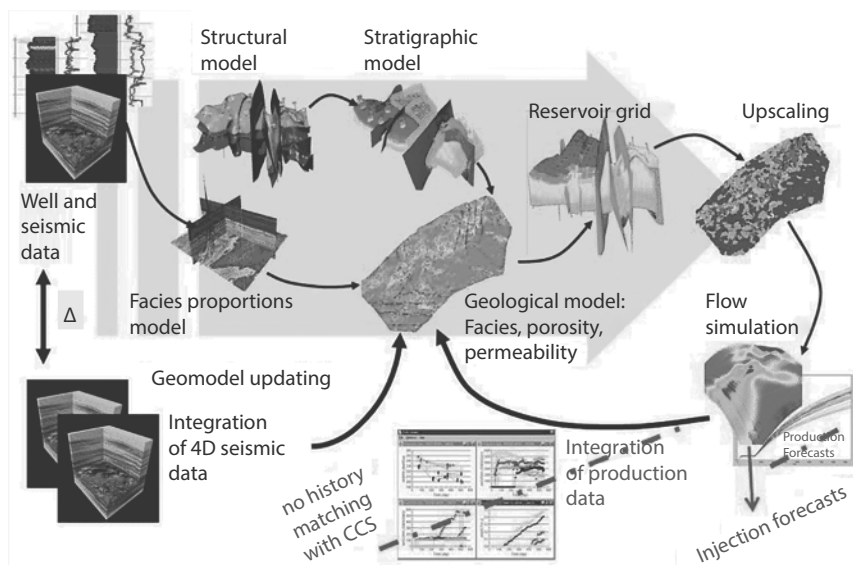


Figure 1.1 Different components of reservoir characterization, from Fornel and Estublier [5].

in geo-model updating monitoring production and the EOR/reservoir stimulation process. Section 1.6 goes into more details on rock physics and reservoir modeling and how reservoir characterization can be used as an input to reservoir simulation and help with enhanced oil recovery and other well stimulation processes.

1.2 Data Requirements for Reservoir Characterization

Well data provides vertically high-resolution model at the well location, however, the distribution of well in a field are sparse. Combining well information with geophysical and geological data allows the necessary constraints for extrapolating high resolution well data beyond where they are measured thus increasing the coverage. For every phase of the reservoir life cycle from discovery to development to operating to maturity and well stimulation (enhanced oil recovery) phase, geophysical tools are used to create reservoir model with the associated properties and update the model based new data collected.

Integration of geophysical data with geologic data, and engineering measurements improves our understanding of the reservoir, reduces uncertainties and mitigates the risk. The detailed spatial coverage offered are calibrated with analysis of well logs, pressure tests, cores, fracture system, geologic depositional knowledge and other information from appraisal wells. 3D seismic is the primary geophysical technique used to create the original reservoir models. 4D seismic (time lapse data) and other new measurements (micro-seismic, new log/pressure data and production data help create updated (dynamic) reservoir model. In addition, gravity, controlled source EM, borehole measurements such as vertical seismic profiling-VSP, borehole gravimeter-BRGM, cross well seismic, cross well EM are also used to build the original and updated reservoir models.

The required information for the petroleum engineers and geologists includes subsurface lithology, net pay, porosity, permeability, reservoir fluid-fill, fluid contacts, reservoir pressure and stress regime. Geophysical tools infer reservoir properties from the measured physical observations by blending these with measurements made at the wells like well logs, well tests and core analyses. During the field appraisal and development stages, understanding of the reservoir matrix properties and fluid distribution within the reservoir are of great importance.

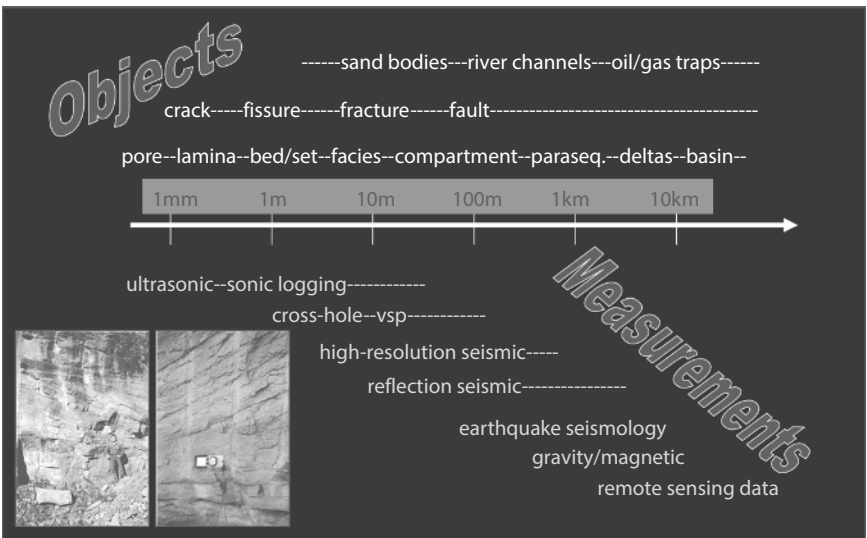


Figure 1.2 Wide range of physical scale for different data types associated with different geological and reservoir features.

1.3 SURE Challenge

The ultimate goal is not only to identify and delineate hydrocarbon charged in reservoirs, but also to quantitatively determine the volume and distribution of oil and gas it contains and quantify the associated uncertainty. No single measurement has the required response to achieve this. It is therefore essential to integrate the various types of data to a common earth model. This information includes seismic data, various types of well data, and geologic concepts. The challenge is to integrate measurements that are of different Scale, Uncertainty, Resolution, and Environment or the SURE Challenge as was introduced by Aminzadeh [1] and further elaborated at Aminzadeh and Dasgupta [2] and Aminzadeh [3]. The entire process of exploration for reservoirs to its abandonment involves acquisition and analysis of different types of data. These data types are associated with an enormous range of scale as shown in Figure 1.2. This spans ultra-sonic measurements of pores of the order of 1 millimeter to remote sensing measurements of basins of over 10 Kilometers wide. Examples of many other data measurements for many other objects that lie in between all the features are shown in this figure.

Admittedly not all the data types are integrated at the same time. Nevertheless, Scale and the wide range of differences for different data types is one of the challenges in reservoir characterizations. To make the matter more complicated is the fact that different data types are associated

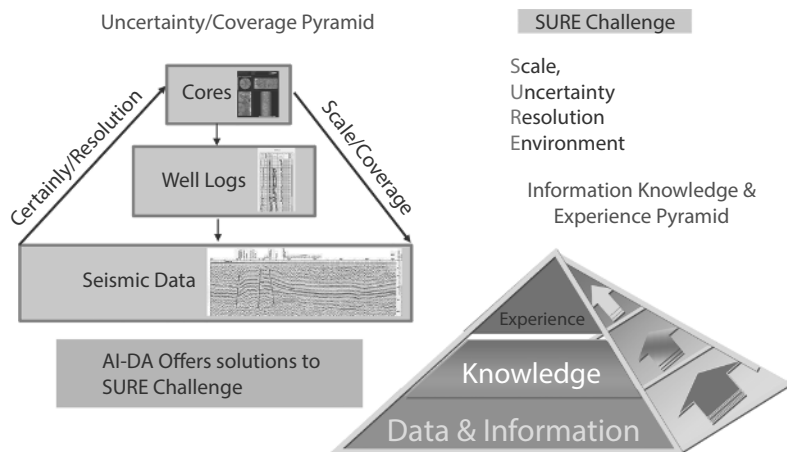


Figure 1.3 SURE Challenge: Having to deal with the wide ranges of Scale, Uncertainty, Resolution and Environment of different data types when integrating them, (from Aminzadeh [3]).

with different levels of uncertainties. For example, the direct measurements of rock properties from the core data may involve little uncertainty. The petrophysical information from well log data may be associated with somewhat more uncertainty. The seismic data used to ascertain reservoir properties, for their indirect nature of measurements involve much more uncertainty. Thus, Uncertainty level and its variations with respect to different data types is poses another challenge in data integration.

In addition, having different data types with vastly different underlying Resolution, also poses a challenge for data fusion. The resolving power of different data types is drastically different. As shown in Figure 1.3, some data types have very high resolving power. For example, while well log data can resolve a reservoir unit of under an inch, seismic data, generally speaking, may not be able to resolve a reservoir under 30 feet. Finally, the effectiveness and usefulness of different data types are impacted by the geological conditions and reservoir “Environment”. This can be associated with different reservoir types (carbonate, clastic, unconventional, heavy oil,) or different reservoir conditions (High Pressure/High Temperature, or reservoir depth (shallow water, Deep, or Ultra Deep Water.)

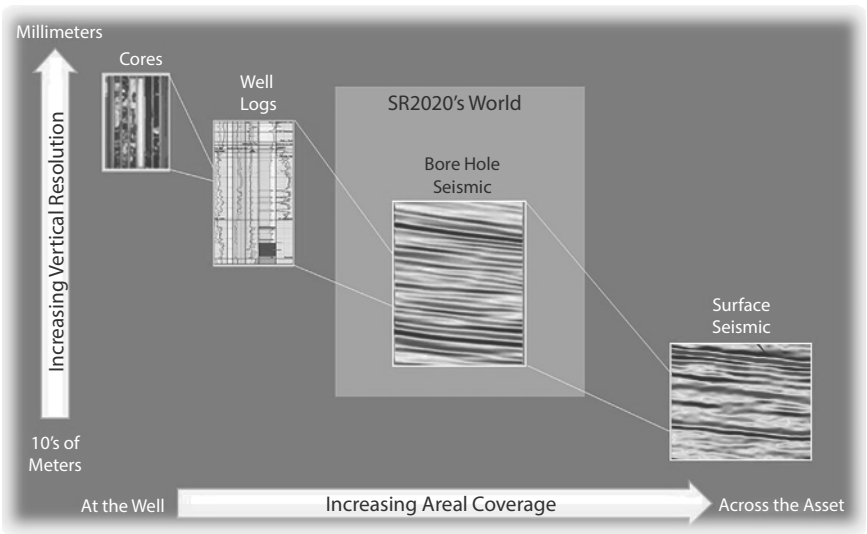
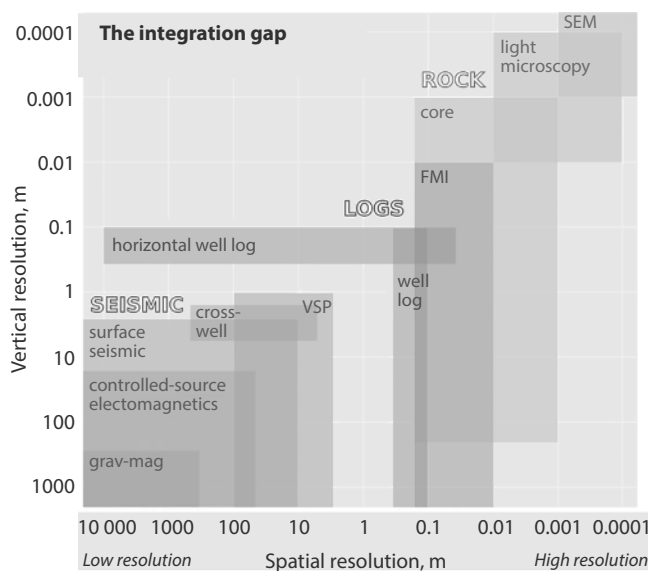


Figure 1.4 Areal coverage of well data is complemented by the larger areal sampling of the geophysical methods. VSP vertical seismic profile and Crosswell seismic fill a resolution “gap” between sonic log measurements and vertical seismic profiles. Courtesy of SR2020 (now Optasens).

We refer to these four key challenges: Scale, Uncertainty, Resolution and Environment as: the SURE Challenges. Top left side of Figure 1.3 illustrates three key data types: core, well log and seismic data. We will refer to it as a data pyramid. The base of the pyramid is the seismic with very large coverage but with limited resolution and lesser level of certainty. The top of the pyramid is the core data with very little coverage (only at a particular well location involving a fraction of the well) but with high level of certainty and resolution. Effective integration of all the data types, in spite of the SURE challenge is what reservoir characterization is all about. As we will show in the last chapter artificial intelligence and data analytics can play a key role in offering solutions to the SURE challenge.

The bottom right-hand side in Figure 1.3 shows an upside-down pyramid comprised of a different aspect of integration. That is, vast amount of data needs to be combined with some technical knowledge and experience to perform effective data mining and ultimately reservoir characterization. As an aside, it must be pointed out that borehole geophysical data (e.g. Vertical Seismic Profile and Cross-Well data) fills the gap between core



Matt Hall 2010 | Agile | agilegeoscience.com



Figure 1.5 Vertical and spatial resolution of various geophysical, well logs and laboratory measurements. From www.agilegeoscience.com (left), and Optaense (right).

data and well log data on one side of the scale and 3D seismic data on the other side.

In general, The resolution of different data types for reservoir characterization and description varies considerably. Figure 1.5 illustrate such a large variability for core to log to borehole geophysics and seismic, gravity magnetics data and control source electromagnetics, among others. This further demonstrates the importance finding a solution to the “SURE Challenge” for reservoir characterization and other E&P problems. Also, see Ma *et al.* [8] addressing integration of seismic and geologic data for modeling petrophysical properties.

1.4 Reservoir Characterization in the Exploration, Development and Production Phases

Reservoir characterization has different focus in different phase of the life of a field. In what follows we briefly highlight the main objective of Reservoir Characterization in Exploration, Development, Production (primary recovery) and Production Enhancement (secondary and tertiary recovery) phase. For the very reason, the notion of reservoir characterization often times means different thing to geologists, geophysicists and reservoir engineers. This is primarily due to the fact that their primary focus is different phases of life of the field.

1.4.1 Exploration Stage/Development Stage

The pre-development (exploration) phase requires delineation of the reservoir limits and assessment of its economic feasibility. Development stage requires somewhat more accurate assessment of the reservoir extent, better appraisal of the economic viability of the reservoir and placement of new wells for further delineation of the reservoir. More detailed depth imaging using advanced geophysical methods, borehole geophysics applications as well as fault seal analysis, and better understanding of reservoir compartmentalization are some of the objectives of reservoir characterization at this stage. At this stage it is necessary to determine the reservoir drive mechanism and the size and strength of the aquifer. At the development phase, reservoir continuity rather than reservoir delineation becomes the focus. The focus in this phase is to identify the structural extension or truncation beyond well control in order to minimize the drilling of dry holes. While the pre-development and development phase require considerable attention to reservoir characterization. Geophysicists construct an initial model

by correlating lithology, porosity, net pay thickness and other properties at the well location using seismic attributes from surface 3D seismic, VSP and synthetic seismograms. The initial model is then updated by computing seismic attributes between the wells in order to predict reservoir properties in 3D. Seismic attributes like acoustic impedance, variations in amplitudes, frequencies, interval velocities and instantaneous phase are applied in the computation.

1.4.2 Primary Production Stage

As the primary production of the reservoir begins, the goal is to position wells at optimal locations that would maximize hydrocarbon recovery. During secondary recovery and then enhanced recovery process, the engineer's objective is to maximize the volume of hydrocarbon contacted by injected fluids. This is to achieve maximum volumetric sweep efficiency for fluid production. To minimize cost and risk, engineers attempt to predict reservoir performance—for both planning and evaluation of hydrocarbon recovery projects. Reservoir description in terms of reservoir architecture, flow paths, and fluid-flow parameters are the key to reservoir engineering. Accurate prediction of reservoir production performance is predicated primarily on how well the reservoir heterogeneities are understood and have been modeled and applied for fluid-flow simulation. This stage requires integration of reservoir characterization models with reservoir simulation, history matching for production optimization. Reservoir management process conducts reservoir related studies and applies the results from fluid flow modeling in defining, updating and optimizing a development plan for producing the reservoir and forecast the production profile. This phase also involves optimization and management of reservoir performance evaluation, surveillance of fluid flow and changes in the reservoir that result in changes in the original distribution of physical properties. The optimization criteria can change during the life cycle of a producing reservoir. Managing the reservoir depletion is a dynamic process and the reservoir engineers constantly react and adapt to the changes as they evolve. Dynamic characterization is a representation of the fluid flow in a static reservoir model and needs to be validated with reservoir performance data.

1.4.3 Secondary/Tertiary Production Stage

When the reservoir ages, intervention to increase production through reservoir stimulation and enhanced oil (or gas) recovery becomes necessary. Here, the main objective shifts to plan the production and injection,

develop an optimum secondary/tertiary recovery mechanism and plan for infill drilling well locations to maximize recovery rate and deliver oil and gas at the planned rate and to extend the economic producing life of the reservoir as much as possible. The finite resources that are available are applied to plan and optimize the economic recovery of oil and gas from the reservoir. Petroleum engineers are responsible for planning and executing the development and of petroleum reserves. They seek to maximize petroleum recovery from the reservoirs. Effective use of reservoir characterization and reservoir model updating play an important role in this process. This is accomplished by incorporating physical property measurements of the reservoir rock and fluid properties that describes the reservoir architecture and its initial fluid distribution to make an optimum production and reservoir stimulation plan. 4D seismic and/or micro-seismic monitoring plays a role in assessing the effectiveness of well different well stimulation approaches (for example EOR, artificial lift or hydraulic fracturing), giving rise to the importance of “dynamic reservoir characterization” at this stage.

Engineers need to monitor the reservoir state of pressure, temperature and fluid distribution during the producing life of a reservoir. This information could 1) identify situations within the reservoir which may potentially impact oil and gas recovery, and 2) locate problems that can cause undesirable leakage or entry into wellbore. If these situations are not corrected in a timely manner, irreversible damage might occur to the reservoir affecting the ultimate oil and gas recovery. Inter-well monitoring of production and injection processes using geophysical techniques also allow improvement of field development plans and optimize reservoir management. Field scale monitoring of reservoir drainage patterns would improve the recovery factor.

1.5 Dynamic Reservoir Characterization (DRC)

Both in the primary and post-primary production phases, we need to have an updated characterization of the reservoir. We will refer to this as DRC. DRC can play a key role in production optimization and monitoring of effectiveness of the EOR operation or hydraulic fracturing. It can help surveillance of fluid flow which is an essential part of reservoir management process. Likewise, changes in the reservoir pressure distribution is also helpful to make important reservoir management decisions. Among many data sets that are used to monitor fluid, pressure and other reservoir properties is 4D seismic and Microearthquake data. For some examples, see Kosco [7], Maity [9] and Maleki [10].

1.5.1 4D Seismic for DRC

Changes in the reservoir fluids or pressure distribution can be imaged by 4D. This is based on the impact of fluid saturation and reservoir pressure on the changes in compressional and shear wave velocities of seismic waves. A simplistic idea is to directly subtract two 3D seismic volumes of acquired in say successive years. This is often referred to as 4D seismic, with the fourth dimension being the time lapse between the two 3D seismic surveys. An example of time lapse seismic is in Figure 1.6. As the reservoir is produced, the distribution of the fluid properties changes with time but the reservoir rock frame properties remain constant during the producing life of the reservoir. Therefore, by repeating the seismic measurements

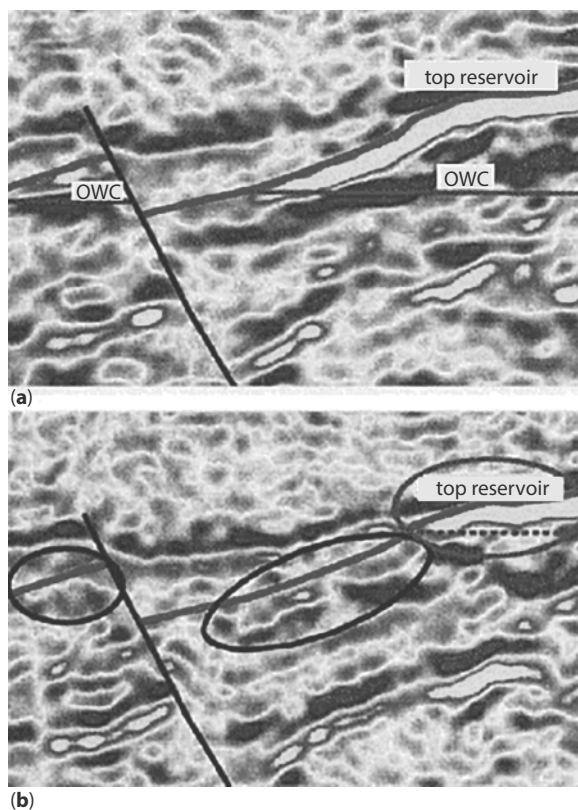


Figure 1.6 Time-lapse seismic response changes caused by different positions of oil-water contact (OWC) in Gullfaks field Tarbert reservoir. (a) Oil-water contact level before production and (b) after production for 10 years. Zones with changes in seismic impedance are circled. <http://accessscience.com>.

i.e., acquiring time lapse seismic data and computing the differences in the seismic attributes between the measurements the changes in the distribution of reservoir fluid properties between wells could often be detected.

The changes in time lapse seismic data are due to the acoustic impedance variation (in this case, mostly the compressional velocity change), caused by the reservoir production or other changes (such as water or CO₂ injection in the EOR process). Acoustic impedance is the product of velocity (V) and density (ρ), for time lapse seismic amplitudes are influenced by the incompressibility (K_{rock}) of the reservoir rock and the production-generated changes in the incompressibility of the pore fluids (ΔK_{fluids}).

The reservoir rocks must therefore be sufficiently compressible so that there is a prominent and measurable contribution from the pore fluids. Soft compressible rocks like unconsolidated sands (younger in geologic times) are ideal for time lapse seismic while rigid or incompressible reservoir rocks such as carbonates do not lend themselves for effective application of this technology.

The acquisition and processing parameters for different vintage 3D seismic should either be the same or necessary calibration should be applied to make them consistent. That is the seismic response should be identical when no changes in the geologic formation due to injection of production has taken place. Some of these difficulties may be mitigated by using permanent sensors in wells and recording time lapse data.

1.5.2 Microseismic Data for DRC

The permanent sensors also can record micro seismic or microearthquake (MEQ) data in passive mode without any seismic source. They detect the seismic events that are induced by hydrocarbon production due to change in the reservoir stress with pressure changes. Many examples of MEQ data applications in DRC and/or monitoring hydraulic fracturing or other well stimulation processes have been reported.

The results of seismic monitoring (4D or MEQ or combination of the two) along with the well log and production data can be used to constrain the flow simulation model in the reservoir history matching and fluid flow prediction process, as well as characterizing the fracture regime. As an example, see Maity and Aminzadeh [8]. Figure 1.7 shows how integration of conventional seismic, well log data and MEQ data have been able to create a 3-D fracture distribution, using a neural network approach through integrating “Fracture Zone Identifier” or FZI attributes.

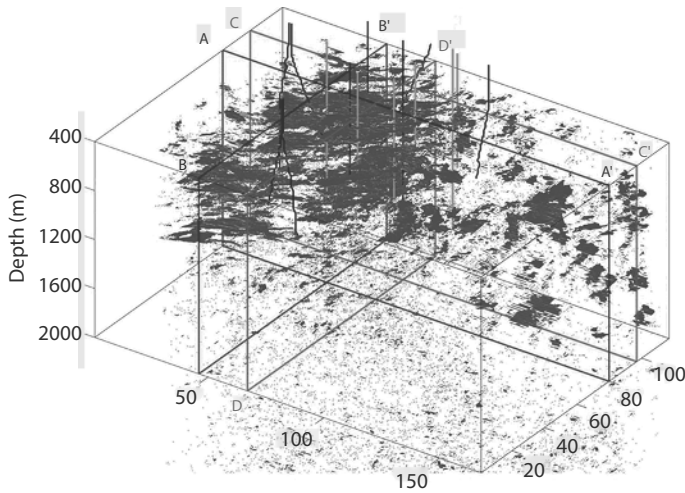


Figure 1.7 Use of conventional seismic, well log data and MEQ data to create a 3-D fracture distribution volume, using a neural network by integrating “Fracture Zone Identifier” or FZI attributes, Maity and Aminzadeh [9].

1.6 More on Reservoir Characterization and Reservoir Modeling for Reservoir Simulation

No discussion on reservoir characterization is complete without understanding rock properties and the corresponding rock physics. Furthermore, reservoir modeling could be considered as the last step for reservoir characterization during different stages of the life of the reservoir. Indeed, ideally, any reservoir simulation and could use reservoir models based on static and dynamic reservoir characterization to improve the process. 4D seismic data can help with the reservoir model updating process, thus enabling creation of a dynamic reservoir model.

Figure 1.8 shows how a static reservoir model with the associated structural earth model and corresponding geologic and reservoir properties such as facies, porosities, and v_{shale} among other parameters can be a starting point (top left). Through reservoir simulation a flow model can be created at different time points, with the respective information about pressure, saturation and temperature. Output of the reservoir simulation model and the earth model could be used to generate (invert for) the reservoir rock physics properties such as density, compressional and shear wave

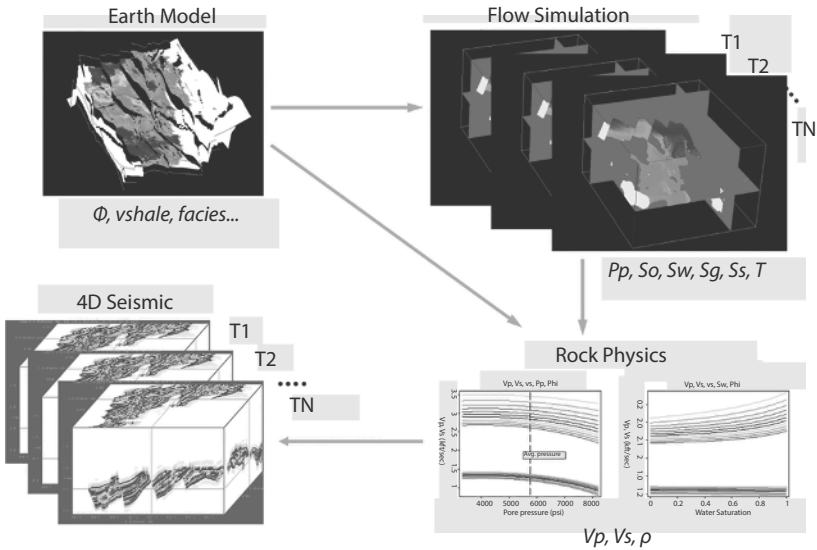


Figure 1.8 The entire process of reservoir model updating through 4D seismic modeling and reservoir simulation, (from Meadows, [11]).

velocities at different time periods. Such information can then be used to generate the synthetic 4D seismic data. Comparison of the synthetic and field 4D seismic data will then lead to an updated Earth model. The process is continuous until we establish a good match between real and simulated seismic and reservoir flow models leading to an acceptable dynamic reservoir characterization results from the accurately derived rock physics properties as well as other reservoir properties such as porosity, permeability, oil and gas saturation, and pressure among other properties.

In what follows we describe rock physics and reservoir modeling briefly.

1.6.1 Rock Physics

Rock physics investigates reservoir rocks properties that affect transmission of seismic waves through the rocks. These physical properties are rigidity, compressibility, and porosity. This provides a connection between elastic properties measured at the surface of the earth, within the borehole environment or in the laboratory with the intrinsic properties of rocks, such as mineralogy, porosity, pore shapes, pore fluids, pore pressures, permeability, viscosity, stresses and overall architecture such as laminations and fractures.

Description of rock and fluid properties between the well control points requires understanding of the linkage of bulk and seismic properties to each other and their changes with geologic age, burial depth, and location. This connection allows us to understand and model the petrophysical and geometrical properties which give rise to the seismic signal. Rock physics requires a knowledge and understanding of geophysics, petrophysics, geomechanics and the causes of distribution of fluids in the subsurface reservoir between wells. From seismic fluid monitoring we can obtain valuable information about reservoir fluid movements and geologic reservoir heterogeneities. The results can also resolve seal integrity issues and guide the optimum placement of wells in complex reservoirs.

Rock physics uses sonic, density and dipole sonic logs to establish a relationship between the geophysical data and the petrophysical properties. In '80s and '90s many oil companies had their own rock physics laboratories. Because of the longer-range objectives and the need to assemble large databases, today such laboratories are found primarily within five or six universities and a few service companies. The focus of rock physics analysis started with estimating porosity and permeability of sandstones and carbonates. Today, much of the research is focused on unconventional reservoirs and on estimating rock strength or "fracability" and the presence of total organic carbon. For some detailed discussion on the value of rock physics analysis in various aspects of reservoir characterization and reservoir property estimation see Dvorkin and Nur [5] and Castagna *et al.* [4].

Integration of 3D seismic interpretation with well measurements provides a powerful tool for characterization a reservoir for the 3D distribution of rock properties and the geometric framework of the reservoir. While the cores, wireline logs and outcrops provide the vertical resolution it is only geophysical data like 3D seismic data that can provide detailed spatial information between the wells for the geological model. Since 3D seismic is a measurement made at the surface of the earth, the subsurface interpretation using seismic data can be done only after proper calibration with available well information. Seismic reflection data provide the gross acoustic properties within a volume of rock and do not have the vertical resolution of wireline logs.

1.6.2 Reservoir Modeling

Quantification of rock properties and the fluids in three dimensions is the process of reservoir modeling. The goal of reservoir modeling and fluid simulation is increased hydrocarbon fluid production with an increased rate of return. The 3D quantification is performed in a geo-cellular model that consists or reservoir geometry, lithology, porosity, permeability and

initial fluid saturation. Integration of information from seismic data, cores, wireline logs and outcrops provide the quantification of the static reservoir model of the reservoir. A geological reservoir characterization is performed using a cellular facies model. Rock properties are assigned to model cells according to the defined facies. The geological models describe the flow layers that account for fluid and displacement phenomenon in the reservoir. It models the inter-well connectivity and continuity of flow units in the rock facies present within the reservoir architecture.

Reservoir fluid simulation is the quantification of fluid flow over time in the 3D reservoir model. The numerical model simulation and forecasts of reservoir performance is based on the geo-cellular static model. Reservoir simulation is performed to infer fluid flow behavior from a mathematical model. The forecast of reservoir performance is improved with increased accuracy in the geological model. Major decisions regarding the development and production plans for the reservoirs e.g., location and spacing of production and injector wells, depletion strategy, maximum production rates are based on the reservoir simulation. As hydrocarbons remaining in place become more difficult to recover, fluid movement in the reservoir needs to be more closely monitored. The location of remaining hydrocarbons must be known to plan injection schemes. Also, the manner in which injected fluids move and make contact with the target oil must be known in order to evaluate and, if necessary, correct the recovery project.

Static reservoir model provides a representation of the structure, thickness, lithology, porosity, initial fluids in the reservoir. As discussed in Section 1.5 on DRC, a dynamic reservoir model is a representation of the changes in fluid flow in the reservoir model that needs to be validated with reservoir performance data-pressure changes, production and injection rates. Rock properties defined in the reservoir rocks from 3D seismic interpretation include: Lithology, Porosity, Net pay thickness (or porosity volume), Fluid type and the respective fluid saturation, as well as the reservoir pressure. The heterogeneity within a petroleum reservoir has a profound influence on its production performance. Structural deformations, fractures, lithological variations, and diagenetic alternations all contribute to the creation or destruction of conduits and barriers to fluid flow through the reservoir matrix. Rock physics is a key component of analyzing the reservoir properties. It is important to monitor changes in the fluid flow or its composition during the producing life of the field. Figure 1.9 illustrates different components of reservoir modeling.

These integrated reservoir models are critical for forecasting, monitoring, and optimizing reservoir performance over the life cycle of the reservoir, from exploration, development, primary production and secondary/tertiary production. They will enable reservoir engineers to more accurately

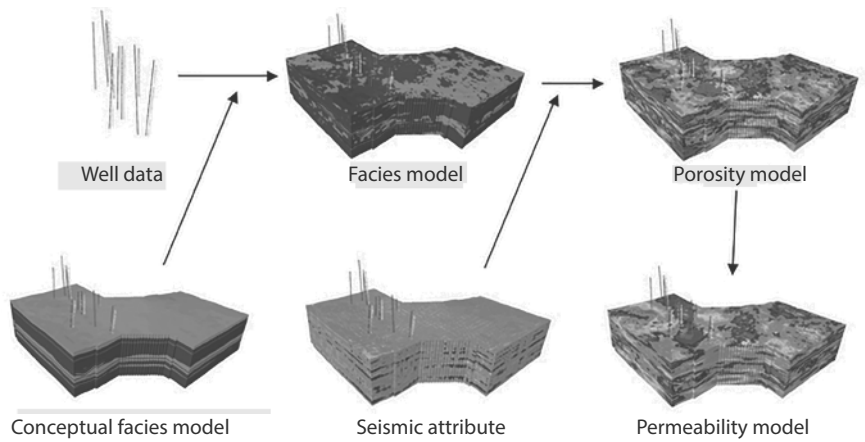


Figure 1.9 Reservoir modeling process workflow. The process takes control of the data within its modeling framework and integrates the various types of data attributes. Courtesy: Roxar-Emerson.

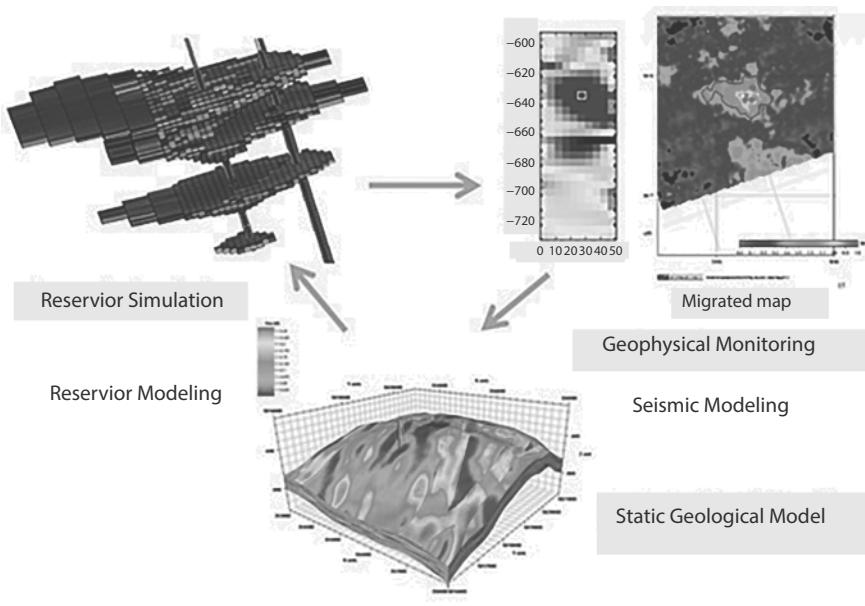


Figure 1.10 Integrated reservoir modeling, fluid simulation update and reiteration by incorporating geophysical monitoring data. <http://www.co2care.org/Sections.aspx?section=538.5>.

perform flow simulation studies, identify permeability flow-paths and barriers, map bypassed oil, and monitor pressure and saturation fronts in the reservoir. All of these are essential for effective reservoir management. Figure 1.10 shows how the original (static) geological or reservoir model based on the integration of geophysical data could be used to for reservoir simulation which in turn it can be used for reservoir monitoring and reservoir model updating.

In Part 7 of this volume, we will discuss Artificial Intelligence (AI) and Data Analytic (DA) can help address some of the remaining complexities associated with reservoir characterization results. For example, Nikravesh and Aminzadeh [12] reported on the past, present and future of AI in reservoir characterization. Twenty years later Aminzadeh [3], discussed how human and machine intelligence can be combined to improve characterization results. It is firmly believed that AI- and DA offer hope solve the issues related to the SURE Challenge discussed earlier.

1.7 Conclusion

Reservoir Characterization Is an important step in the entire life cycle of the reservoir. Reservoir Characterization is aimed at assessing reservoir properties and its condition, using the available data from different sources such as core samples, log data, seismic surveys (3D and 4D) and production data. This is done in different stages of the E&P process from high grading reservoirs in exploration to their delineation, for their development, as well as their description for optimum production to assessing their evolution in their stimulation for enhance oil/gas recovery to extend their economic life. An integrated approach for reservoir characterization bridges the traditional disciplinary divides, leading to better handling of uncertainties and improvement of the reservoir model for field development. Among the main difficulties in reservoir characterization is what I call “SURE” Challenge. The display here demonstrates the complications involved in integrating different data types with different Scale, Uncertainty, Resolution and Environment.

References

1. Aminzadeh, F., 2005, Meta-Attributes: A new concept detecting geologic features and predicting reservoir properties, Second International Congress on Geosciences Merida, Mexico September 2005
2. Aminzadeh, F. and Dasgupta, S., 2013 Geophysics for Petroleum Engineers, Elsevier.

3. Aminzadeh, F., 2021, Reservoir Characterization: Combining Machine Intelligence with Human Intelligence, E&P Plus, April 2021, Vol. 96 Issue 4, E&P Plus, Hart Energy.
4. Castagna, J., Han, D., Batzle, M.L., 1995, *Issues in rock physics and implications for DHI interpretation*, The Leading Edge, August 1995.
5. Dvorkin, J., & Nur, A., 1993, *Dynamic poroelasticity: A unified model with the squirt and the Biot mechanisms*, Geophysics 58, 524-533.
6. Fornel, A. and Estublier, A. 2013. To A Dynamic Update of The Sleipner CO₂ Storage Geological Model Using 4D Seismic Data. Energy Procedia. 37. 4902-4909. 10.1016/j.egypro.2013.06.401.
7. Kosco, K. & Schiøtt, C.R. & Vejbaek, Ole & Herwanger, Jorg & Wold, Rune & Koutsabeloulis, N., 2010, Integrating time-lapse seismic, Reservoir Simulation and Geomechanics. 231. 61-66.
8. Ma, Y. Z., Phillips, D. Gomez, E., 2020 Synergistic Integration of Seismic and Geologic Data for Modeling Petrophysical Properties, The Leading Edge, March 2020.
9. Maity, D., Aminzadeh, F., 2015. Novel Fracture Zone Identifier Attribute Using Geophysical and Well Log Data for Unconventional Reservoirs, Interpretation Journal, Vol.3, No. 3, P.T155-T167.
10. Maleki, M., 2018, Integration of 3D and 4D seismic impedance into the simulation model to improve reservoir characterization. PhD Dissertation, University of Compinas.
11. Meadows, M., 2012, Time-lapse seismic data for reservoir monitoring and characterization Course notes on Advanced Oil Field Operations with Remote Visualization, Guest Lecturer for F. Aminzadeh's course, USC PTE 587.
12. Nikravesh, N. and Aminzadeh, F., 2001, "Past, present and future intelligent reservoir characterization trends," *Journal of Petroleum Science and Engineering*, vol. 31, no. 2, pp. 67-79, 2001.

