URTeC: 336

Estimating Reserves and Tracking the Classification of Reserves and Resources Other than Reserves (ROTR) in Unconventional Reservoirs

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Abstract

The objectives of this paper are to summarize effective Reserves estimation methods for use in unconventional reservoirs, and to propose systematic procedures for classification of Resources other than Reserves (ROTR) volumes. We propose optimal timing for application of decline curve analysis (DCA), rate transient analysis (RTA), and reservoir simulation. Using these techniques, we provide results for one well from a 38-well database in the Permian Basin wells (TX USA). We then describe how the volumes are classified and categorized and how those volumes move between Reserves and ROTR as more information becomes available.

We begin with the analysis of well performance, where we specify the information that is necessary for each estimation method. We then suggest procedures to identify the flow regimes using diagnostic plots, provide guidance on the application of multi-segment DCA models, and finally suggest procedures for the application of RTA and reservoir simulation. We continue with progress toward Reserves classification, starting with suggested procedures to reclassify Prospective Resources as Contingent Resources (upon discovery). We provide post-discovery guidance on development and commerciality for the project maturity sub-classes (within the Contingent Resources classification). We explain that "established technologies" must be technically and economically viable before they can be used for development decisions. And finally, we examine requirements to remove contingencies so that the volumes can be reclassified properly as Reserves.

Our major suggestions for well performance analysis are, first, that the multi-segment DCA approach is most effective in unconventional reservoirs when specifically relevant models are used for transient flow and boundary-dominated flow. Furthermore, we suggest that RTA using analytical models expands possibilities of forecasting for changes in well conditions and for well spacing studies. Though time and computationally time consuming, compositional simulation is required for confident analysis of near-critical reservoir fluids.

For movement of resources toward Reserves , we suggest that there is no linear path to define the movement from Prospective to Contingent Resources, though there are certain criteria which must be met for a given project. Certain contingencies, such as price of oil and available technologies, dominate the classification of resource volumes.

This paper provides a visual representation of when to use each Reserves estimation method depending on available data. We present a thorough analysis of best practices for each Reserves estimation method. We provide graphical representation of the movement between Prospective to Contingent Resources categories, the progression in chance of development and commerciality within project maturity sub-classes for

Contingent Resources, and the contingencies that must be resolved to move from Contingent Resources to Reserves. Finally, we present an explanation of the criteria that must be met before volumes can be reclassified and/or recategorized from undiscovered to discovered.

Introduction

Estimation Methods

Decline curve analysis (DCA) is one of the most frequently used deterministic approaches to forecast future production of a well and can be used once there is enough history to show a well performance trend. DCA is best applied to individual wells rather than to groups of wells or reservoirs. The most common decline model was proposed by Arps (1945), and has three forms: exponential, hyperbolic, and harmonic. The Arps decline models assume a stabilized, unchanging drainage area for a well, which is not the case for many months or years in unconventional low-permeability reservoirs. Wells in these reservoirs have long-duration transient (unstabilized) flow, with drainage area increasing with time. For improved production forecasts in unconventional reservoirs, common practice is to use two-segment Arps models: the first segment for the transient flow period and the second for the stabilized flow period. The long-duration transient flow periods are caused by the ultra-low permeabilities in unconventional reservoirs. The DCA plots are usually semi-log plots of production rate vs. production (not calendar) time. Because the Arps decline model, even with two or more segments, is more empirical than physics-based, there is considerable uncertainty in forecasted results using this model. This uncertainty provides an opportunity to use probabilistic methods to quantify the uncertainty in forecasts with Arps decline models.

Arps decline models include exponential, hyperbolic, and harmonic decline. The models differ in the value of the exponent b in **Eq. 1**.

$$q = \frac{q_i}{\left(1 + bDt\right)^{1/b}} \tag{1}$$

Arps multi-segment DCA can be applied successfully for unconventional wells as long as good judgement and evaluation practice are used.

Rate transient analysis (RTA), also called production analysis, refers "to the use of analytical and numerical models to analyze and model time/rate/pressure. It provides estimates of dynamic formation properties such as permeability, effective fracture half-length, dual-porosity properties, skin factor, and fracture conductivity; and model-based forecasting yields a time-dependent pressure and/or rate forecast. The main objectives of model-based RTA are the following:

- Determine the well and reservoir properties
- Evaluate the completion and stimulation efficiencies
- Forecast the well production
- Assess the uncertainties in both results and production forecast" (SPEE, p. 164).

In RTA, we begin by "analyzing and modeling the performance behavior that is thought to be common for the group, and then extend the results to other wells in the group so that a physical basis can be given to production forecasts" (SPEE, p. 164-165).

Time, rate, and pressure data "are necessary to perform model-based analysis. Proper models need to incorporate bottomhole pressures. In the absence of permanent gauges, surface pressures need to be converted to bottomhole conditions. This adds uncertainty to the interpretation, especially in the case of multiphase flow and artificial lift" (SPEE, p. 165).

Well-completion data are required, "especially the horizontal well length and the number of fracture stages. Additional completion data, such as the amount of proppant and fluid pumped, may be used to refine the analysis. They can be related to model parameters such as effective fracture half-length and conductivity if multiple wells are being analyzed using RTA" (SPEE, p. 165).

Numerical models "may take into account specific items that are a challenge to analytical models and may at least require special transformations. Ultimately, numerical models may be the only solution to integrate the elements below:

- Nonlinearities at multiple scales: stress dependence, desorption, multiphase flow
- Complex PVT behavior
- Complex fractured well and fracture geometry
- Interference between wells
- Unknown drainage area, such as stimulated reservoir volume vs. discrete fracture networks (DFN)
- Very low permeability providing very long transients" (SPEE, p. 167).

The IHS Markit software *Harmony* provides analytical simulation of RTA. This software also has the capability of performing RTA probabilistically which will provide the P90, P50, and P10 results. RTA is usually based on analytical solutions of the diffusivity equation (Wright, 2015). However another form of RTA is the Fetkovich type curve, which combines analytical solutions for radial transient flow with the Arps decline equations and is plotted on a dimensionless log-log graph from which the initial flow rate, decline rate and Arps *b*-factor are obtained (Wright, 2015).

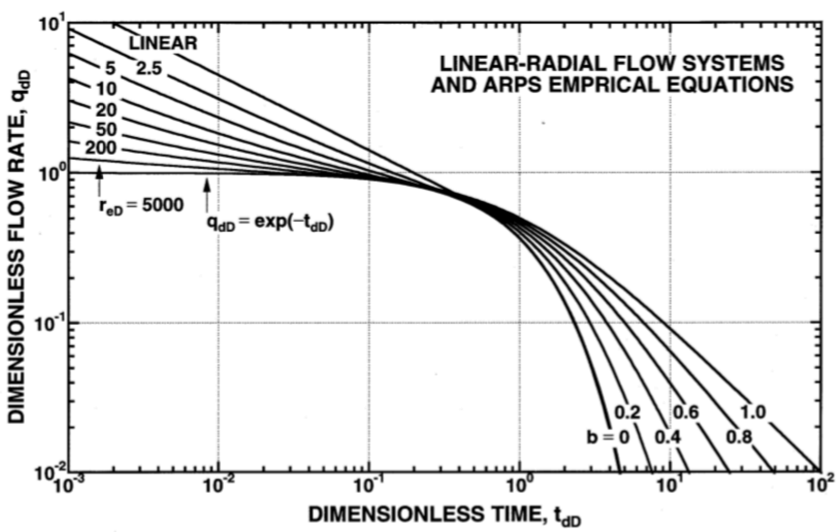

Fig. 1 — Chen *et al.* present the modified Fetkovich curve to include linear flow systems. This type curve can be used for unconventional reservoirs developed with hydraulically fractured wells because it includes linear flow, whereas the original Fetkovich type curve includes only solutions for radial transient flow (Chen *et al.,* 2000)

The modified Fetkovich type curve presented in **Fig. 1** has a half-slope transient stem that can used to estimate volumes in hydraulically fractured wells, either vertical or horizontal.

Reservoir simulation, a complex engineering tool, is used to obtain Reserves estimates though this may not be its primary purpose. A reservoir simulator "represents the reservoir as a number of cells, all interconnected" (Wright, 2015). The cells required in simulation can be arranged into one, two or three dimensions. The size of each cell depends on the complexity of the model created and can be as small or as large as desired. The smaller the cell size, the more complex the model and the more computationally intensive the process.

The input data to the simulator must describe the unique characteristics of that reservoir. This analysis requires several input parameters (unlike the methods discussed previously that require only a limited number of parameters in their equations), including permeability (*x-y-z*), porosity, net-pay thickness, elevation, initial pressure and initial fluid saturations. Furthermore, each region may have different fluid characteristics; therefore, the data input into the simulator for each region includes formation volume factors for the fluids present in the reservoir, viscosities of fluids present, the solution gas-oil ratio and the fluid densities. The rock properties are input by region, and include the relative permeabilities of the fluids present, capillary pressures, and pore-volume compressibilities. Finally, we describe wells using location, producing interval, production history of fluids present, bottomhole flowing pressure and productivity index.

Once the data is input into the simulator, the parameters are adjusted during history matching of the pressure-production of the wells. The advantages of this method include prediction of production from individual wells and visualization of the production scheme once the history match has been achieved. However, these methods involve high cost and a high uncertainty when assumptions are made to obtain a match. A unique match is difficult to achieve and sometimes historical production is matched with physically unreasonable models. The best history match is usually considered to be a 2P Reserves estimate; with a more conservative hydrocarbon volume in place and perhaps some additional geological complexity, the result can be a 1P estimate, and with generous reservoir description, the results can be 3P estimates. 2P estimates can be regarded as objective determinations; 1P and 3P are more subjective.

A more complete discussion of numerical and analytical reservoir simulation methods is provided in SPEE Monograph 4 (2016).

Once we have volume estimates, it is important to understand how these volumes are classified according to the Petroleum Resources Management System (PRMS).

<u>Resources Classification</u>

PRMS provides a framework for classifying petroleum volumes as Reserves, Contingent Resources, or Prospective Resources. These classifications are defined as described below:

<u>Reserves</u> are "those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of a given date) based on the development project(s) applied" (PRMS, p. 49).

Reserves are placed in three categories:

- 1P (Proved Reserves) represents the low estimate of Reserves, or P90 in a probabilistic Reserves estimation
- 2P (Proved plus Probable Reserves) represents the best estimate of Reserves, or P50 in a probabilistic analysis
- 3P (Proved plus Probable plus Possible Reserves) represents the high estimate of Reserves, or P10 in a probabilistic analysis.

The incremental volumes are:

- P1 = 1P = Proved Reserves
- P2 = Probable Reserves = 2P-1P
- P3 = Possible Reserves = 3P-2P

<u>Contingent Resources</u> are defined as "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies" (PRMS, p. 39).

Contingent Resources are separated into three categories:

- 1C denotes the "low estimate of Contingent Resources"
- 2C denotes the "best estimate of Contingent Resources"
- 3C denotes the "high estimate scenario of Contingent Resources" (PRMS, p. 38).

Prospective Resources are defined as "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects" (PRMS, p. 47).

Prospective Resources are also separated into three categories:

- 1U denotes the "unrisked low estimate qualifying as Prospective Resources"
- 2U denotes the "unrisked best estimate qualifying as Prospective Resources"
- 3U denotes the "unrisked best estimate qualifying as Prospective Resources" (PRMS, p. 38).

The PRMS document (SPE, 2018) has created a resources classification framework that presents how these volumes are related (**Fig. 2**).

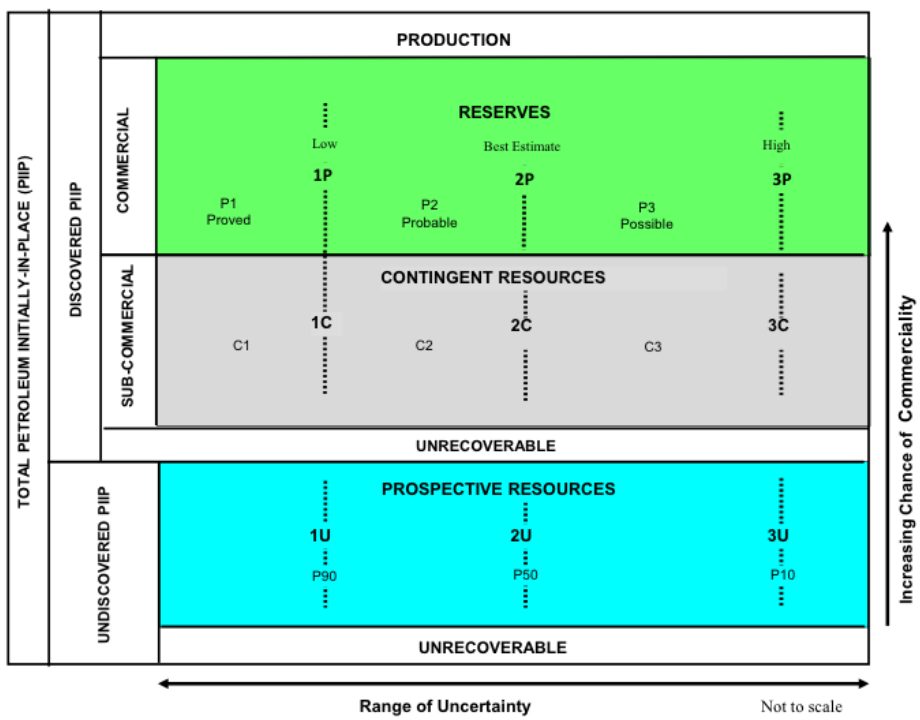

Fig. 2 — The PRMS resources classification system which includes the major petroleum resources classes: Production, Reserves, Contingent Resources, Prospective Resources, and Unrecoverable Petroleum (PRMS, p. 5).

"Orientation to the Matrix for the PRMS resources classification system:

- The x-axis of this matrix indicates the Range of Uncertainty, which is the 'range of estimated quantities potentially recoverable from an accumulation' (PRMS, p. 5). The greatest uncertainty is at the right of the matrix, and the least uncertainty is at the left of the matrix.
- The right y-axis is the Chance of Commerciality, 'that is the chance that the project that will be developed and reach commercial producing status' (PRMS, p. 5). This is defined mathematically as

$$\textit{Chance of Commerciality} = \textit{Chance of Discovery} \times \textit{Chance of Development} \qquad \textbf{(2)}$$

- The left y-axis describes the total petroleum initially in place (PIIP) in an accumulation. Depending on the commercial maturity of the project used or planned to recover the resources, the petroleum is placed into appropriate classes:

  — Reserves = Commercially recoverable discovered PIIP
  — Contingent Resources = Sub-commercial discovered PIIP
  — Prospective Resources = Undiscovered PIIP" (Moridis *et al*., 2019).

The ordering of resources follows the progression in **Fig. 3**:

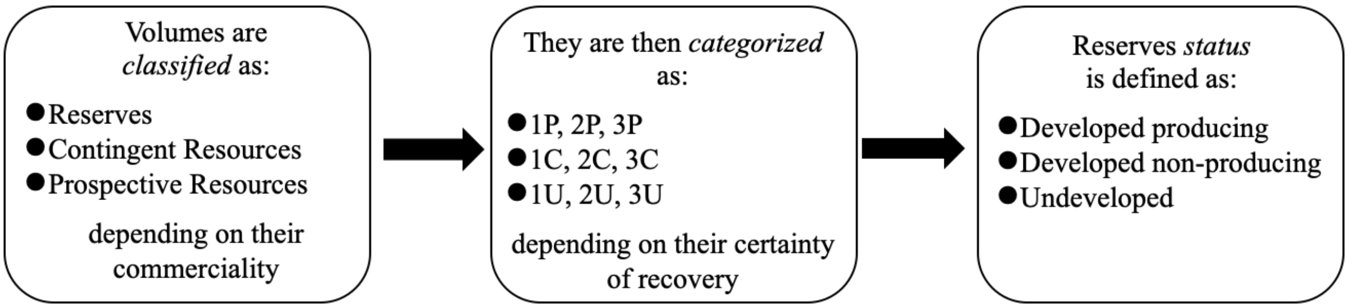

Fig. 3 — The Resources ordering workflow from *classification*, to *categorization,* to Reserves *status*. This workflow identifies *class*, *category*, and *status* within the PRMS matrix (Moridis *et al.*, 2019).

"PRMS uses these terms *classify* and *categorize* when placing resources into inventory. As Fig. 3 indicates, classification depends on the chance of commerciality, and categorization depends on the certainty of recovery. We can then sub-classify resources within a given class based on the differences in their chance of commerciality" (Moridis *et al.*, 2019). SPE 195298 presents the PRMS sub-classes graph and table of sub-class definitions, and the graphic can also be found on page 11 of the PRMS (2018) document.

This paper discusses how to implement different estimation methods based on available data, and how these volumes are placed into classes and how their chance of commerciality influences their classification. Although we focus our efforts on the inventorying of unconventional resources, the proposed methodology can be applied to conventional resources as well.

Methods

Our overall goals are to describe when to use DCA, RTA, and reservoir simulation based on available data in unconventional reservoirs, and how to properly implement a two-segment DCA in unconventional reservoirs. Given that a play has been identified, we summarize the proper order of movements of volumes within the PRMS matrix between ROTR and Reserves, presented in SPE 195298. "These movements are based on changing uncertainty and commerciality, and do not necessarily move directly from one class and/or one category to another through the matrix. We began with the updated PRMS (2018) and COGEH documents (2018) for the current definitions" (Moridis *et al.*, 2019).

Implementing the proper estimation method in unconventional reservoirs can be challenging. As previously discussed each estimation method requires different data and different time requirements. To assist in determining which estimation method is best for your current project/field/time availability, we present the following outline:

- We present the data needed to run each estimation method. As previously mentioned, DCA requires only production rates and time, whereas RTA and reservoir simulation require significantly more data and analysis time.
- We present a workflow which describes when to use each estimation method based on the data available. Though we present this for unconventional reservoirs, the same workflow can be used for conventional reservoirs.
- We present the steps required to identify flow regimes from diagnostic plots, followed by the steps to implement a two-segment DCA to unconventional wells. We include a workflow that shows the three possible outcomes from the diagnostic plots, and the steps to take depending on the flow regimes identified.
- We suggest procedures for best practices for the application of RTA and reservoir simulation. Probabilistic RTA analysis can be implemented in, for example, IHS Harmony. Reservoirs with near-critical fluids require compositional simulation for greatest accuracy, but these models are complex to build and are both computationally and time consuming.

As presented by Moridis *et al.* (2019), the movement from ROTR to Reserves does not necessarily follow a direct path from one class to another. We identify what can cause change and what the change means when classifying Reserves and ROTR. This includes developing a workflow for event-based triggers that drive movements through the matrix and cause reclassification.

The workflow can be outlined as follows:

- We describe the steps necessary to move through Prospective Resources before we can begin moving into the sub-classes of Contingent Resources. We then describe the criteria for Prospective Resources to become discovered, moving these volumes to Contingent Resources.
- We describe the progression, following discovery and classification as Contingent Resources, in chance of development and commerciality within the project maturity sub-classes of Contingent Resources.
- We then describe the criteria for a technology to become established (as defined by PRMS and COGEH), and explain that these technologies must be technically reliable and economic before they can be used for development decisions.
- Finally, we describe the contingencies and the movement through each contingency for the volumes to move to Reserves.

Discussion of Estimation Methods

To answer the question of when and how to apply DCA, RTA, and reservoir simulation in unconventional reservoirs, we divide our presentation into four parts:

1. Requirements of each estimation method based on available data.
2. Steps to identify flow regimes using diagnostic plots and the to build multi-segment DCA models.
3. Suggested practices for applying RTA and reservoir simulation in unconventional reservoirs

Step 1 — When to use each estimation method based on available data

Table 1 presents a summary of the data required for DCA, RTA, and reservoir simulation.

Table 1— Data Required to Run Each Estimation Method (Wright, 2015; SPEE, 2016)

Estimation Method	Data Needed
Decline Curve Analysis (DCA)	Time Production rate (oil, gas)
Rate Transient Analysis (RTA)	Time Production rate (oil, gas) Pressure PVT properties Static reservoir properties Well length (heel to toe) Distance between perforations Number of fracture stages
Reservoir Simulation	Permeability Porosity Net-pay thickness Elevation Initial pressure Initial fluid saturations Formation volume factors Viscosity Solution gas-oil ratio Fluid densities Rock properties Relative permeabilities Capillary pressures Pore-volume compressibilities Well location Producing interval Production history of fluids present Bottomhole pressure and productivity index Perforated lateral length Stage spacing

It is clear from the table above that DCA is the fastest estimation method and requires the least amount of data. DCA does not require any specialized or commercial software. It can be performed using a simple spreadsheet, which is currently the best method for analysis of unconventional reservoirs. RTA requires more data and takes more time to build the model. There are several commercial software packages available to run RTA. Finally, reservoir simulation requires the most data and the most time.

Fig. 4 identifies the estimation method to use depending on available data and time constraints.

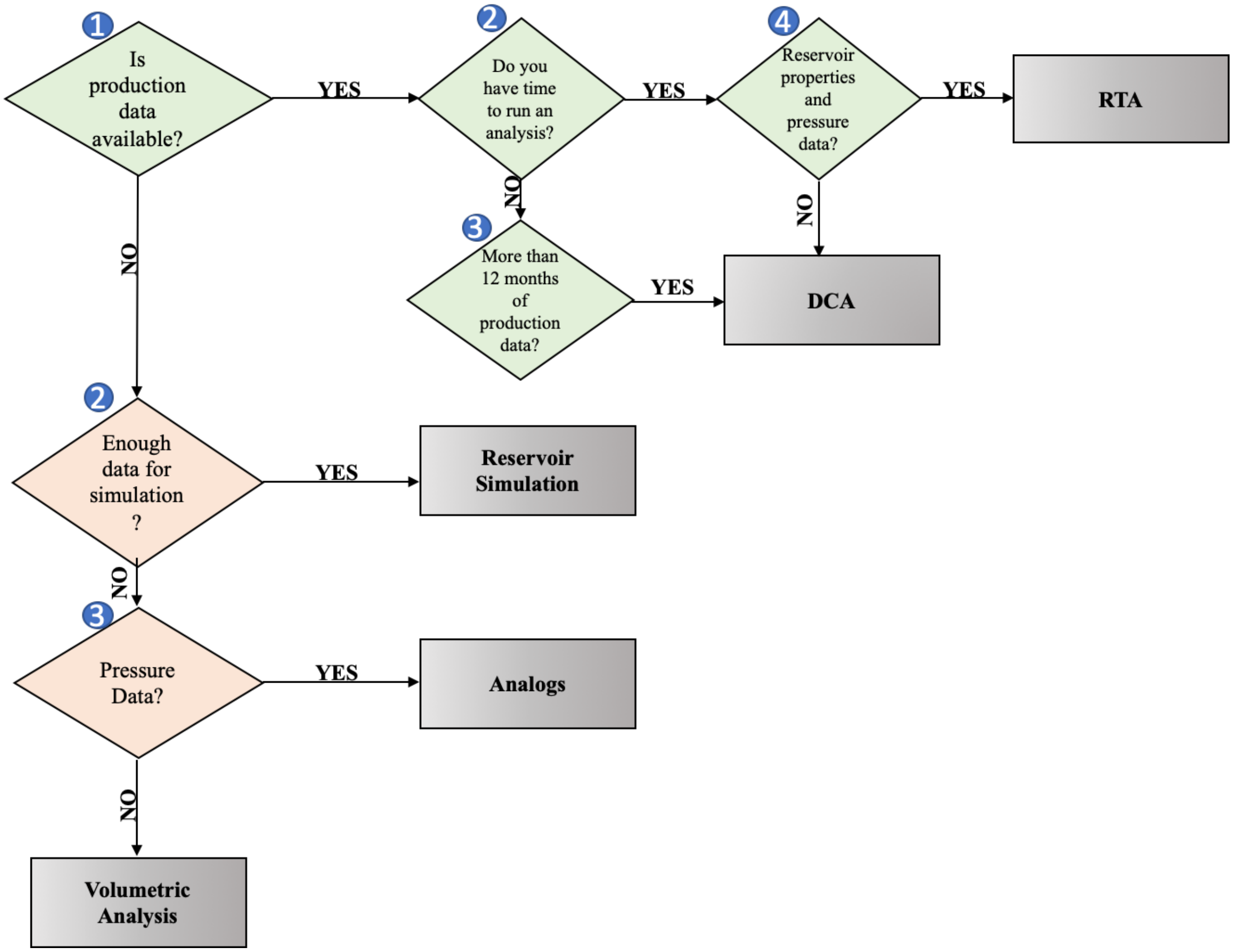

Fig. 4 — A visual representation of when to use the different estimation methods based on available data. DCA and RTA can be implemented if ample production data is available. If not, is there enough data to implement reservoir simulation modeling? If there is not, we determine whether there is pressure data available to implement either a material balance or apply an analog. Finally, type wells can be used or volumetric analysis is a possibility. volumetric analysis can be used in the development stage of the project when there is little information available.

To analyze this workflow, we begin at green node 1, where we ask if production data is available. The two possible outcomes are:

1. Yes (green node 2), production data is available, and we move to green node 3, which asks if we have time to run an analysis. The two possible outcomes are:
   i. Yes (green node 4), where we ask if we have reservoir property and pressure data available. The two possible options are:
      — Yes, and implement RTA
      — No, and implement DCA
   ii. No (green node 3), where we ask if more than twelve months of production data is available. The possible outcomes are:
      — Yes, and implement DCA
      — No, so we recommend using analogy

2. No (orange node 2), no production data is available but we ask if we have enough data for simulation. The two possible outcomes are:
   i. Yes, and implement reservoir simulation
   ii. No (orange node 3), where we ask if pressure data is available. The possible outcomes are:
      — Yes, so use analogs
      — No, so use type wells (aka "type curves")

Step 2 – Identifying flow regimes to build multi-segment DCA models

When implementing DCA in unconventional reservoirs, it is important to first identify the flow regimes. We do this by identifying negative unit and half slopes on a diagnostic plot. The steps to do this are presented in **Fig. 5.**

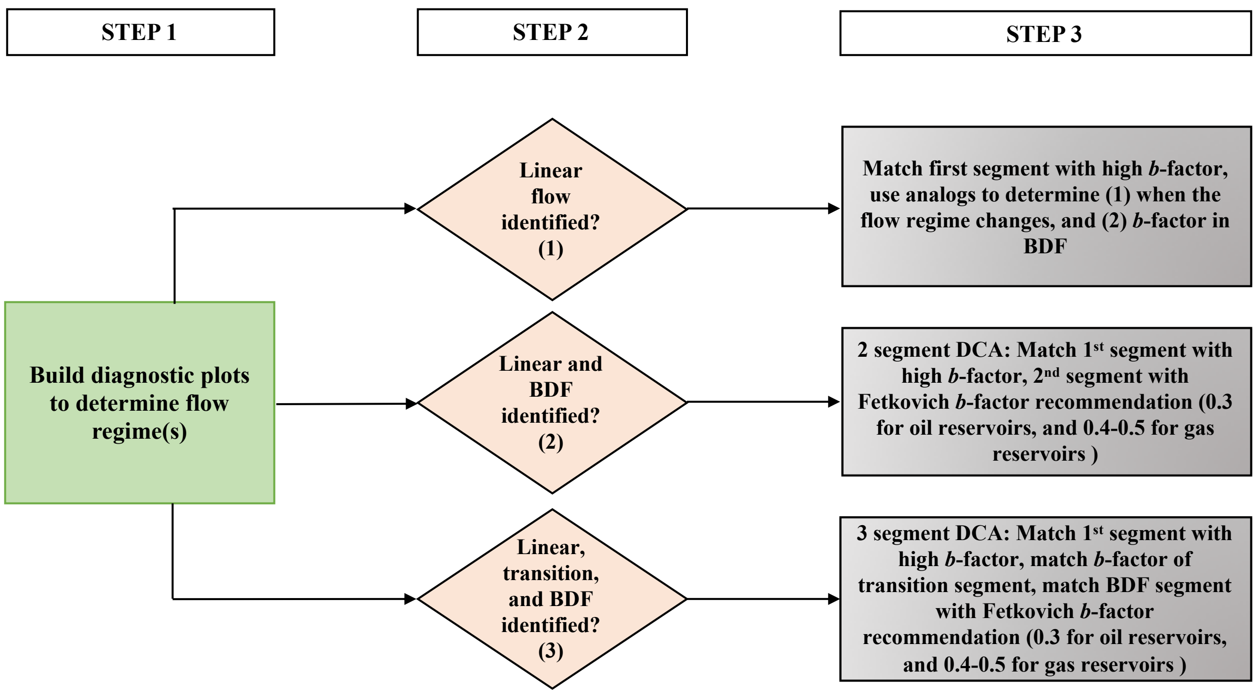

Fig. 5 — The steps to run DCA analysis in unconventional reservoirs. We begin with building diagnostic plots to determine the flow regimes in each production history, and then implement the 2- or 3-segment DCA

As Fig. 5 indicates, to implement DCA in unconventional reservoirs, we must first determine the flow regimes. There are three possible outcomes when building the diagnostic plots. The first is that only linear (or near-linear) flow is identified, meaning that the well has not been on production long enough to reach boundary dominated flow (BDF). Because we do not know when the well will reach BDF, we recommend using analog wells in this case. (We might switch to BDF at a minimum decline rate, D_{min}, determined from analog wells.) The second is that we identify two flow regimes; linear (or near-linear flow by a slope near -1/2, and BDF by a negative unit slope. The third is that we identify three flow regimes; (near-) linear flow and BDF at early and late times, respectively, and a transitional region between the two other flow regimes.

In **Fig. 6** we present the diagnostic plot for Well 3-14 17H in the Permian Basin (TX), which is a log-log plot of the production data against the material balance (MB) time (**Eq. 3**).

$$MBT = \frac{Q}{q} \quad \textbf{(3)}$$

where,

MBT = Material Balance Time

Q = cumulative production

q = flow rate

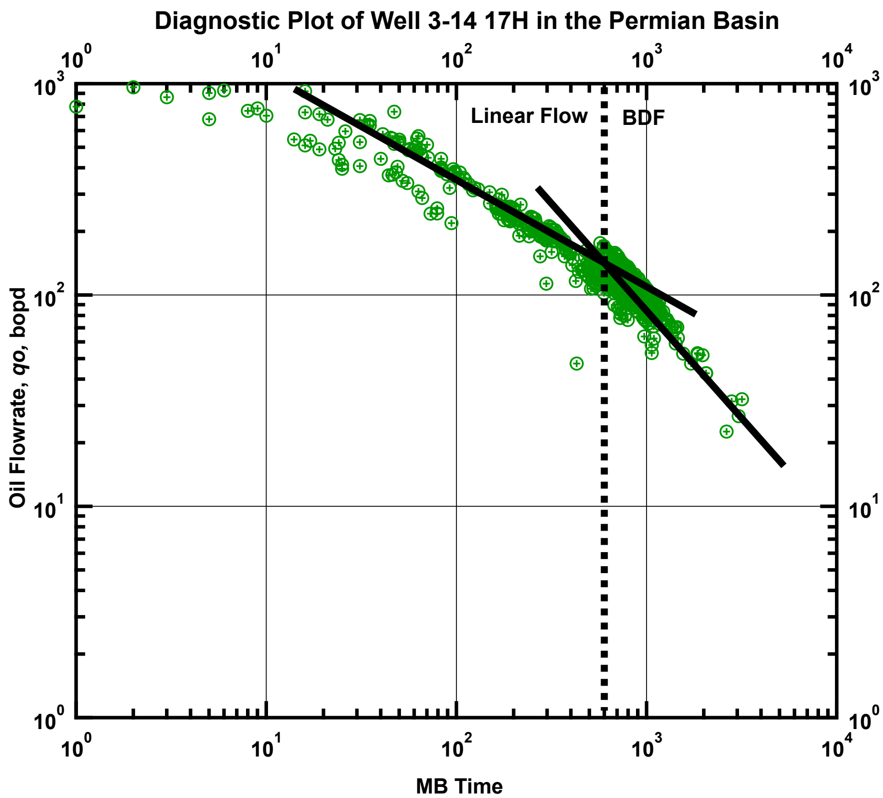

Fig. 6 — Diagnostic plot of Well 3-14 17H in the Permian Basin (TX) shows two flow regimes and the time when the drainage boundary is felt (probably interference between adjacent hydraulic fractures), indicated by the dashed line. As expected, linear flow is identified by the negative half slope on the left side of the graph and BDF is identified by the negative unit slope on the right side of the graph.

In Fig. 6, we first identify the flow regimes by identifying the –½ slope representative of transient linear flow, and the negative unit slope representative of BDF. If the slope is not exactly -1/2, we can still call the flow regime "linear," although is not "ideal" linear flow. The dashed line indicates the transition between the two flow regimes. It is possible that liquid loading will cause data to fall on the unit slope line so we cannot immediately assume that the well has reached BDF. Earliest data typically fall on a trend below the half-slope line; the cause is fracture-fluid clean-up and choked flow in most cases.

Once we have identified the flow regimes, we can clean up the data and remove the early-time outliers. To implement the two-segment DCA, we first match the linear flow where we expect the *b*-factor to be greater than 1 and in BDF to be between 0.3 and 0.5 (Fetkovich, 1987). For Well 3-14 17H, , the *b*-factor in near-linear flow is 1.9 (it would be exactly 2.0 in ideal transient linear flow), and 0.3 in BDF, as presented in **Fig. 7**.

For this work, we set the economic limit (EL) to a flowrate of 5 bopd, which gives an EUR of 400 Mbbls. This analysis is deterministic and these results are best described as the best estimate, or 2P Reserves.

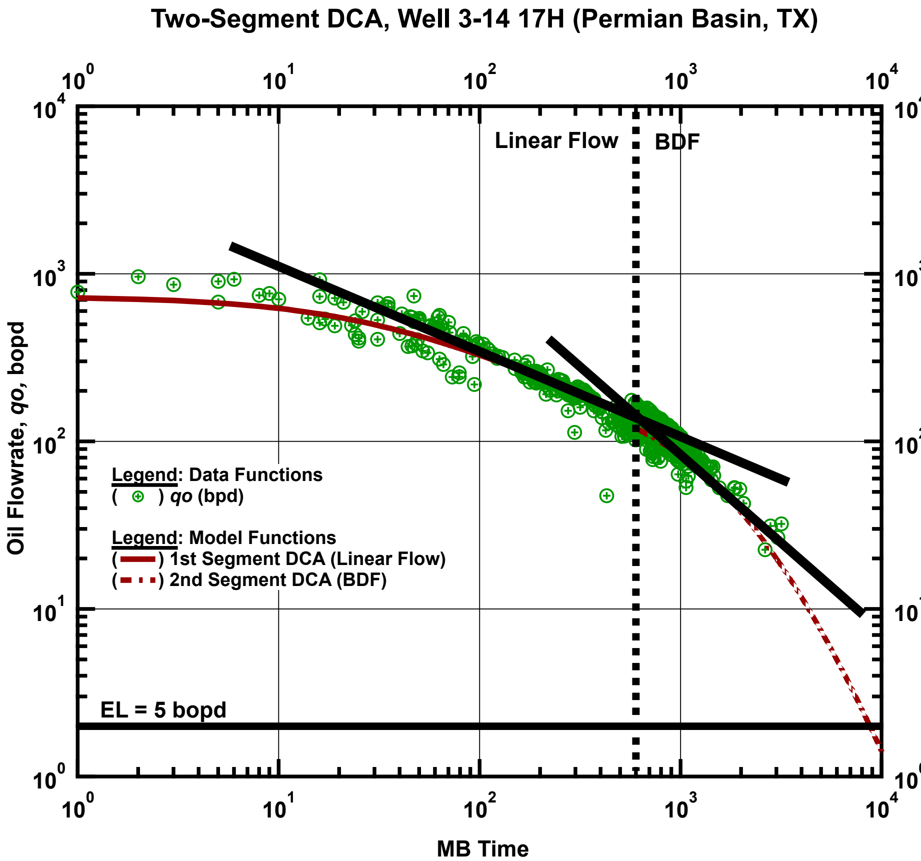

Fig. 7 — Two-segment DCA of Well 3-14 17H in the Permian Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line (as in Fig. 6). We see that in linear flow, the *b*-factor is 1.9 and in BDF it is 0.3.

The multi-segment DCA approach is most effective in unconventional reservoirs when specifically relevant models are used for transient flow and BDF. This methodology can be implemented in any unconventional reservoir and we recommend it because it leads to forecasts of ultimate recovery that are reasonably accurate in most cases.

Step 3 — Best practices for RTA and reservoir simulation in unconventional reservoirs

RTA

RTA using analytical models expands possibilities of forecasting for changes in well conditions and for well spacing studies. RTA can be implemented when there is ample production, pressure, and reservoir characterization data, but it takes considerably more time to run RTA than it does to run DCA. If you have the time, this method is preferred to DCA.

If using IHS *Harmony*, we input the oil, gas, and water production, along with the wellhead and calculated bottomhole pressures (BHP). We recommend implementing either Blasingame's type curve or the multifracture composite analytical model. We obtain the EUR's from either. Blasingame's type curve also provides permeability estimates that are then used when running the compositional multifracture model. We can run a probabilistic model once we have completed the multifracture composite model.

Reservoir Simulation

SPEE (2016) provides an in-depth presentation on the application of numerical methods (Chapter 8). Two types of reservoir simulation are especially useful: black oil simulation and compositional simulation. Compositional simulation is used for reservoirs with near-critical fluids (highly volatile oil, and liquid rich gas condensates) because it is potentially more accurate, whereas black oil simulators are used when modeling black oil or dry gas fields. SPEE presents a six-step process to implement reservoir simulation, from which we can determine EURs in unconventional reservoirs that "produce a range of physically possible EUR values that are based purely on first principles that do not depend on curve-fitting, pattern recognition, or the large list of limiting assumptions associated with DCA-based and RTA-based production data analysis methods" (SPEE, p. 195).

Discussions of Workflows for Reserves Classification (from SPE 195298)

This material is presented more fully in SPE 195298 (Moridis *et al.*, 2019). We present the workflows and a summary of each of the four steps in the following section.

Step 1 — Define movements for undiscovered Resources to become discovered

This first step involves moving the volumes from undiscovered to discovered, summarized in **Fig. 8**. The elements in the discovery process are numbered from one to three in Fig. 8.

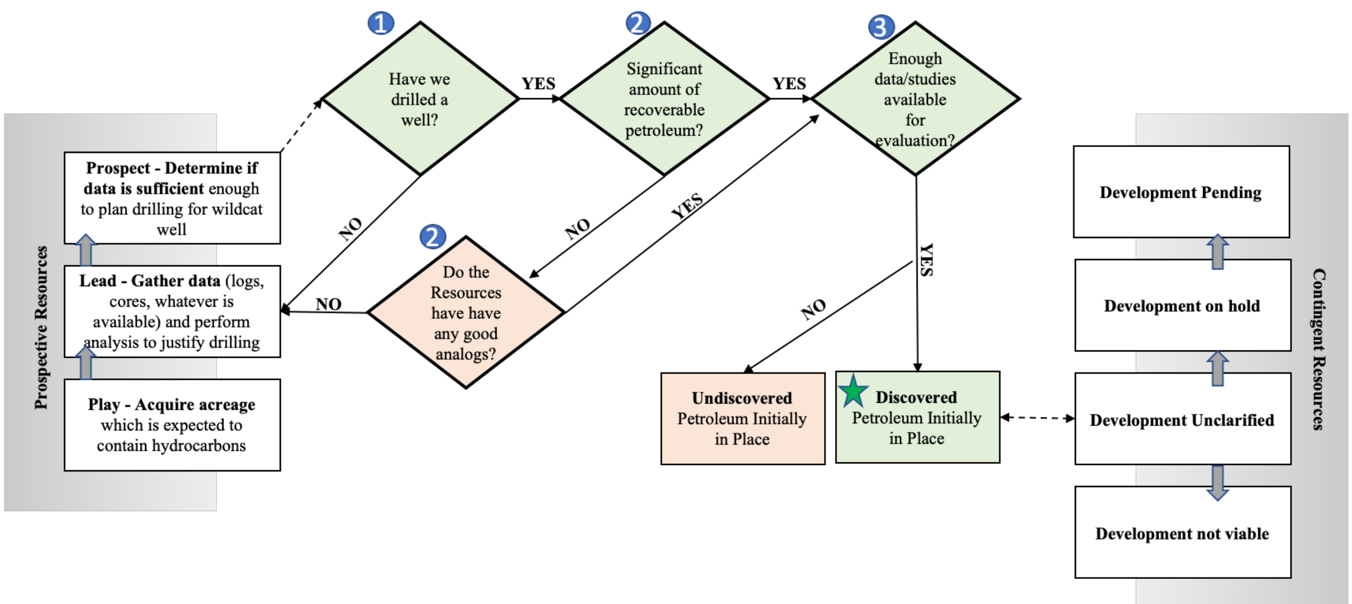

Fig. 8 — A visual representation of a process that can be used to move from "undiscovered Resources" to "discovered." We show how the undiscovered Resources are characterized as chance of discovery increases. Each step in the discovery process is labeled (1-3), eventually reaching a point where we determine whether the resources remain undiscovered or move to discovered. (Moridis *et al.*, 2019)

At the Prospect stage, we proceed to either drill a well or not. If we drill, we can proceed with the workflow, but until we drill we have Prospective Resources.

Once we drill, we move to green node 2: is enough potentially recoverable petroleum present to justify evaluation of a project to recover the petroleum? The three possible outcomes are:

1. No (orange node 2), and the Resources have no good analogs, but we have identified specific drilling locations, the sub-class remains Prospect, and we can go through the workflow again.
2. No (orange node 2), but analogs support further investigation, so we move to green node 3.
3. Yes, and move to green node 3.

At green node 3: is there are enough data and enough studies so that we can properly evaluate the acreage? The two possible outcomes at this node are:

1. No, and the Resources volume remains undiscovered.
2. Yes, the Resources volume is discovered, and are now sub-classified as "development unclarified" Contingent Resources.

We now progress through the project maturity sub-classes of the Contingent Resources classification.

Step 2 — Define progression in chance of development/commerciality within project maturity sub-classes within the Contingent Resources classification.

This step defines progression through criteria which must be met and work which must be performed within each sub-class of the Contingent Resources classification and how the outcome of those decisions affect the chance of development for given Resources. The flowchart for this work is presented in **Fig. 9**.

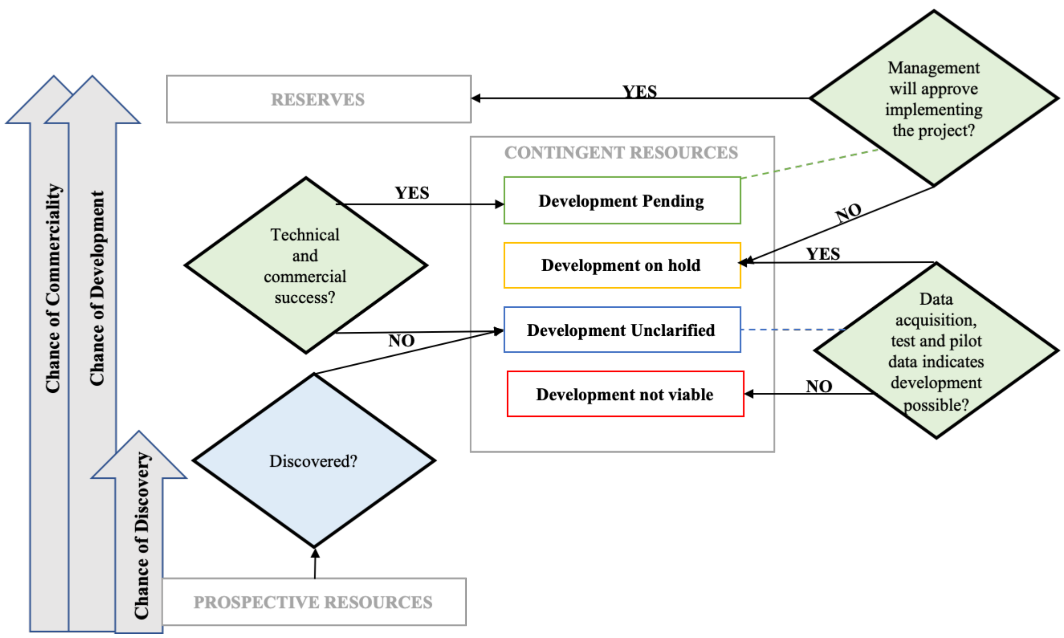

Fig. 9 — A visual representation of progression of the chance of development/commerciality within the project maturity sub-classes of the Contingent Resources classification. This graphic shows the decisions that are made and the work done with each sub-class and how the outcome of those decisions affect the chance of development for given Resources (Moridis *et al.*, 2019)

Starting with this workflow, we have established that Prospective Resources are discovered, and have progressed to the "development unclarified" sub-class of Contingent Resources, presented with the blue node in **Fig. 9**.

We move to the green node: data acquisition, test and pilot data indicates if development is possible? There are two possible outcomes at this node:

1. No, and the Resources move to the "development not viable" sub-class in the Contingent Resources class
2. Yes, and the Resources move to the "development on hold" sub-class in the Contingent Resources class

As the chance of commerciality and development increase, we move to the green node on the left-hand side of the workflow: is there is technical and commercial success? There are two possible outcomes at this node:

1. No (technical and commercial success are not achieved), and the Resources are sub-classified as "development unclarified" in the Contingent Resources class, which moves to the same node as in the first step of this analysis: is development possible? There are two possible outcomes at this node:
   i. No (development is not possible), and the Resources move to the "development not viable" sub-class in the Contingent Resources class
   ii. Yes (development is possible), and the Resources move to the "development on hold" sub-class in the Contingent Resources class
2. Yes (technical and commercial success are achieved), and the Resources are sub-classified as "development pending" in the Contingent Resources class because there is reasonable expectation of technical and commercial success, and moves to the final green node of the workflow

We move to the top green node on the right-hand side of the workflow which asks: can we validate whether there is a good chance that management will approve implementing the project? There are two possible outcomes at this node:

1. No (project does not receive management approval to proceed), and the Resources are sub-classified as "development on hold" in the Contingent Resources class
2. Yes (project does receive management approval to proceed), and the Resources are now classified as Reserves

We can now proceed to describing the elements of a pilot or field testing stage of a technology, and the criteria that must be met to progress the technology to "established technology" status.

Step 3 — Describe the elements of a pilot/field testing stage of a technology, and the criteria required for the technology to progress further to become an "established technology."

PRMS (2018) defines *established technology* as "methods of recovery or processing that have proved to be successful in commercial applications" (PRMS, p. 42). *If neither existing technology nor technology currently under development can be used to evaluate the Resources, then the volumes must be classified as unrecoverable.*

The technology development process is shown in **Fig. 10**. We consider new technology as "experimental technology." Experimental technology must prove that it can repeatedly produce successful results, and do so economically. If the failure rate of technology is low, it may then be considered to be "established technology." To be considered an established technology, it must prove to be reliable, and economic, throughout the stages of its development.

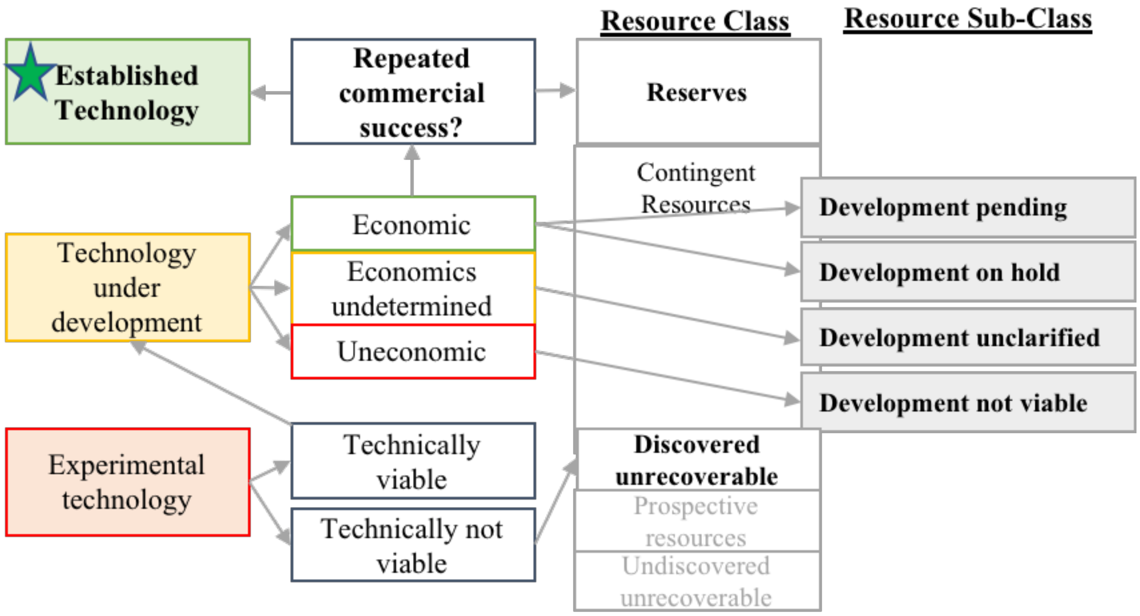

Fig. 10 — Visual representation of the elements of a pilot/field testing stage of a technology, and the criteria required to progress further to becoming an "established technology." The technology being tested needs to be both *technically reliable* and *economic* before it can be used to make development decisions (Moridis *et al.*, 2019).

We begin with an "experimental technology," shown in the red node on the left-hand side of the diagram, which has two possible outcomes:

1. Technically not viable — so the volumes are discovered unrecoverable
2. Technically viable — leads to the next node of technology under development (yellow node)

Once we have established that the technology is under development, there are three possible outcomes:

1. Uneconomic, which is classified as Contingent Resources, and sub-classified as "development not viable"
2. Economics undetermined, which is classified as Contingent Resources, and sub-classified as "development unclarified"
3. Economic, which is classified as Contingent Resources, and can be sub-classified as either "development on hold" or "development pending," depending on its commerciality

Once the proposed technology has proved to be economic, *we must establish that it has had repeated commercial success*. Once this is established, it becomes an established technology, and the Resources evaluated can now be classified as Reserves.

For a technology to become an "established technology," it must succeed in both laboratory testing and field testing. The laboratory testing is usually performed at a smaller scale as the technology is still in its theoretical stage. The field (or pilot) testing is done at a much larger scale once the laboratory testing has proved that the technology is repeatedly successful and economic.

If the technology contingency is the only contingency for a given project, once that technology is established, the volumes for that project can be classified as Reserves. In **Step 4**, the contingencies that must be overcome to classify the volumes as Reserves are elaborated.

Step 4 — Define the different contingencies and the movement through each contingency. This may not be the order of movement for each project, but it does include all contingencies.

How we manage uncertainty is unknown, but we do know that we have to categorize movement from Contingent Resources to Reserves, which depends on the *type of contingency*. The proper/optimal order will differ from case to case, but there are certain contingencies, specifically price and available technology (see **Step 3**), that will dominate the process. Those contingencies that must be met before moving to Reserves are shown in **Fig. 11.**

We will refer to volumes moving from Contingent Resources to Reserves as a *promotion*, and volumes moving from Reserves to Contingent Resources a *demotion*. Several factors can cause a promotion or a demotion between classes, between Reserves and ROTR. These contingencies can be overcome in groups or one-by-one.

The main contingencies to overcome are:

- Economic
- Production
- Drilling extensions
- Infill drilling
- Improved recovery
- Technical revisions
- Discoveries
- Acquisitions
- Dispositions

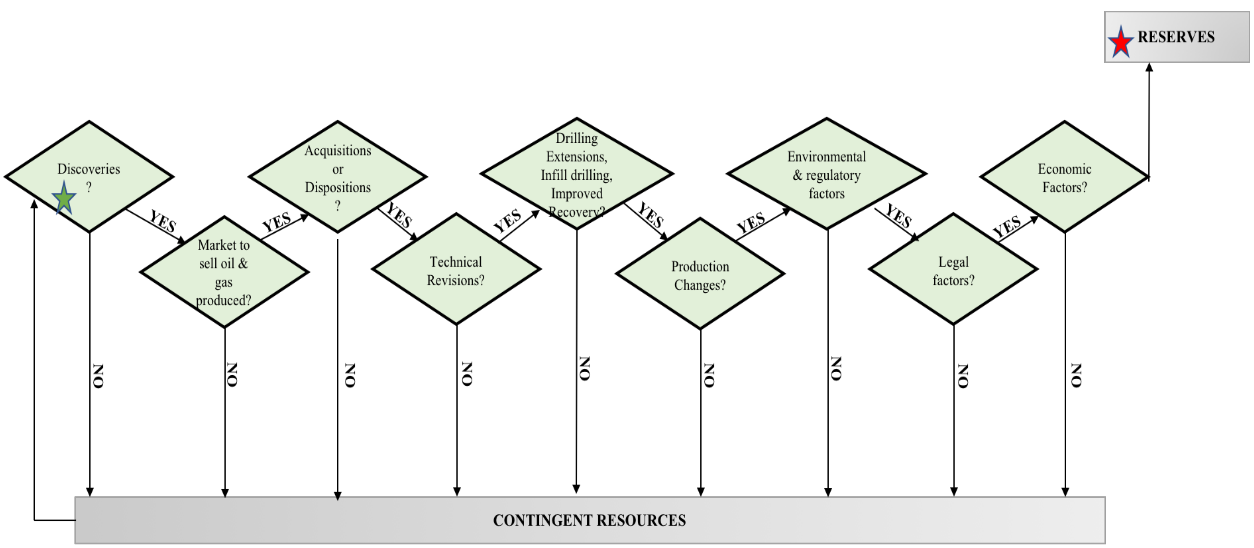

Fig. 11 — This graphic illustrates the different contingencies and the movement path through each contingency. This specific "path map" may not represent the exact order of movement for any given project, but it does present all the contingencies identified in the PRMS and COEGH documents (Moridis *et al*., 2019).

Other requirements for commerciality include funding being made available, management approving the project, and that the project has reasonable time-frame for development.

As previously discussed, the economic contingency is the most important — if this contingency cannot be met, none of the other contingencies matter. The second essential contingency technology (as discussed in **Step 3**). The third contingency that is of importance is the production contingency — production may not cause a direct promotion or demotion between classes of recovery estimates — however, produced volumes do directly impact the quantity of volumes inventoried.

Summary and Conclusions

Summary

This paper provides a high-level analysis of best practices for each Reserves estimation method. This includes an example of how to identify the flow regimes from a diagnostic plot and how to implement a two-segment DCA. We also explore appropriate ways to implement RTA in unconventional reservoirs, and we explore why compositional simulation is required for reservoirs containing near-critical fluids.

The paper also provides a graphical representation of the movement between Prospective and Contingent Resources categories (Fig. 8), the progression in the chance of development and commerciality within project maturity sub-classes for Contingent Resources (Fig. 9), of the steps required for a technology to become established (Fig. 10), and the contingencies that must be resolved to move from Contingent Resources to Reserves (Fig. 11). We also explain the criteria that must be met before volumes can be reclassified and/or recategorized from undiscovered to discovered.

The paper enables the reader to understand how volumes move from undiscovered at the beginning of a project and how those volumes move to become discovered and finally Reserves. When evaluating Reserves in unconventional reservoirs, it is important to understand how to estimate the volumes with adequate accuracy. We only present a deterministic approach to the two-segment DCA, meaning that we present the "best fit," 2P Reserves for Well 3-14 17H. The "low estimate," 1P Reserves, and "high estimate,"3P Reserves can also be determined with higher and lower values for the b-factor and decline rate.

We often build a reservoir simulation model early in the evaluation process. This means that the field may not necessarily have all the wells drilled, even if they are planned. This means that the estimated volumes may be classified as Contingent Resources. The longer the field produces, the more wells we drill and the more we refine the model, moving the estimated volumes to Reserves.

Conclusions

The following conclusions are derived from the observations and results of this work:

- The multi-segment DCA approach is most effective in unconventional reservoirs when specifically relevant models are used for transient flow and boundary-dominated flow
- RTA using analytical models expands possibilities of forecasting for changes in well conditions and for well spacing studies
- Compositional simulation is required for near-critical reservoir fluids
- Until a well is drilled all resources volumes remain Prospective Resources
- Once resources volumes are discovered, they become classified as Contingent Resources and sub-classified as Development Unclarified
- The chance of development and of commerciality increase as we progress through the Contingent Resources sub-classes, moving the resources volumes towards Reserves
- Economics are the most important contingency to overcome, followed by technology, and production that must be met for volumes to be classified as Reserves
- For a technology to become "established" it must have demonstrated repeated commercial success
- All contingencies must be resolved for resources volumes to be classified as Reserves

Nomenclature

bbl	=	Barrel
BDF	=	Boundary Dominated Flow
bopd	=	Barrel of Oil Per Day
COGEH	=	Canadian Oil and Gas Evaluation Handbook
DCA	=	Decline Curve Analysis
EL	=	Economic Limit
MB	=	Material Balance
Mbbl	=	Thousand barrels
PIIP	=	Petroleum Initially-In-Place
PRMS	=	Petroleum Resources Management System
P1	=	Proved Reserves
P2	=	Probable Reserves
P3	=	Possible Reserves
P10	=	There is 10% probability that the actual reserves are greater than the P10 quantile
P50	=	There is 50% probability that the actual reserves are greater than the P50 quantile
P90	=	There is 90% probability that the actual reserves are greater than the P90 quantile
RTA	=	Rate Transient Analysis
ROTR	=	Resources Other Than Reserves
SPE	=	Society of Petroleum Engineers
SPEE	=	Society of Petroleum Evaluation Engineers
1P	=	Proved Reserves
2P	=	Proved + Probable Reserves
3P	=	Proved + Probable + Possible Reserves

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