Knowledge Integrity Service

GEO INDIA 2022

Estimation of In-Place

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Jaipur, Rajasthan, India

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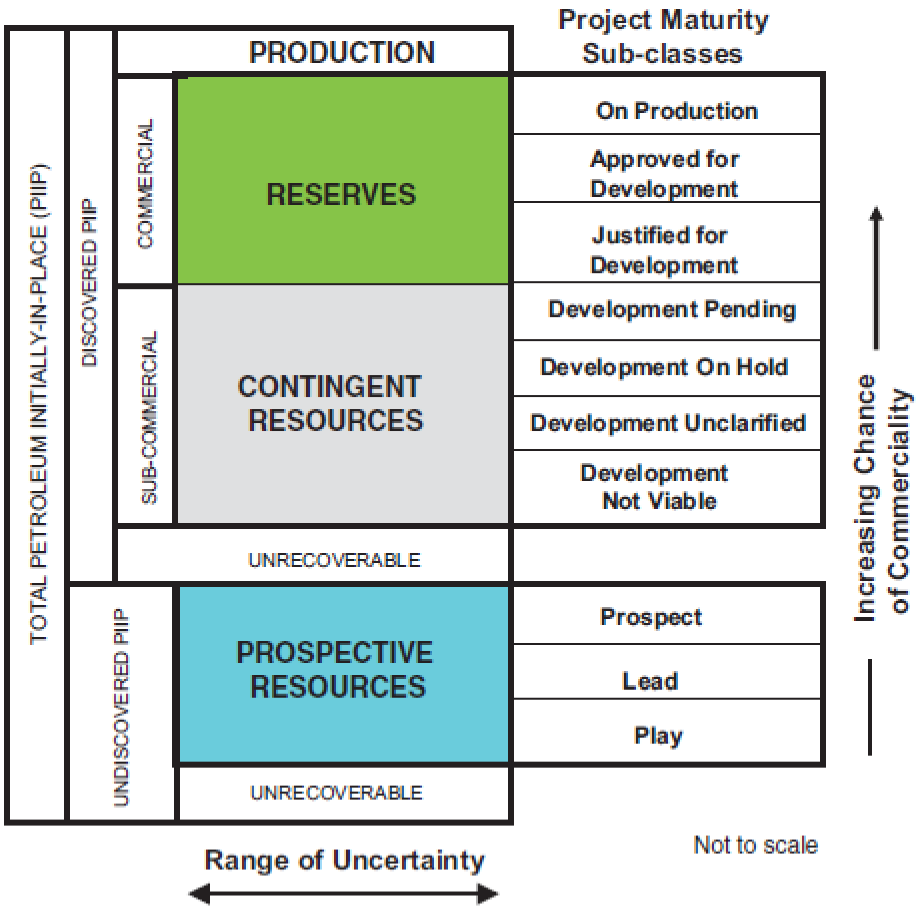
Worldwide Petroleum Consulting

Estimation of In-Place

Discovery Status

- Discovery status requires the following:
  - Exploratory well drilled
  - Significant quantity of potentially recoverable hydrocarbons identified - ”known accumulation”
    - Significant quantity means there is evidence of a sufficient quantity of petroleum to justify estimating the in-place quantity demonstrated by the well(s) and for evaluating the potential for commercial recovery.
    - Confirmed by testing, sampling, and/or logging
    - If no flow test or sampling, need to have confidence in presence of hydrocarbons and evidence of producibility through producing analogs
- Discovered quantities are classified as reserves, contingent resources, or discovered unrecoverable

- Discovery
  - A petroleum accumulation where one or several exploratory wells through testing, sampling, and/or logging have demonstrated the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. In this context, "significant" implies that there is evidence of sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for technical recovery.



Estimation of In-Place

Volumetric Methods

- Methods for estimation of in-place volumes:
  - Volumetrics
  - Analogies
  - Material Balance

Estimation of In-Place

Volumetric Method: When to use

- Early in life of field with limited production performance

- Volumetrics may be useful later in life of field
  - Support performance analysis
  - Identify bypassed reserves

- Uncertainty range of estimates dependent on type, quality, and amount of data

Estimation of In-Place

Uncertainty in Assessment Method Over Project Life

- Even when using good data sets and reasonable methods, estimates are inherently uncertain
- Develop range of estimates
  - Low
  - Best
  - High
- Build a case to support the estimates
  - Document the data and interpretation used to build the case
- Range of uncertainty should decrease over time with additional data
  - More wells
  - Additional seismic
  - Pressure/Production data

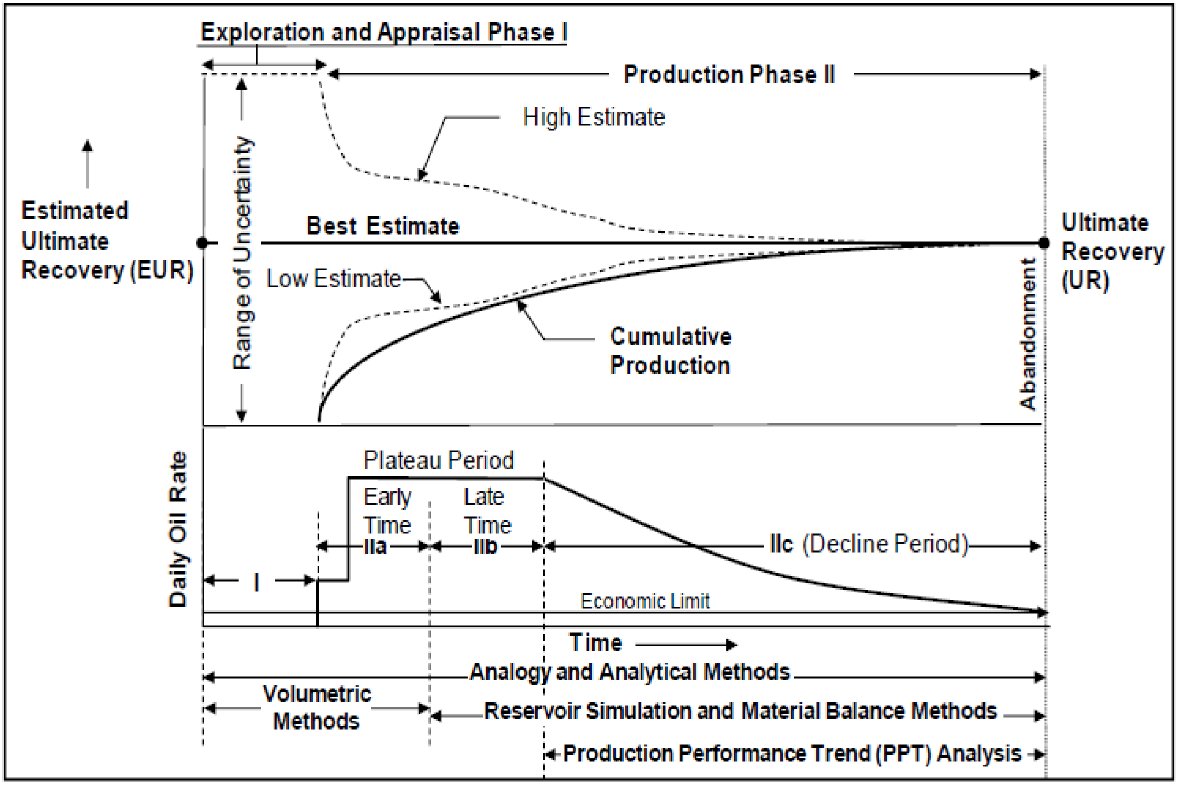


Fig. 4.1—Change in uncertainty and assessment methods over the project's E&P life cycle.

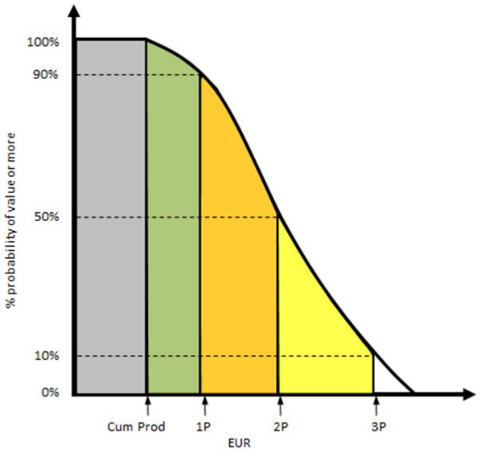
Figure 4.1: SPE, Guidelines for Application of the Petroleum Resources Management System, November 2011

Estimation of In-Place

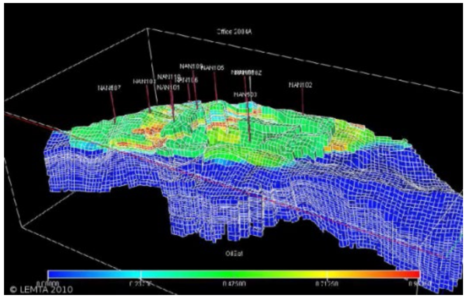
Uncertainty in Assessment Method Over Project Life

- Volumetric estimates can be made using probabilistic or deterministic methods

  - Probabilistic
    - Statistical Analysis Using Established Monte Carlo Methodology
    - Attractive Due to Rigor; Difficult to Explicitly Defend
    - Spreadsheet based
      - Crystal Ball, @Risk, GEOX, etc
    - 3D Model based
      - Petrel, RMS, etc



  - Deterministic
    - Specific Scenario Calculations
    - Seems More Arbitrary; More Easily Explicitly Defended



  - Good practice to cross check methods

Estimation of In-Place

Volumetric Method: Parameters for original in-place calculation

- Oil in-place calculation

- $OOIP = A*h*\phi*(1-S_{wi})/B_o$… Volume
- $OOIP = F*h*m*\beta*\theta*\rho$… Mass

- Where:
  - OOIP = original oil-in-place
  - A = F = area
  - h = average thickness
  - ϕ = m = average porosity
  - S_{wi} = (1- β) = average initial water saturation, decimal
  - B_o = 1/ θ = average oil formation volume factor
  - ρ = average oil density

- Gas in-place calculation

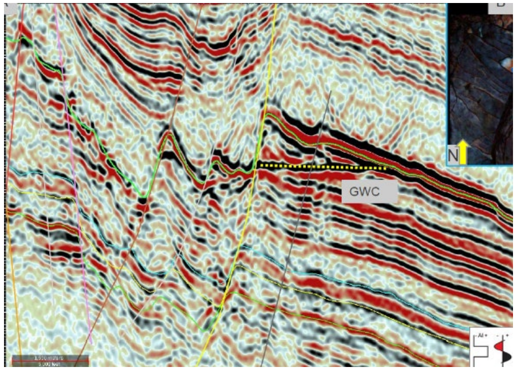
- $OGIP = A*h*\phi*(1-S_{wi})/B_g$… Volume method 1
- $OGIP = F*h*m*\beta*\theta$… Volume method 2

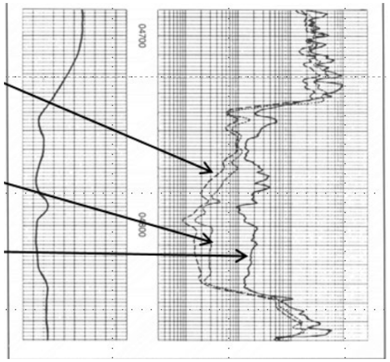
- Where:
  - OGIP = original gas-in-place
  - A = F = area
  - h = average thickness
  - ϕ = m = average porosity
  - S_{wi} = (1- β) = average initial water saturation, decimal
  - B_g = 1/ θ = average gas formation volume factor

Estimation of In-Place

Volumetric Method: Data requirements

- Typical data used in volumetric estimates
  - Seismic data
  - Log data
  - Core analysis
  - Petrophysical analysis
  - Well cross-sections and correlations
  - Drillstem tests
  - Pressure tests
  - Production data





- Interpretation and data are not the same thing
  - Data is a measurement or physical item collected in the field
  - Interpretation is an analysis of data

Estimation of In-Place

Volumetric Method: Subsurface maps

- Requirements
  - Use all available data
  - Consider all possible interpretations and models
  - Apply reasonable mapping techniques

- Benefits of properly constructed maps
  - High credibility
  - Identify additional drilling opportunities
  - Amount of time to evaluate a property may be reduced

- Maps are interpretation, not data

Estimation of In-Place

Volumetric Method: Subsurface maps

- Structure maps
  - Structural surface drawn on top of porosity
  - Surface area above a known fluid limit (LKH, HKW)
  - Well logs and seismic must be carefully correlated
  - Fault-surface maps
  - Cross sections
  - Multiple horizons
  - Interpretative contouring
  - Understanding geologic principles and related disciplines
  - Correct mapping techniques and methods must be used
  - Consider <u>all</u> subsurface data
  - Documentation

Estimation of Hydrocarbons In-Place

2D vs. 3D Volumetric

- 2D
  - Good
    - Simpler - Fewer vertical subdivisions
      - Usually net/non-net models
    - Point data based - Average values per well for NGR, Phi, Sw
    - Good for vertically homogeneous reservoirs
    - Less time to QC
    - Sometimes just a good database (not really a “model”)
  - Not So Good
    - Vertically heterogeneous properties difficult to handle
      - NGR through fluid “wedges”
    - Non-vertical faulting

Estimation of Hydrocarbons In-Place

2D vs. 3D Volumetric

- 3D
  - Good
    - Capture vertical reservoir heterogeneity
    - Use log data directly
    - More accurately represent reservoir properties across contact and fault wedges
  - Not So Good
    - Can be complex
      - Facies models
    - Can be difficult to QC
      - More difficult to spot mistakes

Estimation of Hydrocarbons In-Place

Reserves vs. Simulation Models

- Model Generated for Reserves
  - Focus is on in-place volumes and not permeability distribution
  - Emphasis is on;
    - Mechanics – i.e. does everything tie?
    - Interpretation – optimistic/pessimistic/realistic……is it reasonable
    - Categorization
      - Deterministic - build low, best, high cases
        - Identify and account for a few major uncertainties
      - Probabilistic – identify multiple uncertainties and ranges and run a large number of cases
- Model Generated for Simulation
  - Focus is on building a geological model for input to a reservoir simulator
    - Attempts to accurately model permeability
  - Takes more data and time to build
  - Costs more money
  - Is it more accurate?

Estimation of Hydrocarbons In-Place

Net Model and Facies Models

- Net Model and Facies Models
  - Net models are built using petrophysical cutoffs
    - Limited to rock that passes Vcl, phi, Sw cutoffs
  - Facies models try to predict the distribution of both reservoir quality and non-reservoir quality rocks
    - NGR usually 1
    - Volumes from non-net intervals (i.e. high Sw, low phi, low k) are frequently included in in-place numbers
    - Usually the higher in-place is balanced by a lower recovery factor
      - Is very important to make sure for reserves work that the reservoir engineer knows the model is a facies model and what that actually means.
  - Models/maps don't tie grids
    - 2D models should tie exactly
    - Net maps generated from 3D models sometimes have problems
      - Usually attributable to mismatch between resflags and payflags above the contact

Estimation of Hydrocarbons In-Place

Reserves vs. Simulation Models

- For 2D Models
  - Need grids, point sets and supporting data
    - At worst, all CPI's and sums with some raw and interpreted digital log data, core data, and cutoffs for petrophysicists to check
    - At best, all raw and interpreted log data
- For 3D Models
  - A good 3D model has:
    - Current well set with raw and interpreted logs
    - Well top picks/points
    - 3D structural grid WITH PROPERTIES
      - NGR, Phi, Sw
  - A bad 3D model has:
    - Input with no results – not a model- just a collection of stuff
    - Results with no input – need source data to check model
    - Filters

Estimation of In-Place

Volumetric Method: Petrophysical and PVT parameters

- **Petrophysical parameters**
  - Well log and core analysis
  - Average thickness, porosity, and water saturation usually estimated from petrophysical analysis
  - Net pay thickness mapped using results from each well
  - Porosity and water saturation usually are weighted averages

- **PVT: fluid volume factors**
  - PVT from laboratory experiments
  - Initial properties of oil or gas at initial reservoir pressure and temperature
  - May have wide variation, so is important to determine either through lab work or analogy

Estimation of In-Place

Volumetric Method: Subsurface maps

- Net Pay Isopach Maps
  - Net Reservoir
    - true vertical thickness of porous reservoir quality rock
  - Net Pay
    - true vertical thickness of porous reservoir quality rock that contains hydrocarbons
  - Petrophysical parameter trends must be correlated among wells and with seismic if applicable
  - Consider 3-D nature of reservoir
  - Distribution of pay within a gross interval must be taken into account
  - Thicknesses in deviated wells must be corrected for hole angle and apparent dip

Estimation of In-Place

Volumetric Method: Subsurface maps

- Determining Proved Area
  - Technically “proved” in the geologic sense
    - Reservoir quantities have been estimated with a “reasonable degree of certainty” if deterministic, P90 if probabilistic
  - Area of reservoir
    - Delineated by drilling
    - Defined by fluid contacts or lowest-known hydrocarbon (LKH)
  - Adjoining areas not yet drilled which can be reasonably judged as economically productive
    - Reservoir within a reasonable distance from well control may be classified as proved
    - No reservoir discontinuities or other geologic complexities
  - Reasonably judged as economically productive
    - Production performance from similar wells has guided determination of likely drainage area

Estimation of In-Place

Volumetric Method: Subsurface maps

- Determining Proved Area (con't)
  - Geologic complexity.
  - Facies distribution and diagenetic effects.
  - Final decision on reserves is based on economics.

- Exclusions from Proved reservoir area
  - quantities subject to reasonable doubt due to uncertainties in geology, reservoir characteristics, or economic factors
  - Areas without an approved development plan
  - quantities associated with undrilled prospects (prospective resources)

Estimation of In-Place

Net Pay Maps: Example 1 - OOIP limited by fluid contact

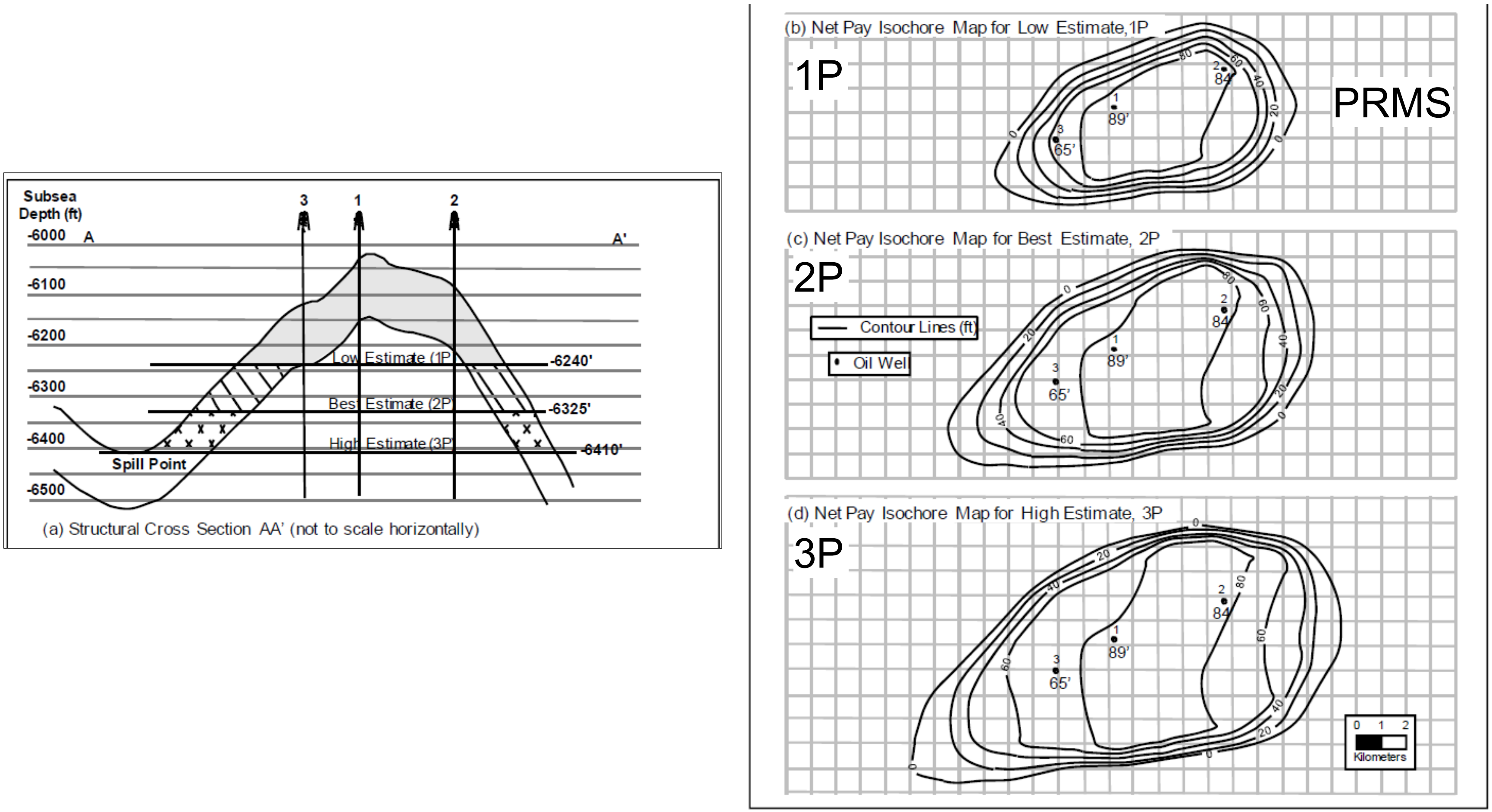
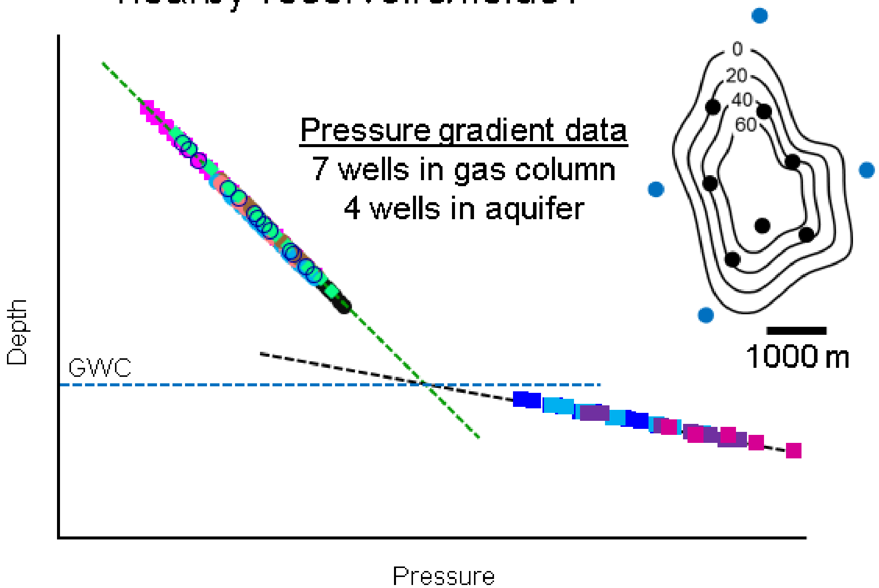


Figure 4.4, SPE, Guidelines for Application of the Petroleum Resources Management System, November 2011

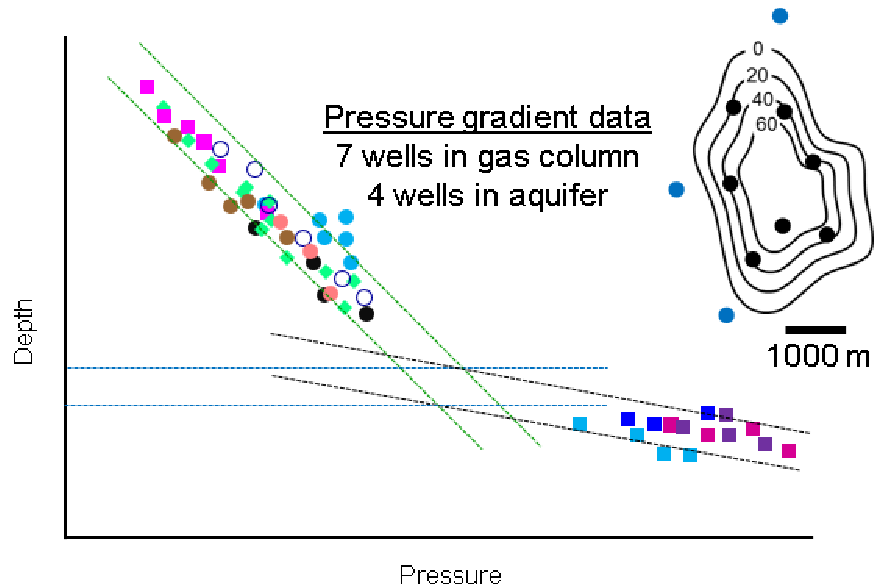
Estimation of In-Place

Reliable Technology: Example – pressure gradients

- **Example 1- Reliable**
  - Consistent data
  - Repeatable – the data and the interpretation are reasonably certain in numerous analogous reservoirs/wells
  - Can you produce the same results in nearby reservoirs/fields?

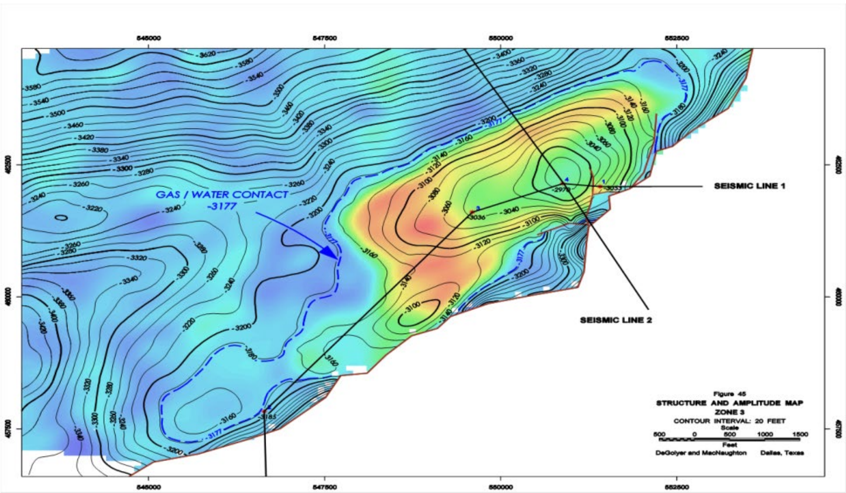


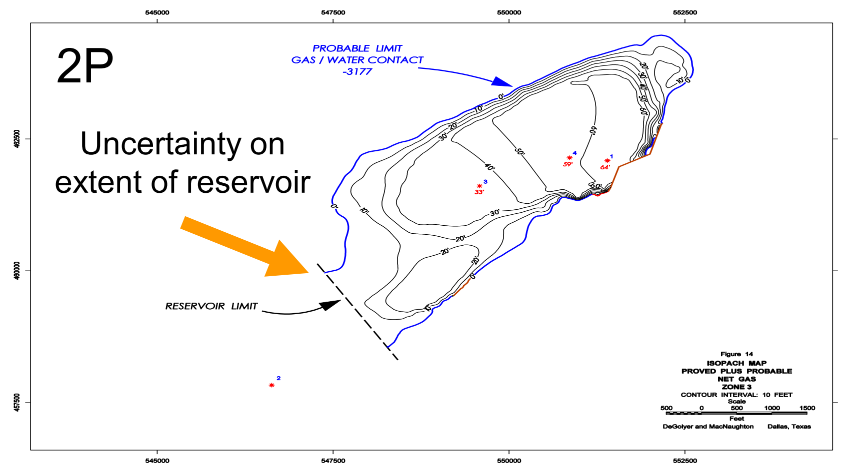
- **Example 2 – Not reliable**
  - Inconsistent data
  - Results are not repeated between the wells

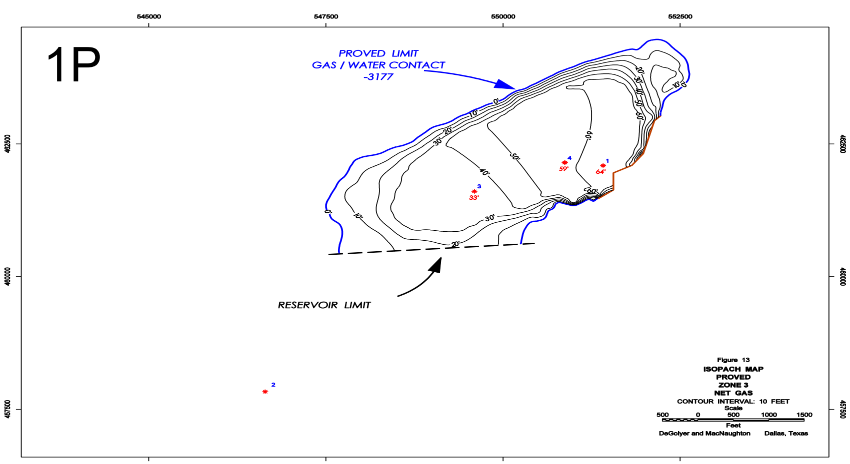


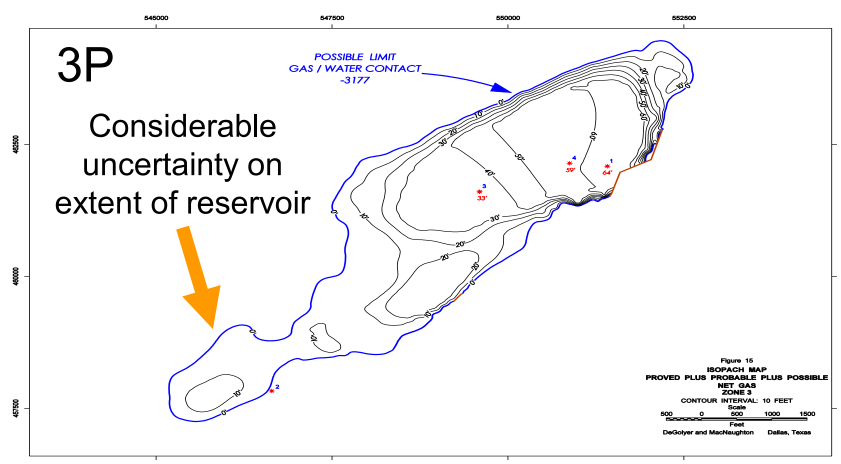
Estimation of In-Place

Net Pay Maps: Example 3 - OOIP limited by areal extent





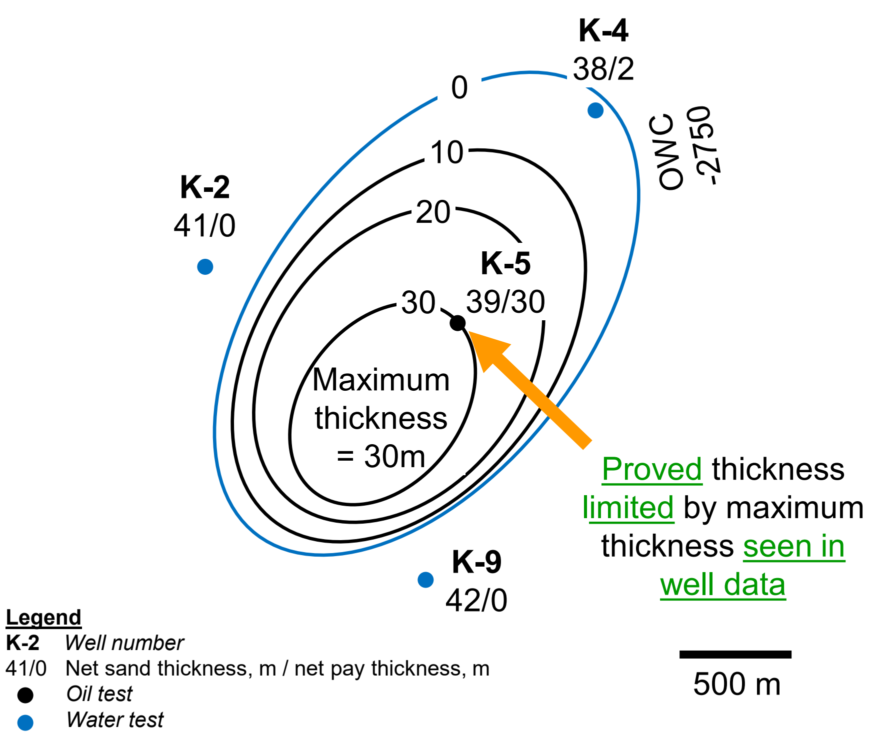




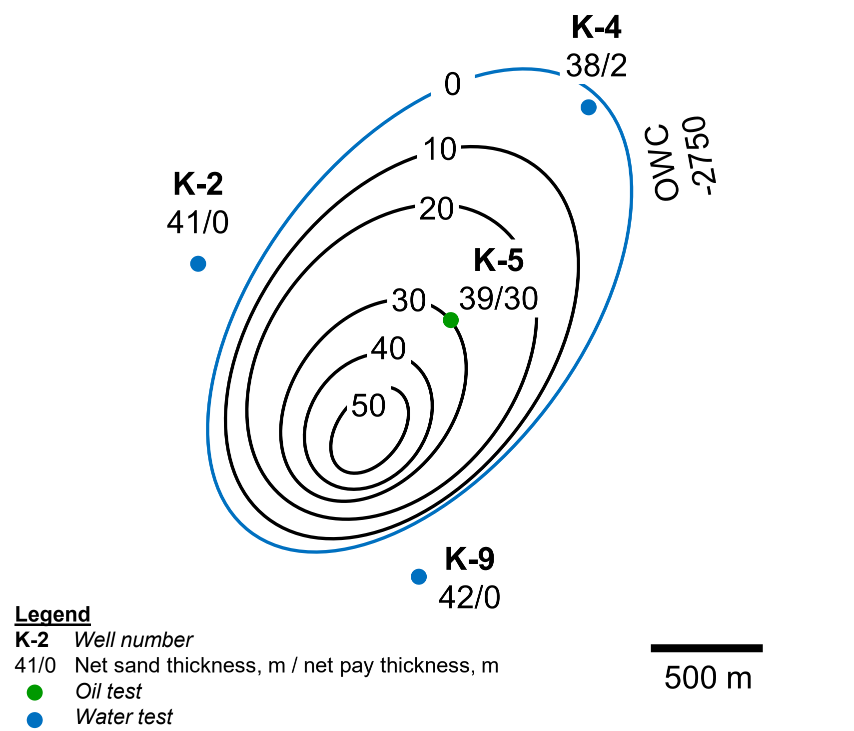
Estimation of In-Place

Net Pay Maps: Example 5 – OOIP limited by well thickness

- 1P net pay thickness map



- 3P net pay thickness map



Estimation of In-Place

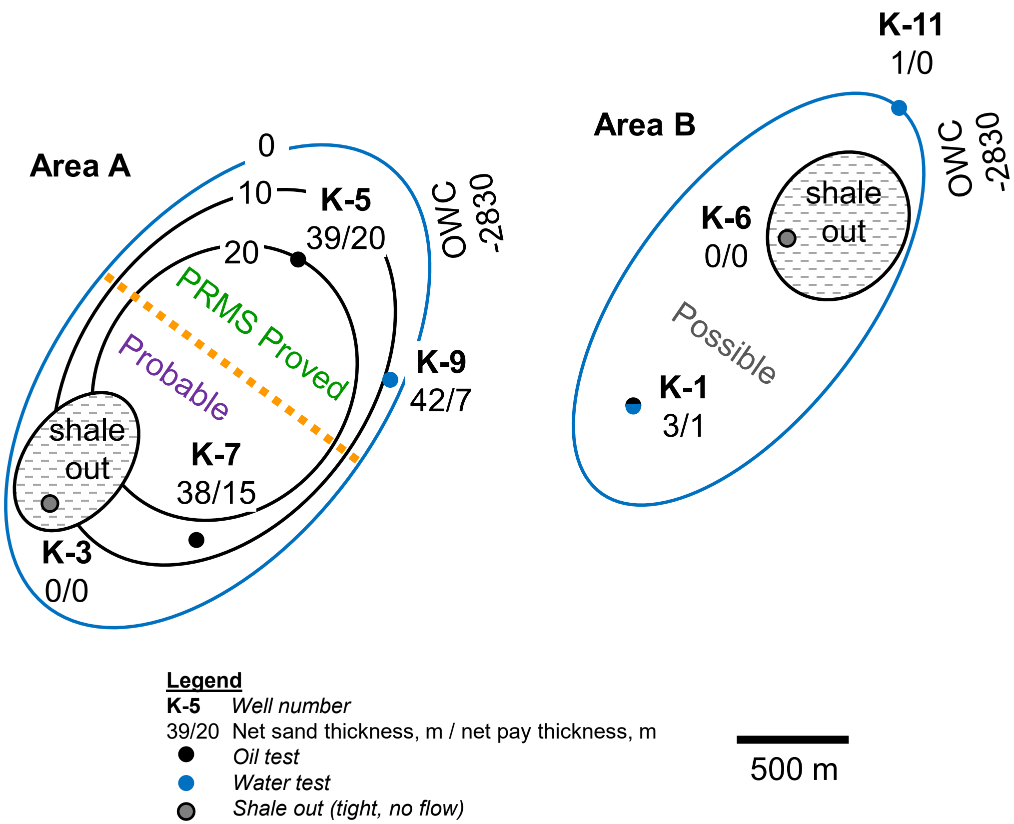
Net Pay Maps: Example 6 - OOIP limited by well test data

- Reserve categories of net pay map

Area A
K-3 no reservoir
K-5 40 m3/d oil, 0 water
K-7 3 m3/d oil, 30 m3/d water
K-9 10 m3/d oil, 2 m3/d water

Area B
K-1 1 m3/d oil, 10 m3/d water
K-6 no reservoir
K-11 0.5 m3/d oil, 5 m3/d water

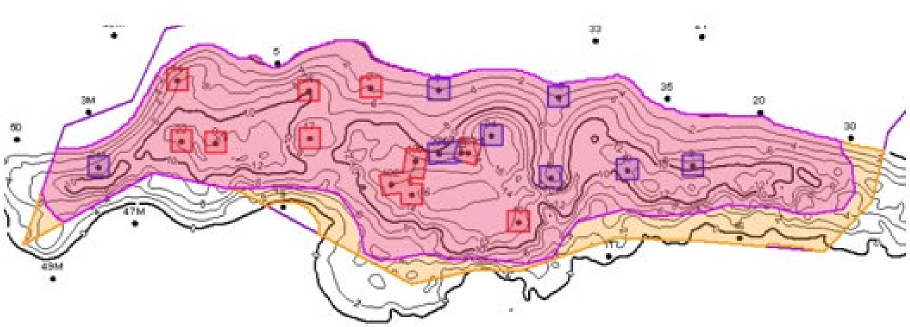
- Well Tests



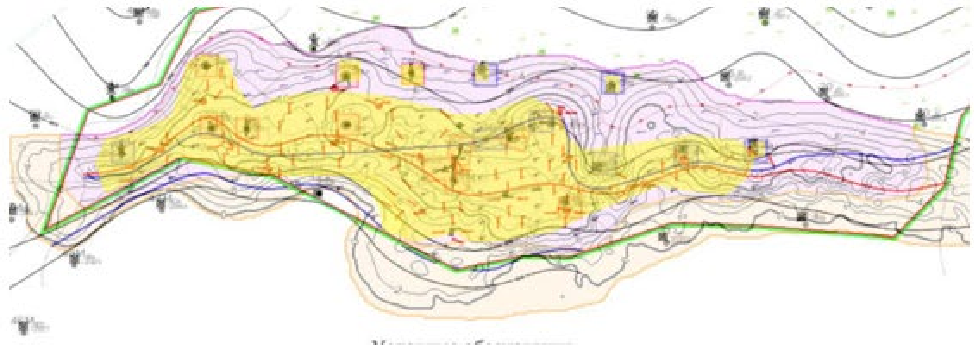
Estimation of Hydrocarbons In-Place

Net Pay Maps: Technical vs. Limited by Development

Technical In-Place

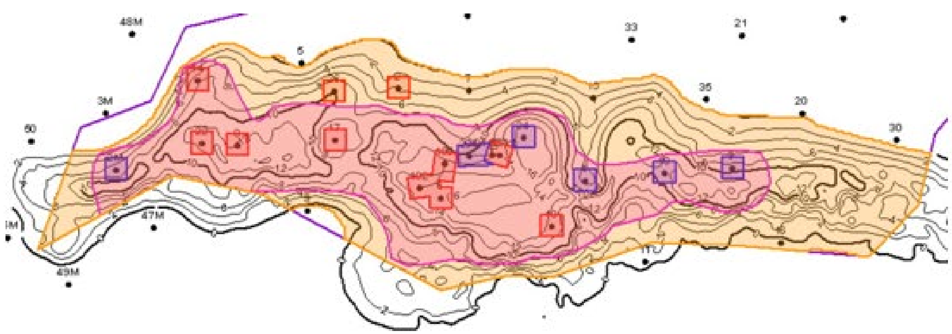


Development Plan



Good test
Poor test

In-Place Limited by Development Plan



Estimation of Hydrocarbons In-Place

This presentation is organized into the following sub-sections

- Methods for estimation of in-place volumes:
  - Volumetrics
  - Analogies
  - Material balance

Estimation of Hydrocarbons in-Place

Analogs and Their Proper Application

- Collect Information About Potential Analogs
- Seek Commonality and Aim for Superiority (in properties, situation, etc.) of Evaluated Asset vs Analog Asset
- Analog Description:
  - Similar Deposition, Trap, and Geological Processes to Form the Reservoir
  - Similar Geological Age and Composition
  - Similar Depth, Pressure/Temperature, Fluid Type, and Drive Mechanism
    - Superior Fluid Type Desirable in Evaluated Field
  - Similar Thickness, Net-to-Gross Ratio (NGR), Lithology
    - Superior Thickness, NGR Desirable in Evaluated Field
  - Similar Rock Properties
    - Superior Permeability and Porosity Desirable in Evaluated Field
    - Lower Water Saturation and Lower Water Mobility Desirable in Evaluated Field
  - Similar Development (Density, Well Types, Completions, etc.)
    - More Maturity and History Desired in Analogy
    - Superior Technology Desired in the Evaluated Field

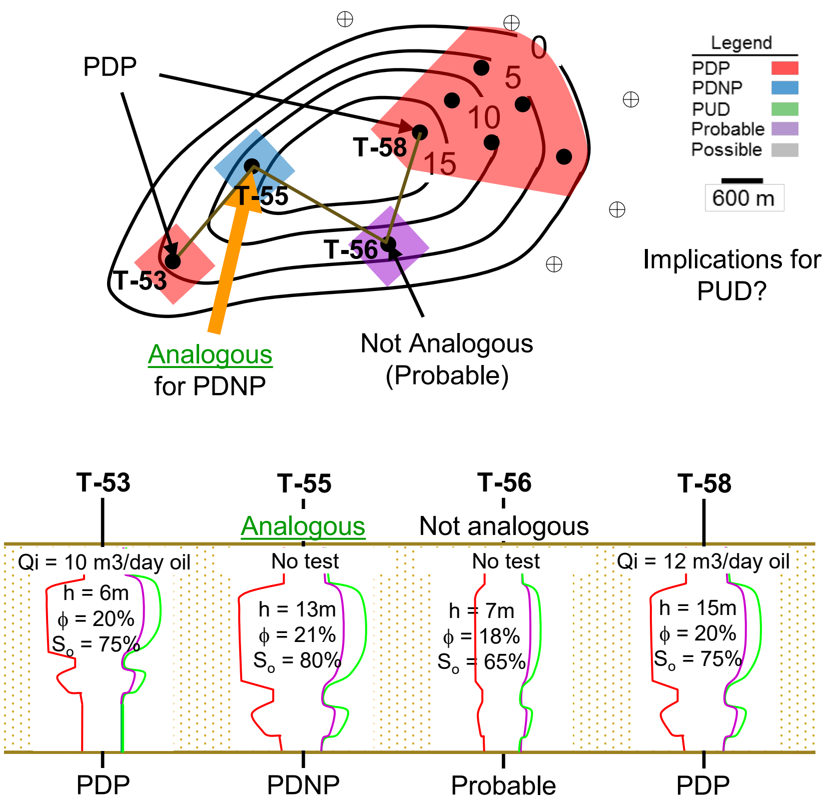
Estimation of In-Place

Analogies

- **Useful Comparison**
  - Environment of deposition
  - Geographically
  - Geologic age
  - Rock properties
  - Fluid types
  - Drive mechanism
  - Well operation techniques
  - Development plan
  - Stage of development

  - Remember, for Proved…
    "as good as or better than …"

- **Analogy: Example – areal PDNP**



Estimation of In-Place

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Estimation of Hydrocarbons In-Place

Material Balance: Gas estimates

- Gas material balance plots
  - P/z vs. cumulative production (P/z plot)
  - Cole plot
  - Energy plot
  - Roach plot

- Can be compared to volumetric estimate of OGIP
  - May be used to estimates gas reserves
    - Abandonment pressure (P_a) is estimated from economic rate (limit)

Estimation of Hydrocarbons In-Place

Gas Material Balance: P/z plot - Example

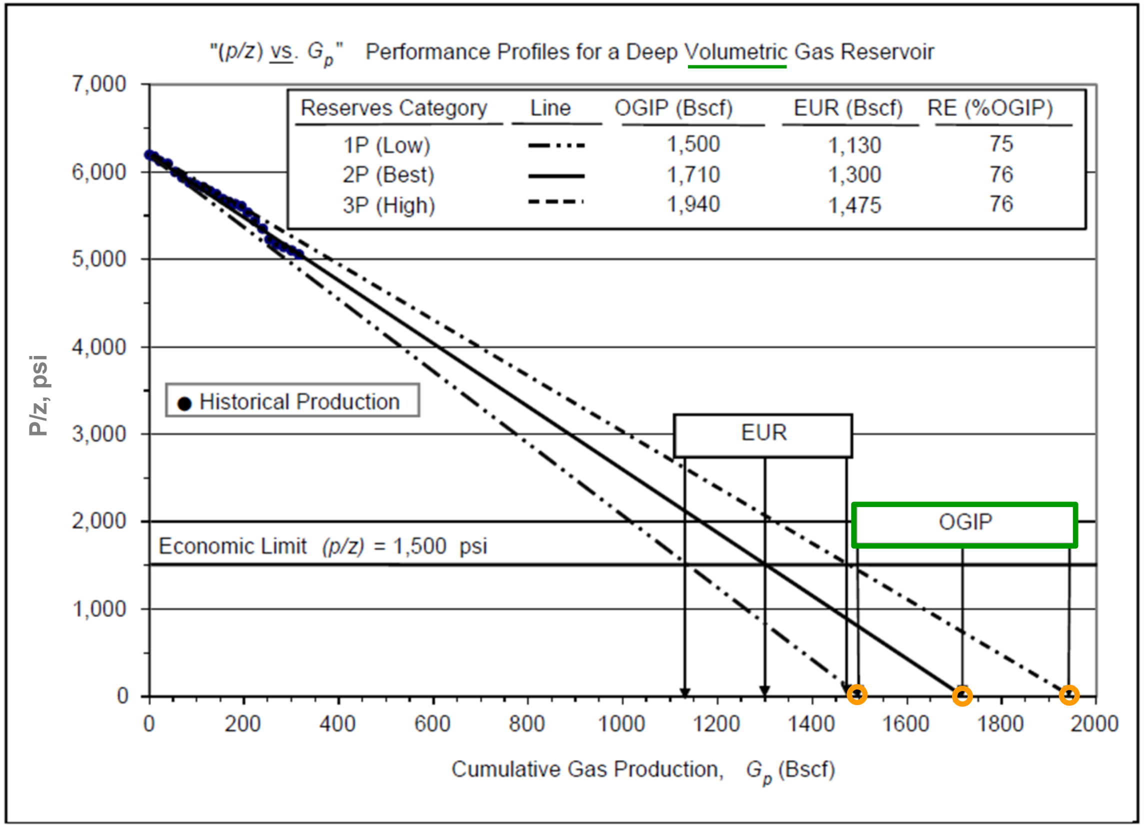


Fig. 4.8—Gas reserves assessment by material balance methods (Late-Production Stage).

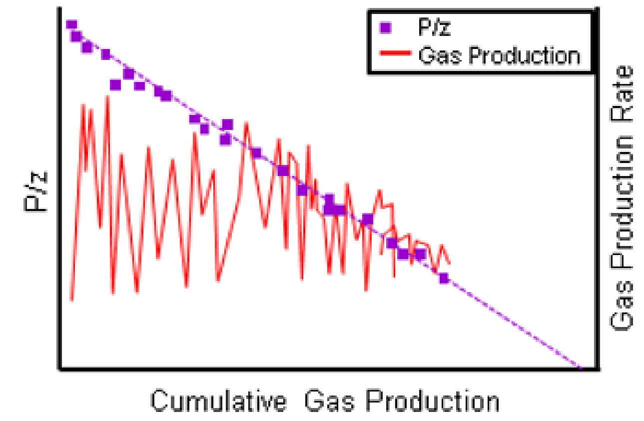
SPE, Guidelines for Application of the Petroleum Resources Management System, November 2011

Estimation of Hydrocarbons In-Place

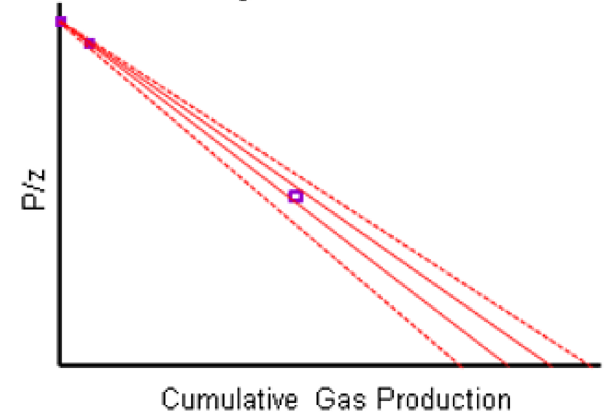
Gas Material Balance: P/z plot

- **Useful when…**
  - When data is sufficient and consistent
  - >30% of OGIP has been produced
  - Production is constrained by operational issues
  - Production performance is not reliable
- **Weak when…**
  - Production is less than 10% of OGIP
  - Water (aquifer) influx; may overstate OGIP estimates
  - Water in wells; may effect accuracy of pressure measurements
  - Reservoir pressure on reservoir flanks is not well known

- Curtailed production



- Uncertainty with time

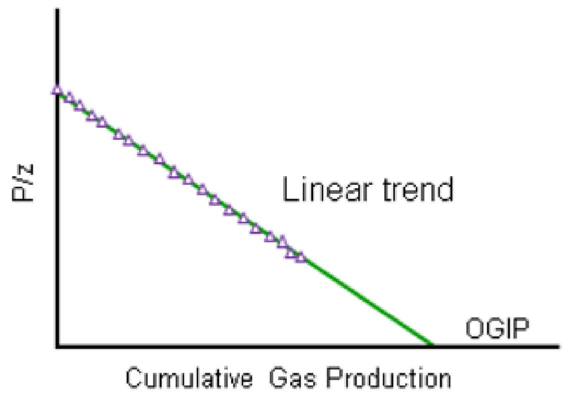


Estimation of Hydrocarbons In-Place

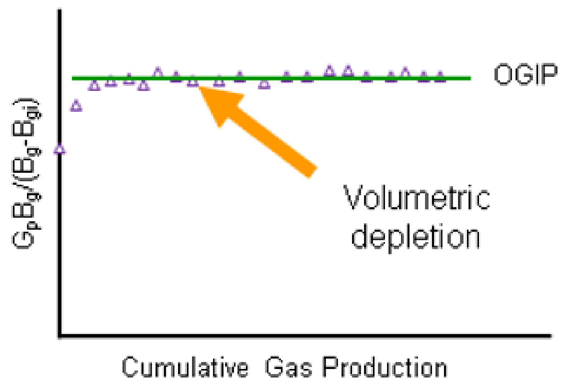
Gas Material Balance: Uncertainty from drive type

- Example - Volumetric depletion

P/z Plot

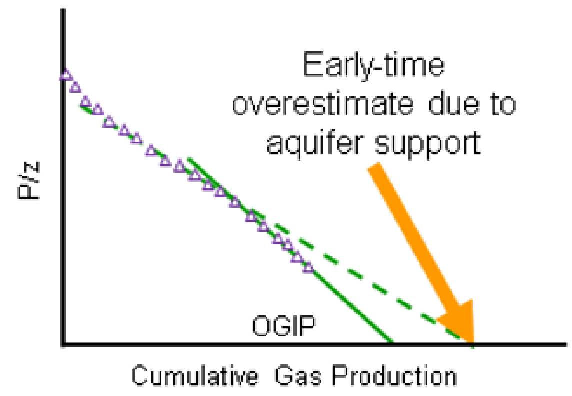


Cole Plot

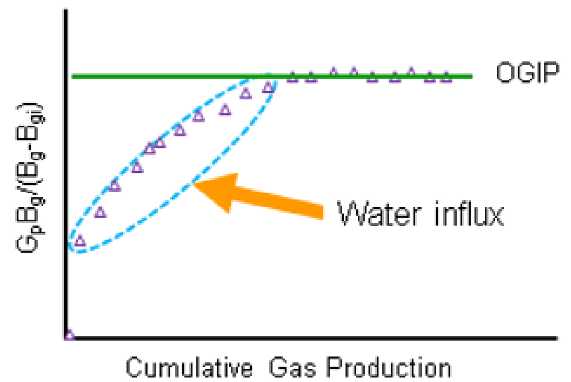


- Example – Aquifer-drive depletion

P/z Plot



Cole Plot



Estimation of Hydrocarbons In-Place

Gas Material Balance: Uncertainty from drive type

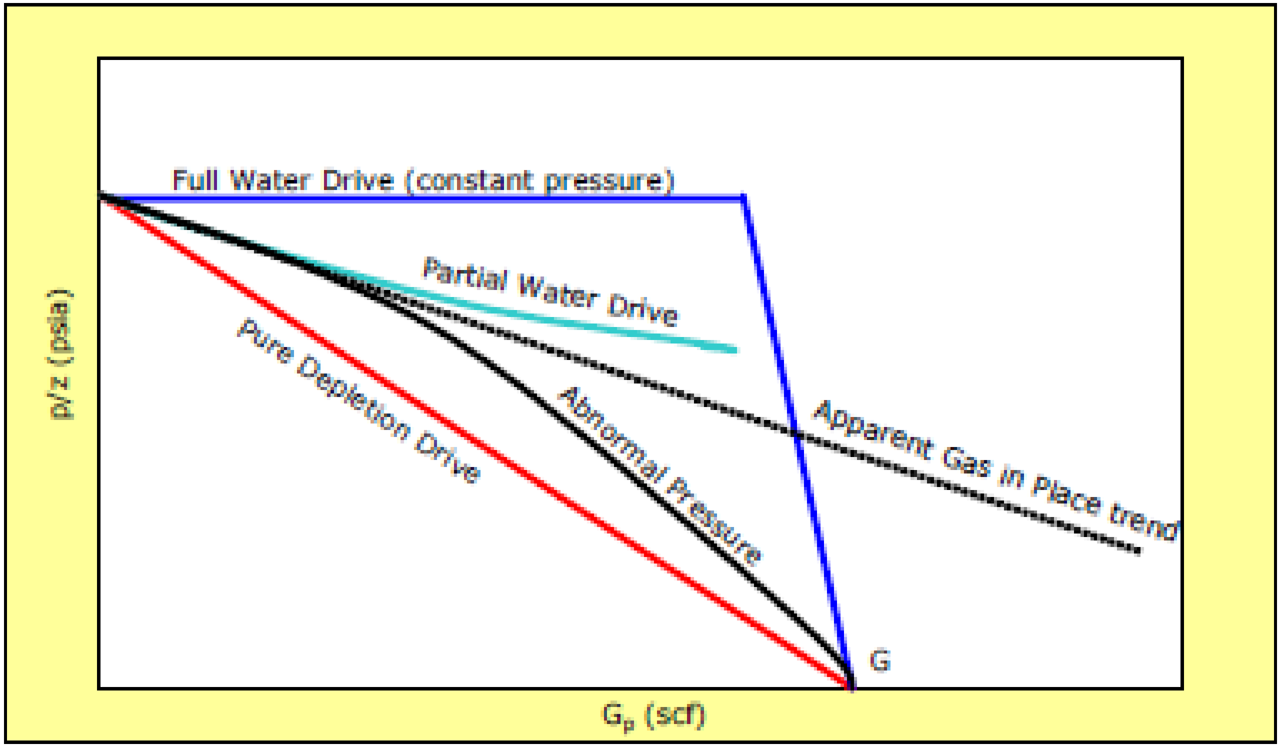


Figure 16. Conceptual gas material balance graph.

Figures 16, SPE 91069, Oil and Gas Reserves Estimates: Recurring Mistakes and Errors

Estimation of Hydrocarbons In-Place

Material Balance: Overview

- P/z vs. cum can be used with confidence…
  - in pressure depletion reservoirs (no water support)
  - later in a field's life (more than 30% depleted)
  - if there is a reliable trend
  - even if production is not at capacity
- P/z vs. cum cannot be used with confidence…
  - the reservoir has an active water support
  - early in the life of the field
  - the trend is not consistent
  - the quality of the pressure data is suspect
- Material balance estimates do not replace volumetric estimates. They should support each other.