Volumetric Estimation
Introduction

- Volumetric estimation:
  (1) Quantify how much oil and gas exists
  (2) Change over time
- Two main methods
  (1) Deterministic
  (2) Probabilistic
Deterministic Methods

Well logs, cores, seismic

Average the data

Estimate the field-wide properties
Deterministic Methods

- Formulae to calculate volumes

\[
\text{STOIIP} = \frac{N}{G} \cdot S_o \cdot \phi \cdot \frac{1}{B_o} \text{[stb]}
\]

\[
\text{GIIP} = \frac{N}{G} \cdot S_g \cdot \phi \cdot \frac{1}{B_g} \text{[stb]}
\]

Ultimate recovery = HCIIP \cdot \text{Recovery factor}[\text{stb}]

Reserves = UR - \text{Cumulative Production}[\text{stb}]
Deterministic Methods

The area-depth

- Assume a constant gross thickness (H)
- Known data: structure map, gross thickness
- Measure the respective area
- Plot the area-depth graph
Volumetric Estimation

- Map
  - 1400
  - 1200
  - 1000
  - OWC
  - Area A
  - 1000
  - 1200
  - Area B
  - 1400
  - Area C

- Cross section
  - H
  - GRV
  - OWC
  - Area

- Depth
  - 1000
  - 1200
  - 1400
  - H = Thickness of reservoir from logs

- Graphical representation showing the relationship between depth and area, with various contour lines indicating different elevations and reservoir boundaries.
Deterministic Methods

The area-thickness

- Assumption of constant thickness no longer apply
- Known data: structure map, net sand map
- Combines the two maps to find a net oil sand map
- Plot the area-thickness graph
Volumetric Estimation
Probabilistic Methods

Field data

Statistics

Geological model

+ 

Predict trends of the field-wide properties
Probabilistic Methods

PDF & Expectation curves
Probabilistic Methods

PDF & Expectation curves

1. Well defined discovery
2. Poorly defined discovery
3. Low risk, low reward
4. High risk, high reward
- Expectation curve for a discovery

- Low estimate = 85% cumulative probability
- Medium estimate = 50% cumulative probability
- High estimate = 15% cumulative probability
- Expectation Value = (High+Medium+Low)/3
- POS (Probability of Success) in exploration step

(1) A source rock where HC were generated
(2) A structure in which the HC might be trapped
(3) A seal on top of the structure to stop the HC migrating further
(4) A migration path for the HC from source rock to trap
(5) The correct sequence of events in time
PDF & Expectation curves

Probability of Failure = 70%
Generating expectation curves

- The Monte Carlo Method

\[ UR = \text{area} \cdot \text{thickness} \cdot \frac{N}{G} \cdot \phi \cdot S_o \cdot \frac{1}{B_o} \cdot RF [\text{stb}] \]
Generating expectation curves

- Parametric method

\[ \mu_c = \mu_a \cdot \mu_b, \mu : \text{mean} \]

\[ (1 + K_C^2) = (1 + K_A^2) \cdot (1 + K_B^2) \]

\[ K = \frac{\sigma}{\mu}, \text{coefficient of variation} \]

\[ UR = \text{area} \cdot \text{thickness} \cdot \frac{N}{G} \cdot \phi \cdot S_o \cdot \frac{1}{B_o} \cdot \text{RF [stb]} \]
Generating expectation curves

- Parametric method:

\[(1 + K_i^2)\] will be greater than 1.0; the higher the value, the more the variable contributes to the uncertainty in the results.

\(\downarrow\) must be cared to reduce the uncertainty in the results.
Generating expectation curves

- Three points method

\[
UR = \text{area} \cdot \text{thickness} \cdot \frac{N}{G} \cdot \phi \cdot S_o \cdot \frac{1}{B_o} \cdot \text{RF} \text{[stb]}
\]
Field Appraisal
Role of appraisal

- Cost effectiveness

Appraisal has meaning if D2-A > D1
Sources of uncertainty

- Parameters for estimation of STOIIP, GIIP, and UR

<table>
<thead>
<tr>
<th>Input parameter</th>
<th>Controlling factors</th>
</tr>
</thead>
<tbody>
<tr>
<td>gross rock volume</td>
<td>shape of structure</td>
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<td>dip of flanks</td>
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<td>position of bounding faults</td>
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<td></td>
<td>position of internal faults</td>
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<td>depth of fluid contacts (e.g., OW)</td>
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<td>net:gross ratio</td>
<td>depositional environment diagenesis</td>
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<tr>
<td>porosity</td>
<td>depositional environment diagenesis</td>
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<td>hydrocarbon saturation</td>
<td>reservoir quality</td>
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<td>capillary pressures</td>
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<tr>
<td>formation volume factor</td>
<td>fluid type</td>
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<td>reservoir pressure and temperature</td>
</tr>
<tr>
<td>recovery factor</td>
<td>physical properties of the fluids ($\mu$, $\rho$)</td>
</tr>
<tr>
<td>(initial conditions only)</td>
<td>formation dip angle</td>
</tr>
<tr>
<td></td>
<td>aquifer volume</td>
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<td></td>
<td>gas cap volume</td>
</tr>
</tbody>
</table>

(1) Consider the factors
(2) Rank the factors
(3) Consider the uncertainty of factors
**Appraisal tools**

- **Main tool:**
  
  Drilling wells and shooting 2D, 3D seismic surveys

- **Others**
  
  (1) An interference test between two wells
  (2) A well drilled in the flank of a field
  (3) A well drilled with a long enough horizontal section
  (4) A production test on a well
  (5) Deepening a well
  (6) Coring a well
Reduction of uncertainty

- Impact of appraisal

\[ \% \text{ uncertainty} = \frac{H-L}{2M} \times 100\% \]

- Well A is oil-bearing or dry
  (1) Expectation curve may shift
  (2) Uncertainty range is reduced
Cost-benefit calculation

- NPV calculation

- With appraisal
  \[ \frac{0+6+66}{3} = +$24 \]

- Without appraisal
  \[ \frac{-40+6+40}{3} = +$2 \]
Reservoir Dynamic Behavior
The driving force for production

- Reduction of pressure \( \rightarrow \) Increase of volume

- Compressibility,
  \[ c = - \frac{1}{V} \frac{dV}{dP} \]

- Underground withdrawal of fluid
  \[ dV = \left[ c_o V_o + c_g V_g + c_w V_w \right] \cdot dP \]
The driving force for production

- Driving force
  (1) primary recovery
  (2) secondary recovery
The driving force for production

- Material balance equation

Relationship

produced fluid volume
compressibility
reservoir pressures
## Reservoir Driving Mechanisms

<table>
<thead>
<tr>
<th>Drive mechanism</th>
<th>Initial condition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solution gas drive</td>
<td>Undersaturated oil (no gas cap)</td>
</tr>
<tr>
<td>Gas cap drive</td>
<td>Saturated oil with a gas cap</td>
</tr>
<tr>
<td>Water drive</td>
<td>Saturated or undersaturated oil</td>
</tr>
<tr>
<td>With a large underlying aquifer</td>
<td></td>
</tr>
</tbody>
</table>
Solution gas drive

- No initial gas cap or active aquifer
- Oil is produced: expansion of oil, connate water and any compaction drive
- Pressure drops rapidly as production takes place, until $p_b$

- Material balance equation

$$N_p B_o = N \cdot B_{oi} \cdot c_e \cdot \Delta P$$
Solution gas drive

- Three phases during oil production
  (1) build up period
  (2) plateau period
  (3) decline period
- Recovery factor is in the range 5- 30%

\[
\text{water cut} = \frac{\text{water production (stb)}}{\text{oil plus water production (stb)}} \times 100(\%)\]
Solution gas drive

- Reservoir Dynamic Behavior

![Graph showing reservoir pressure, oil rate, water cut, and produced GOR over time. The graph illustrates the behavior of a solution gas drive reservoir, with key points marked as Pb and RF = 5 - 30%.](image)
Gas cap drive

- Initial existence of gas cap
- Gas expansion gives drive energy for production
- Well is installed as far away from the gas cap as possible
- Compared to solution gas drive, gas cap drive shows a much slower decline
- Recovery factor is in the rage of 20-60%
Gas cap drive
Water drive

- Occurs when the underlying aquifer is large
- Water must be able to flow into the oil column
- Difficult to plan the reservoir development by a uncertainty of aquifer behavior
- Using the response of reservoir pressure, fluid contact movement and MBE, we can see the reaction of aquifer
- Recovery factor is in the range 30-70%
Water drive
Gas reservoirs

- Produced by expansion of the gas contained in the reservoir
- Must ensure a long sustainable plateau to attain a good sales price for the gas
- Recovery factor depends on how low the abandonment pressure can be reduced
- Recovery factor is in the range 50-80%
Differences between oil and gas field

- The economics of transportation gas
- The market for gas
- Product specifications
- The efficiency of turning gas into energy
Gas sales profiles; influence of contracts

- A guaranteed minimum quantity of gas for as long a duration as possible
- Peak in production when required
Gas sales profiles; influence of contracts

- Daily contact quantity (DCQ)
- Swing factor
- Take or pay agreement
- Penalty clause
Subsurface development

- One of major difference in fluid flow for gas field compared to oil field is mobility difference

\[
\text{mobility} = \frac{k}{\mu}
\]

- In a gas reservoir underlain by an aquifer, the gas is highly mobile to compared to water and flow readily to the producers

- Producer are typically positioned at the crest of the reservoir
Subsurface development

- As the gas is produced, the pressure in the reservoir drops, and the aquifer responds to this by expansion and moving into the gas column.
- Pressure response to production
  (1) primary drive mechanism is the expansion of the gas
  (2) RF is linked to the drop in reservoir pressure in an almost linear manner
Subsurface development
Surface development for gas fields

- The amounts of processing required in the field depends on the composition of the gas and the temperature and pressure to which the gas will be exposed during transportation.
- For dry gas, the produced fluid are often exported with very little processing.
- Wet gas may be dried of the heavier hydrocarbons by dropping the temperature and pressure through a Joule-Thompson expansion valve.
Surface development for gas fields

- Gas containing water vapor may be dried by passing the gas through a molecular sieve.
- Gas reservoirs may also be used for storage of gas.
Fluid displacement in the reservoir

- Oil is left behind due to *by-passing*
- RF = Macroscopic sweep efficiency × Microscopic displacement efficiency
Fluid displacement in the reservoir

- Darcy’s law
- Oil reservoir: 100md (good), 10md (poor)
- Gas reservoir: 1md (reasonable: lower viscosity than oil)
- Relative permeability
- Mobility ratio (\( M \))

\[
\frac{k_{rw}}{\mu_w} \div \frac{k_{ro}}{\mu_o}
\]

- If \( M > 1 \), viscous fingering occurs
Fluid displacement in the reservoir

- Stable Displacement (M < 1)
- Unstable Displacement (M > 1)

Stable Displacement at low rate
Gravity Tonguing at high rate
Reservoir simulation

One Dimensional Model
Cartesian
Two Dimensional Models
Radial
Three Dimensional Model
- Ultimate recovery = HCIIP x RF
- Reserves = UR – cumulative production
- Main technique for estimating the RF
  (1) Field analogues
  (2) Analytical models (displacement calculations, MBE)
  (3) Reservoir simulation
Estimating the production profiles

- Production profile is the only source of revenue for most projects, and making a production forecast is of key importance for economic analysis of a proposal.
Enhanced oil recovery

- Thermal technique: reduce the viscosity of heavy crude
- Chemical technique: polymer flooding / surfactant flooding
- Miscible processes
Enhanced oil recovery

Recovery method considered
- Surfactant Flooding
- Thermal Recovery
- Polymer Flooding
- Infill Wells
- Water Injection
- Gas Injection
- Infill (Horizontal) Wells
Well Dynamic Behavior
The number of development wells

- The drilling expenditure: 20~40% of the total capex
- Estimate the number of wells by considering
  (1) The type of development
      (e.g. gas cap drive, water injection, natural depletion)
  (2) The production / injection potential of individual wells

Number of production wells = \( \frac{\text{Plateau production rate [stb/d]}}{\text{Assumed well initial [stb/d]}} \)
Fluid flow near the wellbore

- Pressure drawdown
  \[ \Delta P_{DD} = P - P_{wf} \]

- Productivity index PI
  \[ PI = \frac{Q}{\Delta P_{DD}} \]

- For semi–steady state,
  \[ Q = \frac{\Delta P_{DD} g k h}{141.2 \mu B_o \left\{ \ln \frac{r_e}{r_w} - \frac{3}{4} + S \right\}} \]
Fluid flow near the wellbore

- Damage skin, geometric skin, turbulent skin
Fluid flow near the wellbore

- Coning: occurs in the vertical plane, when OWC lies directly below the producing well
- Cusping: occurs in the horizontal plane, when OWC doesn’t lie directly beneath the producing well
Fluid flow near the wellbore
Horizontal wells

- Advantage
  (1) Increased exposure to the reservoir giving higher productivity (PI)
  (2) Ability to connect laterally discontinuous features (e.g. fractures, fault blocks)
  (3) Changing the geometry of drainage (e.g. being parallel to fluid contacts)
- Productivity improvement factor (PIF)

\[
\text{PIF} = \frac{1}{h} \cdot \frac{\sqrt{k_v}}{\sqrt{k_h}}
\]

Well Dynamic Behavior

Horizontal wells

- Productivity improvement factor (PIF)
Horizontal wells

- Effective horizontal well length
Horizontal wells

- Ability to connect laterally discontinuous features
Horizontal wells

Changing the geometry of drainage

Minimising the effect of coning or cusping

- Particularly strong advantage in thin oil columns (less than 40m thick)
**Horizontal wells**

- Cresting: the distortion of the fluid interface near the horizontal well
Production testing & $p_{wf}$ testing

- Production testing
  (1) Per month
  (2) Information: liquid flow rate, water cut, gas production rate

- Bottom hole pressure testing
  (1) Determine the reservoir properties (e.g. permeability, skin)
  (2) SBHP (static bottom hole pressure survey)
  (3) FBHP (flowing bottom hole pressure survey)
Production testing & $P_{wf}$ testing
Production testing & $P_{wf}$ testing

Figure 9.10 Pressure drawdown and build-up survey
Production testing & $P_{wf}$ testing
- **Tubing performance**

  - Determine the size
    1. Measure
       - $p_{wf}$ (bottom hole pressure), $p_{th}$ (tubing head pressure), $p_{sep}$ (separator pressure)
    2. Plot IPR curve & TPC
Tubing performance
Well completion

- To provide a safe conduit for fluid flow from the reservoir to the flowline
Well completion

- Many variations exist
  (gravel pack completion, dual string completion)
Well completion

- Horizontal wells

![Diagram of well completion methods: bare foot, slotted liner, cemented liner](image)
Artificial lift

- Add energy to the produced fluids, either to accelerate or to enable production
- Performed in the well
- Common in the North Sea
- Later in a field’s life
Artificial lift

- Types of artificial lift
  (1) Beam Pump (BP)
  (2) Progressive Cavity Pump (PC)
  (3) Electric Submersible Pump (ESP)
  (4) Hydraulic Reciprocating Pump (HP)
  (5) Hydraulic Jet Pump (JET)
  : mixing a fluids of high kinetic energy with a oil
  (6) Continuous Flow Gas Lift (GL)
  (7) Intermittent Gas Lift (IGL)
Artificial lift

- Determine an effective type of artificial lift by capabilities, hydraulic efficiencies, and constraints

![Graph and Table]

**CONRAINTS**

<table>
<thead>
<tr>
<th>CONSTRAINT</th>
<th>DRAWDOWN</th>
<th>VISCOS OIL</th>
<th>SOLIDS</th>
<th>GAS</th>
<th>HIGH TEMP</th>
<th>DEPTH</th>
<th>DEVIATED</th>
<th>DOGLEGED</th>
<th>SURVEYING</th>
<th>TESTING</th>
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<td><strong>GROSS PRODUCTION RATE (B/D)</strong></td>
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<td><strong>FLEXIBILITY</strong></td>
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<td><strong>RELIABILITY</strong></td>
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<td><strong>HYDRAULIC EFFICIENCY (%)</strong></td>
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</table>

* ASSUMING THAT NO INFRASTRUCTURE EXISTS
Surface Facilities
Oil and Gas Processing

Process design

Production from Wells

Separation and Treatment

Gas
Oil
Water
Contaminants
- Description of wellhead fluids: quality & quantity of fluids produced at the wellhead are determined by

   (1) Hydrocarbon composition

   (2) Reservoir character

   (3) Field development scheme
Surface Facilities

- Hydrocarbon properties which influences process design

  (1) PVT characteristics
  (2) Composition
  (3) Emulsion behavior
  (4) Viscosity and density

How volumes & rates will change over the life of the well production profiles → estimate wellhead T,P
- Product specification

(1) Oil : true vapor pressure, base sediment and water content, temperature, salinity, hydrogen sulphide content

(2) Gas : water & HC dew point, HC composition, contaminants content, heating value

(3) Water : oil and solids content
- The process model: factors which must be considered

(1) Product yield
(2) Inter-stage P & T
(3) Compression power required
(4) Cooling & heating requirements
(5) Flowrates for equipment sizes
(6) Implications of changing production profile
- Process flow schemes

- Use of process flow schemes
  (1) Preparing preliminary equipment lists
  (2) Supporting early cost estimates
  (3) Basic risk analysis
- Describing hydrocarbon composition

Reservoir oil sample $\rightarrow$ Calculate yields of oil & gas

HC composition

Volume fraction

Weight fraction

<table>
<thead>
<tr>
<th>Volume (or mol) fraction of each component</th>
<th>Volume in cu.m.</th>
</tr>
</thead>
<tbody>
<tr>
<td>CH₄</td>
<td>0.53</td>
</tr>
<tr>
<td>C₂H₆</td>
<td>0.06</td>
</tr>
<tr>
<td>C₃H₈</td>
<td>0.03</td>
</tr>
<tr>
<td>C₄H₁₀</td>
<td>0.01</td>
</tr>
<tr>
<td></td>
<td>1.00</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Volume (or mol) fraction</th>
<th>Molecular Weight (g/mol)</th>
<th>Weight Composition</th>
</tr>
</thead>
<tbody>
<tr>
<td>CH₄ 0.85</td>
<td>16.04</td>
<td>13.6</td>
</tr>
<tr>
<td>C₂H₆ 0.09</td>
<td>30.07</td>
<td>2.7</td>
</tr>
<tr>
<td>C₃H₈ 0.05</td>
<td>44.10</td>
<td>2.2</td>
</tr>
<tr>
<td>C₄H₁₀ 0.01</td>
<td>58.12</td>
<td>0.6</td>
</tr>
</tbody>
</table>

1 Barrel of Gas Type 'X'
(0.63 cu.m) @ T and P

1 Mole of Gas Type 'X'

19.1 g/mol
Process design

- Separation

To determine how much of each component goes into the gas or liquid phase, $K$ must be known.

For Each Component:

$$K = \frac{Y}{X}$$

$Y$ - Mol fraction of each component in the vapour phase

$X$ - Mol fraction of each component in the liquid phase
- Separation design

- Demister
  1. Impingement demister
  2. Centrifugal demister
- Separation types

(1) Main function
   Knockout vessels / Demister separators

(2) Orientation
   Horizontal separator   Vertical separator
- Dehydration and water treatment

1. Produced water must be separated from oil.
2. Oil contained in separated water must be removed.
3. Method: settling & skimming tank

- Dehydration
- De-oiling

(1) Skimming tank vs. Gravity separator

(2) Oil interceptor: used both offshore & onshore

plate interceptor
Upstream gas processing

- Components which cause pipeline corrosion or blockage:
  - water vapor, heavy HC, CO₂, H₂S
- Associated gas: flared or re-injected
- Pressure reduction: be made across a choke before primary O/G separator
- Gas dehydration

Methods of dehydration:
(1) Cooling
(2) Absorption
(3) Adsorption
- Heavy hydrocarbon removal

(1) High wellhead P over long period
   JT throttling / turbo-expander

(2) High P is not available : refrigeration
Surface Facilities

- Contaminant removal

CO$_2$, H$_2$S

- Pressure elevation (gas compression)

(1) Reciprocating compressors

(2) Centrifugal compressors
Downstream gas processing

Terminology of natural gas:

- Methane (C₁)
- Ethane (C₂)
- Propane (C₃)
- Butane (C₄)
- Pentanes (C₅) and heavier fractions
- Non-Hydrocarbons (Water, CO₂, H₂S, etc.)

NGL
- Contaminant removal

- Natural gas liquid recovery:

When gases rich in $\text{C}_2\text{H}_6$, $\text{C}_3\text{H}_8$, $\text{C}_4\text{H}_{10}$ & there is a local market, recover those components.
Facilities

Production support systems

- Water injection: principle factors studied in an analysis are
  (1) Dissolved solids
  (2) Suspended solids
  (3) Suspended oil
  (4) Bacteria
  (5) Dissolved gases
- Gas injection
  (1) Supplement recovery by maintaining reservoir P
  (2) Dispose gas

- Artificial lift
  (1) Gas lift
  (2) Beam pumping
  (3) Downhole pumping
Surface Facilities

Land based production facilities

- Wellsites

Allow access for future operations & maintenance activity
- Gathering stations

On a land sites, tank type separation equipment is better than vessel type
Surface Facilities

- Evacuation and storage

[Diagram showing fixed and floating roofs with capacity levels and a legend for oil and dead stock]
Surface Facilities

- Bund Wall
- Storm Drain
- Foundation
- Tank
Offshore production facilities

- Offshore platforms
  (1) Steel jacket platforms
  (2) Gravity based platforms
  (3) Tension leg platforms
  (4) Minimum facility systems
Surface Facilities

Control systems

- Electro-hydraulic system

- Monopod system
  (1) Cost effective
  (2) Limiting factor: water depth
- Offshore evacuation systems

- Offshore loading
  (1) Single Buoy Mooring
(2) Spar type storage terminal  (3) Tanker storage & export