Outline Day 1

• Introduction
  – Overview of energy value chains - oil and gas systems in overall context
  – Key issues impacting global energy and trade flows – National Petroleum Council Global Oil and Gas Study
  – National Oil Companies
  – Commodity vs physical markets

• Upstream issues
  – Trends - North America, worldwide
  – Identification of key risks, uncertainties
  – Upstream investment decision considerations
  – Heavy oil resource case study - technology and optimization
Outline Day 2

• Midstream/downstream commercialization
  – Trends - North America, worldwide (oil v gas)
  – Pipeline economics and cost model
  – Refining economics and issues
  – LNG value chain
  – Gas and power business models
• Conclusions
  – Business integration models and asset/enterprise valuation

The Link Between Energy Value Chain Economics, Finance and Frameworks

Upstream Oil and Gas
Global E&P Activity

- Undiscovered Oil & Gas Resources:
  - Middle East: 28%
  - Former Soviet Union: 22%
  - North America: 12%
  - Europe: 7%
  - Africa, Latin America and Asia: 5%

1.9 trillion boe

- Number of New Wells Drilled in 1995-2003:
  - Middle East: 64%
  - Former Soviet Union: 9%
  - North America: 7%
  - Europe: 5%
  - Africa, Latin America and Asia: 4%

24,500 fields


Change in Strategic Focus:
Fewer High Impact Projects

- 0-50 MMBOE:
  - 1990: 65%
  - 1995: 25%
  - 1999: 10%
  - 2004: 28%

- 50-250 MMBOE:
  - 1990: 12%
  - 1995: 25%
  - 1999: 60%
  - 2004: 12%

- >250 MMBOE:
  - 1990: 60%
  - 1995: 65%
  - 1999: 25%
  - 2004: 65%

From: Fred Gibson, Building Investment Frameworks, 2004 CEE New Era
Where is Value Created?

From: Fred Gibson, Building Investment Frameworks, 2004 CEE New Era

Upstream Evaluation is Complex

- The inability to determine with certainty the geological characteristics of a project area → probability analysis.
- Political factors have significant bearing on the outcome.
- A considerable amount of data needs to be collected and analyzed.
**Exploration Costs**

- Topographical, geographical and geophysical (G&G) studies, rights of access to properties to conduct these studies and salaries and other expenses of people involved in these studies.
- Costs of carrying and retaining undeveloped properties, such as rentals, taxes, legal costs and maintenance of the land and lease records.
- Dry hole contributions and bottom hole contributions.
- Costs of drilling and equipping exploratory wells.
- Costs of drilling exploratory-type stratigraphic test wells.

**Additional Data Needed Before Commerciality**

- initial reservoir pressure and temperature,
- formation properties,
- fluid properties,
- short-term flow tests to estimate the potential rate and reservoir extent,
- geological sample data and depth reference points for modification of pre-drilling data.
Hydrocarbon Classification Framework

Resource Evaluation
Reserves are just an estimate

• If reservoir conditions are good, estimate will be more likely to be real:
  – If the pressure in the formation is higher than the pressure in the well, it will push the oil and gas up the well bores.
  – An aquifer, which expands in size as production continues, will act as a piston and push the fluids up.
  – A gas cap, which expands as production continues can push the oil out of the pores toward the well.
  – If the reservoir has enough vertical permeability, gas rises and oil falls because of density differences. This separation of oil and gas enhances oil recovery.

Reserves are just an estimate, II

• If reservoir conditions are bad, estimate will be less likely to be real (and more expensive to prove):
  – Significant capillary forces in tight sections of the formation, where permeability and porosity are low, reduce the flow of oil and gas.
  – Low permeability and porosity mean that the rock is tight and cannot produce at commercial rates.
  – Limitedness of the area of flow around the well bore can also lower the rate of production.
  – If oil is high in viscosity, it will not flow as easily.
  – The farther oil needs to flow to reach the well, that is, the deeper the objective, the greater will be the resistance to flow.
Enhanced Recovery May Be Needed

• Water flooding (secondary recovery) - injection of water under pressure to maintain pressure.
• Tertiary recovery – injection of chemical solutions (detergents), carbon dioxide or other substances.
• Associated gas produced along with oil may be reinjected into the reservoir.
• A steam flood may reduce viscosity and hence increase the rate of flow.
• Part of the oil can be burned in the reservoir to lower viscosity and help produce the rest of oil.
• “Fracing” involves pumping fluids into the producing zones under extremely high pressures in order to increase, widen and connect the naturally occurring fracture system.

Enhanced Recovery is not free

• The decision to employ these methods depends on the expected increase in production rate.
• It is difficult to accurately estimate enhanced recovery performance of each method.
• The success of each method changes from field to field.
• A careful evaluation of options in each individual situation is necessary.
International Upstream Investment

• The financial issue of how costs are recovered and profits divided.
• Division of profits is commonly referred as contractor take and government take.
• The objective of a host government is to maximize wealth from its natural resources by encouraging appropriate levels of exploration and development activity by private companies → governments must design fiscal systems.
Relative Risk/Reserve Position

Recent fiscal regime changes (more/less favorable)


Sample Countries: Upstream Regimes

Source: Governments cut takes to compete as world acreage demand falls, Oil & Gas Journal, April 24, 1995 by Pedro Van Meurs.
Undiscounted Government Take in 50 Selected Fiscal Systems

Source: Government takes decline as nations diversify terms to attract investment, Oil & Gas Journal, May 26, 1997 by Pedro Van Meurs.

Value of Specific Deepwater Fields Under Various Fiscal Country Models

Oil & gas often generates substantial economic rents...because value often greatly exceeds cost of production

From: Paul Boothe, Fiscal Instruments in Oil & Gas Regimes, UN Workshop on Oil & Gas in Iraq, 2006

Oil & gas rents flow to many different stakeholders...in a wide variety of ways

From: Paul Boothe, Fiscal Instruments in Oil & Gas Regimes, UN Workshop on Oil & Gas in Iraq, 2006
Combinations of fiscal instruments work best

Illustration of “front-end” bids and “back-end” royalties/taxes

From: Paul Boothe, Fiscal Instruments in Oil & Gas Regimes, UN Workshop on Oil & Gas in Iraq, 2006
Types of Fiscal Systems

Concessionary Systems

- Production Sharing Contract (PSC)

Contractual Systems

- Service Contracts (SC)

Economics & Technology of the Crude Oil, Natural Gas and LNG Value Chains

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Concessions

- Royalties are the first, and usually the major, take for a government

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Production Sharing Contracts

- **Gross Revenue**
  - **Net Revenue**
    - **Taxes**
      - **Contractor’s Take**
    - **State’s Profit Share**
    - **Cost Recovery (Limited)**
    - **Royalties <= 15%**

Basic Features of PSCs

- Title of hydrocarbons remains with the state.
- State maintains management control and contractor is responsible for execution of petroleum operations according to contract.
- Contractor is required to submit annual work programs and budgets for scrutiny and approval of a state institution, usually the national company.
- The contract is based on production sharing and not profit-sharing basis.
Basic Features of PSCs (cont’d)

• Contractor provides all financing and technology required for operations and bears the risks.
• During contract term, after allowance for up to a specified % of annual production for recovery of costs, remaining production is split between contractor and state.
• Equipment purchased and imported by contractor become property of the state. Service company equipment and leased equipment are exempt.

PSC Structure

<table>
<thead>
<tr>
<th>National Legislation</th>
<th>Contract Negotiation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operational Aspects</td>
<td>Work commitment</td>
</tr>
<tr>
<td>Government participation</td>
<td>Relinquishment</td>
</tr>
<tr>
<td>Ownership transfer</td>
<td>Commerciality</td>
</tr>
<tr>
<td>Arbitration</td>
<td></td>
</tr>
<tr>
<td>Insurance</td>
<td></td>
</tr>
<tr>
<td>Revenue or Production</td>
<td>Bonus payments</td>
</tr>
<tr>
<td>Sharing Elements</td>
<td>Cost recovery limits</td>
</tr>
<tr>
<td>Royalties</td>
<td>Production sharing</td>
</tr>
<tr>
<td>Taxation</td>
<td></td>
</tr>
<tr>
<td>Depreciation rates</td>
<td></td>
</tr>
<tr>
<td>Investment credits</td>
<td></td>
</tr>
<tr>
<td>Domestic obligation</td>
<td></td>
</tr>
<tr>
<td>Ringfencing</td>
<td></td>
</tr>
</tbody>
</table>
An Oil PSC Model


Evaluation Criteria

- NPV
- IRR
- PWP - the time it takes to recover an investment in terms of present value dollars.
- PWI - the ratio of the present value of cash inflows to the present value of the cash outflows.
A Simple Decision Analysis Framework

Assumptions:
- Reserves
- Capital Expenditure
- Oil/Gas Price

Probabilities:
- High
- Median
- Low

Drill

With expected NPV > 0 at the required discount rate, the choice is to drill. The ENPV is the sum of the probabilities times the values for all branches of the tree.

Oil PSC Production & Cash Flow

Production vs. Cash Flow over time.

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### Oil PSC Model Results

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reserves (mmbbls)</td>
<td>319</td>
</tr>
<tr>
<td>O&amp;M cost ($/bbl)</td>
<td>2.00</td>
</tr>
<tr>
<td>Fiscal Terms</td>
<td></td>
</tr>
<tr>
<td>Royalty</td>
<td>12.5%</td>
</tr>
<tr>
<td>Signing Bonus (millions USD)</td>
<td>$50</td>
</tr>
<tr>
<td>Contractor profit share</td>
<td>65%</td>
</tr>
<tr>
<td>Cost recovery limit (usually 80-100%)</td>
<td>80%</td>
</tr>
<tr>
<td>Income Tax</td>
<td>30%</td>
</tr>
<tr>
<td>Oil Price (bbl)</td>
<td>$25.00</td>
</tr>
<tr>
<td>Discount Rate</td>
<td>10%</td>
</tr>
<tr>
<td>Production Profile:</td>
<td></td>
</tr>
<tr>
<td>No of producing wells</td>
<td>25</td>
</tr>
<tr>
<td>Plateau rate (bbls/day)</td>
<td>50,000</td>
</tr>
<tr>
<td>Annual plateau production (mmbbls)</td>
<td>18.3</td>
</tr>
<tr>
<td>Project Life</td>
<td>30</td>
</tr>
<tr>
<td>Decline rate (3% to 7%)</td>
<td>7%</td>
</tr>
</tbody>
</table>

| NPV @ 10%                     | 596   |
| NPV @ 5%                      | 1,147 |
| NPV @ 12%                     | 463   |
| NPV @ 15%                     | 317   |
| IRR                           | 32.25%|
| Total negative cash flow      | (331) |
| Total Investment              | 365   |
| Profit to Investment Ratio PIR| 6.49  |
| Discounted PIR                | 1.47  |
| Payout time (in years)        | 8     |
| Investment Efficiency         | 2.33  |

### Scenario Analysis – Oil PSC, Price Shocks

- **First**
- **Second**

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Gas PSC Model

Gas PSC Model Results

<table>
<thead>
<tr>
<th>Reserves (bcf)</th>
<th>3,900</th>
</tr>
</thead>
<tbody>
<tr>
<td>O&amp;M cost ($/mscf)</td>
<td>0.10</td>
</tr>
</tbody>
</table>

Fiscal Terms:

| Royalty            | 10.0% |
| Signing Bonus (millions USD) | $10 |
| Contractor profit share | 75% |
| Cost recovery limit (usually 80-100%) | 80% |
| Income Tax         | 30%   |
| Gas Price ($/MMbtu) | $1.00 |
| Discount Rate      | 10.00%|

Production Profile:

| No of producing wells | 18    |
| Plateau rate (mmscfd) | 900,000|
| Annual plateau production (bcf) | 328.5 |
| Project Life          | 19    |
| Decline rate (3% to 7%) | 7%    |

NPV @ 10.00%: 461
NPV @ 5%: 812
NPV @ 12%: 369
NPV @ 15%: 265
IRR: 39.26%

Total negative cash flow: (270)
Total Investment: 298
Profit to Investment Ratio PIR: 4.96
Discounted PIR: 1.32
Payout time (in years): 8
Investment Efficiency: 2.36
Case Study: Extra-heavy oil resource

Outline

• Background
• Evolution of fiscal regime
• Fiscal Regimes
  – Royalty-Tax
    • Accelerated depreciation
  – Equity participation
• Uncertainty
• Final comment
The Faja

• The Faja is one of the largest oil deposits in the Western Hemisphere and is now economically viable, over 70 years after its discovery.
• Hydrocarbon ranges from 5 to 12 API and 125m to 1600m of depth.
• Why did production finally take off?

Development of Unconventional Resources

• Geostatistical and production uncertainty
  – Where should wells be located?
  – How much will wells cost to build?
  – How will they perform?
  – For how long?
• And let us not forget
  – For how much will the oil be sold?
    • Historically blended with lighter crude oil.
Impact of Fiscal Regime

• 1976
  – Royalty Relief: No
  – Long run royalty: 16.67%
  – Taxes: 66.7%
  – Private participation: No

• 1990’s
  – Royalty Relief: 1%
  – Long run royalty: 16.67%
  – Taxes: 34%
  – Private participation: 50%

• Price Level
  – $8-$20 per barrel
Investment in the Faja

<table>
<thead>
<tr>
<th>Year</th>
<th>Investment (Million $)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Up to 2000</td>
<td>1,163</td>
</tr>
<tr>
<td>2001</td>
<td>3,606</td>
</tr>
<tr>
<td>2002</td>
<td>6,577</td>
</tr>
<tr>
<td>2003</td>
<td>10,000</td>
</tr>
<tr>
<td>2004</td>
<td>77</td>
</tr>
</tbody>
</table>

**HORIZONTAL WELLS**

Courtesy of Petrozuata
Focus on Petroleum Fiscal Regimes

- Tax royalty agreements
  – Joint Ventures
- Contractual
  – Production Sharing Agreements
    • All costs are usually covered by investor
    • Facilities and hydrocarbons are owned by the host government
    • Payment for service is through a portion of production
    • Cost recovery can be limited at a portion of the total revenue (possibility of carryover)
  – Service Contracts
**Tax – Royalty with depreciation schedule**

- In the simple case
  - Company pays royalty
  - Company pays taxes or profits after considering depreciation

\[
\text{Cash Flow} = (\text{Revenue} - \text{Royalty} - \text{OPEX} - \text{Dep.}) \times (1 - \text{tax}) + \text{Dep.}
\]

---

**Simplified Discounted Cash Flow Model**

For a simple analysis, capital expenditures can be lumped at the beginning of the project period, operation expenditures are incurred as production comes online, and depending on prices, the income changes over time.
Data Input

- Investment Data
- Operating Cost Data
- Price Data
- Years to the date for start of exports

Expected Project Value 1998

P50 $815.12
Expected Project Value 1998


P50 $7,786.79


Expected Value in 1998 vs 2006
Expected Value in 1998 vs 2006

How was the value distributed?

- 1990's
  - Royalty Relief: 1%
  - Long run royalty: 16.67%
  - Taxes: 34%
  - Private participation: 50%
How was the value distributed?

In 2006, the Government takes over

- **1990’s**
  - Royalty Relief: 1%
  - Long run royalty: 16.67%
  - Taxes: 34%
  - Private participation: 50%

- **Price Level**
  - $8 - $12 per barrel

- **2006**
  - Royalty Relief: None
  - Royalty: 33%
  - Taxes: 50%
  - Private participation: 50%

- **Price Level**
  - $50-60 per barrel
How much value would a company lose?

And what happens if prices go down?
What is the status today?

- Incumbents did not add investments during transition of fiscal regime
- Two of the operating incumbents have been removed
- Add on investments still seem attractive
  - Lessons learned are in jeopardy of being lost
  - New operators versus Associations
- New projects will need market for Syncrude
  - Brasil will likely be the likely market for next project

Final Comments and Open Questions

- Technical uncertainty was resolved and initial projects demonstrated viability of the eastern Faja.
- The value of the Faja is mostly untapped and will likely not be tapped in the short term. And Alberta?
- Should royalty change once uncertainty is resolved? Low initial royalty and then one that captures extra rents? Wouldn’t a corporate tax do the same?
- Production and upgrading, should they be taxed differently? Or are they effectively upstream?