The unique geological characteristics of shale resources result in development plans that require the exploitation of large resource areas, a manufacturing approach to drilling operations that allows for the efficient execution of many similar type wells, and a very long drilling time horizon to fully extract the resources. Understanding the difference between conventional and unconventional resources and sub-surface and surface factors is critical to driving capital efficiency, maximizing revenues and generating positive cash flows for unconventional resources. Capital efficiency starts with strategy and requires agility and foresight to pursue, abandon or defer capital projects. This is important to companies who are chasing margin over revenue in the current market. Furthermore, capital efficiency is needed throughout the asset lifecycle from strategy to execution. Benchmarking developments against an expected standard framework can help determine blind spots where value could be captured and achieve the most benefit.

The presentation shows impacts of different competing factors on capital efficiency in development of a shale resources. The presentation will cover:

- Shale play resources maturation due to its unique geological characteristics.
- Impact of key sub-surface and surface factors on project economics required to be considered in development decisions.

This article will also show how the above are modeled in an Excel spreadsheet tool to aid decision making for a hypothetical shale play development. Our experience shows that this tool enhances decision making for shale development and also capital allocation. From a capital allocation perspective, capital efficiency requires a clear investment strategy; optimizing a portfolio and projects to align with that strategy; developing internal processes, procedures, and, most important, the skills and capabilities to execute; establishing how value is measured and enabling technology enhancements within the organization’s capabilities and risk appetite.
Presentation Outline & GCA Introduction

▪ Development Decision-Making Framework
  – Decision Process
  – Deepwater vs. Unconventional
  – 2019 status quo

▪ Dynamic Modeling Case Study
  – Type Well Assumptions
  – Development Scenarios
  – Costs and Pricing Sensitivities
Development Decision-Making Framework

<table>
<thead>
<tr>
<th>Resource Type</th>
<th>Sub-Surface Features</th>
<th>Cash Flow Timeline</th>
<th>Development Decisions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional Deepwater</td>
<td>Higher geological risk to find the “trap”</td>
<td>Capex first, production later</td>
<td>Largely fixed after project sanction</td>
</tr>
<tr>
<td>Unconventional (Shale / LTO)</td>
<td>Lower geological risk associated with continuous accumulations</td>
<td>Concurrent capex and production flows</td>
<td>Iterative decision-making</td>
</tr>
</tbody>
</table>

LTO: Light Tight Oil

Development decisions are driven by sub-surface resource characteristics, and are thus inherently different for shale.
Development Schedule Comparison

Spreading shale investments over a long development period provides more opportunities for improvements in decision-making and operations.
2019: US unconventional resources stays in spotlight and continues to evolve

Operators gradually shift focus from production growth to profit generation through cost reduction and capital discipline.
GCA Unconventional Development Model

**Oil & Gas Price Expectation**

- On-stream well count
  - Available drilling locations
  - Drilled but uncompleted (DUC) wells
  - Drilling activity
  - Completion activity
  - Acreage
  - Well spacing
  - Rig count
  - Rig efficiency
  - Number of frac crews
  - Completions efficiency
  - Drilling days
  - Rig moving time
  - Completion days
  - P/L hook-up time

**Activity allocation**

- Held-by-drilling (HPD) leases
- Pad / Cube development
- Rig contract

**Average production per well**

- Type curves
  - Infill wells
  - Re-completion
  - Enhanced oil recovery

**Production**

- Hydrocarbons-in-place
- Producibility (transmissibility)
- Targeted reservoir at well location
- Well design

**Input / Assumption**

- Pore volume
- Maturation
- Organic richness
- Mineralogy
- Fluid phase
- Pore pressure
- Well orientation
- Lateral length
- Completion method
- Frac stages & stage spacing
- Proppant type & loading
- Fluid type & loading

**Considerations**

- Oil & Gas Price Expectation
- Oil & Gas Price Expectation
- Oil & Gas Price Expectation
Case Study: Hypothetical Development of A 640-acre Section in a Typical Shale Play

**Type Well Assumptions**

- A selection of Wolfcamp wells
- Peer type wells targeting the same level of ultimate recovery in the section

**Illustrative Well Placement**

- **Parent-Child**
- **Peers**

**Crude Price Cases**

- Gas price is assumed to be flat at $3/MMBtu in all scenarios
- Capital and operating cost parameters are modelled after public-domain information about the Permian basin
Flexible Development: Parent-Child Wells

Project Economics

- **Per Well Production in 5 Years**: 494 MBoe
- **Operator After-CIT IRR**: 104%
- **NPV10 US$/Boe**: $6.7/Boe
- **Profitability Index**: 1.8

Profitability Index: Present value of future cash flows divided by initial investments

---

Parent Campaign

- **Cash Flow**: 723 MBoe
- **Operator After-CIT IRR**: 148%
- **NPV10 US$/Boe**: $9.6
- **Profitability Index**: 2.7

---

Child Campaign

- **Cash Flow**: 390 MBoe
- **Operator After-CIT IRR**: 26%
- **NPV10 US$/Boe**: $3.7
- **Profitability Index**: 1.3
Planned Development: Conventional Approach

Project Economics

- Per Well Production in 5 Years: 501 MBoe
- Operator After-CIT IRR: 40%
- NPV10 US$/Boe: $5.9/Boe
- Profitability Index: 1.7

Flexible Dvlp.

- 494 MBoe: 104%
- $6.7/Boe: 1.8
Flexible vs. Planned: Cost Efficiency

5% cost reduction on Child wells

Per Well Production in 5 Years  494 Mboe
Operator After-CIT IRR  109%
NPV10 US$/Boe  $7.0/Boe
Profitability Index  1.9

10% cost reduction on all wells

Per Well Production in 5 Years  501 Mboe
Operator After-CIT IRR  52%
NPV10 US$/Boe  $7.0/Boe
Profitability Index  1.9

40% cost reduction on all wells

Per Well Production in 5 Years  501 Mboe
Operator After-CIT IRR  112%
NPV10 US$/Boe  $10/Boe
Profitability Index  2.9
Flexible vs. Planned: Price Sensitivity

Child wells completed on price recovery trend

- Per Well Production in 5 Years: 494 Mboe
- Operator After-CIT IRR: 128%
- NPV10 US$/Boe: $6.7/Boe
- Profitability Index: 1.8

Wells planned at high prices, produced at low

- Per Well Production in 5 Years: 501 Mboe
- Operator After-CIT IRR: 29%
- NPV10 US$/Boe: $4.5/Boe
- Profitability Index: 1.5

Delayed completion

- Per Well Production in 5 Years: 442 Mboe
- Operator After-CIT IRR: 29%
- NPV10 US$/Boe: $4.9/Boe
- Profitability Index: 1.5
It is not easy to predict commodity prices...

<table>
<thead>
<tr>
<th>Projects start in Jan. 2016</th>
<th>Flexible</th>
<th>Planned</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operator After-CIT IRR</td>
<td>75%</td>
<td>48%</td>
</tr>
<tr>
<td>NPV10 US$/Boe</td>
<td>$7.8</td>
<td>$7.6</td>
</tr>
<tr>
<td>Profitability Index</td>
<td>2.0</td>
<td>1.9</td>
</tr>
</tbody>
</table>

- WTI Spot
- WTI Futures
- HH Spot (RHS)
It is not easy to predict commodity prices...

 Movements of Prices

Projects start in Jan. 2017
Operator After-CIT IRR
NPV10 US$/Boe
Profitability Index

<table>
<thead>
<tr>
<th></th>
<th>Flexible</th>
<th>Planned</th>
</tr>
</thead>
<tbody>
<tr>
<td>IRR</td>
<td>96%</td>
<td>64%</td>
</tr>
<tr>
<td>NPV10 US$/Boe</td>
<td>$8.3</td>
<td>$9.1</td>
</tr>
<tr>
<td>Profitability Index</td>
<td>2.0</td>
<td>2.0</td>
</tr>
</tbody>
</table>
Conclusions

- Dynamic modeling of economics, in addition to modelling production, is necessary in developing unconventional resources such as shale
  - Because it is a complex system with multiple factors interacting with each other at small scales

- The tool used to make strategic development decisions has to be comprehensive, flexible, and quick to run
  - Thus, it should not be only a financial cash flow model, a decline analysis software, or a field planning software

- It is important to understand what drives development decisions
  - Maximizing recovery, investment returns, or operational efficiency may lead to different strategies