Lockhart Crossing: Economically Efficient Reservoir Operations

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*Denbury Resources Inc.*

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Midland, Texas
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Economically Efficient Reservoir Operations Agenda

- Lockhart Crossing Introduction and Background
- Asset Development Principles / Business Plan
- Reservoir Surveillance Metric Creation and Comparison
- Economically Efficient Process Evolution
  - Asset Observations
  - Optimization Process Design and Management Plan
  - Implementation
  - Results
Lockhart’s Geographic Location

Phase 3
44 MMBbls

Phase 4
31 MMBbls

Phase 5
33 MMBbls

Phase 1
86 MMBbls

Phase 2
77 MMBbls

Phase 6
26 MMBbls

Phase 7
Hastings Area
60 - 100 MMBbls

Phase 8
Seabreeze Complex
25 - 35 MMBbls

(1) Proved plus probable tertiary oil reserves as of 12/31/08, including past production, based on a range of recovery factors. Hastings Field was purchased 2/2/09.
Lockhart Crossing 1st Wilcox Structure

OOIP: 56.1 MMBBLs
Production: 18.2 MMBBLs (32%)

Discovery July 1982 Callon Petroleum
3,500 Acres
Unitized 1985
1st Wilcox Bar Isopach

OOIP: 41.8 MMBBLs

Phi: 15 - 24%, avg. 20%

K: 1 - 100 md, avg. 80 md
1st Wilcox Channel Isopach

OOIP: 14.3 MMBBLs

Phi: 10 - 27%, avg. 21%
K: 0.1 – 4,400 md, avg. 500 md
## Lockhart Field Wilcox 1

<table>
<thead>
<tr>
<th>Field Found</th>
<th>1982</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial Operator</td>
<td>Callon</td>
</tr>
<tr>
<td>Formation</td>
<td>Wilcox</td>
</tr>
<tr>
<td>Depth</td>
<td>~10,100'</td>
</tr>
<tr>
<td>OWC</td>
<td>-10,159'</td>
</tr>
<tr>
<td>DRIVE</td>
<td>Solution Gas - Moderate Water</td>
</tr>
<tr>
<td>TTL Field Area (acre)</td>
<td>3,500</td>
</tr>
</tbody>
</table>

### Production History

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Black Oil produced (stb)</td>
<td>18,200,000</td>
</tr>
<tr>
<td>Solution Gas Produced (stb)</td>
<td>17,300,000,000</td>
</tr>
<tr>
<td>Water Produced (stb)</td>
<td>21,200,000</td>
</tr>
<tr>
<td>Water Injected (stb)</td>
<td>38,988,000</td>
</tr>
<tr>
<td>Recovery Primary (stb)</td>
<td>6,808,038</td>
</tr>
<tr>
<td>Recovery Secondary (stb)</td>
<td>11,391,962</td>
</tr>
<tr>
<td>Rf Primary</td>
<td>12%</td>
</tr>
<tr>
<td>Rf Secondary</td>
<td>20%</td>
</tr>
</tbody>
</table>

### Reservoir Description

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Original Pressure (psi)</td>
<td>4,600</td>
</tr>
<tr>
<td>Lowest Pressure (psi)</td>
<td>2,500</td>
</tr>
<tr>
<td>Original Bubble Point (psi)</td>
<td>3,550</td>
</tr>
<tr>
<td>Porosity</td>
<td>20%</td>
</tr>
<tr>
<td>Permeability (md)</td>
<td>80 / 500</td>
</tr>
<tr>
<td>Sw Original (%)</td>
<td>43 / 28</td>
</tr>
<tr>
<td>Avg H Koi (ft)</td>
<td>42</td>
</tr>
<tr>
<td>Bo Original (rb/stb)</td>
<td>1.53</td>
</tr>
<tr>
<td>Gravity (API)</td>
<td>42</td>
</tr>
<tr>
<td>Temp (f)</td>
<td>212</td>
</tr>
<tr>
<td>OOIP (stb)</td>
<td>56,000,000</td>
</tr>
<tr>
<td>OGIP (Solution) (scf)</td>
<td>53,000,000,000</td>
</tr>
<tr>
<td>Solution GOR (scf/stb)</td>
<td>951</td>
</tr>
</tbody>
</table>

### Well Count during Primary and Secondary

<table>
<thead>
<tr>
<th>Category</th>
<th>Count</th>
</tr>
</thead>
<tbody>
<tr>
<td>Primary Total</td>
<td>37</td>
</tr>
<tr>
<td>Secondary Total</td>
<td>49</td>
</tr>
<tr>
<td>Secondary Producers</td>
<td>27</td>
</tr>
<tr>
<td>Secondary Injection</td>
<td>22</td>
</tr>
</tbody>
</table>
DRI Asset Development Philosophies

• Develop assets without utilizing full array of industry tools. This is in efforts to attain relatively higher value through accelerated cash flows that would otherwise be delayed (and slightly more costly)
  – Associated with fields that have:
    • Similar analogue reservoirs in DRI’s asset base
    • Lower relative reservoir complexity
    • Smaller size (economies of scale)

• Integrate the full array of industry’s technical tools as resources for optimal field development
  – Associated with fields that have:
    • Generally unique features relative to DRI’s tertiary asset base
    • Higher relative reservoir complexity
    • Larger in size (the bigger the difference a X% change in recovery makes)
Lockhart’s Business Plan / Development Principles

- Lockhart provides a relatively small tertiary target that requires efficiencies in design, development, and operation to be strong economically

- Utilize known analogues for technical guidance to reduce cost and accelerate timing

- Utilize old wellbores to develop asset at low cost

- Small facilities in design and footprint to minimize CAPEX and LOE
  - Asset Design Capacities
    - 3,500 BOPD
    - 11,000 BWPD
    - 60 MMSCFPD recycle
    - 60 MMSCFPD purchase
Lockhart Crossing Field CO₂ Flood - Milestones

- Well work commenced in January 2007
- Drilling commenced April 2007
- Denbury commenced construction of CO₂ Recycling Facility in May 2007
- After receiving COE permit, pipeline construction commenced September 2007
- Construction of six-mile 8” CO₂ supply pipeline completed 3rd quarter 2007
- Injection of CO₂ began in December 2007
- First CO₂ production occurred in June 2008 – first sales July 2008
- Test Site 1 operational June 2008, Test Site 2 operational January 2009
- Lockhart produced its 1,000,000th BBL of CO2 Oil in June 2010!
Lockhart Original Pattern Design
Lockhart Crossing Field Life

Lockhart Crossing Fluid Rates

Date

BPD

MSCFPD

Oil (bpd)  Water (bpd)  Water Inject (bpd)  CO2 Injection (mscfpd)  CO2 Production (mscfpd)
### Lockhart Crossing Reservoir Surveillance

#### Life Metrics

<table>
<thead>
<tr>
<th>Metric</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Start Date</td>
<td>6/1/2008</td>
</tr>
<tr>
<td>Current date</td>
<td>11/30/2010</td>
</tr>
<tr>
<td>Life to date</td>
<td>2.50 years</td>
</tr>
<tr>
<td>Life to date</td>
<td>7.1%</td>
</tr>
<tr>
<td>Expected Life</td>
<td>35 years</td>
</tr>
</tbody>
</table>

#### Cumulative Metrics

<table>
<thead>
<tr>
<th>Metric</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cum CO2 injected</td>
<td>51,042,000 MCF</td>
</tr>
<tr>
<td>Cum Recycle</td>
<td>19,928,234 MCF</td>
</tr>
<tr>
<td>Cum Purchase</td>
<td>31,113,766 MCF</td>
</tr>
<tr>
<td>Cum Water</td>
<td>6,540,421 BBLs</td>
</tr>
<tr>
<td>Cum Oil</td>
<td>1,411,753 STB</td>
</tr>
<tr>
<td>Cum Current Pattern Total HCPVI</td>
<td>44.00%</td>
</tr>
<tr>
<td>Cum Current Pattern Oil Rec</td>
<td>3.96%</td>
</tr>
<tr>
<td>Oil Rec to HCPVI</td>
<td>0.09 &lt;</td>
</tr>
<tr>
<td>Field Total HCPVI</td>
<td>28%</td>
</tr>
<tr>
<td>Field Oil Rec</td>
<td>2.5%</td>
</tr>
<tr>
<td>Total HCPVI to Oil Rec</td>
<td>0.09 dmsless</td>
</tr>
<tr>
<td>Gross Utilization</td>
<td>36 mcf/stb</td>
</tr>
<tr>
<td>Net Utilization</td>
<td>22 mcf/stb</td>
</tr>
</tbody>
</table>

#### Rate Metrics

<table>
<thead>
<tr>
<th>Metric</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Daily Oil Rate</td>
<td>2,866 STBPD</td>
</tr>
<tr>
<td>Daily Purchase</td>
<td>28.3 mmscfpd</td>
</tr>
<tr>
<td>Daily Recycle</td>
<td>48.1 mmscfpd</td>
</tr>
<tr>
<td>Current Pattern HCPVI/day</td>
<td>0.07%</td>
</tr>
<tr>
<td>HCPV oil recovered/day</td>
<td>0.008%</td>
</tr>
<tr>
<td>HCPV rec/inj/day</td>
<td>0.12 &gt;</td>
</tr>
</tbody>
</table>

LCU phase 3
Dimensionless Top Performer

Dimensionless Comparison LCU Phase 3 vs. LCKT

Oil Recovery (% of HCPV) vs. CO2 Injected (% of HCPV)

LCU Phase #3
LCKT Field
Challenge Comes with Smaller Scale
Presentation Preface

• The communication objective and technical content of this presentation are basic reservoir and economic concepts.

• Though the concepts demonstrated are elementary these concepts provide a high magnitude of economic impact.

• The focus of this presentation is to highlight simple methods of evaluation to ensure maximization of asset value.

• Hindsight is 20/20, when looking back operation modifications may seem implicit, but it might not have been so clear during the implementation.
Reservoir Pressure Surveillance

**IWR**

- \( IWR = \frac{CO2 (RB)}{Gas (RB) + Oil (RB) + Water (RB)} \)
- \( IWR \) (instantaneous) delivers direction your reservoir pressure is going at a given instant.
- \( IWR \) (cumulative) delivers the relative reservoir pressure from the point in time the accumulation began.

**Net Cum Fluid**

- \( Net \ Cum \ Fluid = Cum \ CO2 \ RB - (Cum \ Gas (RB) + Cum \ Oil (RB) + Cum \ Water (RB)) \)
- Delivers direction the reservoir pressure is going at a given instant by the slope of the curve.
- Delivers the relative reservoir pressure from the point in time the accumulation began.
- Delivers magnitude of fluid thus the magnitude of relative pressure change based on reservoir size.

To maintain MMP

To maintain flowing wells
Fluid to Pattern Allocation

- Fluid dynamics within a reservoir are difficult to calculate

- Pattern allocation is a simple method used to account / estimate source of fluid flow
  - Used for Net Cum Fluid calculation
  - Serves as guides to remaining saturations within patterns

- There are many methods for allocation

### Geometric allocation

> Splits Pattern 1 and 2 production of fluid evenly

\[
C_{\text{allocation to Pattern 1}} = \frac{\text{# of wells}}{\text{# of patterns sharing the well}} = \frac{1}{2} = 50\%
\]

### HCPV & I allocation

> Splits Pattern 1 and 2 production based on injection rate and magnitude of HCPV

\[
C_{\text{allocation to Pattern 1}} = \frac{\text{HCPV1} \times \text{Injection rate1}}{\text{HCPV1} \times \text{Injection rate1} + \text{HCPV2} \times \text{Injection rate2}} = \frac{10 \times 150}{(10 \times 150 + 5 \times 100)} = 75\%
\]
Allocation Accuracy Evidence

Net Cumulative Fluid Comparing Allocation Methods

Date

Net Cum Fluid (RB)
0 200,000 400,000 600,000 800,000 1,000,000 1,200,000 1,400,000 1,600,000

Thom 1 I&HCPV
1,400 MRB
1,600 MRB

Thom 1 Geo
5,847 psi
1,050 MRB

5,506 psi
1,016 MRB
Economically Efficient Asset Development

• Economically Efficient (Theoretical)
  – No additional output can be obtained without additional input
  – Production proceeds at the lowest per unit cost
  – The cost of producing a given output is as low as possible
  – ...

• Economically Efficient (Financial)
  – Max IRR
  – Max NPV
  – Abide within cash flow constraints

• Economically Efficient Ranking of Choice = Max NPV
  – Maximize
    • Revenue
    • Delay of negative cash flows
  – Minimize
    • Capital
    • Operating Expense
    • Delay of positive cash flows
    • Cost of Capital
Maximize Oil Reservoir NPV

• Asset Optimization Problem
  – Maximize oil recovery magnitude
  
  – *Minimize recovery time (acceleration)*
  
  – *Minimize cost*
  
  – Maximize delay in capital outlays
Optimize recovery time and cost

Maximize Pressure Drop and Conductivity

Reservoir

Source

Purchase

Recycle

Compress

Manifold

Facility

Minimize cost of attaining pressure drop and conductivity

Constrained by: coning, MMP, and sand production
Reservoir Management

**Net Cumulative Fluid Thom #1 Pattern**

- **1,050 MRB**
- **5,847 psi**
- **Optimum Reservoir Management?**
- **Fill Up**
- **MMP**
- **Open Wells**
- **5,200 psi**
Team Objective Communication 06-09

• Objective
  1. Maximize injection through utilization of all equipment
  2. Accelerate production through accelerated injection
  3. Optimally produce reservoir

• Solution
  1. Open Chokes (increasing production rate)
  2. Reduce IWR <1
  3. Reduce Reservoir Operating Pressure (also helps utilization CO2 expansion)
  4. Increase injection (given 3,000 psi surface injection pressure)
  5. Accelerate production through optimal reservoir operating pressure

• Constraints
  • MMP
  • Surface operation constraints
    • Purchase
    • Recycle
    • Water Handling
Process Management

Net Cumulative Fluid Thom #1 Pattern

Optimum reservoir Management?

Open chokes

1,050 MRB
5,847 psi

Open Wells
5,200 psi

Fill Up

Date

Net Cum Fluid (RB)
Lockhart Crossing CO2 EOR

Lockhart Crossing Fluid Rates

Induced Acceleration

- Oil (bpd)
- CO2 Injection (mscfpd)
- CO2 Production (mscfpd)
- CO2 Purchase (mscfpd)
Opening of Chokes

Cum Net Fluid Injected

Thom #1

Net Cum Fluid

Injection Rate
Results of 2009 to 2010 choke changes

Lockhart Choke Size Increase

<table>
<thead>
<tr>
<th>Category</th>
<th>% Increase</th>
</tr>
</thead>
<tbody>
<tr>
<td>Choke Size</td>
<td>310-374</td>
</tr>
<tr>
<td>Oil Rate Category</td>
<td>1441 bopd</td>
</tr>
<tr>
<td>CO2 Injection</td>
<td>50 mmscfpd</td>
</tr>
</tbody>
</table>

2009 vs 2010

- Choke Size
- Oil Rate
- CO2 Injection
Optimize recovery time and cost

The larger the pressure drop the faster the oil is retrieved.
Optimize recovery time and cost

![Graph showing the relationship between cost and acceleration. The graph illustrates an upward trend, indicating that as acceleration increases, cost also increases.]
Optimize recovery time and cost

The second largest pressure drop provides maximum value
Max incremental rate and therefore max value attainable by the Thom #1

Max incremental rate and therefore max value attainable by the two 3.5 mm/day injection pattern
Lockhart’s Bar Injection Hurdle

- Bar Injection wells injecting at ~5 mmcfpd
- Channel wells maximum injection rate ~17 mmcfpd down 2-7/8” tubing
- Transitionally the bar formation is the bottle neck
  - (not the 2-7/8” tubing)
- Remaining Lockhart development is in the Bar Formation
- NPV is hindered due to a choke at the formation
  - Stimulation is not currently an option
Horizontal vs. Vertical

<table>
<thead>
<tr>
<th></th>
<th>Horizontal</th>
<th>Vertical</th>
</tr>
</thead>
<tbody>
<tr>
<td>Effective Formation Contact</td>
<td>200’</td>
<td>40’</td>
</tr>
<tr>
<td>Injection Rate</td>
<td>5X</td>
<td>1X</td>
</tr>
<tr>
<td>Production Rate</td>
<td>5X</td>
<td>1X</td>
</tr>
</tbody>
</table>

\[ K \times H \times dp \]

\[ u \times \ln \left( \frac{r_e}{r_w} \right) \]

Lateral Length = 1000’
Horizontal Well / Asset Optimization

Well Count

Cost

Fluid Rate

Facilities

Cost

Oil Rate Rate

Revenue Acceleration

NPV

The Optimal Asset Harmony (where NPV is maximum)
Horizontal Well Asset Optimization

Lockhart Future Development Economic Comparison

Lockhart Incremental Future Development PV10 with vertical well development

Injection rate per horizontal (mmscf/pd)

PV10 (M$)

Total Future Horizontal Well Count
Economically Efficient Reservoir Operations Results
Economically Efficient Reservoir Operations

Includes optimization of all of this map plus more…

- Today’s presentation covered some of the topics in the circled area
- There’s significantly more value to be added to the asset outside (and inside) that circle
- I look forward to watching the DRI team further maximize the value of Lockhart Crossing by accomplishing their goals
Special Recognition

Management (names left to right)
Donnie Dubois - Field, Bob Sutherland - Reservoir, John McDaniel - Land, Joey Smith - Operations, James Fields - Land, Charlie Gibson - V.P. West, Don Butvin - Facilities, Bob Schellhorn - Geology, Mary Tombs - Production
Special Recognition

Plano Team  (names left to right)
Special Recognition

Field Team (left to right)
Jason Shaffer, Todd Bergeron, Jimmy Naquin, Eroll Tisdale, Bobby McDougal, Mike Crawford, Henry Schultz, Chris Odom, Donnie Dubois, Dustin Swallow, Cecil Rushing, Dale Louviere, John Duplantis
Questions