Technical and Economic Analysis of Two Options for In Situ Oil Shale Retorting

Eric Robertson
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Authors and Acknowledgements

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  – Michael McKellar
  – Lee Nelson
Outline

• Project Description
• Mass and energy balances
• Background on nuclear option
• Integration of nuclear heat
• Economic results
• Conclusions and Summary
In Situ Oil Shale Retorting

- Heat kerogen in oil shale rock to 700°F over 2 to 4 years
- 3 main heat injection alternatives
  1. In situ combustion
  2. Electric heaters (electricity presumably from coal combustion)
  3. Hot fluid injection (presumably heated by natural gas combustion)
    - Direct – flow through formation
    - Indirect – circulation through closed loop pipes
Two Options for In Situ Oil Shale Retorting

• Both options
  – Circulate high pressure steam through closed-loop pipes to deliver pyrolysis heat
• Heat to generate steam from
  – Combustion of natural gas (Option 1)
  – Nuclear reactor (Option 2)
Mass Balance

<table>
<thead>
<tr>
<th>Product</th>
<th>Kerogen basis</th>
<th>FA oil basis</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>g/g</td>
<td>g/g</td>
</tr>
<tr>
<td>Char</td>
<td>0.286</td>
<td>0.386</td>
</tr>
<tr>
<td>Gas</td>
<td>0.196</td>
<td>0.265</td>
</tr>
<tr>
<td>Shale oil</td>
<td>0.518</td>
<td>0.700</td>
</tr>
<tr>
<td>Total</td>
<td>1.000</td>
<td>—</td>
</tr>
</tbody>
</table>

- Based on published data for Colorado oil shale
  - H/C ratios for kerogen (1.60), char (0.44), and gas (3.00)
  - API gravity of shale-oil (40°API) and FA oil (20°API)
  - Shale-oil/FA ratio (0.70 g/g)
  - FA/kerogen ratios (0.74 g/g)
## Pyrolysis Products / Ton of Raw Oil Shale

<table>
<thead>
<tr>
<th>Pyrolysis product</th>
<th>— Volume —</th>
<th>Energy</th>
<th>Mass</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Gal</td>
<td>million Btu</td>
<td>lb_m</td>
</tr>
<tr>
<td>In situ pyrolysis products</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Shale oil</td>
<td>20.0</td>
<td>2.68</td>
<td>138</td>
</tr>
<tr>
<td>Gas</td>
<td>—</td>
<td>1.15</td>
<td>52</td>
</tr>
<tr>
<td>Char</td>
<td>—</td>
<td>1.03</td>
<td>76</td>
</tr>
<tr>
<td>Fischer Assay oil</td>
<td>25.2</td>
<td>3.68</td>
<td>197</td>
</tr>
</tbody>
</table>
Background on Nuclear Energy

- Next Generation Nuclear Plant
  - High-temperature, gas-cooled reactors (HTGRs)
  - Small, modular reactors (SMRs)

- Integration of HTGRs focus of this work
**HTGR Module = 600 MW\textsubscript{th}**

<table>
<thead>
<tr>
<th>Output</th>
<th>Rate</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electricity</td>
<td>258 MW</td>
<td>43% efficient Rankine cycle</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>61.5 million scf/D</td>
<td>High temperature electrolysis</td>
</tr>
<tr>
<td>Heat</td>
<td>600 MW steam</td>
<td>575°C and 23.5 MPa (1067°F and 3410 psia)</td>
</tr>
</tbody>
</table>
Reasons for Nuclear Reactor Integration

• Provides high pressure steam (or other fluid or form of energy)
  – Reliable
  – Fairly constant cost
  – No CO$_2$ emissions
Basic Block Flow Diagrams and HTGR Integration
Basic Block Flow Diagrams and HTGR Integration

- HTGR / Heat Exchanger
- Gas Conditioning (CO₂ removal)
- Generated Hydrocarbons
- Separation
- Distillation Column
- Produced Fluids
- Stabilized Shale Oil (sale)
- Water
- CO₂
- Gas (sale)
- Light Hydrocarbons
Schematic of Heat Flow Loops

- Modeled using HYSIS (part of Aspen+)
- Values in red were set and fixed
Observations from Flow Loop Modeling (both options)

- Phase diagram of steam through flow loop
- No physical phase change
  - Supercritical as exits heat exchanger and enters the retort zone
  - Compressible liquid as exits retort zone
  - True liquid as enters power cycle and pump
  - Compressible liquid as enters heat exchanger
Observations from Flow Loop Modeling (both options)

- Pipe diameters ≤ 4 in. are not feasible
  - excessive pressure losses
- $T_{ave}$ through retort zone > 470°C are not feasible
  - Temperature constraints on pump inlet $\Rightarrow$ dump excess heat in fluid
  - Electricity generation way to use excess heat
    - Results in electricity generation project with some oil production as a by product
Energy Return on Investment (EROI)

- Base case = 4.44
- HTGR case = 4.80

With HTGR integration
- Much more gas for sale
- Less electricity for sale
- Much less CO$_2$ generated
- Same oil output

Mass and Energy Balance – The Big Picture

- Energy Return on Investment (EROI)

$$\text{EROI} = \frac{\text{Energy out}}{\text{Energy in}}$$
Economic Analysis – Capital Costs

- Total capital investment
  - Base Case = $18,000/DBL
  - HTGR Case = $54,000/DBL

(a) Base Case Capital Costs
- Gas combustor/Steam boiler 21.7%
- Separator and pumps 0.342%
- Power cycle 17.8%
- Gas conditioning plant 2.02%
- Distillation column 6.4%
- Well costs 51.8%

(b) HTGR Case Capital Costs
- Gas conditioning plant 2.72%
- Distillation column 2.09%
- Well costs 20.1%
- Separator and pumps 0.112%
- HTGR 75%

(Includes power cycle and heat exchanger/steam boiler)
# Economic Assumptions – After-Tax Discounted Cash Flow (ATDCF) Analysis

<table>
<thead>
<tr>
<th>Economic parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Plant economic life</td>
<td>30 years (excludes construction time)</td>
</tr>
<tr>
<td>Construction period</td>
<td>Fossil portion: three years HTGR plant: four years</td>
</tr>
<tr>
<td>Start-up assumptions</td>
<td>Operating costs: 120% of steady-state</td>
</tr>
<tr>
<td></td>
<td>Revenues: 65% of steady-state</td>
</tr>
<tr>
<td>Plant availability</td>
<td>90%</td>
</tr>
<tr>
<td>Discount rate</td>
<td>12%</td>
</tr>
<tr>
<td>Inflation rate</td>
<td>3%</td>
</tr>
<tr>
<td>Interest rate on debt</td>
<td>8%</td>
</tr>
<tr>
<td>Debt repayment term</td>
<td>15 years</td>
</tr>
<tr>
<td>Tax basis assumptions</td>
<td>Effective income tax rate: 38%</td>
</tr>
<tr>
<td>Depreciation</td>
<td>HTGR = 15-yr, Wells = 7-yr, Other = 10-yr</td>
</tr>
<tr>
<td>Natural gas price</td>
<td>$5.50/million Btu</td>
</tr>
<tr>
<td>Carbon tax</td>
<td>$0/ton</td>
</tr>
</tbody>
</table>
Economics – Rate of Return v. Crude Oil Price
**Economic Sensitivity – In Situ Oil Shale**

### Critical Input Variables in Descending Order

<table>
<thead>
<tr>
<th>Base Case</th>
<th>HTGR Case</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Project discount rate</td>
<td>1. Project discount rate</td>
</tr>
<tr>
<td>2. CO$_2$ emissions tax</td>
<td>2. Natural gas price</td>
</tr>
<tr>
<td>3. Drilling and completions cost</td>
<td>3. Surface facilities costs</td>
</tr>
<tr>
<td>4. Natural gas price</td>
<td>4. Drilling and completions cost</td>
</tr>
<tr>
<td>5. Debt to equity ratio</td>
<td>5. Debt to equity ratio</td>
</tr>
<tr>
<td>6. Surface facilities costs</td>
<td>6. Debt repayment term</td>
</tr>
</tbody>
</table>

![Graph for Economic Sensitivity](image1)

![Graph for Economic Sensitivity](image2)
Economic Sensitivity – In Situ Oil Shale
Economic Sensitivity – In Situ Oil Shale

The diagram illustrates the relationship between the required oil price for a 12% IRR, in dollars per barrel, and the CO2 emissions tax, in dollars per ton. Two scenarios are shown:

- **Base case**: A linear increase in required oil price with an increase in CO2 emissions tax.
- **HTGR case**: A flatter trend line indicating less sensitivity to CO2 emissions tax compared to the base case.

The graph shows that as the CO2 emissions tax increases, the required oil price for a 12% IRR also increases, but the rate of increase is not uniform across different scenarios.
Summary – Technical Feasibility

- Same oil production output for both cases
- CO$_2$ emissions much lower for HTGR case compared to Base case
- Natural gas available for sale is much higher for HTGR case
- EROI is slightly higher for HTGR case

For R1 zone under AMSO’s RD&D lease
- thickness of 235 ft
- 25.2 gal/ton (FA grade)
- 50,000 bbl/day
  - Development rate of 69 ac/yr
  - If heat source located in center of area, furthest distance to transport steam is
    - 1.0 mi after 30 years
    - 1.4 mi after 60 years
Summary – Economic Feasibility

• Both cases are feasible at today’s crude oil price
  – $38/bbl for Base case
  – $59/bbl for HTGR case

• HTGR case
  – Has larger capital investment
  – Economics are poorer using default input parameters
  – Economics can become more attractive if
    • higher natural gas prices
    • higher carbon taxes
    • Etc.
Final Thoughts

• Can this be done with traditional light-water reactors?
  – No, heat output is too low.

• Time to develop commercial oil shale industry is 10 to 15 years

• Time to develop and build commercial HTGR is 10 to 15 years

• In 10 to 15 years, the reasons to integrate these two energy systems may be even more pronounced
  – Start thinking about it now
Thank you

• Questions?

• Contact information
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